

US EPA ARCHIVE DOCUMENT

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August 29, 2014

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Texas Commission on Environmental
Quality (TCEQ) - MC163
12100 Park 35 Circle
Austin, Texas 78753

Wren Stenger
Multimedia Planning and Permitting
Environmental Protection Agency
Region VI,
1445 Ross Avenue
Dallas, TX 75202

Re: Methanol Unit Project Greenhouse Gas PSD Initial Permit Application
Ticona Polymers, Inc – Bishop Plant
TCEQ RN: 101625721, TCEQ CN: 600124184

Dear Ms. Stenger and Mr. Wilson;

Ticona Polymers, Inc. (Ticona) is planning to construct and operate a new Methanol plant at its plant located in Bishop, Texas. Ticona is submitting the enclosed application to address the Best Available Control Technology requirements for Greenhouse Gases (GHG) that will be emitted from the proposed chemical unit. The Methanol Unit project is also a major source for volatile organic compounds (VOC), nitrogen oxides (NOx), carbon monoxide (CO), particulate matter (PM), particulate matter 10 microns or less (PM₁₀), and particulate matter 2.5 microns or less (PM_{2.5}). The authorization for non-GHG criteria pollutants has been submitted under a separate cover to the TCEQ.

The EPA is currently in the process of delegating permitting authority to the TCEQ. Ticona respectfully requests that, should the delegation be completed prior to public notice, subsequent review of our application be transferred to the TCEQ, so that the TCEQ would be the permit issuing authority for the GHG permit. To expedite this, we are submitting this application to both EPA and the TCEQ. We understand that you will coordinate permit review to avoid double work, and we will work with either or both agencies, as you may request.

If you have any questions or need additional information, please contact Bill Chidester at 361-584-6614 or William.Chidester@celanese.com. Thank you for your time and consideration regarding this matter.

Sincerely,

A handwritten signature in black ink, appearing to read "David W. Townsend".

David Townsend
Engineering Fellow

Attachments

cc: Jeffrey Robinson, USEPA

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14 SEP -3 PM 4:06
AIR PERMITS SECTION
6PD-R



**Greenhouse Gas
Prevention of Significant Deterioration
Permit Application for Methanol Manufacturing**

**Ticona Polymers, Inc.
Bishop Facility**

August 2014

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SECTION 1

INTRODUCTION

1.1 Introduction

Ticona Polymers, Inc. (Ticona) is hereby applying for a Prevention of Significant Deterioration (PSD) permit for greenhouse gases (GHG) that will be emitted from a new methanol manufacturing unit to be located at its Bishop Facility in Bishop, Texas.

1.2 Background

Ticona owns and operates multiple manufacturing units at the Bishop Facility located at 5738 County Road 4, Bishop, Nueces County, Texas. An Area Map, Figure 1-1, of the Bishop Facility and surrounding area has been included in this application. Methanol is one of the feedstocks imported to the facility. Ticona proposes to manufacture methanol in a new unit for sale and for onsite consumption. Steam demand from the new Methanol unit will be supplied by three new boilers proposed in a separate application.

The Ticona Bishop Facility is an existing major source under the federal PSD program. Therefore, physical changes and changes in the method of operation are potentially subject to PSD permitting requirements. The project to construct a new Methanol unit and the project to construct new boilers will be evaluated as a single PSD project. However, two separate applications are being submitted for two GHG PSD permits to facilitate potential transfer of ownership of some of the equipment in the future. A PSD review is required because GHGs are expected to increase by more than 75,000 tons per year (tpy) expressed as CO₂ equivalent (CO₂e) and emissions of at least one of non-GHG PSD criteria pollutants are expected to increase above its respective PSD threshold. The PSD application for non-GHG pollutants is being submitted in a separate application to the Texas Commission on Environmental Quality (TCEQ).

This GHG permit application has been prepared based upon Environmental Protection Agency's guidance, including the following:

- Draft October 1990 "New Source Review Workshop Manual";
- March 2011 document, "PSD and Title V Permitting Guidance for Greenhouse Gases (EPA-457/B-11-001)"; and
- Memo dated October 15, 2012, "Timely Processing of Prevention of Significant Deterioration Permits When EPA or PSD-Delegated Air Agency Issues the Permit."



FIGURE 1-1

SITE LOCATION ON Aerial Photo from Google Earth

TICONA POLYMERS, Inc.

BISHOP PLANT

S A G E ENVIRONMENTAL CONSULTING "Friendly Service, No Surprises!"	DATE: August 2014
	PROJECT: 400-61-8-4-2-1
	FILE NAME: Aerial Photo.srf

SCALE (meters)

0
2000

UTM Zone 14

NORTH

SECTION 2

PROPOSED PROCESS DESCRIPTION

In general, methanol is synthesized from a mixture of carbon monoxide (CO), carbon dioxide (CO₂) and hydrogen (H₂) (otherwise known as synthesis gas) over a catalyst at elevated pressures and temperatures. Methanol and water products are separated out from any unreacted components. The water and methanol are then separated and the final product sent to storage.

The synthesis gas used in this process is produced by steam reforming (Primary Reformer) and oxygen reforming (Secondary Reformer) of natural gas. In this process, pipeline natural gas is compressed, preheated, treated to remove sulfur, saturated with process water, mixed with steam, and reheated. The natural gas/steam mixture is fed to the Primary reformer where a portion of the methane is converted to synthesis gas by reaction with steam inside of externally-heated, catalyst-filled tubes. Heat input to the Primary reformer is provided by the combustion of natural gas and a process stream taken from the converter loop to remove inerts (nitrogen, argon and methane) and excess H₂. Heat is recovered from the flue gases from the Primary reformer prior to venting the flue gases to atmosphere 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.

The partially reformed gas stream from the Primary reformer is sent to the Secondary reformer where it is reacted with oxygen and the remaining methane converted to synthesis gas. Combustion emissions from the Primary reformer are routed to a single stack (EPN: REFORM). The process synthesis gas leaving the Secondary reformer is cooled, compressed and sent to the converter loop where CO, CO₂, and H₂ are reacted to produce crude methanol, a mixture of methanol and water. Process streams including the synthesis gas and converted methanol will be monitored using 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 Methanol 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 process stream from the converter loop. About 60% of the finished methanol is taken overhead in the second column. The residue from the second column feeds a third column. The remainder of the finished methanol is taken overhead in the third column. A side stream from the third column is recycled to the Saturation system. The process water stream from the bottom of the third column is also recycled to the Saturation system. Finished methanol will be sent to the storage area. The storage area will consist of four new internal floating roof (IFR) storage tanks. The storage tanks will not be a source of GHG emissions because any CO₂ and CH₄ will have been removed from the finished product prior to storage.

Finished methanol will be consumed on-site or transferred off-site by pipeline facilities.

There are several other sources that will be associated with the operation of the Methanol unit. A flare (EPN: MEOHFLR) will be available to control emissions as appropriate from Maintenance, Start-up, or Shutdown (EPN: MEOHMSS) activities or emergency vents. MSS GHG emissions not able to be controlled by the flare will be emitted to atmosphere (EPN: MEOHMSS). A back-up diesel emergency generator (EPN: MEOHGEN) will be located in the Methanol unit and will be used for back-up power. Two new firewater pumps will also be installed for fire protection for the unit (EPNs: ICEFW01, ICEFW02). Piping components from the process equipment described above will also be a source of GHG emissions (EPN: MEOHFUG). The cooling tower (EPN: MEOHCT) will provide cooling to the Methanol unit, including equipment containing both GHG and non-GHG process streams. The cooling tower will be subject to 40 CFR Part 63, Subpart F monitoring.

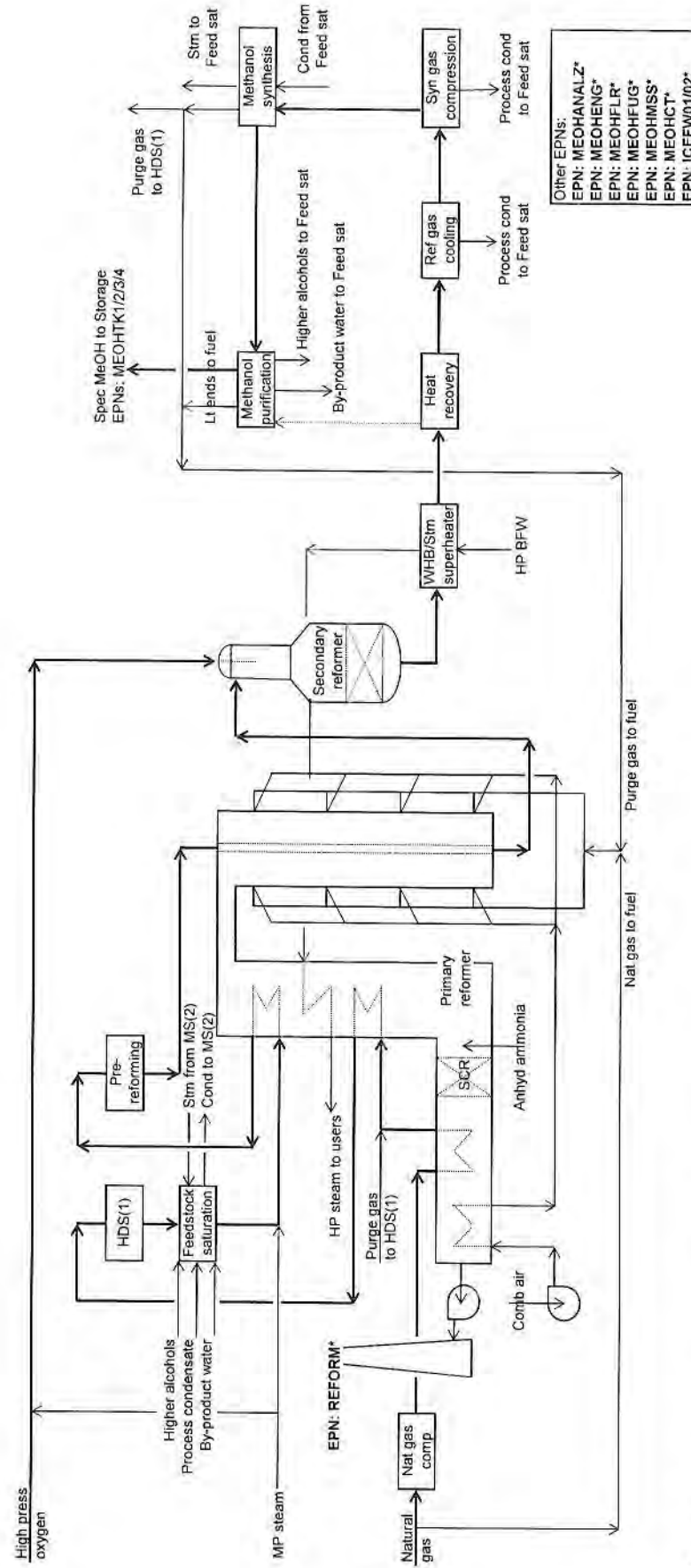
Table 2-1 shows the potential emissions sources for the new Methanol unit and whether they are considered a source of GHG Emissions.

Table 2-1 Sources of Emissions

Source	Description	Source of GHG Emissions
REFORM	Methanol Reformer	Yes
MEOHFLR	MSS Flare	Yes
MEOHMSS	MSS Activities	Yes*
MEOHFUG	Fugitive Sources	Yes*
MEOHCT	Cooling Tower	Yes
MEOHTK01	Methanol Tank	No
MEOHTK02	Methanol Tank	No
MEOHTK03	Methanol Tank	No
MEOHTK04	Methanol Tank	No
MEOHANALZ	Methanol Analyzers	Yes
MEOHGEN	Emergency Generator	Yes
ICEFW01	Firewater Pump	Yes
ICEFW02	Firewater Pump	Yes

*for some equipment or activities

Figure 2-1
Simplified process flow diagram (PFD)
Ticona Polymers
Bishop Plant
New Methanol Unit



Notes:

- (1) HDS = Sulfur removal via hydrogenation/zinc oxide absorption
- (2) MS = Methanol synthesis
- (3) EPNs with * are sources of GHG. All other EPNs are non-GHG emission sources.

SECTION 3

EMISSIONS ESTIMATE METHODOLOGY

Projected emissions of GHG include methane (CH₄), carbon dioxide (CO₂), and nitrous oxide (N₂O). GHG emissions were calculated for the methanol reformer, fugitive equipment sources, the emergency generator, firewater pumps, cooling tower, flare, startup, shutdown, and maintenance (MSS) activities. The small emissions associated with analyzers are within the emission quantity calculations for various other GHG sources. CO₂, CH₄, and N₂O have a global warming potential (GWP) of 1, 25, and 298, respectively.

3.1 Methanol Reformer (EPN: REFORM)

The burners within the primary reformer combust natural gas and a H₂ rich process gas stream to provide heat for the endothermic steam-methane reforming reactions. The emissions from the Primary reformer are emitted from a single stack.

Process Gas Contribution:

The combustion of the process gas produces CO₂, CH₄ and N₂O. CO₂ is created by the stoichiometric conversion of the carbon containing compounds in the process gas stream. Complete conversion of the carbon components of the process gas fuel to CO₂ is used to calculate the worst case emissions via the Tier 3 equation in the EPA GHG Mandatory Reporting Rule, 40 CFR Part 98, Subpart C. N₂O and CH₄ emissions from the combustion of the process gas fuel were calculated using the vendor supplied reformer firing rates and the factors from 40 CFR Part 98, Subpart C, Table C-2.

Natural Gas Contribution:

CO₂ resulting from the combustion of the natural gas fuel was calculated using the vendor supplied firing rate and the factor from the EPA GHG Mandatory Reporting Rule, 40 CFR Part 98, Subpart C, Table C-1. N₂O emissions from the combustion of the natural gas fuel were calculated using the vendor supplied reformer firing rates and the factor from the EPA GHG Mandatory Reporting Rule, 40 CFR Part 98, Subpart C, Table C-2. The uncombusted CH₄ from the natural gas fuel was determined using natural gas fuel flow and the factor from the EPA GHG Mandatory Reporting Rule, 40 CFR Part 98, Subpart C, Table C-2.

3.2 Fugitive Equipment (EPN: MEOHFUG)

Fugitive GHG emissions from the Methanol unit fugitive components in CH₄ or CO₂ service were estimated in accordance with the TCEQ Technical Guidance Package for Equipment Leak Fugitives, October 2000. Emissions were estimated using the SOCMI AP-42 emission factors for SOCMI processes without Ethylene and estimated stream compositions. Reduction credits were taken for the TCEQ 28VHP leak detection and repair program for streams with greater than 10% CH₄ by weight.

3.3 Emergency Engines (EPNs: MEOHGEN, ICFW01, ICEFW02)

Emissions from the emergency generator and the firewater pumps were estimated in accordance with the EPA GHG Mandatory Reporting Rule. Per 40 CFR Part 63 Subpart ZZZZ, emergency engines are only allowed to run up to 100 hours per year in non-emergency situations. GHG emissions were calculated based on the worst case annual heat input for 100 hours of non-emergency use per year.

3.4 MSS Activities of Methane Containing Equipment (EPN: MEOHMSS)

The GHG Emissions from MSS activities were calculated based on a representative maximum volume vented when isolating sections of pipe or equipment for the purposes of maintenance, start-up or shutdown.

3.5 MSS and Emergency Flare (EPN: MEOHFLR)

CO₂ will be emitted from the flare from CO₂ produced in the process as well as from CO₂ produced from the combustion of carbon containing compounds. The flare's destruction removal efficiency (DRE) for CH₄ in the flare is 99% on a 12-month rolling average based on compliance with 40 CFR Part 60 Subpart A. A 99% DRE is utilized for organic chemicals containing no more than 3 carbons with no elements other than carbon or hydrogen as identified in the TCEQ *Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers*. The 1% of undestroyed CH₄ from the process streams and natural gas pilot will be emitted by the flare. The production of N₂O from the heat of combustion and combustion air was calculated using the factor from the EPA GHG Mandatory Reporting Rule, 40 CFR Part 98, Table C-2.

3.6 Cooling Tower (EPN: MEOHCT)

GHG emissions from the cooling tower were estimated using the factor from AP-42, Section 5.1. CH₄ was conservatively assumed to equal 100% of the carbon-containing compounds in cooling water.

SECTION 4

GHG BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

GHG emissions from the new Methanol unit will be greater than 75,000 tons per year (tpy) CO_{2e}. Therefore, the project is subject to PSD regulation, and a BACT review must be conducted for GHG pollutants and applicable emission units. The following sources are subject to Best Available Control Technology (BACT) review:

- Primary Reformer (EPN: REFORM)
- MSS Flare (EPN: MEOHFLR)
- Equipment MSS (EPN: MEOHMSS)
- Fugitive Emissions (EPN: MEOHFUG)
- Engines (EPNs: MEOHGEN, ICEFW01, ICEFW02)
- Cooling Tower (EPN: MEOHCT)

The new unit is designed with many inherent energy efficiency features compared to existing, widely-used process designs. As discussed in the following BACT analysis, the process design chosen by Ticona requires less energy to produce methanol than designs utilized by other existing and proposed Methanol units. The two-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 focuses on how the unique design incorporates elements that prevent the formation of GHG pollutants.

4.1 BACT Analysis Methodology

BACT for GHG emissions from the project have been evaluated via a "top-down" approach that includes the steps outlined in the following subsections.

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); and
- Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Petroleum Refining Industry (hereafter referred to as GHG BACT Guidance for Refineries).

4.2 BACT Top-Down Approach

4.2.1 Step 1 – Identification of Potential GHG Control Technologies

Available control technologies with the practical potential for application to the emission units and regulated air pollutants in question were 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 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 (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emission Rate (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.

In addition, Ticona will use the following additional resource:

- *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy and Plant Managers*

Ticona completed a search of the RBLC and GHG Mitigation Strategies Databases with the following results:

- RBLC database - The newly enhanced RBLC database does not contain a mature stock of determinations under its available Process Codes; however, the database does contain entries under the CO₂ pollutant code. An entry for a steam methane reformer at a Phillips 66 refinery in Louisiana (RBLC ID: LA-0263) is considered relevant to this BACT discussion. In that case, BACT was determined to be Energy Efficiency Options such as heat recovery, installation of an air preheater for the furnace, installation of new burners, as well as Best Operational Practices such as limiting excess air in combustion.

- GHG Mitigation Strategies Database - The GHG Mitigation Strategies Database did not contain any information for emission sources presented in this analysis.

4.2.2 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 pollutant emissions above threshold limits from the source. The first question in determining whether or not a technology is feasible, is whether it is a "demonstrated" technology. 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 emission 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.

4.2.3 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.

4.2.4 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 §52.21(b)(49)(ii), CO₂e emissions must be calculated by scaling the mass of each of the six GHGs by the gas's GWP, which is established in Table A-1 to Subpart A of 40 CFR Part 98. Therefore, to determine the most appropriate strategy for prioritizing the control of CO₂, N₂O, and CH₄ emissions, Ticona considered each

component's relative GWP. As shown in Table 4-1, the GWP of CH₄ is 25 times the GWP of CO₂. Therefore, one ton of atmospheric CH₄ emissions equates to 25 tons of CO₂e emissions. On the other hand, one ton of CH₄ that is combusted to form CO₂ emissions prior to atmospheric release equates to 2.7 tons of CO₂e emissions. Since the combustion of CH₄ decreases GHG emissions by approximately 87 percent on a CO₂e basis, combustion of CH₄ is preferential to direct emission of CH₄.

Table 4-1 Global Warming Potentials

Pollutant	GWP
CO ₂	1
CH ₄	25
N ₂ O	298

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.

4.2.5 Step 5 - Selection of BACT

In the final step, 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.

4.3 GHG BACT Evaluation for Reformer

The following section presents BACT evaluations for GHG emissions produced from the reforming process for methanol production.

4.3.1 Step 1 – Identification of Potential GHG Control Technologies

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

- Selection of Methanol Reforming Process Design;
- Selection of the Lowest Carbon Fuel;
- Installation of Energy Efficiency Options;
- Best Operational Practices;
- Carbon Capture and Storage (CCS); and
- Post-Combustion Catalysts.

4.3.1.1 Selection of Reforming Process Design

Ticona evaluated several potential technologies for reforming (production of synthesis gas) for the Methanol plant. As discussed below, the proposed process design was chosen because it is a demonstrated technology with higher energy efficiency, lower energy consumption, higher product yields and lower potential emissions than other existing technologies.

Based on the project specifications, the following technology process designs were evaluated:

1. Steam-methane reforming process and disposal of waste gas and waste liquid streams;
2. Steam-methane reforming process with recovery/reuse of waste gas and waste liquid streams;
3. Autothermal reforming (oxygen reforming) process and disposal of waste gas and waste liquid streams;
4. Autothermal reforming process with recovery/reuse of waste gas and waste liquid streams;
5. Gas-heated reforming and autothermal reforming in series with recovery/reuse of waste gas and waste liquid streams;
6. Combined reforming (steam-methane reforming and autothermal reforming either in series or parallel) and disposal of waste gas and waste liquid streams; and
7. Combined reforming (steam-methane reforming and autothermal reforming either in series or parallel) with recovery/reuse of waste gas and waste liquid streams.

The methanol process in all designs uses a reformer to react CH_4 to a synthesis gas consisting of primarily H_2 with a small portion of CO_2 , CO 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 4.3.1.3.

Design options 1 and 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 Celanese Ltd. Clear Lake

facility (owned by the same parent company as Ticona Polymers) 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 (i.e., Design 1). The newer SMR processes evaluated ranged between 34 to 35 MMBtu/tonne of Methanol produced (i.e., Design 2). 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 below, additional feed and firing would be required to produce the same number of pounds of methanol per year.

Design options 3 and 4: The 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 CO₂. The CO₂ must be removed from the synthesis gas. The ATR processes evaluated (Design 4) ranged between 32 to 33 MMBtu/tonne of methanol produced.

Design option 5: A Gas-Heated Reforming (GHR) and ATR process was evaluated. The GHR/ATR processes evaluated ranged between 32 to 33 MMBtu/tonne of Methanol produced. However, the process has not been constructed on a production scale comparable to the scale that is being proposed at the Bishop site.

Design option 6 and 7: The Combined Reforming process uses a Primary and a Secondary reformer to produce methanol. The Combined Reforming process will range between 31 and 33 MMBtu/tonne of methanol produced (Design 7). Consequently, the Combined Reforming process will generate fewer GHG emissions than the other processes.

Designs 3 and 6 were eliminated from consideration due to lack of recovery/reuse of waste streams. Design 5 was eliminated from consideration as it has not been proven as a reliable technology at the production capacity needed for the Ticona facility. A summary of the energy demands of each feasible design and the estimated amount of CO_{2e} emissions avoided by choosing Design 7 are as follows:

Reformer Design Process	Heat Required (MMBtu) per Methanol produced (tonne)	Estimated Additional CO _{2e} (tpy)
Design 1: SMR Original Technology	36 – 38	434,537
Design 2: SMR Current Technology	34 – 35	217,269
Design 4: ATR	32 – 33	43,454
Design 7: Combined Reforming*	31 – 33	--

*** Selected Design**

4.3.1.2 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 as low-carbon fuels have less carbon that will be combusted to CO₂. The reformer will combust natural gas as the primary fuel and may combust high H₂ 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 CO₂e emissions; however, the hydrogen rich stream will only be available as fuel during normal operation of the plant because it is generated by the process. During periods of start-up, shutdown, or malfunction, the reformer would fire natural gas.

Utilization of pipeline hydrogen fuel in lieu of natural gas has the potential to reduce reformer GHG emissions, as only N₂O would be generated by H₂ fuel combustion in the reformer. The additional GHG emissions required to generate the pipeline H₂ will be discussed in Section 4.3.4.1.

In summary the available fuel options are:

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

4.3.1.3 Installation of Energy Efficiency Options

Traditional techniques for methanol production using methane reforming are energy intensive and significant sources of GHG emissions. This section describes the energy efficiencies that will be incorporated into the design of Ticona's reformer to reduce GHG 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 Ticona Methanol process. The Energy Star guidelines referenced in the document, *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry* identify 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 the flue gas temperature reaches the dew point; any further heat recovery has the potential to cause process fouling and corrosion.

Heat recovery from the 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 amount of firing required. Heat from the flue gas is also used to superheat steam, which is used internally in the Methanol unit or exported to other users. Subsequently, the production of steam would reduce the plant steam requirements from site boilers, and thereby reduce GHGs. 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 will generate high pressure steam, some of which will be exported allowing optimization of the Bishop's facility energy demand.

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 the deaerator (i.e., reduces amount of steam required to be added to the deaerator).

Although most of the Methanol Unit steam demand will be produced by heat recovery from the Methanol converters and waste heat boilers, there will be an overall increase in steam demand at the Bishop Facility. The increase in steam will be provided by three new boilers which will be permitted separately.

Process gas will be recovered/reused as fuel in the Ticona 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 potential versus using the same heating input of natural gas.

Ticona will utilize efficient low-NO_x design burners to reduce emissions from non-GHG pollutants. The burners will be designed to accomplish good mixing of air and fuel as to not consume excess oxygen. The burners will have an annual average DRE for organic compounds of at least 99.5%. Thus, the fuel demands to produce an equivalent reforming firing duty will be lower than utilizing standard lower efficiency burners.

Ticona will install tube seals in the reformer to contain the heat within the reformer combustion box. Improving heat containment through use of tube seal increases the thermal efficiency of the reformer by 5% on average¹.

4.3.1.4 Best Operational Practices

Ticona will monitor stack excess O₂ to ensure efficient combustion. The fuel requirements increase as the facility operates with more excess air. The reformer stack O₂ concentration will be operated at approximately 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

¹ Neelis, Worrell, Masanet, *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry, An ENERGY STAR® Guide for Energy and Plant Managers*, June 2008.

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. Any lower O₂ to fuel ratio would decrease the combustion efficiency, thereby increasing the amount of CO and VOCs present in the reformer stack.

Ticona will increase energy efficiency in the process by reducing heat loss through insulating the high temperature equipment. 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.

The time required for start-up venting and the resulting volume of waste gas is significantly reduced as Ticona will use pipeline supplied H₂ for converter catalyst activation, which prevents the need for steam or flaring during catalyst activation (typically the activity occurs less frequently than annually). As a result, Ticona's procedure for Methanol converter catalyst activation generates roughly 11,875 tons less GHG emissions per catalyst activation (see calculation in Appendix A) compared to other methanol industry practices. Current industry practice does not include catalyst activation using pipeline H₂.

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 being 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 GHG combustion emissions.

Ticona's maintenance procedure for equipment in natural gas service will include depressuring the system to the flare as appropriate, prior to opening to the atmosphere. Combustion of the methane in natural gas to CO₂ in the flare will decrease the potential CO_{2e} emissions by 25 times.

The reformer will be kept in good working condition in order to sustain GHG emission performance. Maintenance activities include a variety of activities ranging from instrument calibration to cleaning of dirty or fouled mechanical parts. 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*.

4.3.1.5 Carbon Capture and Storage

Carbon Capture and Storage (CCS) involves separation and capture of CO₂ emissions from the flue gas, compression of the captured CO₂, transportation of the compressed CO₂ via pipeline, and injection and long-term geologic storage of the captured CO₂.

Several different technologies have demonstrated the potential to separate and capture CO₂. 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 U.S. EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (EPA-457/B-11-001):

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 CO₂ in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO₂ 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 identify reformers in a methanol production process in the high purity CO₂ stream emitting sector; however, similar reformers are a component of hydrogen production. The flue gas produced by the reformer contains typical combustion device levels of CO₂ and CCS is considered an "available" add-on control technology for this flue gas stream. Currently there are two options for CO₂ capture for high purity CO₂ streams: Post-Combustion Solvent Capture and Stripping and Post-Combustion Membranes.

Capture or separation of the CO₂ stream alone is not a sufficient control technology, but instead requires the additional step of permanent storage. After separation, storage could involve sequestering the CO₂ 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 CO₂ 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. As discussed below, the Ticona Bishop Facility is not located near a permanent CO₂ sequester option; therefore, EOR, saline aquifers, or un-minable coal seams are not a technically feasible option.

The Bishop Facility is located approximately 200 miles from a conceivable recipient of recovered CO₂ gases, the Denbury Green Pipeline. However, the distance to the pipeline, the excessive site-specific cost of designing, constructing, and operating the pipeline to transport compressed CO₂ to the Denbury Green Pipeline as documented in this application, and lack of similar demonstrated projects make this sequestration option infeasible for this project.

In addition to the U.S. EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases*, 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 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 CO₂ will be captured and used in an EOR application;
- Archer Daniels Midland: an ethanol plant in Illinois where 900,000 tonnes per year of CO₂ will be captured and stored in a saline formation directly below the plant site; and
- Air Products: a hydrogen-production facility in Texas where 900,000 tonnes per year of CO₂ will be captured and used in an EOR application.

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.

The August 2010 Federal Interagency Task Force for Carbon Capture and Storage (CCS) report noted the following four fundamental near-term and long-term concerns of CCS as a potential control technology:

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 CO₂ can be stored safely and securely;
3. Clarity with respect to the long-term liability for CO₂ 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; and
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.

4.3.1.6 *Post-Combustion Catalysts*

Post-combustion catalytic oxidation provides rapid conversion of a hydrocarbon into CO₂ and water vapor in the presence of available oxygen. In addition, N₂O catalysts can be used to minimize N₂O emissions by decomposing N₂O into nitrogen and oxygen.

4.3.2 Step 2 – Elimination of Technically Infeasible Control Options

4.3.2.1 *Selection of the Lowest Carbon Fuel*

Natural gas, the lowest carbon fuel, is a technically feasible option for CO₂ control for the reformer. In addition, high H₂ fuel gas may be used as a secondary fuel when practicable and available, which will further reduce CO₂ emissions. Pipeline supplied H₂ fuel could be provided as a primary fuel; however, as discussed below in Step 4, additional H₂ production facilities would have to be constructed to meet demand for the new unit.

4.3.2.2 *Selection of Methanol Reforming Process Design*

As presented in Section 4.3.1.2, “Selection of Methanol Reforming Process Design,” the ATR, SMR and combined ATR and SMR processes proposed by Ticona are technically feasible process designs. The combined GHR and ATR process technology has not been constructed on a production scale comparable to the size being proposed for the Ticona facility. There are reliability concerns such as metal dusting regarding scaling up this technology which has yet be constructed or demonstrated at plant-scale. The GHR and ATR process design is thus, not a technically feasible option.

4.3.2.3 *Installation of Energy Efficiency Options*

The energy efficiency options presented in Section 4.3.1.3 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.

4.3.2.4 *Best Operational Practices*

Ticona will utilize several best operation practices as described in Section 4.3.1.4 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.

4.3.2.5 *Carbon Capture and Storage*

Capture and Compression – CO₂ capture is achieved by separating CO₂ from emission sources where it is then recovered in a concentrated stream that can be sequestered. Currently there are a few options for CO₂ 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 CO₂ in exhaust streams and is an available technology for this application.

Post-combustion membranes technology may also be used to separate or adsorb CO₂ in an exhaust stream. It has been estimated that 80 percent of the CO₂ could be captured using this technology. The captured CO₂ would then be purified and compressed for transport. Per the National Energy Technology Laboratory (owned and operated by the US Department of Energy), the use of membranes for CO₂ capture is still in the development phase.² All listed R&D efforts are still in bench scale or pilot plant phase. Demonstration on an industrial scale level is not anticipated until 2018.³ Since the current state of this technology is primarily in the research stage, post-combustion membranes are not currently feasible.

Sequestration - Lack of Sequestration Sink (Geologic or Pipeline)

While capture-only technologies may be available, a remaining hurdle is the availability of a mechanism (pipeline or geologic formation) to permanently sequester the captured gas.

Figure 4-1 located at the end of this section and Table 4-2 below demonstrate the potential CO₂ Storage facilities near the Bishop Facility.

Table 4-2 Potential CO₂ Storage/EOR Sites⁴

Source	Type	Distance	Capacity	Status
Gulf of Mexico Miocene CO ₂ Site Characterization Mega Transect	Storage	113 miles	68 million tonnes	Research – not commercially viable yet.
ConocoPhillips Sweeny Polygeneration Plant	Capture	162 miles	27,400 tonnes/day	Potential – Planned
Hunton Energy Freeport Plant	Capture and Storage	177 miles	21,920 tonnes/day	Potential – In Development
NRG Energy W.A. Parish Plant	Capture and Storage	185 miles	1,096 tonnes/day	Active – Existing
CEMEX Inc. Cement CO ₂ Capture Project	Capture and Storage	200 miles	N/A	Terminated
Denbury Green Pipeline	Transport (Storage)	200 miles	N/A	Active - Existing

² <http://www.netl.doe.gov/technologies/coalpower/ewr/co2/PostCombustion.html>

³ http://extsearch1.netl.doe.gov/search?q=cache:e0yvzjAh22cJ:www.netl.doe.gov/technologies/carbon_seq/FAQs/tech-status.html+emerging+R%26D&access=p&output=xml_no_dtd&ie=UTF-8&client=default_frontend&site=default_collection&proxystylesheet=default_frontend&oe=ISO-8859-1

⁴ Information obtained from the National Carbon Sequestration Database and Geographic Information System (NATCARB), <http://www.natcarbviewer.com>

As seen in Table 4-2, no sites with a distance of less than 200 miles from the Bishop Facility are suitable candidates for CO₂ storage/EOR. The four sites closer than the Denbury Green Pipeline are unsuitable for the following reasons:

- Gulf of Mexico Miocene CO₂ Site Characterization Mega Transect - this site is still currently in research operations. Therefore it is not currently a long term commercially viable option for permanent CO₂ storage.
- ConocoPhillips Sweeny Polygeneration Plant – ConocoPhillips Sweeny is a chemical manufacturing facility. This site is currently only capturing CO₂ and does not have storage facilities for commercial use.
- Hunton Energy Freeport Plant: site is still in the development phase and is not yet ready for commercial use.
- NRG Energy W.A. Parish Plant: site does not have the CO₂ storage capacity needed to store all of the CO₂ captured from the reformer.

As stated above, the closest existing commercial CO₂ pipeline is approximately 200 miles from the Bishop Facility. The distance to the pipeline, the excessive cost of designing, constructing, and operating the CCS project to transport compressed CO₂ to the Denbury Green Pipeline, and lack of similarly demonstrated projects should all be taken into consideration.

The aforementioned technical and economic challenges raise substantial uncertainties to the feasibility of CCS as BACT for reducing CO₂ emissions from the reformer. However, for the purposes of providing a more thorough and site-specific determination, CCS will be considered technically feasible in this analysis.

4.3.2.6 Post-Combustion Catalysts

N₂O catalysts are typically used in the nitric/adipic acid plants to minimize N₂O emissions. However, N₂O catalysts have not been used to control N₂O emissions in reformer applications. In addition, the low N₂O concentrations present in the exhaust stream (less than 0.25 ppmv) make installation of N₂O catalysts technically infeasible.

For the same reason N₂O catalysts are technically infeasible, installation of a catalyst system for CH₄ emissions is also infeasible. The reformer flue gas is expected to contain CH₄ in the 5 ppmv range, and catalytic oxidization systems are used for inlet concentrations ranging from 100 ppmv - 10,000+ ppmv.

4.3.3 Step 3 – Rank of Remaining Control Technologies

The various options described above for controlling and minimizing GHG emissions may be combined. Those options that are technically feasible and mutually exclusive of one another are ranked based on their overall control effectiveness:

- Carbon Capture and Storage – may reduce CO₂ by up to 90%.

- **Lowest Carbon Fuel** – The utilization of pipeline H₂ fuel will have a greater impact on reducing GHG emissions, specifically at the Bishop Facility using natural gas as the reformer primary fuel.
- **Reformer Design** – 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.
- **Installation of Energy Efficiency Options & Best Operation Practices** - implementing these design elements and best operation practices is effective at minimizing formation of CO₂ in the reformer.

4.3.4 Step 4 – Evaluation of Most Stringent Controls

4.3.4.1 Selection of the Lowest Carbon Fuel

Natural gas is the lowest emitting carbon fuel that could be relied upon for the proposed operation. High H₂ fuel gas with small amounts of carbon containing components may be utilized as a secondary fuel for the reformer when it is available and its use is practicable. Pipeline H₂ in lieu of natural gas for combustion in the methanol reformer would cost an additional \$644 MM above the cost of equivalent heat value of natural gas over the lifetime of the process (assuming 30 year life of equipment) and that would render the project economically unviable. The cost calculation is located in Appendix A. Subsequently, 95% of all commercial H₂ is produced using steam and natural gas reforming. The use of H₂ in lieu of natural gas would require at least 2121 mscf H₂/ hour in order to maintain the needed HHV and to maintain reformer thermal efficiency. The burning of H₂ instead of natural gas would reduce CO₂ emissions from the reformer by 351,874 tpy. However, a hydrogen plant designed to meet the methanol plant demand would emit roughly 530,000 – 575,000 tpy CO₂, based on the current literature⁵, or approximately 10.8 lbs of CO₂ per lb of H₂ produced. Therefore, to replace natural gas with H₂ only would actually increase overall CO₂ emissions by roughly 178,000 to 212,000 tpy.

4.3.4.2 Selection of Methanol Reforming Process Design

Compared to the SMR and ATR Process, the combined reforming process will create the least amount of GHG emissions since the process has a lower energy demand. It is selected because it is the highest ranking technically feasible process design option.

4.3.4.3 Installation of Energy Efficiency Options on the Reformer

The new reformer design will incorporate the energy efficiencies described in Section 4.1.1.3. 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.

⁵ Bonaquist, D., "Analysis of CO₂ Emissions, Reductions, and Capture for Large-Scale Hydrogen Production: A White Paper", October 2010

4.3.4.4 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 minimize GHG emissions.

4.3.4.5 Carbon Capture and Storage

To evaluate the cost effectiveness of CCS as combined system, a discussion of the capture, transport and storage of CO₂ in the reformer flue gases is presented.

As noted in Section 4.3.2.5 above, the method of CO₂ capture that is conceivable for the reformer flue gases are separation by absorption into an amine solvent. Amine solvent absorption has been proven in natural gas purification and ammonia production applications.

The cost figures for the amine treating system and compression system were included in the cost scenario evaluated by Ticona. The cost scenario is comprised of a new amine treating system and a new boiler for the amine treating system as well as compression for CO₂ transport to a nearby abandoned gas field, storage cavern, or equivalent, pipeline materials storage materials, operation and maintenance costs associated with these components, and other costs such as property taxes and insurance. The capital cost for the amine treating system and the compression system were based on engineering estimates. The costs are summarized in the discussion below.

The estimated capital cost of an amine treating system used to capture 90% of flue gas CO₂ is \$106,422,000 to provide a steam system (boiler, deaerator, condensate receiver, boiler feedwater pumps, condensate return pumps, etc.) producing 307,000 lb/hr of 90-psig saturated steam to regenerate the MEA in the system. The capital cost of the boiler is based on the cost of similar boilers used in other recent projects. The cost of natural gas for the boiler would be \$8,868,000/yr, assuming a natural gas price of \$2.77/MMBtu, an 80% boiler efficiency, and an operational period of 8,760 hr/yr. The MEA system would require 5,133 HP of electricity for pumps and air coolers. An additional 5,468 HP, would be required for CO₂ compression. Assuming \$27.70 per MW-hr, the electricity costs of capture and compression are a total \$2,110,000/yr. Labor costs associated with capture and compression are estimated at \$1,000,000/yr. Maintenance, property taxes, and insurance are based on 3.2% of the capital cost, and are approximately \$3,406,000/yr.

An assumed 200 miles of pipeline would be required to transport the captured CO₂ to an abandoned gas field, storage cavern, or equivalent (such as the Denbury pipeline). The costs associated with 8" pipeline transfer were estimated using the methodology established in guidance from the National Energy and Technology Laboratory's *Carbon Dioxide Transport and Storage Costs in NETL Studies* (DOE/NETL-2013/1614)⁶. The materials, labor, right of way, pipeline control system and miscellaneous costs total a capital cost of \$139,229,836, with an additional \$1,690,800/yr for operation and

⁶ http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/QGESS_CO2T-S_Rev2_20130408.pdf

maintenance.

Thus, the future annualized cost for a CCS System is itemized as follows:

Cost Item	Cost (\$/yr)
30-year amortized capital cost of capture including new boiler	\$ 6,922,905
Annual cost for operation, maintenance, taxation, and insurance of capture	\$ 15,383,235
30-year amortized capital cost of pipeline transfer	\$ 9,061,654
Annual cost of operation and maintenance of pipeline transfer	\$ 1,690,800
Total	\$ 33,058,594

90% of captured CO₂ from the reformer flue gas is estimated to be at 479,747 tpy. The new boiler required for an amine system would generate an additional 189,405 tpy CO₂; therefore, the CO₂ emissions avoided by capture would be a difference of approximately 290,342 tpy. The total capital and operating costs for a CCS system for the Methanol unit are annualized to be \$33,058,594/yr. CCS is determined to not be cost effective as the annualized costs equate to ~\$113.86 per ton CO₂ avoided and would increase current project capital costs by more than 25%.

4.3.5 Step 5 – Selection of BACT

Based on the top-down process described above for control of GHG emissions from the reformer, Ticona is proposing that BACT is the combined reforming process. In addition, Ticona plans to implement the use of natural gas as the primary fuel and the above described energy efficiency operations options. This is consistent with other control options found in the RBLC Clearinghouse (RBLC ID: LA-0263).

4.4 GHG BACT Evaluation for Flare

CO₂ and N₂O emissions from flaring process gas are produced from the combustion of process gas streams and the pilot fuel. GHG emissions from the flare are based on the estimated waste gas flow rates 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 CH₄ in the process gas at the flare results in the creation of additional CO₂ emissions via the combustion reaction mechanism. However, given the relative GWPs of CO₂ and CH₄ and the destruction of VOCs and HAPs, it is appropriate to apply combustion controls to CH₄ emissions even though it will form additional CO₂ emissions.

4.4.1 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; and
- Flare Gas Recovery (FGR).

4.4.1.1 Good Process Design

The combined reformer design selected by Ticona recycles loop converter process gas back to the front of the process rather than routing it as a continuous vent to a control device for destruction. This constitutes good process design in that it recycles unreacted components as a feed to the process rather than destroying them in a control device. The proposed flare for this project is intended to control only intermittent vent streams from maintenance, start-up and shutdown activities and malfunctions.

4.4.1.2 Best Operational Practices

Best Operational Practices for the flare include pilot flame monitoring, flow measurement, and monitoring/control of waste gas heating value to ensure flame stability in accordance with 40 CFR §60.18 when waste gas is directed to the flare. The heat value of the waste gas will be supplemented by the addition of natural gas to assure compliance with 40 CFR §60.18. Supplemental fuel will only be added when needed to assure proper operation and combustion in the flare, as required in 40 CFR §60.18. This is a best management practice employed to minimize the amount of uncombusted CH₄ from natural gas.

4.4.1.3 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. The flare will be designed to achieve 99% destruction efficiency for compounds with one to three carbons.

4.4.1.4 Flare Gas Recovery (FGR)

FGR is a technology that emerged from the drive to conserve flared gas streams at large integrated refineries. A FGR system utilizes water seal drums to prevent recoverable gas flow from going to the flare while allowing the flare to function in the event of an emergency. A compressor located on the downstream end of the main flare header is used to increase the pressure of a constant volumetric flow of flare gas, allowing it to reach a facility that can beneficially use the flare gas as fuel. For applications suited to flare gas recovery, the use of the flare is minimized and hence GHG emissions from the flare are also minimized.

4.4.2 Step 2 – Elimination of Technically Infeasible Control Options

All control technologies identified in Section 4.4.1 are considered technically feasible for this project, except the use of FGR. Use of FGR is not suited to the proposed project because the system would not receive a constant volumetric flow of recoverable gases. The vent streams that will be routed to the flare will result from intermittent MSS events.

Furthermore, the reformer would be the most likely recipient of the recovered gas, which is not a viable scenario since the reformer would be in start-up or shutdown mode when the gas is available. FGR is feasible at some refineries with existing fuel gas systems that distribute to a large number of combustion units that constantly need fuel, but is not feasible for the proposed project.

4.4.3 Step 3 – Rank of Remaining Control Technologies

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 CO₂ GHG BACT for the flare in order to minimize emissions from the flare.

4.4.4 Step 4 – Evaluation of Most Stringent Controls

No energy or environmental impacts (that would influence the GHG BACT selection process) would eliminate any of the remaining control options.

4.4.5 Step 5 – Selection of BACT

Ticona 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 CO₂ GHGs.

4.5 GHG BACT Evaluation for Fugitives Emissions

The following section proposes appropriate GHG BACT emission limitations for fugitive CO₂ and CH₄ emissions. The fugitive emission controls presented in this analysis will provide similar levels of emission reduction for both CO₂ and CH₄, therefore, the BACT evaluation for these two pollutants has been combined into a single analysis.

4.5.1 Step 1 – Identification of Potential GHG Control Techniques

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 leakless 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.

4.5.2 Step 2 – Elimination of Technically Infeasible Control Options

Leakless technology valves may be available and currently in use for smaller diameter components, primarily where highly toxic or otherwise hazardous materials are used. These technologies are generally considered cost prohibitive except for specialized service. Some leakless 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 CH₄ and CO₂ due to their global warming potential has not been quantified, and no reasonable cost effectiveness has been determined. Monitoring direct emissions of CO₂ is not feasible with the normally used instrumentation for fugitive emissions monitoring. Instrumented monitoring is technically feasible for components in CH₄ 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. Ticona's pipeline natural gas does not have Mercaptan added for leak detection. Thus, leaks from natural gas components cannot be detected by olfactory methods. Therefore AVO is not a technically feasible method of control.

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 Ticona's Bishop Facility will be constructed with compatible components and designed with gaskets and other materials of construction for the service for which they are intended.

4.5.3 Step 3 – Rank of Remaining Control Technologies

Leakless technologies are highly effective in eliminating fugitive emissions from the specific interface where installed, however leak interfaces remain even with leakless 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 CH₄, but may not be effective for finding leaks of CO₂. With CH₄ having a global warming potential greater than CO₂, 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 is generally assigned a control effectiveness of 97%. For uncontrolled SOCM service without ethylene, the leak rate for valves is 0.0089 lb/hr. Component reductions are therefore 0.0086 lb/hr with quarterly instrumented monitoring and a 500 ppmv leak definition. 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.

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

4.5.4 Step 4 – Evaluation of Most Stringent Controls

Leakless technologies have not been adopted as BACT, LAER, or even as Maximum Achievable Control Technology (MACT) Standards meant for hazardous compounds. Given methane's low toxicity relative the hazardous compounds regulated by MACT, 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 leakless 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.

Design to incorporate high quality components is effective in providing longer term emissions control because components with greater mechanical integrity are less apt to leak.

4.5.5 Step 5 – Selection of BACT

Ticona proposes to utilize Method 21 instrumented monitoring equivalent to VOC BACT as GHG BACT. Ticona proposes to monitor via instrumented Method 21 monitoring as required by a regulation or separate permitting action for components that are in greater than 10%-wt CH₄ service.

4.6 GHG BACT Evaluation for Stationary Engines

The following section proposes appropriate GHG BACT emission limitations for greenhouse gas emissions from combustion of diesel fuel in the emergency generator and firewater pumps. Because emission controls presented in this analysis will provide similar levels of emission reduction for CO₂, N₂O, and CH₄, the BACT evaluation for these three pollutants has been combined into a single analysis.

4.6.1 Step 1 – Identification of Potential GHG Control Techniques

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

- Vendor certified Tier 3 engine;
- Selection of a clean burn engine;
- Restrict hours of operation; and
- Use of low carbon fuels.

4.6.2 Step 2 – Elimination of Technically Infeasible Control Options

Many vendors certify emissions meeting Tier 3 design criteria for their combustion engines which are expected to be less than 560 kilowatts in accordance with 40 CFR Part 60, Subpart IIII. Therefore, 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.

Use of fuels containing lower concentrations of carbon generates less CO₂ than other higher carbon fuels. Typically, gaseous fuels such as natural gas or high-hydrogen plant tail gas contain less carbon, and thus lower CO₂e potential, than liquid or solid fuels such as diesel or coal. Ticona proposes to use diesel fuel for the engines as the purpose of the unit is to be available during emergency conditions and non-volatile fuel must be used and available at such times. For this reason the use of low carbon fuels for the emergency generator and firewater pumps is considered technically infeasible.

4.6.3 Step 3 – Rank of Remaining Control Technologies

All of the options identified in Section 4.6.1 except for low carbon fuel would be effective for GHG control.

4.6.4 Step 4 – Evaluation of Most Stringent Controls

As stated in Section 4.6.3, all of the options identified in Section 4.6.1 except for low carbon fuel would be effective for GHG control.

4.6.5 Step 5 – Selection of BACT

Ticona will utilize Tier 3, clean burn engines and restrict operating time to less than one hundred hours per year for non-emergency use consistent with applicable requirements in 40 CFR Part 60, Subpart IIII (NSPS IIII) and 40 CFR Part 63, Subpart ZZZZ (MACT ZZZZ).

4.7 GHG BACT Evaluation for Cooling Tower

The following section proposes appropriate GHG BACT emission limitations from potential leaks in the cooling water system.

4.7.1 Step 1 – Identify All Control Technologies

The following technologies were identified as potentially available for the cooling tower that will be part of the project:

- Air Cooling - Process of using an air cooling system (such as fin-fans) rather than evaporative cooling system to reduce process temperatures; and
- Water Cooling Tower (Evaporative Cooling) Monitoring and Repair – A program to detect and repair process leaks into the cooling water system.

4.7.2 Step 2 – Elimination of Technically Infeasible Control Options

Ticona has already implemented the utilization of air coolers where practical to increase the heat removal and energy efficiencies of the unit. Air coolers are restrained in the amount of cooling they are able to provide based on the cooling medium (i.e. ambient air). The temperatures needed for Methanol unit operation cannot be reached by using air coolers. Therefore, this technology is technically infeasible for this application. A water cooling tower monitoring and repair program is technically feasible.

4.7.3 Step 3 – Rank of Remaining Control Technologies

Implementation of a cooling tower leak monitoring and repair system is ranked at the top of the list as the only technically feasible control option available for the new cooling tower.

4.7.4 Step 4 – Evaluation of Most Stringent Controls

There are no known energy or environmental impacts that would influence the GHG BACT selection process that would eliminate the remaining control option.

4.7.5 Step 5 – Selection of BACT

Ticona is proposing to implement a cooling tower leak monitoring and repair program that utilizes the monitoring and repair requirements of 40 CFR Part 63, Subpart F (HON MACT) or using monitoring methods in TCEQ's Sampling Procedures Manual Appendix P. TOC will be substituted for HAP if utilizing the HON MACT to determine if a GHG leak is present.



◆	Ticona Methanol Project
★	Capture Project - DOE Support
■	Capture Project - No DOE Support
★	Storage Project - DOE Support
■	Storage Project - No DOE Support
★	Capture and Storage Project - DOE Support
■	Capture and Storage Project-No DOE Support

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FIGURE 4-1

CO₂ Pipeline & EOR Site Map

Ticona Methanol Project

Nueces County, TX

DATE: August 2014

PROJECT: 61-8-3

FILE NAME: Ticona EOR Map.pdf

SECTION 5

MONITORING AND COMPLIANCE DEMONSTRATION

Ticona proposes the following compliance demonstrations that will be utilized in the Methanol production unit to show compliance with GHG emission limits and BACT requirements. Table 5-1 summarizes the proposed compliance demonstrations.

5.1 Fugitives (MEOHFUG)

The CO_{2e} emissions estimated from equipment leaks in new and modified piping and equipment amount to 344 tpy, or less than 0.01% of the total CO_{2e} emissions from the project. Tracking emissions against a numeric limit is considered infeasible due to the insignificant quantity of emissions expected and the unpredictability of component leaks. Ticona proposes following the monitoring, recordkeeping, and repair practices of Texas's 28VHP fugitive monitoring program to ensure the minimization of GHG emissions from LDAR components for components containing greater than 10%-wt CH₄. The 28VHP monitoring program meets and/or exceeds BACT requirements for equipment fugitive components.

5.2 MSS Flare (MEOHFLR)

Ticona proposes an operating practice of maintaining the minimum heating value required by 40 CFR §60.18 when waste gas is directed to the non-assisted flare. This operating practice will ensure the flare achieves at least a 99% DRE for methane in the waste gas resulting from MSS activities. Valve position indicators or equivalent will be tracked in the distributed control system (DCS) or through operator's log or equivalent. These indications will be used to record time periods when waste gas is directed to the flare. During those periods the waste gas flow will be continuously monitored at the flare header and recorded in a data historian. The composition of the waste gas will be determined on an hourly basis by a composition analyzer or equivalent at the flare header. The composition analyzer will be calibrated such that it will identify at least 95% of the compounds in the waste gas. Metered supplemental fuel will also be continuously monitored to maintain the minimum heating value necessary for flame stability. The presence of a flame will be continuously monitored by thermocouple or IR camera. Note that a nitrogen sweep gas may be directed to the flare during periods when waste gas is not, and that the minimum heating value demonstration is not applicable during those periods.

The flow meter and analyzers used for flare compliance will be operational at least 95% of the time when the flare is operational, averaged over a calendar year. The flow meter will be calibrated per manufacturer's recommendation to ensure reliability of measurement. The composition analyzer will have a single point calibration check monthly.

Data from the flow and the composition of the waste gas will be used to calculate monthly GHG emissions from the flare consistent with the methodology found in this application.

5.3 Reformer (REFORM)

The reformer furnace represents the majority of GHG emissions from the Methanol unit and will be equipped with monitoring and instrumentation sufficient to demonstrate the following:

- The Reformer minimizes CO₂e emissions by meeting the output-based limit of 30 MMBtu/ton (33 MMBtu/tonne) methanol produced on a 12-month rolling average basis;
- The furnace meets an annual CO₂e limit of 533,629 tpy; and
- The furnace runs efficiently based on stack O₂ concentration and stack temperature.

The combined reforming design of the new Methanol unit minimizes CO₂e emissions by achieving a low heat input (including raw material) per ton of product produced. Ticona proposes a heat input per product output (MMBtu HHV/ton methanol) limit to ensure that this is achieved. Natural gas fed as fuel and/or raw material to the reformer and composition in combination with HHV for the fuel gas components, will be used to calculate the hourly heat input associated with methanol reformer going to the furnace on a 12 month basis. The natural gas flow to the reformer will be continuously monitored and recorded in a data historian. Per 40 CFR § 98.34(b)(1)(ii), the GHG Mandatory Reporting Rule, the fuel flow meter will be calibrated annually, at the minimum frequency established per manufacturer's recommendation, or at the interval specified by industry standard practice. A composition analyzer at the inlet will be used to determine the composition of the process fuel on at least a monthly basis as required by 40 CFR § 98.34(b)(3). If the composition analyzer is not online, weekly sampling and analysis will be used per 40 CFR § 98.34(b)(3). The natural gas composition will be determined sampling and analysis in accordance with 40 CFR § 98.34(b)(3) or per the natural gas vendor. The concentration of the fuel gas components will be used to determine CO₂e emissions on a 12-month rolling basis.

Heat input, composition, and flow will be used to calculate GHG emissions from the reformer consistent with the methodology found in this application on calendar month basis. Compliance with the annual permitted emission limits will be evaluated against the rolling 12-month actual emission rate.

When the reformer is firing at or above 75% of design heat input, measurement of O₂ and temperature downstream of furnace heat recovery will be used to show that BACT is applied continuously during normal operation. O₂ will be measured by an O₂ CEMS in the stack and will be evaluated against a limit of 3%. Reliability of the measurement will be ensured by a weekly zero and span and a semi-annual cylinder gas audit. Temperature will be monitored in the stack and the 12-month rolling average will be evaluated against a limit of 350° F. The flow meters, analyzers, O₂, temperature monitoring, and recording equipment used for reformer compliance will be operated at least 95% of the time when the reformer is operational, averaged over a calendar year.

5.4 Emergency Engines (MEOHGEN, ICEFW01, ICEFW02)

A diesel-fueled emergency generator with a rating no greater than 350 KW will be installed to supply power to critical sources during an emergency. Two firewater pumps rated no greater than 530 KW each will be installed for fire protection of the new unit. Estimated CO₂e emissions from these engines are insignificant compared to that of the project, and compliance with a CO₂e limit is considered infeasible. The non-emergency hours that the engines will operate will be

Table 5-1 Proposed Compliance Demonstration By Source

GHG Emission Unit	EPN	Emission Limit or Standard	Monitoring/Testing	Recordkeeping
Fugitives	MEOHFUG	None - Limit infeasible because emissions < 0.01% of total	28 VHP Fugitive emission monitoring program for streams containing > 10% wt CH ₄ .	Data will be maintained in accordance with the 28VHP program.
MSS Flare	MEOHFLR	1,524 tpy CO ₂ e, 12 month rolling	Composition analyzer and flow meter will be installed at flare header system and take continuous measurements. The analyzer and flow meter will have at least 95% online reliability when the flare is receiving waste gas and the analyzer is not being calibrated, averaged over a calendar year.	Block one-hour flow and composition records will be maintained.
		Presence of pilot flame through thermocouple or infrared monitor.		
		Heating value required by §60.18 when waste gas is directed to the flare	The analyzer will be single point calibrated monthly. The flow meter will be calibrated per manufacturer's recommendation.	
Reformer	REFORM	533,629 tpy CO ₂ e, 12 month rolling 30 MMBtu (HHV)/ton methanol	Composition analyzer and flow meter will be installed to analyze the streams going to the reformer. Process gas will be analyzed in accordance with 40 CFR 98.34(b)(3)(ii)(E) when a composition analyzer is online per the GHG mandatory reporting rule. Natural gas composition will be determined by semiannual sampling and analysis or obtained quarterly from vendor's analysis per 40 CFR 98.34(b)(3). The flow meter will continuously measure the fuel flow to the reformer. The monitoring equipment will have at least 95% online reliability when the reformer is in operation and not being calibrated, averaged over a calendar year. The analyzer will be zero and spanned as needed and per the manufacturer's recommendation. The flow meter will be calibrated per manufacturer's recommendation.	Block one-hour flow records and all daily/weekly/semi-annual concentration data will be maintained. CO ₂ e emission will be calculated on a 12-month rolling average.

GHG Emission Unit	EPN	Emission Limit or Standard	Monitoring/Testing	Recordkeeping
Reformer	REFORM	3% O ₂ in stack gas during normal operation ($\geq 75\%$ load)	A O ₂ CEMS will be installed on the reformer and record O ₂ concentration daily. Zero and span calibrations will be performed weekly. In addition, semi-annual cylinder gas audits will be performed.	Daily O ₂ measurements will be recorded.
		350° F in stack gas during normal operation ($\geq 75\%$ load)	Temperature monitoring equipment (thermocouple or equivalent) will be installed to measure temperature of stack gas daily.	Daily Temperature readings will be recorded.
Emergency Engines	MEOHGEN ICEFW01 ICEFW02	CO ₂ e limit infeasible because emissions < 0.01% of total CO ₂ e.	A non-resettable runtime meter will be installed on each engine.	Monthly engine runtimes meter reading.
		100 hr/calendar yr non-emergency use.		
Cooling Tower	MEOHCT	None - Limit infeasible because emissions < 0.1 % of total	The cooling tower will be monitored for GHG leaks utilizing 40 CFR Part 63, Subpart F monitoring requirements for heat exchange systems or TCEQ Appendix P.	Quarterly monitoring results will be recorded.

SECTION 6

OTHER ADMINISTRATIVE REQUIREMENTS

The following administrative information related to this permit application is provided in the following Table:

Table 6-1 Other Administrative Information

- Company name:
Ticona Polymers, Inc.
- Company official and associated contact information:
Brian E. Connelly
Brian.Connelly@celanese.com
- Technical contact and associated contact information:
William Chidester
361-584-6614
William.Chidester@celanese.com
- Project location, Standard Industrial Code (SIC), and North American Industry Classification System (NAICS) code:
5738 County Road 4, Bishop, TX 78343
SIC: 2869; NAICS: 325199
- Projected start of construction and start of operation dates; and
Start of Construction: January 2016
Start of Operation: March 2017

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;
- Carbon Content Calculations;
- Fugitive Emissions Calculations;
- Emergency Generator & Firewater Pump Emissions Calculations;
- Methanol unit Flare Calculations;
- MSS Emissions Calculations;
- Cooling Tower Calculations;
- Pipeline Hydrogen Cost Calculations;
- Catalyst Activation Calculations; and
- Carbon Transfer and Storage Cost Calculations.

GHG Emissions Summary

EPN	Description	CO ₂ (tpy)	CH ₄ (tpy)	N ₂ O (tpy)	CO ₂ e (tpy)
REFORM	Reformer	533,052	11	1.05	533,629
MEOHFLR	Flare	42,147	15	0.42	42,650
MEOHMSS	MSS		0.96		24
MEOHFUG	Fugitive	12	13		344
MEOHENG, ICEFW01, ICEFW02	Engines	386	0.02	0.00	388
MEOHCT	Cooling Tower		16.80		420
Total		575,597	57	1	577,456

Emissions less than 0.005 are represented as 0.00.

Reformer Furnace
EPN: REFORM

Fuel component	GHG	Formula	Eq.	Applicability	Fuel flow ¹ (scf/yr)	HHV ² (MMBtu/scf)	CC ³	MW ³	Emissions (ton/yr)	Emissions (tonne/yr)	GHG factor ⁴	CO _{2e} (tonne/yr)	CO _{2e} (ton/yr)
Process Gas	CO ₂	$44/12 \cdot \text{Fuel flow} \cdot \text{CC} \cdot \text{MW}_{\text{fuel}}/835.6 \text{ scf/kg-mol} \cdot 0.001$	C-5	98.33(b)(3)(ii)	10,337,500,800	0.0003422	0.30	12.13	180,912.07	164,120.72	1	164,121	180,912
	CH ₄	$0.001 \cdot \text{Fuel flow} \cdot \text{HHV} \cdot 0.001$	C-8	98.33(c)(1)					3.90	3.54	25	88	97
	N ₂ O	$0.001 \cdot \text{Fuel flow} \cdot \text{HHV} \cdot 0.0001$	C-8	98.33(c)(1)					0.39	0.35	298	105	116
	CO ₂	$0.001 \cdot \text{scf fuel/yr} \cdot \text{MMBtu/scf} \cdot 53.05$	C-2a	98.33(b)(2)(ii), 98.33(b)(3)(iii)(A)					352,139.96	319,456.09	1	319,456	352,140
Natural Gas	CH ₄	$0.001 \cdot \text{Fuel flow} \cdot \text{HHV} \cdot 0.001$	C-8	98.33(c)(1)	5,850,979,200	0.001029	-	-	6.64	6.02	25	151	166
	N ₂ O	$0.001 \cdot \text{Fuel flow} \cdot \text{HHV} \cdot 0.0001$	C-8	98.33(c)(1)					0.66	0.60	298	179	198
	Total											484,101	533,629

Example calculation (purge gas CO₂):
 $44/12 \cdot 10337500800 \text{ scf/yr} \cdot 0.3 \text{ kg C/kg fuel} \cdot 12.13/835.6 \text{ scf/kg-mol} \cdot 0.001 = 164,121 \text{ tonne/yr}$

Notes:

1. Fuel flow to reformer from vendor estimate.
2. Heating value of process gas and natural gas from vendor estimate
3. See Carbon Content calculation.
4. January 2014 version of Table A-1 to subpart A of part 98.

Carbon Content (CC) Calculation

Process Gas^{1,2}

Basis:

$$CC = 12 * \sum(Ni * Xi) / \sum(Xi * Mi)$$

where

CC = Carbon content of process fuel (lb carbon/lb fuel)

Ni = Number of carbons per molecule

Xi = mole fraction of component

Mi = MW of component

Component	Purge gas composition ²	# carbons	MW lb/lbmol	Purge gas	
	mol-frac			Ni * Xi	Xi * Mi
Hydrogen	0.6669	0	2.02	0.0000	1.3443
Carbon Monoxide	0.0390	1	28.01	0.0390	1.0916
Methanol	0.0160	1	32.04	0.0160	0.5111
Methane	0.0929	1	16.04	0.0929	1.4903
Ethane	0.0000	2	30.07	0.0000	0.0000
Propane	0.0000	3	44.10	0.0000	0.0000
Butane	0.0000	4	58.12	0.0000	0.0000
Isopentane	0.0000	5	72.15	0.0000	0.0000
Pentane	0.0000	5	72.15	0.0000	0.0000
Hexane	0.0000	6	86.18	0.0000	0.0000
Carbon dioxide	0.1448	1	44.01	0.1448	6.3716
Water	0.0046	0	18.02	0.0000	0.0833
Methyl Formate	0.0031	2	60.05	0.0062	0.1851
Acetone	0.0000	3	58.08	0.0000	0.0008
Dimethyl Ether	0.0015	2	46.07	0.0031	0.0703
Argon	0.0085	0	39.95	0.0000	0.3387
Nitrogen	0.0228	0	28.01	0.0000	0.6387
Σ =				0.3019	12.1257
Fuel Gas MW =					12.1257
Fuel Gas Carbon Content =					0.2987

Notes:

1. As required by the GHG Monitoring and Reporting Rule, carbon content will be used to calculate GHG emissions for the process gas because the process gas is not a fuel listed in 40 CFR Part 98, Subpart C, Table C-1.

2. The values used in and determined by this calculation are estimations only, not limits upon which compliance shall be based.

Methanol Equipment Fugitive En
EPN: MEOHFUG

Stream Name	LDAR Program	Concentration - Wt%		Emissions			
			Carbon Monoxide	Total Fugitives		Methane	Carbon Dioxide
Factors			0				
Factors	28VHP		0%				
Factors	28VHP/ACM		0%				
Factors	AVO		0%				
Factors	Not Monitored		0%	lb/hr	tpy	lb/hr	lb/hr
Total	28VHP	%	3.94%	6.12	26.81	2.99	1.41
Total	28VHP/ACM	%	0.36%	1.14	4.97	0.01	0.17
Total	AVO	%	0.00%	0.08	0.35	0.00	0.00
Total	Not Monitored	%	39.79%	3.81	16.69	0.03	1.11
				11.15	48.83	3.04	2.70

HON connectors are monitored annually (ACM)
 Zero emission components (double seal with
 Emissions less than 0.005 are represented as
 Trace quantities of miscellaneous air contaminants
 Per 30 TAC §101.1(108), relating to definitions of
 hydrogen, water, nitrogen, oxygen, and n
 This representation does not cover all operational
 ACM = Annual Connector Monitoring

Methanol Emergency Engines
EPN: MEOHENG, ICEFW01, ICEFW02
Emissions Summary

Parameter	FW Pump	Em Gen	Unit	Note
Fuel, Emer Gen	156.88	29.6	gph	
Operating Hours	100		hr/yr	RICE MACT maximum non-emergency hours

GHG

CH ₄	0.003	kg / MMBtu	Table C-2. Petroleum (Residual Fuel Oil No. 2)
N ₂ O	0.0006	kg / MMBtu	Table C-2. Petroleum (Residual Fuel Oil No. 2)
CO ₂	73.96	kg / MMBtu	Table C-1. Residual Fuel Oil No. 2
HHV	0.138	MMBtu/gal	Table C-1. Residual Fuel Oil No. 2
Annual Heat Input	4738	MMBtu/yr	Maximum engine rating, emergency engine

Combined	tpy	GWP	CO ₂ (e) tpy
CH ₄	0.02	25	0.39
N ₂ O	0.00	298	0.93
CO ₂	386.20	1	386.20
Total CO₂(e)			388

Notes:

Emissions less than 0.005 are represented as 0.00.

This representation does not cover all operating scenarios, however represented scenarios cover worst case emissions.

Flare
EPN: MEOHFLR

Fuel component	GHG	Formula	Eq.	Flare flow (scf/yr)	CC ¹	MW	Emissions (tonne/yr)	Emissions (ton/yr)	GHG factor ²	CO ₂ e (tonne/yr)	CO ₂ e (ton/yr)
Flare Gas	CO ₂	$0.98 * 0.001 * 44/12 * \text{Flare flow} * \text{MW}_{\text{fuel gas}}/836.6 \text{ scf/kg-mol} * \text{CC}$	Y-1a	2,354,092,381	0.33	11.60	38,235.21	42,147.09	1	38,235	42,147
	CH ₄	$(\text{CO}_2 * 0.003/60) + (\text{CO}_2 * 0.02/0.98 * 16/44 * f_{\text{CH}_4})$	Y-4				13.71	15.11	25	343	378
	N ₂ O	$\text{CO}_2 * 0.0006/60$	Y-5				0.38	0.42	298	114	126
Total										38,692	42,650

Example calculation (CO₂):

$$0.98 * 0.001 * 44/12 * 2,354,092,381 \text{ MW}_{\text{fuel}} \text{ gas} / 836.6 \text{ scf/kg-mol} * \text{CC} = 38,235.21 \text{ tonne/yr}$$

Notes:

1. See Carbon Content calculation.
2. January 2014 version of Table A-1 to subpart A of part 98

Carbon Content (CC) Calculation

Flare Gas¹

Basis:

$$CC = 12 * \sum(Ni * Xi) / \sum(Xi * Mi)$$

where

CC = Carbon content of flare gas (lb carbon/lb fuel)

Ni = Number of carbons per molecule

Xi = mole fraction of component

Mi = MW of component

Component	Flare gas composition ²	# carbons	MW lb/lbmol	Flare gas	
	mol-frac			Ni * Xi	Xi * Mi
Methane	0.0301	1	16.04	0.0301	0.4823
Hydrogen	0.6672	0	2.02	0.0000	1.3449
Carbon Monoxide	0.2009	1	28.01	0.2009	5.6285
Methanol	0.0011	1	32.04	0.0011	0.0340
Ethane	0.0005	2	30.07	0.0010	0.0154
Propane	0.0001	3	44.10	0.0003	0.0038
Butane	0.0000	4	58.12	0.0001	0.0021
Isopentane	0.0000	5	72.15	0.0000	0.0004
Pentane	0.0000	5	72.15	0.0000	0.0004
Hexane	0.0000	6	86.18	0.0001	0.0009
Carbon dioxide	0.0809	1	44.01	0.0809	3.5593
Water	0.0033	0	18.02	0.0000	0.0591
methyl formate	0.0002	2	60.05	0.0004	0.0125
acetone	0.0000	3	58.08	0.0000	0.0001
dimethyl ether	0.0001	2	46.07	0.0002	0.0047
Argon	0.0012	0	39.95	0.0000	0.0486
Nitrogen	0.0144	0	28.01	0.0000	0.4038
Σ =				0.3151	11.6008
Fuel Gas MW =					11.6008
Fuel Gas Carbon Content =					0.3260

Notes:

1. The values used in and determined by this calculation are estimations only, not limits upon which compliance shall be based.

MSS Emissions
EPN: MEOHMSS

Emissions Basis

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

Annual volume cleared	15000 ft ³
Pressure	44.7 psia
Temperature	60 F
Gas Constant	10.73 ft ³ * psia / (R * lbmol)
Methane MW	16.04 lb/lbmol
Methane Annual emissions	0.96 tpy
Total CO ₂ (e)	24.09 tpy

Notes:

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

Example calculation:

$$15,000 \text{ ft}^3 * 44.7 \text{ psia} / 10.73 \text{ ft}^3 * \text{psia} / (\text{R} * \text{lbmol}) / (60 + 460 \text{ R}) * 16.04 \text{ lb/lbmol} * 1 \text{ ton}/2000 \text{ lb} * 25 = 24.09 \text{ tpy CO}_2\text{e}$$

Carbon Content (CC) Calculation

Flare Gas¹

Basis:

$$CC = 12 * \sum(Ni * Xi) / \sum(Xi * Mi)$$

where

CC = Carbon content of flare gas (lb carbon/lb fuel)

Ni = Number of carbons per molecule

Xi = mole fraction of component

Mi = MW of component

Component	Flare gas composition ²	# carbons	MW lb/lbmol	Flare gas	
	mol-frac			Ni * Xi	Xi * Mi
Methane	0.0301	1	16.04	0.0301	0.4823
Hydrogen	0.6672	0	2.02	0.0000	1.3449
Carbon Monoxide	0.2009	1	28.01	0.2009	5.6285
Methanol	0.0011	1	32.04	0.0011	0.0340
Ethane	0.0005	2	30.07	0.0010	0.0154
Propane	0.0001	3	44.10	0.0003	0.0038
Butane	0.0000	4	58.12	0.0001	0.0021
Isopentane	0.0000	5	72.15	0.0000	0.0004
Pentane	0.0000	5	72.15	0.0000	0.0004
Hexane	0.0000	6	86.18	0.0001	0.0009
Carbon dioxide	0.0809	1	44.01	0.0809	3.5593
Water	0.0033	0	18.02	0.0000	0.0591
methyl formate	0.0002	2	60.05	0.0004	0.0125
acetone	0.0000	3	58.08	0.0000	0.0001
dimethyl ether	0.0001	2	46.07	0.0002	0.0047
Argon	0.0012	0	39.95	0.0000	0.0486
Nitrogen	0.0144	0	28.01	0.0000	0.4038
Σ =				0.3151	11.6008
Fuel Gas MW =					11.6008
Fuel Gas Carbon Content =					0.3260

Notes:

1. The values used in and determined by this calculation are estimations only, not limits upon which compliance shall be based.

Catalyst Activation Calculations

Basis: Lean gas, SOR (Case C2)

Assumptions:

hrs req'd for converter catalyst reduction	96
% (minimum) turndown for Primary and Secondary reformers	40
% (combustion) efficiency (est'd at 40% rates because of high fixed radiative and convective heat losses)	80
% of total heat absorbed in Primary reformer is for steam-methane reforming reactions	50
Req'd Steam-to-carbon ratio	1.80

Case 1: Use NG as fuel for Primary reformer, flare ALL reformed gas downstream of Primary reformer (maximum CO2 emissions case)

Catalyst reduction performed by recovered gases from primary and secondary reformer

Natural gas feedstock, Mscfh	1637.5
MMBtu/hr for steam-methane reforming reaction	175.452
MMBtu/hr total req'd heat input	438.630
Btu/scf (HHV of reformed gas)	301
Mscfh Reformed gas	5686.6
Mscfh Reformed gas to Primary reformer burners	0.0
MMBtu/hr available from Reformed gas	0.000
MMBtu/hr heat req'd from Nat gas	438.630
Btu/scf (HHV of Nat gas)	1,029
Natural gas fuel, Mscfh	426.2
Natural gas demand, Mscfh	2063.7

C factor (moles of carbon/mole of Nat gas)	1.044
lb CO2/Mscf Nat gas	121.1

Mlb/hr steam required for steam-methane reforming reactions	146.055
Mlb/hr steam req'd to operate Primary reformer (ID fan, FD fan and BFW pumps)	45.259
Mlb/hr steam req'd to operate Recirc compressor (est'd at 20% of normal)	14.700
Mlb/hr steam req'd to operate MeOH Unit	206.014
Mlb/hr steam produced by heat recovery from reformed gas	258.1432
Steam required from Utility boilers, ¹ Mlb/hr	0.000
Gas Steam Conversion Factor, MMBtu/Mlb	1.404
Natural gas for steam demand, Mscfh	0.000
Converter catalyst reduction duration, hrs	96
lb CO2/Mscf Nat gas ²	72.7
CO2 emissions generated, tpy	11,991

Catalyst reduction performed by pipeline hydrogen

Natural gas feedstock, Mscfh	0.000
Natural gas fuel, Mscfh	0.000
Natural gas demand, Mscfh	0.000
Steam required from Utility boilers, ³ Mlb/hr	14.700
Gas Steam Conversion Factor, MMBtu/Mlb	1.404
Converter catalyst reduction duration, hrs	96
MMBtu/hr heat input req'd	20.6
Btu/scf (HHV of Nat gas)	1,029
Natural gas for steam demand, Mscfh	20.1
lb CO2/Mscf Nat gas ²	121.1
CO2 emissions generated, tpy	117

Difference in catalyst reduction methods

CO2 emissions, tpy	11,875
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Notes:

1. Steam provided by heat recovery during reformer operation.
2. Engineering estimate.
3. Steam needed for ancillary equipment such as compressors.

Estimated Cost for Carbon Transfer and Storage

CO₂ Transfer and Storage Data

Pipeline Length to Denbury	200 miles
Pipeline Diameter	8 inches

Equations below from: The National Energy Technology Laboratory guidance, "Carbon Dioxide Transport and Storage Costs in NETL Studies," DOE/NETL - 2013/1614, March 2013

Cost Type	Units	Cost	
Pipeline Costs			
Pipeline Materials	\$ Diameter (inches), Length (miles)	$\$70,350 + \$2.01 \times L \times (330.5 \times D^2 + 686.7 \times D + 26,920)$	\$ 21,603,721
Pipeline Labor	\$ Diameter (inches), Length (miles)	$\$371,850 + \$2.01 \times L \times (343.2 \times D^2 + 2,074 \times D + 170,013)$	\$ 84,216,910
Pipeline Miscellaneous	\$ Diameter (inches), Length (miles)	$\$147,250 + \$1.55 \times L \times (8,417 \times D + 7,234)$	\$ 23,263,950
Pipeline Right of Way	\$ Diameter (inches), Length (miles)	$\$51,200 + \$1.28 \times L \times (577 \times D + 29,788)$	\$ 8,858,624
Other Pipeline Capital			
CO ₂ Surge Tank	\$	1,244,724	\$ 1,244,724.00
Pipeline Control System	\$	111,907	\$ 111,907
Total Pipeline Capital			\$ 139,299,836
O&M Pipeline			
Fixed O&M	\$/mile/year	$\$8454 \times L$	\$ 1,690,800
Total O&M Pipeline			\$ 1,690,800

Summary of Cooling Tower Emissions

EPN: MEOHCT

Reference	
VOC: AP-42, Section 5.1, Table 5.1-2, Cooling Towers, 1/95.	
Annual Hours of Operation	8,760
Throughput (gal/min) of all water	91,300
Hourly Operating Throughput (1000 gal./hr)	5478
Annual Operating Throughput (1000 gal./yr)	47,987,280
VOC Emission Factor (lb/MMgal)	0.7
TOTAL CH₄ TPY	16.80
TOTAL CO₂e TPY	420

Notes:

1. All carbon content assumed to be CH₄ as worst case operating scenario.
2. Throughput based on maximum pumping rate.
3. EPA AP-42, Section 5.1, Table 5.1-2, Cooling Towers "controlled emissions" for monitored leaks.
4. This representation does not cover all operating scenarios
5. Conversion to CO₂e uses factors in January 2014 version of Table A-1 to subpart A of part 98

Example Calculation:

$0.7 \text{ lb VOC/MMgal} \times \text{lb CH}_4/\text{lb VOC} \times 47,987,280 \text{ Mgal/yr} / 1000/2000 \text{ lb/ton} = 16.8 \text{ tpy CH}_4$
 $16.8 \text{ tpy CH}_4 \times 25 = 420 \text{ tpy CO}_2\text{e}$

Cost to Replace Natural Gas Fuel with Hydrogen

Case C1, Lean gas, EOR (End of Run)

Natural gas to fuel	667.9 Mscfh
Cost of Natural gas, \$	2.77 /MMBtu
Cost of Natural gas, ¹ \$	16,661,873 /yr
Hydrogen required to maintain total HHV heat input	
Hydrogen required ²	2121.0 Mscfh
Cost of Hydrogen, ³ \$	6.28 /MMBtu
Cost of Hydrogen, ³ \$	38,124,962 /yr
ΔCost of Hydrogen, \$	21,463,089 /yr
ΔCost of Hydrogen (30 yr), \$	643,892,670

Notes:

1. $(667.92 \text{ Mscfh} * 1,028 \text{ Btu/scf} / 1000) * \$/\text{MMBtu} * 24\text{hr/day} * 365 \text{ day/yr} = 16661873 \$/\text{yr}$
2. Assumed 324 Btu/scf HHV for hydrogen
3. Engineering estimate