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REVISED EPA GHG AIR PERMIT APPLICATION FOR A NEW NATURAL GAS TO GASOLINE PLANT

Prepared for

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LIST OF ACRONYMS

BACT	Best Available Control Technology
bbl	barrel
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
DME	dimethyl ether
DRE	destruction removal efficiency
dscf	Dry Standard Cubic Foot
EPN	Emission Point Number
GHG	greenhouse gas
GtG	Gas to Gasoline
HAP	hazardous air pollutants
H_2S	Hydrogen Sulfide
HGT	heavy gasoline treatment
IFR	internal floating roof
IR	infrared
LAER	Lowest Achievable Emission Rate
Lb/hr	pounds per hour
LDAR	leak detection and repair
LEL	lower explosive limit
LPG	liquid petroleum gas
MACT	Maximum Achievable Control Technology
MeOH	Methanol
MMBtu/hr	10^6 British Thermal Units per hour
MMgal/yr	10^6 gallons per year
MSS	maintenance, startup, and shutdown
MtG	Methanol to Gasoline
NAAQS	National Ambient Air Quality Standards
NNSR	Non-attainment New Source Review
NO_X	Nitrogen Oxides
NSPS	New Source Performance Standards
NSR	New Source Review
NSRPD	New Source Review Permits Division

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PM	Particulate Matter
ppmvd	Parts Per Million, Volumetric Dry
ppmw	parts per million by weight
PSD	Prevention of Significant Deterioration
PTE	potential to emit
RN	regulated entity number
RVP	Reid Vapor Pressure
SCR	selective catalytic reduction
SO_2	Sulfur Dioxide
TAC	Texas Administrative Code
TCAA	Texas Clean Air Act
TCEQ	Texas Commission on Environmental Quality
tpy	short ton per year
VCU	vapor combustion unit
VFR	vertical fixed roof
VOCs	volatile organic compounds

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1. INTRODUCTION

Natgasoline, LLC (Natgasoline) proposes to construct a new motor-grade gasoline production facility in Beaumont, Texas that uses natural gas as feedstock. The proposed new facility will include two main process units. The first process unit is identified herein as the "Methanol Unit" and it will convert natural gas and water into methanol. The second process unit is identified herein as the "Methanol-to-Gasoline (MtG) Unit," and it will convert methanol into motor vehicle gasoline and water. With this substantial investment in the Beaumont area, Natgasoline plans to:

- create over 130 permanent new jobs;
- construct the first Gas to Gasoline (GtG) plant in the United States (U.S.); and
- create a new commercially viable pathway to reduce foreign oil demand by leveraging natural gas (the fastest growing domestic energy resource in the U.S.) to manufacture gasoline.

With this application, Natgasoline requests a Greenhouse Gas (GHG) air quality permit authorization to construct and operate the proposed new GtG facility in Beaumont, Texas. This initial GHG permit application is provided consistent with the requirements in Title 40, Part 52 of the Code of Federal Regulations (40 CFR 52) and specifically with the §52.21 Prevention of Significant Deterioration (PSD) requirements. The new GtG facility will be an independent source for purposes of the PSD permitting rules as discussed in **Section 1.3** below.

An area map showing the location of the proposed new GtG facility is included in this section as **Figure 1-1**. A facility plot plan for the proposed new GtG plant is included as **Figure 1-2**.

1.1 PROJECT OVERVIEW

Natgasoline is proposing to construct a motor-grade gasoline production plant in Beaumont, Texas. The new plant will have two primary process units:

- A 5,500-metric ton per day (tpd) methanol production unit that synthesizes refined methanol using natural gas feedstock and water; and
- A 22,000-barrel per day (bpd) gasoline production unit that synthesizes gasoline and water using the refined methanol from the proposed new methanol production unit or other off-site sources.

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New process equipment associated with this project includes external combustion sources (e.g., process heaters); flare; cooling tower; storage tanks; and liquid loading with associated piping and other equipment components. The new GtG facility will be authorized under a new PSD permit.

1.2 DEFINITION OF STATIONARY SOURCE

For purposes of air permitting, the Natgasoline GtG plant is proposed as a separate, new stationary source. Natgasoline is a recently incorporated company that does not own or operate any other facility in the area of the proposed GtG plant. Ownership, operational control, and management of the Natgasoline GtG plant will be entirely independent from any other existing facility. As a stand-alone new source, the proposed new GtG plant will constitute a major source for PSD applicability evaluation purposes, as discussed in **Section 1.3** below.

1.3 PSD APPLICABILITY EVALUATION

This application is provided to the EPA to request PSD permit authorization as required under 40 CFR §52.21for constructing a new major stationary source of regulated GHG air pollutants. Construction of the new GtG facility will occur after 1 July 2011 and the associated GHG potential to emit for the entire facility is greater than 100,000 tons per year (tpy) of carbon dioxide equivalent (CO_2e). Therefore, a PSD permit appears to be required for GHG emissions as specified in §52.21(b)(49).

PSD applicability tables are included in **Appendix C** to document the determination that the proposed GtG plant construction is subject to PSD permitting requirements for GHG emissions. Project-related GHG potential to emit calculations are included in **Appendix D**. Because this is a proposed new stationary source, and there are no contemporaneous projects to evaluate, PSD netting tables are not included in **Appendix C**. **Table D-1** (in **Appendix D**) summarizes the project-related GHG potential emissions, and **Appendix C** provides additional PSD emission summaries and PSD applicability analysis information.

The proposed Natgasoline project will be subject to PSD permitting for regulated air pollutants other than GHG pollutants, and Natgasoline will comply with all applicable PSD permitting requirements for all pollutants that are subject to PSD as specified in 40 CFR §52.21. On 16

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January 2013, Natgasoline delivered a separate PSD air permit application to the Texas Commission on Environmental Quality (TCEQ) covering all regulated PSD pollutants except for GHG pollutants. Natgasoline will provide air pollutant dispersion modeling analyses to the TCEQ to demonstrate that the proposed new source will not cause or contribute to a violation of the National Ambient Air Quality Standards (NAAQS) as specified in §52.21(k). Based on §52.21 and related EPA guidance documents, Natgasoline understands the following with regard to other evaluations required for PSD permitting of regulated GHG pollutants:

- EPA has not established NAAQS specific to regulated GHG pollutants.
- Air dispersion modeling of the regulated GHG pollutants is not required under §52.21(k) at this time.
- Preconstruction air quality monitoring of regulated GHG pollutants is not required under §52.21(m)(1)(ii) at this time.

Additional impacts analysis of regulated GHG pollutants on designated Class I areas is not required under §52.21(o) at this time. In any case, the proposed project is located more than 500 kilometers from the nearest designated Class I area, the Caney Creek Wilderness Area in Arkansas.

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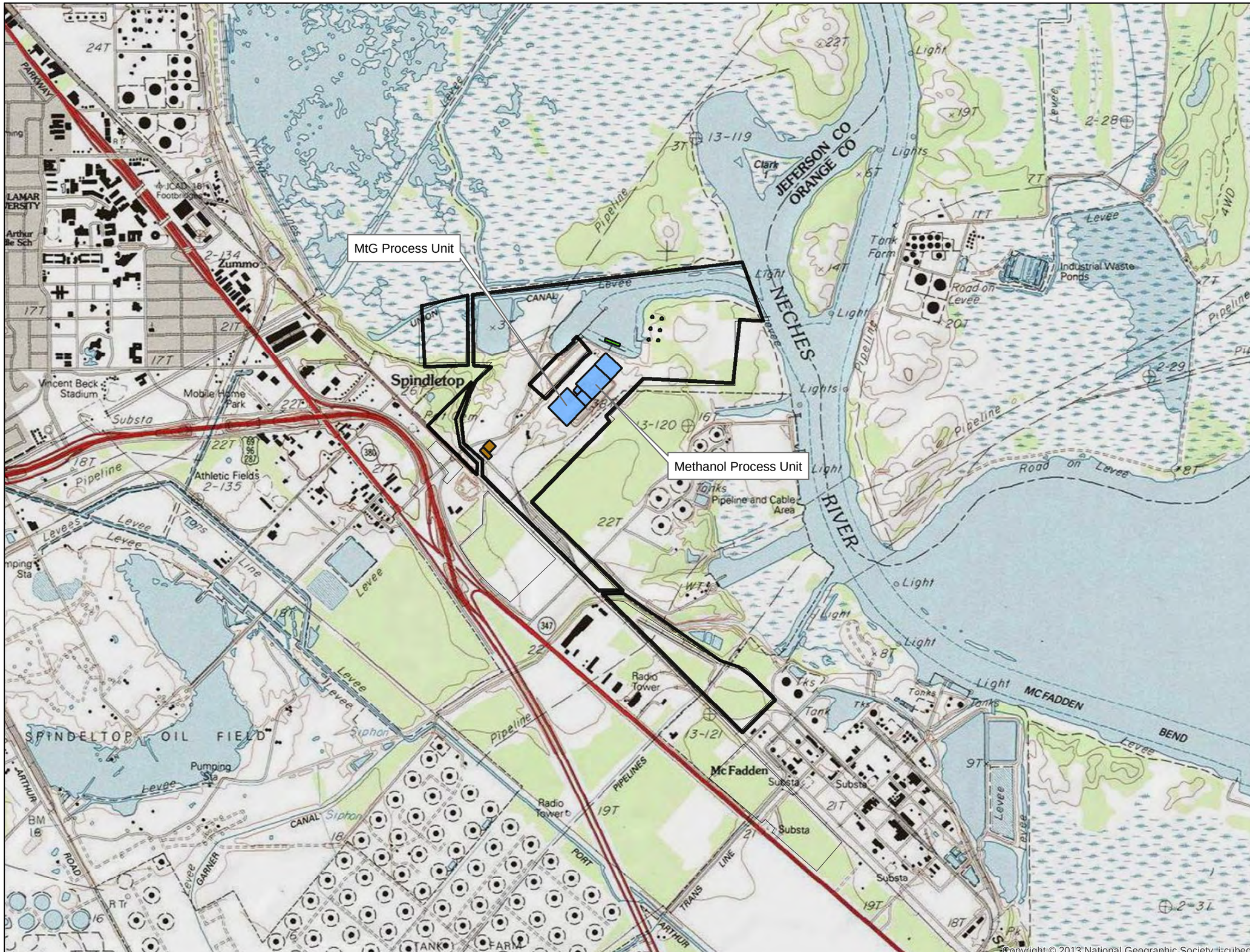

LEGEND

- PROCESS AREAS
- PROPERTY BOUNDARY
- STORAGE AND LOADING
- EMISSION POINTS
- OTHER STRUCTURES

N

0 2,000 4,000

Feet

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FIGURE 1-1

GtG PLANT

NATGASOLINE, LLC
BEAUMONT, TX

DATE	PROJECT NO	SCALE
AUG 2013	15089.001.001	AS SHOWN

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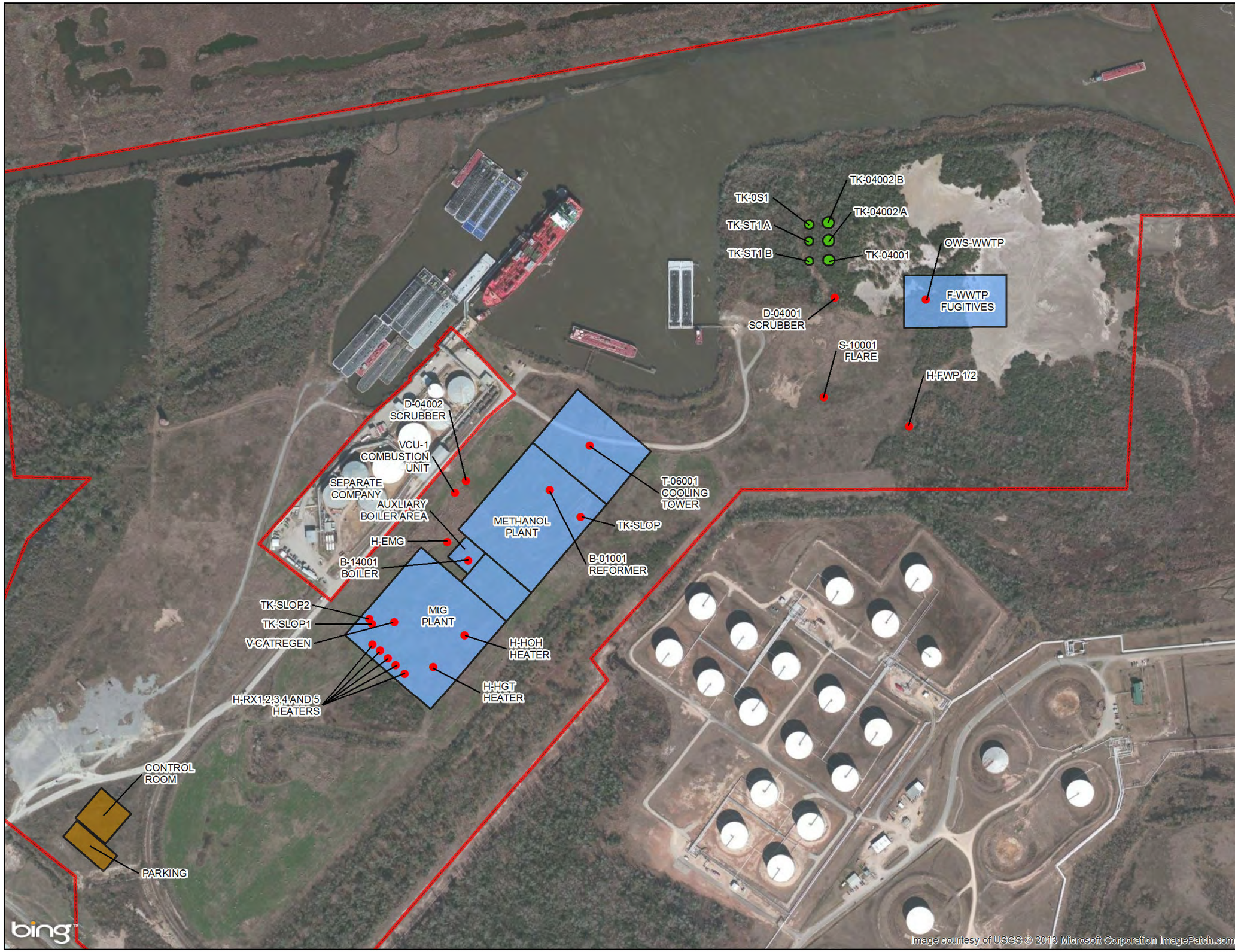

LEGEND

- PROCESS AREAS
- STORAGE AND LOADING
- EMISSION POINTS
- OTHER STRUCTURES
- PROPERTY BOUNDARY
- EMISSION POINTS

N

0 400 800

Feet

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FIGURE 1-2

PLANT LAYOUT

NATGASOLINE, LLC
BEAUMONT, TX

DATE	PROJECT NO	SCALE
AUG 2013	15089.001.001	AS SHOWN

FILE: I:\GIS Project Files\15089_Natgasoline LLC\001_Beaumont\Proposed Plot Plan Ver 6.mxd 10:43:11 AM 8/27/2013 cookd

2. PROCESS DESCRIPTION

The proposed new GtG facility will be composed of two main process operations: the methanol unit and the MtG unit. The methanol unit will be designed to produce 5,500 tons per day of methanol from natural gas feedstock. The MtG unit will be designed to produce 22,000 barrels per day of gasoline from methanol feedstock. The GtG Plant will also be supported by utility operations and other ancillary equipment as described below. Process flow diagrams for the methanol unit and MtG unit are provided at the end of this section as **Figures 2-1** and **2-2**, respectively.

2.1 METHANOL UNIT PROCESS DESCRIPTION

The proposed new methanol unit will synthesize methanol using natural gas as feedstock. Natural gas will be delivered to the methanol unit by pipeline. The majority of the natural gas received by the facility will be used as chemical feedstock for the methanol process, and a portion of the natural gas will be burned as fuel. The chemical feedstock portion of the natural gas will first be treated to remove sulfur compounds and then otherwise pretreated for use in the methanol process.

The pretreated natural gas feedstock will be combined with steam and recycled process gases and routed to the reforming section of the methanol unit. The reforming section will convert the methane, steam, and other compounds into synthesis gas (or "syngas"). Syngas is a gaseous mixture that includes varying concentrations of hydrogen, carbon monoxide, and carbon dioxide. The reforming section will include one primary reformer and one secondary reformer. The primary reformer will include a gas-fired combustion source (EPN: B-01001). The secondary reformer will be an Auto-thermal Reformer (ATR), which does not include any fired combustion heating. The ATR will process a portion of the pre-reformed gas feedstock as well as reformed gas from the steam reformer.

The syngas from the reforming section will be compressed and then sent to the methanol synthesis section of the methanol unit, which contains a series of reactors to convert the syngas into crude methanol. The crude methanol liquid from the reaction section will include water, liquid impurities, and dissolved gases that will be removed in downstream distillation operations.

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The crude methanol stream will be routed from the synthesis section to the distillation section, where the methanol will be fed through a series of distillation columns in order to remove the impurities, such as water, listed above. The effluent stream from this process will be the refined methanol product which will either be sent to storage for further processing in the MtG Unit or for product loading via either the shared methanol/gasoline railcar and truck loading facilities or off-site for third party storage and loading.

See **Section 2.4** for more detailed information regarding planned maintenance, startup, and shutdown (MSS) activities.

2.2 MTG UNIT PROCESS DESCRIPTION

The proposed new MtG unit will synthesize motor-grade gasoline using methanol as feedstock. The methanol feedstock will generally be the methanol product from the proposed new methanol unit. However, the MtG unit will also be able to process methanol from other methanol manufacturers.

The methanol feedstock will be fed through a series of MtG reactors, which convert the methanol into a raw gasoline and liquefied petroleum gas (LPG) mixture. There will be six gas-fired process heaters associated with the MtG reaction unit: five reactor heaters associated with each MtG reactor (EPN: H-RXH1-5) that will supply heat to the reaction, and the regeneration heater (EPN: H-REGEN), which will periodically combust a carbonaceous (i.e., coke) deposit that will build up on the reactor catalyst during operation. The emissions from the catalyst regeneration vents (EPN: V-CATREGEN) will be routed to atmosphere only during catalyst regeneration events.

After the MtG reaction portion, the combined raw gasoline and LPG mixture will be sent to separation where it will be separated into three streams: 1) an LPG stream to be sent to 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 heavy gasoline treatment (HGT) for further processing.

The HGT unit will process heavy gasoline fraction from the separation portion in order to convert undesired components. The HGT feed stream will be heated using the HGT Treater Heater (EPN: H-HGT), and will then pass through a series of reactors to convert selected

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components into more valuable hydrocarbon components. The HGT reaction section will produce an LPG stream that will be routed to LPG storage and a heavy gasoline stream that will be blended with the light gasoline stream from the separation portion and routed to product gasoline storage and loading.

Gasoline product loading will take place at the shared methanol/gasoline railcar and truck loading facilities.

2.3 SUPPORTING OPERATIONS

The proposed new GtG Plant will be supported by various auxiliary operations. An auxiliary boiler (EPN: B-14001) will be used to provide steam to the plant process units. A cooling system will be utilized that includes both air cooling and a cooling water tower (EPN: T-06001). Additionally, a plant flare (EPN: S-10001)/[MSS] will control emissions in cases of upset or emergency and planned MSS activities. An on-site wastewater treatment plant will receive and treat wastewater from the MeOH and MtG units.

2.4 PLANNED MAINTENANCE, STARTUP, AND SHUTDOWN ACTIVITIES

Planned MSS activities will occur in order to ensure the operation of the GtG Plant. Such activities will require shutdown of the processes and subsequent start-up to return to normal operations. A common flare at the site will control emissions from planned MSS activities, including combustion of synthesis gas, reformer fuel gas, and/or gases from equipment clearing.

2.4.1 Methanol Unit Startup

The startup of the methanol unit will include periods of flaring of several different gas stream types and compositions during the methanol plant startup process. During this time, different gases will be routed in sequence to the flare. Gases routed to flare during the methanol unit startup include the following:

- Natural gas will be blended with nitrogen, circulated through reformer equipment to raise the temperature, and then routed to flare until appropriate reformer operating temperatures are achieved.
- Synthesis gas from the reformer will be routed to flare until the downstream methanol synthesis process is stabilized.

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- Reformer fuel gas streams from the methanol unit will be routed to flare until stable conditions are established for normal fuel gas processing.

The entire startup is estimated to last approximately 22 hours. Additionally, one more stream will be routed to flare when the methanol reactor catalyst is reduced from its oxidized form to its metallic form, which is normally estimated to occur only once every three years. During the required catalyst activation period, a mixture of nitrogen and hydrogen will be circulated in the reactor system until the temperature is high enough to cause the release of carbon dioxide (CO_2) from the catalyst into the circulated gas. The volume percent of CO_2 in the circulated gas will be maintained at optimal levels for catalyst reduction, and the nitrogen/hydrogen/CO_2 mixture will be routed to flare for a short duration until the reduction process has been completed.

2.4.2 Plant-Wide Turnarounds

A plant-wide turnaround, in which the entire GtG plant equipment volume is cleared to flare, is estimated to occur up to once per year. The equipment will be drained of any remaining liquids before being degassed to the plant flare (if required). Large equipment, including vessels and heat exchangers, will not be opened to atmosphere until an acceptable level of VOC concentration remains.

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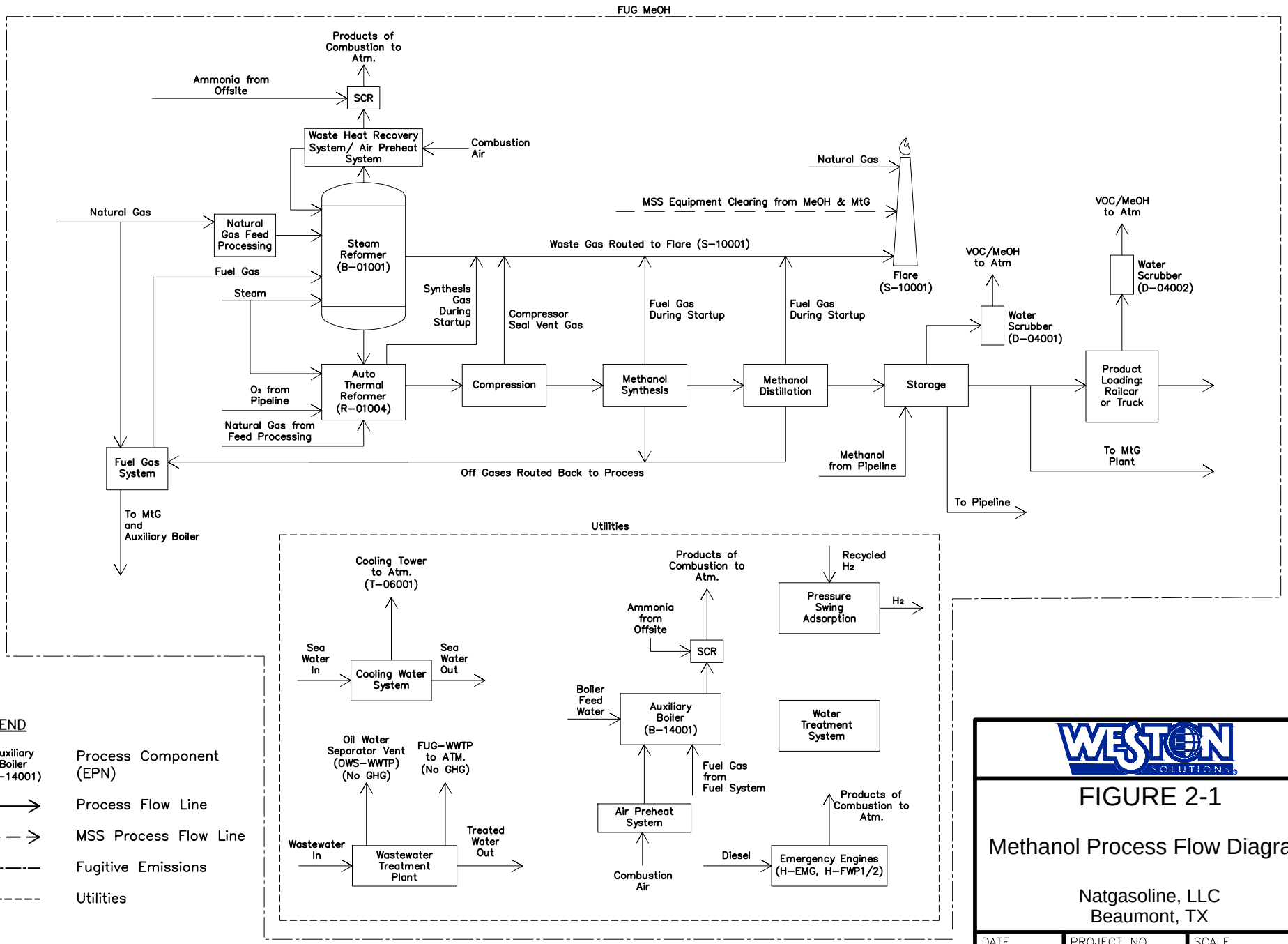

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FIGURE 2-1

Methanol Process Flow Diagram

Natgasoline, LLC
Beaumont, TX

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AUG 2013	15089.001.001	NONE

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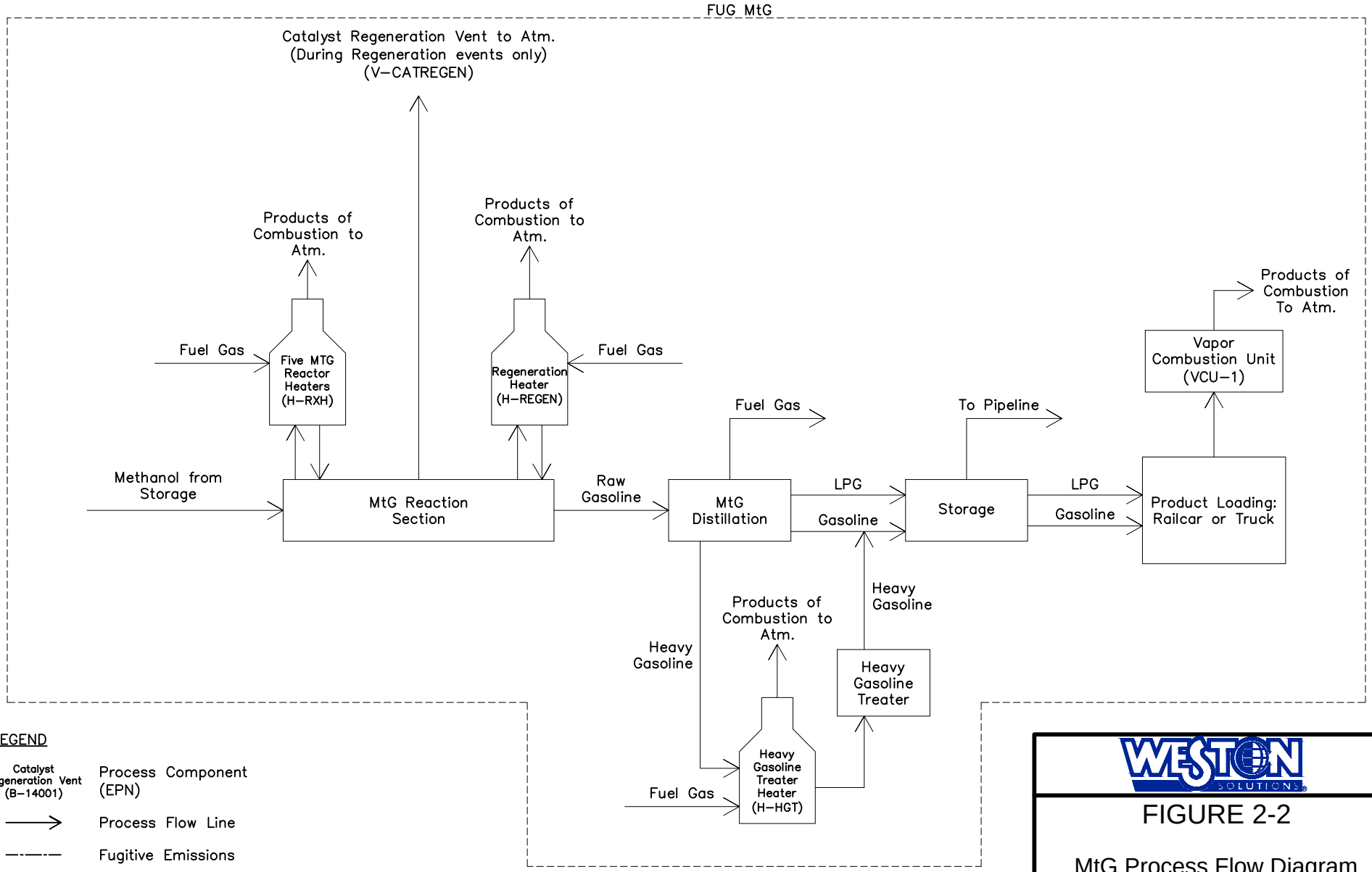

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FIGURE 2-2

MtG Process Flow Diagram

Natgasoline, LLC
Beaumont, TX

DATE	PROJECT NO.	SCALE
AUG 2013	15089.001.001	NONE

3. EMISSION CALCULATIONS

The following sections describe GHG emission calculation methods applied to each source type associated with the proposed GtG project.

3.1 COMBUSTION SOURCES

Natgasoline proposes to construct nine new external combustion sources as part of the GtG project: the steam reformer (EPN: B-01001), auxiliary boiler (EPN: B-14001), and seven process heaters (EPNs: H-REGEN, H-RXH1-5, and H-HGT). GHG emissions from these nine combustion units were calculated using the proposed hourly and annual firing rates and GHG emission factors for natural gas fuel combustion from 40 CFR Part 98 Subpart C, Table C-1 and Table C-2. The CO_2 emissions from the steam reformer were based on fuel-specific carbon content, using the calculation methodology referenced to in 40 CFR Part 98 Subpart C, equation C-5. A process gas analyzer will emit very low quantities of GHG pollutants and these analyzer emissions are included as part of the calculated reformer emissions. Detailed emission calculations from the combustion sources are provided in **Table D-2** in **Appendix D**.

3.2 PROCESS FLARE EMISSIONS

During normal operations, only natural gas (pilot gas and supplemental fuel) and compressor seal vent gas (process waste gas) will be combusted in the plant flare (EPN: S-10001). Emissions from the combustion of the pilot gas were calculated using estimated maximum hourly and annual pilot gas flow rates in conjunction with the emission factor for CO_2 from U.S. EPA's AP-42 Table 1.4-2 (July 1998) and emission factors for CH_4 and N_2O from 40 CFR Part 98 Subpart C, Table C-2.

The compressor seal vent gas is primarily comprised of nitrogen with some concentration (≤100 ppmv) of hydrocarbon contamination. There will also be some supplemental natural gas combined with this stream in order to raise the heating value of the waste gas to an acceptable level per §60.18. Emissions from the compressor seal vents were calculated using the estimated waste gas and supplemental natural gas flow rates and compositions and the appropriate emission factors. The CO_2 emissions were based on fuel-specific carbon content, using the

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calculation methodology referenced to in 40 CFR Part 98 Subpart C, equation C-5. Emissions of N_2O were based on the emission factor 40 CFR Part 98 Subpart C, Table C-2. Emissions of CH_4 were based on the estimated concentration of CH_4 in the waste gas stream and a flare destruction efficiency of 99%.

Waste gas flaring will occur during periods of methanol unit startups. Specifically, natural gas, synthesis gas, and reformer fuel gas will be routed to the flare (EPN: S-10001[MSS]) during limited portions of the methanol unit startup operations. Additionally, MSS-related flaring will take place during methanol reactor catalyst reduction, which will occur each time the catalyst is replaced. There will be supplemental natural gas associated with this event. For CO_2, emission rates from startup flaring events were calculated using the fuel-specific carbon content as specified in Equation C-5, which is the relevant calculation methodology in 40 CFR Part 98 Subpart C. N_2O emission rates were based on the emission factor 40 CFR Part 98 Subpart C, Table C-2. Emissions of CH_4 were based on the concentration of CH_4 in the waste gas stream and a flare destruction efficiency of 99%.

Waste gas flaring will also occur during equipment clearing for maintenance purposes. Flare emissions from planned clearing of equipment were calculated based on the flare burning a volume of saturated vapor with a small amount of volatilized residual liquid volume. Hourly equipment clearing emissions for the flare were calculated assuming the largest process vessel on-site would be cleared to the flare in a single hour. Annual equipment clearing emissions were calculated based on the maximum number of planned plant shutdowns estimated to occur in any 12-month period and assuming each shutdown will include the total volume of all plant process equipment. Supplemental natural gas may also be required during the equipment clearing events and is included in the emission calculations. These emission calculation methods are intended to provide conservative potential GHG emissions estimates and should not be considered operational limits or constraints.

Emissions of CO_2, CH_4, and N_2O from flaring during equipment clearing were calculated using the estimated organic vapor flow rates and emission factors from 40 CFR Part 98 Subpart C, Table C-1 and C-2. Global warming potential values in carbon dioxide equivalent (CO_2e) were

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calculated based on the factors in 40 CFR Part 98 Subpart A, Table A-1. Detailed emission calculations from the flare are provided in **Tables D-3** through **D-6** in **Appendix D**.

3.3 VAPOR COMBUSTOR

Vapors collected from gasoline product loading operations will be routed to a vapor combustor (EPN: VCU-1) for control. CO_2 emissions from burning the collected loading vapors were calculated using the loading vapor loss calculations in U.S. EPA's AP-42 Section 5.2 (June 2008) and GHG emission factors from U.S. EPA's AP-42 Table 1.4-2 (July 1998). Detailed emission calculations from the vapor combustor are provided in **Table D-7** in **Appendix D**.

3.4 FUGITIVE COMPONENTS

Fugitive emissions of methane from components in natural gas service were calculated based on the calculated VOC fugitive emission rates and the methane content of the natural gas. Additionally, all normal process fugitives in light liquid or gas/vapor service in the methanol unit were assumed to have a 5% methane content. VOC fugitive component leak emission factors were based on the estimated number of fugitive components and "SOCMI without Ethylene" factors from TCEQ's Technical Guidance Package for Equipment Leak Fugitives (November 2000). The monitoring credits were based on TCEQ's 28VHP leak detection and repair (LDAR) program. Total CH_4 emissions were calculated based the fuel gas containing 90% methane and 10% VOC by weight. Detailed emission calculations from the fugitive components are provided in **Tables D-8** and **D-9** in **Appendix D**.

3.5 CATALYST REGENERATION

The catalyst in the MtG reactors (EPN: V-CATREGEN) will be regenerated on a frequent basis to remove the coke that accumulates on the catalyst. The coke will be removed in a combustion process that will produce CO_2 emissions, which will then be routed to the atmosphere. Emissions were calculated using the estimated flue gas flow rate and CO_2 concentration. Detailed emission calculations from the catalyst regeneration vents are provided in **Table D-10** in **Appendix D**.

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3.6 EMERGENCY GENERATOR AND FIREWATER PUMP ENGINES

Natgasoline proposes to construct one new diesel-fired emergency generator (EPN: H-EMG) and two diesel-fired firewater pump engines (EPN H-FWP1/2) as part of the GtG project. GHG emissions from the engines were calculated using the proposed hourly and annual firing rates and GHG emission factors for distillate fuel no. 2 combustion from 40 CFR Part 98 Subpart C, Table C-1 and Table C-2. Detailed emission calculations from the generator and engine are provided in **Table D-11** in **Appendix D**.

3.7 COOLING WATER TOWER

Methane emissions from the process cooling water tower (EPN: T-06001) were calculated using the cooling water recirculation rate and the controlled emission factor for cooling towers in EPA's AP-42 Chapter 5.1.1, Table 5.1-2 (January 1995), since this cooling tower will be subject to monthly monitoring using the "El Paso" method (or equivalent).

Emission calculations for the cooling tower are provided in **Table D-12** in **Appendix D**.

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4. BACT ANALYSIS

Every new source that is subject to PSD regulations for GHGs must perform a Best Available Control Technology (BACT) analysis as part of the PSD permit application. A BACT analysis is a structured evaluation of available emissions-reducing technologies or techniques including associated feasibility, energy, environmental, and economic aspects. The following BACT analysis is in support of a PSD permit application for GHG emissions associated with the new GtG plant proposed by Natgasoline. GHG emissions for the proposed project will be produced by individual sources of CO_2, CH_4, and N_2O emissions, including combustion units, process vents, and potential fugitive equipment leaks.

The EPA's "top-down" BACT Analysis methodology for GHG sources is outlined in PSD and Title V Permitting Guidance for Greenhouse Gases (EPA-457/B-11-001, March 2011) and includes the following steps:

Step 1: Identify all available control technologies.

Step 2: Eliminate technically infeasible options.

Step 3: Rank remaining control technologies based on control effectiveness.

Step 4: Evaluate most effective controls in terms of economic, energy and environmental impacts and document results.

Step 5: Select the BACT.

The top-down BACT review is the EPA's preferred methodology for a BACT analysis for pollutants and emission sources subject to PSD review; therefore, the top-down approach was followed in the BACT analysis for this GHG permit application.

The following new GHG-emitting source types are associated with this permit application and are subject to BACT requirements:

- Plant-wide;
- Steam reformer/process heaters;
- Auxiliary boiler;
- Flare;
- Vapor combustor;

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- Process vents; and
- Equipment leak fugitive components.

In order to perform the BACT analysis for the above GHG emission sources, the following resources were utilized:

- EPA's Reasonably Available Control Technology/Best Available Control Technology/ Lower Achievable Emission Rate Clearinghouse (RBLC) database;
- Approved GHG permit applications for similar source types in the state of Texas;
- EPA's *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry*, November 2010 (referred to herein as GHG BACT for Refineries);
- EPA's *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boilers*, November 2010 (referred to herein as GHG BACT for Boilers);
- Department of Energy's *Report of the Interagency Task Force on Carbon Capture and Storage*, August 2010; and
- Ernest Orlando Lawrence Berkeley National Laboratory's *Energy Efficiency Improvement and Cost Savings for the Petrochemical Industry*, July 2008.

Table E-1 in **Appendix E** of this application shows the proposed BACT limits (where applicable) and compliance demonstrations for each source of GHGs.

4.1 ALTERNATIVE METHANOL PRODUCTION PROCESSES

Methane reforming is the only available conversion process to support methanol production in quantities necessary for the viability of this project, although several different types of other feedstocks have been used for methanol production as discussed below. At the most fundamental level, methane reforming consists of converting methane plus steam into a gas mixture known as "synthesis gas" (i.e., "syngas") that consists of hydrogen, carbon dioxide, and carbon monoxide, with low concentrations of methane. The synthesis process for converting syngas into methanol requires compatibility with the selected methane reforming process, and the majority of all GHG emissions from the entire methanol unit will be generated in the methane reforming process and the associated auxiliary boiler. Therefore, selection of the

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methane reforming process design is the primary determinant for establishing the GHG emissions performance for the entire methanol unit.

For purposes of this BACT review, the appropriate source category definition for the methanol unit is a reforming process for converting natural gas methane into methanol. Consideration of other carbon feedstocks (e.g., coal or petroleum oil) would constitute redefinition of the proposed source, which is outside the scope of BACT evaluation requirements. Natgasoline evaluated all commercially available methane reforming process design types during the selection of the proposed reforming process design as the lowest GHG-emitting design basis that is technically feasible and economically reasonable within the appropriate source category definition. Within the proposed source category definition, Natgasoline evaluated the following reforming process design options for BACT selection purposes:

1. Steam methane reforming (SMR) only;
2. Autothermal reforming (ATR) only;
3. Partial Oxidation (POX) only;
4. Combined Gas Heated Reformer (GHR) and ATR; and
5. Combined SMR and ATR.

Following is a discussion of each above-listed design option to explain why the selection of combined SMR/ATR is BACT for GHG emissions.

Design Option 1 – Steam Methane Reforming (SMR) Only

The majority of existing methanol production plants use SMR-only reforming designs (i.e., without ATR). However, overall methanol conversion efficiency in a SMR-only process design is limited to approximately 90% maximum conversion of the process feed methane, whereas Natgasoline's selected SMR/ATR design achieves almost 95% conversion of the process feed methane. The SMR-only design option results in an unconverted 10% fraction of the feed methane which cannot be utilized in methanol production except to be burned as fuel or waste gas. As compared to the proposed combined SMR/ATR design, applying an SMR-only design would require 10% greater reformer firing rates to achieve the production rates necessary for this project. Additionally, there are no methanol plants in the world that have successfully operated at the proposed plant capacity using an SMR-only reforming design. In summary, an

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SMR-only design is not BACT for this project because it would result in higher GHG emissions per unit of methanol produced as compared to the combined SMR/ATR design selected by Natgasoline for this project.

Design Option 2 – Autothermal Reforming (ATR) Only

No existing methanol production plant of reasonable size is based on ATR-only process design. As compared to the SMR-only process, the ATR-only design produces a syngas with different ratios of hydrogen to carbon oxides (i.e., CO_2 and CO). The syngas from an ATR-only process contains more carbon oxide than can be utilized in the process. Therefore, some syngas and purge gas from the synthesis would need to be processed in a hydrogen recovery unit (e.g., PSA), or additional hydrogen would need to be produced from the syngas with a shift reactor to make an ATR-only design technically feasible. With this theoretical ATR-only design, the hydrogen from the PSA would be mixed with the syngas to get the appropriate hydrogen to carbon-oxides ratio for methanol synthesis. This theoretical ATR-only design would need to include feed preheating and steam superheating, which would require relatively higher gas combustion with higher GHG emission rates as compared to the combined SMR/ATR design selected by Natgasoline. Therefore, even if combined ATR-only design were considered technically feasible (which has never been demonstrated), an ATR-only design is not BACT for this project because it would result in higher GHG emissions per unit of methanol produced as compared to the combined SMR/ATR design selected by Natgasoline for this project.

Design Option 3 – Partial Oxidation (POX) Only

Pure Non-Catalytic Partial Oxidation (POX) would potentially be associated with lower GHG emissions than a comparable SMR-only process. There are two large scale Fischer-Tropsch plants that generate syngas using this POX technology in operation. However, the use of this POX technology has led to immense cost and to multiple POX reactors, and, as such, this technology is considered to be technically and economically infeasible. Additionally, this POX technology is not available for licensing within the construction schedule required for this project, which further justifies the determination of technical infeasibility.

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Design Option 4 – Combined Gas Heated Reforming (GHR)

A GHR design, which is an ATR with heat recovery and a primary reformer in one vessel, would potentially be associated with lower GHG emissions than the proposed combined SMR/ATR reforming process. However, no GHR methanol production process has ever been constructed with methanol production rates comparable to those necessary for the proposed Natgasoline project. Technical problems associated with the GHR design could never been resolved to stabilize the methanol production. Therefore, the combined GHR/ATR design is considered technically infeasible for this project.

Design Option 5 – Combined SMR/ATR

Combined SMR/ATR reforming is the lowest GHG emitting technology with proven technical feasibility and economic viability on a large scale, and at least four plants in operation around the world have established the minimum required confidence necessary to apply combined SMR/ATR technology to this project. 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 (which results in a smaller SMR with a lower SMR flue gas temperature) and due to the favorable ratio of hydrogen to carbon oxides in the syngas, which is a result of the oxygen used as an internal heat source in the ATR. Natgasoline selected this technology as BACT for the proposed new methanol unit because the SMR/ATR design results in lower GHG emissions for each unit of methanol produced compared to every other process design with demonstrated capability to produce methanol at the rates necessary for this project.

4.2 ALTERNATIVE FUEL PRODUCTION PROCESSES

Based on the proposed gasoline synthesis process, Fischer-Tropsch is an alternate design basis for converting syngas into liquid fuels. Fischer-Tropsch synthesis is used in natural gas-to-liquid and coal-to-liquid processes. However, the Fischer-Tropsch process would convert the synthesis gas into a wide variety of different products (e.g., mainly wax, and then oxygenates like alcohols, aldehydes, carbonic-acids, and unsaturated hydrocarbons). The wax would require further treatment in order to produce gasoline and diesel. This process would generate significantly more GHG emissions to produce the commercial-grade fuels than the proposed natural gas to

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methanol to gasoline process proposed by Natgasoline. Therefore, the Fischer-Tropsch process would not be considered BACT.

4.3 PLANT-WIDE SOURCES

Step 1 – Identification of Potential Control Technologies

Carbon Dioxide Capture and Sequestration (CCS): CCS technologies involve the separation, collection, and compression of CO_2 gas from point source emissions, transportation of the compressed CO_2 gas to an on-site or off-site storage facility, and sequestering of the CO_2 in a viable storage facility.

The proposed Natgasoline GtG plant will emit CO_2 from a number of different processes and emission points throughout the facility. The consideration of the CCS at this site would likely be limited to the larger CO_2-emitting stacks, such as the reformer and the auxiliary boiler. The capture of the CO_2 gas emissions would require separation of the CO_2 gas from the combined combustion exhaust flows using a CO_2 separation process.

The proposed 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 already presently has more than 3,000 miles of CO_2 pipelines used to transport CO_2 for Enhanced Oil Recovery (EOR).

Captured, compressed, and transported CO_2 may be stored or sequestered by means of currently available methods, including storage in geologic formations, EOR, and injection of CO_2 into an active oil reserve, brine aquifer, un-mined coal seam, basalt rock formation, or an organic shale bed. The U.S. Department of Energy (DOE) has been supporting Regional Partnerships that are initiating large-scale tests to determine how geologic storage reservoirs and their surrounding environments respond to large amounts of injected CO_2 in a variety of geological formations and regions across the United States. Because CO_2 storage is still an emerging technology, regulations and standards have not been developed.

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Step 2 – Technical Feasibility

The process of CO_2 capture concentrates the CO_2 stream so it can be transported and/or stored. To date, successful CCS implementation has only involved highly concentrated CO_2 streams for practical and economic reasons.

The CO_2 must be separated from the combustion flue gas by a complex process that 1) filters out particulates, 2) cools the flue gas, and 3) compresses and separates the CO_2. This process would require the installation of equipment that would otherwise not be used at the facility. For example, the separated CO_2 stream requires large compression equipment, capable of acidic gas handling (since CO_2 is highly corrosive) and high energy consumption to pressurize the gas for pipeline transportation. The energy demand that would be required to operate a carbon capture system would potentially require the construction and operation of a cogeneration unit (cogen unit). A cogen unit could be associated with a significant amount of emissions of GHGs and other regulated pollutants that would require additional controls. Although a CCS system would be technically challenging since no CCS system has been built and operated at the required capacity, it may not be infeasible and therefore needs to be considered in Step 3 of the top-down BACT analysis.

Step 3 – Rank remaining control technologies based on control effectiveness

The economic reasonableness assessment is based on a 80% capture efficiency of the following CO_2-emitting sources at the site:

- Reformer Heater (EPN: B-01001);
- Auxiliary Boiler (EPN: B-14001);

These two sources contribute 90% to the total CO_2e emissions. Therefore, a CCS system for these sources would be the most effective method of controlling site-wide CO_2 emissions.

Step 4 – Evaluate most effective controls in terms of economic, energy, and environmental impacts and document results

A search of the EPA RBLC database revealed no facilities listed as using CCS for BACT. However, though many aspects of CCS prove it to be technically challenging, economics is a consideration in the BACT analysis. Natgasoline has performed a rough order of magnitude cost analysis for the above-mentioned sources of GHG. **Table 4-1** on the following page summarizes

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the cost of carbon capture and compression, transport, and storage. The cost of CCS for the project is estimated to be greater than $100 per ton of CO_2e controlled. The total annual cost of CCS technology to control all sources of GHG emissions is over $95 million. These costs are not considered to be effective for GHG control and, if required, would make the entire proposed project economically unviable. Therefore, CCS is not selected as a control option, and no further analysis will be considered in this permit application documentation.

Table 4-1
Cost of CO_2 Capture and Sequestration

CCS System Component	Cost [1] ($/ton of CO_2 Controlled)	Tons of CO_2 Controlled per Year [5]	Total Annual Cost (rounded)
Carbon Dioxide Capture and Compression [2]	$104	862,000	$90,000,000
Transportation of Compressed Gas [3]	$1	862,000	$1,000,000
Carbon Dioxide Storage [4]	$6	862,000	$5,000,000
Total CCS System Cost	$111	N/A	**$96,000,000**

Notes:

1) Cost estimates for capture, transport, and storage vary greatly and are dependent on a variety of factors. Cost ranges in this table are based on recent available costs associated with current commercial-scale projects (DOE, 2010). These values assume capital costs have been fully amortized.

2) Estimates of capture and compression costs based on the CO_2 capture for new NGCC power plants converted to U.S. tons. (DOE, 2010 ,Page 33)

3) Estimates of transportation costs based on 100-kilometer pipeline transporting 5 million metric tons per year.

4) Estimates of storage costs derived from current commercial-scale projects.

Source:

DOE. (2010). Report of the Interagency Task Force on Carbon Capture and Storage. US Department of Energy, Interagency Task Force. August 2010. Accessed online at http://www.fe.doe.gov/programs/sequestration/ccstf/CCSTaskForceReport2010.pdf.

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4.4 REFORMER/PROCESS HEATERS

Step 1 – Identification of Potential Control Technologies

Energy Efficiency Design Technologies

As detailed below, there are several energy efficiency technologies that can be incorporated into the design of the methanol reformer and process heaters:

1. 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. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Process Heaters, November 2010).*

2. Efficient Burner Design: New burner designs have improved fuel mixing capabilities, which increases the burner efficiency and reduces GHG emissions. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from ICI Boilers, November 2010.)*

3. Heat Recovery System: The flue gas from the combustion source is routed through a waste heat recovery system, which reduces the exit flue gas temperature and increases the thermal efficiency of the combustion source. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Process Heaters, November 2010).*

4. 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. (*Energy Efficiency Improvement and Cost Savings for the Petrochemical Industry, July 2008).*

Best Operational Practices

As detailed below, there are several best practices that can be incorporated into the operation or design of the methanol reformer and process heaters:

1. Combustion Air Controls (Limitations on Excess Air/Oxygen): Oxygen 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 2-3% oxygen. (*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).*

2. Periodic Maintenance: Maintaining the combustion sources through a maintenance program results in increased average thermal efficiency and energy savings.

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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).*

3. Fuel Selection: Firing natural gas or other gaseous fuels results in lower potential GHG emissions as demonstrated by Table C-1 in 40 CFR Part 98, Subpart C for "General Stationary Fuel Combustion Sources."

Step 2 – Elimination of Technically Infeasible Options

The seven process heaters in the MtG Unit (EPNs H-REGEN, H-RXH1-5, and H-HGT) are smaller heaters with maximum firing rates <100 MMBtu/hr. Therefore, installing combustion air preheat and waste heat recovery systems on these heaters would be technically infeasible.

For the Reformer (EPN B-01001), 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 – Rank remaining control technologies based on control effectiveness

The control technologies specified in Step 1 above are all top-ranked control technologies for process heaters. 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. However, in order for completeness, the following table lists the technically feasible control technologies and their typical control efficiencies where they are available:

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Table 4-2
Reformer/Process Heater BACT Control Efficiencies

Control Technology Description	Item No.	Control Technology Description	Typical Overall Control Eff. (%)	Source
Energy Efficiency Design	1.	Air Preheat System	10-15	GHG BACT for Refineries (Heat Recovery - Air Preheater)
Energy Efficiency Design	2.	Efficient Burner Design	N/A	GHG BACT for Refineries (Heat Recovery - Air Preheater)
Energy Efficiency Design	3.	Heat Recovery System	2-4	GHG BACT for Refineries (Recover Heat from Process Flue Gas)
Energy Efficiency Design	4.	Increased Heat Transfer	5-10	Energy Efficiency Improvement (Section 8)
Best Operational Practices	5.	Combustion Air Controls (Limits on Excess Air)	1-3	GHG BACT for Refineries (Combustion Air Controls - Limitations on Excess Air)
Best Operational Practices	6.	Periodic Maintenance	1-10	GHG BACT for Refineries (Improved Maintenance)
Best Operational Practices	7.	Fuel Selection	40	40 CFR Part 98, Subpart C, Table C-1, "Default CO2 Emission Factors and High Heat Values for Various Types of Fuel" - Comparing natural gas to liquid fuels.

Step 4 – Evaluate most effective controls in terms of economic, energy and environmental impacts and document results

All the aforementioned control technologies are considered economically reasonable since this will be a brand new site with the most up-to date technology. However, the use of an air preheat system could potentially increase emissions of thermal NO_x due to the increased temperature of combustion, which is an adverse environmental impact and potentially conflicts with BACT requirements for NO_x emissions. For sources to be equipped with SCR, NO_x emissions would not be impacted by an air preheat system, since the SCR system could be designed for the increase in NO_x emissions. The remaining potential control technologies listed will not result in any adverse environmental impacts.

Step 5 – Select BACT

Natgasoline proposes that BACT for the reformer is the combination of all the BACT options listed in Step 1. Natgasoline proposes that BACT for the seven smaller process heaters in the

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MtG Unit is the combination of all BACT options listed in Step 1, with the exception of combustion air preheat and waste heat recovery systems.

4.5 AUXILIARY BOILER

Step 1 – Identification of Potential Control Technologies

Energy Efficiency Design Technologies

As detailed below, there are several energy efficiency technologies that can be incorporated into the design of the auxiliary boiler:

1. Air Preheat System: The combustion air is preheated prior to combustion, which reduces the required heat load and increases thermal efficiency. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from ICI Boilers, November 2010).*

2. Efficient Burner Design: New burner designs have improved fuel mixing capabilities, which increases the burner efficiency and reduces GHG emissions. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from ICI Boilers, November 2010).*

3. Boiler Insulation: Insulating the outside surface area of the boiler reduces heat loss, which reduces the required heat load for the boiler and decreases potential GHG emissions. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from ICI Boilers, November 2010).*

4. Economizer: An economizer recovers waste from the boiler stack flue gas and preheats the boiler feed water, which reduces the required heat load for the boiler and decreases potential GHG emissions. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from ICI Boilers, November 2010).*

5. Condensate Return System: Hot condensate is returned to the boiler system to be used as boiler feed water, which reduces the required heat load for the boiler and decreases potential GHG emissions. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from ICI Boilers, November 2010).*

6. Refractory Material Selection: Use of refractory materials that provide the highest insulating capacity reduces heat loss and increases the energy efficiency of the boiler. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from ICI Boilers, November 2010).*

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Best Operational Practices

As detailed below, there are several best practices that can be incorporated into the operation or design of the auxiliary boiler:

1. Combustion Air Controls (Limitations on Excess Air/Oxygen): Oxygen 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 approximately 10-15% or lower for a natural gas-fired boiler. (*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).*

2. 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 that contains official documented procedures and a schedule for routine inspections and evaluations can be developed. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Improved Maintenance, November 2010).*

3. Fuel Selection: Firing natural gas or other gaseous fuels results in lower potential GHG emissions, as demonstrated by Table C-1 in 40 CFR Part 98, Subpart C for "General Stationary Fuel Combustion Sources."

Step 2 – Elimination of Technically Infeasible Options

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 – Rank Remaining Control Technologies Based On Control Effectiveness

The control technologies specified in Step 1 above 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. However, in order for completeness, the following table lists the technically feasible control technologies and their typical control efficiencies where they are available:

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Table 4-3
Auxiliary Boiler BACT Control Efficiencies

Control Technology Description	Item No.	Control Technology Description	Typical Overall Control Eff. (%)	Source
Energy Efficiency Design	1.	Air Preheat System	10-15	GHG BACT for Refineries (Heat Recovery - Air Preheater)
Energy Efficiency Design	2.	Efficient Burner Design	N/A	GHG BACT for ICI Boilers (Replace/Upgrade Burners)
Energy Efficiency Design	3.	Boiler Insulation	6-26	Energy Efficiency Improvement (Section 7.1)
Energy Efficiency Design	4.	Economizer	2-4	GHG BACT for Refineries (Recover Heat from Process Flue Gas)
Energy Efficiency Design	5.	Condensate Return System	1-10% of steam energy use	GHG BACT for Refineries (Install Steam Condensate Return Lines)
Energy Efficiency Design	6.	Refractory Material Selection	N/A	GHG BACT for ICI Boilers (Refractory Material Selection)
Best Operational Practices	7.	Combustion Air Controls (Limits on Excess Air)	1-3	GHG BACT for Refineries (Combustion Air Controls - Limitations on Excess Air)
Best Operational Practices	8.	Periodic Maintenance	1-10	GHG BACT for Refineries (Improved Maintenance)
Best Operational Practices	9.	Fuel Selection	40	40 CFR Part 98, Subpart C, Table C-1, "Default CO2 Emission Factors and High Heat Values for Various Types of Fuel" - Comparing natural gas to liquid fuels.

Step 4 – Evaluate Most Effective Controls in Terms Of Economic, Energy, and Environmental Impacts and Document Results

All the aforementioned control technologies are considered economically reasonable since this will be a brand new site with the most up-to date technology. Additionally, the potential control technologies listed will not result in any adverse environmental impacts since this combustion source will be equipped with SCR.

Step 5 – Select BACT

Natgasoline proposes that BACT for the auxiliary boiler (EPN: B-14001) is the combination of all the BACT options listed in Step 1.

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4.6 PLANT FLARE

Step 1 – Identification of Potential Control Technologies

1. Flare Gas Recovery: Installation and operation of a flare gas recovery system reduces GHG combustion emissions by routing flared gases back to the fuel gas system. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Flares, November 2010)*

2. 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.

3. Proper Operation and Good Combustion Practices: Utilizing proper operation and combustion techniques (e.g., flare gas heat content) for the plant flare reduces combustion inefficiencies, resulting in decreased methane emissions. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Flares, November 2010).*

4. Fuel Selection: Firing natural gas or other gaseous fuels results in lower potential GHG emissions as demonstrated by Table C-1 in 40 CFR Part 98, Subpart C for "General Stationary Fuel Combustion Sources."

5. Minimize MSS Event Duration: Minimizing flaring events associated with MSS activities results in decreased GHG emissions from the plant flare.

Step 2 – Elimination of Technically Infeasible Options

The 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. For BACT determination purposes, potential alternatives to a flare include a vapor combustor, thermal oxidizer, or flare gas recovery system. However, any other technology must serve both the VOC emission control and vital safety-related functions of a flare in order to be considered as a comparable BACT option.

A vapor combustor or thermal oxidizer would not be capable of safely managing the high vapor flow rates, high fuel heat input rates, and rapidly changing conditions that are inherent to emergency or upset events. Therefore, vapor combustors and thermal oxidizers are technically infeasible to serve as alternatives for the flare.

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There are only two streams routed to the flare on a continuous basis (pilot gas and the compressor seal vents). A flare gas recovery system would be technically infeasible due to the very low volume of gas sent to the flare on a continuous basis. Additionally, the compressor seal vent gas composition is primarily nitrogen with only a small (<100 ppm) concentration of organics, and therefore it would not be practicable to route that stream back to process as fuel gas.

The following table lists the technically feasible control technologies and their typical control efficiencies where they are available (item Nos. 1 and 2 above were determined to be technically infeasible and are not shown in the below table):

Table 4-4
Plant Flare BACT Control Efficiencies

Item No.	Control Technology Description	Typical Overall Control Eff. (%)	Source
3.	Proper Flare Operation	N/A	GHG BACT for Refineries (Proper Flare Operation)
4.	Fuel Selection	40	40 CFR Part 98, Subpart C, Table C-1, "Default CO2 Emission Factors and High Heat Values for Various Types of Fuel" - Comparing natural gas to liquid fuels.
5.	Minimize Duration of MSS Events	N/A	N/A

Step 3 – Rank remaining control technologies based on control effectiveness

The above-mentioned control technologies identified in Step 1 (with the exception of the flare gas recovery system and alternative control devices) are all 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.

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Step 4 – Evaluate Most Effective Controls in Terms of Economic, Energy and Environmental Impacts and Document Results

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

Step 5 – Select BACT

Natgasoline proposes that BACT for the plant flare (EPN: S-10001) is the combination of all the BACT options listed in Step 1, with the exception of the flare gas recovery system and alternative control device.

4.7 RAILCAR/TRUCK LOADING/VAPOR COMBUSTOR

Step 1 – Identification of Potential Control Technologies

1. Alternative Control Device Options: Installation of a vapor recovery unit (VRU) would eliminate CO_2e emissions resulting from combustion.

2. Alternative Control Device Options: Installation of a carbon adsorption unit would eliminate CO_2e emissions resulting from combustion.

3. Proper Operation and Good Combustion Practices: Utilizing proper operation and combustion techniques (e.g., fuel-to-air ratio) for the vapor combustor reduces combustion inefficiencies, which results in decreased methane emissions. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Flares, November 2010).*

4. Fuel Selection: Firing natural gas or other gaseous fuels results in lower potential GHG emissions as demonstrated by Table C-1 in 40 CFR Part 98, Subpart C for "General Stationary Fuel Combustion Sources."

Step 2 – Elimination of Technically Infeasible Options

A VRU or carbon adsorption system would not be able to manage the mass flow of vapors associated with loading gasoline into railcars or trucks considering the applicable air quality emission standards and the gasoline transfer rates necessary to support this GtG project. Therefore, the VRU and carbon adsorption alternatives are technically infeasible for purposes of minimizing emissions from these gasoline loading operations.

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A vapor combustor (also called a direct-fired thermal oxidizer) uses combustion of the waste gas to control VOC emissions. A vapor combustor is proposed as BACT due to cost effectiveness and its ability to handle fluctuations in waste gas composition.

All other identified control technologies (item Nos. 3 and 4 listed above) are technically feasible and therefore are considered in Step 3 below.

Step 3 – Rank remaining control technologies based on control effectiveness

The control technologies identified in Step 1 and not eliminated in Step 2 are top-ranked control technologies for vapor combustors/thermal oxidizers. 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. However, in order for completeness, the following table lists the technically feasible control technologies and their typical control efficiencies where they are available (item Nos. 1 and 2 were eliminated in Step 2):

Table 4-5
Vapor Combustor BACT Control Efficiencies

Item No.	Control Technology Description	Typical Overall Control Eff. (%)	Source
3.	Proper Operation/Good Combustion Techniques	N/A	GHG BACT for ICI Boilers
4.	Fuel Selection	40	40 CFR Part 98, Subpart C, Table C-1, "Default CO2 Emission Factors and High Heat Values for Various Types of Fuel" - Comparing natural gas to liquid fuels.

Step 4 – Evaluate most effective controls in terms of economic, energy, and environmental impacts and document results

All the aforementioned control technologies listed (except those ruled out in Step 2) are considered economically reasonable since this will be a brand new site with the most up-to-date technology. Additionally, the potential control technologies listed will not result in any adverse environmental impacts.

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Step 5 – Select BACT

Natgasoline proposes that BACT for gasoline loading is a vapor combustor (EPN: VCU-1). GHG emissions from the vapor combustor will be minimized using the combination of BACT item Nos. 3 and 4 listed in Step 1.

4.8 CATALYST REGENERATION VENT (EPN V-CATREGEN)

Coke buildup on the catalyst in the MtG reaction process is an unavoidable part of the MtG reaction process, and the coke must be removed in accordance with manufacturer specifications to ensure the catalyst works properly and does not cause unnecessary process shutdowns.

Step 1 – Identification of Potential Control Technologies

Proper Operating Techniques: Utilizing proper operating techniques (e.g., minimizing catalyst coke 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.

Step 2 – Elimination of Technically Infeasible Options

The option identified in Step 1 is considered technically feasible and therefore needs to be considered in Step 3 of the top-down BACT analysis.

Step 3 – Rank Remaining Control Technologies Based on Control Effectiveness

The catalyst regeneration duration time is approximately 15 hours and occurs 110 times per year week for a total of 1,681 hours/year. Emissions of CO_2e from this vent are insignificant (5,446 tons/year); therefore, this is BACT for the catalyst regeneration vent.

Step 4 – Evaluate Most Effective Controls in Terms of Economic, Energy and Environmental Impacts and Document Results

The aforementioned control technology is considered economically reasonable since no add-on control is necessary.

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Step 5 – Select BACT

Natgasoline proposes that BACT for the catalyst regeneration vent (EPN: V-CATREGEN) is the option listed in Step 1.

4.9 PROCESS FUGITIVES

Step 1 – Identification of Potential Control Technologies

1. Installation of Leakless Technology: Installing leakless technology components would eliminate GHG emissions from fugitive components.

2. Implementation of LDAR Program: 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. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Fuel Gas System, November 2010).*

3. 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.

4. Compressor Selection: Utilizing dry-seal compressors (rather than wet-seal) and rod packing for reciprocating compressors results in decreased emissions of GHG pollutants from compressors. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Fuel Gas System, November 2010).*

Step 2 – Technical Feasibility

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 – Control Effectiveness

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. Equipment in natural gas service or fuel gas service where methane is one of the primary

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constituents of the stream is generally not monitored under existing LDAR programs since methane is not a VOC. 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 methane service.

The TCEQ's 28LAER program is the most stringent of their LDAR monitoring programs. 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 a less stringent program than 28LAER, but it is considered BACT for fugitive components in VOC service for this project. 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. This program does not require directed maintenance.

Alternative Monitoring Program

Leak detection using IR camera technology is considered by the EPA to be partial alternative monitoring technology to Method 21 (gas analyzer), meaning that the programs are equivalent if, in addition to the remote sensor monitoring, components are also monitored using Method 21 at least annually. Therefore, the control effectiveness for remote sensing technology alone is assumed to be 75%, based on TCEQ's 28LAER program for connector monitoring.

Compressor Design

Use of dry-seal compressors and rod packing (for any reciprocating compressors) are considered effective methods of controlling GHG emissions from compressors; however, there is no data available to support exact control efficiencies.

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Step 4 – Economic, Energy, and Environmental Impacts

Leakless Technologies

Leakless technology, while the most effective of the control technologies, has not been adopted as BACT or Lowest Achievable Emission Rate (LAER) for any projects with GHG emissions from fugitive components. Additionally, leakless technology is not required to control fugitive emissions of toxic or other hazardous air pollutants (HAPs) under Federal rules. Therefore, it is not reasonable to install leakless components for the control of methane, which has no known hazardous impacts.

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}). Based on economic reasonableness, Natgasoline proposes that BACT for fugitive emission is 28VHP, which is the same program that will be used for components in VOC service that require monitoring. Implementing 28VHP will reduce the uncontrolled GHG emissions from fugitive components by 70% to less than 360 tpy. The cost of performing directed maintenance and monitoring connectors quarterly (as required by 28LAER) would be unreasonable to only achieve an additional 26% reduction in fugitive emissions. Following is a brief cost analysis associated with annual monitoring of connectors. The analysis does not take into account any additional costs associated with directed maintenance, which would be entirely variable based on the number of detected leaks and therefore would be difficult to estimate.

- Estimated number of connectors that emit methane = **5,742** (3,059 connectors in "HON" service [e.g., monitored annually] + 2,683 connectors in non-"HON" service [e.g., non-monitored).
- CO_2e emissions associated with connectors under proposed 28VHP LDAR program = 314 tpy.
- CO_2e emissions associated with connectors under 28LAER LDAR program = 13.58 tpy (i.e., a 200 tpy reduction as compared to implementing 28VHP).
- Additional cost associated with quarterly LAER connector monitoring for non-"HON" components = 5 minutes/connector / 60 min/hour * $50/hour for LDAR technician time

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(conservative estimate) * 2,683 non-monitored connectors/quarter * 4 quarters per year = **$44,717 / year.**

- Additional cost associated with quarterly LAER connector monitoring for "HON" components = 5 minutes/connector / 60 min/hour * $50/hour for LDAR technician time (conservative estimate) * 3,059 monitored connectors/quarter * 3 quarters per year = **$38,238 / year.**

- Cost per ton of CO_2e reduced = $44,717 year + 38,238/year = $82,954/year / 200 tons of CO_2e/year = **$276/tpy CO_2e.**

Compressor Design

All the aforementioned control technologies listed are considered economically reasonable. Additionally, the potential control technologies listed will not result in any adverse environmental impacts.

Step 5 – Selection of BACT

The proposed GtG plant will implement TCEQ's 28VHP program for equipment in VOC service. Additionally, the proposed GtG plant will monitor equipment in natural gas or fuel gas service under the 28VHP program. Natgasoline will also install compressors that meet the seal and rod packing requirements as BACT for compressors.

4.10 EMERGENCY GENERATOR AND FIREWATER PUMP ENGINES (EPNS H-EMG AND H-FWP1/2)

Step 1 – Identification of Potential Control Technologies

As detailed below, there are several energy efficiency technologies and best practices that can be incorporated into the design and operation of the emergency generator and firewater pump engines:

1. Vendor-Certified Tier 4 and Clean Burn Engine: The U.S. EPA has set stringent emission standards for non-road diesel engines in accordance with 40 CFR Part 60, Subpart IIII. Compliance with these standards will result in lower potential GHG emissions.

2. Fuel Selection: Firing natural gas or other gaseous fuels results in lower potential GHG emissions as demonstrated by Table C-1 in 40 CFR Part 98, Subpart C for "General Stationary Fuel Combustion Sources."

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3. Operation Restriction: Dedication to emergency service will limit the total hours of operation as well as GHG emissions. Operating hours can be monitored with the use of a run-time meter in conjunction with administrative controls to reduce engine use.

Step 2 – Elimination of Technically Infeasible Options

During emergency conditions, non-volatile fuel (such as diesel or other heavy oils) is required to be used and readily available. Natural gas or other gaseous fuels would not be available during certain emergency events; therefore, these lower carbon fuels are not technically feasible options for emergency engines. All remaining 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 – Rank remaining control technologies based on control effectiveness

The control technologies specified in Step 1 above are all top-ranked control technologies for emergency engines, with the exception of low carbon fuel selection. The use of one technology or practice does not preclude the use of any other control technology or practice, and the combination of control technologies and practices will result in higher energy efficiency than any one.

Step 4 – Evaluate most effective controls in terms of economic, energy and environmental impacts and document results

Except for low carbon fuel selection, all the aforementioned control technologies are considered economically reasonable. These listed potential control technologies will not result in any adverse environmental impacts.

Step 5 – Select BACT

Natgasoline proposes that BACT for the emergency generator engine and the firewater pump engines is the combination of all the BACT options listed in Step 1, with the exception of low carbon fuel selection.

4.11 COOLING TOWER (EPN T-06001)

Step 1 – Identification of Potential Control Technologies

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

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

2. Cooling Water 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 Options

Use of exclusively 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 (ex. the methanol synthesis air cooler). The ambient dry bulb temperature will typically be too high in Beaumont, Texas to cool some process to 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 water tower monitoring and repair program identified in Step 1 is considered technically feasible and therefore needs to be considered in Step 3 of the top-down BACT analysis.

Step 3 – Rank remaining control technologies based on control effectiveness

Implementation of a cooling water tower LDAR 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 water tower emission factor from EPA's AP-42 Chapter 5.1.1, Table 5.1-2 (January 1995).

Step 4 – Evaluate most effective controls in terms of economic, energy, and environmental impacts and document results

There are no negative economic, energy, or environmental impacts associated with the cooling water tower LDAR program.

Step 5 – Select 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 water tower LDAR program. The program will be based on the monitoring and repair requirements specified in 40 CFR Part 63, Subpart F. In order to detect GHG emissions, total organic compounds will be monitored in lieu of HAPs.

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APPENDIX A
ADMINISTRATIVE APPLICATION FORM

Administrative Information

I. Applicant Information		
A. Company or Other Legal Name: **Natgasoline, LLC**		
B. Company Official Contact Name: **Kevin Struve**		
Title: **Manager**		
Mailing Address: **P.O. Box 1647**		
City: **Nederland**	State: **Texas**	ZIP Code: **77627**
Telephone No.: **409-723-1900**	Fax No.: **TBD**	E-mail Address: **kstruve@orascomci.co.uk**
C. Technical Contact Name: **Same as above**		
Title:		
Company Name:		
Mailing Address:		
City:	State:	ZIP Code:
Telephone No.:	Fax No.:	E-mail Address:
D. Site Name: **Beaumont Gas-to-Gasoline Plant**		
E. Area Name/Type of Facility: **Beaumont Gas-to-Gasoline Plant**		☒ Permanent ☐ Portable
F. Principal Company Product or Business: **Industrial Organic Chemicals**		
Principal Standard Industrial Classification Code (SIC): **2869**		
Principal North American Industry Classification System (NAICS): **325199**		
G. Projected Start of Construction Date: **1st Quarter 2014**		
Projected Start of Operation Date: **2nd Quarter 2015**		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: **Approximately 0.3 miles due north of the interchange between TX-347/North Twin City Highway and U.S. 287 S/US-69 S/US-96 N at the intersection of Highway 380 Access Road and Sulphur Plant Road.**		
City/Town: **Beaumont**	County: **Jefferson**	ZIP Code: **77705**
I. TCEQ Customer Reference Number (CN): **CN604256412**		
J. TCEQ Regulated Entity Number (RN): **RN106586795**		

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APPENDIX B
TABLE 1(A)

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Texas Commission on Environmental Quality
Table 1(a) Emission Point Summary
Natgasoline, LLC - New GtG Plant

Date: Revised November 2013	**Permit No.:** TBD	**Regulated Entity No.:**	RN106586795
Area Name: Natgasoline GtG Plant		**Customer Reference No.:**	CN604256412

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA						EMISSION POINT DISCHARGE PARAMETERS										
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate		4. UTM Coordinates of Emissions Point			Source							
									5. Building Height (Ft.)	6. Height Above Ground (Ft.)	7. Stack Exit Data			8. Fugitives		
(A) EPN	(B) FIN	(C) Name		(A) Pound Per Hour	(B) TPY	Zone	East (Meters)	North (Meters)			(A) Diameter (Ft.)	(B) Velocity (FPS)	(C) Temperature (°F)	(A) Length (Ft.)	(B) Width (Ft.)	(C) Axis Degrees
B-01001	B-01001	Reformer	CO_2	190,135.41	718,867.17	15	399,190	3,323,129	--	190	11	52	424	--	--	--
			CH_4	3.42	12.94											
			N_2O	0.34	1.29											
			CO_2e	190,313.35	719,539.94											
B-14001	B-14001	Auxiliary Boiler	CO_2	111,058.97	357,224.59	15	399,041	3,323,076	--	190	11	27	356	--	--	--
			CH_4	2.09	6.74											
			N_2O	0.21	0.67											
			CO_2e	111,167.89	357,574.95											
H-REGEN	H-REGEN	Regeneration Heater	CO_2	5,210.77	12,732.92	15	398,965	3,322,957	--	90	3	52	700	--	--	--
			CH_4	0.10	0.24											
			N_2O	0.01	0.02											
			CO_2e	5,215.88	12,745.41											
H-RX1 H-RX2 H-RX3 H-RX4 H-RX5	H-RX1 H-RX2 H-RX3 H-RX4 H-RX5	Reactors Heaters	CO_2	11,369.83	52,873.91	15	398,915 (Average)	3,322,962 (Average)	--	90	1	162	600	--	--	--
			CH_4	0.21	1.00											
			N_2O	0.02	0.10											
			CO_2e	11,380.98	52,925.77											
H-HGT	H-HGT	Heavy Gasoline Heater Treater	CO_2	975.11	3,843.90	15	398,985	3,323,034	--	50	1	56	600	--	--	--
			CH_4	0.02	0.07											
			N_2O	<0.01	0.07											
			CO_2e	976.07	3,847.67											
S-10001	S-10001	MeOH Flare Pilot & Normal Operation	CO_2	586.91	2,570.66	15	399,532	3,323,263	--	200	N/A	66	1,831	--	--	--
			CH_4	1.50	6.54											
			N_2O	<0.01	<0.01											
			CO_2e	618.66	2,709.21											
S-10001 (MSS)	F-10001	MeOH Flare MSS Vents	CO_2	892,983.86	14,785.98	15	399,532	3,323,263	--	200	N/A	66	1,831	--	--	--
			CH_4	670.65	10.99											
			N_2O	1.46	0.02											
			CO_2e	907,519.89	15,024.47											

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Texas Commission on Environmental Quality
Table 1(a) Emission Point Summary
Natgasoline, LLC - New GtG Plant

Date: Revised November 2013	**Permit No.:** TBD	**Regulated Entity No.:**	RN106586795
Area Name: Natgasoline GtG Plant		**Customer Reference No.:**	CN604256412

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA						EMISSION POINT DISCHARGE PARAMETERS										
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate		4. UTM Coordinates of Emissions Point			Source							
									5. Building Height (Ft.)	6. Height Above Ground (Ft.)	7. Stack Exit Data			8. Fugitives		
(A) EPN	(B) FIN	(C) Name		(A) Pound Per Hour	(B) TPY	Zone	East (Meters)	North (Meters)			(A) Diameter (Ft.)	(B) Velocity (FPS)	(C) Temperature (°F)	(A) Length (Ft.)	(B) Width (Ft.)	(C) Axis Degrees
VCU-1	VCU-1	MtG VCU	CO_2	1,275.52	1,061.30	15	399,031	3,323,168	--	75	2	74	1,830	--	--	--
			CH_4	0.02	0.02											
			N_2O	<0.01	<0.01											
			CO_2e	1,276.76	1,062.33											
FUG-MEOH	FUG-MEOH	MeOH Fugitives	CO_2	-	-	15	399,111	3,323,142	--	10	--	--	--	--	--	--
			CH_4	2.31	10.10											
			N_2O	-	-											
			CO_2e	48.42	212.10											
FUG-MTG	FUG-MTG	MtG Fugitives	CO_2	-	-	15	398,967	3,322,998	--	10	--	--	--	--	--	--
			CH_4	1.58	6.93											
			N_2O	-	-											
			CO_2e	33.24	145.59											
V-CATREGEN	V-CATREGEN	Catalyst Regeneration Vent	CO_2	6,479.25	5,445.81	15	398,946	3,322,930	--	20	3	10	102	--	--	--
			CH_4	-	-											
			N_2O	-	-											
			CO_2e	6,479.25	5,445.81											
H-EMG	H-EMG	Emergency Generator	CO_2	2,782.18	139.11	15	TBD	TBD	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	0.11	0.01											
			N_2O	0.02	<0.01											
			CO_2e	2,791.54	139.58											
H-FWP1 H-FWP2	H-FWP1 H-FWP2	Firewater Pump Engines	CO_2	2,782.18	139.11	15	TBD	TBD	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	0.11	0.01											
			N_2O	0.02	<0.01											
			CO_2e	2,791.54	139.58											
T-06001	T-06001	MeOH Cooling Tower	CO_2	-	-	15	399,214 (Average)	3,323,232 (Average)	--	22	11	183	95	--	--	--
			CH_4	7.91	34.65											
			N_2O	-	-											
			CO_2e	166.14	727.69											

EPN = EMISSION POINT NUMBER

FIN = FACILITY IDENTIFICATION NUMBER

This form designed to correspond with TCEQ - 10153 (Revised 04/08) Table 1(a).

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APPENDIX C
PSD EVALUATION FORMS

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.: **TBD**	Application Submittal Date: **February 2013; Updated November 2013**
Company: **Natgasoline, LLC**	
RN: **RN106586795**	Facility Location: **Approximately 0.3 miles due north of the interchange between TX-347/North Twin City Highway and U.S. 287 S/US-69 S/US-96 N at the intersection of Highway 380 Access Road and Sulphur Plant Road.**
City: **Beaumont**	County: **Jefferson**
Permit Unit I.D.: **NA**	Permit Name: **TBD**
Permit Activity: ☒ New Source ☐ Modification	
Project or Process Description: **Natgasoline LLC is proposing to construct a new gasoline production plant in Beaumont, Texas. The new gasoline production plant will synthesize motor-grade gasoline from methanol using a natural gas feedstock. The new plant will be authorized under a new NSR and PSD permit.**	

Complete for all Pollutants with a Project Emission Increase.	POLLUTANTS						
	Ozone		CO	PM_{10}	NO_X	SO_2	Other[1] CO_2e
	VOC	NO_X					
Nonattainment? (yes or no)							**No**
Existing site PTE (tpy)?							**NA**
Proposed project emission increases (tpy from 2F)[3]							**1,172,240.09**
Is the existing site a major source? [2]If not, is the project a major source by itself? (yes or no)							**NA**
If site is major, is project increase significant?							**Yes**
If netting required, estimated start of construction?	**1st Quarter 2014**						
Five years prior to start of construction	**1st Quarter 2009**				contemporaneous		
Estimated start of operation	**2nd Quarter 2015**					period	
Net contemporaneous change, including proposed project, from Table 3F. (tpy)							**NA**
FNSR APPLICABLE? (yes or no)							**Yes**

1 Other PSD pollutants.
2 Nonattainment major source is defined in Table 1 in 30 TAC 116.12(11) by pollutant and county. PSD thresholds are found in 40 CFR § 51.166(b)(1).
3 Sum of proposed emissions minus baseline emissions, increases only. Nonattainment thresholds are found in Table 1 in 30 TAC 116.12(11) and PSD thresholds in 40 CFR § 51.166(b)(23).

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TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]:	CO_2e	**Permit:**	TBD
Baseline Period:	**Not applicable (proposed new stationary source)**		

	Affected or Modified Facilities[2] FIN	EPN	Permit No.	Actual Emissions[3]	A Baseline Emissions[4]	B Proposed Emissions[5]	Projected Actual Emissions	Difference (B-A)[6]	Correction[7]	Project Increase[8]
1	B-01001	B-01001	TBD	-	-	719,539.94	-	719,539.94		719,539.94
2	B-14001	B-14001	TBD	-	-	357,574.95	-	357,574.95		357,574.95
3	H-REGEN	H-REGEN	TBD	-	-	12,745.41	-	12,745.41		12,745.41
4	H-RX1 H-RX2 H-RX3 H-RX4 H-RX5	H-RX1 H-RX2 H-RX3 H-RX4 H-RX5	TBD	-	-	52,925.77	-	52,925.77		52,925.77
5	H-HGT	H-HGT	TBD	-	-	3,847.67	-	3,847.67		3,847.67
6	S-10001	S-10001	TBD	-	-	2,709.21	-	2,709.21		2,709.21
7	F-10001	S-10001 (MSS)	TBD	-	-	15,024.47	-	15,024.47		15,024.47
8	VCU-1	VCU-1	TBD	-	-	1,062.33	-	1,062.33		1,062.33
9	FUG-MEOH	FUG-MEOH	TBD	-	-	212.10	-	212.10		212.10
10	FUG-MTG	FUG-MTG	TBD	-	-	145.59	-	145.59		145.59
13	V-CATREGEN	V-CATREGEN	TBD	-	-	5,445.81	-	5,445.81		5,445.81
14	H-EMG	H-EMG	TBD	-	-	139.58	-	139.58		139.58
15	H-FWP1 H-FWP2	H-FWP1 H-FWP2	TBD	-	-	139.58	-	139.58		139.58
16	T-06001	T-06001	TBD	-	-	727.69	-	727.69		727.69
								Page Subtotal[9]	0.00	1,172,240.09

All emissions must be listed in tons per year (tpy). The same baseline period must apply for all facilities for a given NSR pollutant.

1. Individual Table 2Fs should be used to summarize the project emission increase for each criteria pollutant
2. Emission Point Number as designated in NSR Permit or Emissions Inventory
3. All records and calculations for these values must be available upon request
4. Correct actual emissions for currently applicable rule or permit requirements, and periods of non-compliance. These corrections, as well as any MSS previously demonstrated under 30 TAC 101, should be explained in the Table 2F supplement.
5. If projected actual emission is used it must be noted in the next column and the basis for the projection identified in the Table 2F supplemen
6. Proposed Emissions (column B) minus Baseline Emissions (column A).
7. Correction made to emission increase for what portion could have been accommodated during the baseline period. The justification and basis for this estimate must be provided in the Table 2F supplement.
8. Obtained by subtracting the correction from the difference. Must be a positive number
9. Sum all values for this page.
10. Type of note. Generally would be baseline adjustment, basis for projected actual, or basis for correction (what could have been accommodated)

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APPENDIX D
EMISSION CALCULATIONS

Table D-1 Revised November 2013
Summary of Potential to Emit
Natgasoline, LLC - New GtG Plant

A. Annual Potential to Emit (PTE) Summary

Emission Source Description	Potential Annual Emissions (tons/year) [1]				Reference Table
	CO_2	CH_4	N_2O	CO_2e	
Methanol Reformer	718,867.17	12.94	1.29	719,539.94	D-2
Methanol Auxiliary Burner	357,224.59	6.74	0.67	357,574.95	D-2
MtG Regeneration Heater	12,732.92	0.24	0.02	12,745.41	D-2
MtG Reactors Heaters	52,873.91	1.00	0.10	52,925.77	D-2
MtG Heavy Gasoline Heater Treater	3,843.90	0.07	0.07	3,847.67	D-2
Methanol Flare Pilot & Normal Operation	2,570.66	6.54	<0.01	2,709.21	D-3
Methanol Flare MSS Vents	14,785.98	10.99	0.02	15,024.47	D-4
MtG VCU	1,061.30	0.02	<0.01	1,062.33	D-7
Methanol Fugitives	-	10.10	-	212.10	D-8
MtG Fugitives	-	6.93	-	145.59	D-9
Catalyst Regeneration Vent	5,445.81	-	-	5,445.81	D-10
Emergency Generator	139.11	0.01	<0.01	139.58	D-11
Firewater Pump Engines	139.11	0.01	<0.01	139.58	D-11
MeOH Cooling Tower	-	34.65	-	727.69	D-12
Total Proposed PTE	**1,169,684.47**	**90.24**	**2.20**	**1,172,240.09**	Totals
Major Source Threshold	NA	NA	NA	100,000	-
Triggers Major Source Permitting?	**NA**	**NA**	**NA**	**Yes**	-

Notes:

1) All sources associated with this project are new sources; therefore, baseline emissions are zero and the total emissions increases for purposes of federal applicability are equal to the PTEs. See PSD Table 2F for additional details.

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Table D-1 Revised November 2013
Summary of Potential to Emit
Natgasoline, LLC - New GtG Plant

B. Hourly Potential To Emit (PTE) Summary

Emission Source Description	Potential Hourly Emissions (lb/hour)				Reference Table
	CO_2	CH_4	N_2O	CO_2e	
Methanol Reformer	190,135.41	3.42	0.34	190,313.35	D-2
Methanol Auxiliary Burner	111,058.97	2.09	0.21	111,167.89	D-2
MtG Regeneration Heater	5,210.77	0.10	0.01	5,215.88	D-2
MtG Reactors Heaters	11,369.83	0.21	0.02	11,380.98	D-2
MtG Heavy Gasoline Heater Treater	975.11	0.02	<0.01	976.07	D-2
Methanol Flare Pilot & Normal Operation	586.91	1.50	<0.01	618.66	D-3
Methanol Flare MSS Vents	892,983.86	670.65	1.46	907,519.89	D-4
MtG VCU	1,275.52	0.02	<0.01	1,276.76	D-7
Methanol Fugitives	-	2.31	-	48.42	D-8
MtG Fugitives	-	1.58	-	33.24	D-9
Catalyst Regeneration Vent	6,479.25	-	-	6,479.25	D-10
Emergency Generator	2,782.18	0.11	0.02	2,791.54	D-11
Firewater Pump Engines	2,782.18	0.11	0.02	2,791.54	D-11
MeOH Cooling Tower	-	7.91	-	166.14	D-12
Total Proposed PTE	**1,225,639.98**	**690.05**	**2.09**	**1,240,779.63**	Totals

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Table D-2 Revised November 2013
Potential Greenhouse Gas Emissions from Combustion Sources
Natgasoline, LLC - New GtG Plant

A. Emission Factors and Global Warming Potential (GWP) Equivalency Factors

CO_2[(1)]	53.02 kg CO_2/MMBtu	&	**CO_2**[(2)]	=	1 ton of CO2 equivalent
CH_4[(1)]	0.001 kg CH_4/MMBtu	&	**CH_4**[(2)]	=	21 tons of CO2 equivalent
N_2O[(1)]	0.0001 kg N_2O/MMBtu	&	**N_2O**[(2)]	=	310 tons of CO2 equivalent

B. Emission Calculations

Emission Source	Design Firing Rate		CO_2 Emissions		CH_4 Emissions		N_2O Emissions		CO_2e Emissions [(5)]	
	Max.	Aver.	Hourly	Annual	Hourly	Annual	Hourly	Annual	Hourly	Annual
	MMBtu/hr	MMBtu/hr	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Reformer (MeOH) (6)	1,552	1,340	190,135	718,867	3.42	12.94	0.34	1.29	190,313	719,540
Auxiliary Boiler (MeOH)	950	698	111,059	357,225	2.09	6.74	0.21	0.67	111,168	357,575
Regeneration Heater (MtG)	45	25	5,211	12,733	0.10	0.24	0.01	0.02	5,216	12,745
Reactors Heaters (MtG) (7)	24	21	11,370	52,874	0.21	1.00	0.02	0.10	11,381	52,926
Heavy Gasoline Heater Treater (MtG)	8	8	975	3,844	0.02	0.07	0.00	0.01	976	3,848
Sub total MeOH Unit Sources			301,194	1,076,092	5.52	19.68	0.55	1.97	301,481	1,077,115
Sub total MtG Unit Sources			17,556	69,451	0.33	1.31	0.03	0.13	17,573	69,519
		Totals	**318,750**	**1,145,543**	**5.85**	**20.99**	**0.58**	**2.10**	**319,054**	**1,146,634**

Notes:

(1) Emission factors are based on 40 CFR Part 98 Subpart C, Table C-1 and Table C-2 for natural gas.

(2) Global warming potential factors are based on 40 CFR Part 98 Subpart A, Table A-1.

(3) Hourly emissions are based on the emission factor * max. hourly firing rate * 2.204 lb/kg.

(4) Annual emissions are based on the emission factor * aver. hourly firing rate (normal) * 2.204 lb/kg * 8,760 hours/year / 2000 lb/ton

(5) CO_2e emissions are based on the sum of the CO_2, CH_4, and N_2O emissions times their respective GWP factors.

(6) CO2 emissions for the Reformer are based on Reformer-specific fuel carbon content of 0.4898 and a molecular weight of 16 lb/lb-mole.

(7) The hourly emissions are multiplied by four since only four heaters will be fired at maximum design firing at one time. The annual emissions are based on an average firing rate that includes startup time for the fifth heater coming online. Therefore, the annual emissions are multiplied by five.

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Table D-2 Revised November 2013
Potential Greenhouse Gas Emissions from Combustion Sources
Natgasoline, LLC - New GtG Plant

C. Supplemental Table for Reformer Fuel Carbon Content Calculation

Constituent	Volume %	MW	Mass %	No. of Carbons	Carbon Content
H2	40.49%	2	5.22%	-	-
CH4	38.15%	16	39.32%	1	0.2952
C2H6	1.34%	30	2.59%	2	0.0207
C3H8	0.85%	44	2.41%	3	0.0197
C4H10	0.33%	58	1.23%	4	0.0102
C5H12	0.09%	72	0.42%	5	0.0035
C6H14	<0.01	86	<0.01	6	0.0051
CH3OH	0.02	32	0.04	1	0.0145
N2	<0.01	28	0.02	-	-
CO2	0.14	44	0.39	1	0.1077
CO	0.02	28	0.03	1	0.0132
H2S	<0.01	34.08	<0.01	-	-
H2O	<0.01	18.02	<0.01	-	-
Total	99.88	-	100.00		**0.4898**

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Table D-3 Revised November 2013
Flare - Pilot and Normal Operation Emission Calculations
Natgasoline, LLC - New GtG Plant

A. Pilot Gas Emissions

Parameter Name & Variable		Value & Units	Basis/Calculations/Notes
1. General Values and Calculations			
Hourly Flow Rate	F_H	1,045 scf/hr	Estimated Max Hourly Flow
Annual Flow Rate	F_A	9,154,200 scf/yr	Estimated Average Annual Flare Flow
Heat Content	H	1,020 Btu/scf	Typical Heat Content of Natural Gas
2. CO_2 Emission Rate Calculations			
CO_2 Emission Factor	F_{CO2}	120,000 lb/MMscf	AP-42, Table 1.4-2
CO_2 Hourly Emission Rate	-	**125.40 lb/hr**	= (F_H / 1,000,000 scf/MMscf) x F_{CO2}
CO_2 Annual Emission Rate	-	**549.25 tpy**	= (F_A / 1,000,000 scf/MMscf) x F_{CO2} / 2,000 lb/ton
3. CH_4 Emission Rate Calculations			
CH_4 Emission Factor	F_{CH4}	0.00220 lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2
CH_4 Hourly Emission Rate	ER_{CH4}	**<0.01 lb/hr**	= F_H x (H / 1,000,000 Btu/MMBtu) x F_{CH4}
CH_4 Annual Emission Rate	ER_{CH4}	**<0.01 tpy**	= F_A x (H / 1,000,000 Btu/MMBtu) x F_{CH4} / 2,000 lb/ton
Hourly Global Warming Potential	GWP_{CH4}	0.05 lb/hr	= ER_{CH4} * 21 CO_2e
Annual Global Warming Potential	GWP_{CH4}	<0.01 tpy	= ER_{CH4} * 21 CO_2e
4. N_2O Emission Rate Calculations			
N_2O Emission Factor	F_{N2O}	0.00022 lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2
N_2O Hourly Emission Rate	ER_{N2O}	**<0.01 lb/hr**	= F_H x (H / 1,000,000 Btu/MMBtu) x F_{N2O}
N_2O Annual Emission Rate	ER_{N2O}	**<0.01 tpy**	= F_A x (H / 1,000,000 Btu/MMBtu) x F_{N2O} / 2,000 lb/ton
Hourly Global Warming Potential	GWP_{N2O}	0.07 lb/hr	= ER_{N2O} * 310 CO_2e
Annual Global Warming Potential	GWP_{N2O}	<0.01 tpy	= ER_{N2O} * 310 CO_2e
5. Total CO_2e Emission Rates			
Hourly Global Warming Potential	-	**125.52 lb/hr**	= ER_{CO2} + GWP_{CH4} + GWP_{N2O}
Annual Global Warming Potential	-	**549.25 tpy**	= ER_{CO2} + GWP_{CH4} + GWP_{N2O}

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Table D-3 Revised November 2013
Flare - Pilot and Normal Operation Emission Calculations
Natgasoline, LLC - New GtG Plant

B. Compressor Seal Vent Flare Emissions (plus supplemental natural gas)

Parameter Name & Variable		Value & Units		Basis/Calculation/Notes
1. General Values and Calculations				
Hourly Vapor Mass to Flare	M_H	1,201 lb/hr		Based on Estimated Flow to Flare
Annual Vapor Mass to Flare	M_A	10,520,689 lb/year		Based on M_H * 8760 hrs/year
Hourly Vapor Volume to Flare	Q_H	18,630 scf/hr		Based on Estimated Flow to Flare
Annual Vapor Volume to Flare	Q_A	163 MMscf/yr		Based on Q_H * 8760 hrs/year
Max. Hourly Vapor Heat Input to Flare	H_H	4 MMBtu/hr		Based on Typical Stream Composition and Flow
Annual Vapor Heat Input to Flare	H_A	33,612 MMBtu/yr		Based on Typical Stream Composition and Flow
2. Combined Gas Composition		Volume %	MW	
N_2 Volume Percent & Molecular Weight		76.13	28.01	Based on Typical Stream Composition
H_2 Volume Percent & Molecular Weight		4.00	2.02	Based on Typical Stream Composition
CH_3OH Volume Percent & Molecular Weight		0.01	32.04	Based on Typical Stream Composition
C_4H_{10} Volume Percent & Molecular Weight		0.60	58.12	Based on Typical Stream Composition
CH_4 Volume Percent & Molecular Weight		19.26	16.04	Based on Typical Stream Composition
Total Molecular Weight	MW_T	24.84 lb/lb-mol		Based on Typical Stream Composition
3. CO_2 Emission Rate Calculations				
Carbon Content	CC	0.10		= Σ (No. of Carbons * 12/MW_i * MW_i/MW_T)
CO_2 Hourly Emission Rate	ER_{CO2H}	**462 lb/hr**		= 44/12 * Q_H * CC * MW_T / 385 scf/lb-mol
CO_2 Annual Emission Rate	ER_{CO2A}	**2,021 tpy**		= 44/12 * Q_A * CC * MW_T / 385 scf/lb-mol / 2,000 lb/ton
4. CH_4 Emission Rate Calculations				
CH_4 Weight Percent	W_{CH4}	12.44 %		Assumes natural gas component is 90% methane by weight
Flare DRE for CH_4	%	99 %		TCEQ Flare Guidance Document (October 2000)
CH_4 Hourly Emission Rate	ER_{CH4H}	**1.49 lb/hr**		= W_{CH4} * M_H * (100%-DRE)
CH_4 Annual Emission Rate	ER_{CH4A}	**6.54 tpy**		= W_{CH4} * M_A * (100%-DRE) / 2000 lb/ton
Hourly Global Warming Potential	GWP_{CH4H}	31 lb/hr		= ER_{CH4H} * 21 CO_2e
Annual Global Warming Potential	GWP_{CH4A}	137 tpy		= ER_{CH4A} * 21 CO_2e

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Table D-3 Revised November 2013
Flare - Pilot and Normal Operation Emission Calculations
Natgasoline, LLC - New GtG Plant

5. N_2O Emission Rate Calculations			
N_2O Emission Factor	F_{N2O}	0.00022 lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2
N_2O Hourly Emission Rate	ER_{N2OH}	**<0.01 lb/hr**	$= H_H * F_{N2O}$
N_2O Annual Emission Rate	ER_{N2OA}	**<0.01 tpy**	$= H_A * F_{N2O}$ / 2000 lbs/ton
Hourly Global Warming Potential	GWP_{N2OH}	0.26 lb/hr	$= ER_{N2OH} * 310\ CO_2e$
Annual Global Warming Potential	GWP_{N2OA}	1.15 tpy	$= ER_{N2OA} * 310\ CO_2e$
6. Total CO_2e Emission Rates			
Hourly Global Warming Potential	-	**493 lb/hr**	$= ER_{CO2H} + GWP_{CH4H} + GWP_{N2OH}$
Annual Global Warming Potential	-	**2,160 tpy**	$= ER_{CO2A} + GWP_{CH4A} + GWP_{N2OA}$

Notes:

1) Flow and composition from the compressor vent seals include supplemental natural gas (90% methane and 10% VOC estimate).

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Table D-4 Revised November 2013
Flare - Maintenance, Startup, and Shutdown (MSS) Emissions Summary
Natgasoline, LLC - New GtG Plant

A. Annual Emission Rates

Source	CO_2	CH_4	N_2O	CO_2e
MeOH Unit Start-Up Flaring	14,786	10.99	0.02	15,024
Equipment Clearing	98.29	<0.01	<0.01	98.39
Annual Total (tpy)	**14,786**	**10.99**	**0.02**	**15,024**

B. Hourly Emission Rates

Source	CO_2	CH_4	N_2O	CO_2e
MeOH Unit Start-Up Flaring	892,984	670.65	1.46	907,520
Equipment Clearing	34,029	0.64	0.06	34,062
Hourly Total (lb/hr)	**892,984**	**671**	**1.46**	**907,520**

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Table D-5 Revised November 2013
Flare - Methanol Unit "Cold" Startup Flaring MSS Emission Calculations
Natgasoline, LLC - New GtG Plant

A. Synthesis Gas Flaring Scenario

Parameter Name & Variable	Value & Units	Basis/Calculation/Notes
Volumetric Flow Rate	19.41 MMScf/hr	Based on plant engineering design.
Fuel Heating Value (LHV)	271 Btu/Scf	= Σ (Volume $\%_i$ * HV_i)
Molecular Weight	11.42 lb/lb-mole	= Σ (Volume $\%_i$ * MW_i)
Duration of Flaring Scenario	8 hours/event	Based on plant engineering design.
Cold Startup Flaring Event Frequency	4 events/yr	Maximum number in one year.
Carbon Content	0.33	= Σ (No. of Carbons * 12/MW_i * MW_i/MW_T)

Synthesis Gas Composition	Volume %	MW	HV	No. of C	
CO_2 Chemical Properties	8.57	44.01	0	1	Based on engineering estimate of average gas composition. *MW = Molecular weight of compound *HV = Lower heating value of compound in Btu/scf *No. of C = Number of carbons in compound
CO Chemical Properties	21.20	28.01	322	1	
H_2 Chemical Properties	68.26	2.02	275	0	
CH_4 Chemical Properties	1.61	16.04	915	1	
C_{4+} Chemical Properties	0.00	58.12	3,142	4	
N_2 Chemical Properties	0.09	28.02	0	0	
H_2O Chemical Properties	0.26	18.02	0	0	

Hourly Synthesis Gas Flaring Emissions

Pollutant	Emission Factor	Activity Level [1]	Calculated Hourly PTE
CO_2	0.33 Carbon Content	19.41 MMScf/hr	696,184 lb/hr
CH_4	2.27 wt% CH4 (2) ; 99% DRE (3)	575,209 lb/hr	130.30 lb/hr
N_2O	0.00022 lb/MMBtu (4)	5,255 MMBtu/hr	1.16 lb/hr
CO_2e	$F_{GWP,CO2}$ = 1 ; $F_{GWP,CH4}$ = 21 ; $F_{GWP,N2O}$ = 310 (5)		699,279 lb/hr

Annual Synthesis Gas Flaring Emissions

Pollutant	Emission Factor	Activity Level [6]	Calculated Annual PTE
CO_2	0.33 Carbon Content	621 MMScf/yr	11,139 tpy
CH_4	2.27 wt% CH4 (2) ; 99% DRE (3)	18,406,684 lb/yr	2.08 tpy
N_2O	0.00022 lb/MMBtu (4)	168,162 MMBtu/yr	0.02 tpy
CO_2e	$F_{GWP,CO2}$ = 1 ; $F_{GWP,CH4}$ = 21 ; $F_{GWP,N2O}$ = 310 (5)		11,188 tpy

Notes:

1) The maximum hourly activity levels are based on a maximum flaring rate of 19.41 MMScf/hr during MeOH unit start-ups and site-specific stream properties.
2) CH_4 content based on typical stream composition.
3) Flare destruction removal efficiency (DRE) based on TCEQ Flare Guidance Document (October 2000).
4) N_2O emission factor based on 40 CFR Part 98, Subpart C, Table C-2 for natural gas.
5) The global warming potentials are based on 40 CFR 98, Subpart A, Table A-1.
6) The annual average activity levels are based on a maximum flaring rate of 19.41 MMScf/hr during MeOH unit start-ups, a start-up duration of 8 hours, 4 start-up events per year, and the site-specific stream properties.

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Table D-5 Revised November 2013
Flare - Methanol Unit "Cold" Startup Flaring MSS Emission Calculations
Natgasoline, LLC - New GtG Plant

B. Reformer Start-up Fuel Gas Flaring Scenario

Parameter Name & Variable	Value & Units	Basis/Calculation/Notes
Volumetric Flow Rate	1.96 MMScf/hr	Based on plant engineering design.
Fuel Heating Value (LHV)	364 Btu/Scf	= Σ (Volume $\%_i$ * HV_i)
Molecular Weight	11.84 lb/lb-mole	= Σ (Volume $\%_i$ * MW_i)
Duration of Flaring Scenario	8 hours/event	Based on plant engineering design.
Cold Startup Flaring Event Frequency	4 events/yr	Maximum number in one year.
Carbon Content	0.37	= Σ (No. of Carbons * 12/MW_i * MW_i/MW_T)

Reformer Start-up Fuel Gas Composition	Volume %	MW	HV	No. of C	
CO_2 Chemical Properties	13.98	44.01	0	1	Based on engineering estimate of average gas composition.
CO Chemical Properties	1.88	28.01	322	1	
H_2 Chemical Properties	62.88	2.02	275	0	
CH_4 Chemical Properties	18.21	16.04	915	1	
C_{4+} Chemical Properties	0.15	58.12	3,142	4	
N_2 Chemical Properties	1.01	28.02	0	0	
H_2O Chemical Properties	0.07	18.02	0	0	
CH_3OH Chemical Properties	1.83	32.04	768	1	

Hourly Reformer Start-up Fuel Gas Flaring

Pollutant	Emission Factor	Activity Level [(1)]	Calculated Hourly PTE
CO_2	0.37 Carbon Content	2 MMScf/hr	81,514 lb/hr
CH_4	24.67 wt% CH4 (2) ; 99% DRE (3)	60,037 lb/hr	148.13 lb/hr
N_2O	0.00022 lb/MMBtu (4)	712 MMBtu/hr	0.16 lb/hr
CO_2e	$F_{GWP,CO2}$ = 1 ; $F_{GWP,CH4}$ = 21 ; $F_{GWP,N2O}$ = 310 (5)		84,673 lb/hr

Annual Reformer Start-up Fuel Gas Flaring

Pollutant	Emission Factor	Activity Level [(6)]	Calculated Annual PTE
CO_2	0.37 Carbon Content	63 MMScf/yr	1,259 tpy
CH_4	24.67 wt% CH4 (2) ; 99% DRE (3)	1,921,180 lb/yr	2.37 tpy
N_2O	0.00022 lb/MMBtu (4)	22,790 MMBtu/yr	<0.01 tpy
CO_2e	$F_{GWP,CO2}$ = 1 ; $F_{GWP,CH4}$ = 21 ; $F_{GWP,N2O}$ = 310 (5)		1,309 tpy

Notes:

1) The maximum hourly activity levels are based on a maximum flaring rate of 1.96 MMScf/hr during MeOH unit start-ups and site-specific stream properties.
2) CH_4 content based on typical stream composition.
3) Flare destruction removal efficiency (DRE) based on TCEQ Flare Guidance Document (October 2000).
4) N_2O emission factor based on 40 CFR Part 98, Subpart C, Table C-2 for natural gas.
5) The global warming potentials are based on 40 CFR 98, Subpart A, Table A-1.
6) The annual average activity levels are based on a maximum flaring rate of 1.96 MMScf/hr during MeOH unit start-ups, a start-up duration of 8 hours, 4 start-up events per year, and the site-specific stream properties.

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Table D-5 Revised November 2013
Flare - Methanol Unit "Cold" Startup Flaring MSS Emission Calculations
Natgasoline, LLC - New GtG Plant

C. Natural Gas Flaring Scenario

Physical Properties	Value & Units	Basis/Calculation/Notes
Volumetric Flow Rate	1.50 MMScf/hr	Based on plant engineering design.
Fuel Heating Value (LHV)	918 Btu/Scf	AP-42 value of 1,020 adjusted by 90% for LHV.
Molecular Weight	19.00 lb/lb-mole	$= \Sigma$ (Volume $\%_i$ * MW_i)
Duration of Flaring Scenario	6 hours/event	Based on plant engineering design.
Cold Startup Flaring Event Frequency	4 events/yr	Maximum number in one year.
Weight Percent of CH_4	73 %	Calculated from composition data below.
Carbon Content	0.73	$= \Sigma$ (No. of Carbons * 12/MW_i * MW_i/MW_T)

Natural Gas Composition	Volume %	MW	No. of C	
CO_2 Chemical Properties	1.10	44.01	1	Based on typical natural gas composition from Perry's Chemical Engineers' Handbook, 7th Edition, Table 27-8, pg 27-12.
CH_4 Chemical Properties	95.20	16.04	1	
C_2H_6 Chemical Properties	8.10	30.07	2	
C_3H_8 Chemical Properties	2.80	44.10	3	
C_4H_{10} Chemical Properties	0.66	58.12	4	
C_5H_{12} Chemical Properties	0.44	72.15	5	
C_{6+} Chemical Properties	0.09	86.18	6	
N_2 Chemical Properties	2.47	28.00	0	
He Chemical Properties	0.06	4.00	0	

Hourly Natural Gas Flaring

Pollutant	Emission Factor	Activity Level [1]	Calculated Hourly PTE
CO_2	0.73 Carbon Content	2 MMScf/hr	196,800 lb/hr
CH_4	73.07 wt% CH4 (2) ; 99% DRE (3)	73,948 lb/hr	540.36 lb/hr
N_2O	0.00022 lb/MMBtu (4)	1,377 MMBtu/hr	0.30 lb/hr
CO_2e	$F_{GWP,CO2} = 1$; $F_{GWP,CH4} = 21$; $F_{GWP,N2O} = 310$ (5)		208,241 lb/hr

Annual Natural Gas Flaring

Pollutant	Emission Factor	Activity Level [6]	Calculated Annual PTE
CO_2	0.73 Carbon Content	36 MMScf/yr	2,362 tpy
CH_4	73.07 wt% CH4 (2) ; 99% DRE (3)	1,774,761 lb/yr	6.48 tpy
N_2O	0.00022 lb/MMBtu (4)	33,048 MMBtu/yr	<0.01 tpy
CO_2e	$F_{GWP,CO2} = 1$; $F_{GWP,CH4} = 21$; $F_{GWP,N2O} = 310$ (5)		2,499 tpy

Notes:

1) The maximum hourly activity levels are based on a maximum flaring rate of 1.50 MMScf/hr during MeOH Unit start-ups and the material properties of natural gas.
2) CH_4 content calculated from stream composition data above.
3) Flare destruction removal efficiency (DRE) based on TCEQ Flare Guidance Document (October 2000).
4) N_2O emission factor based on 40 CFR Part 98, Subpart C, Table C-2 for natural gas.
5) The global warming potentials are based on 40 CFR 98, Subpart A, Table A-1.
6) The annual average activity levels are based on a maximum flaring rate of 1.50 MMScf/hr during MeOH Unit start-ups, a start-up duration of 6 hours, 4 cold start-up event per year, and the material properties of natural gas.

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Table D-5 Revised November 2013
Flare - Methanol Unit "Cold" Startup Flaring MSS Emission Calculations
Natgasoline, LLC - New GtG Plant

D. Reformer Catalyst Activation Flaring Scenario

Physical Properties	Value & Units	Basis/Calculation/Notes
Waste Gas Vol. Flow Rate	0.28 MMScf/hr	Based on plant engineering design.
Supplemental Gas Vol. Flow Rate	0.07 MMScf/hr	Based on plant engineering design.
Combined Fuel Heating Value (LHV)	219 Btu/Scf	= Σ (Volume $\%_i$ * HV_i)
Molecular Weight	27.47 lb/lb-mole	= Σ (Volume $\%_i$ * MW_i)
Duration of Flaring Scenario	4 hours/event	Based on plant engineering design.
Flaring Event Frequency	1 events/yr	Maximum number in one year.
Weight Percent of CH_4	11 %	= Volume $\%_i$ * MW_i / MW_T
Carbon Content	0.15	= Σ (No. of Carbons * 12/MW_i * MW_i/MW_T)

Waste & Supplemental Gas Composition	Volume %	MW	No. of C	
CO_2 Chemical Properties	9.61	44.01	1	Based on engineering estimate of average gas composition.
CH_4 Chemical Properties	18.63	16.04	1	
C_2H_6 Chemical Properties	1.59	30.07	2	
C_3H_8 Chemical Properties	0.55	44.10	3	
C_4H_{10} Chemical Properties	0.13	58.12	4	
C_5H_{12} Chemical Properties	0.09	72.15	5	
C_{6+} Chemical Properties	0.02	86.18	6	
N_2 Chemical Properties	69.22	28.00	0	
He Chemical Properties	0.01	4.00	0	
H_2 Chemical Properties	0.16	2.02	0	

Hourly Waste Gas Flaring

Pollutant	Emission Factor	Activity Level [1]	Calculated Hourly PTE
CO_2	0.15 Carbon Content	0.34 MMScf/hr	13,411 lb/hr
CH_4	10.88 wt% CH4 (2) ; 99% DRE (3)	24,527 lb/hr	26.68 lb/hr
N_2O	0.00022 lb/MMBtu (4)	75 MMBtu/hr	0.02 lb/hr
CO_2e	$F_{GWP,CO2}$ = 1 ; $F_{GWP,CH4}$ = 21 ; $F_{GWP,N2O}$ = 310 (5)		13,976 lb/hr

Annual Waste Gas Flaring

Pollutant	Emission Factor	Activity Level [6]	Calculated Annual PTE
CO_2	0.15 Carbon Content	1.38 MMScf/yr	27 tpy
CH_4	10.88 wt% CH4 (2) ; 99% DRE (3)	98,108 lb/yr	0.05 tpy
N_2O	0.00022 lb/MMBtu (4)	301 MMBtu/yr	<0.01 tpy
CO_2e	$F_{GWP,CO2}$ = 1 ; $F_{GWP,CH4}$ = 21 ; $F_{GWP,N2O}$ = 310 (5)		28 tpy

Notes:

1) The maximum hourly activity levels are based on a maximum flaring rate of 0.28 MMScf/hr waste gas and 0.07 MMScf/hr supplemental gas during reformer catalyst regeneration and stream composition data above.
2) CH_4 content calculated from stream composition data above.
3) Flare destruction removal efficiency (DRE) based on TCEQ Flare Guidance Document (October 2000).
4) N_2O emission factor conservatively based on 40 CFR Part 98, Subpart C, Table C-2 for natural gas.
5) The global warming potentials are based on 40 CFR 98, Subpart A, Table A-1.
6) The annual average activity levels are based on flaring 0.28 MMScf/hr waste gas and 0.07 MMScf/hr supplemental gas during each regeneration event, duration of 4 hours per event, maximum of 1 regeneration events per year, and stream composition data above.

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Table D-5 Revised November 2013
Flare - Methanol Unit "Cold" Startup Flaring MSS Emission Calculations
Natgasoline, LLC - New GtG Plant

E. MeOH Start-Up Flaring - Emission Totals

Pollutant	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Maximum Hourly Emission Summary Basis* (Annual emissions = sum of annual emissions for each scenario)
CO_2	892,984	14,786	= 696,184.32 lb/hr (Synthesis Gas) + 196,799.54 lb/hr (Natural Gas)
CH_4	670.65	10.99	= 130.30 lb/hr (Synthesis Gas) + 540.36 lb/hr (Natural Gas)
N_2O	1.46	0.02	= 1.16 lb/hr (Synthesis Gas) + 0.30 lb/hr (Natural Gas)
CO_2e	907,520	15,024	= 699,279 lb/hr (Synthesis Gas) + 208,241 lb/hr (Natural Gas)

Note on Hourly Emissions Summaries:

* - Highest short-term flaring emission conditions associated with the synthesis gas flaring scenario may overlap with the natural gas flaring scenario, but the highest short-term flaring emission conditions associated with the reformer start-up fuel gas scenario or the reformer catalyst activation flaring scenario will not overlap with the other startup flaring scenarios. Therefore, the hourly maximum emission rate for each pollutant is selected as the highest of either (synthesis gas + natural gas combined), (reformer start-up fuel gas only), or (reformer catalyst generation gas only).

Example Calculations:

Flaring Emissions - All Gas Types

CO_2:
Hourly PTE (lb/hr) = 44/12 * Max Gas Flow (MMScf/hr) * 1,000,000 * Carbon Content * Molecular Weight (lb/lb-mole) / 385 scf/lb-mol
Annual PTE (tpy) = Hourly PTE (lb/hr) * Duration of Flaring Scenario (hr/event) * Cold Startup Flaring Event Frequency (event/yr) / 2,000 lb/ton

CH_4:
Hourly PTE (lb/hr) = Max Gas Flow (MMScf/hr) * 1,000,000 * Molecular Weight (lb/lb-mole) / 385 scf/lb-mol * wt% CH4 * (100 - DRE)
Annual PTE (tpy) = Hourly PTE (lb/hr) * Duration of Flaring Scenario (hr/event) * Cold Startup Flaring Event Frequency (event/yr) / 2,000 lb/ton

N_2O:
Hourly PTE (lb/hr) = Max Gas Flow (MMscf/hr) * Heating Value (Btu/Scf) * Emission Factor (lb/MMBtu)
Annual PTE (tpy) = Hourly PTE (lb/hr) * Duration of Flaring Scenario (hr/event) * Cold Startup Flaring Event Frequency (event/yr) / 2,000 lb/ton

CO_2e:
Hourly PTE (lb/hr) = 1 * CO_2 Hourly PTE (lb/hr) + 21 * CH_4 Hourly PTE (lb/hr) + 310 * N_2O Hourly PTE (lb/hr)
Annual PTE (tpy) = 1 * CO_2 Annual PTE (tpy) + 21 * CH_4 Annual PTE (tpy) + 310 * N_2O Annual PTE (tpy)

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Table D-6 Revised November 2013
Flare - Equipment Clearing MSS Emission Calculations
Natgasoline, LLC - New GtG Plant

A. Equipment Clearing Emissions - Waste Gas

General Value & Variable	Methanol	MtG	Basis/Calculation/Notes
Average Vapor Molecular Weight, $MW_{V,i}$	32 lb/lb-mole	64 lb/lb-mole	Based on TANKS 4.0.9d report for respective material
Density, ρ_i	5.7 lb/gal	6.2 lb/gal	Based on Perry's Chemical Engineers' Handbook for methanol and AP-42 Appendix A divided by ρ for gasoline
Heating Value, HV_i	9,250 Btu/lb	21,070 Btu/lb	Based on typical value for methanol and AP-42 Appendix A divided by ρ for gasoline
Standard Molar Volume, MV	385 ft3/lb-mole		Based on molar volume at standard conditions
Purging Temperature, T	555 °R		Based on typical value
Unit Equipment Volume, V_i	242,755 ft3	91,693 ft3	Based on Total Volume of All Unit Vessels with Additional 30% Factor for Pumps and Piping
Total Equipment Volume, V_T	334,448 ft3		Sum of Methanol Unit Volume and MtG Unit Volume
Volume of Largest Vessel, V_L	81,719 ft3		Largest Volume of Gas for Worst-case Hourly Emission Rate
Total Unit Equipment Volume %, V%,i	80 %	20 %	$= V_i + V_{RA,i} / (V_{MeOH} + V_{MtG})$
Residual Liquid Volume %, $V_{\%R}$	0.5%		Conservatively assume a small amount of residual liquid volatilizes and is routed to flare
Hourly Flow to Flare from Residual Liquid, V_{RH}	210,132 ft3		$= V_{\%R} * V_L * 7.481 * \rho_{MeOH} * MV / MW_{V,MeOH}$
Annual Flow to Flare from Residual Liquid, $V_{RA,i}$	624,220 ft3	127,434 ft3	$= V_{\%R} * V_i * 7.481 * \rho_i * MV / MW_{V,i}$ * 1 plant-wide clearing event/yr
Hourly Total Gas Volumetric Flow, Q_H	291,851 Scf/hr		$= V_L + V_{RH}$
Annual Total Gas Volumetric Flow, Q_A	1,086,102 Scf/yr		$= (V_T$ * 1 plant-wide clearing event/yr) + $V_{RA,MeOH}$ + $V_{RA,MtG}$
Hourly Total Gas Mass Flow, M_H	24,232 lb MeOH/hr		$=(Q_H * MW_{V,i}) / MV$ * 1 event/hr
Annual Total Gas Mass Flow, M_A	71,985 lb MeOH/yr	36,388 lb gasol./yr	$= (Q_A * V_{\%,I} * MW_{V,I})/ MV$ * 1 plant-wide clearing event/yr
Hourly Heat Input to Flare	224 MMBtu/hr		$= M_H * Hv_i$ / 1,000,000 Btu/MMBtu
Annual Heat Input to Flare	666 MMBtu/yr	767 MMBtu/yr	$= (M_{A,MeOH} * HV_{MeOH}$ / 1,000,000 Btu/MMBtu) + ($M_{A,MtG}$ * HV_{MtG} / 1,000,000 Btu/MMBtu)

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Table D-6 Revised November 2013
Flare - Equipment Clearing MSS Emission Calculations
Natgasoline, LLC - New GtG Plant

B. Equipment Clearing Emissions - Waste Gas

Hourly Equipment Clearing Emissions - Waste Gas			
Pollutant	**Emission Factor**	**Activity Level**	**Calculated Hourly PTE**
CO_2	117 lb/MMBtu (1)	224 MMBtu/hr	26,200 lb/hr
CH_4	0.0022 lb/MMBtu (1)	224 MMBtu/hr	0.49 lb/hr
N_2O	0.00022 lb/MMBtu (1)	224 MMBtu/hr	0.05 lb/hr
CO_2e	$F_{GWP,CO2}$ = 1 ; $F_{GWP,CH4}$ = 21 ; $F_{GWP,N2O}$ = 310 (3)		26,225 lb/hr

Annual Equipment Clearing Emissions - Waste Gas			
Pollutant	**Emission Factor**	**Activity Level**	**Calculated Annual PTE**
CO_2	117 lb/MMBtu (1)	1,433 MMBtu/yr	83.72 tpy
CH_4	0.0022 lb/MMBtu (1)	1,433 MMBtu/yr	<0.01 tpy
N_2O	0.00022 lb/MMBtu (1)	1,433 MMBtu/yr	<0.01 tpy
CO_2e	$F_{GWP,CO2}$ = 1 ; $F_{GWP,CH4}$ = 21 ; $F_{GWP,N2O}$ = 310 (2)		83.80 tpy

Notes:

1) CO_2, CH_4, and N_2O emission factors based on 40 CFR Part 98, Subpart C, Tables C-1 and C-2 for natural gas.
2) The global warming potentials are based on 40 CFR 98, Subpart A, Table A-1.

Example Calculations:

CO_2, CH_4, N_2O:
Hourly PTE (lb/hr) = Max Gas Flow (MMBtu/hr) * Emission Factor (lb/MMBtu)
Annual PTE (tpy) = Avg Annual Gas Flow (MMBtu/yr) * Emission Factor (lb/MMBtu) / 2,000 lb/ton

CO_2e:
Hourly PTE (lb/hr) = 1 * CO_2 Hourly PTE (lb/hr) + 21 * CH_4 Hourly PTE (lb/hr) + 310 * N_2O Hourly PTE (lb/hr)
Annual PTE (tpy) = 1 * CO_2 Annual PTE (tpy) + 21 * CH_4 Annual PTE (tpy) + 310 * N_2O Annual PTE (tpy)

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Table D-6 Revised November 2013
Flare - Equipment Clearing MSS Emission Calculations
Natgasoline, LLC - New GtG Plant

C. Equipment Clearing Emissions - Supplemental Gas

Physical Properties	Hourly Annual	Basis/Calculation/Notes
Heating Value of Supplemental Natural Gas, HV_{Supp}	918 Btu/Scf	Based on standard value of 1,020 adjusted by 90% to lower heating value.

Hourly Equipment Clearing Emissions - Supplemental Gas

Pollutant	Emission Factor	Activity Level (1,2)	Calculated Hourly PTE
CO_2	117 lb/MMBtu (3)	67 MMBtu/hr	7,829 lb/hr
CH_4	0.0022 lb/MMBtu (4)	67 MMBtu/hr	0.15 lb/hr
N_2O	0.00022 lb/MMBtu (4)	67 MMBtu/hr	0.01 lb/hr
CO_2e	$F_{GWP,CO2} = 1$; $F_{GWP,CH4} = 21$; $F_{GWP,N2O} = 310$ (5)		7,837 lb/hr

Annual Equipment Clearing Emissions - Supplemental Gas

Pollutant	Emission Factor	Activity Level (1,2)	Calculated Annual PTE
CO_2	117 lb/MMBtu (3)	249 MMBtu/yr	14.57 tpy
CH_4	0.0022 lb/MMBtu (4)	249 MMBtu/yr	<0.01 tpy
N_2O	0.00022 lb/MMBtu (4)	249 MMBtu/yr	<0.01 tpy
CO_2e	$F_{GWP,CO2} = 1$; $F_{GWP,CH4} = 21$; $F_{GWP,N2O} = 310$ (5)		14.58 tpy

Notes:

1) The maximum hourly and annual average supplemental gas mass flow rates and the supplemental gas volumetric flow rates are based on a ratio of process gas to supplemental gas of 4 to 1.
2) The maximum hourly and annual average vapor heat inputs to flare are based on the maximum/average supplemental volumetric flow rate * the heating value of natural gas.
3) CO_2 emission factor based on 40 CFR Part 98, Subpart C, Table C-1 for natural gas.
4) CH_4 and N_2O emission factors based on 40 CFR Part 98, Subpart C, Table C-2 for natural gas.
5) The global warming potentials are based on 40 CFR 98, Subpart A, Table A-1.

Example Calculations:

CO_2, CH_4, N_2O:
Hourly PTE (lb/hr) = Max Supplemental Gas Flow (MMBtu/hr) * Emission Factor (lb/MMBtu)
Annual PTE (tpy) = Avg Annual Supplemental Gas Flow (MMBtu/yr) * Emission Factor (lb/MMBtu) / 2,000 lb/ton

CO_2e:
Hourly PTE (lb/hr) = 1 * CO_2 Hourly PTE (lb/hr) + 21 * CH_4 Hourly PTE (lb/hr) + 310 * N_2O Hourly PTE (lb/hr)
Annual PTE (tpy) = 1 * CO_2 Annual PTE (tpy) + 21 * CH_4 Annual PTE (tpy) + 310 * N_2O Annual PTE (tpy)

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Table D-6 Revised November 2013
Flare - Equipment Clearing MSS Emission Calculations
Natgasoline, LLC - New GtG Plant

C. Equipment Clearing Emissions - Totals

Pollutant	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Basis/Calculation/Notes
CO_2	34,029	98.29	= CO_2 Emissions from Flare Waste Gas + CO_2 Emissions from Flare Supplemental Gas
CH_4	0.64	<0.01	= CH_4 Emissions from Flare Waste Gas + CH_4 Emissions from Flare Supplemental Gas
N_2O	0.06	<0.01	= N_2O Emissions from Flare Waste Gas + N_2O Emissions from Flare Supplemental Gas
CO_2e	34,062	98.39	= CO_2e Emissions from Flare Waste Gas + CO_2e Emissions from Flare Supplemental Gas

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Table D-7 Revised November 2013
Vapor Combustor for Product Loading Operations - Potential Emissions
Natgasoline, LLC - New GtG Plant

A. MtG Unit Rail Controlled Loading Emissions

Parameter Name & Variable		Value & Units	Basis/Calculation/Notes
1. General Values and Calculations			
Maximum Hourly Loading Rate	Q_H	60 10^3Gal/hr	Conservative estimate - loading two (2) 30,000 gallon capacity railcars per hour
Average Annual Loading Rate	Q_A	126,473 10^3Gal/yr	Based on 50% of total gasoline production
Saturation Factor	S	0.6 -	Based on Submerged Loading: Dedicated Normal Service
Maximum Gasoline True Vapor Pressure	P_{MAX}	11.84 psia	Based on TANKS 4.09d report for Gasoline at 95°F
Average Gasoline True Vapor Pressure	P_{AVG}	7.72 psia	Based on TANKS 4.09d report for Gasoline at 70°F
Gasoline Molecular Weight	M_V	64.0 lb/lb-mole	Based on TANKS 4.09d report
Maximum Temperature of Bulk Liquid Loaded	T_{HR}	95.0 °F 555.0 °R	Based on TCEQ guidance = (" °F " value) + 460
Average Temperature of Bulk Liquid Loaded	T_{ANN}	68.4 °F 528.4 °R	Based on TANKS 4.09d report = (" °F " value) + 460
Short Term Loading Loss	L_{LHR}	10.21 lb/10^3gal	=12.46 x S x P_{MAX} x M / T_{HR} *AP-42 Section 5.2.2.1.1, Equation 1*
Long Term Loading Loss	L_{LANN}	6.99 lb/10^3gal	=12.46 x S x P_{AVG} x M / T_{ANN} *AP-42 Section 5.2.2.1.1, Equation 1*
Vapor Collection Efficiency	CE	100 %	Based on TCEQ guidance
2. VOC Emission Rate Calculations			
Hourly Vapors Routed to Control (1)	$m_{controlA}$	**419.6 lb/hr VOC**	= L_L x Q_H x (CE)
Annual Vapors Routed to Control (1)	$m_{controlA}$	**442 tpy VOC**	= LL x QA x (CE) / 2000 lbs/ton

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Table D-7 Revised November 2013
Vapor Combustor for Product Loading Operations - Potential Emissions
Natgasoline, LLC - New GtG Plant

B. MtG Unit Truck Controlled Loading Emissions

Parameter Name & Variable		Value & Units	Basis/Calculation/Notes
1. General Values and Calculations			
Maximum Hourly Loading Rate	Q_H	16 10^3Gal/hr	Conservative estimate - loading two (2) 8,000 gallon capacity trucks per hour
Average Annual Loading Rate	Q_A	126,473 10^3Gal/yr	Based on 50% of total gasoline production
Saturation Factor	S	0.6 -	Based on Submerged Loading: Dedicated Normal Service
Maximum Gasoline True Vapor Pressure	P_{MAX}	11.84 psia	Based on TANKS 4.09d report for Gasoline at 95°F
Average Gasoline True Vapor Pressure	P_{AVG}	7.72 psia	Based on TANKS 4.09d report for Gasoline at 70°F
Gasoline Molecular Weight	M_V	64.0 lb/lb-mole	Based on TANKS 4.09d report
Maximum Temperature of Bulk Liquid Loaded	T_{HR}	95.0 °F 555.0 °R	Based on TCEQ guidance = (" °F " value) + 460
Average Temperature of Bulk Liquid Loaded	T_{ANN}	68.4 °F 528.4 °R	Based on TANKS 4.09d report = (" °F " value) + 460
Short Term Loading Loss	L_{LHR}	10.21 lb/10^3gal	=12.46 x S x P_{MAX} x M / T_{HR} *AP-42 Section 5.2.2.1.1, Equation 1*
Long Term Loading Loss	L_{LANN}	6.99 lb/10^3gal	=12.46 x S x P_{AVG} x M / T_{ANN} *AP-42 Section 5.2.2.1.1, Equation 1*
Vapor Collection Efficiency	CE	100.0 %	Department of Transportation Vapor-Tightness Testing
2. VOC Emission Rate Calculations			
Hourly Vapors Routed to Control (1)	$m_{controlA}$	**111.9 lb/hr VOC**	= L_L x Q_H x (CE)
Annual Vapors Routed to Control (1)	$m_{controlA}$	**442 tpy VOC**	= LL x QA x (CE) / 2000 lbs/ton

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Table D-7 Revised November 2013
Vapor Combustor for Product Loading Operations - Potential Emissions
Natgasoline, LLC - New GtG Plant

C. Input Data for Emission Calculations	Value	Basis
Fuel Type(s):	Mixture of Natural Gas and Gasoline Loading Vapors	Design
Average Natural Gas Heating Value:	1,020 Btu/scf	AP-42 value
Average Waste Gas Heating Value:	20,400 Btu/lb (HHV)	Based on motor gasoline vapor
Average Annual Natural Gas Firing Rate:	2.00 MMBtu/hr	Natural gas flow to vapor combustor during hot standby
Maximum Hourly Waste Gas Flow:	531 lb VOC/hr 10.8 MMBtu/hr	Based on maximum hourly collected vapors from truck loading and railcar loading (1)
Average Annual Waste Gas Flow:	884,419 lb VOC/yr 18,042 MMBtu/yr	Based on total annual collected vapors from worst-case transport method (railcar loading) (2)

D. Emission Calculations

Pollutant	Emission Factor (3)	Hourly PTE lb/hr	Annual PTE tpy
CO_2	117.65 lb/MMBtu	1,276	1,061
CH_4	0.0022 lb/MMBtu	0.02	0.02
N_2O	0.00022 lb/MMBtu	<0.01	<0.01
CO_2e (4)	117.78 lb/MMBtu	1,277	1,062

Notes:

(1) The maximum hourly waste gas flow rate is estimated from the conservative assumption that any loading method (railcar or truck) can occur at the same time.
(2) The average annual waste gas flow rate is estimated from the worst-case transport method.
(3) Indicated factors are from AP-42 Table 1.4-2. Listed lb/million scf values are divided by 1,020 to convert to lb/MMBtu.
(4) The CO_2e emission factor is based on the sum of the CO_2, CH_4, and N_2O emission factors multiplied by their respective global warming potential factors in 40 CFR Part 98 Subpart A, Table A-1.

Example Calculations:

Hourly PTE (lb/hr) = Max Natural Gas Flow (MMBtu/hr) * Emission Factor (lb/MMBtu)

Annual PTE (tpy) = Avg Gas Flow (MMBtu/yr) * Emission Factor (lb/MMBtu) / 2,000 lb/ton

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Table D-8 Revised November 2013
Fugitive Equipment Components in Methanol Unit - Potential Emissions
Natgasoline, LLC - New GtG Plant

Component Type and Service	Estimated Number of New Components	USEPA SOCMI w/out C2 Emission Factor [1] (lb/hr-component)	Control Efficiency [2] (percent)	Precontrol Emission Rates	Calculated Emission Rates [3]	
				lb/hour	lb/hour	tpy
Valves - Gas/Vapor in Process Piping [4]	350	0.0089	97	3.12	0.09	0.41
Valves - Gas/Vapor in Fuel Gas Piping [5]	422	0.0089	97	3.76	0.11	0.49
Valves - Light Liquid [4]	1,224	0.0035	97	4.28	0.13	0.56
Valves - Heavy Liquid [6]	5	0.0007	0	0.00	<0.01	0.02
Pumps - Light Liquid [4]	40	0.0386	85	1.54	0.23	1.01
Compressors - Process Gas [4]	2	0.5027	85	1.01	0.15	0.66
Compressors - Fuel Gas [5]	2	0.5027	85	1.01	0.15	0.66
Flanges - Gas/Vapor in Process Piping [4]	875	0.0029	30	2.54	1.78	7.78
Flanges - Gas/Vapor in Fuel Gas Piping [5]	1,055	0.0029	30	3.06	2.14	9.38
Flanges - Light Liquid [4]	3,059	0.0005	75	1.53	0.38	1.67
Flanges - Heavy Liquid [6]	14	0.00007	30	0.00	<0.01	<0.01
Relief Valves - Gas Vapor [4]	4	0.2293	100	0.92	-0.0-	-0.0-
Process Drains - Light Liquid [4]	30	0.07	97	2.10	0.06	0.28
			Total VOC	**74.32**	**2.93**	**12.83**
			Total CH_4	**34.56**	**2.31**	**10.10**
			Total CO_2e [7]	**725.75**	**48.42**	**212.10**

Notes:

1) Air Permit Technical Guidance Package for Chemical Sources - Equipment Leak Fugitives. TCEQ. (October 2000).

2) Control efficiencies based on TCEQ Leak Detection and Repair Program 28VHP and water-seals on drains. All relief valves are routed to flare for control. Connectors in light liquid service will be monitored annually based on requirements for connectors under HON.

3) Sample Calculations - Fugitive Emissions (Gas/Vapor Valves)

lb VOC / hr = 422 gas/vapor valves * 0.0089 lb VOC / hr / component * (100% -97%) = 0.11 lb VOC/hr

tons VOC / yr = 0.11 lb VOC / hr * 8760 hr /yr / 2000 lb/ton = 0.49 tons VOC/yr

4) Conservatively estimate that methanol unit process piping includes up to 5% methane by weight on average.

5) Fuel gas contains 90% methane and 10% VOC by weight average.

6) No methane is expected to be present in components in heavy liquid service.

7) Global warming potential factor for CH_4 is 21 as indicated on 40 CFR Part 98 Subpart A, Table A-1.

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Table D-9 Revised November 2013
Fugitive Equipment Components in MtG Unit - Potential Emissions
Natgasoline, LLC - New GtG Plant

Component Type and Service	Estimated Number of New Components	USEPA SOCMI w/out C2 Emission Factor [1] (lb/hr-component)	Control Efficiency [2] (percent)	Precontrol Emission Rates	Calculated Emission Rates [3]	
				lb/hour	lb/hour	tpy
Valves - Gas/Vapor in Fuel Gas Piping [4]	301	0.0089	97	2.68	0.08	0.35
Compressors - Fuel Gas [4]	2	0.5027	85	1.01	0.15	0.66
Flanges - Gas/Vapor in Fuel Gas Piping [4]	753	0.0029	30	2.18	1.53	6.69
			Total VOC	**0.77**	**0.18**	**0.77**
			Total CH_4	**23.13**	**1.58**	**6.93**
			Total CO_2e [5]	**485.64**	**33.24**	**145.59**

Notes:

1) Air Permit Technical Guidance Package for Chemical Sources - Equipment Leak Fugitives. TCEQ. (October 2000).

2) Control efficiencies based on TCEQ Leak Detection and Repair Program 28VHP.

3) Sample Calculations - Fugitive Emissions (Gas/Vapor Valves)

lb VOC / hr = 301 gas/vapor valves * 0.0089 lb VOC / hr / component * (100% -97%) = 0.08 lb VOC/hr

tons VOC / yr = 0.08 lb VOC / hr * 8760 hr /yr / 2000 lb/ton = 0.35 tons VOC/yr

4) Fuel gas contains 90% methane and 10% VOC by weight on average. MtG process piping will not include methane.

5) Global warming potential factor for CH_4 is 21 as indicated on 40 CFR Part 98 Subpart A, Table A-1.

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Table D-10 Revised November 2013
Potential Greenhouse Gas Emissions from MtG Catalyst Regeneration
Natgasoline, LLC - New GtG Plant

Emission Source	Flow Rate		Mol Wt of Stream	% CO_2		Emission Time [1]	CO_2 Calculated Emission Rates [2]	
	lbmol/hr	lb/hr	lb/lbmol	mol%	wt%	hrs/yr	lb/hr	TPY
Vented Gas from Main Burn (MtG)	836.1	25,719	30.72	17.586%	25.192%	1681	**6,479**	**5,446**

Notes:

1) Emission time for each catalyst regeneration burn phase is based on the catalyst being regenerated approximately 110 times each year.

2) Sample Calculations - CO_2 Emissions (Vented Gas from Main Burn)

TPY CO2 = 25719 lb/hr * 0.2519 lb/lb

TPY CO2 = 25719 lb/hr * 0.2519 lb/lb * 1681 hrs/yr * 8,760 hrs/yr

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Table D-11
Potential Greenhouse Gas Emissions from Emergency Equipment
Natgasoline, LLC - New GtG Plant

A. Emission Factors and Global Warming Potential (GWP) Equivalency Factors

CO_2[1]	73.96	kg CO_2/MMBtu	&	**CO_2**[2]	=	1 ton of CO2 equivalent
CH_4[1]	0.003	kg CH_4/MMBtu	&	**CH_4**[2]	=	21 tons of CO2 equivalent
N_2O[1]	0.0006	kg N_2O/MMBtu	&	**N_2O**[2]	=	310 tons of CO2 equivalent

B. Emission Calculations

Emission Source	Design Firing Rate [6]		CO_2 Emissions		CH_4 Emissions		N_2O Emissions		CO_2e Emissions [5]	
	Max.	Aver.	Hourly	Annual	Hourly	Annual	Hourly	Annual	Hourly	Annual
	MMBtu/hr	MMBtu/hr	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Emergency Engine	17	17	2,782	139	0.11	0.01	0.02	0.001	2,792	140
Firewater Pump Engines [7]	17	17	2,782	139	0.11	0.006	0.02	0.001	2,792	140
		Totals	**5,564**	**278**	**0.23**	**0.01**	**0.05**	**0.002**	**5,583**	**279**

Notes:

(1) Emission factors are based on 40 CFR Part 98 Subpart C, Table C-1 and Table C-2 for distillate fuel oil no. 2.

(2) Global warming potential factors are based on 40 CFR Part 98 Subpart A, Table A-1.

(3) Hourly emissions are based on the emission factor * max. hourly firing rate * 2.204 lb/kg.

(4) Annual emissions are based on the emission factor * aver. hourly firing rate (normal) * 2.204 lb/kg * 100 hours/year / 2000 lb/ton.

(5) CO_2e emissions are based on the sum of the CO_2, CH_4, and N_2O emissions times their respective GWP factors.

(6) The design firing rate is based on a 2,000 KW engine with 40% efficiency.

(7) The design firing rate for both firewater pump engines is based on a 1,000 KW engine with 40% efficiency.

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Table D-12
Potential Greenhouse Gas Emissions from Cooling Tower Added November 2013
Natgasoline, LLC - New GtG Plant

A. Emission Factors and Global Warming Potential (GWP) Equivalency Factors

CH_4 Emission Factor[1] 0.7 lb CH_4/MMGal

CH_4 GWP [2] 21 tons of CO_2 equivalent

B. Emission Calculations

Emission Source	Inlet Flow Rate [3]	CH_4 Emissions [4],[5]		CO_2e Emissions [6]	
		Hourly	Annual	Hourly	Annual
	MMGal/hr	lb/hr	TPY	lb/hr	TPY
MeOH Cooling Tower	11.3	7.91	34.652	166	728
	Totals	**7.91**	**34.65**	**166**	**728**

Notes:

(1) Emission factor is based on AP-42 Table 5.1-2, with the assumption that 100% of VOC is CH_4.

(2) Global warming potential factor is based on 40 CFR Part 98 Subpart A, Table A-1.

(3) The inlet flow rate is based on total flow into cooling tower.

(4) Hourly emissions are based on the emission factor * inlet flow rate.

(5) Annual emissions are based on the emission factor * inlet flow rate * 8,760 hours/year / 2000 lb/ton.

(6) CO_2e emissions are based on the CH_4 emissions times the GWP factor.

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APPENDIX E
PROPOSED BACT LIMITS AND COMPLIANCE DEMONSTRATION

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Table E-1
Proposed BACT Limits and Compliance Demonstration
Natgasoline, LLC - New GtG Plant

GHG Emission Source	EPN	BACT Emission Limit	Compliance Demonstration Description	BACT Limit Compliance Determination Frequency
Methanol Reformer	B-01001	Minimum 90% Thermal Efficiency	1. An O_2 continuous monitoring system (CMS) will be installed in order to measure O2 concentration in the flue gas every 15 minutes. The required zero and span calibrations will take place daily and quarterly cylinder gas audits (CGAs) will also be performed. Records will be maintained onsite for a period of at least five years.	Rolling 12-month average basis
			2. A temperature monitor (ex. thermocouple) will be installed to record the temperatures of the combustion flue gas on a continuous basis.	Rolling 12-month average basis
			3. The thermal efficiency of the boiler will be calculated hourly using the parameters outlined in (1) and (2) above, excluding data from startups, shutdowns, and malfunctions. Thermal efficiency will be calculated using Equation G.1 in Annex G from the American Petroleum Institute's Standard 560. Records will be maintained onsite for a period of at least five years.	Rolling 12-month average basis
		Maximum 3% O_2 in stack gas (normal operation)	1. An O_2 CMS will be installed in order to measure O2 concentration in the flue gas every 15 minutes. The required zero and span calibrations will take place daily and quarterly CGAs will also be performed. Records will be maintained onsite for a period of at least five years.	Rolling 12-month average basis
		Maximum 350°F in stack gas (normal operation)	1. A temperature monitor (ex. thermocouple) will be installed to record the temperature of the combustion flue gas on a daily basis. Records will be maintained onsite for a period of at least five years.	Rolling 12-month average basis
Auxiliary Boiler	B-14001	Minimum 85% Thermal Efficiency	1. An O_2 CMS will be installed in order to measure O2 concentration in the flue gas every 15 minutes. The required zero and span calibrations will take place daily and quarterly CGAs will also be performed. Records will be maintained onsite for a period of at least five years.	Rolling 12-month average basis
			2. A temperature monitor (ex. thermocouple) will be installed to record the temperatures of the combustion flue gas on a continuous basis.	Rolling 12-month average basis
			3. The thermal efficiency of the boiler will be calculated hourly using the parameters outlined in (1) and (2) above, excluding data from startups, shutdowns, and malfunctions. Thermal efficiency will be calculated using Equation G.1 in Annex G from the American Petroleum Institute's Standard 560. Records will be maintained onsite for a period of at least five years.	Rolling 12-month average basis

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Natgasoline, LLC - New GtG Plant

GHG Emission Source	EPN	BACT Emission Limit	Compliance Demonstration Description	BACT Limit Compliance Determination Frequency
Regeneration Heater	H-REGEN	Gaseous Fuel, Good Combustion Practices (1)	1. The heater burners will be cleaned during each unit turnaround, or at least every five years (whichever is less) to remove any buildup and maintain heat transfer efficiency. Records will be maintained onsite for a period of at least five years.	Minimum every five years
			2. The regeneration heater will be equipped with an automated air/fuel control system to maintain optimal combustion efficiency. The automated fuel/air control system will be calibrated and preventative maintenance will be performed at least quarterly. Records will be maintained onsite for a period of at least five years.	Quarterly
			3. The regeneration heater will be designed with materials that provide proper insulation in order to reduce heat transfer losses.	Design
MtG Reactor Heaters	H-RXH1-5	Gaseous Fuel, Good Combustion Practices (1)	1. The heater burners will be cleaned during each unit turnaround, or at least every five years (whichever is less) to remove any buildup and maintain heat transfer efficiency. Records will be maintained onsite for a period of at least five years.	Minimum every five years
			2. The MtG reactor heaters will be equipped with an automated air/fuel control system to maintain optimal combustion efficiency. The automated fuel/air control system will be calibrated and preventative maintenance will be performed at least quarterly.	Quarterly
			3. The MtG reactor heaters will be designed with materials that provide proper insulation in order to reduce heat transfer losses.	Design
MtG Heavy Gasoline Treater Heater	H-HGT	Gaseous Fuel, Good Combustion Practices (1)	1. The heater burners will be cleaned during each unit turnaround, or at least every five years (whichever is less) to remove any buildup and maintain heat transfer efficiency. Records will be maintained onsite for a period of at least five years.	Minimum every five years
			2. The heavy gasoline treater heater will be equipped with an automated air/fuel control system to maintain optimal combustion efficiency. The automated fuel/air control system will be calibrated and preventative maintenance will be performed at least quarterly.	Quarterly
			3. The heavy gasoline treater heater will be designed with materials that provide proper insulation in order to reduce heat transfer losses.	Design
Plant Flare	S-1001/MSS	Good Design and Combustion Practices, Minimize Flaring	1. A flow meter and colorimeter will be installed on the flare header and will continuously take measurements of the flow to the flare and the flare gas heat value. The flow meter and colorimeter will be calibrated on a frequency as recommended by manufacturer specifications. Records will be maintained onsite for a period of at least five years.	Continuous
			2. The flare will be designed and operated in accordance with 40 CFR§60.18, including the minimum value of the waste heat gas, maximum tip velocity, and pilot flame monitoring (e.g., with a thermocouple, infrared monitor, or other equivalent).	Design
			3. The flare will achieve at least a 99% destruction efficiency for all carbon compounds with three carbons or less (including methane) and a 98% destruction efficiency for all carbon compounds with greater than 3 carbons.	Design
			4. Flaring as a result of MSS events will take place as quickly as is technically practicable.	MSS Event Duration

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GHG Emission Source	EPN	BACT Emission Limit	Compliance Demonstration Description	BACT Limit Compliance Determination Frequency
Vapor Combustor	VCU-1	Limited Operating Hours, Good Combustion Practices (<0.5% of total CO_2e emissions)	1. VCU operation will be intermittent and will only take place during gasoline loading operations.	Loading Event Duration
			2. Only pipeline-quality natural gas will be used as supplemental fuel during loading operations.	Loading Event Duration
			3. Loading operations will be completed as quickly as is technically practicable.	Loading Event Duration
Catalyst Regeneration Vent	EPN-CATREGEN	Proper Operating Techniques (<0.5% of total CO_2e emissions)	1. The number of catalyst regenerations and the regeneration duration will be minimized as is technically practicable in order to maintain low CO_2e emissions.	Catalyst Regeneration Duration
Process Fugitives	FUG-MEOH/FUG-MTG	Implementation of LDAR Program (<0.5% of total CO_2e emissions)	1. The 28VHP program will be implemented for streams that contain >10% methane by weight. Data and other records will be maintained onsite for a period of at least five years.	Quarterly
Emergency Generator and Firewater Pump Engines	H-EMG/H-FWP	Proper Operating Techniques, Limited Operating Hours (<0.5% of total CO_2e emissions)	1. The emergency generator and firewater pump engines will not be operated more than 100 hours per year, for non-emergency uses (e.g., testing). Run-time meters will be installed on all three engines.	Annual
Cooling Water Tower	T-06001	Implementation of Heat Exchanger Leak Monitoring and Repair Program (<0.5% of total CO2e emissions)	1. The cooling water will be monitored for TOC leaks on a monthly basis using the "El Paso" method (or equivalent)	Monthly

Notes:

1) The smaller heaters in the MtG Unit all contribute <1.5 percent each to the total CO_2e emissions. Therefore, establishing a numerical BACT limit (such as thermal efficiency) to these heaters would not result in a significant reduction in GHG emissions.