Statement of Basis

Greenhouse Gas Prevention of Significant Deterioration Preconstruction Draft Permit
for New Natural Gas to Gasoline Facility

Permit Number: PSD-TX-1340-GHG

August 2014

This document serves as the Statement of Basis (SOB) for the above-referenced draft permit, as required by 40 Code of Federal Regulations (CFR) § 124.7. This document sets forth the legal and factual basis for the draft permit conditions and provides references to the statutory or regulatory provisions, including provisions in 40 CFR § 52.21, that would apply if the permit is finalized. This document is intended for use by all parties interested in the permit.

I. Executive Summary

On February 18, 2013, Natgasoline, LLC (Natgasoline) submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions for a greenfield natural gas to gasoline (GtG) facility. A revised application was submitted on November 1, 2013 with additional supplemental responses addressing questions posed by EPA (hereinafter, referred to as "the application"). In connection with the same proposed project, Natgasoline submitted a PSD permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on January 18, 2013. Natgasoline proposes to construct a new methanol and motor-grade gasoline production facility in Beaumont, Texas, that uses natural gas as feedstock. The facility is estimated to have a capacity of 5,500 metric tons of methanol production per day (MTPD) and 22,000 barrels per day (BPD) of gasoline.

The proposed GtG facility will include two main process plants. The first process plant will be the "Methanol Plant" (MeOH), designed as a single plant that will produce up to 5,500 MTPD methanol. Natural gas feed to the methanol reformers will be synthesized to form a mixture of carbon monoxide (CO), carbon dioxide (CO_2), and hydrogen (H_2) known as synthesis gas (syngas). The syngas will then be compressed and heated to form methanol and condensate water products. Methanol will be purified in a series of distillation columns, and the condensate and gases from this process will be recycled for use in various sections of the methanol plant. The final methanol product will be sent to storage and can either be sold or used as feed in the "Methanol-to-Gasoline (MtG) plant" being proposed for construction in this permit. The MtG plant will convert methanol into motor vehicle gasoline and liquefied petroleum gas through a series of reactors, heaters, and distillation columns. After reviewing the application, EPA prepared the following SOB and draft PSD permit that, when finalized, will authorize the construction of new equipment for the Natgasoline facility.

EPA Region 6 concludes that Natgasoline's application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable PSD permit regulations. EPA's conclusions rely upon information provided in the permit application, supplemental information provided by Natgasoline at EPA's request, and EPA's own technical analysis. EPA is making this information available as part of the public record.

II. Applicant

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III. Permitting Authority

On May 3, 2011, EPA published a federal implementation plan (FIP) that makes EPA Region 6 the PSD permitting authority for the pollutant GHGs. See 75 FR 25178 (promulgating 40 CFR § 52.2305). Texas still retains approval of its plan and PSD program for pollutants that were subject to regulation before January 2, 2011, i.e., regulated NSR pollutants other than GHGs. The GHG PSD Permitting Authority for the State of Texas is:

EPA, Region 6
1445 Ross Avenue
Dallas, TX 75202

The EPA, Region 6 Permit Writer is:
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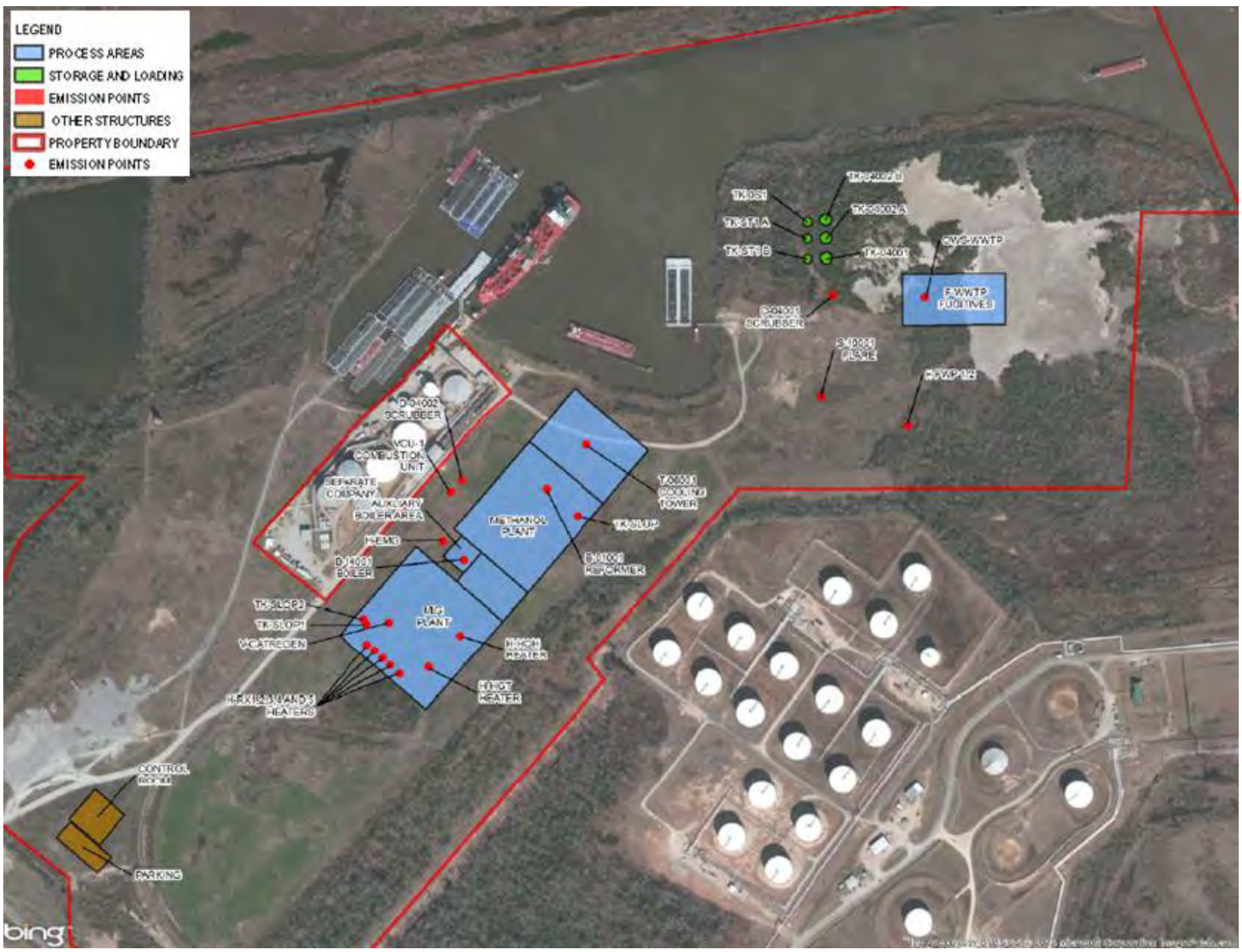
IV. Facility Location

The GtG facility is located in Jefferson County, Texas, and this area is currently designated "attainment" for all pollutants. The nearest Class 1 area, the Caney Creek Wilderness in Arkansas, is located approximately 483 kilometers (km) from the project site. The geographic coordinates for this facility are as follows:

Latitude: 30.012241 North
Longitude: -94.036453 West

Below, Figure 1 illustrates the facility location for this draft permit.



V. Applicability of Prevention of Significant Deterioration (PSD) Regulations

EPA Region 6 implements a GHG PSD FIP for the State of Texas under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305. On June 23, 2014, the United States Supreme Court issued a decision addressing the application of stationary source permitting requirements to GHGs. *Utility Air Regulatory Group v. Environmental Protection Agency* (No. 12-1146). The Supreme Court said that EPA may not treat greenhouse gases as an air pollutant for purposes of determining whether a source is a major source required to obtain a PSD or Title V permit. The Court also said that EPA could continue to require that PSD permits that are otherwise required based on emissions of conventional pollutants contain limitations on GHG emissions based on the application of Best Available Control Technology (BACT). Pending further EPA engagement in the ongoing judicial process before the U.S. Court of Appeals for the D.C. Circuit, EPA is proposing to issue this permit consistent with EPA's understanding of the Supreme Court's decision.

Natgasoline is a PSD named 100 tons per year (tpy) source. The facility is a major source with the potential to emit (PTE) 435.5 tpy carbon monoxide (CO), 99.8 tpy nitrogen oxides (NOx), 153.6 tpy particulate matter (PM), 72.3 tpy particulate matter less than or equal to 10 microns in diameter (PM_{10}), 54.4 tpy particulate matter less than or equal to than 2.5 microns in diameter ($PM_{2.5}$), and 99.2 tpy volatile organic chemicals (VOC). In this case, the applicant represents that TCEQ, the permitting authority for regulated NSR pollutants other than GHGs, has determined the facility and project is subject to PSD review for the following conventional regulated NSR pollutants: VOC, NO_x, CO, PM, PM_{10}, and $PM_{2.5}$. The applicant also estimates that this same project emits or has the potential to emit 1,174,012 tpy CO_2e of GHGs, which well exceeds the 75,000 ton per year CO_2e threshold in EPA regulations. 40 C.F.R § 52.21(49)(iv)(b); *see also, PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011) at 12-13. Since the Supreme Court recognized EPA's authority to limit application of BACT to sources that emit GHGs in greater than *de minimis* amounts, EPA believes it may apply the 75,000 tons per year threshold in existing regulations at this time to determine whether BACT applies to GHGs at this facility.

Accordingly, this project continues to require a PSD permit that includes limitations on GHG emissions based on application of BACT. The Supreme Court's decision does not materially limit the FIP authority and responsibility of Region 6 with regard to this particular permitting action. Accordingly, under the circumstances of this project, TCEQ will issue the non-GHG portion of the permit and EPA will issue the GHG portion. [1]

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[1] *See* EPA, Question and Answer Document: Issuing Permits for Sources with Dual PSD Permitting Authorities, April 19, 2011, http://www.epa.gov/nsr/ghgdocs/ghgissuedualpermitting.pdf

EPA Region 6 proposes to follow the policies and practices reflected in EPA's PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011). For the reasons described in that guidance, we have not required the applicant to model or conduct ambient monitoring for GHGs, nor have we required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions. Instead, EPA believes that compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs. We note again, however, that the project has regulated NSR pollutants that are non-GHG pollutants, which are addressed by the PSD permit to be issued by TCEQ.

VI. Project Description

With this permit application, Natgasoline is proposing to construct a new GtG production facility in Beaumont, Texas, using natural gas as feedstock. The proposed GtG facility will include two main process plants, the methanol (MeOH) plant and the methanol to gasoline (MtG) plant. See the process flow diagrams in Appendix B. The proposed MeOH plant will synthesize methanol using natural gas as feedstock. Natural gas will be delivered to the methanol plant by pipeline. The majority of the natural gas received by the facility will be used as chemical feedstock (feed) for the MeOH process, and a portion of the natural gas will be burned as fuel.

The natural gas feed will first be treated to remove sulfur compounds. After sulfur removal, the feed gas will be processed through a saturator that will saturate the feed gas with hot process water from the distillation section and process condensate from the waste heat recovery process. Next, the saturated feed gas will be processed in the pre-reformer with steam to complete the process of pre-treating the feed for steam and Auto-thermal Reformer (ATR) reforming. None of these pre-treatment processes will include any fuel combustion or result in GHG or other pollutant emissions except for potential fugitive equipment leaks.

The reforming section will include a primary steam reformer (SMR) and an ATR. SMR uses steam and natural gas to produce syngas that results in excess hydrogen and about unconverted 10% fraction of the feed. The ATR process uses a standalone oxygen reformer that produces a syngas that is rich in carbon oxides and low in hydrogen (below stoichiometric conditions) for methanol production. The design of the combined SMR/ATR technology allows for a smaller SMR that operates at a higher pressure and lower temperatures since it is combined with an ATR that operates at higher temperature. The primary reformer will use a natural gas-fired combustion source (emission point number EPN: B-01001) to heat catalyst-filled tubes within the radiant section of the reformer. In the upper section of the ATR, natural gas, hydrogen, and other compounds created in the primary reformer will be mixed with steam and oxygen, and reaction heat for the endothermic reforming reaction will be created by combusting part of the natural gas. The mixed gases from the ATR upper section will then pass through the lower catalyst filled section in which the reforming reactions are supported by the catalyst. The ATR will produce syngas slightly under stoichiometric composition for methanol synthesis. Heat recovery systems will convert excess heat generated by the steam reformer and ATR into useful energy for steam generation and process heating.

The syngas from the reforming section will be compressed and converted into crude methanol in three methanol synthesis reactors. Two synthesis reactors configured in parallel will be water-cooled and perform the initial conversion step, while the third synthesis reactor will be gas-cooled and perform a second conversion step into crude methanol.

The crude methanol will be sent to a three-column energy conserving distillation train. Overhead gases from the first column will be routed to the fuel gas system, and remaining liquids will be fed to the second column. The bottoms from the second column will be fed to the third column for additional methanol purification. The process water stream from the bottom of the third column will be recycled to the saturator. The overhead gases from the second and third columns will be condensed into methanol product, which will be sent to intermediate methanol storage.

The MtG plant will convert methanol into motor vehicle gasoline and a liquefied petroleum gas (LPG) mixture. The MtG plant feed may include methanol from the MeOH Unit or methanol purchased from off-site manufacturers. The methanol feed will be converted into gasoline and LPG in a series of five MtG reactors configured in parallel. The five MtG reactors will be supported by five gas-fired MtG reactor heaters (EPNs: H-RX1 - H-RX5) to supply heat for the reaction. One gas-fired MtG regeneration heater (EPN: H-REGEN) will generate heat to periodically combust carbonaceous deposits that accumulate on the reactor catalyst during operation, and the gas from these periodic catalyst regeneration processes will vent to the atmosphere (EPN: V-CATREGEN).

The reactor effluent will be sent to separation where it will be separated into three streams: 1) an LPG stream to be sent to pressurized LPG storage; 2) a "light" gasoline stream to be sent to gasoline blending and storage; and 3) a "heavy" gasoline stream to be routed to the MtG Heavy Gasoline Treatment (HGT) Unit for further processing into more valuable hydrocarbons. The MtG HGT Unit includes one reactor supported by one gas-fired HGT heater (EPN: H-HGT) to supply heat for the reaction. The HGT reactor will convert some of the "heavy" gasoline feed into converted "heavy" gasoline for mixing with the "light" gasoline to produce the blended gasoline product. Some of the HGT reactor feed will be converted into LPG that is sent to pressurized LPG storage.

Steam required for operating the MeOH and MtG Plants will be supplied by heat recovery systems in the MeOH Plant and also by a gas-fired auxiliary boiler (EPN: B-14001). These process units will also be supported by a cooling tower (EPN: T-06001). A common elevated plant flare (EPN: S-10001) will control emissions from compressor seals and planned Maintenance, Start-up, or Shutdown (MSS) activities. MSS emissions that cannot be routed to the flare because the pressure of the stream is below 0.5 psia will be emitted to atmosphere (EPNs: FUG-MEOH, FUG-MTG, and TEMP-MSS).

Power will be provided from the public grid and from a small steam-driven power generator. Piping components from the process equipment described above will also be a source of GHG emissions (EPNs: FUG-MEOH and FUG-MTG). A gas-fired Vapor Combustion Unit (EPN: VCU-1) will control emissions from loading product gasoline into rail cars or trucks.

Planned MSS activities will occur in order to ensure continued operation of the methanol and MtG Plants. Such activities will require shutdown of the processes and subsequent start-up to return to normal operations. Planned MSS GHG emissions are included as part of the total GHG potential to emit (PTE) emissions, and each plant (MeOH and MtG) is assumed to have four startups/shutdowns each per year. The cold startup of the methanol unit will include periods of flaring of several different gas stream types and compositions for about 22 hours, until the process is stable for production of syngas. Gases routed to the flare during the methanol unit startup will include natural gas blended with nitrogen and syngas from the reformer. Additionally, once every four years, the MeOH Plant will shut down for a catalyst charge. The CO_2 emissions from the catalyst regeneration of the primary reformer are estimated to be de minimis at 20 TPY CO_2e. Natgasoline will control emissions from all planned MSS activities, including vent gases from equipment clearing at the common flare. Releases to the atmosphere will be limited to no more than 15,000 cubic feet (ft^3) of gases on a 12-month rolling basis (not including any gases routed to flare).

Steam from the plant will be used to support an air separation unit (ASU) located right next to the MeOH Plant. Oxygen (O_2) from the ASU will be supplied to the ATR and nitrogen (N_2) will be supplied to the plant for use as inert gas and other general utility needs. The ASU will also supply plant and instrument air. The ASU may also supply N_2 into a pipeline running along the site. There are no GHG emissions associated with ASU operations.

VII. General Format of the BACT Analysis

The BACT analyses for this draft permit are consistent with EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011), which outlines the steps for conducting a "top-down" BACT analysis. Those steps are listed below.

(1) Identify all potentially available control options;
(2) Eliminate technically infeasible control options;
(3) Rank remaining control technologies based on effectiveness;
(4) Evaluation of Economic, Energy, and Environmental Impacts; and
(5) Select BACT.

VIII. Applicable Emission Units

The majority of GHG emissions associated with the project are from combustion sources (i.e., reformer furnace, boiler, heaters, emergency generator, and flare). The site has some fugitive emissions from piping components that contribute a relatively small amount (< 0.04%) of the total facility's GHG emissions. The stationary combustion sources primarily emit CO_2 and small amounts of nitrous oxide (N_2O) and methane (CH_4).

The proposed facility design includes an emergency generator engine (EPN: H-EMG) and two firewater pumps (EPNs: H-FWP-1 and H-FWP-2). The generator engine shall be rated no greater than 2000 kW, while the firewater pumps shall be rated no greater than 1000 kW. All three units are designed to use diesel fuel, stored in onsite tanks, so that emergency power is available for safe shutdown of the facility in the event of a power outage that may also include natural-gas supply curtailments. GHG emissions from the units will result from the combustion of diesel fuel and are comprised primarily of CO_2, with CH_4, and N_2O present in smaller quantities. The proposed emergency generator engine and firewater pumps operate at a low annual capacity factor, 100 hours per year in non-emergency use.

BACT is being evaluated for the GtG facility and following emission units that are subject to this GHG PSD permit:

A. Methanol Plant
B. Combustion Units:
    1. Methanol Reformer Furnace (EPN: B-01001)
    2. Auxiliary boiler (EPN: B-14001)
    3. Process Heaters (EPN: H-REGEN) (EPNs: H-RX1 – H-RX5) & (EPN: H-HGT)
C. Reactor Catalyst Regenerator (EPN: V-CATREGEN)
D. Process Flare & MSS Emissions (EPN: S-10001)
E. Railcar/Truck Loading/Vapor Combustor (EPN: VCU-1)
F. Fugitive Emissions (EPN: FUG-MEOH & FUG-MTG)
G. Emergency Generator (EPN: H-EMG) and Firewater Pumps (EPN: H-FWP1& H-FWP2)
H. Cooling Tower (EPN: T-06001)

IX. BACT Discussion

A. GtG Facility Methanol Plant Process Analysis

Methanol can be produced from a wide array of feedstocks that can be converted into syngas. Natgasoline has designed the plant to use only natural gas as the feedstock. The basic methanol production process is the synthesis of hydrogen, carbon monoxide, and oxygen to form liquid hydrocarbons under catalytic, temperature, and pressure conditions. The majority of all GHG emissions from the methanol plant will be generated in the methane reforming process and the associated auxiliary boiler. Therefore, selection of the methane reforming process design is the primary determinant for establishing the GHG emissions performance for the methanol plant. Combined steam methane (SMR/ATR) reforming is the lowest GHG emitting technology with proven technical feasibility and economic viability on a large scale. At least four such plants are operating around the world. The lower GHG emitting capability associated with combined SMR/ATR is mainly due to the ability to operate with a higher pressure in the syngas generation section and an ideal stoichiometric ratio. This design allows the use of a smaller SMR with a lower product exit temperature.

As part of the analyses for the MeOH process, Natgasoline evaluated various current methanol technologies that are commercially available, are currently operating at plants with reliable proven efficiencies, and that would meet the project's design and implementation requirements.

Identification of Potentially Available Production Technologies

Steam methane reforming (SMR): The majority of existing methanol production plants use SMR-only reforming designs. This process only has a 90% conversion process. The SMR-only design option results in an unconverted 10% fraction of the feed methane and hydrogen that cannot be utilized in methanol production except to be burned as fuel or waste gas, resulting in higher GHG emissions. The SMR process requires combusting a fuel source to provide radiant heat to crack a carbon-containing feed in the presence of steam. The SMR processes evaluated ranged between 34 to 35 MMBtu/metric ton of methanol produced.

Autothermal reforming (ATR): The ATR process uses a standalone oxygen reformer that produces a syngas that is rich in carbon oxides and low in hydrogen (below stoichiometric conditions) for methanol production. There are three commercial 10,000 TPD methanol plants operating using the ATR process worldwide. This process uses selective reactor technology and pure oxygen. GHG (combustion) emissions are comparatively lower than the SMR process. The ATR process reacts natural gas and oxygen below stoichiometric conditions. The ATR process has a lower methanol conversion efficiency than SMR since the process does not produce enough hydrogen to consume all the CO_2. The ATR processes evaluated ranged between 32 to 33 MMBtu/metric ton of methanol produced.

Partial Oxidation (POX): Non-catalytic POX uses very high temperatures and pure oxygen for methanol production. This process[2] is mainly utilized for producing syngas from heavy hydrocarbons, including deasphalter pitch and petroleum coke. There are two commercial operations worldwide, and the technology is restricted (licensed). There is no known commercial operation using natural gas as the feedstock.

Combined Gas Heated Reformer (GHR): A GHR design is an ATR with heat recovery and a primary reformer in one vessel. This technology is primarily used for small scale methanol plants of about 1,500 MTPD due to the high consumption of pure oxygen, and there is no commercial operation of a larger scale plant, in series or parallel.

Combined SMR/ATR Reforming (SMR/ATR): The design of the combined SMR/ATR technology allows for a smaller SMR that operates at a higher pressure and lower temperatures since it is combined with an ATR that uses pure oxygen to operate at higher temperature. The combined reforming process evaluated ranged between 31 and 33 MMBtu/metric ton of methanol produced. Consequently, the combined reforming process will generate fewer GHG emissions than the other processes.

Elimination of Technically Infeasible Production Technologies

All of the above options were considered in the design for the Natgasoline MtG plant. Published literature on the POX and GHR processes for methanol production using natural-gas feedstock does not confirm a single successful commercial demonstration.[3] Additionally the applicant has confirmed that "there is not a single operating commercial plant in the world that uses POX or GHR technology for producing methanol from natural gas feedstock. This statement is not conditional on the scale of the operation because no such commercial natural gas-to-methanol plant operates in the world at any scale."[4] The POX and GHR processes are not intended for large scale commercial production of methanol and are instead mostly used in bench scale units. Therefore, these two processes are considered technically infeasible for this large scale natural gas to methanol production plant. SMR, ATR, and the combined SMR/ATR processes are technically feasible.

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[2] Davy Process Technology Brochure available at: http://www.davyprotech.com/pdfs/Methanol%20Brochure.pdf
[3] See Celanese Revised 2012 application and information on these processes at: http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/celanese-revised-app06142013.pdf
[4] See email from Blake Soyars to Braganza Bonnie on July 11, 2014

Ranking of Remaining Production Technologies Based on Effectiveness

In ranking the remaining technologies, Natgasoline provided an analysis of the energy used per metric ton of methanol produced, for its specific project.

In Table 1, Natgasoline based the equivalent reformer fuel consumption and GHG emissions on additional process-gas flaring, feed pre-heating, and/or steam superheating that do not contribute to GHG emissions, but would be required for alternative design Options 1 and 2 to produce the same quantity of MeOH. Options 1 and 2 for fuel consumption and GHG emissions are estimated for comparison to the selected Option 3 based on conceptual design differences. An example equivalent fuel consumption calculation based on Option 3 in Table 1 is provided as follows:

$$Equivalent\ Fuel\ Consumption$$
$$= \frac{24\frac{\text{hr}}{\text{day}} * 1{,}340\frac{\text{MMBtu}}{\text{hr}}\text{avg. reformer firing}}{5{,}500\frac{\text{mt}}{\text{day}}\text{MeOH permit basis}} * 5.85\text{ MMBtu HHV fuel}\frac{\text{fired}}{\text{mt}}\text{MeOH}$$

Table 1

Option No.	Reformer Design Configuration Options	Equivalent Fuel Consumption (High Heating Value [HHV] of fuel fired per metric ton of methanol produced)	Equivalent Reformer GHG Emission Estimate (CO_2e)
1	SMR Only	6.44 MMBtu[a] fuel/mt[b] MeOH = 110% of selected design	791,534 TPY emitted (71,958 TPY additional beyond base case)
2	ATR Only	6.14 MMBtu fuel/mt MeOH = 105% of selected design	755,555 TPY emitted (35,979 TPY additional beyond base case)
3	Combined SMR/ATR (selected/base case)	5.85 MMBtu fuel/mt MeOH = 100% of selected design	719,576 TPY emitted

Evaluation of Production Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

The above table indicates the quantities of GHG and other combustion emissions emitted for each design option. As indicated above, there is a shortage of hydrogen produced in the pure ATR process and a significant excess in the SMR process, and therefore the combined reforming process will generate fewer GHG emissions than the other processes. This was the most energy efficient design evaluated. There are no known adverse environmental impacts from any of the above options.

Selection of Methanol Production Process

Natgasoline has chosen the combined SMR/ATR process, which has the lowest fuel combusted (energy) per ton of methanol produced and therefore the least GHG emissions.

Based on current permitted methanol plants, EPA compiled the information in Table 2 on the reformer sections of the methanol plants. Natgasoline proposed methanol production process is estimated to be one of the lowest emitters of CO_2e per ton of methanol produced.

Table 2

Facility	Methanol Production tpy	CO_2e Emissions tpy	Reformer HHV duty-MMBtu/hr	Ton CO_2e/ton methanol
Equistar - Channelview PSD- TX-761 February 2013 (Only reformer section modified)	903,150 or 273 MM gals/yr	831,675	1,615 15.66 MMBtu per ton of methanol	0.92
Celanese Clear Lake PSD –TX-1296 issued December 2013- New methanol plant	1,433,000	532,218	1,225 7.48 MMBtu per ton of methanol	0.37
OCI Beaumont - PSD-TX-1334 issued August 2014 (Only reformer section modified)[a]	1,210,338	951,343	1,923 11.95 MMBtu per ton of methanol	0.78
Natgasoline New major source/facility	2,214,856	719,576	1,552 6.45 MMbtu per ton of methanol	0.32

a - The CO_2e emissions are based on methanol production with the addition of CO_2 to the synthesis gas for further methanol production.

While this demonstrates the methanol production process selected for this project will be efficient, unit specific BACT analyses for emission units in the methanol production plant and the methanol-to-gasoline plant will follow in Section IX.B. below.

B. Combustion Units BACT Analysis

The Natgasoline facility will include a number of combustion units. The methanol reformer furnace and the auxiliary boiler will comprise approximately 94% of the GHG emissions (See Appendix A). The process heaters are much smaller and contribute less GHG emissions. The remaining combustion units will operate intermittently because they are only required for emergency use or to control periodic operating units, and these emissions are considered separately. The primary contribution of GHGs from all combustion units will be CO_2, whereas the concentration of CH_4 and N_2O emissions in the stream will be de minimis. This section includes a combined BACT analysis for the methanol reformer furnace, the auxiliary boiler, and the process heaters. The BACT emission limits and other requirements are established in separate sections on a unit-by-unit basis.

Step 1 – Identification of Potential Control Technologies

Carbon Capture and Storage (CCS): CCS is an available add-on control technology that is applicable for all of the site's affected combustion units. CCS is classified as an add-on pollution control technology, which involves the separation and capture of CO_2 from flue gas, pressurizing of the captured CO_2 into a pipeline for transport, and injection/storage within a geologic formation. CCS is generally applied to "facilities emitting CO_2 in large concentrations, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing)."[5]

CCS systems involve the use of adsorption or absorption processes to remove CO_2 from flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The three main capture technologies for the CCS are pre-combustion capture, post-combustion capture, and oxyfuel combustion (IPCC, 2005). Of these approaches, pre-combustion capture is applicable primarily to gasification plants, where solid fuel such as coal is converted into gaseous components by applying heat under pressure in the presence of steam and oxygen (U.S. Department of Energy, 2011). At this time, oxyfuel combustion has not yet reached a commercial stage of deployment and still requires the development of oxy-fuel combustors and other components with higher temperature tolerances (IPCC, 2005). Accordingly, pre-combustion capture and oxyfuel combustion have no practical application for this proposed GtG facility. The third approach, post-combustion capture, is available for the proposed reformers, process heaters, and boilers.

With respect to post-combustion capture, a number of methods may potentially be used for separating the CO_2 from the exhaust gas stream, including adsorption, physical absorption,

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[5]U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, http:/www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf

chemical absorption, cryogenic separation, and membrane separation (Wang et al., 2011). Many of these methods are either still in development or are not suitable for treating power plant flue gas and other large combustion sources due to the characteristics of the exhaust stream (Wang, 2011; IPCC, 2005). Of the potentially applicable technologies, post-combustion capture with an amine solvent such as monoethanolamine (MEA) is currently the preferred option because it is the most mature and well-documented technology (Kvamsdal et al., 2011), and because it offers high capture efficiency, high selectivity, and the lowest energy use compared to the other existing processes (IPCC, 2005). Post-combustion capture using MEA is also the only process known to have been previously demonstrated in practice on combustion sources such as gas turbines (Reddy, Scherffius, Freguia, & Roberts, 2003). As such, post-combustion capture using MEA is the sole carbon capture technology considered in this BACT analysis.

In a typical MEA absorption process, the flue gas is cooled before it is contacted counter-currently with the lean solvent in a reactor vessel. The scrubbed flue gas is cleaned of solvent and vented to the atmosphere, while the rich solvent is sent to a separate stripper where it is regenerated at elevated temperatures and then returned to the absorber for re-use. Fluor's Econamine FG Plus process operates in this manner, and it uses an MEA-based solvent that has been specially designed to recover CO_2 from oxygen-containing streams with low CO_2 concentrations typical of combustion sources (Fluor, 2009).

Once CO_2 is captured from the flue gas, the captured CO_2 is compressed to 100 atmospheres (atm) or higher for ease of transport (usually by pipeline). The proposed GtG facility will not have on-site CO_2 storage. Therefore, any CO_2 captured and compressed would need to be transported off-site via a third party CO_2 pipeline system. The United States presently has more than 3,000 miles of CO_2 pipelines used to transport CO_2 for Enhanced Oil Recovery (EOR) in crude oil production, or for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam. There is a large body of ongoing research and field studies focused on developing better understanding of the science and technologies for CO_2 storage.

Fuel Selection: Natural gas is the lowest emitting carbon-containing fuel that can be relied upon for the proposed operation. High hydrogen fuel-gas streams may and will be utilized as a secondary fuel for the reformer furnace when they are available and practicable. However, purchasing hydrogen from an off-site source to fuel combustion units with 100% hydrogen is not expected to provide any environmental benefit. Any hydrogen purchased from offsite suppliers would be produced using steam methane reforming (SMR), which would more than offset the onsite GHG emission reductions from firing purchased hydrogen as fuel. The plant will recover vent streams to be used as process fuel gas that supplements the natural-gas fuel in the plant. The alternate option for these vent streams would be to send it to the flare, which would increase the GHG emissions from the facility.

Energy Efficiency Design Technologies: In general, the energy efficiency technologies that can be incorporated into the design of a combustion unit include:

a. Design of the unit to reduce heat losses via radiation with the use of good insulation;
b. Design of the combustion unit to optimize efficiency of the product with lowest energy consumption at maximum feed input;
c. Recovery of heat from the stack flue gases; and
d. Good burner design for effective mixing having a good flame pattern to increase radiation transfer for reactant conversions.

Best Operational Practices: Best operation practices for combustion units include:

a. Combustion Air Controls (Limitations on Excess Air/O_2): O_2 monitors and intake air flow monitors can be used to optimize the fuel-to-air ratio and limit excess air, which results in increased combustion efficiency and decreased GHG emissions. Excess air should be limited to 3% O_2 in flue gas. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Process Heaters, November 2010, Energy Efficiency Improvement and Cost Savings for the Petrochemical Industry, July 2008*).
b. Periodic Maintenance: Maintaining the combustion sources through a maintenance program results in increased average thermal efficiency and energy savings. Maintenance activities include regular calibrations of fuel flow meters and gas composition analyzers and regular cleaning of fouled or dirty parts. A maintenance plan can be developed that contains official documented procedures and a schedule for routine inspections and evaluations. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Improved Maintenance, November 2010*).

Step 2 – Elimination of Technically Infeasible Alternatives

CCS has not been demonstrated and operated successfully on a GtG facility or at a large capacity MeOH plant that has high stack flue gas rates and low CO_2 concentration. Natgasoline estimates that the combined large stack flow rates have an average CO_2 concentration of 8.9%. Natgasoline also indicates that CCS has not been used in practice with a MeOH plant having a capacity of 5,500 MTD, or at an MtG Plant. The EPA is evaluating whether CCS is technically feasible for the GtG facility and will consider public comments on this issue. Because there is a basis to eliminate CCS on other grounds in Step 4 of the BACT analysis after considering the energy, environmental, and economic impacts of the technology, we will assume, for purposes of this specific permitting action, that potential technical barriers do not make CCS technically infeasible.

All other options identified in Step 1 are considered technically feasible and have been proposed by the applicant.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The following is a ranking of technically feasible control technologies based on the best available information:

- Carbon capture and storage (CCS) (up to 90%)
- Fuel Selection (varies based on the carbon content of the fuel)
- Process Design (varies up to 40%)
- Best Operation Practices (varies up to 10%)

Step 4 - Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts:

Natgasoline developed a site-specific cost analysis demonstrating that CCS can be eliminated as BACT for this project in Step 4 based on the excessive costs associated with construction and operation of CCS, as well as the negative environmental and energy impacts. Natgasoline has estimated a projected capital cost of CCS at the Natgasoline plant of $1,178,902,874 to construct CCS.[6] The proposed project capital cost without CCS is approximately $1.1 billion. The applicant's estimates for a CCS for this source are projected to double the projected total cost of the entire facility without CCS. This cost does not include the cost of control for the additional GHGs generated by the CCS equipment or the increases of criteria pollutants generated by operation of this equipment.

The costs were based on a MEA-based carbon capture technology because it is the most mature and well-documented technology and because it offers high capture efficiency, high selectivity, and the lowest energy use compared to the other existing processes. The conceptual process design of this system would include the following key equipment and processing steps:

- Feed Gas Air Cooler to reduce exhaust temperatures to appropriate range for MEA absorption;
- Absorber column to contact cooled feed gas with "lean" MEA;
- Regenerator to strip CO_2 from "rich" MEA using steam;
- MEA Recovery Tower to recover (expensive) MEA solution from Absorber overheads prior to venting overhead vapors to atmosphere;

[6] Natgasoline Updated Cost Calculations for CCS dated June 27, 2014 to EPA, Mr. Jeff Robinson

- Condensers, reboilers, coolers, and other heat exchange/recovery units including reclaimer/degradation management system;
- Other, smaller MEA process equipment vessels and piping;
- Natural gas-fired steam boiler to produce steam for the Regenerator;
- CO_2 compressor to bring recovered CO_2 to pipeline pressure; and
- Equipment needed to supply increased electrical demand.

The relevant environmental impact estimate from Natgasoline for implementing CCS includes additional emissions (fugitive and vents) from the various pieces of CCS equipment and, more importantly, the installation of a MEA regeneration steam boiler, which would generate an additional 478,362 TPY CO_2 equivalent to 45% of the total CO_2 emissions from the proposed plant.[7]

The CCS system would increase the criteria pollutant of NO_x in an area that has been redesignated from non-attainment for the 8-hour ozone levels to attainment.[8] New NO_x sources in this area require plants to have controls to reduce NO_x emissions. Both the reformer furnaces and boiler will be using SCR to reduce NO_x. Other environmental impacts include the large consumption of fresh water and the additional waste streams created by the amine system.

Natgasoline conducted a search on the large scale methanol plants worldwide and concluded that no plant employs any form of carbon capture from the reformer flue gas (largest combustion source in the plant). Additionally there is a very large scaling up risk involved with the application of a CCS which transfers into an economic risk for non-operation of CCS and the MeOH plant (and then likely the total plant). Very large CCS projects for power plants and hydrogen plants have recently been canceled (Mongstad, Norway, a country with a CO_2 tax system)[9] or are awaiting further government funding (ROAD, The Netherlands) even though the respective permits for construction had been issued. EPA notes that a DOE-funded demonstration plant in 2010 constructed at the Valero Refinery in Port Arthur that captures the CO_2 from SMR reactors has recently started operations, but is still considered a pilot demonstration process. The design basis for the Natgasoline plant is for larger production of methanol using the combined SMR/ATR process and therefore does not have the similarities and economics of this demonstration project.

While we take no position on the energy and environmental impacts of CCS, many of which likely could be mitigated, we agree with the applicant that CCS is not economically feasible for

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[7] See 10 January 2014 Response to 20 December 2013 Completeness Determination letter, Attachment B.
[8] See Chapter 4 of the Texas submittal at:
http://www.tceq.texas.gov/assets/public/implementation/air/sip/bpa/08006sip_ado_complete.pdf
EPA's approval at: http://www.gpo.gov/fdsys/pkg/FR-2010-10-20/pdf/2010-26261.pdf
[9] See: http://www.bloomberg.com/news/2013-09-20/norway-drops-moon-landing-as-mongstad-carbon-capture-scrapped.html

this specific application because it would increase the total project cost by a minimum of 107%. Therefore, CCS has been eliminated as BACT for the combustion units at the Natgasoline plant.

Step 5 – Selection of BACT

Fuel selection, process design, and best operating practices are selected as BACT. A more detailed description of the BACT compliance requirements for each of the three primary combustion units is listed below.

Methanol Reformer Furnace (EPN: B-01001) BACT Requirements

Natgasoline designed the methanol plant based on minimizing utility usage by maximizing energy recovery in the reformer section of the plant. The reformer section is designed to use two common technologies, SMR and ATR having a 90% thermal efficiency.

Fuel Selection: The methanol reformer furnace will use natural gas supplemented by plant-process gas that contains hydrogen when available from the process that reduces the carbon content in the combustion fuel. Natgasoline based the GHG emission estimates on utilizing the plant-process gas supplemented with natural gas, having a specific carbon content of 0.4898.

Process Design: The methanol reformer furnace design has been optimized to ensure highest efficiency, lowest energy consumption, highest raw material yields, and lowest potential emissions based on site-specific considerations by:

a) Air Preheat System: The combustion air is preheated prior to combustion, which reduces the required heat load for the reformer heater and increases thermal efficiency.
b) Efficient Burner Design: New burner designs have improved fuel mixing capabilities, which increase the burner flame pattern and thus radiant section efficiency and reduce GHG emissions.
c) Heat Recovery System: The flue gas from the combustion unit is routed through a waste heat recovery system, which reduces the exit flue gas temperature and increases the thermal efficiency of the combustion unit.
d) Increased Heat Transfer: Energy inefficiencies due to heat loss can be reduced by proper insulation and clean heat exchange surfaces. Maintenance plans can be developed in order to ensure the heat exchange surfaces are free from fouling.

Best operation practices: These effectively support the energy efficient design and are:

a) Minimizing fuel required to heat excess air by monitoring the stack O_2 levels to be at or below 3% concentration during normal operation.

b) Maintaining the combustion unit through periodic burner tuning and inspections.
c) Maintenance plans can be developed in order to ensure the heat exchange surfaces are free from fouling.
d) Regular calibrations of fuel flow meters and gas composition analyzers and regular cleaning of fouled or dirty parts.
e) Developing a maintenance plan that contains documented procedures and schedule for routine inspections and evaluations.
f) Inspection of the insulation and replacement as necessary to ensure heat loss from the furnace is minimized.

BACT Limits and Compliance:

1. Only use natural gas or process fuel gas containing hydrogen in the methanol reformer furnace that has a low carbon content estimated to be 0.5% based on a 12-month average to comply with the annual CO_2 limit. See the emission limits in Appendix A. A gas composition analyzer and a fuel flow meter will be installed at the point after the natural gas mixes with the process gas to be able to determine the composition and flow of the fuel being combusted in the reformer. The analyzer at the inlet will be used to determine the composition of the process fuel on a daily basis as required by 40 CFR § 98.34(b)(3)(ii)(E). If process fuel gas is monitored separately, then the natural gas composition will be determined semi-annually or obtained from the natural gas supplier If the fuel gas composition analyzer is not online, weekly sampling and analysis of the fuel gas composition may be performed per 40 CFR § 98.34(b)(3)(ii)(E).

2. The fuel gas flow to the reformer will be continuously monitored and recorded. Per 40 CFR § 98.34(b)(1)(ii), the fuel flow meter will be calibrated per manufacturer's recommendation.

3. Natgasoline will calculate the CO_2 emissions for the reformer furnace using the heat input, flow, and the site-specific fuel analysis for process fuel gas. The equation for estimating CO_2 emissions from combustion of process fuel gas is specified in 40 CFR § 98.33(a)(3)(iii) as follows:

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 * 1.102311$$

Where:
CO_2 = Annual CO_2 mass emissions from combustion of natural gas and/or plant produced high hydrogen gas (short tons)

Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to 40 CFR § 98.3(i).
CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV at 40 CFR § 98.33(a)(2)(ii).
MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedure as specified for HHV at 40 CFR § 98.33(a)(2)(ii).
MVC = Molar volume conversion factor at standard conditions, as defined in 40 CFR § 98.6.
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.

4. Natgasoline shall calculate the CO_2e emission limits using CH_4 and N_2O emission factors provided in 40 CFR Part 98, Subpart C, Table C-2, site-specific analysis of process fuel gas, the actual HHV, and equations C-8 and C-9a of 40 CFR § 98.33. Comparatively, the emissions from CO_2 contribute the most (greater than 99%) to the overall emissions from the furnaces. Therefore, additional site-specific emission factors are not required for CH_4 and N_2O.

5. Continuously monitor the methanol reformer furnace's exhaust stack temperature and control to a stack exit temperature of 350°F or less on a 12-month rolling average basis.

6. The methanol reformer furnace will be operated below 3% stack O_2 concentration during normal operation, monitored by an analyzer in the reformer stack. The O_2 analyzers shall be quality-assured at least quarterly using cylinder gas audits (CGAs) in accordance with 40 CFR Part 60, Appendix F, Procedure 1, § 5.1.2. The natural-gas composition will be determined quarterly or obtained from the natural-gas supplier. Additionally, the O_2 analyzers will be validated with zero and span gas at least weekly to maintain 1% accuracy based on full scale.

7. The concentration of CO will be monitored in the stack, as an indicator of complete combustion to reduce CH_4 emissions.

8. The flow meters, analyzers, O_2 and CO CEMS, and temperature monitoring equipment used for methanol reformer furnace compliance will be operated at

least 95% of the time when the reformer is operational, averaged over a 12-month rolling basis.

9. A thermal efficiency of 90% will be maintained on a rolling 12-month average. The efficiency calculation will be based on a heat balance procedure based on the American Petroleum Institute (API) methods 560 (4^{th} ed.) Annex G, using equation G-1.

10. Periodic burner tuning, flame inspection and maintenance of air preheater, fuel and oxygen monitors shall be performed as specified by their design and manufacturers' recommendations.

11. Natgasoline will develop a maintenance plan that contains documented procedures and schedule for routine inspections and evaluations as indicated in the best operating practices in this section.

12. An initial stack test demonstration will be required for CO_2 emissions from the reformers. The stack test demonstration for CH_4 and N_2O emissions is not required because the CH_4 and N_2O emission are less than 0.1% of the total CO_2e emissions from the heaters and are considered a de minimis level in comparison to the CO_2 emissions.

Auxiliary Boiler (EPN: B-14001) BACT Requirements:

The auxiliary boiler will supply the steam for the GtG facility and will burn pipeline quality natural gas or process fuel gas, when available.

The feasible control technologies specified in Step 1 of the BACT analysis are all top-ranked control technologies for industrial boilers. The use of one technology does not preclude the use of any other control technology, and the combination of control technologies and practices will result in higher energy efficiency than any one alone. The following Table lists BACT limits or control efficiencies for natural gas/process gas-fired steam boilers for recently permitted units.

Auxiliary Boiler BACT Control Efficiencies

Facility/Project Name	Permit Number	Month/Year Issued	Boiler Firing Capacity	Boiler BACT
Diamond Shamrock Refining Company, L.P. – Sunray TX.	PSD-TX-861-GHG	Sept. 2013	225 MMBtu/hr	0.11 lbs CO2/scf fuel fired, 365-day avg.
ExxonMobil Chemical Company – Mont Belvieu	PSD-TX-103048- GHG	Sept. 2013	98 MMBtu/hr each (2 total)	77% minimum thermal efficiency
Chevron Phillips Chemical Company LP – Baytown	PSD-TX-748-GHG	Jan. 2013	500 MMBtu/hr	77% minimum thermal efficiency
BASF FINA Petrochemicals LP – Port Arthur	PSD-TX-903-GHG	Aug. 2012	425.4 MMBtu/hr each (2 total)	77% minimum thermal efficiency
PLPropylene, Houston	PSD-TX-18999-GHG	June 2013	383 MMBtu/hr	117 lb CO_2 /MMBtu 365 day average
Rohm & Haas Inc, Deer Park	PSD-TX-1320 GHG	Feb. 2014	515 MMBtu/hr 2 steam boilers	117 lb CO_2 /MMBtu 365 day average
Enterprise Products Operating LLC	PSD-TX- 1336-GHG	April 2014	Natural gas or process gas boiler	Natural gas -118.5 Process gas 131.5 CO_2/MMBtu HHV

The Natgasoline boiler will have a design firing capacity of 950 MMBtu/hr and will be designed for a minimum thermal efficiency of 77% (LHV), which is similar to other permitted units as noted in the table.

Fuel Selection: Natgasoline will only use natural gas and/or plant fuel gas for fuel to the boiler.

Process Design: The higher efficiency boiler will have an efficient burner design and both the internal refractory material and insulation at the boiler will be specified/designed to minimize heat loss from the boiler. Additionally, heat from the boiler flue gas will be recovered using an economizer that will preheat the boiler feed water. The condensate return system will be designed to have an aerator prior to entering the boiler feed water system.

Best Operational Practices: Best operational practices include appropriate maintenance of equipment and operating within the recommended combustion air and fuel ranges of the equipment as specified by its design, with the assistance of oxygen trim control.

<u>BACT Limits and Compliance</u>

1. Only use natural gas or process fuel gas containing hydrogen in the boiler. Comply with the annual CO_2 limit in the permit.

2. The fuel gas flow to the boiler will be continuously monitored and recorded. Per 40 CFR § 98.34(b)(1)(ii), the fuel flow meter will be calibrated per manufacturer's recommendation.

3. Natgasoline will demonstrate compliance with the CO_2 emission limit for the boiler using the emission factors for natural gas from 40 CFR Part 98, Subpart C, Table C-1. Boiler design, use of low carbon fuels, use of energy efficient options, and best operational practices of the boiler corresponds to a permit limit of 357,594 TPY CO_2e. Equation C-5 for estimating CO_2 emissions as specified in 40 CFR § 98.33(a)(3)(iii) is as follows:

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 * 1.102311$$

Where:
CO_2 = Annual CO_2 mass emissions from combustion of natural gas and/or plant produced high hydrogen gas (short tons)
Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to 40 CFR § 98.3(i).
CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV at 40 CFR § 98.33(a)(2)(ii).
MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedure as specified for HHV at 40 CFR § 98.33(a)(2)(ii).
MVC = Molar volume conversion factor at standard conditions, as defined in 40 CFR § 98.6.
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.

4. The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Subpart C, Table C-2, site-specific analysis of process fuel gas, the actual heat input (HHV), and equations C-8 and C-9a of 40 CFR § 98.33 . To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1. Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 12-month total, rolling monthly.

5. The boilers will maintain a 77% thermal efficiency (LHV basis) on a 12-month rolling average for each boiler. The thermal efficiency will be calculated from

these parameters using equation G-1 from American Petroleum Institute (API) methods 560 (4^{th} ed.) Annex G, or an equivalent method approved by EPA.

6. An initial stack test demonstration will be required for CO_2 emissions from the emission unit as well as the boiler thermal efficiency. An initial stack test demonstration for CH_4 and N_2O emissions is not required because the CH_4 and N_2O emissions are approximately 0.1% of the total CO_2e emissions from the boilers and are considered a de minimis level in comparison to the CO_2 emissions. Natgasoline will also perform quality-assured CGAs at least quarterly on the O_2 analyzers.

7. Boiler inspection will occur at a minimum of every five years.

8. Maintenance of analyzers and controls will be performed as recommended by the manufacturer and as in 40 CFR Part 98.

Process Heaters (EPNs: H-REGEN, H-RX1, H-RX2, H-RX3, H-RX4, H-RX5, and H-HGT) BACT Requirements

The seven process heaters in the MeOH and MtG Units (EPNs: H-REGEN, H-RX1 – H-RX5, and H-HGT) are small heaters, with each having a maximum firing rate of less than 45 MMBtu/hr. EPNs H-REGEN and H-RX1 – H-RX5 will operate intermittently, while EPN HGT will operate on a continuous basis. The following is a discussion of how these emission units will apply the BACT selected for combustion units (above).

Fuel Selection: The heaters will use low carbon fuel (natural gas) with as much high-hydrogen fuel gas as practical. Natural gas and high-hydrogen fuel gas will be the only fuels fired in the proposed heaters. These are the lowest carbon fuels available for use at Natgasoline's MeOH Plant.

Process Design: The heaters will all be designed with efficient burners and will have air/fuel controls to reduce excess air. The heaters will primarily use natural gas or low-carbon process fuel gas as noted in the reformer section.

Best Operation Practices: Periodic inspection of the heaters to ensure good flame pattern and adjustment of the fuel/air controls as necessary to minimize heat loss via the flue gas. Preventative maintenance checks of gas flow meters including calibration and cleaning of burners including burner tips on an as-needed basis every five years or each unit turnaround (whichever is more frequent).

These activities ensure maximum thermal efficiency is maintained; however, it is not possible to quantify an efficiency improvement. Although the associated emission reductions cannot be quantified, regularly scheduled tune-ups and inspections are considered a standard practice to maintain optimal thermal efficiency and are therefore proposed as BACT for these heaters.

Automatic controls of the air/fuel ratio enable the heaters to operate under optimal conditions ensuring heater efficiency.

BACT Limits and Compliance

1. Compliance with permit limits of 12,746 TPY CO_2e for EPN H-REGEN; 52,929 TPY total CO_2e for all five EPNs H-RX1 – H-RX5 that operate intermittently based on process needs; and 3,848 TPY CO_2e for EPN H-HGT will be determined by calculating the emissions on a monthly basis using the actual firing rate for the heaters.

2. The firing rate for each of the reactor heaters (H-RX1, H-RX2, H-RX3, H-RX4, and H-RX5) will be limited to a maximum of 25 MMBtu/hr. The firing rate of the regeneration heater (H-REGEN) will be limited to a maximum of 45 MMBtu/hr. The firing rate of the heavy gasoline heater treater (H-HGT) will be limited to a maximum of 8 MMBtu/hr.

3. Natgasoline will demonstrate compliance with the CO_2 emission limit for the heaters using the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-1 and equation C-2a. Equation C-5 will be used for estimating CO_2 emissions from process gas as specified in 40 CFR § 98.33(a)(3)(iii).

4. The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Subpart C, Table C-2, site-specific analysis of process fuel gas, the actual heat input (HHV), and equations C-8 and C-9a of 40 CFR § 98.33 . To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1. Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 12-month total, rolling monthly.

5. An initial stack test demonstration will be required for CO_2 emissions from each of the heaters. An initial stack test demonstration for CH_4 and N_2O emissions are not required because the CH_4 and N_2O emission are approximately 0.1% of the total

CO_2e emissions from the heater and are considered a de minimis level in comparison to the CO_2 emissions.

6. Natgasoline will calibrate and perform preventative maintenance on the air/fuel control system at least once per quarter, at a minimum.

C. Catalyst Regeneration Vent (EPN: V-CATREGEN) BACT Analysis

Carbon deposit buildup on the MtG reactor catalyst in the MtG reaction process is an unavoidable part of the reaction. This carbon deposit must be removed when the methanol-to-gasoline conversion efficiency becomes unacceptable for continued process operations as determined by standard operating procedures and to avoid any unnecessary process shutdowns. The catalyst regeneration uses heat from the fired heater EPN H-REGEN, and regeneration duration time is approximately 15 hours and occurs 110 times per year for a total of 1,681 hours per rolling 12-month period. Emissions of CO_2e from this vent are 5,446 TPY and is 0.5% of the total GtG plant's CO_2 emissions.

Step 1 – Identification of Potential Control Technologies

Proper Operating Techniques: Utilizing proper operating techniques (e.g., minimizing catalyst carbon deposits and the number of catalyst regeneration per year without negatively impacting the overall energy efficiency of the MtG process) results in decreased GHG emissions from MtG catalyst regeneration. The number of regenerations will be limited. The catalyst regenerator is being designed as part of the MtG plant and will be based on good design and control technology. Catalyst regeneration does not produce product and uses heated gas (with heat supplied by the MtG regeneration heater H-REGEN) for oxidizing and removing the carbon from the catalyst surface. Therefore, good operations and design will be an inherent part of the catalyst regeneration process.

A detailed analysis under Steps 2-4 is not necessary because the applicant has selected the only available control option.

Step 5 – Select BACT

BACT is proper operation of the MtG reactor to minimize carbon deposits. The catalyst regeneration duration time is approximately 15 hours and occurs 110 times per year for a total of 1,681 hours per rolling 12-month period. Emissions of CO_2e from the catalyst regeneration vent are de minimis (<0.5 % total project emissions). Therefore, proper operating techniques are BACT.

BACT Limits and Compliance

1. Meet compliance with the emission limit of 5,446 TPY CO_2e from 110 regeneration events. Compliance with this limit will be determined by calculating the emissions on a monthly basis, including the actual measured and duration of each regeneration venting event as indicated above, of the regeneration vent stream and based on a 12-month rolling total.

2. Natgasoline shall employ good plant operations by minimizing the carbon deposits on the catalyst in the reactors of the MtG plant.

D. Flare and MSS Emissions (EPN: S-10001) BACT Analysis

The Natgasoline plant flare serves two primary purposes: as a VOC emissions control device, and also as a vital safety system for managing combustible gas and vapor materials generated during certain events, such as emergency and upset events. CO_2 emissions result from the flaring of process gases and are produced from the combustion of carbon containing compounds (e.g., CO, VOCs, CH_4) in the process-gas streams and the pilot fuel. The proposed flare is non-assisted and shall have a minimum destruction and removal efficiency (DRE) of 98% for CH4 on a 12-month rolling average basis. The flare is an example of a control device in which the control of certain pollutants causes the formation of collateral GHG emissions. Specifically, the control of CH_4 in the process gas at the flare results in the creation of additional CO_2 emissions via the combustion reaction mechanism. However, given the relative GWPs of CO_2 and CH_4, it is appropriate to apply flare combustion controls to reduce CH_4 emissions because the impact of that GHG reduction will be greater than the GHG impact of the additional CO_2 emissions resulting from combustion, and there will also be concurrent destruction of VOCs and Hazardous Air Pollutants (HAPs). This flare will emit GHG emissions as part of normal operations.

Step 1 – Identification of Potential Control Technologies

Good Flare Design: Good flare design for the flows and stream compositions can be employed to destroy large fractions of the flare gas.

Fuel Selection: Use of natural gas for the pilot of the flare.

Flare Gas Recovery System (FGRS): Installation and operation of a FGRS reduces GHG combustion emissions by routing flared gases back to the fuel gas system

Alternative Control Device Options: Installation of an alternative control device with a better control efficiency (e.g., thermal oxidizer) increases combustion efficiency, resulting in decreased methane emissions.

Proper Operation: Utilizing proper operation and combustion techniques (e.g., flare gas heat content) for the plant flare reduces combustion inefficiencies, resulting in decreased methane emissions. Monitoring the pilot flame with temperature monitors, installing a flare-gas flow meter and periodically cleaning the burner to assure proper combustion and efficiency. Additionally, proper operation of the plant and reduction of MSS emissions to the flare will reduce GHG emissions.

Minimization of MSS emissions and flaring events. Good plant operations and venting of gas back to process units will reduce the quantities of gases to be flared.

Step 2 – Elimination of Technically Infeasible Alternatives

Potential alternatives to a flare include a vapor combustor/thermal oxidizer or FGRS. However, the continuous flow to the flare primary is from the pilot gas and the compressor seals that contain the N_2 and small quantities of VOC (< 100 ppm). Therefore, recovery is not possible using a FGRS. All the other devices, including the FGRS, are not suitable for large variation in flows and composition of gases from the plant, and would pose a safety concern. Therefore, these options are technically infeasible and eliminated as BACT.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Good flare design, fuel selection, proper operation and minimization of MSS emissions and flaring events are top-ranked control technologies for plant flares. The use of one technology does not preclude the use of any other control technology, and the combination of control technologies and practices will result in higher energy efficiency than any one alone.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

All technically feasible control technologies listed are considered economically reasonable because this will be a new site with the most up-to-date technology. Additionally, the potential control technologies listed will not result in any adverse energy or environmental impacts.

Step 5 – Selection of BACT

Natgasoline proposes that BACT for the plant flare (EPN: S-10001) is the combination of all of the technically feasible BACT options.

BACT Limits and Compliance

1. Natgasoline will install a flow meter for the gases to the flare and will estimate the composition of the gases based on the material balance from the unit(s) that are venting to the flare. The flow meter will meet the requirements of 40 CFR Part 98 or that of 40 CFR Part 60.

2. Natgasoline will use only natural gas for the pilot flare burner and will comply with the flare requirements of 40 CFR § 60.18 and meet a VOC including methane control efficiency of 99%.

3. Natgasoline will minimize duration and quantities of the MSS events, as specified in the TCEQ permit PSD- TX-1340. Records will be maintained of each event, date, time, and estimated volume of the release.

4. Based on the identified control technologies and the project design, emission limits for the flare of 2,735 TPY CO_2e for normal operation and 16,497 TPY CO_2e for MSS operation have been established. Compliance with these limits will be determined by calculating GHG emissions on a monthly basis using the natural gas usage in the pilots. Natgasoline will also demonstrate compliance with the CO_2e emission limit using the emission factors for natural gas from 40 CFR Part 98, Subpart C, Table C-1, and the site specific composition and flow for waste gas. The equation for estimating CO_2 emissions as specified in 40 CFR § 98.253(b)(1)(ii)(A) is as follows:

$$CO_2 = 0.99 \times 0.001 \times \left(\sum_{p=1}^{n} [\frac{44}{12} \times Flare)_p \times \frac{(MW)_p}{MVC} \times (CC)_p)] \right) * 1.102311$$

Where:
CO_2 = Annual CO_2 emissions for a specific fuel type (short tons/year).
0.99 = Assumed combustion efficiency of the flare.
0.001 = Unit conversion factor (metric tons per kilogram, mt/kg).
$\sum$ = summation of n_1 to n_x

n = Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).
p = Measurement period index.
44 = Molecular weight of CO_2 (kg/kg-mole).
12 = Atomic weight of C (kg/kg-mole).
$(Flare)_p$ = Volume of flare gas combusted during the measurement period (standard cubic feet per period, scf/period). If a mass flow meter is used, measure flare gas flow rate in kg/period and replace the term "$(MW)_p/MVC$" with "1".
$(MW)_p$ = Average molecular weight of the flare gas combusted during measurement period (kg/kg-mole). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
MVC = Molar volume conversion factor (849.5 scf/kg-mole).
$(CC)_p$ = Average carbon content of the flare gas combusted during measurement period (kg C per kg flare gas). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
1.102311 = Conversion of metric tons to short tons.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Subpart C, Table C-2, site-specific analysis of process fuel gas, and the actual heat input (HHV).

E. Railcar/Truck Loading/Vapor Combustor (EPN: VCU-1) BACT Analysis

Step 1 – Identification of Potential Control Technologies

Vapor Combustion Unit (VCU): Serves as a vent control system, which is not anticipated to operate (except in hot standby/pilot-only mode) more than the equivalent of four to eight weeks each year. Vapors collected from gasoline product loading operations and natural gas used to maintain the required minimum combustion chamber temperature to achieve adequate destruction will be routed to the VCU for control. The VCU will be designed to have a DRE of 99% for CH_4 and will be fueled by pipeline quality natural gas or process fuel gas, when available and applicable.

Vapor Recovery Unit: Designed to recover the vapor from loading of gasoline and return it to the storage tank.

Carbon Adsorption: Will absorb the vapors from gasoline, which are then be transported offsite for regeneration.

Proper Operation and Good Combustion Practices: This consists of fuel to air ratio control to minimize excess air and also the use of natural gas that will have a lower carbon content and therefore produces less GHG on combustion.

Step 2 – Elimination of Technically Infeasible Alternatives

The vapor recovery unit and carbon adsorption systems cannot be designed to manage the mass flow of vapors associated with loading gasoline into railcars or trucks in a way that will meet the applicable State and Federal air quality emission standards for the gasoline transfer rates at this facility and are technically infeasible.

Therefore, the VCU and proper operation and good combustion practices are the remaining two technically feasible options.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Both of the technically feasible options have been proposed by the applicant. The use of one technology does not preclude the use of any other control technology, and the combination of control technologies and practices will result in higher energy efficiency than any one alone.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Both the technically feasible options are being proposed and therefore this step is not necessary.

Step 5 – Selection of BACT

Natgasoline proposes that BACT for gasoline loading is a VCU with proper operations and good combustion practices.

<u>BACT Limits and Compliance</u>

1. Natgasoline will keep records of the time and duration of the loading operations of gasoline to meet the applicable federal and state regulations.

2. The minimum temperature of the VCU will be 1,400°F and will be monitored continuously when operated and records maintained.

3. Natgasoline will only use natural gas to maintain the VCU temperature and will install a fuel-flow meter at the VCU to meet the requirements of 40 CFR § 98.3(i).

4. The emission limit for the VCU is 1,062 TPY CO_2e. Natgasoline will demonstrate compliance with the CO_2 emission limit using equation C-5 in 40 CFR § 98.33, converted to short tons. CO_2 emitted from the combustion of natural gas in tons/yr shall be calculated using equation C-2a in 40 CFR § 98.33, converted to short tons. Compliance shall be based on a 12-month rolling basis to be updated by the last day of the following month.

5. The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Subpart C, Table C-2, site-specific analysis of process fuel gas, and the actual heat input (HHV).

6. An initial stack test demonstration will be required for CO_2 emissions from the VCU. An initial stack test demonstration for CH_4 and N_2O emissions is not required because the CH_4 and N_2O emission are approximately 0.1% of the total CO_2e emissions from the heater and are considered a de minimis level in comparison to the CO_2 emissions.

F. Emergency Generator (EPN: H-EMG) and Firewater Pumps (H-FWP-1 and H-FWP-2) BACT Analyses

The emergency generator and firewater pumps' engines proposed for use at the Natgasoline facility will have limited operation of less than 100 hours per year for maintenance and testing operations. During emergency conditions, non-volatile fuel (such as diesel) is required to be used and readily available. Low-sulfur diesel fuel will be stored in tanks and will be used only for emergency purposes and for maintenance or testing purposes. Each engine is designed to use diesel fuel, stored in onsite tanks, for emergency purposes to mitigate emission releases during these events such as a power outage.

Step 1 – Identification of Potential Control Technologies

The RBLC database did not identify any add-on GHG control technologies for emergency r diesel engines. Only good combustion practices were identified in the RBLC as BACT for emergency diesel generators, and Natgasoline considered this option for the BACT analysis. Good combustion practices for compression ignition engines include appropriate maintenance of equipment (such as periodic testing as will be conducted weekly) and operating within the air to fuel ratio recommended by the manufacturer. Using good combustion practices results in longer life of the equipment and more efficient operation. Therefore, such practices indirectly reduce GHG emissions by supporting operation as designed by the manufacturer.

Step 2 – Elimination of Technically Infeasible Alternatives

Use of good combustion practices is considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Good combustion practices are the only control option identified in Step 2 and are being proposed for this project.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Natgasoline will incorporate good combustion practices as recommended by the emergency diesel generator and pump manufacturers. An evaluation of the energy, environmental, and economic impacts of the proposed measure is not necessary for this application.

Step 5 – Select BACT

Natgasoline proposes to incorporate the good combustion practices discussed in Step 2 as BACT for controlling CO_2 emissions from the emergency generators. Additionally, the new engines will be subject to the federal New Source Performance Standard (NSPS) for Stationary Compression Ignition Internal Combustion Engines (40 CFR Part 60, Subpart IIII). The NSPS has specific emissions standards for various pollutants which must be met during normal operation. Therefore, the engine will meet or exceed BACT.

<u>BACT Limits and Compliance</u>

1. Natgasoline will maintain the good operations of the compression ignition engines by the maintenance of equipment per manufacturer's recommendations, periodic testing, and operating within the recommended air to fuel ratio, as specified by its design.

2. Annual operation for each engine is limited to testing and maintenance up to 100 hrs per year in non-emergency situations.

3. Operating hours will be monitored with the use of a run-time meter in conjunction with administrative controls to ensure proper engine operations.

4. Using the operating and maintenance practices identified above results in an emission limit of 280 tpy CO_2e for all three engines combined. Natgasoline will demonstrate compliance with the CO_2 emission limit using the emission factors for diesel fuel from 40 CFR Part 98 Subpart C, Table C-1. The equation for estimating CO_2 emissions as specified in 40 CFR § 98.33(a)(3)(ii) is as follows:

$$CO_2 = \frac{44}{12} * Fuel * CC * 0.001 * 1.102311$$

Where:
CO_2 = Annual CO_2 mass emissions from combustion of diesel fuel (short tons)
Fuel = Annual volume of the liquid fuel combusted (gallons). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to 40 CFR § 98.3(i).
CC = Annual average carbon content of the liquid fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV at 40 CFR § 98.33(a)(2)(ii).
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.
The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2.

G. Fugitive Emissions (EPNs: FUG-MEOH and FUG-MTG) BACT Analysis

GHG emissions from leaking pipe components (fugitive emissions) in the proposed project contain CO_2 and CH_4. The majority of the fugitive emissions is CH_4 and is calculated to be approximately 0.03% of the total GHG emissions from the facility.

Step 1 – Identification of Potential Control Technologies

1. Installation of Leakless Technology: Installing leakless technology components would eliminate GHG emissions from fugitive components. This includes barrier sealing systems for pumps and compressors, rupture discs for relief devices, and bellows sealed valves and dry-seal compressors (rather than wet-seal) for reciprocating compressors. Leakless technology to eliminate fugitive emissions sources is an expensive design option usually reserved for toxic and hazardous gases. Leakless equipment cannot be maintained online and would require a shutdown to repair the defective sealing components, or continue leaking until the plant shuts down.

2. Auditory, Visual, and Olfactory (AVO) Monitoring Program: AVO programs are common practice in the natural gas industry. This program can be performed at a lower cost and more frequently, and therefore, leaks can be detected and repaired immediately. AVO means of identifying leaks owes its effectiveness to repair leaks as a result of the frequency of observation opportunities. These opportunities arise as technicians make inspection rounds. This method can generally identify leaks from natural gas pipelines due to the odor, but cannot normally detect low pressure low leak rate as instrumented readings can identify. However, low leak rates have lower potential impacts than larger leaks.

3. Implementation of Leak Detection and Repair (LDAR) Program: LDAR programs are typically used to control VOC emissions and can achieve up to 97% control of VOC emissions. Although not specifically designed for GHG emissions, they can be used to control methane emissions. Monitors typically used for Method 21 instrument monitoring cannot detect CO_2 leaks, but can determine methane leaks. It is assumed that the same control factors can be applied to methane emission sources. Utilizing a vapor analyzer or other organic vapor sensing technology to monitor fugitive components for leaks on a set basis results in decreased emissions of GHG pollutants. For purposes of this analyses, the corresponding LDAR programs of TCEQ is considered. Because there are several TCEQ programs depending on the type of emissions and control requirements, these will be discussed in Step 3 of the BACT analyses.

4. Alternative Monitoring Using Infrared Technology: Similar to implementation of an LDAR program, the use of sensitive infrared (IR) camera technology to detect leaks of hydrocarbons results in a decrease in GHG emissions.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible, and therefore, need to be considered in Step 3 of the top-down BACT analysis.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The following is a ranking of technically feasible control technologies and their typical control efficiencies based on best information available:

Leakless Technologies: Leakless technology would result in a control effectiveness of approximately 100%. This is the most effective of the available control technologies.

LDAR Programs: LDAR programs are generally designed to reduce VOC emissions from leaking components. There is no data for the control effectiveness of LDAR programs on components in GHG service. Therefore, the same control efficiencies under the TCEQ VOC monitoring program are used for components in CH_4 service.

The TCEQ's 28LAER program is the most stringent of their LDAR monitoring programs that is used in ozone non-attainment areas. The 28LAER program achieves a control efficiency of 97% for valves, 95% for compressors, and 75% for connectors in VOC service monitored under the program. This program requires quarterly monitoring of valves and compressors and annual monitoring of connectors. Additionally, leak repair is required to be performed using directed maintenance, which requires an approved gas analyzer to be used throughout the maintenance and repair process.

The TCEQ's 28VHP LDAR program is used primarily for chemical plants in attainment areas. The 28VHP program achieves a control efficiency of 97% for valves, 85% for compressors, and 30% for connectors in VOC service monitored under the program.

Alternative Monitoring Program: Leak detection using IR camera technology is considered by the EPA to be a partial monitoring technology alternative to Method 21 (gas analyzer), since the quantity of leak cannot be measured unlike using Method 21. This is a more expensive technology resulting in the same effectiveness as a directed maintenance LDAR program.

AVO Monitoring Program: The AVO program is considered the least effective if the gas odor or leaks are small such that the leak cannot be detected. Also the gas leaks cannot be quantified without the use of an analyzer.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Leakless Technology: While the most effective of the control technologies, this strategy has concerns with being adopted for this project. Use of leakless technology can have adverse environmental impacts. In addition, the sealing mechanism, such as a bellows, is not repairable online and may leak in the event of a failure until the next unit shutdown. Following a failure of one of these parts, the component is most often not repairable online and may leak until the next unit shutdown, resulting in the emissions from the leak itself as well as the emissions of GHGs and other criteria pollutants that result from the need to shut down and re-start the facility. Regular maintenance activities in the GtG plant and units would potentially require a process unit shut down since isolation of the equipment would not be available. Emissions of GHG and conventional pollutants from maintenance activities would be increased due to having to degas larger sections of piping and perform unit shutdowns. Flanges and connectors inherently cannot be leakless, and the facility cannot be properly and effectively constructed, operated, or maintained without the use of flanges and connectors. Natgasoline cannot eliminate the use of flanges and connectors, but will use welded piping (leakless) where practicable in the plant. In large plants like MtG, fugitive equipment and components are normally maintained onstream, not requiring a plant shutdown since a plant shutdown would create additional flaring emissions. The use of leakless technology for all fugitive emission components has been eliminated.

LDAR Programs: Two different LDAR monitoring programs were analyzed for control effectiveness, TCEQ's 28LAER and 28VHP. Uncontrolled GHG emissions from fugitive components contribute less than 1% to the total GHG emissions from the project (<1,300 TPY of CO_2e). Implementing 28VHP will reduce the uncontrolled GHG emissions from fugitive components by 70% to less than 434 TPY. The directed maintenance and monitoring connectors quarterly (28LAER) will further reduce the emissions to 40 TPY. The cost estimate provided by Natgasoline for 28LAER is estimated at $82M/year or $208/ton CO_2e. It should be noted that fugitive emissions are just an estimate and not necessarily actual emissions since good design and maintenance of equipment will mitigate these estimated numbers considerably. Natgasoline believes that this cost is considered excessive for the small reduction of GHG. Therefore the 28LAER program has been eliminated based on the above cost.

Step 5 – Selection of BACT

The proposed GtG plant will implement TCEQ's 28VHP program for equipment in CH_4 service. Additionally, the proposed GtG plant will monitor equipment in natural gas or fuel gas service under the 28VHP program. Natgasoline will also implement an as-observed AVO program to monitor for fugitive emissions between instrumented monitoring as required by TCEQ's 28VHP program. Further, Natgasoline will install compressors that meet the seal and rod packing requirements to minimize emissions from compressors. Natgasoline will also use high quality components and materials of construction that are compatible with the service in which they are employed.

BACT Limits and Compliance

Natgasoline will use the TCEQ 28VHP program to monitor the fugitive leaks and is limited to CO_2e emissions from the GtG facility to 434 TPY. These emissions will be documented by annual reports as described by TCEQ's 28VHP program.

H. Cooling Tower (EPN: T-06001) BACT Analysis

Although Natgasoline will utilize non-contact cooling water and a closed loop system for its cooling water needs, the potential exists for equipment (heat exchanger) leaks to cause CH_4 to be entrained in the cooling water, which could be air-stripped during the evaporative cooling of the water in the cooling tower.

Step 1 – Identification of Potential Control Technologies

The following is a list of control technologies that minimize GHG emissions from the cooling tower.

1. Air Cooling System: An air-cooling system (e.g., fin fans) would eliminate GHG emissions from the plant cooling process.

2. Cooling Tower Monitoring and Repair Program: Implementation of a leak-detection program reduces GHG emissions by detecting and subsequently repairing leaks in the cooling water system.

Step 2 – Elimination of Technically Infeasible Alternatives

Exclusive use of an air cooling system is technically infeasible due to the location of the GtG plant, although air cooling is used throughout the plant wherever it is technically practicable (e.g., the methanol synthesis air cooler). The ambient dry bulb temperature will typically be too high in Nederland, Texas to cool some process equipment and piping to the required temperature. Therefore, this control technology by itself will not be considered any further in the BACT analysis. The cooling tower monitoring and repair program identified in Step 1 is considered technically feasible, and therefore, will be considered in Step 3, 4 and 5 of the BACT analysis.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Implementation of a cooling tower monitoring and repair program reduces emissions from the cooling tower by almost 90% based on comparison of the uncontrolled cooling water VOC emission factor and the controlled cooling tower emission factor from EPA's AP-42 Chapter 5.1.1, Table 5.1-2 (*January 1995*).

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

There are no known negative economic, energy, or environmental impacts associated with the cooling tower monitoring and repair program.

Step 5 – Selection of BACT

Natgasoline proposes that BACT for the cooling tower (EPN: T-06001) is the use of air cooling systems where technically feasible and implementation of a structured cooling tower monitoring and repair program. The program will be based on the monitoring and repair requirements specified in 40 CFR Part 63, Subpart F, to detect GHG emissions, total organic compounds will be monitored in lieu of HAPs.

<u>BACT Limits and Compliance</u>

1. The annual emission limit on the cooling tower (EPN: T-06001) is 866 TPY of CO_2e.
2. This limit will be calculated as part of monitoring and repair requirements specified in 40 CFR Part 63, Subpart F. Total Organic Carbon (TOC) will be substituted for HAP to determine if a GHG leak is present. TOC will be measured utilizing Method 5310 from Standard Methods for the Examination of Water and Wastewater. It will be assumed that any hydrocarbon detected utilizing this method will be CH_4.

IX. Endangered Species Act (ESA)

Pursuant to Section 7(a)(2) of the Endangered Species Act (ESA) (16 U.S.C. 1536) and its implementing regulations at 50 CFR Part 402, EPA is required to insure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any federally-listed endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat.

To meet the requirements of Section 7, EPA has reviewed and adopted a Biological Assessment (BA) dated June 2013 and revised May 1 2014, prepared by Weston Solutions, Inc. ("Weston") on behalf of Natgasoline, LLC ("Natgasoline") and EPA. The draft BA identified nine (9) species listed as federally endangered or threatened in Jefferson County, Texas:

Federally Listed Species for Jefferson County by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS), and the Texas Parks and Wildlife Department (TPWD)	Scientific Name
Birds	
Piping plover	*Charadrius melodus*
Fish	
Smalltooth sawfish	*Pristis pectinata*
Mammals	
Louisiana black bear	*Ursus americanus luterolus*
Red wolf	*Canis rufus*
Reptiles	
Green sea turtle	*Chelonia mydas*
Kemp's ridley sea turtle	*Lepidochelys kempii*
Leatherback sea turtle	*Dermochelys coriacea*
Loggerhead sea turtle	*Caretta caretta*
Hawksbill sea turtle	*Eretmochelys imbricate*

EPA has determined that issuance of the proposed permit to Natgasoline for a new methanol and motor-grade gasoline production (GtG) facility will have no effect on the nine (9) listed species, as there are no records of occurrence, no designated critical habitat, nor potential suitable habitat for any of these species within the action area.

Because of EPA's "no effect" determination, no further consultation with the USFWS and NMFS is needed.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on listed species. The final draft biological assessment can be found at EPA's Region 6 Air Permits website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

X. Magnuson-Stevens Act

The 1996 Essential Fish Habitat (EFH) amendments to the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act) set forth a mandate for the National Oceanic Atmospheric Administration's National Marine Fisheries Service (NMFS), regional fishery management councils, and other federal agencies to identify and protect important marine and anadromous fish habitat.

To meet the requirements of the Magnuson-Stevens Act, EPA is relying on an EFH Assessment prepared by Weston on behalf of Natgasoline and reviewed and adopted by EPA.
The facility is adjacent to tidally influenced portions of the Lower Neches River that adjoins to Lake Sabine leading to the Gulf of Mexico. These tidally influenced portions have been

identified as potential habitats of postlarval, juvenile, subadult or adult stages of red drum (*Sciaenops ocellatus*), shrimp (4 species), and reef fish (43 species). The EFH information was obtained from the NMFS's website (http://www.habitat.noaa.gov/protection/efh/efhmapper/index.html)

Based on the information provided in the EFH Assessment, EPA concludes that the proposed PSD permit allowing Natgasoline for a new methanol and motor-grade gasoline production (GtG) facility will have no adverse impacts on listed marine and fish habitats. The assessment's analysis, which is consistent with the analysis used in the BA discussed above, shows the project's construction and operation will have no adverse effect on EFH.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on listed species. The final essential fish habitat report can be found at EPA's Region 6 Air Permits website at:
http://yosemite.epa.gov/r6/Apermit.nsf/AirP

XI. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties eligible for inclusion in the National Register of Historic Places. To make this determination, EPA relied on and adopted a cultural resource report prepared by Weston and AmaTerra Environmental, Inc. ("AmaTerra") on behalf of Natgasoline and EPA and submitted in July 28, 2014.

For purposes of the NHPA review, the Area of Potential Effect (APE) was divided into three (3) tracts of land of 1.2, 3.3, 17.6 acres each for a total of 22 acres that contains the construction footprint of the project and pipeline corridor. Weston and AmaTerra performed a field survey of the property and a desktop review on the archaeological background and historical records within a 1-mile radius of the APE.

Based on the results of the field survey, no archaeological resources or historic structures were found within the APE. Based on the desktop review for the site, two cultural surveys were previously conducted within the APE. There are five archaeological and seven historical sites, four historical markers and one historic district identified within a 1.8-mile radius of the APE. Ten of these sites are eligible or potentially eligible for listing on the National Register; however, they are all outside the APE.

On April 24, 2014, EPA sent letters to Indian tribes identified by the Texas Historical Commission as having historical interests in Texas to inquire if any of the tribes have historical interest in the particular location of the project and to inquire whether any of the tribes wished to consult with EPA in the Section 106 process. EPA received no requests from any tribe to consult on this proposed permit. EPA will provide a copy of the report to the State Historic Preservation Officer for consultation and concurrence with its determination. Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties. A copy of the report may be found at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XII. Environmental Justice (EJ)

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive branch policy on environmental justice. Based on this Executive Order, the EPA's Environmental Appeals Board (EAB) has held that environmental justice issues must be considered in connection with the issuance of federal Prevention of Significant Deterioration (PSD) permits issued by the EPA Regional Offices [See, e.g., *In re Prairie State Generating Company*, 13 E.A.D. 1, 123 (EAB 2006); *In re Knauf Fiber Glass*, Gmbh, 8 E.A.D. 121, 174-75 (EAB 1999)]. This permitting action, if finalized, authorizes emissions of GHG, controlled by what we have determined is the Best Available Control Technology for those emissions. It does not select environmental controls for any other pollutants. Unlike the criteria pollutants for which the EPA has historically issued PSD permits, there is no National Ambient Air Quality Standard (NAAQS) for GHGs. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [PSD and Title V Permitting Guidance for GHGS at 48]. Thus, we conclude it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, we have determined an environmental justice analysis is not necessary for the permitting record.

XIII. Conclusion and Proposed Action

Based on the information supplied by Natgasoline, our review of the BACT analyses contained in the TCEQ PSD Permit Application, and the GHG PSD Permit Application, and our independent evaluation of the information contained in our Administrative Record, it is our determination that the proposed facility would employ BACT for GHGs under the terms contained in the draft permit. Therefore, EPA is proposing to issue Natgasoline a PSD permit for GHGs for the facility, subject to the PSD permit conditions specified therein. This permit is subject to review and comments. A final decision on issuance of the permit will be made by EPA after considering comments received during the public comment period.

APPENDIX A

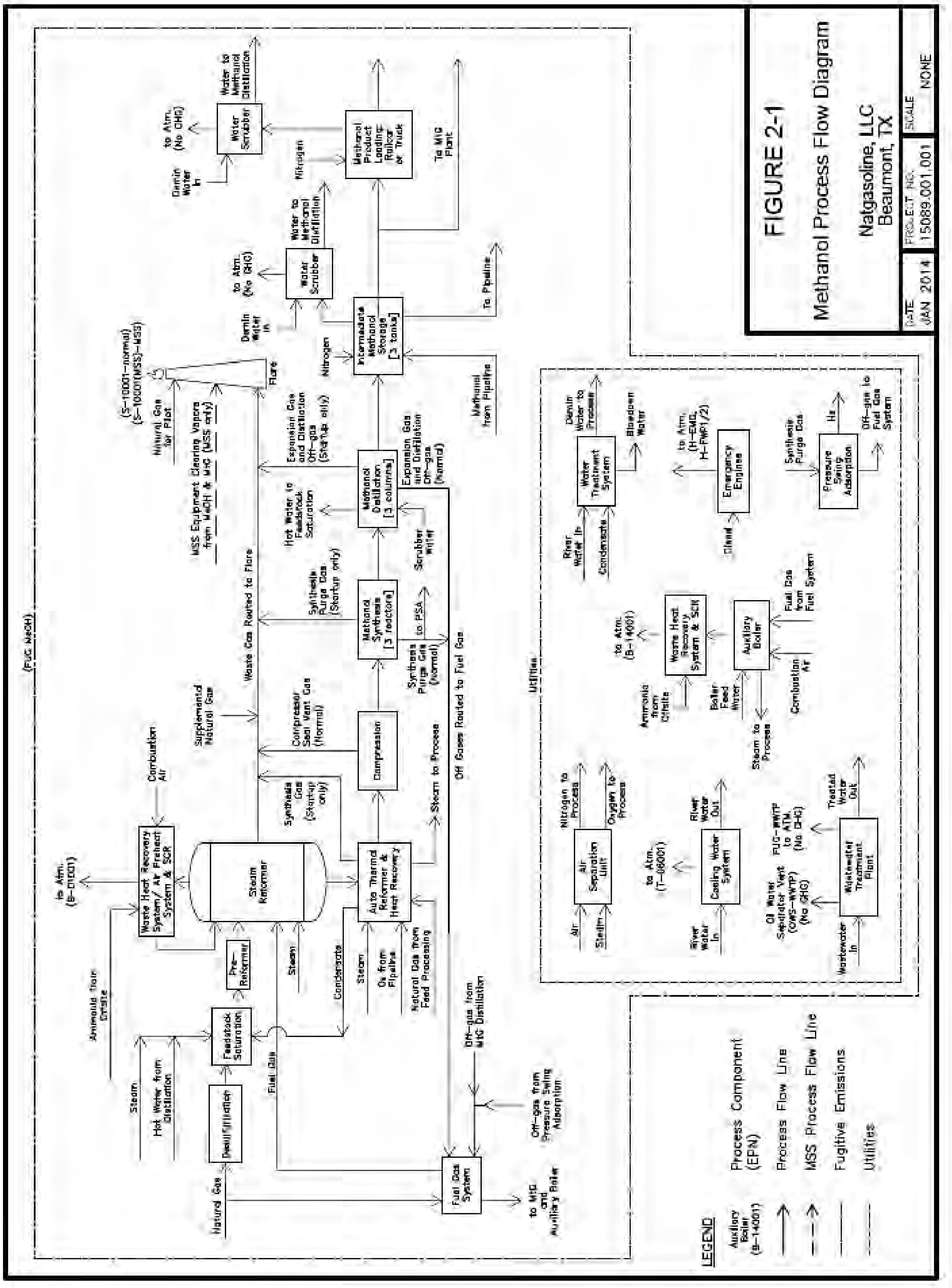
Table 1. Annual Emission Limits [1]

EPN	FIN	Description	GHG Mass Basis: Pollutant	GHG Mass Basis: TPY [2]	TPY CO_2e [2,3]	BACT Requirements
B-01001	B-01001	Reformer	CO_2	718,867	719,576	Minimum 90 (%)Thermal Efficiency, Maximum 3% oxygen (O_2) in stack gas (normal operation), Maximum 350°F in stack gas (normal operation). See permit condition III.A.1
			CH_4	12.94		
			N_2O	1.29		
B-14001	B-14001	Auxiliary Boiler	CO_2	357,225	357,594	Minimum 77% Thermal Efficiency. See permit condition III.A.2
			CH_4	6.74		
			N_2O	0.67		
H-REGEN	H-REGEN	Regeneration Heater	CO_2	12,733	12,746	Maximum Firing Rate of 45 MMBtu/hr, Gaseous Fuel, Good Combustion Practices. See permit condition III.A.3
			CH_4	0.24		
			N_2O	0.02		
H-RX1 H-RX2 H-RX3 H-RX4 H-RX5	H-RX1 H-RX2 H-RX3 H-RX4 H-RX5	MtG Reactor Heaters	CO_2	52,874[4]	52,929[4]	Maximum Firing Rate of 25 MMBtu/hr, Gaseous Fuel, Good Combustion Practices. See permit condition III.A.3
			CH_4	1.00[4]		
			N_2O	0.10[4]		
H-HGT	H-HGT	MtG Heavy Gasoline Heater Treater	CO_2	3,844	3,850	Maximum Firing Rate of 8 MMBtu/hr, Gaseous Fuel, Good Combustion Practices. See permit condition III.A.3
			CH_4	0.07		
			N_2O	0.01		
S-10001	S-10001	Flare Pilot & Normal Operation	CO_2	2,571	2,735	Good Design and Combustion Practices, Minimize Flaring events. See permit condition III.A.4
			CH_4	6.54		
			N_2O	<0.01		
S-10001 (MSS)	F-10001	Flare MSS Vents	CO_2	16,203	16,497	Good Operational Practices. See permit condition III.A.5
			CH_4	11.43		
			N_2O	0.03		
VCU-1	VCU-1	MtG VCU	CO_2	1,061	1,062	Maintain minimum combustion temperature as determined by testing. Good Combustion Practices. See permit condition III.A.6
			CH_4	0.02		
			N_2O	<0.01		
FUG-MEOH	FUG-MEOH	MeOH Fugitives	CH_4	No Numerical limit is established[5]		Implementation of Leak Detection and Repair (LDAR) Program. See permit condition III.A.7
FUG-MTG	FUG-MTG	MtG Fugitives	CH_4	No Numerical limit is established[5]		Implementation of LDAR Program. See permit condition III.A.7
V-CATREGEN	V-CATREGEN	Catalyst Regeneration Vent	CO_2	5,446	5,446	Proper Operating Techniques. See permit condition III.A.8
H-EMG	H-EMG	Emergency Generator	CO_2	139	140	Proper Operating Techniques Limited Operating Hours. See permit condition III.A.9
			CH_4	0.01		
			N_2O	<0.01		

EPN	FIN	Description	GHG Mass Basis		TPY CO_2e [2,3]	BACT Requirements
			Pollutant	TPY [2]		
H-FWP1 H-FWP2	H-FWP1 H-FWP2	Firewater Pump Engines	CO_2	139	140	Proper Operating Techniques, Limited Operating Hours. See permit condition III.A.9
			CH_4	0.01		
			N_2O	<0.01		
T-06001	T-06001	Cooling Tower	CO_2	-	866	Implementation of Heat Exchanger Leak Monitoring and Repair Program. See permit condition III.A.10
			CH_4	34.65		
			N_2O	-		
Totals [6]			CO_2	1,171,102	1,174,027	
			CH_4	91.49		
			N_2O	2.12		

1. Compliance with the annual emission limits (TPY) is based on a 12-month rolling basis.
2. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations, including MSS activities.
3. Global Warming Potentials (GWP): Methane (CH_4) = 25, Nitrous Oxide (N_2O) = 298
4. The emissions shown for the reactor heaters (H-RX1, H-RX2, H-RX3, H-RX4, and H-RX5) is an emissions cap for all five heaters combined.
5. Fugitive process emissions from EPN FUG-MEOH are estimated to be 10.91 TPY of CH_4 and 273 TPY CO_2e. emissions cap for all five heaters combined. Fugitive process emissions from EPN FUG-MTG are estimated to be 6.93 TPY of CH_4 and 173 TPY CO_2e. In lieu of an emission limit, the emissions will be limited by implementing an LDAR monitoring program.
6. The total emissions for CH_4 and Carbon dioxide equivalent (CO_2e) include the Potential to Emit (PTE) for process fugitive emissions of CH_4. These totals are given for informational purposes only and do not constitute emission limits.

Appendix B
Methanol Plant Process Flow Diagram.



Methanol Gas to Gasoline Flow Diagram