Clear Lake Plant

Celanese Chemicals
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Pasadena, TX 77507
Mailing Address:
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Celanese

August 8, 2012
JLD-09c-12

HAND DELIVERY

Mr. Carl Edlund, P.E., Director
Multimedia Planning and Permitting Division
EPA, Region 6
1445 Ross Avenue
Dallas, TX 75202

Received
AUG 10 2012
by
Admin Specialist
6PD

Re: **GHG PSD Permit Application**
Methanol Unit
Celanese Ltd., Clear Lake Plant

Dear Mr. Edlund:

Celanese Ltd. (Celanese) operates several process units at its Clear Lake Plant under existing Air Permits and Permit-By-Rules issued by the Texas Commission on Environmental Quality. Celanese is requesting authorization for a new Methanol Unit. Celanese is submitting the enclosed application to address the authorization requirements at its Clear Lake Plant for Greenhouse Gases that will be emitted from the proposed Methanol Unit. The authorization for other criteria pollutants, VOC, PM, SO2, CO and NOx has been submitted under a separate cover to the Texas Commission on Environmental Quality.

Should you have any questions concerning this submittal, please contact Mrs. Jan Day at (281) 474-8802.

Sincerely,

8/8/12

Paresh Bahkta
Site Director

Clear Lake Plant

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cc: TCEQ Region 12
5425 Polk Ave., Ste. H
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Director
Harris County Pollution Control
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City of Pasadena
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Pasadena, Texas 77501-0672

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Greenhouse Gas
Prevention of Significant Deterioration
Permit Application for Methanol Manufacturing

Celanese Clear Lake Plant
Pasadena, Texas

August 2012

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SECTION 1
INTRODUCTION

1.1 Introduction

Celanese Ltd. (Celanese) is hereby requesting an authorization to construct a new Methanol manufacturing unit to be located at its Clear Lake Plant in Pasadena, Texas.

1.2 Background

Celanese owns and operates multiple chemical manufacturing units at the Clear Lake Plant located at 9502 Bayport Blvd., Pasadena, Harris County, Texas. An area map, Figure 1-1, of the Clear Lake plant and surrounding area has been included in this application. Currently, methanol is one of the feedstocks imported to the facility. To provide improved reliability of their methanol supply and reduce transportation expenses, Celanese proposes to manufacture methanol onsite with the construction of a new methanol manufacturing unit.

The Celanese Clear Lake Plant is an existing major source as defined within the Federal Prevention of Significant Deteriorations (PSD) Permit Program. Therefore, physical changes and changes in the method of operation are potentially subject to PSD permitting requirements. The proposed project will trigger PSD review for Greenhouse Gas (GHG). The permit application has been prepared based upon EPA’s “New Source Review Workshop Manual” and additional GHG guidance.

1.3 Project Scope

The proposed project will create greenhouse gas emissions, and thus Celanese requests to authorize the following activities:

- Authorize the construction of a new methanol unit including major equipment and auxiliary equipment.
- Authorize the construction of an emergency generator and fuel storage tank
- Authorize increase in utilities emissions.

The project is estimated to increase $CO_{2(e)}$ emissions by above significance levels$_2$, 75,000 tons per year. There are no creditable decreases in the contemporaneous window that will reduce the site impact below the significance level.

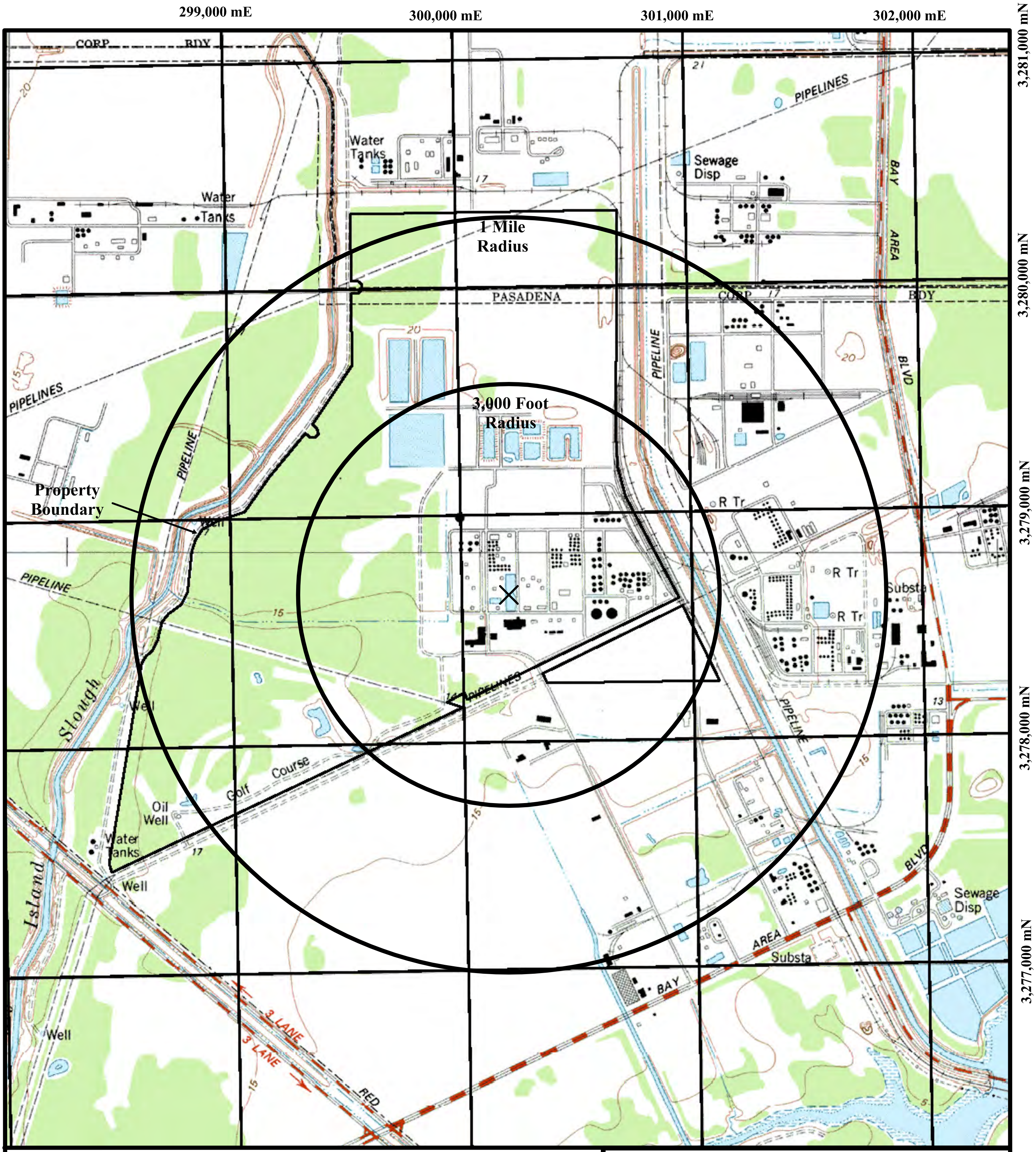
Changes that do not impact green house gas emissions are excluded from this application and can be found in the PSD/non-attainment application submitted to the Texas Commission on Environmental Quality on June 12, 2012, and subsequent submittals, for the proposed Methanol Unit.

A summary of the biological, archeological and cultural study of the proposed site area will be submitted under separate cover at a later date.

1.4 Process Description

The design capacity of the new Methanol plant is 1,300 kta (thousand metric tons per year).

Pipeline natural gas is compressed, preheated, treated to remove sulfur, saturated with process water, mixed with steam, reheated and the natural gas/steam mixture fed to the primary reformer where a portion of the methane is converted to synthesis gas (a mixture of carbon monoxide, carbon dioxide and hydrogen). Heat input to the primary reformer is provided by natural gas and a purge stream that is taken from the converter loop to remove inerts (nitrogen, argon and methane) and excess hydrogen. Heat is recovered from the flue gases from the primary reformer (by super-heating steam, reheating the natural gas/steam mixture fed to the primary reformer, preheating the natural gas feed to the sulfur removal system and preheating combustion air) prior to venting the flue gases to atmosphere. The partially reformed gas stream from the primary reformer is sent to the secondary reformer where it is reacted with oxygen and most of the remaining methane converted to synthesis gas. The synthesis gas leaving the secondary reformer is cooled, compressed and sent to the converter loop where carbon monoxide, carbon dioxide and hydrogen are reacted to produce crude methanol, a mixture mainly of methanol and water. Process streams including, but not limited to, the synthesis gas and converted methanol will be monitored using various process analyzers. Most of the steam that is required to operate the Methanol plant is produced by heat recovery from the synthesis gas leaving the secondary reformer; the remainder is produced by heat recovery from the converters. The crude methanol is sent to a three-column distillation train. Light ends are taken overhead in the first column and combined with the purge stream from the converter loop. Finished methanol is taken overhead in the second column. The residue from the second column feeds a third column. The finished methanol is also taken overhead in the third column. A side stream from the third column is recycled to the saturator. The process water stream from the bottom of the third column is recycled to the saturator. Finished methanol is sent to the storage area. The storage area consists of five existing fixed-roof storage tanks and a proposed new IFR storage tank. All of the tanks will be routed to the existing Tank farm vent scrubber, 55T43. Finished methanol is fed to the Acetic acid plant or shipped from the Methanol plant by truck, railcar and/or pipeline. The loading emissions are controlled by a 3rd party. No net increase in GHG emissions from 3rd party will result since heat requirements are off-set by reduction in natural gas required.



SCALE 1:24,000

0 MILES 0.5 1.0 MILES

0 FEET 2500 5000 FEET

U.S.G.S. 7.5 MINUTE SERIES

LA PORTE, TEXAS QUADRANGLE
LEAGUE CITY, TEXAS QUADRANGLE

NORTH

FIGURE 4-1
AREA MAP

Celanese Ltd., Clear Lake Plant
SITE LOCATION ON USGS MAP
Clear Lake, TX

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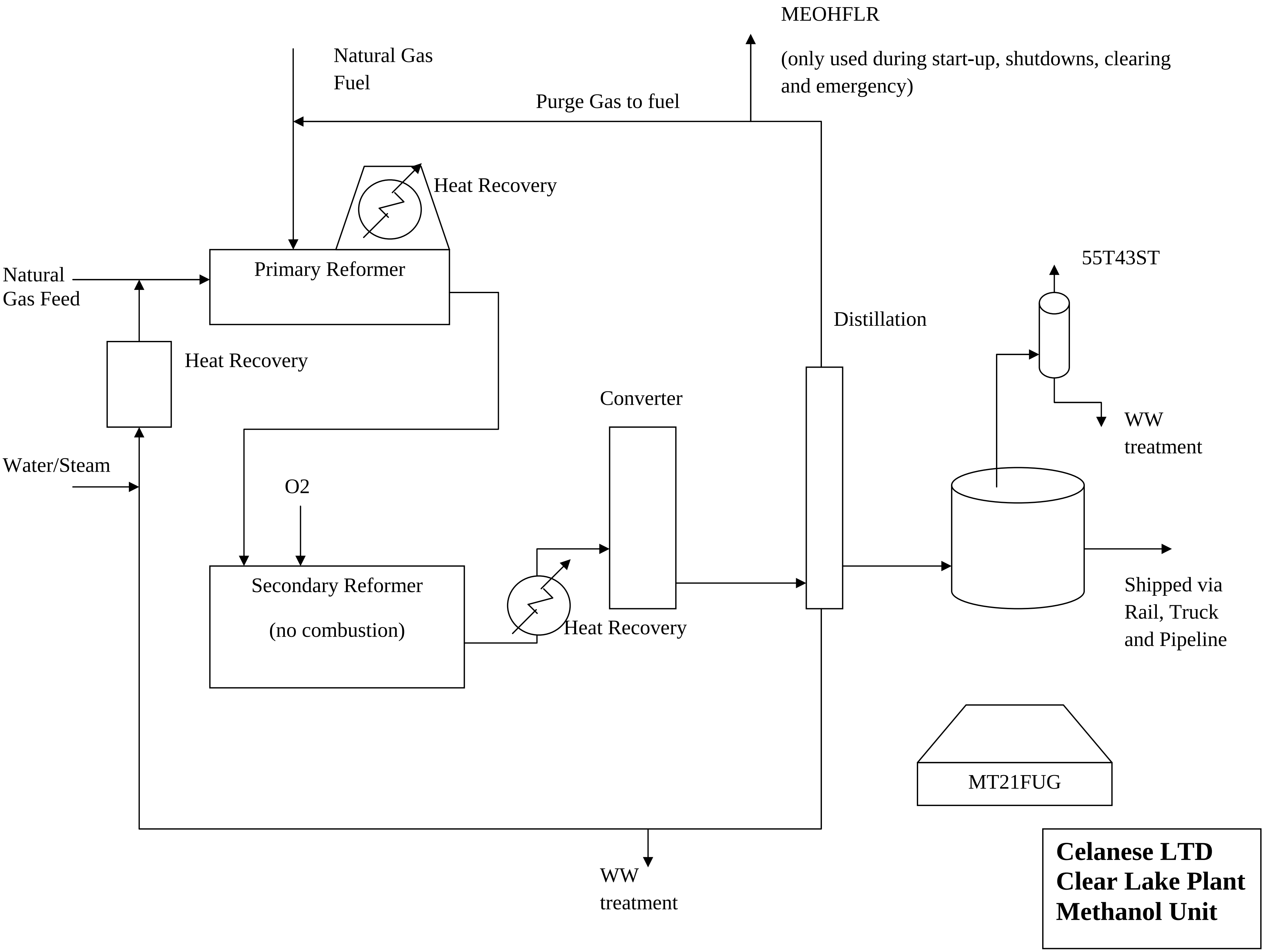
"Friendly Service, No Surprises!"

DATE:	May 2003
PROJ. #	A-61-01-03
FILE NAME:	CL Area Map.dwg



Celanese LTD
Clear Lake Plant
Methanol Unit

SECTION 2
EMISSIONS ESTIMATE METHODOLOGY

The emissions of the greenhouse gases methane (CH_4), carbon dioxide (CO_2), and nitrous oxide (N_2O) were determined for the methanol reformer, fugitive equipment sources, the emergency generator, the start-up, shutdown and emergency flare, and maintenance activities. Methane has a greenhouse gas equivalent rating of 21 to CO2, and nitrous oxide has a greenhouse gas equivalent rating of 310 to CO2.

2.1 Methanol Reformer

The reformer combusts methane and a hydrogen rich process gas stream to make synthesis gas. The combustion process produces CO_2 and N_2O. Complete conversion of all carbon containing compounds in the hydrogen rich gas stream to CO2 is assumed in the emission estimates. The burners are assumed to combust all carbon containing compounds in the process gas on an annual average reduction efficiency of 99.5%. Subsequently, 0.5% of the methane from the process gas fuel will be present in the reformer stack. The production of nitrous oxide from the heat of combustion and combustion air was calculated using the factor from the EPA GHG Mandatory Monitoring Rule, 40 CFR Part 98. The uncombusted methane from the natural gas fuel was determined using the factor from the Mandatory Monitoring Rule.

2.2 Fugitive Equipment

Emissions for the Methanol Unit fugitive components in methane or carbon dioxide service were estimated in accordance with the TCEQ Technical Guidance Package for Equipment Leak Fugitives. Emissions were estimated using the appropriate SOCMI emission factors (without ethylene). Reduction credits were taken for the TCEQ 28VHP leak detection and repair program for streams with >5% methane by weight.

2.3 Emergency Generator

Emissions from the emergency generator were estimated in accordance with the EPA GHG Mandatory Monitoring Rule. The estimated annual heat input for a maximum of 100 hours of non-emergency use per year for testing and maintenance purposes was assumed to determine the total emissions.

2.4 Start-up, Shutdown and Maintenance Activities of Methane Equipment

Emissions from opening equipment in natural gas service were determined the equivalent pounds of methane that would be released from a specific annual volume cleared.

2.5 Start-up, Shutdown, and Emergency Flare

Emissions of CO_2 will be emitted from the flare from CO_2 produced in the process as well as CO_2 produced from combustion of carbon containing compounds in the flare. The flare destruction efficiency for methane in the flare is 99% on a 12-month rolling average. Subsequently, 1% of the methane from the process streams and natural gas pilot will be emitted by the flare. The production of nitrous oxide from the heat of combustion and combustion air was calculated using the factor from the EPA GHG Mandatory Monitoring Rule, 40 CFR Part 98.

SECTION 3
GHG BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

The increase in GHG emissions associated with the proposed project is above the PSD threshold for GHG. As such, any new or modified emissions unit with a net increase in CO_2, CH_4, and N_2O emissions is subject to BACT review. The sources subject to BACT review in the proposed methanol unit include a reformer, maintenance, startup and shutdown activities, fugitive components, emergency engine, and emission abatement equipment.

The new unit is designed with many inherent energy efficiency features compared to existing, widely-used process designs. The process design chosen by Celanese requires less energy to produce methanol than designs utilized by other existing and proposed Methanol Units. Thus, the proposed 2-step reforming process to be utilized in this proposed project will create less GHG emissions per ton of Methanol produced than existing single step reforming technology. The following evaluation, therefore, focuses on how the unique design incorporates elements that prevent the formation of greenhouse gas pollutants and less on back-end control options.

3.1 BACT Analysis Methodology

Greenhouse Gas (GHG) Best Available Control Technology (BACT) for the facility has been evaluated via a "top-down" approach which includes the steps outlined in the following subsections.

GHG emissions increases from the new methanol unit are greater than 75,000 tons per year (tpy) expressed as carbon dioxide equivalents ($CO_{2(}e_{)}$). Therefore, the project is subject to regulation under Prevention of Significant Deterioration (PSD), and a BACT review must be conducted for GHG pollutants and applicable emission units. In the proposed project, GHGs are potentially emitted from the following sources:

- Reformer (EPN: REFORM)
- MSS Flare (EPN: MEOHFLR)
- Equipment MSS (EPN: MEOHMSS)
- Fugitive Emissions (EPN: MEOHFUG)
- Engine (EPN: MEOHGEN)

GHG emissions of CO_2, CH_4, and N_2O are anticipated as a result of combustion at the flare, within the reformer, and within the engine. The additional sources of GHGs include CO_2 and CH_4 fugitive emissions from piping components.

U.S. EPA has issued limited guidance documents related to the completion of GHG BACT analyses. The following guidance documents were utilized as resources in completing the GHG BACT evaluation for the proposed project:

- PSD and Title V Permitting Guidance For Greenhouse Gases (hereafter referred to as General GHG Permitting Guidance)
- Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boiler (hereafter referred to as GHG BACT Guidance for Boilers)
- Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Petroleum Refining Industry (hereafter referred to as GHG BACT Guidance for Refineries)

3.2 BACT Top-Down Approach

3.2.1 Step 1 – Identify Control Technology

Available control technologies with the practical potential for application to the emission unit and regulated air pollutant in question are identified. Available control options include the application of alternate production processes and control methods, systems, and techniques including fuel cleaning and innovative fuel combustion, when applicable and consistent with the proposed project. The application of demonstrated control technologies in other similar source categories to the emission unit in question can also be considered. While identified technologies may be eliminated in subsequent steps in the analysis based on technical and economic infeasibility or environmental, energy, economic or other impacts; control technologies with potential application to the emission unit under review are identified in this step.

The following resources are typically consulted when identifying potential technologies for criteria pollutants:

1. EPA's Reasonably Available Control Technology (RAC1)/Best Available Control Technology (BACT)/Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) database;

2. Determinations of BACT by regulatory agencies for other similar sources or air permits and permit files from federal or state agencies;

3. Engineering experience with similar control applications;

4. Information provided by air pollution control equipment vendors with significant market share in the industry; and/or

5. Review of literature from industrial technical or trade organizations.

Celanese will rely primarily on items (2) through (6) above, and the following additional resources such:

- RBLC database - Searching the newly enhanced RBLC database returned no results on permitting decisions for gaseous fuel and gaseous fuel mixture combustion in

Process Code 11.300, synthetic organic chemical manufacturing industry (SOCMI), in Process Code 64.000, or flare in Process Code 19.300.

- GHG Mitigation Strategies Database - The GHG Mitigation Strategies Database did not contain any information for emission sources presented in this analysis.
- *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy and Plant Managers*

3.2.2 Step 2 - Eliminate Technically Infeasible Options

After the available control technologies have been identified, each technology is evaluated with respect to its technical feasibility in controlling the PSD-triggering pollutant emissions from the source in question. The first question in determining whether or not a technology is feasible is whether or not it is demonstrated. Demonstrated has specific meaning in this regard. Demonstrated means that it has been installed and operated successfully elsewhere on a similar facility. This step should be straightforward for control technologies that are demonstrated-if the control technology has been installed and operated successfully on the type of source under review, it is demonstrated and it is technically feasible.

An undemonstrated technology is only technically feasible if it is "available" and "applicable." A control technology or process is only considered available if it has reached the licensing and commercial sales phase of development and is "commercially available". Control technologies in the R&D and pilot scale phases are not considered available. Based on EPA guidance, an available control technology is presumed to be applicable if it has been permitted or actually implemented by a similar source. Decisions about technical feasibility of a control option consider the physical or chemical properties of the emissions stream in comparison to emissions streams from similar sources successfully implementing the control alternative. The NSR Manual explains the concept of applicability as follows: "An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration.” Applicability of a technology is determined by technical judgment and consideration of the use of the technology on similar sources as described in the NSR Manual.

3.2.3 Step 3 - Rank Remaining Control Technologies

All remaining technically feasible control options are ranked based on their overall control effectiveness for the pollutant under review.

3.2.4 Step 4 - Evaluate the Most Effective Controls and Document Results

After identifying and ranking available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option. If adverse collateral impacts do not disqualify the top-ranked option from consideration it is selected as the basis for the BACT limit. Alternatively, in the judgment of the permitting agency, if unreasonable adverse economic, environmental, or energy impacts are associated with the top control option, the next most stringent option is evaluated. This process continues until a control technology is identified.

According to 40 CFR §52.2I (b)(49)(ii), $CO_{2(e)}$ emissions must be calculated by scaling the mass of each of the six GHGs by the gas's associated global warming potential (GWP), which is established in Table A-I to Subpart A of 40 CFR Part 98. Therefore, to determine the most appropriate strategy for prioritizing the control of CO_2 and CH_4 emissions, Celanese considered each component's relative GWP. As presented in Table 2-1. Global Warming Potentials Table 2-1, the GWP of CH_4 is 21 times the GWP of CO_2. Therefore, one ton of atmospheric CH_4 emissions equates to 21 tons of $CO_{2(e)}$ emissions. On the other hand, one ton of CH_4 that is combusted to form CO_2 emissions prior to atmospheric release equates to 2.7 tons of $CO_{2(e)}$ emissions. Since the combustion of CH_4 decreases GHG emissions by approximately 87 percent on a $CO_{2(e)}$ basis, combustion of CH_4 is preferential to direct emission of CH_4.

Table 3-1 Global Warming Potentials

Pollutant	**GWP**
CO_2	1
CH_4	21
N_2O	310

Please note that the GHG BACT assessment presents a unique challenge with respect to the evaluation of CO_2 and CH_4 emissions. The technologies that are most frequently used to control emissions of CH_4 in hydrocarbon-rich streams (e.g., flare and thermal oxidizers) actually convert CH_4 emissions to CO_2 emissions. Consequently, the reduction of one GHG (i.e., CH_4) results in a proportional increase in emissions of another GHG (i.e., CO_2). However, due to the higher global warming potential of CH_4, generating CO_2 from combustion is preferred if elimination of GHGs through process front-end design is not an option.

Permitting authorities have historically considered the effects of multiple pollutants in the application of BACT as part of the PSD review process, including the environmental impacts of collateral emissions resulting from the implementation of emission control technologies. To clarify the permitting agency's expectations with respect to the BACT evaluation process, states have sometimes prioritized the reduction of one pollutant above another. For example, technologies historically used to control NO_x emissions frequently caused increases in CO emissions. Accordingly, several states prioritized the reduction of NO_x emissions above the reduction of CO emissions, approving low NO_x control strategies as BACT that result in elevated CO emissions relative to the uncontrolled emissions scenario.

3.2.5 Step 5 - Selection of BACT

In the final step, the BACT is determined for each emission unit under review based on evaluations from the previous step.

Although the first four steps of the top-down BACT process involve technical and economic evaluations of potential control options (i.e., defining the appropriate technology), the selection of BACT in the fifth step involves an evaluation of emission reductions achievable with the selected control technology.

NAAQS have not been established for GHGs and a dispersion modeling analysis for GHG emissions is not a required element of a PSD permit application for GHGs. Since localized short-term health and environmental effects from GHG emissions are not recognized, Celanese proposes to implement the most stringent demonstrated and technologically feasible control as BACT.

3.3 Reformer – GHG BACT

The following section presents BACT evaluations for GHG emissions produced from the auto-thermal methanol reformer combustion process.

3.3.1 Step 1 – Identification of Potential GHG Control Techniques

The following potential GHG control strategies for the reformer were considered as part of this BACT analysis:

- Selection of the lowest carbon fuel
- Selection of Methanol Reforming Process Design
- Installation of Energy Efficiency Options
- Best Operational Practices
- Carbon capture and storage (CCS)

3.3.1.1 *Selection of the Lowest Carbon Fuel*

For GHG BACT analyses, low-carbon intensity fuel or non-carbon based fuels are the primary control option that can be considered for a lower emitting process. The reformer will combust natural gas as the primary fuel and may combust high H_2 fuel gas as a secondary fuel when practicable and available. Natural gas is the lowest emitting GHG fuel on a direct carbon basis compared to other typical fossil fuels. Supplementing the reformer fuel with a hydrogen rich stream will reduce the $CO_{2(e)}$ emissions by 28,139 tpy. The hydrogen rich process stream will be available as fuel during normal operation of the plant. During periods of start-up, shutdown or malfunction the hydrogen rich process stream may not be available to use as fuel.

Utilization of pipeline hydrogen fuel over natural gas has the potential to reduce reformer GHG emissions by up to 280,000 tpy directly at the facility. The GHG emissions required to generate the pipeline H2 will be discussed in Step 4 below.

In summary the available fuel options are:

- High content carbon fuels
- Natural gas
- Natural gas and hydrogen rich supplemental fuel
- Pipeline hydrogen fuel and hydrogen rich supplemental fuel

3.3.1.2 *Selection of Methanol Reforming Process Design*

Celanese evaluated several potential technologies for the Methanol Reforming Process. The proposed process design was chosen because it was a demonstrated technology that showed higher energy efficiency, lower energy consumption, higher raw material yields and subsequently lower potential emissions than other existing technologies.

The technologies evaluated consisted of the following key process designs:

1. Steam methane reforming process and abatement of waste gas and water streams
2. Steam methane reforming process with integration of waste gas stream and treatment and/or loading of waste liquids
3. Auto thermal reforming process and abatement of waste gas and water streams
4. Auto thermal reforming process with integration of waste gas stream and treatment and/or loading of waste liquids
5. Gas-heated reforming and Auto thermal reforming in series
6. Combined Reforming (Steam methane reforming and Auto-thermal reforming either in series or parallel) and abatement of waste gas and water streams
7. Combined Reforming (Steam methane reforming and Auto-thermal reforming either in series or parallel) with integration of waste gas stream and treatment and/or loading of waste liquids

The methanol process in all designs uses a reformer to react methane to a synthesis gas consisting of primarily hydrogen with carbon dioxide, carbon monoxide and other organics. The energy efficiency values identified below for each design option in this section include the energy usage for the reformer and additional energy efficiency options identified in section 2.3.1.1.2.

The steam methane reforming (SMR) process requires combusting a fuel source to provide radiant heat to crack a carbon-containing feed in the presence of steam. The SMR process previously used at the Clear Lake site to produce Methanol (the Methanol Unit was shut down in 2005 and removed in 2007) required 36 to 38 MMBtu (HHV)/tonne of Methanol produced. The SMR processes evaluated ranged between 34 to 35 MMBtu/tonne of Methanol produced. The methanol production efficiency in a standard thermal reforming process is 90%. The 10% unconverted methane feed would require combustion abatement, creating additional GHG emissions. Additionally, to reach the higher production rate in the combined reforming process described later, additional feed and firing would be required to produce the same number of pounds of Methanol per year.

Autothermal reforming (ATR), process reacts natural gas and oxygen below stoichiometric number. The ATR process has a lower conversion efficiency since the process does not produce enough H2 to consume all the CO_2. The CO_2 must be removed from the synthesis gas. The ATR processes evaluated ranged between 32 to 33 MMBtu/tonne of Methanol produced.

A combined gas thermal reforming (GTR) and ATR process was evaluated, The GTR/ATR processes evaluated ranged between 32 to 33 MMBtu/tonne of Methanol produced. However, the process has not been demonstrated on a production scale comparable to the scale that is being proposed at the Clear Lake site.

Combined reforming process uses a primary and a secondary reformer to produce methanol. The combined reforming process will range between 32 and 33 MMBtu/tonne of Methanol produced. Consequently, the combined reforming process will generate fewer GHG emissions than the other processes.

A summary of the energy demands of each design are as follows:

Reformer Design Process	Heat Required (MMBtu) per Methanol produced (tonne)
Design A: SMR Original Technology	36 – 38
Design B: SMR Current Technology	34 – 35
Design C: ATR	32 – 33
Design D: Combined Reforming	30 – 32

3.3.1.3 ***Installation of Energy Efficiency Options***

Traditional techniques for methanol production using methane reforming are energy intensive, and are a significant source of GHG emissions in a methanol manufacturing unit. This section describes the energy efficiencies that will be incorporated into the design of Celanese's reformer to reduce greenhouse gas emissions.

An air preheater will be installed to heat the incoming combustion air. Utilization of air preheaters is identified in the Energy Star guidelines referenced in the document, *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry* as a means to increase the thermal efficiency of the reformer. Additionally, the burners have been designed for pre-heated air for optimal efficiency.

Heat recovery is a central design element in the proposed Celanese Methanol process. The Energy Star guidelines referenced in the document, *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry* identifies flue gas recovery as an option to increase the thermal efficiency of the reformer from 8 – 18% on average. Process and utility fluids are used for heat transfer, eliminating the need for additional steam for preheating feed, distillation reboilers, and steam feed. Heat Recovery can be accomplished up to the point where a minimum temperature is reached for the flue gas that reaches the dew point. The condensed gas has the potential to be corrosive to process equipment and cause fouling.

Heat recovery from Primary Reformer occurs through cross exchange with the flue gas and various feed and utility streams. Heat from the flue gas from the radiant box is used to preheat feed gas to the reformer tubes, reducing the amounting of firing required. Heat from the flue gas is used to superheat steam, which is used internally in the unit. Subsequently, the production of steam would reduce the plant steam requirements from utility boilers, and greenhouse gases. Additionally, the superheated steam will allow the site to run a turbine to generate electricity. The generated electricity will feed internal demand and will reduce plant dependency on the external electrical grid. The flue gas heat is used to pre-heat combustion air and fuel to the burners, which reduces the amount of needed fuel gas. The hotter the fuel and air, the lower the fuel required for firing.

Heat recovery from Reformed Gas leaving the Secondary Reformer provides heat to many of the utility streams in the plant, reducing the need for importing steam from utility boilers. The recovered heat is used to generate high pressure steam. Additionally the heat recovery from the reformed gas is used to preheat the boiler feed water, thus increasing the amount of steam that is able to be produced within the unit.

Some of the reboiler heat requirements in the purification section of the plant will be provided through heat recovery from the reformed gas. Additionally, the recovered heat is used to preheat make-up/demineralized water going to deaerator (reduces amount of steam required to be added to the deaerator).

Ninety percent of the steam required for SMR is produced by heat recovery from the methanol reactor; older technology cools the reactors without fully capturing heat. Instead of using natural gas to produce steam for the methanol reforming process, heat recovery is used to produce the steam used by the process. Therefore, there will not be an increase of the steam required from existing boilers during normal operation.

Process gas will be captured and utilized as fuel in the Celanese Methanol Unit design.   This allows the process to be more energy efficient by reducing the amount of natural gas fuel required.   The process gas is a high hydrogen content stream, further reducing the GHG gas potential versus using the same heating value of natural gas.

Celanese will utilize high efficiency burners to reduce emissions from non-GHG pollutants. The burners will have an annual average Destruction and Removal Efficiency (DRE) for organic compounds of at least 99.5%. Subsequently, the fuel demands to produce an equivalent reforming firing duty will be lower than utilizing standard non-high efficiency burners.

Celanese will install tube seals in the reformer to contain the heat within the reformer combustion box. As identified in the Energy Star document *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry*, improving heat containment through use of tube seal is an additional measure to increase the thermal efficiency of the reformer by 5% on average.

3.3.1.4 *Best Operational Practices*

Celanese will monitor stack excess O2 to ensure efficient combustion. The fuel requirements and combustion efficiency increase as the facility operates with more excess air. The reformer will be operated at 3% stack O2 concentration during normal operation, monitored by an analyzer in the reformer stack. The stack O2concentration should be operated near 2-3% during normal operation as identified in the Energy Star document *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry* as a means to increase the thermal efficiency of the reformer by 5 – 25% on average. During periods of equipment turndown, the O2 concentration will exceed 3%, however the overall fuel consumption will be lower than during normal operation. To maintain a lower O2 to fuel ratio, the combustion efficiency decreases, subsequently increasing the amount of CO and VOCs present in the reformer stack. Celanese, will install catalyst to convert the CO and VOCs to CO2 to reduce the impact of the VOC and CO criteria pollutants while allowing operation at lower excess air.

Celanese will increase energy efficiency in the process by reducing heat loss by insulating the high temperature equipment to reduce heat loss. As identified in the Energy Star document *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry*, improving heat containment through use of insulation to reduce radiant heat loss will increase the thermal efficiency of the reformer by 5% on average. Internally insulated piping and equipment will have color changing paint or portable optical monitoring instruments will be utilized to identify piping or equipment requiring maintenance. Externally insulated piping and equipment will be visually inspected for any issues.

Celanese's procedure for methanol converter catalyst activation generates less greenhouse gas emissions compared to other technologies using catalyst because the time required for start-up venting, and resulting volume of waste gas, is significantly reduced. Celanese will use pipeline supplied hydrogen, which prevents the need for steam or flaring during catalyst activation. Catalyst activation flaring is reduced during the activation event (typically converter catalyst activation activity occurs less frequently than annually).
During start up the nitrogen sweep used to heat the process equipment prior to methane feed introduction will be recycled through the system equipment rather than flared. Current industry practice is to purge the nitrogen to a flare, which requires natural gas assist to maintain good combustion in the flare. Recycling nitrogen while the equipment heats-up reduces natural gas consumption and greenhouse gas combustion emissions. Additionally, using nitrogen minimizes the steam requirements from facility boilers during start-up.

Celanese's maintenance procedure for equipment in natural gas service will include depressuring the system to the flare, when possible, prior to opening to the atmosphere. Combustion of the methane to CO_2 in the flare will decrease the potential $CO_{2(e)}$ emissions by 21 times.

The reformer, to the extent practicable and in accordance with usual industry preventative maintenance practices, will be kept in good working condition. These maintenance activities include a variety of activities ranging from instrument calibration to cleaning of dirty or fouled mechanical parts. With respect to GHG emissions potential, these activities maintain performance as opposed to enhancing performance. Performing proper maintenance on the system will increase thermal efficiency on average by 10% as identified in the Energy Star document *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry*.

3.3.1.5 ***Carbon Capture and Storage***

Carbon capture and storage (CCS) involves separation and capture of CO_2 emissions from the flue gas, compression of the captured CO_2, transportation of the compressed CO_2 via pipeline, and finally injection and long-term geologic storage of the captured CO_2. Several different technologies have demonstrated the potential to separate and capture CO_2. To date, some of these technologies have been demonstrated at the laboratory scale only, while others have been proven effective at the slip-stream or pilot-scale. Numerous projects are currently planned for the full-scale demonstration of CCS technologies.

According to the recently issued U.S. EPA guidance for PSD and Title V Permitting of Greenhouse Gases:

“For the purposes of a BACT analysis for GHG, EPA classifies CCS as an add-on pollution control technology that is "available" for facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing).”

The guidance document does not specifically identify reformers in a methanol production process in the high purity CO_2 stream emitting sector; however, similar reformers are a component of hydrogen production. Therefore, the flue gas produced by the reformer contains typical combustion device levels of CO_2 and CCS is considered an "available" add-on control technology for this flue gas stream. Currently there are two options for CO_2 capture for high purity CO_2 streams: Post-Combustion Solvent Capture and Stripping and Post-Combustion Membranes.

Capture or separation of the CO_2 stream alone is not a sufficient control technology, but instead requires the additional step of permanent storage. After separation, storage could involve sequestering the CO_2 through various means such as enhanced oil recovery (EOR), saline aquifers, and sequestration in un-minable coal seams.

There are additional methods of sequestration such as potential direct ocean injection of CO_2 and algae capture and sequestration (and subsequent conversion to fuel); however, these methods are not as widely documented in the literature for industrial scale applications. As such, while capture-only technologies may be technologically available at a small-scale, the limiting factor is the availability of a mechanism (pipeline or geologic formation) to permanently sequester, store, or inject the captured gas. The Celanese Clear Lake Plant is not located near a permanent CO_2 sequester option; therefore EOR, Saline Aquifers, or un-minable coal seams are not a technically feasible option. The Clear Lake Plant is located approximately 12 miles from the Denbury Green Pipeline; however, the distance from the pipeline, the excessive cost of designing, constructing, and operating the pipeline to transport compressed CO_2 to the Denbury Green Pipeline, and lack of similar demonstrated projects make this sequestration option infeasible for this project.

In addition to the U.S. EPA permitting guidance for GHG, white papers for GHG reduction options were reviewed for discussion of CCS technologies. In the GHG BACT Guidance for Boilers white paper, a brief overview of the CCS process is provided and the guidance cites the Interagency Task Force on Carbon Capture and Storage for the current development status of CCS technologies. In the Interagency Task Force report on CCS technologies, a number of pre- and post-combustion CCS projects are discussed in detail; however, many of these projects are in formative stages of development and are predominantly power plant demonstration projects (and mainly slip stream projects). Capture-only technologies are technically available; however, not commercially demonstrated. In addition, the limiting factors in CCS projects are typically the lack of a geologic formation or pipeline for the carbon to be permanently sequestered or the extremely high cost of the design, construction, and operation of a CCS project.

Beyond power plant CCS demonstration projects, the Interagency Task Force (ITF) report also discusses three relevant industrial CCS projects that are being pursued under the Industrial Carbon Capture and Storage (ICCS) program for the following companies/installations:

- Leucadia Energy: a methanol plant in Louisiana where 4 million tonnes per year of CO_2 will be captured and used in an enhanced oil recovery (EOR) application.

- Archer Daniels Midland: an ethanol plant in Illinois where 900,000 tonnes per year of CO_2 will be captured and stored in a saline formation directly below the plant site.

- Air Products: a hydrogen-production facility in Texas where 900,000 tonnes per year of CO_2 will be captured and used in an EOR application.

At present, these industrial deployments were selected for funding in July 2010 and are moving into a construction/demonstration phase. Therefore, they are not yet demonstrated. In addition, the Department of Energy is providing significant financial assistance for these projects to offset the cost and make these projects economically feasible.

In addition, the August 2010 federal Interagency Task Force for Carbon Capture and Storage (CCS) report noted the following four fundamental near-term and long-terms concerns for CCS:

1. The existence of market failures, especially the lack of a climate policy that sets a price on carbon and encourages emission reductions.

2. The need for a legal/regulatory framework for CCS projects that facilitates project development, protects human health and the environment, and provides public confidence that CO_2 can be stored safely and securely.

3. Clarity with respect to the long-term liability for CO_2 sequestration, in particular regarding obligations for stewardship after closure and obligations to compensate parties for various types and forms of legally compensable losses or damages.

4. Integration of public information, education, and outreach throughout the lifecycle of CCS projects in order to identify key issues, foster public understanding, and build trust between communities and project developers.

3.3.2 Step 2 – Elimination of Technically Infeasible Control Options

3.3.2.1 *Selection of the Lowest Carbon Fuel*

Natural gas, the lowest carbon fuel, is a technically feasible option for CO_2 control of the reformer. In addition, high H_2 fuel gas may be used as a secondary fuel when practicable and available, which will further reduce CO_2 emissions. Pipeline supplied hydrogen fuel can be provided. However, additional hydrogen production facilities must be constructed to meet the Celanese demand.

3.3.2.2 *Selection of Methanol Reforming Process Design*

As presented in section 2.3.1.2, “Selection of Methanol Reforming Process Design,” the ATR, SMR and combined ATR and SMR processes proposed by Celanese are technically feasible process designs. The combined GTR and ATR process technology has not been demonstrated on a production scale comparable to the size being proposed for the Celanese facility. Concerns regarding scaling up unproven technology exist with equipment reliability, including metal dusting. The GTR and ATR process design is thus, not a technically feasible option.

3.3.2.3 *Installation of Energy Efficiency Options*

The energy efficiency options presented in 2.3.1.3 such as integrated heat recovery, recycling waste gas as fuel, and high efficiency burner design are all technically feasible when combined with the chosen process reforming design.

3.3.2.4 *Best Operational Practices*

Celanese will utilize several best operation practices as described above in 2.3.1.4 to minimize the potential for future GHG emissions. The best operational practices from proper equipment maintenance to operational monitoring will be utilized to ensure the unit is able to operate efficiently. All the best operational practices described are technically feasible.

3.3.2.5 *Carbon Capture and Storage*

Capture and Compression – CO_2 capture is achieved by separating CO_2 from emission sources where it is then recovered in a concentrated stream that can be sequestered. Currently there are a few options for CO_2 capture from combustion device flue gas streams: Post-Combustion Solvent Capture and Stripping and Post-Combustion Membranes. Post-combustion capture uses solvent scrubbing, typically using monoethanolamine (MEA) as the solvent, is a commercially mature technology. Solvent scrubbing has been used in the chemical industry for separation of CO_2 in exhaust streams and is an available technology for this application. However, this technology has not been demonstrated in large scale industrial chemical process applications and is therefore an infeasible option for this project.

Post-combustion membranes technology may also be used to separate or adsorb CO_2 in an exhaust stream. It has been estimated that 80 percent of the CO_2 could be captured using this technology. The captured CO_2 would then be purified and compressed for transport. The current state of this technology is primarily in the research stage, with industrial application at least 10 years away; therefore post-combustion membranes are also technically infeasible because they are not currently demonstrated and available for this application.

Sequestration - Lack of Sequestration Sink (Geologic or Pipeline)
While capture-only technologies may be available and demonstrated on pilot scales, a remaining hurdle is the availability of a mechanism (pipeline or geologic formation) to permanently sequester the captured gas. As stated above, the closest existing pipeline is approximately 12 miles from the Clear Lake facility. The distance from the pipeline, the excessive cost of designing, constructing, and operating the CCS project to transport compressed CO_2 to the Denbury Green

Pipeline, and lack of similarly demonstrated projects make this sequestration option infeasible for this project.
Based on the aforementioned technical challenges with capture, compression and storage of CO_2, CCS as a combined technology is not considered technically feasible as BACT for reducing CO_2 emissions from the reformer. Accordingly, CCS is eliminated as a potential control option in this BACT assessment for CO_2 emissions due to technical infeasibility.

3.3.3 Step 3 – Rank of Remaining Control Technologies

The various options described above for controlling and minimizing green house gas emissions may be combined. Those options that are technically feasible and mutually exclusive of one another are ranked.

The utilization of pipeline H2 fuel will have a greater impact on reducing GHG emissions specifically at the Clear Lake site than using natural gas as the reformer primary fuel. The combined primary and secondary reforming process is the highest ranking process design since the process will utilize a lower energy demand than either the singular SMR or ATR processes.

3.3.4 Step 4 – Evaluation of Most Stringent Controls

3.3.4.1 *Selection of the Lowest Carbon Fuel*

Natural gas is the lowest emitting carbon fuel that could be relied upon for the proposed operation. High H_2 fuel gas may be utilized as a secondary fuel for the reformer when it is available and its use is practicable. Pipeline hydrogen for combustion in the methanol reformer would cost an additional $400,000,000 above the cost of equivalent heat value of natural gas over the lifetime of the process and that would render the project economically unviable. Subsequently, 95% of all commercial hydrogen is produced using steam and natural gas reforming. The process of producing H2 for use as fuel will create 8.89 pounds of greenhouse gas emissions per pound of hydrogen produced. The avoided greenhouse gas emissions at the Clear Lake plant from burning pipeline hydrogen rather than natural gas in the reformer would result in a decrease of 7.02 pounds of greenhouse gas. Consequently, the net global impact would be higher to produce and subsequently combust hydrogen as fuel rather than to combust natural gas as primary fuel in the reformer.

3.3.4.2 *Selection of Methanol Reforming Process Design*

The combined reforming process is the higher ranking technically feasible option. Subsequently, the combined reforming process will create the least amount of greenhouse gas emissions since the process has a lower energy demand. The SMR process has the potential for an additional 40% GHG emissions as compared to the combined process. Additionally, the ATR process has the potential for an additional 35% GHG emissions as compared to the chosen combined process.

3.3.4.3 *Installation of Energy Efficiency Options on the Reformer*

The new reformer design will incorporate the energy efficiencies described in Section 2.3.1.1.3. The technologies being employed are proven and can be implemented to increase the energy efficiency from the unit. All technologies described above will be utilized in the process design.

3.3.4.4 *Best Operational Practices*

The implementation of regular maintenance, monitoring, and minimizing uncontrolled emissions during start-up, shutdown and maintenance will be utilized to maintain the system performance and reduce potential for future GHG emissions.

3.3.5 Step 5 – Selection of GHG BACT

Based on the top-down process described above for control of GHG emissions from the reformer, Celanese is proposing that firing natural gas as the primary fuel source along with several energy efficiency operations options constitutes BACT for the combined reforming process.

3.4 Flare – GHG BACT Evaluation

CO_2 and N_2O emissions from flaring process gas are produced from the combustion of carbon containing compounds (e.g., CO, VOCs, CH_4) present in the process gas streams and the pilot fuel. GHG emissions from the flare are based on the estimated flow rates of CO_2 and flared carbon- containing gases derived from heat and material balance data.

The flare is an example of a control device in which the control of certain pollutants causes the formation of collateral GHG emissions. Specifically, the control of CH_4 in the process gas at the flare results in the creation of additional CO_2 emissions via the combustion reaction mechanism. However, given the relative GWPs of CO_2 and CH_4 and the destruction of VOCs and HAPs, it is appropriate to apply combustion controls to CH_4 emissions even though it will form additional CO_2 emissions.

3.4.1 Step 1 – Identification of Potential GHG Control Techniques

The following potential GHG control strategies for the flare were considered as part of this BACT analysis:

- Good Process Design
- Best Operational Practices
- Good Flare Design

3.4.1.1 *Good Flare Design*

Good flare design can be employed to destroy large fractions of the flare gas. Much work has been done by flare and flare tip manufacturers to assure high reliability and destruction efficiencies. Good flare design includes pilot flame monitoring, flow measurement, and monitoring/control of waste gas heating valve.

3.4.2 Step 2 – Elimination of Technically Infeasible Control Options

Best operational practices are also technically feasible since they can be described in unit startup and shutdown procedures. System pressures and temperatures will be monitored to minimize flaring, and monitoring will be available to prevent bypass to atmosphere from NG systems.

Use of a good flare design following operational best practices is a demonstrated and available option.

3.4.3 Step 3 – Rank Remaining Control Options by Effectiveness

Use of a good flare design, good process design, and best operational practices is the most effective option for control. Natural gas-fired pilots and good flare design will be applied as CO_2 GHG BACT for the flare in order to minimize emissions from the flare.

3.4.4 Step 4 – Top-Down Evaluation of Control Options

No significant adverse energy or environmental impacts (that would influence the GHG BACT selection process) associated with operating a flare to control process gas or using good flare design are expected.

3.4.5 Step 5 – Selection of CO_2 BACT for Flare

Celanese will use good flare design with appropriate instrumentation and control in addition to good process design, and best operational practices as best available control options for reducing CO_2 GHGs.

3.5 GHG BACT Evaluation for Fugitives Emissions

The following section proposes appropriate GHG BACT emission limitations for fugitive CO_2 and CH_4 emissions. The fugitive emission controls presented in this analysis will provide similar levels of emission reduction for both CO_2 and $CH_{4,}$ therefore the BACT evaluation for these two pollutants has been combined into a single analysis.

3.5.1 Step 1 – Identify All Control Technologies

In determining whether a technology is available for controlling GHG emissions from fugitive components, permits and permit applications and U.S. EPA’s RBLC were consulted. Based on these resources, the following available control technologies were identified:

- Installation of leak less technology components to eliminate fugitive emission sources;
- Implementing various LDAR programs in accordance with applicable state and federal air regulations;
- Implement alternative monitoring program using a remote sensing technology such as infrared camera monitoring;
- Implementing an audio/visual/olfactory (AVO) monitoring program for compounds; and
- Design and construct facilities with high quality components, with materials of construction compatible with the process.

3.5.2 Step 2 – Technical Feasibility Analysis

Leak less technology valves are available and currently in use, primarily where highly toxic or otherwise hazardous materials are used. These technologies are generally considered cost prohibitive except for specialized service. Some leak less technologies, such as bellows valves, if they fail, cannot be repaired without a unit shutdown that often generates additional emissions.

LDAR programs have traditionally been developed for control of VOC emissions. BACT determinations related to control of VOC emissions rely on economic reasonableness for these instrumented programs. The adverse impact of fugitive emissions of CH_4 and CO_2 due to their global warming potential has not been quantified, and no reasonable cost effectiveness has been determined. Monitoring direct emissions of CO_2 is not feasible with the normally used instrumentation for fugitive emissions monitoring. Instrumented monitoring is technically feasible for components in CH_4 service.

Alternate monitoring programs such as remote sensing technologies have been proven effective in leak detection and repair. The use of sensitive infrared camera technology has become widely accepted as a cost effective means for identifying leaks of hydrocarbons.

Leaking fugitive components can be identified through Audio/Visual/Olfactory (AVO) methods. The fuel gases and process fluids in the methanol unit are expected to not have a highly detectable odor. A large leak can be detected by sound (audio) and sight. The visual detection can be a direct viewing of leaking gases, or a secondary indicator such as condensation around a leaking source due to cooling of the expanding gas as it leaves the leak interface. AVO programs are common and in place in industry.

A key element in control of fugitive emissions is the use of high quality equipment that is designed for the specific service in which it is employed. For example, a valve that has been manufactured under high quality conditions can be expected to have lower run out on the valve stem, and the valve stem is typically polished to a smoother surface. Both of these factors greatly reduce the likelihood of leaking. The Methanol Unit at Celanese's Clear Lake Plant will be constructed with compatible components and designed with gaskets and other materials of construction for the service for which they are intended.

3.5.3 Step 3 – Rank of Remaining Control Technologies by Effectiveness

Leak less technologies are highly effective in eliminating fugitive emissions from the specific interface where installed, however leak interfaces remain even with leak less technology components in place. In addition the sealing mechanism, such as a bellow, is not repairable online and may leak in the event of a failure until the next unit shutdown. This is the most effective of the controls.

Instrumented monitoring is effective for identifying leaking CH_4, but may not be effective for finding leaks of CO_2. With CH_4 having a global warming potential greater than CO_2, instrumented monitoring of the fuel and feed systems would be the second most effective method for control of GHG emissions. Quarterly instrumented monitoring with a leak definition of 500 ppmv, accompanied by intense directed maintenance, is generally assigned a control effectiveness of 97%. For uncontrolled SOCMI service without ethylene, the leak rate for valves is 0.0089 lb/hr and for connectors the rate is 0.0029 lb/hr. Component reductions are therefore 0.0086 lb/hr and 0.0028 lb/hr with quarterly instrumented monitoring, a 500 ppmv leak definition, and intense directed maintenance on leaking components.

Remote sensing using infrared imaging has proven effective for identification of leaks. The process has been the subject to EPA rulemaking for an alternative monitoring method to Method 21. Effectiveness is likely comparable to EPA Method 21 with cost being included in the consideration.

Audio/Visual/Olfactory (AVO) means of identifying leaks owes its effectiveness to the frequency of observation opportunities. Those opportunities arise as operating technicians make rounds, inspecting equipment during those routine tours of the operating areas. This method cannot generally identify leaks at a low leak rate as instrumented reading can identify; however low leak rates have lower potential impacts than do larger leaks. This method, due to frequency of observation is effective for identification of larger leaks.

Use of high quality components is effective in preventing emissions of GHGs, relative to use of lower quality components.

3.5.4 Step 4 – Top-Down Evaluation of Control Options

Recognizing that leak less technologies have not been universally adopted as LAER or BACT, even for toxic or extremely hazardous services, it is reasonable to state that these technologies are impractical for control of GHG emissions whose impacts have not been quantified. Any further consideration of available 1eakless technologies for GHG controls is unwarranted.

The use of instrumented leak detection and infrared monitoring are technically feasible for methane. Both detection methods have been demonstrated to be comparable, based on EPA's presentation of the infrared monitoring as an acceptable alternative.

Celanese is requesting the option to use either infrared monitoring or Method 21 instrumented monitoring.

The AVO monitoring option is believed to be effective in finding larger leaks, but the Method 21 and camera options are better at finding smaller leaks.

Design to incorporate high quality components is effective in proving longer term emissions control.

3.5.5 Step 5 – Selection of CH_4 BACT for Fugitive Emissions

Celanese elects to either purchase and utilize an Infrared (IR) Camera for early detection of methane fugitive leaks or utilize Method 21 instrumented monitoring equivalent to VOC BACT. Celanese proposes to either conduct remote sensing for detection of leaks for those pipeline sized fugitive emissions components that are in >10% methane service or monitor via instrumented Method 21 monitoring as required by a regulation or separate permitting action.

3.6 GHG BACT Evaluation for Emergency Generator (EPN: MEOHGEN)

The following section proposes appropriate GHG BACT emission limitations for greenhouse gas emissions from combustion of diesel fuel in the emergency generator. The emission controls presented in this analysis will provide similar levels of emission reduction for CO_2, N_2O, and CH_4, therefore the BACT evaluation for these two pollutants has been combined into a single analysis.

3.6.1 Step 1 – Identify All Control Technologies

Latest engine technology incorporates energy efficiency and emission reduction features. BACT for the emergency generator could consist of the following options for new engines:

- Vendor guaranteed Tier 3 engine
- Selection of a clean burn engine
- Restrict hours of operation

3.6.2 Step 2 – Technical Feasibility Analysis

Many vendors will guarantee emission factors meet Tier 3 design criteria for their engines, so this is a technically feasible option. Additionally, clean burning engines are widely available for purchase at competitive prices.

Operating hours can be monitored with the use of a run-time meter in conjunction with administrative controls to reduce engine use.

3.6.3 Step 3 – Rank of Remaining Control Technologies by Effectiveness

All of the options identified in Step 1 would be effective for GHG control.

3.6.4 Step 4 – Top-Down Evaluation of Control Options

As stated in Step 3, all of the options identified in Step 1 would be effective for GHG control.

3.6.5 Step 5 – Selection of CH_4 BACT for Fugitive Emissions

Celanese will utilize a Tier three, clean burn engine and restrict operating time to less than one hundred hours per year for non-emergency use.

SECTION 4
OTHER ADMINISTRATIVE REQUIREMENTS

The following administrative information related to this permit application is provided in Table 3-1. This information includes:

- Company name;

  Celanese Ltd.

- Company official and associated contact information;

  Paresh Bhakta

  281-474-6201

  paresh.bhakta@celanese.com

- Technical contact and associated contact information;

  Jan Day

  281-474-8802

  Jan.day@celanese.com

- Project location, Standard Industrial Code (SIC), and North American Industry Classification System (NAICS) code;

  9502 Bayport Blvd., Pasadena, TX 77507

  SIC: 2869; NAICS: 325199

- Projected start of construction and start of operation dates; and

  Start of Construction: July 2013

  Start of Operation: March 2015

- Company official signature transmitting the application.

  Official signature of transmittal is found on accompanying cover letter.

APPENDIX A
GHG EMISSION CALCULATIONS

The following tables are included in this appendix in the following order:

- **GHG Emissions Summary by Source**
- **Reformer Emissions Calculations**
- **Fugitive Emissions Calculations**
- **Emergency Generator Emissions Calculations**
- **MSS Flare Emissions Calculations**
- **MSS Emissions Calculations**

GHG Emissions Summary

EPN	CO2	CH4	N2O	CO2(e)
REFROM	417,929	82	0	419,764
MEOHFLR	770,593	4	3	771,537
MEOHMSS		2		44
MEOHFUG	3	10		205
MEOHGEN	241	0	0	242
Total	1,188,766	98	3	**1,191,793**

Methanol Unit Reformer

EPN: REFORM

CH4 EF	0.001	kg/mmBtu	Subpart C tabl C-2
N2O EF	0.0001	kg/mmBtu	Subpart C table C-3

	Firing Option A	Firing Option B	Firing Option C	Firing Option D
	MMBtu/hr	MMBtu/hr	MMBtu/hr	MMBtu/hr
Natural Gas Fuel	566.96	507.32		
Pipeline H2 Fuel			566.96	507.32
H2 Fuel Gas	274.36	351.45	274.36	351.45
Maximum Firing Rate	841.32	858.77	841.32	858.77

	Composition Fuel Gas	Composition Fuel Gas	Composition Fuel Gas	Composition Fuel Gas
	mol%	mol%	mol%	mol%
Hydrogen	65.81	67.30	65.81	67.30
Carbon Monoxide	1.94	3.82	1.94	3.82
Methanol	1.81	1.53	1.81	1.53
Methane	10.97	8.51	10.97	8.51
Ethane	0.00	0.00	0.00	0.00
Propane	0.00	0.00	0.00	0.00
Isobutane	0.00	0.00	0.00	0.00
N-Butane	0.00	0.00	0.00	0.00
Isopentane	0.00	0.00	0.00	0.00
N-Pentane	0.00	0.00	0.00	0.00
Hexane	0.00	0.00	0.00	0.00
Carbon dioxide	13.94	14.63	13.94	14.63
Methyl Formate	0.41	0.32	0.41	0.32
Acetone	0.00	0.00	0.00	0.00
Dimethyl Ether	0.20	0.16	0.20	0.16

	tpy	tpy	tpy	tpy
CO2	409,889	417,929	409,889	417,929
Unreacted CH4	79	82	79	82
N2O	0.26	0.34	0.26	0.34
Total Fuel Gas CO2(e)	411,624	419,764	411,624	419,764

Natural Gas GHG	tpy	tpy	tpy	tpy
CO2	279,939	250,491		
CH4	5.47	4.90		
N2O	0.55	0.49	0.55	0.49
Total Natural Gas CO2(e)	280,224	250,746	170	152

Total CO2(e)	**691,848**	**670,510**	**411,794**	**419,916**

Methanol Equipment Fugitive Emissions
EPN: MEOHFUG

				Valves		Connections - Flanges or Screwed		Compr	Relief Valves		wt% Composition			**Emissions**		
Stream Name		LDAR Program	SOCMI Type	Gas/Vapor	Light Liquid	Gas/Vapor	Light Liquid	Gas/Vapor	Gas/Vapor	Sampling Connection	Total Emissions	Methane	CO2	Total Fugitives	Methane	CO2
Factors			SOCMI Without C2	0.009	0.004	0.0029	0.0005	0.503	0.229	0.033						
Factors		28LAER		97%	97%	97%	97%	95%	97%	97%						
Factors		28VHP		97%	97%	30%	30%	85%	97%							
Factors		NM		0%	0%	0%	0%	85%	0%	0%				tpy	tpy	tpy
CO2		28LAER	SOCMI Without C2	4	0	6	0			2	104	6.8	58.3	0.02	0.00	0.01
CO2/methanol		28LAER	SOCMI Without C2	37	12	60	5			2	104	6.8	58.3	0.08	0.01	0.05
hydrogen		NM	SOCMI Without C2	329	55	1030	108	2		2	125	17.3	9.0	27.92	4.84	2.51
methane		28VHP	SOCMI Without C3	157	9	324	26				103	94.8	1.2	3.11	2.95	0.04
methane/h2		28LAER	SOCMI Without C4	55	9	94	14				117	35.9	14.8	0.11	0.04	0.02
methanol		28LAER	SOCMI Without C5	156	535	740	1243			2	128	0.1	0.8	0.80	0.00	0.01
methanol/water		28LAER	SOCMI Without C6	26	124	89	101				119	0.2	0.4	0.13	0.00	0.00
Ammonia		28LAER	SOCMI Without C6	101		220			2		180			0.26		
N2		28LAER	SOCMI Without C2	59	0	118	25				100			0.12		
water		28LAER	SOCMI Without C2	35	57	97	84				108			0.11		
water/co/hydrogen		NM	SOCMI Without C2	43	0	113	0			2	100	2.9	5.4	3.41	0.10	0.18
water/methane		28VHP	SOCMI Without C2	22	0	761	0				100	25.4	0.3	6.79	1.72	0.02
TOTAL				**1024**	**801**	**3651**	**1607**	**2**	**2**					**42.85**	**9.65**	**2.83**

Note:
Emission rates less than 0.005 lb/hr or tpy are represented as 0.00.
Low concentrations of miscellaneous VOCs may be present.
Zero emission components (double seal with barrier fluid, etc.) are not represented above.

Celanese Ltd
Clear Lake Plant
Emergency Generator Greenhouse Gas Emissions Calculations

Methanol Emergency Generator
EPN: MEOHENG
Emissions Summary

Pollutant	GWP
CO_2	1
CH_4	21
N_2O	310

Default High Heat Value	0.138	MMBTU/gallon	Table C-1. Residual Fuel Oil No. 2
Default CO_2 Emission Factor	73.96	kg CO_2 / MMBTU	Table C-1. Residual Fuel Oil No. 2
Default CH_4 Emission Factor	0.003	kg CH_4 / MMBTU	Table C-2. Petroleum (Residual Fuel Oil No. 2)
Default N_2O Emission Factor	0.0006	kg N_2O / MMBTU	Table C-2. Petroleum (Residual Fuel Oil No. 2)

Fuel Economy (gal/hr)	Operating Hours per year (hr/yr)	Gallons (gal/yr)	Annual Heat Input (MMBtu/year)	CH_4 Emissions (tpy)	N_2O Emissions (tpy)	CO_2 Emissions (tpy)	Total CO_2e Emissions (tpy)
29.6	100	2960	408.48	0.001	0.0020	241.36	242.00

CH4 Emission = Fuel(gal/hr) * Opeation hours(hr/yr) * High Heat(MMBTU/gal) * Emission Factor (kg/MMBtu) * (2.205 lb/kg) /2000(lb/ton)
= (29.6*100*0.138*0.003*2.205/2000)
= 1.35E-03 tpy

N2O Emission = Fuel(gal/hr) * Opeation hours(hr/yr) * High Heat(MMBTU/gal) * Emission Factor (kg/MMBtu) * (2.205 lb/kg) /2000(lb/ton)
= (29.6*100*0.138*0.0006*2.205/2000)
= 1.96E-03

CO2 Emission = Fuel(gal/hr) * Opeation hours(hr/yr) * High Heat(MMBTU/gal) * Emission Factor (kg/MMBtu) * (2.205 lb/kg) /2000(lb/ton)
= (29.6*100*0.138*73.96*2.205/2000)
= 241.36 tpy

CO2e Emission = CH4 Emissions(tpy)* GWP+ N2O Emission(tpy)* GWP + CO2 emission(tpy) * GWP
= (0.001*21+0.002*310+241.36*1)
= 242.00 tpy

GHG calculation for CH4, CO2, N2O

Methanol Unit Flare
EPN: MEOHFLR
Emissions Summary

Methane DRE	99%		
N2O EF	0.0001	kg/mmBtu	Subpart C table C-3

	Annual Flow	Heating Value	CO2 produced	CH4 Unreacted	N2O
	MMscf/yr	MMBtu/yr	tpy	tpy	tpy
Methane	1,016	924,194	21,470	3.53	
Hydrogen	65,842	18,058,520	0		
Carbon Monoxide	19,910	6,388,967	734,938		
Methanol	70	50,726	2,960		
Carbon dioxide	8,007	0	8,007		
methyl formate	15	14,842	2,322		
acetone	0	124	15		
dimethyl ether	7	10,931	881		
Total	95,275	25,448,305	770,593	4	3
			1	21	310
CO2(e)			770,593	74	869

Total CO2(e) **771,537** **tpy**

MSS Emissions
EPN: MEOHMSS

Emissions Basis

Maximum volume vented when isolating section of pipe for maintenance, start-up or shutdown

Annual volume cleared	10	ft3
Pressure	75	psia
Temperature	50	F
Gas Constant	10.73	ft3 * psia / (R * lbmol)
Methane MW	16.04	lb/lbmol
Methane Annual emissions	2.10	tpy
Total CO2(e)	44.13	tpy

Emissions vented to atmosphere determined using Ideal Gas Law and volume of system cleared
Actual conditions including temperature and pressure may very.

APPENDIX B
EPA DULY AUTHORIZED REPRESENTATIVE LETTER

Celanese, hereby requests that Cardno ENTRIX is assigned as a duly authorized company on behalf of the US EPA for the sole purposes of consultation with US FWS for the Endangered Species Act and biological assessment required for the Celanese Methanol Expansion Project GHG Permit Application and permit authorization.