ROHM AND HAAS TEXAS INCORPORATED

1900 TIDAL ROAD
DEER PARK, TEXAS 77536
(281) 228-8100

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AIR PERMITS SECTION
6PD-R

October 22, 2012

CERTIFIED MAIL RETURN RECEIPT REQUESTED

Mr. Jeff Robinson
Chief, Air Permits Section
U.S. EPA Region 6, 6PD
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

ROHM AND HAAS TEXAS, INCORPORARTED – DEER PARK, RN: 100223205
PSD – GREENHOUSE GAS PERMIT APPLICATION
PROPOSED BOILER HOUSE UNIT EXPANSION

Introduction

Rohm and Haas Texas, Incorporated (Rohm and Haas), a Wholly Owned Subsidiary of the Dow Chemical Company, is proposing to install two new gas-fired steam boilers at their chemical manufacturing facility in Deer Park, Texas (Harris County).

Rohm and Haas is hereby submitting the attached application for a Prevention of Significant Deterioration (PSD) air quality permit for greenhouse gas emissions resulting from this proposed project. The application is submitted to EPA under authority EPA has asserted through its Federal Implementation Plan (FIP) for the regulation of greenhouse gases.

The attached application includes a copy of the Texas Commission on Environmental Quality (TCEQ) Form PI-1 - General Application for Air Preconstruction Permit and Amendments, submitted to the TCEQ in September 2012, to authorize the state/PSD air permit for non-greenhouse gas emissions for the project, along with a full copy of the permit amendment application that was submitted to the TCEQ.

Confidential Information

Rohm and Haas is not including any confidential information in this permit application.

Future Contact

For future correspondence, please contact:

Monique Bass	(281) 228-8079 or
FAX	(281) 228-3540 or
e-mail	MNBass@dow.com

Sincerely,

Tim May

Tim May
Responsible Care® Leader

Certified Mail
7009 2820 0003 7512 04028 EPA Region 6

ROHM AND HAAS

ROHM AND HAAS TEXAS INCORPORATED
A WHOLLY OWNED SUBSIDIARY OF THE DOW CHEMICAL COMPANY

GREENHOUSE GAS
PREVENTION OF SIGNIFICANT DETERIORATION
PERMIT APPLICATION

FOR

BOILER HOUSE UNIT

October 22, 2012

TABLE OF CONTENTS

1.0 INTRODUCTION

Rohm and Haas Texas Incorporated (Rohm and Haas), a Wholly Owned Subsidiary of the Dow Chemical Company, owns a chemical manufacturing facility in Deer Park, Texas (Harris County). Rohm and Haas proposes to install two new gas-fired steam boilers through this permit action. The start of construction is planned for September 2013 and the proposed start of operation is September 2014. The proposed Boiler House expansion project represents a major modification to an existing major source with respect to Nonattainment New Source Review (NNSR) for the ozone precursors nitrogen oxide (NOx) and volatile organic compounds (VOC), as well as Prevention of Significant Deterioration (PSD) review for NOx and particulate matter (PM_{10} and $PM_{2.5}$). Rohm and Haas has submitted a new source review permit application to the Texas Commission on Environmental Quality (TCEQ) to authorize the construction of the new boilers at the Boiler House Unit and its associated emissions.

On June 3, 2010, the EPA published final rules for permitting sources of Greenhouse Gases (GHGs) under the prevention of significant deterioration (PSD) and Title V air permitting programs, known as the GHG Tailoring Rule. After July 1, 2011, new sources emitting more than 100,000 tons per year (tpy) of carbon dioxide equivalents (CO_2e) and modifications increasing GHG emissions more than 75,000 tpy on a CO_2e basis at existing major sources are subject to GHG PSD review, regardless of whether PSD was triggered for other pollutants.

On December 9, 2010, EPA signed a Federal Implementation Plan (FIP) authorizing EPA to issue PSD permits in Texas for GHG sources until Texas submits the required State Implementation Plan (SIP) revision for GHG permitting and it is approved by EPA.

GHG PSD review is triggered for the Boiler House expansion project because the project will increase GHG emissions by more than 75,000 tpy on a CO_2e basis. Pursuant to the EPA Tailoring Rule, Rohm and Haas is also submitting this PSD application for the expansion project to EPA to authorize the project's GHG emissions.

This application includes a project scope description, area map and plot plan, GHG emissions calculations, and GHG Best Available Control Technology (BACT) analysis. Since there are no significant decreases in GHG emissions at the Rohm and Haas facility in the contemporaneous period that could potentially result in the project's netting out of GHG PSD review, a detailed GHG contemporaneous netting is not included in this application.

2.0 ADMINISTRATIVE INFORMATION FORM

This section contains the following forms:

- Administrative Information
- GHG PSD Applicability Summary

Since this application covers only GHG emissions, and PSD permitting of other pollutants is being reviewed by TCEQ, this PSD applicability form only includes GHG emissions. As shown in this form, GHG emissions from the project exceed 75,000 tpy of CO_2e, and there are no significant creditable decreases of CO_2e emissions in the contemporaneous period that would change the PSD applicability determination. Therefore, PSD review is required for the project GHG emissions in accordance with the EPA Tailoring Rule.

Administrative Information
Greenhouse Gas Prevention of Significant Deterioration
Preconstruction Permit Application

I. Applicant Information		
A. Company or Other Legal Name: **Rohm And Haas Texas Incorporated – Deer Park, RN:100223205**		
Texas Secretary of State Charter/Registration Number (*if applicable*):		
B. Company Official Contact Name: **Mr. Harry Engelhardt, Jr.**		
Title: **Site Leader**		
Mailing Address: **1900 Tidal Road**		
City: **Deer Park**	State: **Texas**	ZIP Code: **77536-2416**
Telephone No.: **(281) 228- 8204**	Fax No.: **(281) 228-3162**	E-mail Address: **HLEngelhardtjr@dow.com**
C. Technical Contact Name: **Monique Bass**		
Title: **Environmental Air Permit Writer**		
Company Name: **Rohm And Haas Texas Incorporated – Deer Park, RN:100223205**		
Mailing Address: **1900 Tidal Road**		
City: **Deer Park**	State: **Texas**	ZIP Code: **77536-2416**
Telephone No.: **(281) 228- 8079**	Fax No.: **(281) 228-3540**	E-mail Address: **MNBass@dow.com**
D. Site Name: **Rohm And Haas Texas, Incorporated – Deer Park**		
E. Area Name/Type of Facility: **Boiler House Unit**		☒ Permanent ☐ Portable
F. Principal Company Product or Business: **Chemical Manufacturing Plant**		
Principal Standard Industrial Classification Code (SIC): **2869**		
Principal North American Industry Classification System (NAICS): **32511**		
G. Projected Start of Construction Date: **September 1, 2013**		
Projected Start of Operation Date: **September 1, 2014**		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: **1900 Tidal Road**		
City/Town: **Deer Park**	County: **Harris**	ZIP Code: **77536-2416**
Latitude (nearest second): **29°43'40" N**	Longitude (nearest second): **95°5'59" W**	
II. Signature		
The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that I understand my signature indicates that this application meets all applicable prevention of significant deterioration permitting requirements.		
Name: Tim May, Responsible Care® Leader		
Signature: Tim May *Original Signature Required*		
Date: 10/22/2012		

GHG PSD Applicability Summary

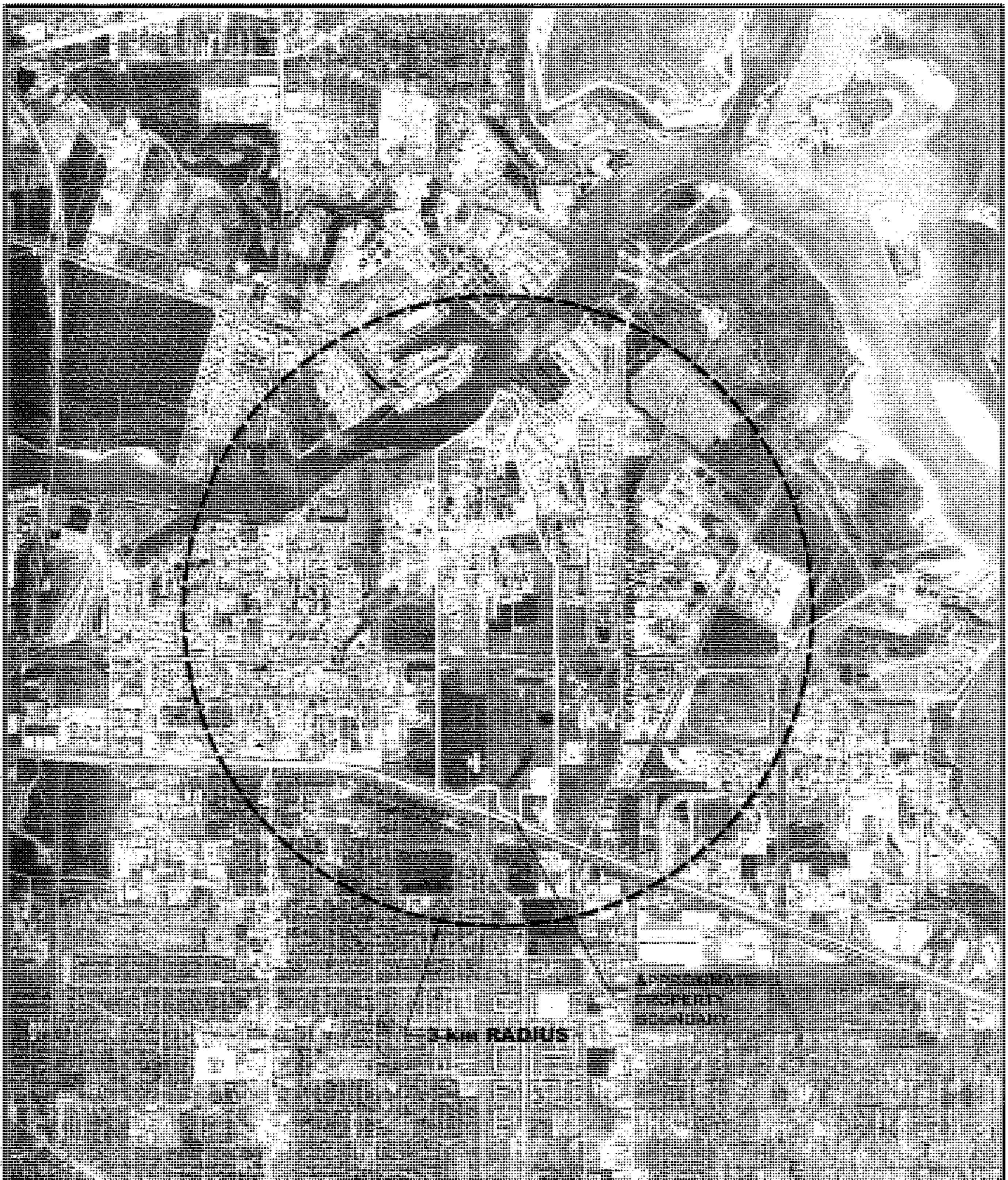
Permit No.: **TBD**	Application Submittal Date: **October 17, 2012**
Company: **Rohm And Haas Texas, Incorporated**	
Facility Location: **Deer Park, Texas**	
City: **Deer Park**	County: **Harris**
Permit Unit I.D.: **Gas Fired Boilers and Piping Fugitives**	Permit Name: **Boiler House Unit GHG PSD**
Permit Activity: ☐ New Source ☒ Modification	
Project or Process Description: **GHG Permit for Boiler House Expansion**	

Complete for all Pollutants with a Project Emission Increase.	**POLLUTANTS**								
	Ozone		**CO**	**PM**	**PM_{10}**	**$PM_{2.5}$**	**NO_X**	**SO_2**	**Other[1] CO_2e**
	VOC	**NO_X**							
Nonattainment? (yes or no)	Yes	Yes	No	No	No	No	No	No	No
Existing site PTE (tpy)?									>75,000
Proposed project emission increases (tpy)									550,863
Is the existing site a major source? [2]If not, is the project a major source by itself? (yes or no)									Yes
Significance Level (tpy)	40	40	100	25	15	10	40	40	75,000
If site is major, is project increase significant?									Yes
If netting required, estimated start of construction?	**September 1, 2013**								
Five years prior to start of construction	**September 1, 2008**				contemporaneous				
Estimated start of operation	**September 1, 2014**					period			
Net contemporaneous change, including proposed project (tpy)									>75,000
FNSR APPLICABLE? (yes or no)									Yes (PSD)

[1] Other PSD pollutants.
[2] PSD thresholds are found in 40 CFR § 51.166(b)(1).

3.0 AREA MAP AND PLOT PLAN

An area map and plot plan for the proposed Rohm and Haas Boiler House Unit is provided in Figure 3-1 and Figure 3-2, respectively.



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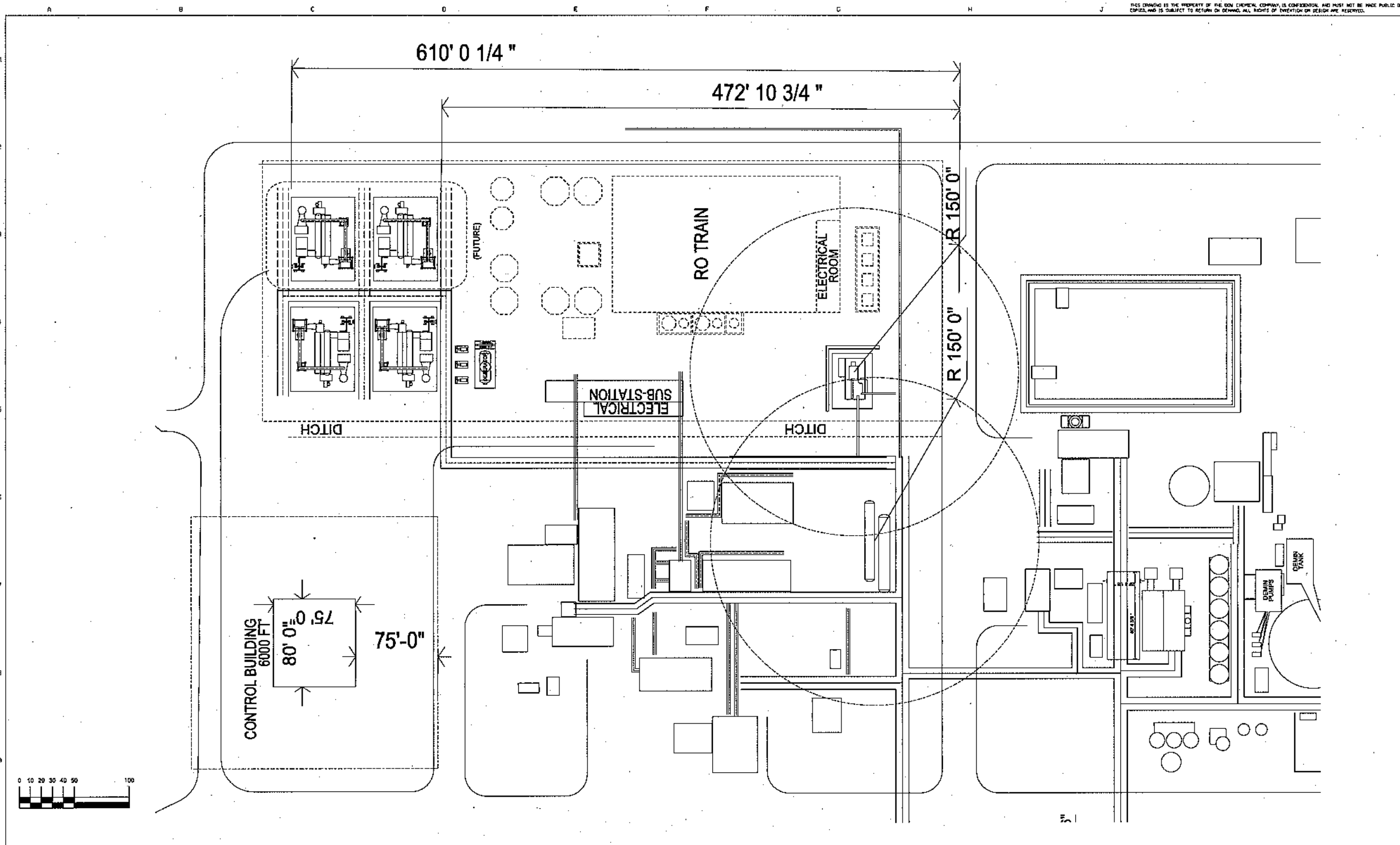
Area Map

Deer Park, Harris County, Texas

Dow Chemical Company



REV. MARK	REVISION	BY	CHK	APP	DATE	REV. MARK	REVISION	BY	CHK	APP	DATE

DRAWING ISSUE RECORD

ISSUE NO.	REV	MATERIAL OF JOB SPEC	BID	FAB	CONST	REF
			DATE ISSUED FOR			

DESIGNED
DRAWN
CHECKED
APPROVED
PROJ. ENGR.
MFG. REP.

STATUS
PLANT NO.
P.E. SEAL

SCALE
REV.
PRINTED
YER.

#TIME #DATE #PERSON #FILENAME #INSTRUCTIONS

4.0 PROJECT AND PROCESS DESCRIPTION

4.1 PROJECT DESCRIPTION

Rohm and Haas proposes to install two (2) new gas-fired steam boilers (EPN: BH-2-5 and EPN: BH-2-6) and the associated piping and equipment at the Deer Park facility. Each boiler will be permitted to operate 8,760 hr/yr. During normal operations, these boilers will burn either natural gas or a combination of natural gas and absorber off-gas from the N-Area Unit. During the boilers startup and shutdown activities, and when N-Area is down for maintenance, the boilers will only burn natural gas. The purpose of the proposed project is to give Rohm and Haas Boiler house facility the ability to perform planned maintenance on steam producing equipment without sacrificing peak steam production, as well as, providing adequate reliability in efficiently burning the absorber off-gas from the N-Area unit.

Hot Standby mode will be utilized when steam production is curtailed. During this time, the boilers will operate at less than full capacity; thus reducing combustion optimization. Based on data from a similar application, when the boilers are curtailed during Hot Standby mode the maximum hourly emission rates will be less than 5.0 lb NOx / hr. This maximum hourly emission rate is below the 5.15 lb NOx / hr emissions that can potentially occur when the boilers are running at full capacity. Therefore, when the boilers are in Hot Standby mode they will never exceed the proposed routine operating hourly or annual emission rates.

The major pieces of equipment associated with the boilers include a new control building, a new Motor Control Center/Substation, one (1) deaerator, three (3) boiler feedwater pumps, a back-up instrument air system, two (2) fuel knock out drums, a new potable water system and a condensate blowdown system. Each gas fired boiler package will contain an economizer, an ammonia injection grid and SCR (Selective Catalytic Reduction) system, a forced draft fan and an emission stack. Existing utilities (such as plant air, nitrogen, process water, demineralized water, potable water and cooling water) will support the project as needed.

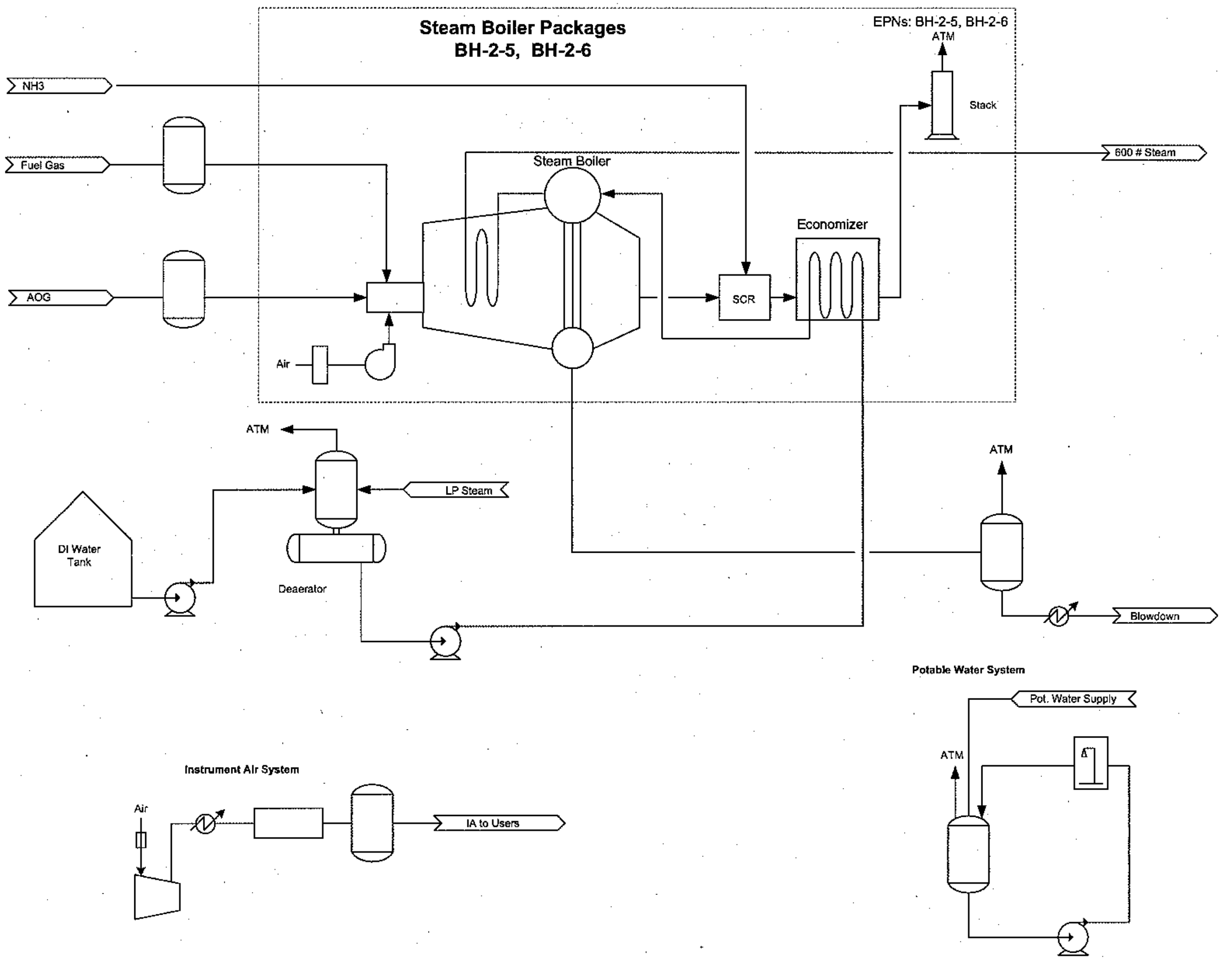
The NOx emissions from the proposed project will be controlled using a Selective Catalytic Reduction (SCR) unit on each proposed boiler accompanied with a Continuous Emission Monitoring System (CEMS).

4.2 PROCESS DESCRIPTION

Boiler No. 3 (BH-2-3) and Boiler No. 4 (BH-2-4) are currently the primary boilers for the Deer Park Site. Boiler No. 4 (BH-2-4) is intended to operate for up to 8,760 hr/yr. During normal operations, the boiler burns either natural gas or a combination of natural gas and absorber off-gas from the N-Area Unit. During planned maintenance, startup, and shutdown (MSS) activities, no absorber off-gas is sent to Boiler No. 4; only natural gas. Boiler No. 3 (BH-2-3) is permitted to run for up to 8,760 hr/yr. Currently, Boiler No. 3 only burns natural gas and normally runs at a reduced rate to save on steam efficiency.

Boiler No. 5 (BH-2-5) and Boiler No. 6 (BH-2-6) are boilers that will be constructed to increase steam supply reliability for the Deer Park Site. These boilers will operate like Boiler No. 4, in which they will have the ability to burn either natural gas or a combination of natural gas and absorber off-gas from the N-Area Unit during routine operations and burn only natural gas during MSS activities. During periods where the demand for steam within the Deer Park site is low, these boilers will operate in Hot Standby mode.

Similar to other industrial boilers, water is feed through the boiler tubes where it is heated to a specific temperature in order to produce steam. This is accomplished by using natural gas or a combination of natural gas and absorber off gas (AOG) from the N-Area Unit within the Deer Park site. Through this process each boiler can produce 600 pound steam to be supplied to manufacturing facilities within the Rohm and Haas Deer Park site. The combusted gases from the boiler are feed through a Selective Catalytic Reduction (SCR) where NOx emissions are reduced. The gas stream is then fed through an economizer to recover heat from the combusted gases by increasing the temperature of the water feed that will be sent from the deaerator to the boiler as feed water. This gas stream is then emitted from the boiler stack. A simplified process flow diagram is provided on the subsequent page.



DEER PARK BOILER PROJECT
PROCESS DIAGRAM
BH-2-5, BH-2-6
29-AUG-12

5.0 EMISSIONS CALCULATIONS

Detailed GHG emission calculations for the proposed Boiler House expansion project are provided in Appendix A of this application. The calculation methodology used is described in the following sections.

The GHG emissions from the proposed Boiler House Unit will include carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). GHG emissions are calculated from the following sources for the proposed project:

- Boilers
- Fugitive emissions from piping components in GHG service

The CO_2e emissions are calculated based on the estimated annual mass rates for each applicable GHG multiplied by the global warming potential (GWP) for each specific GHG as provided in Table A-1 of Subpart A of 40 CFR part 98.

Table 5-1, at the end of this section, provides proposed emission rates for individual GHGs and corresponding CO_2e.

5.1 BOILERS

Two new boilers will be installed as part of the Boiler House expansion project. The boilers will have the ability to fire either 100% natural gas or a combination of natural gas and absorber off-gas (AOG). GHG emissions are calculated in accordance with the procedures in the Mandatory Greenhouse Gas Reporting Rule, 40 CFR §98.30 Subpart C — General Stationary Fuel Combustion Sources. Calculations use equation C-1 from the Tier 1 Calculation Methodology specified in Subpart C. The default emission factors are taken from Subpart C Tables C-1 and C-2 for CO_2, CH_4 and N_2O and the default high heat value for pipeline natural gas is obtained from Subpart C Table C-1. Firing natural gas in the boiler provides the most conservative GHG emission rates. However, the calculation provides emission rate estimates for both fuel firing scenarios. Therefore, fuel usage is based on the maximum heat capacity of the boilers, the high heat value of the fuel, and 8,760 hours of operation per year. Detailed GHG calculations from these boilers are provided in Appendix A.

5.2 PIPING FUGITIVES

The fugitive emissions from piping components in natural gas and absorber off-gas at the Boiler House Unit are detailed in Appendix A. Natural gas contains primarily methane, with additional heating value derived mostly from ethane and VOCs. Absorber off-gas is primarily composed of nitrogen, with additional heating value derived mostly from hydrogen and carbon monoxide.

Although there are no established GHG piping fugitive emission factors, Rohm and Haas applied the Oil and Gas Production Operation and Synthetic Organic Chemical Manufacturing Industry (SOCMI) without ethylene emissions factors to the estimated natural gas and absorber gas piping component types and quantities to estimate fugitive total mass emissions from the natural gas and absorber off-gas piping at the Boiler House Unit.

5.3 PLANNED MAINTENANCE, STARTUP, AND SHUTDOWN (MSS) EMISSIONS

Boiler Startup and Shutdown

Maintenance startup and shutdown of the two new gas-fired boilers will result in CO_2e emissions. During boiler MSS activities (startup and shutdown), and when N-Area is down for maintenance the boilers will fire only 100% natural gas and only one boiler will be shutdown and started up at a time. Emissions from these activities are considered intermittent. Detailed GHG MSS emission calculations from the boilers are provided in Appendix A.

Table 5-1
Rohm and Haas Boiler Expansion
Proposed GHG Emission Limits

Date:	October 2012	Permit No.:	TBD	RN Number:	100223205
Area Name:	Rohm and Haas Texas, Incorporated - Boiler House Unit			CN Number:	600131395

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
EPN (A)	FIN (B)	Name (C)		Pounds per Hour (A)	Tons per Year (B)
Boiler House Unit					
BH-2-5 and BH-2-6	BH-2-5 and BH-2-6	Boiler No. 5 and Boiler No. 6	CO_2	123,724.23	541,912.13
			CH_4	2.33	10.22
			N_2O	0.23	1.02
			CO_2e	123,845.58	542,443.62
BLR-FUG2	BLR-FUG2	Piping Fugitives	CO_2	0.03	0.15
			CH_4	0.65	2.84
			CO_2e	13.66	59.81
BH-2-5_MSS and BH-2-6_MSS	BH-2-5_MSS and BH-2-6_MSS	Boiler No. 5 MSS and Boiler No. 6 MSS	CO_2	61,862.12	8,351.39
			CH_4	1.17	0.16
			N_2O	0.12	0.02
			CO_2e	61,922.79	8,359.58

6.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

The PSD Rule in 40 CFR §52.21(b)(12) defines Best Available Control Technology (BACT) as:

Best available control technology means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under [the] Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

In the EPA guidance document titled *PSD and Title V Permitting Guidance for Greenhouse Gases – March 2011,* EPA recommended the use of the Agency's five-step "top-down" BACT process to determine BACT for GHGs[1]. In brief, the top-down process calls for all available control technologies for a given pollutant to be identified and ranked in descending order of control effectiveness. The permit applicant should first examine the highest-ranked ("top") option. The top-ranked options should be established as BACT unless the permit applicant demonstrates to the satisfaction of the permitting authority that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the top ranked technology is not "achievable" in that case. If the most effective control strategy is eliminated in this fashion, then the next most effective alternative should be evaluated, and so on, until an option is selected as BACT.

EPA has broken down this analytical process into the following five steps:

Step 1: Identify all available control technologies
Step 2: Eliminate technically infeasible options
Step 3: Rank remaining control technologies
Step 4: Evaluate most effective controls and document results
Step 5: Select the BACT

The project contains the following sources of GHG emissions:

- Gas fired boilers; and
- Fugitive emissions from piping components in GHG service.

[1] Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases*, United States Environmental Protection Agency, pg 18, March 2011.

CO_2 emissions account for approximately 99 percent of the total CO_2e emissions for the proposed project. CH_4 and N_2O contribute insignificantly to the overall GHG emissions potential. Therefore, the GHG BACT analysis is focused on CO_2. Rohm and Haas searched the EPA RACT/BACT/LAER Clearinghouse (RBLC) database only for applicable CO_2 BACT determinations to assist in identifying potential GHG control technologies relevant to the proposed emissions sources. The results of a RBLC Database search are included in Appendix B to this application. Applicable technologies are included in this BACT analysis.

6.1 BACT FOR GAS FIRED BOILERS

6.1.1 Step 1 – Identify Available Control Technologies

The following technologies were identified as potential control options for gas fired boilers based on review of available information and data sources:

- Use of low carbon gaseous fuel;
- Use of good operating and maintenance practices;
- Energy efficiency; and
- Carbon Capture and Storage (CCS).

6.1.1.1 Low-Carbon Gaseous Fuel

CO_2 is a product of combustion generated with any carbon-containing fuel. The preferential use of gaseous fuels such as natural gas or absorber off-gas, is a method of lowering CO_2 emissions versus use of solid or other fuels available at the Rohm and Haas site. Rohm and Haas proposes to use natural gas or a combination of natural gas and absorber off-gas.

6.1.1.2 Good Combustion Practices

Another opportunity for reducing GHG emissions is good combustion practices. This includes proper equipment maintenance and operation including periodic burner tuning, good fuel/air mixing in combustion zone, proper fuel gas supply system design and operation to minimize instability of fuel gas during load changes, and sufficient excess air for complete combustion. Using good combustion practices results in longer life of the equipment and more efficient operation. Because CO_2 emissions are a direct result of the amount of fuel fired (for a given fuel), the more efficient the process, the less fuel that is required and the less greenhouse gas emissions that result.

Rohm and Haas will incorporate such combustion practices as recommended by the boiler manufacturer.

6.1.1.3 Energy Efficiency

CO_2 emissions are inversely proportional to boiler efficiency. As the efficiency improves, less fuel is consumed and less CO_2 emitted. There are many factors that can affect the efficiency of a boiler. The following list the most significant factors that affect boiler efficiency.

- Excess Air – The amount of air beyond stoichiometric combustion. Boiler efficiency decreases as excess air increases.
- Air Temperature – Boiler efficiency is relative to an arbitrary air temperature, typically 80°F. Efficiency increases at temperatures above this point and lower when temperatures are colder.

- Exit Flue Gas Temperature – Temperature of flue gas leaving the boiler system. Heat transfer equipment extracts heat from the hot flue gases lowering its temperature. The lower the temperature, the more heat has been extracted and the higher the efficiency.
- Fuel Composition – Particularly the presence of hydrogen and inerts. Boiler efficiency decreases as percentage of hydrogen or inerts in the fuel increases.
- Boiler Burner Tune-Ups – Periodic tune-ups on the boiler can help maintain boiler efficiency.

The effect of excess air on boiler efficiency is due to the large percentage of nitrogen in the air. This nitrogen absorbs heat from the combusted fuel. Heat not transferred to produce steam exhausts to atmosphere. When excess air increases, larger volumes of nitrogen absorb more heat from the fuel and exhaust the incremental heat to atmosphere. Therefore boiler efficiency drops as excess air increases. Some excess air must be present to effectively combust the fuel. When there is insufficient air present to react with the fuel, partially oxidized fuel will be present. Partially oxidized fuel is an unsafe condition that also increases pollutants. The unsafe condition occurs when fresh air mixes with the partially oxidized fuel. That pocket of fuel can ignite creating a deflagration or boiler explosion. Partially oxidized fuel can also produce air pollutants. Such pollutants could be carbon monoxide and organic carbons that did not fully oxidize to carbon dioxide. The amount of excess air required is a function of boiler load, rate of change of boiler load, fuels being burned and burner design.

Heat transfer equipment such as an economizer is installed to recover heat from the combusted flue gases and lower the flue gas temperature. The economizer transfers heat from the flue gases to preheat boiler feedwater. However, as heat is recovered and flue gas temperature drops, at some point moisture in the flue gas begins to condense. Sulfates are also present in the flue gas from the combustion of sulfur in the natural gas. The sulfates combine with the moisture creating corrosive acids which destroy the heat exchange equipment, ductwork, and/or stack. Therefore, boiler manufacturers design the boiler system to limit the Exit Flue Gas Temperature. A typical limit is 280°F at full design capacity when burning natural gas.

The combustion of hydrogen results in a significant loss of efficiency. When hydrogen is combusted it produces moisture. The moisture absorbs heat vaporizing it to a gaseous state. This is the latent heat of water. Then the moisture absorbs sensible heat to reach flue gas temperature. Both the latent and sensible heat, if not transferred to the steam, is lost to atmosphere. Two fuels will be utilized in the new boilers: natural gas and absorber off-gas (AOG). Both contain hydrogen. The AOG also contains a significant amount of nitrogen. The nitrogen in the AOG fuel degrades boiler efficiency in a similar manner as described above with excess air. AOG is never fired alone but always co-fired with natural gas.

Although boiler tune-ups cannot directly quantify efficiency improvements, periodic boiler tune-ups such as checking fuel/air mixing in combustion zone can aid in optimizing boiler performance. This was further discussed above in Good Combustion Practices.

The boiler efficiency is inversely proportional to the amount of AOG fueled because of the hydrogen and nitrogen present – as the amount of AOG increases, the boiler efficiency decreases. However, the carbon content of AOG is low with the majority as CO and CO_2 at 7% and small traces of methane and ethane. Therefore, the sole combustion of AOG produces little GHG. The AOG must be co-fired with natural gas for safe effective combustion. As the amount of AOG fueled is increased, less natural gas is fired. Boiler efficiency decreases, causing an incremental increase in GHG emissions from natural gas, but GHG emissions due solely to AOG combustion decreases. The net effect of increasing the amount of AOG fueled results in about 1% incremental increase of CO_2 emissions from no AOG to maximum AOG.

GHG performance for these boilers can be determined by either boiler efficiency or measuring CO_2 emissions at the stack. If determined by boiler efficiency, the input-output method provides the simplest calculation. Heat output into the steam system is divided by heat input of fuel. Drum type boilers must remove a small percentage of water from the steam drum to control water chemistry. This is called blowdown and is a portion of the heat absorbed by the steam system.

$$Boiler\ Efficiency = \frac{m_s * (h_s - h_f) + m_f * \%BD * (h_d - h_f)}{q_{NG} * H_{NG} + q_{AOG} * H_{AOG}}$$

m_s = Steam flow exiting boiler, lb/hr
m_f = Inlet Boiler Feedwater, lb/hr
%BD = Drum blowdown, expressed as % of boiler feedwater
h_s = Exit steam enthalpy, Btu/lb
h_f = Inlet boiler feedwater enthalpy, Btu/lb
h_d = Boiler drum enthalpy, Btu/lb
q_{NG} = flow of natural gas, scfh
q_{AOG} = flow of AOG, scfh
H_{NG} = Natural gas higher heating value, Btu/scf
H_{AOG} = AOG higher heating value, Btu/scf

The boilers will perform with an efficiency of no less than 76%. Rohm and Haas will operate the boilers as recommended by the boiler manufacture to save energy and increase the boiler efficiency.

6.1.1.4 Carbon Capture and Storage

CO_2 capture is a relatively new concept. In its March 2011 PSD and Title V Permitting Guidance for GHGs, EPA takes the position that, *"for the purpose of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing). For these types of facilities, CCS should be listed in Step 1 of a top-down BACT analysis for GHGs". (Reference 1 pg 32)*

These emerging carbon capture and storage (CCS) technologies generally consist of processes that separate CO_2 from combustion process flue gas, compression of the separated CO_2, transportation via pipeline to a site for injection and then inject it into geologic formations such as oil and gas reservoirs, un-mineable coal seams, and underground saline formations. Of the emerging CO_2 capture technologies that have been identified, only amine absorption is currently commercially used for state-of-the-art CO_2 separation processes. Amine absorption has been applied to processes in the petroleum refining and natural gas processing industries and for exhausts from gas-fired industrial boilers. Other potential absorption and membrane technologies are currently considered developmental.

6.1.2 Step 2 – Eliminate Technically Infeasible Options

6.1.2.1 Low-Carbon Gaseous Fuel

Use of low-carbon gaseous fuel is considered technically feasible. Rohm and Haas will burn either natural gas or a combination of natural gas and absorber off-gas. Both of these fuels have low carbon content compared to the fossil fuels fuel oil and coal.

6.1.2.2 Good Combustion Practices

Use of good combustion practices is considered technically feasible. To optimize combustion, Rohm and Haas will operate the boilers as recommended by the boiler manufacturer.

6.1.2.3 Energy Efficiency

Use of certain energy efficiency measures is considered technically feasible. Rohm and Haas recommends monitoring boiler stack temperature and oxygen concentrations to aid in optimizing boiler efficiency. They also plan to periodically (on an as-needed basis) perform boiler tune-ups to ensure optimum boiler performance. Additionally, to provide the best boiler operation, Rohm and Haas will utilize an economizer, and use the most cost effective fuel. These options for maximizing energy efficiency will be utilized on the new boilers; therefore, they are not addressed in Steps 3 and Steps 4 of this analysis.

6.1.2.4 Carbon Capture and Storage

Rohm and Haas has evaluated CCS for the proposed project based on technological, environmental, and economic feasibility as discussed below:

The following table summarizes the current CCS technology and its associated components, which is based on the IPCC's *Carbon Dioxide Capture and Storage*[2] report:

Table 6-1

CCS Component	CCS Technology
Capture and Compression	Post-Combustion
	Pre-Combustion
	Oxy-Fuel Combustion
	Industrial Separation (natural gas processing, ammonia production)
Transportation	Pipeline
	Shipping
Geological Storage	Enhanced Oil Recovery (EOR)
	Gas or Oil Fields
	Saline Formations
	Enhanced Coal Bed Methane Recovery (ECBM)
Ocean Storage	Direct Injection (Dissolution Type)
	Direct Injection (Lake Type)
Mineral Carbonation	Natural Silicate Minerals
	Waste Minerals
CO_2 Utilization/Application	Industrial Uses of CO_2 (e.g. carbonated products)

[2] Intergovernmental Panel on Climate Change (IPCC) Special Report, Bert Metz, Ogunlade Davidson, Heleen de Coninck, Manuela Loos and Leo Meyer (Eds.), *Carbon Dioxide Capture and Storage* (New York: Cambridge University Press, 2005), Table SPM.2,8.

CO_2 Capture and Compression

According to the U.S. Department of Energy's National Energy Technology Laboratory (DOE-NETL) separating CO_2 from flue gas streams is challenging for several reasons:

- CO_2 is present at dilute concentrations (13-15 volume percent in coal-fired systems and 3-4 volume percent in gas-fired turbines) and at low pressure (15-25 pounds per square inch absolute [psia]), which dictates that a high volume of gas be treated.
- Trace impurities (particulate matter, sulfur dioxide, nitrogen oxides) in the flue gas can degrade sorbents and reduce the effectiveness of certain CO_2 capture processes.
- Compressing captured or separated CO_2 from atmospheric pressure to pipeline pressure (about 2,000 psia) represents a large auxiliary power load on the overall power plant system

Further, President Obama Administration's Interagency Task Force on Carbon Capture and Storage confirms this in its recently completed report on the current status of development of CCS systems:

"Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Since the CO_2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment."[3]

Separating CO_2 from the boiler exhaust streams at the Boiler House Unit is challenging because CO_2 is present in dilute concentrations in the boiler exhaust streams. The boiler exhaust gas has the potential to contain between 4.2 and 8.7 vol% CO_2 in the stack gas on an average annual basis. These are not high-purity streams, as recommended in USEPA's guidance. To achieve the necessary CO_2 concentration for effective sequestration, the recovery and purification of CO_2 from the stack gases would require additional equipment, operating complexity, and increased energy consumption from the plant resulting in energy and environmental/air quality penalties. This may, in turn, potentially increase the natural gas fuel use of the plant, with resulting increases in emissions of non-GHG pollutants, to overcome these efficiency losses, or would result in less energy being produced. The *Report of the Interagency Task Force on Carbon Capture and Storage* has estimated that an energy penalty of as much as 15% would result from inclusion of CO_2 capture (Reference 3, pg A-14) and would also result in an overall loss of energy efficiency.

CO_2 Transport

Even if it is assumed that the CO_2 could be segregated efficiently from the boiler exhausts, it would need to be compressed and the high volume stream would need to be transported via pipeline to a geologic formation capable of long-term storage.

[3] President Obama's Interagency Task Force on Carbon Capture and Storage, *Report of the Interagency Task Force on Carbon Capture and Storage,* August 2010, pg 50.

A map showing potential geologic storage sites in Texas, Louisiana, and Mississippi to which CO_2 could be transported if a pipeline was constructed is attached at the end of this section[4]. The capabilities for CO_2 storage in the vicinity around Deer Park are early in development, and there is tenuous commercial viability and demonstration of large-scale, long-term CO_2 storage; therefore, the capital and legal risks of building infrastructure solely for CO_2 storage from this boiler expansion project are unreasonable. However, if a pipeline was constructed, Denbury Resources owns and operates a CO_2 pipeline that has a terminus point at Hastings Field[5], and is in reasonable proximity for a tie-in to Rohm and Haas Deer Park. The Denbury Green Pipeline that crosses the Galveston Bay area is located approximately 23 miles from Rohm and Haas Deer Park and the Hastings Field EOR site is approximately 25 miles from Rohm and Haas Deer Park; however, there is no existing connection to the pipeline or Hastings Field and currently the level of anthropogenic sources of CO_2 in the Green Pipeline being sent to Hastings Field is minimal.

Other potential sequestration sites in Texas which are presently commercially viable, such as the SACROC enhanced oil recovery unit in the Permian Basin, are more than 500 miles from the proposed project site. The closest site that is currently being field-tested to demonstrate its capacity for large-scale geological storage of CO_2 is the Southeast Regional Carbon Sequestration Partnership's (SECARB) Cranfield test site located in Adams and Franklin counties in Mississippi and is over 300 miles away from the proposed project site. Therefore, assuming that it is eventually demonstrated to indefinitely store a substantial portion of the large volume of CO_2 generated by the proposed project, a very long and sizable pipeline would need to be constructed to transport the large volume of high-pressure CO_2 from the plant to the potential storage facility. Therefore, assuming that it is eventually demonstrated to indefinitely store a substantial portion of the large volume of CO_2 generated by the proposed project, a very long and sizable pipeline would need to be constructed to transport the large volume of high-pressure CO_2 from the plant to the potential storage facility. Typical costs for installation of a pipeline for flat, dry areas can be estimated at $50,000 (Reference 3, pg 50) per inch-diameter per mile. Thus, the high cost of CO_2 transport via pipelines to a long-term storage site 50 miles or greater in length renders it infeasible for the proposed project.

CO_2 Storage

Even if it is assumed that CO_2 capture and compression could feasibly be achieved for the proposed project and that the CO_2 could be transported economically, it must be stored in a suitable sequestration site. A suitable reservoir or geologic formation is not located within a reasonable proximity to the proposed site.

Potential storage sites, including enhanced oil recovery (EOR) sites and saline formations exist in Texas, Louisiana, and Mississippi. The Southeast Texas enhanced oil recovery (EOR) reservoir and other geologic formation sites are all early in development and there is tenuous commercial viability and demonstration of large-scale, long-term CO_2 storage; therefore the capital cost and legal risks of building infrastructure solely for CO_2

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[4] Susan Hovorka, University of Texas at Austin, Bureau of Economic Geology, Gulf Coast Carbon Center, New Developments: Solved and Unsolved Questions Regarding Geologic Sequestration of CO2 as a Greenhouse Gas Reduction Method (GCCC Digital Publication #08-13) at slide 4 (April 2009), available at: http://www.beg.utexas.edu/gccc/forum/codexdownloadpdf.php?ID=100 (last visited October 4, 2012).

[5] Denbury, Green Pipeline Projects, available at http://www.denbury.com/Corporate-Responsibility/Pipeline-Projects/green-pipeline-project/default.aspx (last visited October 10, 2012).

storage from this boiler expansion project are economically challenging. There are salt dome caverns near the site; however, these limestone formations have not been demonstrated to safely store acid gases such as CO_2, nor is there adequate availability of space. Instead, these domes are used for cyclical storage of liquefied petroleum gases (LPGs) for use in the Gulf Coast as well as for shipment throughout the United States via pipeline. To replace this critical active storage with long-term CO_2 sequestration would jeopardize energy supplies locally and nationally. Other potential sequestration sites in Texas that are presently commercially viable, such as the SACROC enhanced oil recovery unit in the Permian Basin, are more than 500 miles from the proposed project site. The closest site that is currently being field-tested to demonstrate its capacity for large-scale geological storage of CO_2 is the Southeast Regional Carbon Sequestration Partnership's (SECARB) Cranfield test site located in Adams and Franklin Counties Mississippi and is over 300 miles away from the proposed project site, thereby making CCS infeasible for the project.

In addition, potential environmental impacts that would still require assessment before CCS technology can be considered feasible include:

- Uncertainty concerning the significance of dissolution of CO_2 into brine,
- Risks of brine displacement resulting from large-scale CO_2 injection, including a pressure leakage risk for brine into underground drinking water sources and/or surface water,
- Risks to fresh water as a result of leakage of CO_2, including the possibility for damage to the biosphere, underground drinking water sources, and/or surface water, and
- Potential effects on wildlife.

Economic Analysis

Based on the reasons provided above, Rohm and Haas believes that CCS is not a technically feasible control option for the proposed boilers at the Rohm and Haas Boiler House Unit. However, an economic feasibility analysis was completed for a hypothetical CCS systems to address questions from the public and EPA concerning cost. The results of the cost analysis are detailed in Table 6-4 at the end of this section. This cost analysis is an amortized cost of the capital, operating, and maintenance expenses for the CCS expressed in annual cost of US dollars per ton of CO_2 controlled. The analysis assumes that the two gas-fired boilers are controlled by CCS and 90% of the CO_2 is recovered. The estimate is broken into the three CCS components discussed above: capture, transportation, and storage. For the three CCS components, a minimum, maximum, and average cost was provided.

CCS control technology is estimated to cost on average $90.07 per ton of CO_2 controlled or $44,114,656.66 annually (this includes capital cost for installation, operating cost, and maintenance expenses) to control 90% of the CO_2 emissions from the boilers, with the capture and compression technology contributing the bulk of the CCS cost. The Department of Energy analysis that was the basis for the Interagency report estimated capture cost to range from $54.43/ton of CO_2 avoided to $103.42/ton CO^2 avoided (Reference 3, pg 33-34), and this was based on a very large power plant (550MWe). In comparison, the *CO_2 Capture in Industries and Distributed Energy Systems: Possibilities and Limitations* report estimated the capture cost of a cement production stream boiler to range from $70/ton of CO_2 avoided to $106/ton of CO_2 avoided[6]. The scale of the boilers at the Rohm and Haas Deer Park plant would be significantly smaller than the power plant represented in the Interagency report, so it is likely

[6] Kuramochi, T, 2011. *CO_2 Capture in Industries and Distributed Energy Systems: Possibilities and Limitations*, pg 45.

the capture cost / ton would be on the higher end of the range rather than the average. CCS is presently a high cost technology and would make the proposed boiler expansion project economically unfeasible if selected.

Although some elements of CCS are technically feasible, the overall evaluation shows that it's economically infeasible for the size of this project and the network for collection of anthropogenic CO_2 and pipeline management is too early in development for this area to be considered. The following table lists the technologies that are technically feasible and those that are infeasible.

Table 6-2

Summary of CCS Technical Feasibility for Rohm and Haas Boiler House Unit

CCS Component	CCS Technology	Technical Feasibility
Capture and Compression	Post-Combustion	Y
	Pre-Combustion	N
	Oxy-Fuel Combustion	N
	Industrial Separation (natural gas processing, ammonia production)	N
Transportation	Pipeline	Y
	Shipping	Y
Geological Storage	Enhanced Oil Recovery (EOR)	Y
	Gas or Oil Fields	N
	Saline Formations	N
	Enhanced Coal Bed Methane Recovery (ECBM)	N
Ocean Storage	Direct Injection (Dissolution Type)	N
	Direct Injection (Lake Type)	N
Mineral Carbonation	Natural Silicate Minerals	N
	Waste Minerals	N
Large Scale CO_2 Utilization/Application		N

6.1.3 Step 3 – Rank Remaining Control Technologies

Since the remaining control measures identified in Section 6.1.1 – low-carbon fuels, good combustion practices, and energy efficient design, are being proposed for this project, a ranking of the control technologies is not necessary for this application.

6.1.4 Step 4 – Evaluate the Most Effective Controls

Rohm and Haas proposes to utilize low carbon fuels, good combustion practices, and operate the boilers at optimum efficiency. The adverse environmental impacts and economic infeasibility of CCS technology is addressed in section 6.1.2.4.

6.1.5 Step 5 –Select BACT

Rohm and Haas proposes to incorporate low-carbon gaseous fuels, good combustion practices and energy efficient design discussed in Section 6.1.1 as BACT for controlling CO_2 emissions from boiler combustion and its corresponding steam supply/demand as integrated with the process unit's equipment downstream of the boilers. A table listing the GHG sources, GHG emission rates, and the proposed BACT for each source is provided at the end of this section.

6.2 Piping Fugitives

The proposed project will include piping components with GHG emissions. GHGs from piping fugitives will be generated primarily from plant natural gas and absorber off-gas lines at the Boiler House Unit.

6.2.1 Step 1 – Identify Potential Control Technologies

Piping fugitives may be controlled by various techniques, including:

- Installation of leakless technology to eliminate fugitive emissions sources;
- Implementation of instrument leak detection and repair (LDAR) programs as prescribed by various federal and state regulations and permit conditions;
- Implementation of alternative monitoring using remote sensing using infrared cameras; and
- Implementation of audio/visual/olfactory (AVO) leak detection methods.

6.2.2 Step 2 – Eliminate Technically Infeasible Options

6.2.2.1 Leakless/Sealless Technology

Leakless technology valves are used in situations where highly toxic or otherwise hazardous materials are present. These technologies cannot be repaired without a unit shutdown. Because natural gas and absorber off-gas are not considered highly toxic nor hazardous materials, these materials do not warrant the risk of unit shutdown for repair. Therefore, leakless valve technology for fuel lines is considered technically impracticable.

6.2.2.2 Instrument LDAR Programs

Use of instrument LDAR is considered technically feasible.

6.2.2.3 Remote Sensing

Use of remote sensing measures is considered technically feasible.

6.2.2.4 AVO Monitoring

Emissions from leaking components can be identified through AVO methods. Natural gas and some process fluids are odorous, making them detectable by olfactory means. Therefore, use of as-observed AVO monitoring is considered technically feasible.

6.2.3 Step 3 – Rank According to Effectiveness

Instrument LDAR programs and the alternative work practice of remote sensing using an infrared camera have been determined by EPA to be equivalent methods of piping fugitive controls.

As-observed AVO methods are generally somewhat less effective since they are not conducted at specified intervals. However, since pipeline natural gas is odorized with very small quantities of mercaptan, as-observed olfactory observation is a very effective method for identifying and correcting leaks in natural gas systems. Due to the pressure and other physical properties of plant fuel gas, as-observed audio and visual observations of potential fugitive leaks are likewise moderately effective.

6.2.4 Step 4 – Evaluate the Most Effective Controls

Although instrument LDAR and/or remote sensing of piping fugitive emissions in natural gas and absorber off-gas service may be somewhat more effective than as-observed AVO methods, the economic practicability of such programs cannot be verified. Specifically, fugitive emissions are estimates only, based on factors derived for a statistical sample and not specific to any single piping component nor specifically for natural gas and absorber off-gas service. Therefore, since the total contribution to the site's CO_2e PTE from piping fugitives is less than 0.01%, which is less than the statistical accuracy of the development of the factors themselves[7], instrument LDAR programs or their equivalent alternative method, remote sensing, are not economically practicable control methods for the piping fugitive GHGs emissions for this project.

6.2.5 Step 5 – Select BACT

Rohm and Haas proposes to incorporate the as-observed AVO as BACT for the piping components at the Boiler House Unit in natural gas and absorber off-gas service. A table listing the GHG sources, GHG emission rates, and the proposed BACT for each source is provided at the end of this section.

[7] In Appendix B, Table B-2-2, of EPA's Protocol for Equipment Leak Emissions Estimates (EPA 453/R-95-017), November 1995, the Agency considered only the upper and lower 95% confidence limits in developing revised SOCMI emission factors.

Table 6-3
Annual Facility Emission Limits and BACT Selection

The following table represents the annual routine and MSS emissions in tons per year (tpy). The annual routine emissions are based on a 365 day rolling average and the annual MSS emissions are based on maximum annual hours for each MSS activity. The boilers will not exceed these limits and will meet the BACT requirements listed below.

Date:	October 2012	Permit No.:	TBD	RN Number:	100223205
Area Name:	Rohm and Haas Texas, Incorporated - Boiler House Unit			CN Number:	600131395

Boiler House Unit						
Unit ID	EPN	Description	GHG Mass Basis Emission Rates		CO_2e	BACT Selection
			Pollutant	Ton per Year	Ton per Year	
BH-2-5 and BH-2-6	BH-2-5 and BH-2-6	Boiler No. 5 and Boiler No. 6	CO_2	541,912.13	542,443.62	Minimal Thermal Efficiency of 76%.
			CH_4	10.22		
			N_2O	1.02		
BLR-FUG2	BLR-FUG2	Piping Fugitives	CO_2	0.15	59.81	Implementation of AVO Program.
			CH_4	2.84		
BH-2-5_MSS and BH-2-6_MSS	BH-2-5_MSS and BH-2-6_MSS	Boiler No. 5 MSS and Boiler No. 6 MSS	CO_2	8,351.39	8,359.58	Minimal Thermal Efficiency of 76%.
			CH_4	0.16		
			N_2O	0.02		

Table 6-4

Range of Approximate Annual Costs for Instillation and Operation of Capture, Transport, and Storage System for Control of CO_2 Emissions from the Proposed Boiler Expansion Project at Rohm and Haas Deer Park, Harris County, Texas.

Carbon Capture and Storage (CCS) Component System	Factors for Approximating Costs for CCS Systems	Annual System CO_2 Throughput (tons of CO_2 captured, transported, and stored)[1]	Pipeline Length for CO_2 Transport System (km CO_2 transported)[2]	Range of Approximate Annual Costs for CCS Systems ($/year)
Post-Combustion CO_2 Capture and Compression System				
Minimum Cost[3]	$54.43 /ton of CO2 avoided	495,777		$26,985,663.91
Maximum Cost[3]	$103.42 /ton of CO2 avoided	495,777		$51,272,761.43
Average Cost[4]	$78.93 /ton of CO2 avoided	495,777		$39,129,212.67
CO_2 Transport System				
Minimum Cost[5]	$.91 /ton of CO2 transported per 100km	495,777	40.23	$180,950.12
Maximum Cost[5]	$2.72 /ton of CO2 transported per 100km	495,777	40.23	$542,850.36
Average Cost[4]	$1.81 /ton of CO2 transported per 100km	495,777	40.23	$361,900.24
CO_2 Storage System				
Minimum Cost[6]	$.51 /ton of CO2 stored	495,777		$251,866.20
Maximum Cost[6]	$18.14 /ton of CO2 stored	495,777		$8,995,221.30
Average Cost[4]	$9.33 /ton of CO2 stored	495,777		$4,623,543.75
Total Cost for CO_2 Capture and Compression, Transportation, and Storage Systems				
Minimum Cost	$55.85 /ton of CO2 transported per 100km3	495,777		$27,418,480.23
Maximum Cost	$124.28 /ton of CO2 transported per 100km3	495,777		$60,810,833.09
Average Cost[4]	$90.07 /ton of CO2 transported per 100km3	495,777		$44,114,656.66

Footnotes:

[1] The throughput assumes that a CCS system would be capable of 90% capture of the total CO_2 emissions generated from the two gas-fired boilers.

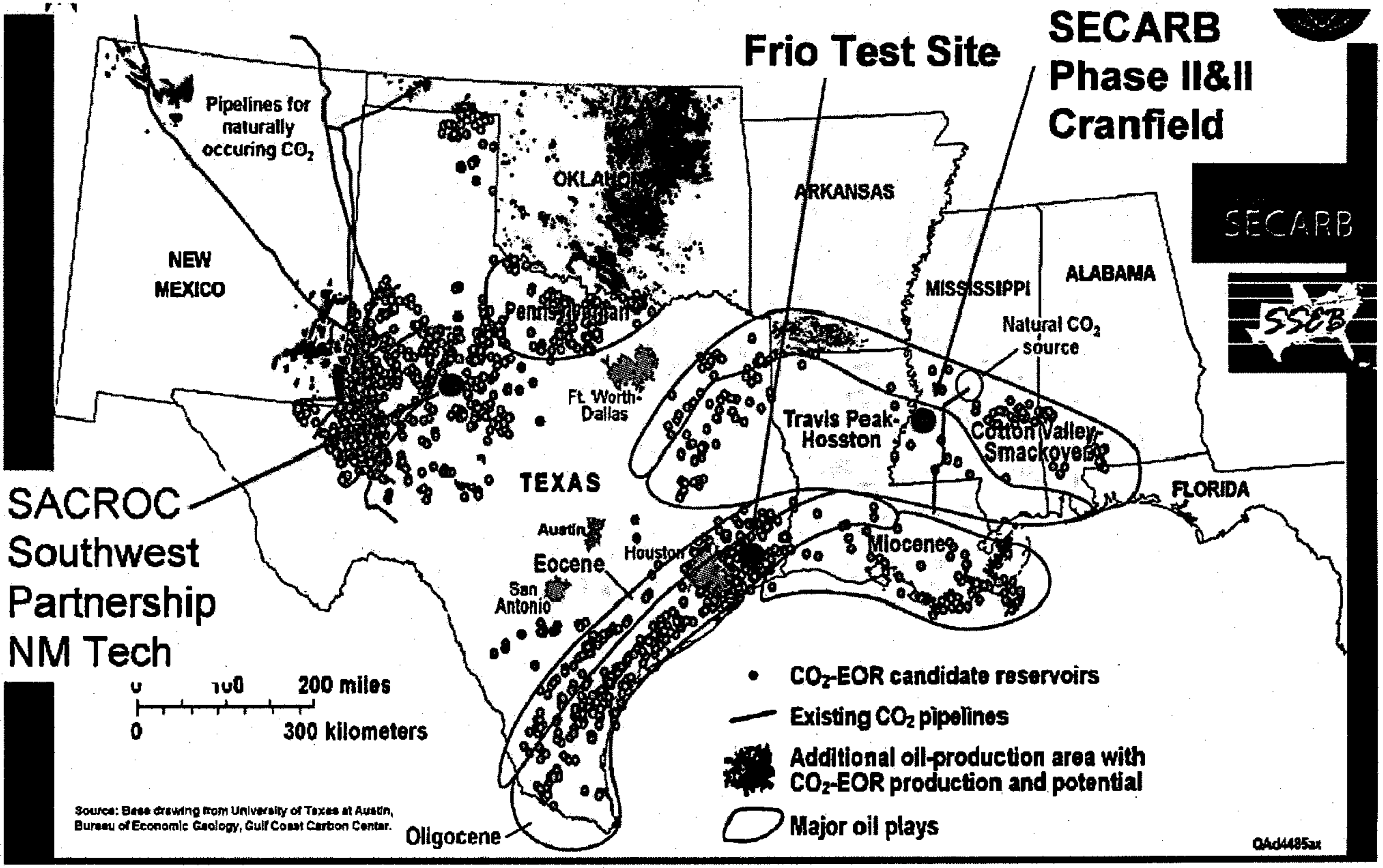
[2] The pipeline length is assumed to be the distance from Rhom and Haas Deer Park to Hastings Field, which is the closest potential geologic storage site. Denbury currently operates a CO_2 pipeline that terminates at Hastings Oil Field. Denbury started CO_2 injections in December 2010. This information was obtained from Denbury 2011 Annual Report, 2011 Form 10-K, pg 12, available at: http://www.denbury.com/files/doc_downloads/2011%20Annual%20Report.pdf (Last visted October 10, 2012)

[3] The cost factors for the CO_2 Capture and Compression System were obtained from the *Report of Interagency Task Force on Carbon Capture and Storage*, pg 33 and 34, and are based on the amount of CO_2 avoided. The eost values ranged rom $60/tonne for IGCC to $114/tonne for NGCC. These factors were converted to $/ton in the table above.

[4] The average cost factors were calculated as the arithmetic mean of the minimum and maximum factors for each of the CCS component systems and for all the components combined.

[5] The cost factors for the CO_2 Transport System were obtained from the *Report of Interagency Task Force on Carbon Capture and Storage*, pg 37. The report provides a cost range of $1/tonne to $3/tonne for a 100-km CO_2 pipeline transporting 5 million tonnes per year. The cost is dependent on numerous factors, which is discussed on pg 37. The cost range was converted to $/ton in the table above.

[6] The cost factors for the CO_2 Storage System were obtained from the *Report of Interagency Task Force on Carbon Capture and Storage*, pg 44. The storage cost range from $0.40/tonne to $20/tonne This cost is dependent on several factors, which is discussed on pg 447. The cost range was converted to $/ton in the table above.



Frio Test Site
SECARB
Phase II&II
Cranfield
SECARB
SSEB
Pipelines for naturally occuring CO_2
NEW MEXICO
ARKANSAS
MISSISSIPPI
ALABAMA
Natural CO_2 source
Travis Peak-Hosston
Cotton Valley-Smackover
FLORIDA
TEXAS
Ft. Worth-Dallas
Austin
Houston
Eocene
San Antonio
Miocene
Oligocene
SACROC
Southwest
Partnership
NM Tech
200 miles
0
300 kilometers
CO_2-EOR candidate reservoirs
Existing CO_2 pipelines
Additional oil-production area with CO_2-EOR production and potential
Major oil plays
Source: Base drawing from University of Texas at Austin, Bureau of Economic Geology, Gulf Coast Carbon Center.
QAd4485ax

7.0 OTHER PSD REQUIREMENTS

7.1 IMPACTS ANALYSIS

An impacts analysis is not being provided with this application in accordance with EPA's document *PSD and Title V Permitting Guidance For Greenhouse Gases, March. 2011(Pages 47& 48)*:

"Since there are no NAAQS or PSD increments for GHGs, the requirements in sections 52.21(k) and 51.166(k) of EPA's regulations to demonstrate that a source does not cause or contribute to a violation of the NAAQS are not applicable to GHGs. Thus, we do not recommend that PSD applicants be required to model or conduct ambient monitoring for CO_2 or GHGs".

7.2 GHG PRECONSTRUCTION MONITORING

A pre-construction monitoring analysis for GHG is not being provided with this application in accordance with EPA's document *PSD and Title V Permitting Guidance For Greenhouse Gases, March. 2011(Page 48):*

"Monitoring for GHGs is not required because EPA regulations provide an exemption in sections 52.21(i)(5)(iii) and 51.166(i)(5)(iii) for pollutants that are not listed in the appropriate section of the regulations, and GHGs are not currently included in that list. However, it should be noted that sections 52.21(m)(1)(ii) and 51.166(m)(1)(ii) of EPA's regulations apply to pollutants for which no NAAQS exists. These provisions call for collection of air quality monitoring data "as the Administrator determines is necessary to assess ambient air quality for that pollutant in any (or the) area that the emissions of that pollutant would affect." In the case of GHGs, the exemption in sections 52.21(i)(5)(iii) and 51.166(i)(5)(iii) is controlling since GHGs are not currently listed in the relevant paragraph. Nevertheless, EPA does not consider it necessary for applicants to gather monitoring data to assess ambient air quality for GHGs under section 52.21(m)(1)(ii), section 51.166(m)(1)(ii), or similar provisions that may be contained in state rules based on EPA's rules. GHGs do not affect "ambient air quality" in the sense that EPA intended when these parts of EPA's rules were initially drafted. Considering the nature of GHG emissions and their global impacts, EPA does not believe it is practical or appropriate to expect permitting authorities to collect monitoring data for purpose of assessing ambient air impacts of GHGs."

7.1 ADDITIONAL IMPACTS ANALYSIS

A PSD additional impacts analysis is not being provided with this application in accordance with EPA's document *PSD and Title V Permitting Guidance For Greenhouse Gases, March. 2011(Page 48):*

"Furthermore, consistent with EPA's statement in the Tailoring Rule, EPA believes it is not necessary for applicants or permitting authorities to assess impacts from GHGs in the context of the additional impacts analysis or Class I area provisions of the PSD regulations for the following policy reasons. Although it is clear that GHG emissions contribute to global warming and other climate changes that result in impacts on the environment, including impacts on Class I areas and soils and vegetation due to the global scope of the problem, climate change modeling and evaluations of risks and impacts of GHG emissions is typically conducted for changes in emissions orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible with current climate change modeling. Given these considerations, GHG emissions would serve as the more appropriate and credible

proxy for assessing the impact of a given facility. Thus, EPA believes that the most practical way to address the considerations reflected in the Class I area and additional impacts analysis is to focus on reducing GHG emissions to the maximum extent. In light of these analytical challenges, compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs."

Appendix A
Emissions Calculations

Greenhouse Gas (GHG) Emission Calculations - Boiler Routine Operation

Basis of Calculation:
GHG PTE emission rate calculations for the sources at the Boiler House Unit are provided below and the calculations are based on the following:

- Guidance per the EPA MRR, Subpart C (40 CFR § 98.30), dated October 30, 2009, Tier 1 Methodology;
- Default emission factors for combustion emissions of CO_2, CH_4, and N_2O per Tables C-1 and C-2 to Subpart C of Part 98;
- Global warming potentials to convert speciated GHG emission rates to emissions of CO_2e based on Table A-1 to Subpart A of Part 98; and
- Fuel usage at the Boiler House Unit is based on 8,760 operational hours per year and the maximum heat capacity rating of the combustion source.

Calculation Parameters

Description	Parameter	Value	Units	EPA MRR Source
Default Emission Factor - CO_2	Natural Gas	53.02	(kg/MMBtu)	Table C-1 to Subpart C of Part 98
Emission Factor - CO_2	AOG	47.79	(kg/MMBtu)	Calculated based on AOG Composition
Default Emission Factor - CH_4	Natural Gas	1.0E-03	(kg/MMBtu)	Table C-2 to Subpart C of Part 98
Default Emission Factor - N_2O	Natural Gas	1.0E-04	(kg/MMBtu)	Table C-2 to Subpart C of Part 98
Default High Heat Value	Natural Gas	1.028E-03	(MMBtu/scf)	Table C-1 to Subpart C of Part 98
High Heat Value	AOG	7.632E-05	(MMBtu/scf)	Based on AOG stream composition
Global Warming Potential (100 yr.)[1]	CO_2	1	N/A	Table A-1 to Subpart A of Part 98
Global Warming Potential (100 yr.)[1]	CH_4	21	N/A	Table A-1 to Subpart A of Part 98
Global Warming Potential (100 yr.)[1]	N_2O	310	N/A	Table A-1 to Subpart A of Part 98

Footnotes:
[1] Global warming potentials are used to convert speciated GHG emission rates to emissions of CO_2e where CO_2e is the carbon dioxide equivalent.

Greenhouse Gas (GHG) Emission Calculations - Boiler Routine Operation (Continued)

Boiler House Unit Potential Combustion Source List and Heat Capacity Ratings

EPN	FIN	Name	Fuel Type[1]	Heat Capacity MMBtu/hr	Typical High Heat Value of Fuel to Boiler Btu/scf	Fuel Usage MMscf/hr[2]	Heat Capacity MMBtu/yr	Fuel Usage MMscf/yr[2]
BH-2-5	BH-2-5	Boiler No. 5	Natural Gas	515.00	1,000.34	0.51	4,511,400.00	4,509.85
BH-2-5	BH-2-5	Boiler No. 5	Natural Gas/AOG (AOG Contribution)	305.29	76.32	4.00	2,674,335.16	35,040.00
BH-2-5	BH-2-5	Boiler No. 5	Natural Gas/AOG (NG Contribution)	209.71	1,000.34	0.21	1,837,064.84	1,836.43
BH-2-6	BH-2-6	Boiler No. 6	Natural Gas	515.00	1,000.34	0.51	4,511,400.00	4,509.85
BH-2-6	BH-2-6	Boiler No. 6	Natural Gas/AOG (AOG Contribution)	305.29	76.32	4.00	2,674,335.16	35,040.00
BH-2-6	BH-2-6	Boiler No. 6	Natural Gas/AOG (NG Contribution)	209.71	1,000.34	0.21	1,837,064.84	1,836.43

Footnote:

[1] Boilers No.5 and No.6 have the ability to burn either 100% natural gas or a combination of natural gas and absorber off gas (AOG).

[2] Calculated emission rates are based on maximum potential emissions; therefore, fuel usage (MMscf/hr and MMscf/yr) is based on the maximum heat capacity (MMBtu/hr and MMBtu/yr) for each boiler and the calculated high heat value for the fuel.

Maximum Hourly GHG Emissions

EPN	FIN	Name	Fuel Gas Usage (MMscf/hr)	Hourly GHG Emissions (lb/hr)			
				CO_2	CH_4	N_2O	CO_2e
BH-2-5	BH-2-5	Boiler No. 5	0.51	61,862.12	1.17	0.12	61,922.79
BH-2-5	BH-2-5	Boiler No. 5	4.00	57,355.53	1.15	0.11	57,415.23
BH-2-5	BH-2-5	Boiler No. 5	0.21				
BH-2-6	BH-2-6	Boiler No. 6	0.51	61,862.12	1.17	0.12	61,922.79
BH-2-6	BH-2-6	Boiler No. 6	4.00	57,355.53	1.15	0.11	57,415.23
BH-2-6	BH-2-6	Boiler No. 6	0.21				
Total - Boilers No.5 and No.6 Burning 100% Natural			**1.03**	**123,724.23**	**2.33**	**0.23**	**123,845.58**
Total - Boilers No.5 and No.6 Burning NG and AOG			**8.42**	**114,711.05**	**2.30**	**0.23**	**114,830.46**

Annual GHG Emissions

EPN	FIN	Name	Fuel Gas Usage (MMscf/yr)	Annual GHG Emissions (tpy)			
				CO_2	CH_4	N_2O	CO_2e
BH-2-5	BH-2-5	Boiler No. 5	4,509.85	270,956.07	5.11	0.51	271,221.81
BH-2-5	BH-2-5	Boiler No. 5	35,040.00	251,217.20	5.03	0.50	251,478.71
BH-2-5	BH-2-5	Boiler No. 5	1,836.43				
BH-2-6	BH-2-6	Boiler No. 6	4,509.85	270,956.07	5.11	0.51	271,221.81
BH-2-6	BH-2-6	Boiler No. 6	35,040.00	251,217.20	5.03	0.50	251,478.71
BH-2-6	BH-2-6	Boiler No. 6	1,836.43				
Total - Boilers No.5 and No.6 Burning 100% Natural			**9,019.69**	**541,912.13**	**10.22**	**1.02**	**542,443.62**
Total - Boilers No.5 and No.6 Burning NG and AOG			**73,752.86**	**502,434.41**	**10.06**	**1.01**	**502,957.42**

Greenhouse Gas (GHG) Emission Calculations - Boiler Routine Operation (Continued)

Example Calculations

100% Natural Gas Combustion Emissions - Boiler House Unit Boiler No. 5

Hourly CO2 Emission Rate (lb/hr) = 1 x 10^-3 (metric ton/kg) * Hourly Fuel Usage (MMscf/hr) * Default High Heat Value (MMBtu/scf) * Default Emission Factor (kg/MMBtu) * 2,204.62 (lb/metric ton) * 10^6 (scf/MMscf)
Hourly CO2 Emission Rate = 1 x 10^-3 metric ton/kg * 0.51 MMscf/hr * 1.028E-03 MMBtu/scf * 53.02 kg/MMBtu * 2,204.62 lb/metric ton * 10^6 scf/MMscf = 61,862.12 lb/hr CO2

Annual CO2 Emission Rate (tpy) = 1 x 10^-3 (metric ton/kg) * Annual Fuel Usage (MMscf/yr) * Default High Heat Value (MMBtu/scf) * Default Emission Factor (kg/MMBtu) * 2,204.62 (lb/metric ton) * 10^6 (scf/MMscf)/ 2,000 (lb/short ton)
Annual CO2 Emission Rate = 1 x 10^-3 metric ton/kg * 4,510 MMscf/yr * 1.028E-03 MMBtu/scf * 53.02 kg/MMBtu * 2,204.62 lb/metric ton * 10^6 scf/MMscf / 2,000 lb/short ton = 270,956.07 tpy CO2

Hourly CH4 Emission Rate (lb/hr) = 1 x 10^-3 (metric ton/kg) * Hourly Fuel Usage (MMscf/hr) * Default High Heat Value (MMBtu/scf) * Default Emission Factor (kg/MMBtu) * 2,204.62 (lb/metric ton) * 10^6 (scf/MMscf)
Hourly CH4 Emission Rate = 1 x 10^-3 metric ton/kg * 0.51 MMscf/hr * 1.028E-03 MMBtu/scf * 1.0E-03 kg/MMBtu * 2,204.62 lb/metric ton * 10^6 scf/MMscf = 1.17 lb/hr CH4

Annual CH4 Emission Rate (tpy) = 1 x 10^-3 (metric ton/kg) * Annual Fuel Usage (MMscf/yr) * Default High Heat Value (MMBtu/scf) * Default Emission Factor (kg/MMBtu) * 2,204.62 (lb/metric ton) * 10^6 (scf/MMscf)/ 2,000 (lb/short ton)
Annual CH4 Emission Rate = 1 x 10^-3 metric ton/kg * 4,510 MMscf/yr * 1.028E-03 MMBtu/scf * 1.0E-03 kg/MMBtu * 2,204.62 lb/metric ton * 10^6 scf/MMscf / 2,000 lb/short ton = 5.11 tpy CH4

Hourly N2O Emission Rate (lb/hr) = 1 x 10^-3 (metric ton/kg) * Hourly Fuel Usage (MMscf/hr) * Default High Heat Value (MMBtu/scf) * Default Emission Factor (kg/MMBtu) * 2,204.62 (lb/metric ton) * 10^6 (scf/MMscf)
Hourly N2O Emission Rate = 1 x 10^-3 metric ton/kg * 0.51 MMscf/hr * 1.028E-03 MMBtu/scf * 1.0E-04 kg/MMBtu * 2,204.62 lb/metric ton * 10^6 scf/MMscf = 0.12 lb/hr N2O

Annual N2O Emission Rate (tpy) = 1 x 10^-3 (metric ton/kg) * Annual Fuel Usage (MMscf/yr) * Default High Heat Value (MMBtu/scf) * Default Emission Factor (kg/MMBtu) * 2,204.62 (lb/metric ton) * 10^6 (scf/MMscf)/ 2,000 (lb/short ton)
Annual N2O Emission Rate = 1 x 10^-3 metric ton/kg * 4,510 MMscf/yr * 1.028E-03 MMBtu/scf * 1.0E-04 kg/MMBtu * 2,204.62 lb/metric ton * 10^6 scf/MMscf / 2,000 lb/short ton = 0.51 tpy N2O

Hourly CO2e Emission Rate (lb/hr) = [Hourly CO2 Emission Rate (lb/hr) * CO2 GWP] + [Hourly CH4 Emission Rate (lb/hr) * CH4 GWP] + [Hourly N2O Emission Rate (lb/hr) * N2O GWP]
Hourly CO2e Emission Rate = [61,862.12 lb/hr * 1] + [1.17 lb/hr * 21] + [0.12 lb/hr * 310] = 61,922.79 lb/hr CO2e

Annual CO2e Emission Rate (tpy) = [Annual CO2 Emission Rate (tpy) * CO2 GWP] + [Annual CH4 Emission Rate (tpy) * CH4 GWP] + [Annual N2O Emission Rate (tpy) * N2O GWP]
Annual CO2e Emission Rate = [270,956.07 tpy * 1] + [5.11 tpy * 21] + [0.51 tpy * 310] = 271,221.81 tpy CO2e

Greenhouse Gas (GHG) Emission Calculations - Boiler Routine Operation (Continued)

Natural Gas and AOG Combustion Emissions - Boiler House Unit Boiler No. 5

Hourly CO2 Emission Rate (lb/hr) = (1 x 10^-3 (metric ton/kg) * Natural Gas Hourly Fuel Usage (MMscf/hr) * Natural Gas Default High Heat Value (MMBtu/scf) * Natural Gas CO2 Default Emission Factor (kg/MMBtu) * 2,204.62 (lb/metric ton) * 10^6 (scf/MMscf)) + (1 x 10^-3 (metric ton/kg) * AOG Hourly Fuel Usage (MMscf/hr) * AOG High Heat Value (MMBtu/scf) * AOG CO2 Default Emission Factor (kg/MMBtu) * 2,204.62 (lb/metric ton) * 10^6 (scf/MMscf))

Hourly CO2 Emission Rate = (1 x 10^-3 metric ton/kg * 0.21 MMscf/hr * 1.028E-03 MMBtu/scf * 53.02 kg/MMBtu * 2,204.62 lb/metric ton * 10^6 scf/MMscf) + (1 x 10^-3 metric ton/kg * 4.00 MMscf/hr * 7.632E-05 MMBtu/scf * 47.79 kg/MMBtu * 2,204.62 lb/metric ton * 10^6 scf/MMscf) = 57,355.53 lb/hr CO2

Annual CO2 Emission Rate (tpy) = (1 x 10^-3 (metric ton/kg) * Natural Gas Annual Fuel Usage (MMscf/yr) * Natural Gas Default High Heat Value (MMBtu/scf) * Natural Gas CO2 Default Emission Factor (kg/MMBtu) * 2,204.62 (lb/metric ton) * 10^6 (scf/MMscf) / 2,000 (lb/short ton)) + (1 x 10^-3 (metric ton/kg) * AOG Annual Fuel Usage (MMscf/yr) * AOG High Heat Value (MMBtu/scf) * AOG CO2 Default Emission Factor (kg/MMBtu) * 2,204.62 lb/metric ton * 10^6 scf/MMscf / 2,000 lb/short ton)

Annual CO2 Emission Rate = (1 x 10^-3 metric ton/kg * 1,836.43 MMscf/yr * 1.028E-03 MMBtu/scf * 53.02 kg/MMBtu * 2,204.62 lb/metric ton * 10^6 scf/MMscf / 2,000 lb/short ton) + (1 x 10^-3 metric ton/kg * 35,040.00 MMscf/yr * 7.632E-05 MMBtu/scf * 47.79 kg/MMBtu * 2,204.62 lb/metric ton * 10^6 scf/MMscf / 2,000 lb/short ton) = 251,217.20 tpy CO2

Hourly CH4 Emission Rate (lb/hr) = (1 x 10^-3 (metric ton/kg) * Natural Gas Hourly Fuel Usage (MMscf/hr) * Natural Gas Default High Heat Value (MMBtu/scf) * CH4 Default Emission Factor (kg/MMBtu) * 2,204.62 (lb/metric ton) * 10^6 (scf/MMscf)) + (1 x 10^-3 (metric ton/kg) * AOG Hourly Fuel Usage (MMscf/hr) * AOG High Heat Value (MMBtu/scf) * CH4 Default Emission Factor (kg/MMBtu) * 2,204.62 (lb/metric ton) * 10^6 (scf/MMscf))

Hourly CH4 Emission Rate = (1 x 10^-3 metric ton/kg * 0.21 MMscf/hr * 1.028E-03 MMBtu/scf * 1.0E-03 kg/MMBtu * 2,204.62 lb/metric ton * 10^6 scf/MMscf) + (1 x 10^-3 metric ton/kg * 4.00 MMscf/hr * 7.632E-05 MMBtu/scf * 1.0E-03 kg/MMBtu * 2,204.62 lb/metric ton * 10^6 scf/MMscf) = 1.15 lb/hr CH4

Annual CH4 Emission Rate (tpy) = (1 x 10^-3 (metric ton/kg) * Natural Gas Annual Fuel Usage (MMscf/yr) * Natural Gas Default High Heat Value (MMBtu/scf) * CH4 Default Emission Factor (kg/MMBtu) * 2,204.62 (lb/metric ton) * 10^6 (scf/MMscf) / 2,000 (lb/short ton)) + (1 x 10^-3 (metric ton/kg) * AOG Annual Fuel Usage (MMscf/yr) * AOG High Heat Value (MMBtu/scf) * CH4 Default Emission Factor (kg/MMBtu) * 2,204.62 lb/metric ton * 10^6 scf/MMscf / 2,000 lb/short ton)

Annual CH4 Emission Rate = (1 x 10^-3 metric ton/kg * 1,836.43 MMscf/yr * 1.028E-03 MMBtu/scf * 1.0E-03 kg/MMBtu * 2,204.62 lb/metric ton * 10^6 scf/MMscf / 2,000 lb/short ton) + (1 x 10^-3 metric ton/kg * 35,040.00 MMscf/yr * 7.632E-05 MMBtu/scf * 1.0E-03 kg/MMBtu * 2,204.62 lb/metric ton * 10^6 scf/MMscf / 2,000 lb/short ton) = 5.03 tpy CH4

Hourly N2O Emission Rate (lb/hr) = (1 x 10^-3 (metric ton/kg) * Natural Gas Hourly Fuel Usage (MMscf/hr) * Natural Gas Default High Heat Value (MMBtu/scf) * N2O Default Emission Factor (kg/MMBtu) * 2,204.62 (lb/metric ton) * 10^6 (scf/MMscf)) + (1 x 10^-3 (metric ton/kg) * AOG Hourly Fuel Usage (MMscf/hr) * AOG High Heat Value (MMBtu/scf) * N2O Default Emission Factor (kg/MMBtu) * 2,204.62 (lb/metric ton) * 10^6 (scf/MMscf))

Hourly N2O Emission Rate = (1 x 10^-3 metric ton/kg * 0.21 MMscf/hr * 1.028E-03 MMBtu/scf * 1.0E-04 kg/MMBtu * 2,204.62 lb/metric ton * 10^6 scf/MMscf) + (1 x 10^-3 metric ton/kg * 4.00 MMscf/hr * 7.632E-05 MMBtu/scf * 1.0E-04 kg/MMBtu * 2,204.62 lb/metric ton * 10^6 scf/MMscf) = 0.11 lb/hr N2O

Annual N2O Emission Rate (tpy) = (1 x 10^-3 (metric ton/kg) * Natural Gas Annual Fuel Usage (MMscf/yr) * Natural Gas Default High Heat Value (MMBtu/scf) * N2O Default Emission Factor (kg/MMBtu) * 2,204.62 (lb/metric ton) * 10^6 (scf/MMscf) / 2,000 (lb/short ton)) + (1 x 10^-3 (metric ton/kg) * AOG Annual Fuel Usage (MMscf/yr) * AOG High Heat Value (MMBtu/scf) * N2O Default Emission Factor (kg/MMBtu) * 2,204.62 lb/metric ton * 10^6 scf/MMscf / 2,000 lb/short ton)

Annual N2O Emission Rate = (1 x 10^-3 metric ton/kg * 1,836.43 MMscf/yr * 1.028E-03 MMBtu/scf * 1.0E-04 kg/MMBtu * 2,204.62 lb/metric ton * 10^6 scf/MMscf / 2,000 lb/short ton) + (1 x 10^-3 metric ton/kg * 35,040.00 MMscf/yr * 7.632E-05 MMBtu/scf * 1.0E-04 kg/MMBtu * 2,204.62 lb/metric ton * 10^6 scf/MMscf / 2,000 lb/short ton) = 0.50 tpy N2O

Hourly CO2e Emission Rate (lb/hr) = [Hourly CO2 Emission Rate (lb/hr) * CO2 GWP] + [Hourly CH4 Emission Rate (lb/hr) * CH4 GWP] + [Hourly N2O Emission Rate (lb/hr) * N2O GWP]
Hourly CO2e Emission Rate = [57,355.53 lb/hr * 1] + [1.15 lb/hr * 21] + [0.11 lb/hr * 310] = 57,415.23 lb/hr CO2e

Annual CO2e Emission Rate (tpy) = [Annual CO2 Emission Rate (tpy) * CO2 GWP] + [Annual CH4 Emission Rate (tpy) * CH4 GWP] + [Annual N2O Emission Rate (tpy) * N2O GWP]
Annual CO2e Emission Rate = [251,217.20 tpy * 1] + [5.03 tpy * 21] + [0.50 tpy * 310] = 251,478.71 tpy CO2e

Greenhouse Gas (GHG) Emission Calculations - Piping Fugitives

Basis of Calculation:
GHG PTE emission rate calculations for the sources at the Boiler House Unit are provided below and the calculations are based on the following:
- Guidance per the EPA MRR, Subpart C (40 CFR § 98.30), dated October 30, 2009, Tier 1 Methodology;
- Default emission factors for combustion emissions of CO_2, CH_4, and N_2O per Tables C-1 and C-2 to Subpart C of Part 98;
- Global warming potentials to convert speciated GHG emission rates to emissions of CO_2e based on Table A-1 to Subpart A of Part 98; and
- Fugitive emissions are calcualated based on Oil and Gas Production Operation and Synthetic Organic Chemical Manufacturing Industry (SOCMI) without ethylene emissions factors. These factors are applied to the estimated natural gas and absorber gas piping component types and quantities to estimate fugitive total mass emissions from the natural gas and absorber off-gas piping that in the Boiler House Unit.

Calculation Parameters

Description	Parameter	Value	Units	EPA MRR Source
Default Emission Factor - CO_2	Natural Gas	53.02	(kg/MMBtu)	Table C-1 to Subpart C of Part 98
Default Emission Factor - CH_4	Natural Gas	1.0E-03	(kg/MMBtu)	Table C-2 to Subpart C of Part 98
Default Emission Factor - N_2O	Natural Gas	1.0E-04	(kg/MMBtu)	Table C-2 to Subpart C of Part 98
Default High Heat Value	Natural Gas	1.028E-03	(MMBtu/scf)	Table C-1 to Subpart C of Part 98
Global Warming Potential (100 yr.)[1]	CO_2	1	N/A	Table A-1 to Subpart A of Part 98
Global Warming Potential (100 yr.)[1]	CH_4	21	N/A	Table A-1 to Subpart A of Part 98
Global Warming Potential (100 yr.)[1]	N_2O	310	N/A	Table A-1 to Subpart A of Part 98

Footnotes:
[1] Global warming potentials are used to convert speciated GHG emission rates to emissions of CO_2e where CO_2e is the carbon dioxide equivalent.

Natural Gas Fuel Delivery System

Equipment	Service	Equipment Components	Factor (lb/hr-component)	Natural Gas Content (Wt%)	Emission Rates (lb/hr)	Emission Rates (tpy)
Valves	Gas/Vapor	50	0.00992	100	0.50	2.17
Flanges	Gas/Vapor	125	0.00086	100	0.11	0.47
Relief Valves	Gas/Vapor	6	0.0194	100	0.12	0.51
Sampling Connections	Gas/Vapor	15	0.00044	100	0.01	0.03
TOTAL					**0.73**	**3.18**

Natural Gas Speciated Emissions

Compound	Typical Wt%	Emission Rates (lb/hr)	Emission Rates (tpy)
Methane (CH_4)	89.05%	0.647	2.834
Ethane (C_2H_6)	3.44%	0.025	0.109
Propane (C_3H_8)	1.04%	0.008	0.033
n-Butane (n-C_4H_{10})	0.32%	0.002	0.010
i-Butane (i-C_4H_{10})	0.22%	0.002	0.007
n-Pentane (n-C_5H_{12})	0.22%	0.002	0.007
i-Pentane (i-C_5H_{12})	0.21%	0.002	0.007
Hexane + (C_6H_{14}+)	0.37%	0.003	0.012
Nitrogen (N_2)	1.24%	0.009	0.039
Carbon Dioxide (CO_2)	3.90%	0.028	0.124
Total VOC	**2.37%**	**0.017**	**0.076**

Greenhouse Gas (GHG) Emission Calculations - Piping Fugitives (Continued)

AOG Delivery System

Equipment	Service	Equipment Components	Factor (lb/hr-component)	AGO (Wt%)	Emission Rates (lb/hr)	(tpy)
Valves	Gas/Vapor	25	0.0089	100	0.22	0.97
Flanges	Gas/Vapor	65	0.0029	100	0.19	0.83
TOTAL					**0.41**	**1.80**

AOG Speciated Emissions

Compound	Typical Wt%	Emission Rates (lb/hr)	(tpy)
Hydrogen (H_2)	1.38%	0.00567	0.02484
Methane (CH_4)	0.37%	0.00152	0.00666
Ethane (C_2H_6)	0.09%	0.00037	0.00162
Hydrogen Cyanide (HCN)	0.01%	0.00005	0.00022
Nitrogen (N_2)	87.98%	0.36159	1.58375
Carbon Monoxide (CO)	6.46%	0.02655	0.11629
Carbon Dioxide (CO_2)	1.55%	0.00637	0.02790
Oxygen (O_2)	0.12%	0.00049	0.00216
Ammonia (NH_3)	0.001%	0.00000	0.00002
Water (H_2O)	0.46%	0.00189	0.00828
Inerts	1.58%	0.00649	0.02844
Total VOC	**0.01%**	**0.00005**	**0.00022**

Natural Gas Distillate

Equipment	Service	Equipment Components	Factor (lb/hr-component)	Natural Gas Content (Wt%)	Emission Rates (lb/hr)	(tpy)
Valves	Gas/Vapor	10	0.0089	100	0.09	0.39
Valves	Light Liquid	10	0.0035	100	0.04	0.15
Flanges	Gas/Vapor	30	0.0029	100	0.09	0.38
Flanges	Light Liquid	30	0.0005	100	0.02	0.07
Relief Valves	Gas/Vapor	2	0.2293	100	0.46	2.01
TOTAL					**0.68**	**3.00**

Natural Gas Distillate Speciated Emissions

Compound	Typical Wt%	Emission Rates (lb/hr)	(tpy)
Methane (CH_4)	0.02%	0.0001	0.0005
Ethane (C_2H_6)	0.22%	0.0015	0.0065
Propane (C_3H_8)	3.45%	0.0236	0.1035
n-Butane (n-C_4H_{10})	12.21%	0.0836	0.3662
i-Butane (i-C_4H_{10})	2.75%	0.0188	0.0825
n-Pentane (n-C_5H_{12})	15.57%	0.1066	0.4668
i-Pentane (i-C_5H_{12})	11.77%	0.0806	0.3531
Hexane + (C_6H_{14}+)	54.01%	0.3697	1.6195
Total VOC	**99.76%**	**0.68**	**2.99**

Greenhouse Gas (GHG) Emission Calculations - Piping Fugitives (Continued)

Maximum Hourly GHG Emissions

EPN	FIN	Name	[illegible]	[illegible]			
				CO_2	CH_4	N_2O	CO_2e
[illegible]	[illegible]	Piping Fugitives	NA	0.03	0.65	--	13.66
Total			NA	0.03	0.65	--	13.66

Annual GHG Emissions

EPN	FIN	Name	[illegible]	[illegible]			
				CO_2	CH_4	N_2O	CO_2e
[illegible]	[illegible]	Piping Fugitives	NA	0.15	2.84	--	59.81
Total			NA	0.15	2.84	--	59.81

Example Calculations

Fugitives Emission Calculations

Sample Calculation: AOG Gas/Vapor Valves

Emission Rate (lb/hr) = Equipment Count (cpt) * Emission Factor (lb/hr/cpt) * Wt% AOG in the Stream
lb/hr = 25 (cpt) * 0.0089 (lb/hr/cpt) * 100 %
lb/hr = 0.22
Emission Rate (tpy) = Maximum Hourly Emission Rate (lb/hr) * 8,760 (hr/yr) / 2,000 (lb/ton)
tpy = 0.22 lb/hr * 8,760 hr/yr / 2,000 lb/ton
tpy = 0.97

Speciated Sample Calculation: Methane (CH_4)

Methane Maximum Hourly Emission Rate (lb/hr) = Wt% Methane in AOG Delivery System * Total AOG Fugitive Emissions (lb/hr)
lb/hr = 0.37 % * 0.41 lb/hr
lb/hr = 0.0015
Methane Annual Emission Rate (tpy) = Wt% Methane in AOG Delivery System * Total AOG Fugitive Emissions (tpy)
tpy = 0.37 % * 1.80 tpy
tpy = 0.0067

Fugitive GHG Emission Calculations

Fugitive Emissions from Fuel Usage - Boiler House Unit Piping Fugitives

Hourly CO_2e Emission Rate (lb/hr) = [Hourly CO_2 Emission Rate (lb/hr) * CO_2 GWP] + [Hourly CH_4 Emission Rate (lb/hr) * CH_4 GWP] + [Hourly N_2O Emission Rate (lb/hr) * N_2O GWP]

Hourly CO2e Emission Rate = [0.03 lb/hr * 1] + [0.65 lb/hr * 21] + [0.00 lb/hr * 310] = 13.66 lb/hr CO2e

Annual CO_2e Emission Rate (tpy) = [Annual CO_2 Emission Rate (tpy) * CO_2 GWP] + [Annual CH_4 Emission Rate (tpy) * CH_4 GWP] + [Annual N_2O Emission Rate (tpy) * N_2O GWP]

Annual CO2e Emission Rate = [0.15 tpy * 1] + [2.84 tpy * 21] + [0.00 tpy * 310] = 59.81 tpy CO2e

Greenhouse Gas (GHG) Emission Calculations - Boiler Maintenance Startup and Shutdown Activities

Basis of Calculation:
GHG PTE emission rate calculations for the sources at the Boiler House Unit are provided below and the calculations are based on the following:

- Guidance per the EPA MRR, Subpart C (40 CFR § 98.30), dated October 30, 2009, Tier 1 Methodology;
- Default emission factors for combustion emissions of CO_2, CH_4, and N_2O per Tables C-1 and C-2 to Subpart C of Part 98;
- Global warming potentials to convert speciated GHG emission rates to emissions of CO_2e based on Table A-1 to Subpart A of Part 98; and
- Fuel usage at the Boiler House Unit during MSS activities are based on maximum annual hours of operation for each activity.

Calculation Parameters

Description	Parameter	Value	Units	EPA MRR Source
Default Emission Factor - CO_2	Natural Gas	53.02	(kg/MMBtu)	Table C-1 to Subpart C of Part 98
Default Emission Factor - CH_4	Natural Gas	1.0E-03	(kg/MMBtu)	Table C-2 to Subpart C of Part 98
Default Emission Factor - N_2O	Natural Gas	1.0E-04	(kg/MMBtu)	Table C-2 to Subpart C of Part 98
Default High Heat Value	Natural Gas	1.028E-03	(MMBtu/scf)	Table C-1 to Subpart C of Part 98
Global Warming Potential (100 yr.)[1]	CO_2	1	N/A	Table A-1 to Subpart A of Part 98
Global Warming Potential (100 yr.)[1]	CH_4	21	N/A	Table A-1 to Subpart A of Part 98
Global Warming Potential (100 yr.)[1]	N_2O	310	N/A	Table A-1 to Subpart A of Part 98

Footnotes:
[1] Global warming potentials are used to convert speciated GHG emission rates to emissions of CO_2e where CO_2e is the carbon dioxide equivalent.

Boiler House Unit Potential Combustion Source List and Heat Capacity Ratings

EPN	FIN	Name	Fuel Type	Heat Capacity MMBtu/hr	Typical High Heat Value of Fuel to Boiler Btu/scf	Fuel Usage MMscf/hr [1]	Heat Capacity MMBtu/yr	Fuel Usage MMscf/yr [1]
BH-2-5_MSS	BH-2-5_MSS	Boiler No. 5 Startup	Natural Gas	515.00	1,000.34	0.51	61,800.00	61.78
BH-2-5_MSS	BH-2-5_MSS	Boiler No. 5 Shutdown	Natural Gas	515.00	1,000.34	0.51	7,725.00	7.72
BH-2-6_MSS	BH-2-6_MSS	Boiler No. 6 Startup	Natural Gas	515.00	1,000.34	0.51	61,800.00	61.78
BH-2-6_MSS	BH-2-6_MSS	Boiler No. 6 Shutdown	Natural Gas	515.00	1,000.34	0.51	7,725.00	7.72

Footnote:
[1] Calculated emission rates are based on maximum potential emissions; therefore, Fuel Usage (MMscf/hr and MMscf/yr) is based on the Maximum Heat Capacity (MMBtu/hr and MMBtu/yr) for each boiler and the calculated High Heat Value (1,000.34 Btu/scf) for the fuel.

Greenhouse Gas (GHG) Emission Calculations - Boiler Maintenance Startup and Shutdown Activities (Continued)

Maximum Hourly GHG Emissions

EPN	FIN	Name	Fuel Gas Usage (MMscf/hr)	Hourly GHG Emissions (lb/hr)			
				CO_2	CH_4	N_2O	CO2e
BH-2-5_MSS	BH-2-5_MSS	Boiler No. 5 Startup	0.51	61,862.12	1.17	0.12	61,922.79
BH-2-5_MSS	BH-2-5_MSS	Boiler No. 5 Shutdown	0.51	61,862.12	1.17	0.12	61,922.79
BH-2-6_MSS	BH-2-6_MSS	Boiler No. 6 Startup	0.51	61,862.12	1.17	0.12	61,922.79
BH-2-6_MSS	BH-2-6_MSS	Boiler No. 6 Shutdown	0.51	61,862.12	1.17	0.12	61,922.79
Total			**2.06**	**61,862.12**	**1.17**	**0.12**	**61,922.79**

NOTE: During MSS activities, the boilers will not be shutdown and started up in the same hour. Additionally, only one boiler will be shutdown and started up at a time. Therefore, the total hourly GHG emission rates are calculated by taking the maximum emissions from boiler No. 5 and boiler No. 6 startup and shutdown activities.

Annual GHG Emissions

EPN	FIN	Name	Fuel Gas Usage (MMscf/yr)	Annual GHG Emissions (tpy)			
				CO_2	CH_4	N_2O	CO_2e
BH-2-5_MSS	BH-2-5_MSS	Boiler No. 5 Startup	61.78	3,711.73	0.07	0.01	3,715.37
BH-2-5_MSS	BH-2-5_MSS	Boiler No. 5 Shutdown	7.72	463.97	0.01	0.00	464.42
BH-2-6_MSS	BH-2-6_MSS	Boiler No. 6 Startup	61.78	3,711.73	0.07	0.01	3,715.37
BH-2-6_MSS	BH-2-6_MSS	Boiler No. 6 Shutdown	7.72	463.97	0.01	0.00	464.42
Total			**139.00**	**8,351.39**	**0.16**	**0.02**	**8,359.58**

Greenhouse Gas (GHG) Emission Calculations - Boiler Maintenance Startup and Shutdown Activities (Continued)

Example Calculations

Natural Gas Combustion Emissions - Boiler House Unit Boiler No. 5 Startup

Hourly CO_2 Emission Rate (lb/hr) = 1 x 10^-3 (metric ton/kg) * Hourly Fuel Usage (MMscf/hr) * Default High Heat Value (MMBtu/scf) * Default Emission Factor (kg/MMBtu) * 2,204.62 (lb/metric ton) * 10^6 (scf/MMscf)
Hourly CO_2 Emission Rate = 1 x 10^-3 metric ton/kg * 0.51 MMscf/hr * 1.028E-03 MMBtu/scf * 53.02 kg/MMBtu * 2,204.62 lb/metric ton * 10^6 scf/MMscf = 61,862.12 lb/hr CO_2

Annual CO_2 Emission Rate (tpy) = 1 x 10^-3 (metric ton/kg) * Annual Fuel Usage (MMscf/yr) * Default High Heat Value (MMBtu/scf) * Default Emission Factor (kg/MMBtu) * 2,204.62 (lb/metric ton) * 10^6 (scf/MMscf) / 2,000 (lb/short ton)

Annual CO_2 Emission Rate = 1 x 10^-3 metric ton/kg * 62 MMscf/yr * 1.028E-03 MMBtu/scf * 53.02 kg/MMBtu * 2,204.62 lb/metric ton * 10^6 scf/MMscf / 2,000 lb/short ton = 3,711.73 tpy CO_2

Hourly CH_4 Emission Rate (lb/hr) = 1 x 10^-3 (metric ton/kg) * Hourly Fuel Usage (MMscf/hr) * Default High Heat Value (MMBtu/scf) * Default Emission Factor (kg/MMBtu) * 2,204.62 (lb/metric ton) * 10^6 (scf/MMscf)
Hourly CH_4 Emission Rate = 1 x 10^-3 metric ton/kg * 0.51 MMscf/hr * 1.028E-03 MMBtu/scf * 1.0E-03 kg/MMBtu * 2,204.62 lb/metric ton * 10^6 scf/MMscf = 1.17 lb/hr CH_4

Annual CH_4 Emission Rate (tpy) = 1 x 10^-3 (metric ton/kg) * Annual Fuel Usage (MMscf/yr) * Default High Heat Value (MMBtu/scf) * Default Emission Factor (kg/MMBtu) * 2,204.62 (lb/metric ton) * 10^6 (scf/MMscf) / 2,000 (lb/short ton)
Annual CH_4 Emission Rate = 1 x 10^-3 metric ton/kg * 62 MMscf/yr * 1.028E-03 MMBtu/scf * 1.0E-03 kg/MMBtu * 2,204.62 lb/metric ton * 10^6 scf/MMscf / 2,000 lb/short ton = 0.07 tpy CH_4

Hourly N_2O Emission Rate (lb/hr) = 1 x 10^-3 (metric ton/kg) * Hourly Fuel Usage (MMscf/hr) * Default High Heat Value (MMBtu/scf) * Default Emission Factor (kg/MMBtu) * 2,204.62 (lb/metric ton) * 10^6 (scf/MMscf)
Hourly N_2O Emission Rate = 1 x 10^-3 metric ton/kg * 0.51 MMscf/hr * 1.028E-03 MMBtu/scf * 1.0E-04 kg/MMBtu * 2,204.62 lb/metric ton * 10^6 scf/MMscf = 0.12 lb/hr N_2O

Annual N_2O Emission Rate (tpy) = 1 x 10^-3 (metric ton/kg) * Annual Fuel Usage (MMscf/yr) * Default High Heat Value (MMBtu/scf) * Default Emission Factor (kg/MMBtu) * 2,204.62 (lb/metric ton) * 10^6 (scf/MMscf) / 2,000 (lb/short ton)
Annual N_2O Emission Rate = 1 x 10^-3 metric ton/kg * 62 MMscf/yr * 1.028E-03 MMBtu/scf * 1.0E-04 kg/MMBtu * 2,204.62 lb/metric ton * 10^6 scf/MMscf / 2,000 lb/short ton = 0.01 tpy N_2O

Hourly CO_2e Emission Rate (lb/hr) = [Hourly CO_2 Emission Rate (lb/hr) * CO_2 GWP] + [Hourly CH_4 Emission Rate (lb/hr) * CH_4 GWP] + [Hourly N_2O Emission Rate (lb/hr) * N_2O GWP]
Hourly CO_2e Emission Rate = [61,862.12 lb/hr * 1] + [1.17 lb/hr * 21] + [0.12 lb/hr * 310] = 61,922.79 lb/hr CO_2e

Annual CO_2e Emission Rate (tpy) = [Annual CO_2 Emission Rate (tpy) * CO_2 GWP] + [Annual CH_4 Emission Rate (tpy) * CH_4 GWP] + [Annual N_2O Emission Rate (tpy) * N_2O GWP]
Annual CO_2e Emission Rate = [3,711.73 tpy * 1] + [0.07 tpy * 21] + [0.01 tpy * 310] = 3,715.37 tpy CO_2e

Appendix B
RACT/BACT/LAER Clearinghouse Search Results

Facility Information

RBLC ID: TX-0481 (final)

Corporate/Company Name: AIR PRODUCTS LP

Facility Name: AIR PRODUCTS BAYTOWN I I

Facility Contact: KATHLEEN BRANDT 2818380202

Facility Description: THIS FACILITY GETS RAW SYNTHESIS GAS FROM EXXON¿S SYNTHESIS GAS MANUFACTURING UNIT. THE RAW SYNGAS STREAM FROM THE EXXON PLANT, CONSISTING OF CO2, CO, H2, H2S, COS, HCN, NH3 AND METHANE, IS PIPED TO THE AIR PRODUCTS PLANT WHERE THE ACID GASES AND AMMONIA WILL BE REMOVED BY AIR PRODUCTS¿ RECTISOL UNIT. THE PRODUCTS PRODUCED INCLUDE CO, AND TWO PURE SYNTHESES GAS PRODUCTS. THESE PRODUCTS ARE DISTRIBUTED TO CUSTOMERS VIA PIPELINES. AN IMPURE SYNGAS IS ALSO PRODUCED AND USED OFFSITE AS FUEL. THE NEW PROCESS WILL CONVERT A PORTION OF THE SYNGAS TO HYDROGEN. THE HYDROGEN WILL BE PURIFIED AND DISTRIBUTED TO CUSTOMERS.

Permit Type: U: Unspecified

Permit URL:

EPA Region: 6

Facility Connty: HARRIS

Facility State: TX

Facility ZIP Code: 77520

Permit Issued By: TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ) (Agency Name)
MR. JOHNNY VERMILLION(Agency Contact) (512) 239-1292 John.Vermillion@tceq.texas.gov

Permit Notes: AIR PRODUCTS REQUESTED AN AMENDMENT TO AUTHORIZE THE ADDITION OF A HYDROGEN PURIFICATION SYSTEM TO THEIR SYN GAS PRODUCTION FACILITY. THE REQUESTED ADDITIONS INCLUDED: 1) A SHIFT REACTOR TO PRODUCE ADDITIONAL HYDROGEN 2) 2 PRESSURE SWING ADSORBERS (PSA¿S) TO PURIFY HYDROGEN 3) A 350 MMBTU/HR BOILER (EPN 7) TO GENERATE STEAM FIRING PSA TAIL GAS . THE BOILER EMITS MORE THAN 100 TPY CO, MAKING THIS PERMIT A PSD PROJECT FOR CO, PSD PERMIT NO. P1044. THE COMPANY

Date Determination
Last Updated: 10/01/2007

Permit Number: PSD-TX-1044 / 35873

Permit Date: 11/02/2004 (actual)

FRS Number: 110012710423

SIC Code: 492

NAICS Code: 486210

COUNTRY: USA

ALSO INCLUDED THE FOLLOWING PERMIT BY RULES: AUTHORIZATION TYPE NUMBER DESCRIPTION PBR 43611 A DIESEL FUEL TANK (EPN 8), MEETS BACT, SEE SOURCES AND CONTROLS PBR 43611 A PROCESS STEAM VENT (EPN SVENT1), MEETS BACT, SEE SOURCES AND CONTROLS 106.511 NONE AN EMERGENCY GENERATOR (EPN 9), MEETS BACT, SEE SOURCES AND CONTROLS FINALLY, THE COMPANY AUTHORIZED A START UP PROCESS VENT FOR THE SHIFT REACTOR STEAM DRUM. THERE ARE VIRTUALLY NO VOC EMISSIONS FROM THE VENT. THERE WAS A SMALL INCREASE IN FUGITIVE EMISSIONS DUE TO NEW PIPING FOR THE SHIFT REACTOR SYSTEM.

Process/Pollutant Information

PROCESS NAME: BOILER STACK

Process Type: 11.390 (Other Gaseous Fuel & Gaseous Fuel Mixtures)

Primary Fuel: NATURAL GAS

Throughput:

Process Notes: CO EMISSIONS ARE ELIGIBLE FOR PSD

POLLUTANT NAME: Carbon Monoxide

CAS Number: 630-08-0

Test Method: Unspecified

Pollutant Group(s): (InOrganic Compounds)

Emission Limit 1: 28.3000 LB/H

Emission Limit 2: 123.8000 T/YR

Standard Emission:

Did factors, other than air pollution technology considerations influence the BACT decisions: U

Case-by-Case Basis: N/A

Other Applicable Requirements:

Control Method: (N)

Est. % Efficiency:

Compliance Verified: Unknown

Pollutant/Compliance Notes:

POLLUTANT NAME: Nitrogen Oxides (NOx)
CAS Number: 10102
Test Method: Unspecified
Pollutant Group(s): (InOrganic Compounds , Oxides of Nitrogen (NOx) , Particulate Matter (PM))
Emission Limit 1: 6.0000 LB/H
Emission Limit 2: 9.2100 T/YR
Standard Emission:
Did factors, other than air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: N/A
Other Applicable Requirements:
Control Method: (N)
Est. % Efficiency:
Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Sulfur Dioxide (SO2)
CAS Number: 7446-09-5
Test Method: Unspecified
Pollutant Group(s): (InOrganic Compounds , Oxides of Sulfur (SOx))
Emission Limit 1: 24.2000 LB/H
Emission Limit 2: 9.9400 T/YR
Standard Emission:
Did factors, other than air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: N/A
Other Applicable Requirements:
Control Method: (N)
Est. % Efficiency:
Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Ammonia (NH3)
CAS Number: 7664-41-7
Test Method: Unspecified
Pollutant Group(s): (InOrganic Compounds)
Emission Limit 1: 2.4500 LB/H
Emission Limit 2: 10.7400 T/YR
Standard Emission:
Did factors, other than air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: N/A
Other Applicable Requirements:
Control Method: (N)
Est. % Efficiency:
Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Volatile Organic Compounds (VOC)
CAS Number: VOC
Test Method: Unspecified
Pollutant Group(s): (Volatile Organic Compounds (VOC))
Emission Limit 1: 33.1800 LB/H
Emission Limit 2: 9.2100 T/YR
Standard Emission:
Did factors, other than air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: N/A
Other Applicable Requirements:
Control Method: (N)
Est. % Efficiency:
Compliance Verified: Unknown

Pollutant/Compliance Notes:

POLLUTANT NAME:	Particulate matter, filterable < 10 µ (FPM10)
CAS Number:	PM
Test Method:	Unspecified
Pollutant Group(s):	(Particulate Matter (PM))
Emission Limit 1:	2.6100 LB/H
Emission Limit 2:	11.4300 T/YR
Standard Emission:	

Did factors, other than air pollution technology considerations influence the BACT decisions: U

Case-by-Case Basis:	N/A
Other Applicable Requirements:	
Control Method:	(N)
Est. % Efficiency:	
Compliance Verified:	Unknown
Pollutant/Compliance Notes:	

Process/Pollutant Information

PROCESS NAME:	BOILER STACK (HIGH BTU FUEL)
Process Type:	11.390 (Other Gaseous Fuel & Gaseous Fuel Mixtures)
Primary Fuel:	
Throughput:	
Process Notes:	

POLLUTANT NAME:	Nitrogen Oxides (NOx)
CAS Number:	10102
Test Method:	Unspecified
Pollutant Group(s):	(InOrganic Compounds , Oxides of Nitrogen (NOx) , Particulate Matter (PM))

Emission Limit 1: 21.0000 LB/H
Emission Limit 2:
Standard Emission:
Did factors, other than air pollution technology considerations inflnence the BACT decisions: U
Case-by-Case Basis: N/A
Other Applicable Requirements:
Control Method: (N)
Est. % Efficiency:
Compliance Verified: Unknown
Pollutant/Compliance Notes:

Process/Pollutant Information

PROCESS NAME: BOILER STACK (START UP)
Process Type: 13.390 (Other Gaseous Fuel & Gaseous Fuel Mixtures)
Primary Fuel:
Tbroughput:
Process Notes:

POLLUTANT NAME: Nitrogen Oxides (NOx)
CAS Number: 10102
Test Method: Unspecified
Pollutant Group(s): (InOrganic Compounds , Oxides of Nitrogen (NOx) , Particulate Matter (PM))
Emission Limit 1: 176.7800 LB/H
Emission Limit 2:
Standard Emission:
Did factors, other than air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: N/A
Other Applicable

Requirements:
Control Method: (N)
Est. % Efficiency:
Compliance Verified: Unknown
Pollutant/Compliauce Notes:

Facility Information

RBLC ID: LA-0248 (final)

Date Determination Last Updated: 12/08/2011

Corporate/Company Name: CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC - NUCOR

Permit Number: PSD-LA-751

Facility Name: DIRECT REDUCTION IRON PLANT

Permit Date: 01/27/2011 (actual)

Facility Contact: STEVE ROWLAN (704) 366-7000

FRS Number: 110037583442

Facility Description: The DRI process reduces the iron oxide content of iron ore pellets into iron metal through direct contact with a reducing gas. The effectiveness of this reduction process is called metallization, and the process equipment will be designed to achieve a metallization rate of at least 92% of the oxides within the ore. The reduction will take place in a countercurrent vertical shaft furnace, where reducing gas passes up through iron oxide pellets, which feed through the furnace by gravity. The major elements of the DRI process include the following: (1) iron oxide preparation; (2) reducing gas preparation; (3) DRI reactor shaft furnace; (4) spent reducing gas preparation for reuse, (5) DRI product handling; and (6) ancillary operations, including a package boiler, two cooling towers, and a flare for emergency situations.

SIC Code: 3312

Permit Type: B: Add new process to existing facility

NAICS Code: 331111

Permit URL:

EPA Region: 6

COUNTRY: USA

Facility County: ST JAMES PARISH

Facility State: LA

Facility ZIP Code: 70723

Permit Issued By: LOUISIANA DEPARTMENT OF ENV QUALITY (Agency Name)
MR. BRYAN D. JOHNSTON(Agency Contact) (225)219-3450 BRYAN.JOHNSTON@LA.GOV

Other Agency Contact Info: Kermit Wittenburg
kermit.wittenburg@la.gov

Permit Notes: This PSD permit also evaluated BACT for Green House Gases

Facility-wide Emissions:

Pollutant Name:	Facility-wide Emissions Increase:
Carbon Monoxide	581.8400 (Tons/Year)
Nitrogen Oxides (NOx)	117.6200 (Tons/Year)
Particulate Matter (PM)	135.5600 (Tons/Year)
Sulfur Oxides (SOx)	28.3400 (Tons/Year)
Volatile Organic Compounds (VOC)	33.9400 (Tons/Year)

Process/Pollutant Information

PROCESS NAME: DRI-109 - DRI Unit #1 Package Boiler Flue Stack

Process Type: 11.310 (Natural Gas (includes propane and liquefied petroleum gas))

Primary Fuel: Natural Gas

Throughput: 1760.00 Billion Btu/yr

Process Notes: The package boilers provide steam to each DRI unit. The steam is primarily used to heat the reboiler in the acid gas absorption system, as well as for utility purposes.

POLLUTANT NAME: Particulate matter, filterable < 10 µ (FPM10)

CAS Number: PM

Test Method: EPA/OAR Mthd 201A

Pollutant Group(s): (Particulate Matter (PM))

Emission Limit 1: 2.3800 LB/H

Emission Limit 2: 8.6400 T/YR

Staudard Emission: 0.0046 GRAINS/DSCF

Did factors, other than air pollution technology considerations influence the BACT decisions: N

Case-by-Case Basis: BACT-PSD

Other Applicable Requirements:

Control Method: (P) good combustion practices

Est. % Efficiency:

Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Carbon Monoxide
CAS Number: 630-08-0
Test Method: EPA/OAR Mthd 10
Pollutant Group(s): (InOrganic Compounds)
Emission Limit 1: 11.4200 LB/H
Emission Limit 2: 41.5400 T/YR
Standard Emission: 0.0390 LB/MMBTU
Did factors, other than air pollution technology considerations influence the BACT decisions: N
Case-by-Case Basis: BACT-PSD
Other Applicable Requirements:
Control Method: (P) Good Combustion Practices
Est. % Efficiency:
Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Sulfur Dioxide (SO2)
CAS Number: 7446-09-5
Test Method: Unspecified
Pollutant Group(s): (InOrganic Compounds , Oxides of Sulfur (SOx))
Emission Limit 1: 0.0900 LB/H
Emission Limit 2: 0.3300 T/YR
Standard Emission:
Did factors, other than air pollution technology considerations influence the BACT decisions: N
Case-by-Case Basis: BACT-PSD
Other Applicable Requirements:
Control Method: (P) Emissions of SO2 are usually attributable to the sulfur contained within the fuel being combusted.

	Therefore the use of a low sulfur fuel can drastically reduce emissions of SO2 when compared to other potential fuels.
Est. % Efficiency:	
Compliance Verified:	Unknown
Pollutant/Compliauce Notes:	Sulfur dioxide: Purchase natural gas with a sulfur content less than 2000 grains per million standard cubic feet of gas. Sulfur content shall be monitored and recorded monthly and shall be based on either the natural gas analysis provided by the supplier or direct sampling by the facility

POLLUTANT NAME:	Nitrogen Oxides (NOx)
CAS Number:	10102
Test Method:	EPA/OAR Mthd 7E
Pollutant Group(s):	(InOrganic Compounds , Oxides of Nitrogen (NOx) , Particulate Matter (PM))
Emission Limit 1:	0.9400 LB/H
Emission Limit 2:	3.4100 T/YR
Standard Emission:	0.0032 LB/MMBTU

Did factors, other than air pollution technology considerations iufluence the BACT decisions: N

Case-by-Case Basis:	BACT-PSD
Other Applicable Requirements:	NSPS
Control Method:	(B) BACT for the package boiler is selected to be low NOX burners, combined with selective catalytic reduction.
Est. % Efficiency:	90.000
Compliance Verified:	No
Pollutant/Compliance Notes:	

POLLUTANT NAME:	Volatile Organic Compounds (VOC)
CAS Number:	VOC
Test Method:	Unspecified
Pollutant Group(s):	(Volatile Organic Compounds (VOC))
Emission Limit 1:	1.5600 LB/H
Emission Limit 2:	4.7500 T/YR
Staudard Emissiou:	

Did factors, other than air pollution technology considerations influence the BACT decisions: N

Case-by-Case Basis: BACT-PSD

Other Applicable Requirements:

Control Method: (P) good combustion practices

Est. % Efficiency:

Compliance Verified: Unknown

Pollutant/Compliance Notes:

Process/Pollutant Information

PROCESS NAME: DRI-209 - DRI Unit #2 Package Boiler Flue Stack

Process Type: 11.310 (Natural Gas (includes propane and liquefied petroleum gas))

Primary Fuel: Natural Gas

Throughput: 1760.00 Billion Btu/yr

Process Notes: The package boilers provide steam to each DRI unit. The steam is primarily used to heat the reboiler in the acid gas absorption system, as well as for utility purposes.

POLLUTANT NAME: Particulate matter, filterable < 10 µ (FPM10)

CAS Number: PM

Test Method: EPA/OAR Mthd 201A

Pollutant Group(s): (Particulate Matter (PM))

Emission Limit 1: 2.3800 LB/H

Emission Limit 2: 8.6400 T/YR

Standard Emission: 0.0046 GRAINS/DSCF

Did factors, other than air pollution technology considerations influence the BACT decisions: N

Case-by-Case Basis: BACT-PSD

Other Applicable Requirements:

Control Method: (P) good combustion practices

Est. % Efficiency:
Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Carbon Monoxide
CAS Number: 630-08-0
Test Method: EPA/OAR Mthd 10
Pollutant Group(s): (InOrganic Compounds)
Emission Limit 1: 11.4200 LB/H
Emissiou Limit 2: 41.5400 T/YR
Standard Emissiou: 0.0390 LB/MMBTU
Did factors, other than air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: BACT-PSD
Other Applicable Requirements:
Control Method: (P) Good Combustion Practices
Est. % Efficiency:
Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Sulfur Dioxide (SO2)
CAS Number: 7446-09-5
Test Method: Unspecified
Pollutant Group(s): (InOrganic Compounds , Oxides of Sulfur (SOx))
Emission Limit 1: 0.0900 LB/H
Emission Limit 2: 0.3300 T/YR
Standard Emission:
Did factors, other than air pollution technology considerations influence the BACT decisions: N
Case-by-Case Basis: BACT-PSD
Other Applicable Requirements:

Control Method:	(P) Emissions of SO2 are usually attributable to the sulfur contained within the fuel being combusted. Therefore the use of a low sulfur fuel can drastically reduce emissions of SO2 when compared to other potential fuels.
Est. % Efficiency:	
Compliance Verified:	Unknown
Pollutant/Compliance Notes:	Sulfur dioxide: Purchase natural gas with a sulfur content less than 2000 grains per million standard cubic feet of gas. Sulfur content shall be monitored and recorded monthly and shall be based on either the natural gas analysis provided by the supplier or direct sampling by the facility

POLLUTANT NAME:	Nitrogen Oxides (NOx)
CAS Number:	10102
Test Method:	EPA/OAR Mthd 7E
Pollutant Group(s):	(InOrganic Compounds , Oxides of Nitrogen (NOx) , Particulate Matter (PM))
Emission Limit 1:	0.9400 LB/H
Emissiou Limit 2:	3.4100 T/YR
Standard Emission:	0.0032 LB/MMBTU

Did factors, other than air pollution technology considerations influence the BACT decisions: N

Case-by-Case Basis:	BACT-PSD
Other Applicable Requirements:	NSPS
Control Method:	(B) BACT for the package boiler is selected to be low NOX burners, combined with selective catalytic reduction.
Est. % Efficiency:	90.000
Compliance Verified:	No
Pollutant/Compliance Notes:	

POLLUTANT NAME:	Volatile Organic Compounds (VOC)
CAS Number:	VOC
Test Method:	Unspecified
Pollutant Group(s):	(Volatile Organic Compounds (VOC))
Emission Limit 1:	1.1900 LB/H
Emission Limit 2:	4.7500 T/YR

Standard Emission:

Did factors, other than air pollution technology considerations influence the BACT decisions: N

Case-by-Case Basis:	BACT-PSD
Other Applicable Requirements:	
Control Method:	(P) good combustion practices
Est. % Efficiency:	
Compliance Verified:	Unknown
Pollutant/Compliance Notes:	

Facility Information

RBLC ID:	LA-0254 (final)	**Date Determination Last Updated:**	12/12/2011
Corporate/Company Name:	ENTERGY LOUISIANA LLC	**Permit Number:**	PSD-LA-752
Facility Name:	NINEMILE POINT ELECTRIC GENERATING PLANT	**Permit Date:**	08/16/2011 (actual)
Facility Contact:	CHRISTEE HERBERT (504) 576-5699 CHERBER@ENTERGY.COM	**FRS Number:**	110002049328
Facility Description:	1827 MW POWER PLANT (PRE-PROJECT). NATURAL GAS IS PRIMARY FUEL; NO. 2 & NO. 4 FUEL OIL ARE SECONDARY FUELS. PROJECT INVOLVES DECOMMISSIONING OF 2 BOILERS AND THE CONSTRUCTION OF 2 COMBINED CYCLE GAS TURBINES WITH DUCT BURNERS, A NATURAL GAS-FIRED AUXILIARY BOILER, A DIESEL GENERATOR, 2 COOLING TOWERS, A FUEL OIL STORAGE TANK, A DIESEL-FIRED FIREWASTER PUMP, AND AN ANHYDROUS AMMONIA TANK. FUELS FOR THE TURBINES INCLUDE NATURAL GAS, NO. 2 FUEL OIL, AND ULTRA LOW SULFUR DIESEL.	**SIC Code:**	4911
Permit Type:	B: Add new process to existing facility	**NAICS Code:**	221112
Permit URL:			
EPA Region:	6	**COUNTRY:**	USA
Facility County:	JEFFERSON		

Facility State:	LA
Facility ZIP Code:	70094
Permit Issued By:	LOUISIANA DEPARTMENT OF ENV QUALITY (Agency Name) MR. BRYAN D. JOHNSTON(Agency Contact) (225)219-3450 BRYAN.JOHNSTON@LA.GOV
Other Agency Contact Info:	PERMIT WRITER: CHRIS SMITH, (225) 219-3417
Permit Notes:	APPLICATION ACCEPTED RECEIVED DATE = DATE OF ADMINISTRATIVE COMPLETENESS BACT FOR GREENHOUSE GASES (CO2E) FROM THE COMBINED CYCLE TURBINE GENERATORS (UNITS 6A & 6B) IS OPERATING PROPERLY AND PERFORMING NECESSARY ROUTINE MAINTENANCE, REPAIR, AND REPLACEMENT TO MAINTAIN THE GROSS HEAT RATE AT OR BELOW 7630 BTU/KW-HR (HHV) (ANNUAL AVERAGE).

Process/Pollutant Information

PROCESS NAME:	AUXILIARY BOILER (AUX-1)
Process Type:	11.310 (Natural Gas (includes propane and liquefied petroleum gas))
Primary Fuel:	NATURAL GAS
Throughput:	338.00 MMBTU/H
Process Notes:	

POLLUTANT NAME:	Particulate matter, total < 10 µ (TPM10)
CAS Number:	PM
Test Method:	Unspecified
Pollutant Group(s):	(Particulate Matter (PM))
Emission Limit 1:	7.6000 LB/MMSCF ANNUAL AVERAGE
Emission Limit 2:	
Standard Emission:	7.6000 LB/MMSCF ANNUAL AVERAGE

Did factors, other than air pollution technology considerations influence the BACT decisions: U

Case-by-Case Basis:	BACT-PSD
Other Applicable Requirements:	OPERATING PERMIT
Control Method:	(P) USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES
Est. % Efficiency:	

Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Particulate matter, total < 2.5 μ (TPM2.5)
CAS Number: PM
Test Method: Unspecified
Pollutant Group(s): (Particulate Matter (PM))
Emission Limit 1: 7.6000 LB/MMSCF ANNUAL AVERAGE
Emission Limit 2:
Standard Emission: 7.6000 LB/MMSCF ANNUAL AVERAGE
Did factors, other than air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: BACT-PSD
Other Applicable Requirements: OPERATING PERMIT
Control Method: (P) USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES
Est. % Efficiency:
Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Carbon Monoxide
CAS Number: 630-08-0
Test Method: Unspecified
Pollutant Group(s): (InOrganic Compounds)
Emission Limit 1: 84.0000 LB/MMSCF ANNUAL AVERAGE
Emission Limit 2:
Standard Emission: 84.0000 LB/MMSCF ANNUAL AVERAGE
Did factors, other than air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: BACT-PSD
Other Applicable Requirements: OPERATING PERMIT
Control Method: (P) USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES

Est. % Efficiency:
Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Volatile Organic Compounds (VOC)
CAS Number: VOC
Test Method: Unspecified
Pollutant Group(s): (Volatile Organic Compounds (VOC))
Emission Limit 1: 5.5000 LB/MMSCF ANNUAL AVERAGE
Emission Limit 2:
Standard Emission: 5.5000 LB/MMSCF ANNUAL AVERAGE
Did factors, other than air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: BACT-PSD
Other Applicable Requirements: OPERATING PERMIT
Control Method: (P) USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES
Est. % Efficiency:
Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Carbon Dioxide
CAS Number: 124-38-9
Test Method: Unspecified
Pollutant Group(s): (Acid Gasses/Mist , Greenhouse Gasses (GHG) , InOrganic Compounds)
Emission Limit 1: 117.0000 LB/MMBTU
Emission Limit 2:
Standard Emission: 117.0000 LB/MMBTU
Did factors, other than air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: BACT-PSD
Other Applicable Requirements: OPERATING PERMIT

Control Method: (P) PROPER OPERATION AND GOOD COMBUSTION PRACTICES
Est. % Efficiency:
Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Methane
CAS Number: 74-82-8
Test Method: Unspecified
Pollutant Group(s): (Greenhouse Gasses (GHG) , Organic Compounds (all) , Organic Non-HAP Compounds)
Emission Limit 1: 0.0022 LB/MMBTU
Emission Limit 2:
Standard Emission: 0.0022 LB/MMBTU
Did factors, other than air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: BACT-PSD
Other Applicable Requirements: OPERATING PERMIT
Control Method: (P) PROPER OPERATION AND GOOD COMBUSTION PRACTICES
Est. % Efficiency:
Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Nitrous Oxide (N2O)
CAS Number: 10024-97-2
Test Method: Unspecified
Pollutant Group(s): (Greenhouse Gasses (GHG) , InOrganic Compounds , Oxides of Nitrogen (NOx) , Particulate Matter (PM))
Emission Limit 1: 0.0002 LB/MMBTU
Emission Limit 2:
Standard Emission: 0.0002 LB/MMBTU
Did factors, other than air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: BACT-PSD
Other Applicable OPERATING PERMIT

Requirements:
Control Method: (P) PROPER OPERATION AND GOOD COMBUSTION PRACTICES
Est. % Efficiency:
Compliance Verified: Unknown
Pollutant/Compliance Notes:

Facility Information

RBLC ID: AR-0095 (final)

Date Determination Last Updated: 03/09/2009

Corporate/Company Name: NUCOR CORPORATION (NUCOR STEEL, ARKANSAS)

Permit Number: 1139-AOP-R9

Facility Name: NUCOR STEEL, ARKANSAS

Permit Date: 12/12/2007 (actual)

Facility Contact: WAYNE TURNEY 8707622100

FRS Number: 110000452180

Facility Description: NUCOR STEEL (NUCOR), A DIVISION OF NUCOR CORPORATION, OWNS AND OPERATES A SCRAP STEEL MILL IN HICKMAN, MISSISSIPPI COUNTY, ARKANSAS (APPROXIMATELY 10 MILES EAST OF BLYTHEVILLE). NUCOR PRODUCES FLAT-ROLLED STEEL PRIMARILY FROM STEEL SCRAP AND SCRAP SUBSTITUTES USING THE ELECTRIC ARC FURNACE (EAF) PROCESS.

SIC Code: 3312

Permit Type: C: Modify process at existing facility

NAICS Code: 331111

Permit URL:

EPA Region: 6

COUNTRY: USA

Facility County: MISSISSIPPI

Facility State: AR

Facility ZIP Code: 72315

Permit Issued By: ARKANSAS DEPT OF ENVIRONMENTAL QUALITY (Agency Name)
MR. TOM RHEAUME(Agency Contact) (501) 682-0762 rheaume@adeq.state.ar.us

Permit Notes:

Process/Pollutant Information

PROCESS PICKLE LINE BOILER

NAME:

Process Type: 13.390 (Other Gaseous Fuel & Gaseous Fuel Mixtures)

Primary Fuel: NATURAL GAS

Throughput: 12.60 MMBTU/H

Process Notes: THREE (3) NATURAL GAS-FIRED BOILERS (SN-52) WITH MAXIMUM HEAT INPUT CAPACITY OF 12.6 MMBTU/HR EACH

POLLUTANT NAME: Nitrogen Oxides (NOx)

CAS Number: 10102

Test Method: Unspecified

Pollutant Group(s): (InOrganic Compounds , Oxides of Nitrogen (NOx) , Particulate Matter (PM))

Emission Limit 1: 0.0750 LB/MMBTU

Emission Limit 2: 0.0750 LB/MMBTU

Standard Emission:

Did factors, other than air pollution technology considerations influence the BACT decisions: U

Case-by-Case Basis: BACT-PSD

Other Applicable Requirements:

Control Method: (A) LOW NOX BURNERS

Est. % Efficiency:

Compliance Verified: Unknown

Pollutant/Compliance Notes:

POLLUTANT NAME: Carbon Monoxide

CAS Number: 630-08-0

Test Method: Unspecified

Pollutant Group(s): (InOrganic Compounds)

Emission Limit 1: 0.0840 LB/MMBTU

Emission Limit 2: 0.0840 LB/MMBTU

Standard Emission:

Did factors, other than air pollution technology considerations influence the BACT decisions: U

Case-by-Case Basis: BACT-PSD

Other Applicable Requirements:
Control Method: (P) GOOD COMBUSTION PRACTICE
Est. % Efficiency:
Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Particulate matter, filterable < 10 μ (FPM10)
CAS Number: PM
Test Method: Unspecified
Pollutant Group(s): (Particulate Matter (PM))
Emission Limit 1: 0.0076 LB/MMBTU
Emission Limit 2: 0.0076 LB/MMBTU
Standard Emission:
Did factors, other than air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: BACT-PSD
Other Applicable Requirements:
Control Method: (P) GOOD COMBUSTION PRACTICE
Est. % Efficiency:
Compliance Verified: Unknown
Pollutant/Compliance Notes:

Process/Pollutant Information

PROCESS NAME: VTD BOILER
Process Type: 81.290 (Other Steel Manufacturing Processes)
Primary Fuel: NATURAL GAS
Throughput: 50.21 MMBTU/H

Process Notes:

POLLUTANT NAME: Carbon Monoxide
CAS Number: 630-08-0
Test Method: Unspecified
Pollutant Group(s): (InOrganic Compounds)
Emission Limit 1: 0.0610 LB/MMBTU
Emission Limit 2: 0.0610 LB/MMBTU
Standard Emission:
Did factors, other than air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: BACT-PSD
Other Applicable Requirements:
Control Method: (P) GOOD COMBUSTION PRACTICE
Est. % Efficiency:
Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Nitrogen Oxides (NOx)
CAS Number: 10102
Test Method: Unspecified
Pollutant Group(s): (InOrganic Compounds , Oxides of Nitrogen (NOx) , Particulate Matter (PM))
Emission Limit 1: 0.0350 LB/MMBTU
Emission Limit 2: 0.0350 LB/MMBTU
Standard Emission:
Did factors, other than air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: BACT-PSD
Other Applicable Requirements:
Control Method: (A) ULTRA LOW NOX BURNERS
Est. % Efficiency:

Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Particulate matter, filterable < 10 μ (FPM10)
CAS Number: PM
Test Method: Unspecified
Pollutant Group(s): (Particulate Matter (PM))
Emission Limit 1: 0.0076 LB/MMBTU
Emission Limit 2: 0.0076 LB/MMBTU
Standard Emission:
Did factors, other than air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: BACT-PSD
Other Applicable Requirements:
Control Method: (P) GOOD COMBUSTION PRACTICE
Est. % Efficiency:
Compliance Verified: Unknown
Pollutant/Compliance Notes:

Facility Information

RBLC ID:	AL-0231 (final)	**Date Determination Last Updated:**	08/31/2009
Corporate/Company Name:	NUCOR CORPORATION	**Permit Number:**	712-0037
Facility Name:	NUCOR DECATUR LLC	**Permit Date:**	06/12/2007 (actual)
Facility Contact:	JEFF BROWN 2563013508 JBROWN@NSDECATUR.COM	**FRS Number:**	110000589328
Facility Description:	THE FACILITY PRODUCES STEEL COILS PRIMARILY FROM STEEL SCRAP USING THE ELECTRIC ARC FURNACE (EAF) PROCESS.	**SIC Code:**	3312
Permit Type:	D: Both B (Add new process to existing facility) &C (Modify process at existing facility)	**NAICS Code:**	331111
Permit URL:			

EPA Region: 4 **COUNTRY:** USA

Facility County: MORGAN

Facility State: AL

Facility ZIP Code: 35673

Permit Issued By: ALABAMA DEPT OF ENVIRONMENTAL MGMT (Agency Name)
MR. ANTHONY SMILEY(Agency Contact) (334) 271-7714 ASMILEYSR@ADEM.STATE.AL.US

Other Agency Contact Info: PLEASE SEND ANY QUESTIONS TO CHARLES KILLEBREW, ADEM PERMIT ENGINEER, AT 334-270-5675.

Permit Notes: FACILITYWIDE EMISSIONS CONTINUED: PB - 1.5 T/YR

Affected Boundaries:

Boundary Type:	Class 1 Area State:	Boundary:	Distance:
CLASS1	AL	Sipsey	< 100 km

Facility-wide Emissions:

Pollutant Name:	Facility-wide Emissions Increase:
Carbon Monoxide	1553.8000 (Tons/Year)
Nitrogen Oxides (NOx)	303.0000 (Tons/Year)
Particulate Matter (PM)	155.1000 (Tons/Year)
Sulfur Oxides (SOx)	302.4000 (Tons/Year)
Volatile Organic Compounds (VOC)	130.3000 (Tons/Year)

Process/Pollutant Information

PROCESS NAME: VACUUM DEGASSER BOILER

Process Type: 13.310 (Natural Gas (includes propane and liquefied petroleum gas))

Primary Fuel: NATURAL GAS

Throughput: 95.00 MMBTU/H

Process Notes:

POLLUTANT NAME: Nitrogen Oxides (NOx)

CAS Number: 10102

Test Method: Unspecified

Pollutant Group(s): (InOrganic Compounds , Oxides of Nitrogen (NOx) , Particulate Matter (PM))

Emission Limit 1: 0.0350 LB/MMBTU

Emission Limit 2: 3.3300 LB/H

Standard Emission:

Did factors, other than air pollution technology considerations influence the BACT decisions: N

Case-by-Case Basis: BACT-PSD

Other Applicable Requirements:

Control Method: (P) ULTRA LOW NOX BURNERS

Est. % Efficiency:

Compliance Verified: Unknown

Pollutant/Compliance Notes:

POLLUTANT NAME: Carbon Dioxide

CAS Number: 124-38-9

Test Method: Unspecified

Pollutant Group(s): (Acid Gasses/Mist , Greenhouse Gasses (GHG) , InOrganic Compounds)

Emission Limit 1: 0.0610 LB/MMBTU

Emission Limit 2: 5.8000 LB/H

Standard Emission:

Did factors, other than air pollution technology considerations influence the BACT decisions: Y

Case-by-Case Basis: BACT-PSD

Other Applicable Requirements:

Control Method: (N)

Est. % Efficiency:

Compliance Verified: Unknown

Pollutant/Compliance Notes:

POLLUTANT NAME: Sulfur Dioxide (SO2)

CAS Number: 7446-09-5

Test Method: Unspecified

Pollutant Group(s): (InOrganic Compounds , Oxides of Sulfur (SOx))

Emission Limit 1: 0.0006 LB/MMBTU

Emission Limit 2: 0.0570 LB/H

Standard Emission:

Did factors, other than air pollution technology considerations influence the BACT decisions: N

Case-by-Case Basis: BACT-PSD

Other Applicable Requirements:

Control Method: (N)

Est. % Efficiency:

Compliance Verified: Unknown

Pollutant/Compliance Notes:

POLLUTANT NAME: Volatile Organic Compounds (VOC)

CAS Number: VOC

Test Method: Unspecified

Pollutant Group(s): (Volatile Organic Compounds (VOC))

Emission Limit 1: 0.0026 LB/MMBTU

Emission Limit 2: 0.2500 LB/H

Standard Emission:

Did factors, other than air pollution technology considerations influence the BACT decisions: N

Case-by-Case Basis: BACT-PSD

Other Applicable Requirements:

Control Method: (N)

Est. % Efficiency:

Compliance Verified: Unknown

Pollutant/Compliance Notes:

POLLUTANT NAME: Particulate Matter (PM)

CAS Number: PM

Test Method: Unspecified

Pollutant Group(s): (Particulate Matter (PM))

Emission Limit 1: 0.0076 LB/MMBTU
Emission Limit 2: 0.7200 LB/H
Standard Emission:
Did factors, other than air pollution technology considerations iufluence the BACT decisions: N
Case-by-Case Basis: BACT-PSD
Other Applicable Requirements:
Control Method: (N)
Est. % Efficiency:
Compliauce Verified: Unknown
Pollutant/Compliance Notes:

Facility Information

RBLC ID:	OK-0135 (final)	**Date Determination Last Updated:**	02/18/2010
Corporate/Company Name:	PRYOR PLANT CHEMICAL COMPANY	**Permit Number:**	2008-100-C PSD
Facility Name:	PRYOR PLANT CHEMICAL	**Permit Date:**	02/23/2009 (actual)
Facility Contact:		**FRS Number:**	4009700008
Facility Description:		**SIC Code:**	2873
Permit Type:	C: Modify process at existing facility	**NAICS Code:**	325311
Permit URL:			
EPA Regiou:	6	**COUNTRY:**	USA
Facility County:	MAYES		
Facility State:	OK		
Facility ZIP Code:	73107		

Permit Issued By: OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY (Agency Name)
MR. JERRY GOOCHEY(Agency Contact) (405)702-4189 JERRY.GOOCHEY@DEQ.OK.GOV

Permit Notes: PRYOR PLANT CHEMICAL COMPANY (PPCC) SUBMITTED AN APPLICATION DATED MARCH 27, 2008 TO AIR QUALITY DIVISION (AQD) WITH THE REQUIRED FEE OF $2,000 FOR A CONSTRUCTION PERMIT TO PLACE INTO OPERATION A SYNTHETIC FERTILIZER MANUFACTURING PLANT (SIC 2873) THAT HAS BEEN SHUT

DOWN FOR APPROXIMATELY TEN YEARS. RATHER THAN ATTEMPT TO RECONCILE EXISTING PERMITS WITH CHANGES THAT MAY RESULT FROM RE-STARTING A PLANT THAT HAS BEEN INACTIVE FOR TEN YEARS TO EVALUATE WHERE SIGNIFICANT MODIFICATIONS ARE OCCURRING, A DECISION TO SIMPLIFY THE PERMITTING PROCESS WAS MADE BY THE APPLICANT AND ACCEPTED BY AQD. A FULL PSD (PREVENTION OF SIGNIFICANT DETERIORATION) ANALYSIS HAS BEEN COMPLETED FOR THIS PERMIT ISSUANCE. IN ADDITION, EVALUATION OF COMPLIANCE ASSURANCE MONITORING (CAM) IS REQUIRED.

Affected Boundaries:

Boundary Type:	Class 1 Area State:	Boundary:	Distance:
CLASS1	AR	Caney Creek	100km - 50km
CLASS1	MO	Hercules-Glades	100km - 50km
CLASS1	AR	Upper Buffalo	100km - 50km

Facility-wide Emissions:

Pollutant Name:	Facility-wide Emissions Increase:
Carbon Monoxide	176.5000 (Tons/Year)
Nitrogen Oxides (NOx)	361.8000 (Tons/Year)
Particulate Matter (PM)	34.4200 (Tons/Year)
Sulfur Oxides (SOx)	7.4200 (Tons/Year)
Volatile Organic Compounds (VOC)	50.8000 (Tons/Year)

Process/Pollutant Information

PROCESS NAME: BOILERS #1 AND #2

Process Type: 13.310 (Natural Gas (includes propane and liquefied petroleum gas))

Primary Fuel: NATURAL GAS

Throughput: 80.00 MMBTU/H

Process Notes: THE BOILERS WILL PROVIDE THE STEAM NEEDED TO OPERATE THE VARIOUS PIECES OF EQUIPMENT AT THE FACILITY.

POLLUTANT NAME: Particulate matter, total < 10 μ (TPM10)

CAS Number: PM

Test Method: Unspecified

Pollutant Group(s): (Particulate Matter (PM))

Emission Limit 1: 0.5000 LB/H 24-HOUR

Emission Limit 2:

Standard Emission:

Did factors, other than air pollution technology considerations influence the BACT decisions: U

Case-by-Case Basis: BACT-PSD
Other Applicable Requirements: N/A
Control Method: (N)
Est. % Efficiency:
Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Particulate matter, total (TPM)
CAS Number: PM
Test Method: Unspecified
Pollutant Group(s): (Particulate Matter (PM))
Emission Limit 1: 0.6000 LB/H
Emission Limit 2:
Standard Emission:
Did factors, other than air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: BACT-PSD
Other Applicable Requirements: N/A
Control Method: (N)
Est. % Efficiency:
Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Sulfur Dioxide (SO2)
CAS Number: 7446-09-5
Test Method: Unspecified
Pollutant Group(s): (InOrganic Compounds , Oxides of Sulfur (SOx))
Emission Limit 1: 0.2000 LB/H
Emission Limit 2: 0.2000 LB/MMBTU STATE LIMIT
Standard Emission:

Did factors, other than air pollution technology considerations influence the BACT decisions: U

Case-by-Case Basis: BACT-PSD

Other Applicable Requirements: N/A

Control Method: (N)

Est. % Efficiency:

Compliance Verified: Unknown

Pollutant/Compliance Notes:

POLLUTANT NAME: Volatile Organic Compounds (VOC)

CAS Number: VOC

Test Method: Unspecified

Pollutant Group(s): (Volatile Organic Compounds (VOC))

Emission Limit 1: 0.5000 LB/H

Emission Limit 2:

Standard Emission:

Did factors, other than air pollution technology considerations influence the BACT decisions: U

Case-by-Case Basis: BACT-PSD

Other Applicable Requirements: N/A

Control Method: (N)

Est. % Efficiency:

Compliance Verified: Unknown

Pollutant/Compliance Notes:

POLLUTANT NAME: Formaldehyde

CAS Number: 50-00-0

Test Method: Unspecified

Pollutant Group(s): (Hazardous Air Pollutants (HAP) , Organic Compounds (all) , Volatile Organic Compounds (VOC))

Emission Limit 1: 0.1000 LB/H

Emission Limit 2:

Standard Emission:

Did factors, other than air pollution technology considerations influence the BACT decisions: U

Case-by-Case Basis:	BACT-PSD
Otber Applicable Requirements:	N/A
Control Method:	(N)
Est. % Efficiency:	
Compliance Verified:	Unknown
Pollutant/Compliance Notes:	

POLLUTANT NAME:	Nitrogen Oxides (NOx)
CAS Number:	10102
Test Method:	Unspecified
Pollutant Group(s):	(InOrganic Compounds , Oxides of Nitrogen (NOx) , Particulate Matter (PM))
Emission Limit 1:	4.0000 LB/H 3-H/168-H ROLLING CUMMULATIVE
Emission Limit 2:	0.2000 LB/MMBTU STATE LIMIT
Standard Emission:	

Did factors, other than air pollution technology considerations influence the BACT decisions: U

Case-by-Case Basis:	BACT-PSD
Other Applicable Requirements:	N/A
Control Method:	(P) LOW-NOX BURNERS AND GOOD COMBUSTION PRACTICES
Est. % Efficiency:	
Compliance Verified:	Unknown
Pollutant/Compliance Notes:	

POLLUTANT NAME:	Carbon Monoxide
CAS Number:	630-08-0
Test Method:	Unspecified
Pollutant Group(s):	(InOrganic Compounds)
Emission Limit 1:	6.6000 LB/H 1-HOUR/8-HOUR

Emission Limit 2:

Standard Emission:

Did factors, other than air pollution technology considerations influence the BACT decisions: U

Case-by-Case Basis: BACT-PSD

Other Applicable Requirements: N/A

Control Method: (N) GOOD COMBUSTION PRACTICES

Est. % Efficiency:

Compliance Verified: Unknown

Pollutant/Compliance Notes:

Facility Information

RBLC ID: TX-0374 (final)

Corporate/Company Name: BP AMOCO CHEMICAL CO

Facility Name: CHOCOLATE BAYOU PLANT

Facility Contact: JOEL ROBINS 2815813597

Facility Description: BP AMOCO PROPOSES TO CONSTRUCT A GAS- FIRED STEAM AND ELECTRIC GENERATING FACILITY. THE PROPOSED PROJECT WILL BE CALLED THE GREEN POWER UNIT ONE. THE PROJECT WILL CONSIST OF TWO DUAL SHAFT GAS-FIRED ELECTRIC GENERATING TURBINES EACH RATED AT APPROX. 35 MW (BASE LOAD), EACH TURBINE WILL HAVE A HEAT RECOVERY STEAM GENERATOR (HRSG) EQUIPPED WITH 312 MMBTU/H DUCT BURNERS. GREEN POWER UNIT ONE WILL BE CAPABLE OF PRODUCING AN ESTIMATED NOMINAL 70 MW OF ELECTRICITY. STEAM PRODUCED IN THE HRSGS WILL BE USED IN THE CHOCOLATE BAYOU WORKS CHEMICAL COMPLEX. THE CHEMICAL COMPLEX WILL CONSUME APPROX. HALF OF THE ELECTRICAL OUTPUT PRODUCED BY THE TWO NEW TURBINES. EXCESS POWER PRODUCED BY THE COMBUSTION TURBINES WILL BE SOLD TO THE GRID. THE COMBUSTION TURBINES WILL ONLY BURN PIPELINE QUALITY SWEET NAT GAS. THE DUCT BURNERS

Date Determination Last Updated: 01/04/2005

Permit Number: PSD-TX-983

Permit Date: 03/24/2003 (actual)

FRS Number: 110000606933

SIC Code: 2869

WILL BURN NAT GAS, COMPLEX GAS, OR MIXTURES OF NAT GAS AND COMPLEX GAS.

Permit Type: A: New/Greenfield Facility **NAICS Code:** 325110

Permit URL:

EPA Region: 6 **COUNTRY:** USA

Facility County: BRAZORIA

Facility State: TX

Facility ZIP Code: 775121488

Permit Issued By: TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ) (Agency Name)
MR. JOHNNY VERMILLION(Agency Contact) (512) 239-1292 John.Vermillion@tceq.texas.gov

Other Agency Contact Info: ERIK HENDRICKSON
TX
(512) 239-1095

Permit Notes: PETROCHEMICAL FACILITY

Process/Pollutant Information

PROCESS NAME: NAT GAS & FUEL GAS FUGITIVES

Process Type: 19.900 (Other Misc. Combustion)

Primary Fuel: NAT GAS

Throughput:

Process Notes:

POLLUTANT NAME: Volatile Organic Compounds (VOC)

CAS Number: VOC

Test Method: Unspecified

Pollutant Group(s): (Volatile Organic Compounds (VOC))

Emission Limit 1: 0.4500 LB/H

Emission Limit 2: 1.9800 T/YR

Standard Emission:

Did factors, other than air pollution technology considerations influence the BACT decisions: Unknown

Case-by-Case Basis:	Other Case-by-Case
Other Applicable Requirements:	
Control Method:	(N) NONE INDICATED
Est. % Efficiency:	
Compliance Verified:	Unknown
Pollutant/Compliance Notes:	

POLLUTANT NAME:	Hydrogen Sulfide
CAS Number:	7783-06-4
Test Method:	Unspecified
Pollutant Group(s):	(InOrganic Compounds)
Emission Limit 1:	0.0010 LB/H LESS THAN
Emission Limit 2:	0.0010 T/YR LESS THAN
Standard Emission:	

Did factors, other than air pollution technology considerations influence the BACT decisions: Unknown

Case-by-Case Basis:	Other Case-by-Case
Other Applicable Requirements:	
Control Method:	(N) NONE INDICATED
Est. % Efficiency:	
Compliance Verified:	Unknown
Pollutant/Compliance Notes:	

Process/Pollutant Information

PROCESS NAME:	AMMONIA (NH_3) FUGITIVES, NH3FUG2
Process Type:	19.900 (Other Misc. Combustion)
Primary Fuel:	

Throughput:

Process Notes:

POLLUTANT NAME: Ammonia (NH3)

CAS Number: 7664-41-7

Test Method: Unspecified

Pollutant Group(s): (InOrganic Compounds)

Emission Limit 1: 0.2600 LB/H

Emission Limit 2: 1.1500 T/YR

Standard Emission:

Did factors, other than air pollution technology considerations influence the BACT decisions: Unknown

Case-by-Case Basis: Other Case-by-Case

Other Applicable Requirements:

Control Method: (N) NONE INDICATED

Est. % Efficiency:

Compliance Verified: Unknown

Pollutant/Compliance Notes:

Attachment A

NSR 2165 TCEQ Permit Amendment Application
Submitted on September 14, 2012

Certified Mail
7009 2820 0003 7512 04028- EPA, Region 6

ROHM AND HAAS TEXAS INCORPORATED

1900 TIDAL ROAD
DEER PARK, TEXAS 77536
(281) 228-8100

September 14, 2012

CERTIFIED MAIL

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)
Air Permits Initial Review Team (APIRT), MC-161
P.O. Box 13087
Austin, TX 78711-3087

ROHM AND HAAS TEXAS, INCORPORARTED – DEER PARK, RN: 100223205
AIR PERMIT APPLICATION
PROPOSED BOILER HOUSE UNIT EXPANSION

Introduction	Rohm and Haas Texas, Incorporated (Rohm and Haas), a Wholly Owned Subsidiary of the Dow Chemical Company, owns a chemical manufacturing facility in Deer Park, Texas (Harris County). At the Deer Park facility, Rohm and Haas operates the Boiler House Unit under New Source Review (NSR) Permit No. 2165. Rohm and Haas proposes to install two new gas-fired steam boilers.
Permit Fee	The permit fee is being delivered directly to TCEQ's Financial Division with an appropriate copy of the PI-1 form.
Confidential Information	Rohm and Haas is not including any confidential information in this permit application.
Future Contact	For future correspondence, please contact: Monique Bass (281) 228-8079 or FAX (281) 228-3540 or e-mail MNBass@dow.com

Sincerely,

Tim May

Tim May
Responsible Care® Leader

Certified Mail Information
7009 2820 0003 7512 1522-TCEQ MC-161
7009 2820 0003 7512 1539-TCEQ Region XII
7009 2820 0003 7512 1546-HCPCSD

TABLE OF CONTENTS

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

I. Applicant Information (continued)	
I. Account Identification Number (leave blank if new site or facility):	**HG-0632-T**
J. Core Data Form.	
Is the Core Data Form (Form 10400) attached? If *No*, provide customer reference number and regulated entity number (complete K and L).	☐ YES ☒ NO
K. Customer Reference Number (CN):	**CN600131395**
L. Regulated Entity Number (RN):	**RN100223205**
II. General Information	
A. Is confidential information submitted with this application? If *Yes*, mark each **confidential** page **confidential** in large red letters at the bottom of each page.	☐ YES ☒ NO
B. Is this application in response to an investigation or enforcement action? If *Yes*, attach a copy of any correspondence from the agency.	☐ YES ☒ NO
C. Number of New Jobs: **Zero (0)**	
D. Provide the name of the State Senator and State Representative and district numbers for this facility site:	
Senator: **Mario Gallegos**	District No.: **6**
Representative: **Ken Legler**	District No.: **144**
III. Type of Permit Action Requested	
A. Mark the appropriate box indicating what type of action is requested. Initial ☐ Amendment ☒ Revision (30 TAC 116.116(e)) ☐ Change of Location ☐ Relocation ☐	
B. Permit Number (if existing): **2165**	
C. Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)* Construction ☒ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Prevention of Significant Deterioration ☐ Hazardous Air Pollutant Major Source ☐ Plant-Wide Applicability Limit ☐ Other:________	
D. Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c).	☐ YES ☒ NO

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

III. Type of Permit Action Requested (continued)	
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*	
2. Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. (check all that apply)	
GOP Issued ☐	GOP application/revision application submitted or under APD review ☐
SOP Issued ☒	SOP application/revision application submitted or under APD review ☐
IV. Public Notice Applicability	
A. Is this a new permit application or a change of location application?	☐ YES ☒ NO
B. Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.	☐ YES ☒ NO
C. Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit?	☐ YES ☒ NO
D. Is this application for a PSD or major modification of a PSD located within 100 kilometers or less of an affected state or Class I Area?	☐ YES ☒ NO
If *Yes*, list the affected state(s) and/or Class I Area(s).	
E. Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E.3.	
1. Is there any change in character of emissions in this application?	☒ YES ☐ NO
2. Is there a new air contaminant in this application?	☒ YES ☐ NO
3. Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?	☐ YES ☒ NO
F. List the total annual emission increases associated with the application (*list* **all** *that apply and attach additional sheets as needed*): ***MSS emissions are provided in parenthesis.***	
Volatile Organic Compounds (VOC): **27.87 (0.38)**	
Sulfur Dioxide (SO_2): **1.80 (0.99)**	
Carbon Monoxide (CO): **134.04 (13.21)**	
Nitrogen Oxides (NO_x): **45.11 (9.73)**	
Particulate Matter (PM): **27.06 (0.42)**	
PM $_{10}$ microns or less (PM_{10}): **27.06 (0.42)**	
PM $_{2.5}$ microns or less ($PM_{2.5}$): **27.06 (0.42)**	
Lead (Pb): **0.02 (0.01)**	
Hazardous Air Pollutants (HAPs): Mercury (Hg) – **0.01 (0.01)**	
Other speciated air contaminants **not** listed above: Ammonia (NH_3) – **16.73**; Sulfuric Acid (H_2SO_4) – **0.20**	

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

V. Public Notice Information (complete if applicable) (continued)		
3. Provide the name, mailing address of the chief executives of the city and county, State, Federal Land Manager, or Indian Governing Body for the location where the facility is or will be located. *(continued)*		
Name of the Indian Governing Body:		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
D. Bilingual Notice		
Is a bilingual program **required** by the Texas Education Code in the School District?		☒ YES ☐ NO
Are the children who attend either the elementary school or the middle school closest to your facility eligible to be enrolled in a bilingual program provided by the district?		☒ YES ☐ NO
If *Yes*, list which languages are required by the bilingual program? **Spanish**		
VI. Small Business Classification (Required)		
A. Does this company (including parent companies and subsidiary companies) have fewer than 100 employees or less than $6 million in annual gross receipts?		☐ YES ☒ NO
B. Is the site a major stationary source for federal air quality permitting?		☒ YES ☐ NO
C. Are the site emissions of any regulated air pollutant greater than or equal to 50 tpy?		☒ YES ☐ NO
D. Are the site emissions of all regulated air pollutants combined less than 75 tpy?		☐ YES ☒ NO
VII. Technical Information		
A. The following information must be submitted with your Form PI-1 (this is just a checklist to make sure you have included everything)		
1. Current Area Map ☒		
2. Plot Plan ☒		
3. Existing Authorizations ☒		
4. Process Flow Diagram ☒		
5. Process Description ☒		
6. Maximum Emissions Data and Calculations ☒		
7. Air Permit Application Tables ☒		
a. Table 1(a) (Form 10153) entitled, Emission Point Summary ☒		
b. Table 2 (Form 10155) entitled, Material Balance ☒		
c. Other equipment, process or control device tables ☒		

TCEQ

IX. Federal Regulatory Requirements **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment** ***The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.***	
D. Do nonattainment permitting requirements apply to this application?	☐ YES ☐ NO **TBD**
E. Do prevention of significant deterioration permitting requirements apply to this application?	☐ YES ☐ NO **TBD**
F. Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application?	☐ YES ☒ NO
G. Is a Plant-wide Applicability Limit permit being requested?	☐ YES ☒ NO
X. Professional Engineer (P.E.) Seal	
Is the estimated capital cost of the project greater than $2 million dollars?	☒ YES ☐ NO
If *Yes*, submit the application under the seal of a Texas licensed P.E.	
XI. Permit Fee Information	
Check, Money Order, Transaction Number, ePay Voucher Number:	Fee Amount: $ **75,000**
Company name on check: **The Dow Chemical Company**	Paid online?: ☐ YES ☒ NO
Is a copy of the check or money order attached to the original submittal of this application?	☒ YES ☐ NO ☐ N/A
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?	☒ YES ☐ NO ☐ N/A

Application Overview

Introduction

The permit application includes the following information to fulfill the Form PI-1 requirements:

PI-1 Section	Description	See Page
II.	General Information	2
VII.	Technical Information	4
VIII.	State Regulatory Requirements	20
IX.	Federal Regulatory Requirements	25
X.	Professional Engineer Seal	29
XI.	Permit Fee Information	31

PI-1 Section II: General Information (Continued)

FIN and EPN Additions

There are five FINs and EPNs that will be added to Permit No. 2165 as a result of this permit action. They are provided below:

FIN	EPN	Description
BH-2-5	BH-2-5	Boiler No. 5
BH-2-6	BH-2-6	Boiler No. 6
BLR-FUG2	BLR-FUG2	Piping Fugitives
BH-2-5_MSS	BH-2-5_MSS	Boiler No. 5 MSS
BH-2-6_MSS	BH-2-6_MSS	Boiler No. 6 MSS

FIN and EPN Deletions

There are no deletions of existing FIN and/or EPNs associated with this permit action.

FIN and EPN Changes

There are no changes to existing FINs and/or EPNs associated with this permit action.

Title V Permit Applicability

The proposed Boiler House Unit Expansion will require a revision to the current Title V Permit (O-2232).

Planned Maintenance, Startup, and Shutdown (MSS) Activities Applicability

This permit application includes planned maintenance, startup, and shutdown (MSS) activities for the two new gas-fired boilers, EPN BH-2-5 and EPN BH-2-6. There are no request for modifications to the current authorized MSS activities listed in NSR 2165 through this permit action.

Area Map

Area Map The following page includes the area map for the proposed project.

Plot Plan(s)

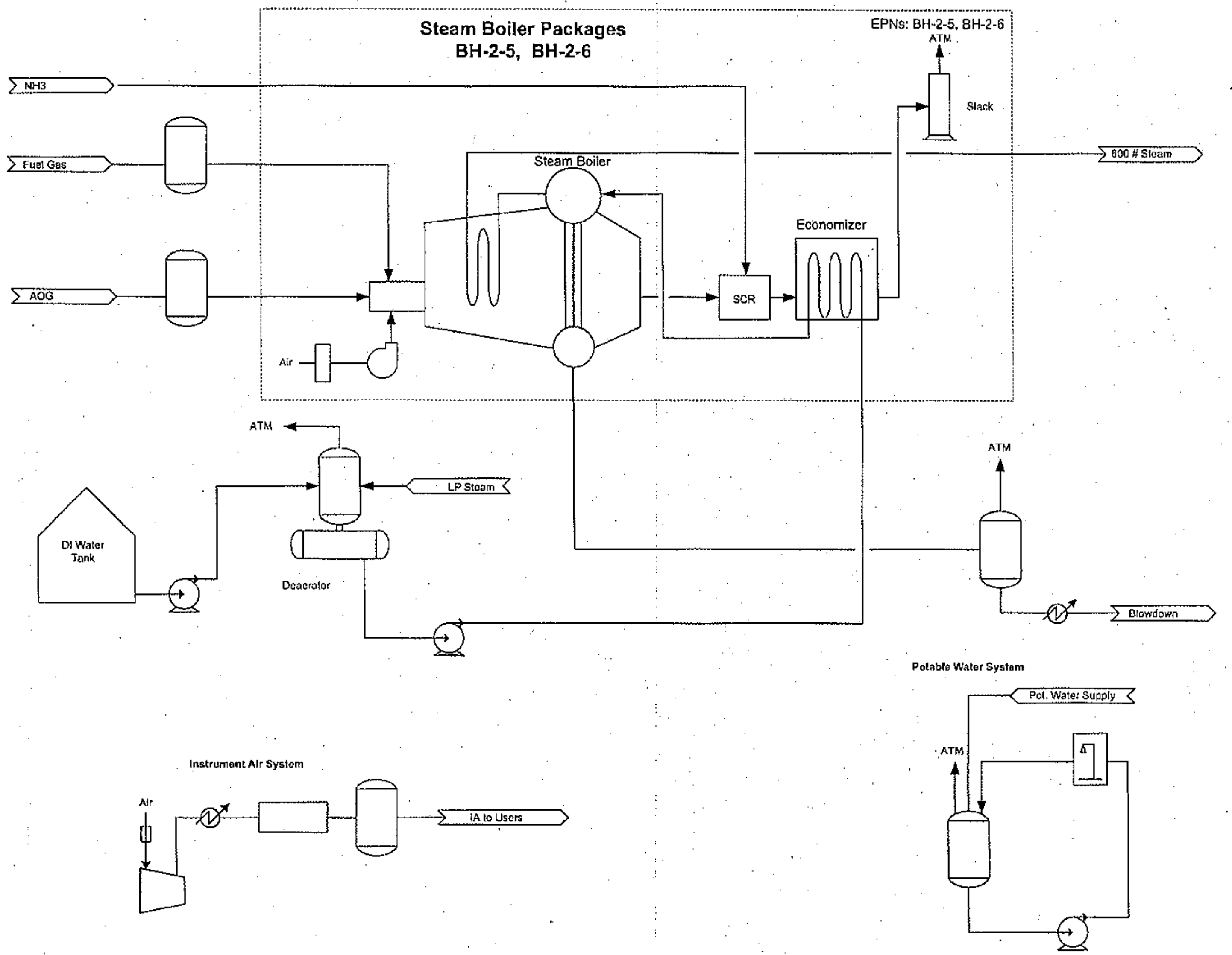
Plot Plan	The following page provides the plot plan for the Boiler House Unit.

Existing Authorizations

Existing Authorizations

The following table documents existing authorizations in relation to this permit.

Unit/Group/Process ID No.	Emission Unit Name/Description	New Source Review Authorization
BLR-FUG	BLR/FUG	2165
BH-2-3	BH-2-3	2165
BH-2-4	BH-2-4	2165



DEER PARK BOILER PROJECT
PROCESS DIAGRAM
BH-2-5, BH-2-6
29-AUG-12

Maximum Emissions Data and Calculations

Maximum Emissions Data and Calculations

Appendix A contains the maximum emissions data for the facilities routine sources and maintenance, startup, and shutdown (MSS) activities. Rohm and Haas has provided detailed emission rate calculations in Appendix D.

Routine Emission Sources

For routine operations, the following table documents the Facility Identification Number (FIN) to Emission Point Number (EPN) relationship.

EPN	FIN	Description
BH-2-5	BH-2-5	Boiler No. 5
BH-2-6	BH-2-6	Boiler No. 6
BLR-FUG2	BLR-FUG2	Piping Fugitives

Planned MSS Activities

For MSS activities associated with this project, the following table documents the Facility Identification Number (FIN) to Emission Point Number (EPN) relationship.

EPN	FIN	Description
BH-2-5_MSS	BH-2-5_MSS	Boiler No. 5 MSS
BH-2-6_MSS	BH-2-6_MSS	Boiler No. 6 MSS

Material Balance

Material Balance	The Material Balance is located in Appendix A, Emission Tables.

Planned MSS Activities

Planned Maintenance, Startup, and Shutdown (MSS) Activities

Maintenance, startup, and shutdown (MSS) activities are authorized in the current Boiler House Unit Permit No. 2165. There is no request for modifications to the current MSS activities through this permit application.

This permit application proposes to authorize emission rates from MSS activities for the two new gas-fired boilers that will be installed at the Boiler House Unit. The calculations provide the following information on the boilers MSS activities: (1) overview of MSS activity; (2) calculation basis for MSS activity; and (3) any Best Available Control Technology (BACT) considerations. Additional information will be provided upon request. The MSS emission rate calculations are included in Appendix D.

Air Pollutant Watch List

Air Pollutant Watch List	Rohm and Haas is located in Harris County, which is on the Air Pollutant Watch List (APWL) 1204 for styrene. This project does not include emissions from styrene.

Compliance with 30 TAC Rules

§116.111(a)(2)(A)(i) "The emissions from the proposed facility will comply with all rules and regulations of the commission and with the intent of the Texas Clean Air Act (TCAA), including protection of the health and physical property of the public."

NSRPD Disaster Review This application does not involve any air contaminants for which a disaster review is required, as the facilities included in this permit application do not handle sufficient quantities of the chemicals for which a disaster review would be required.

TCEQ Rules This facility will comply with all applicable TCEQ rules as specified on the following table:

30 TAC	Applicable?	Plant Area
§101 General	Y	
§111 Visible Emissions	Y	Boilers - Opacity Limits
§111 Waste Mgmt	N	
§112 Sulfur	Y	Boilers
§113 HAP	Y	General Provisions - 40 CFR 63 Subpart A
§114 Vehicles	N	
§115 VOC Storage	N	
§115 VOC Vents	N	Exempt per §115.127 (a)(7)
§115 Water Separation	N	
§115 Waste Water	N	
§115 Batch Process	N	
§115 Fugitives	Y	Process Areas
§115 VOC Loading	N	
§115 Degas. & Clean.	N	
§115 HRVOC Cmpds.	N	
§116 Permits	Y	2165
§117 Nitrogen Cmpds	Y	Boilers
§118 Episodes	Y	Respond as needed – plan not required.
§122 Op. Permit	Y	O-2232

Continued on following page

Compliance with 30 TAC Rules (Continued)

§116.111(a)(2)(B) Measurement of Emissions	"The proposed facility will have provisions for measuring the emission of significant air contaminants as determined by the executive director. This may include the installation of sampling ports on exhaust stacks and construction of sampling platforms in accordance with guidelines in the 'Texas Commission on Environmental Quality Sampling Procedures Manual.' " **Rohm and Haas will conduct actual measurement of emissions if required by the Special Conditions of this permit.**
§116.111(a)(2)(C) Best Available Control Technology (BACT)	"Best available control technology (BACT) must be evaluated for and applied to all facilities subject to the TCAA. Prior to evaluation of BACT under the TCAA, all facilities with pollutants subject to regulation under Title I Part C of the Federal Clean Air Act (FCAA) shall evaluate and apply BACT as defined in §116.160(c)(1)(A) of this title (relating to Prevention of Significant Deterioration Requirements)." **BACT is demonstrated for all of the sources within this permit.**
§116.111(a)(2)(G) Performance Demonstration	"The proposed facility will achieve the performance specified in the permit application. The applicant may be required to submit additional engineering data after a permit has been issued in order to demonstrate further that the proposed facility will achieve the performance specified in the permit application. In addition, dispersion modeling, monitoring, or stack testing may be required." **The facility will perform as represented in this permit application. Rohm and Haas will monitor for demonstration of compliance if required by the Special Conditions of this permit.**
§116.111(a)(2)(J) Air Dispersion Modeling	"Computerized air dispersion modeling may be required by the executive director to determine the air quality impacts from the facility or source modification." **Rohm and Haas will provide additional air dispersion modeling results upon request by TCEQ.**
§116.111(a)(2)(L) Mass Cap and Trade Allowances	"If subject to Chapter 101, Subchapter H, Division 3, of this title (relating to Mass Emissions Cap and Trade Program), the proposed facility, group of facilities, or account must obtain allowances to operate." **No allowances will be necessary for this project.**

BACT – MSS Activities

For routine operations, the following table summarizes BACT for emitting units within the proposed Boiler House Unit Expansion.

BACT –MSS Activities

Emission Unit(s)	Pollutant	BACT Proposed
Boilers • BH-2-5_MSS • BH-2-6_MSS	ALL	Rohm and Haas will minimize the frequency and duration of all boiler MSS activities.
	CO_2	53.02 kg/MMBtu (Table C-2 40CFR 98 Subpart C)
	NO_x	140.00 lb/MMscf (large boiler with low NO_x burners)
	CO	0.19 lb/MMBtu (historical boiler data)
	VOC	5.50 lb/MMscf
	SO_2	5.00 grains S/100 scf (Max Fuel Sulfur)
	$PM/PM_{10}/PM_{2.5}$	6.00 lb/MMscf (Vendor Data)
	CH_4	0.001 kg/MMBtu (Table C-2 40CFR 98 Subpart C)
	C_2H_6	3.10 lb/MMscf
	Hg	0.0003 lb/MMscf
	Pb	0.0005 lb/MMscf

Federal Regulatory Summary

In This Section The following provides an applicability summary of federal regulations:

NSPS The following table summarizes the applicability status of New Source Performance Standards (NSPS) to this unit:

§60 Subpart	NSPS Scope	Applies?
A	General Provisions	Y
Db	Steam Units greater than 100 MMBTU/Hr	Y
Kb	Storage Vessels	N
VVa	Equipment Leaks	N

NESHAPS The Boiler House Unit does not produce any applicable hazardous air pollutants in this regulation; therefore, the requirements of 40 CFR 61 are not applicable.

MACT Standards The following table summarizes the applicability status for MACT standards.

§63 Subpart	MACT Scope	Applies?
A	General Provisions	Y
DDDDD	Boiler MACT	Y

Continued on following page

PI-1 Section X: Professional Engineer (P.E.) Seal

Professional Engineer Seal	The following page includes the required Professional Engineer Seal.

PI-1 Section XI: Permit Fee Information

Permit Fee	The permit fee is being mailed directly to TCEQ's Financial Division with a copy of the PI-1 form. The following page contains the Table 30 for the proposed project.

Dow International Finance S.a.r.l.
Attn: Accounts Payable
2511 E Patrick Road
Midland, MI 48641-1286

09/04/12

2100231 01 SD T 6172 CKPR -P00231

TEXAS COMMISSION ON ENVIRONMENTAL Q
12100 PARK 35 CIR BLDG A
AUSTIN TX 78753-180

YOUR INVOICE NO.	INVOICE AMOUNT	DISCOUNT / DEDUCTION	NET AMOUNT	INVOICE DATE	OUR DOCUMENT NO.	PAYMENT ON BEHALF OF
20120824750000	$75,000.00	$0.00	$75,000.00	08/24/2012	2000028879	ROHM & HAAS TEXAS INC.

TOTAL: $75,000.00

SD2100231-0001_of_0001 6172-0000231 (P23S)

DETACH AND RETAIN THIS STUB FOR YOUR RECORDS

CHECK # 2000028879 ATTACHED

Dow International Finance S.a.r.l.
Attn: Accounts Payable
2511 E Patrick Road
Midland, MI 48641-1286

62-20
311

No. 2000028879

09/04/12

PAYMENT ON BEHALF OF: SEE ATTACHED REMITTANCE ADVICE

PAY TO THE ORDER OF
TEXAS COMMISSION ON ENVIRONMENTAL Q
12100 PARK 35 CIR BLDG A
AUSTIN TX 78753-180

$$$$$$$$$$75,000.00

NOT VALID AFTER 1 YEAR

Ronald C. Edmonds
AUTHORIZED SIGNATURE

Seventy-five Thousand and 00/100 Dollars

CITIBANK, N.A.
ONE PENN'S WAY, NEW CASTLE, DE 19720

⑈2000028879⑈ ⑆031100209⑆ 38859814⑈

Appendix A: Emission Tables

Overview

In This Section The following is a list of emission tables submitted in this section:

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY
Table 1(a) MSS Emissions Point Summary

Date:	September 2012	Permit Number:	2165	RN Number:	100223205
Area Name:	Rohm and Haas Texas, Incorporated - Boiler House Unit			CN Number:	600131395

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
EPN (A)	FIN (B)	Name (C)		Pounds per Hour (A)	Tons per Year (B)
BH-2-5_MSS and BH-2-6_MSS	BH-2-5_MSS and BH-2-6_MSS	Boiler No. 5 MSS and Boiler No. 6 MSS	CO	97.85	13.21
			NOx	72.08	9.73
			PM	3.09	0.42
			PM_{10}	3.09	0.42
			$PM_{2.5}$	3.09	0.42
			SO_2	7.35	0.99
			VOC	2.83	0.38
			Hg	0.01	0.01
			Pb	0.01	0.01

Footnotes
EPN = Emission Point Number
FIN = Facility Identification Number

Speciated Routine Emission Rates, lb/hr

EPN	Methane (CH_4)	Ethane (C_2H_6)	Hydrogen Cyanide (HCN)	Propane (C_3H_8)	n-Butane (n-C_4H_{10})	i-Butane (i-C_4H_{10})	n-Pentane (n-C_5H_{12})	i-Pentane (i-C_5H_{12})	Hexane + (C_6+)	Carbon Dioxide (CO_2)
BH-2-5 and BH-2-6	2.33	26.10	3.29	2.47	0.77	0.53	0.52	0.49	0.88	123,724.23
BLR-FUG2	0.65	0.03	0.00001	0.03	0.09	0.02	0.11	0.08	0.37	0.03
Totals	**2.98**	**26.13**	**3.29**	**2.50**	**0.85**	**0.55**	**0.63**	**0.57**	**1.25**	**123,724.26**

Speciated Routine Emission Rates, tpy

EPN	Methane (CH_4)	Ethane (C_2H_6)	Hydrogen Cyanide (HCN)	Propane (C_3H_8)	n-Butane (n-C_4H_{10})	i-Butane (i-C_4H_{10})	n-Pentane (n-C_5H_{12})	i-Pentane (i-C_5H_{12})	Hexane + (C_6+)	Carbon Dioxide (CO_2)
BH-2-5 and BH-2-6	10.22	114.32	14.42	10.81	3.37	2.34	2.29	2.16	3.84	541,912.13
BLR-FUG2	2.84	0.12	0.00006	0.14	0.38	0.09	0.47	0.36	1.63	0.13
Totals	**13.06**	**114.43**	**14.42**	**10.95**	**3.74**	**2.43**	**2.76**	**2.52**	**5.47**	**541,912.27**

Hourly and Annual Speciated MSS Emission Rates

Speciated MSS Emission Rates, lb/hr

EPN	Methane (CH_4)	Ethane (C_2H_6)	Propane (C_3H_8)	n-Butane ($n\text{-}C_4H_{10}$)	i-Butane ($i\text{-}C_4H_{10}$)	n-Pentane ($n\text{-}C_5H_{12}$)	i-Pentane ($i\text{-}C_5H_{12}$)	Hexane + (C_6+)	Carbon Dioxide (CO_2)
BH-2-5_MSS	1.17	1.60	1.23	0.38	0.27	0.26	0.25	0.44	61,862.12
BH-2-6_MSS	1.17	1.60	1.23	0.38	0.27	0.26	0.25	0.44	61,862.12
Totals[1]	**1.17**	**1.60**	**1.23**	**0.38**	**0.27**	**0.26**	**0.25**	**0.44**	**61,862.12**

Speciated MSS Emission Rates, tpy

EPN	Methane (CH_4)	Ethane (C_2H_6)	Propane (C_3H_8)	n-Butane ($n\text{-}C_4H_{10}$)	i-Butane ($i\text{-}C_4H_{10}$)	n-Pentane ($n\text{-}C_5H_{12}$)	i-Pentane ($i\text{-}C_5H_{12}$)	Hexane + (C_6+)	Carbon Dioxide (CO_2)
BH-2-5_MSS	0.08	0.11	0.08	0.03	0.02	0.02	0.02	0.03	4,175.69
BH-2-6_MSS	0.08	0.11	0.08	0.03	0.02	0.02	0.02	0.03	4,175.69
Totals[1]	**0.16**	**0.22**	**0.17**	**0.05**	**0.04**	**0.04**	**0.03**	**0.06**	**8,351.39**

Table 2 – Boiler No. 5 and 6 Material Balance

This material balance table is used to quantify possible emissions of air contaminants and special emphasis should be placed on potential air contaminants, for example: If feed contains sulfur, show distribution to all products. Please relate each material (or group of materials) listed to its respective location in the process flow diagram by assigning point numbers (taken from the flow diagram) to each material.

LIST EVERY MATERIAL INVOLVED IN EACH OF THE FOLLOWING GROUPS	Point No. from Flow Diagram	Process Rate (lbs/hr or SCFM) standard conditions: 70°F, 14.7 PSIA. Check appropriate column at right for each process.	Measurement	Estimation	Calculation
1. Raw Materials – Input					
Air	1	Up to 119,245 scfm / boiler	X		
Water	2	Up to 450,000 lb/hr / boiler	X		
2. Fuels – Input					
Natural Gas	3	Up to 8,580.38 scfm / boiler	X		
N-Area Off-Gas	4	Up to 66,667 scfm / boiler	X		
3. Products & By-Products – Output					
Steam	6	350,000 lb/hr / boiler	X		
4. Solid Wastes – Output					
N/A	N/A	N/A			
5. Liquid Wastes – Output					
N/A	N/A	N/A			
6. Airborne Waste (Solid) – Output					
$PM/PM_{10}/PM_{2.5}$, Pb, Hg	5	See Table 1(a)			X
7. Airborne Wastes (Gaseous) – Output					
VOC, NOx, CO, SO_2, NH_3, H_2SO_4	5	See Table 1(a)			X

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Project Summary of Emission Changes
Proposed Boiler House Unit Expansion

	CO	NOx	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC	Pb	H_2SO_4
Total of Increases Only	147.25	54.84	27.48	27.48	27.48	2.79	28.25	0.03	0.20
PSD Significance Levels	100	40	25	15	10	40		0.6	7
PSD Significant Increase?	YES	YES	YES	YES	YES	NO		NO	NO
PSD Netting Required?[1]	YES	YES	YES	YES	YES	NO		NO	NO
Site Contemporaneous Net	TBD	TBD	TBD	TBD	TBD	N/A		N/A	N/A
PSD Significant Net Increase?	TBD	TBD	TBD	TBD	TBD	NO		NO	NO
NNSR Significance Levels		5					5		
NNSR Significant Increase?		YES					YES		
NNSR Internal Project Net		N/A					N/A		
NNSR Netting Required?[2]		YES					YES		
Site Contemporaneous Net		TBD					TBD		
NNSR Significant Net Increase?		TBD					TBD		

Footnotes:

[1]During the technical review, Rohm and Haas will submit final PSD contemporaneous netting tables for CO, NO_x, PM, PM_{10} and $PM_{2.5}$.

[2]During the technical review, Rohm and Haas will submit final NNSR contemporaneous netting tables for NO_x and VOC.

Post-Project Maximum Allowable Annual Emissions, tpy

Project Sources EPN	Project Sources FIN	CO (tpy)	NO_x (tpy)	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	VOC (tpy)	Pb (tpy)	H_2SO_4 (tpy)
Routine										
BH-2-5 and BH-2-6	BH-2-5 and BH-2-6	134.01	45.11	27.06	27.06	27.06	1.80	24.80	0.02	0.20
BLR-FUG2	BLR-FUG2	0.03						3.07		
Maintenance, Startup, and Shutdown										
BH-2-5_MSS and BH-2-6_MSS	BH-2-5_MSS and BH-2-6_MSS	13.21	9.73	0.42	0.42	0.42	0.99	0.38	0.01	

Pre-Project Actual Annual Emissions, tpy (24 month average)

Substitute the Pre-Project Allowable if it is Smaller Than the Actual

Project Sources EPN	Project Sources FIN	CO (tpy)	NO_x (tpy)	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	VOC (tpy)	Pb (tpy)	H_2SO_4 (tpy)
Routine										
BH-2-5 and BH-2-6	BH-2-5 and BH-2-6									
BLR-FUG2	BLR-FUG2									
Maintenance, Startup, and Shutdown										
BH-2-5_MSS and BH-2-6_MSS	BH-2-5_MSS and BH-2-6_MSS									

(Post-Project Allowable, tpy) - (Pre-Project Actual, tpy)

Project Sources EPN	Project Sources FIN	CO (tpy)	NO_x (tpy)	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	VOC (tpy)	Pb (tpy)	H_2SO_4 (tpy)
Routine										
BH-2-5 and BH-2-6	BH-2-5 and BH-2-6	134.01	45.11	27.06	27.06	27.06	1.80	24.80	0.02	0.20
BLR-FUG2	BLR-FUG2	0.03						3.07		
Maintenance, Startup, and Shutdown										
BH-2-5_MSS and BH-2-6_MSS	BH-2-5_MSS and BH-2-6_MSS	13.21	9.73	0.42	0.42	0.42	0.99	0.38	0.01	

TABLE 6
BOILERS AND HEATERS

Type of Device: **Boiler**	Manufacturer: **TBD**
EPNs: **BH-2-5**	Model Number: **TBD**

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
Natural Gas **AOG**	**Table B-1**	**Ambient**	Average **Table B-2**	Design Maximum **Table B-2**
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) Table B-2	Average Table B-2 scfm _15_ % excess (vol)	Design Maximum Table B-2____scfm _15_ % excess (vol)

HEAT TRANSFER MEDIUM

Type Transfer Medium	Temperature °F		Pressure (psia)		Flow Rate (specify units)	
(Water, oil, etc.)	Input	Output	Input	Output	Average	Design Maxim
Water	**235**	**750**	**800**	**615**	**230,000 lb/hr**	**350,000 lb/hr**

OPERATING CHARACTERISTICS

Ave. Fire Box Temp. at max. firing rate	Fire Box Volume(ft.^{3}), (from drawing)	Gas Velocity in Fire Box (ft/sec) at max firing rate	Residence Time in Fire Box at max firing rate (sec)
TBD	**TBD**	**TBD**	**TBD**

STACK PARAMETERS

Stack Diameters	Stack Height	Stack Gas Velocity (ft/sec)		Stack Gas	Exhaust
		(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp °F	scfm
8.0 ft	**125 ft**		**50.5**	**300**	**215,747 acfm**

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
	See Table 1(a)

Attach an explanation on how temperature, air flow rate, excess air or other operating variables are controlled.

Also supply an assembly drawing, dimensioned and to scale, in plan, elevation, and as many sections as are needed to show clearly the operation of the combustion unit. Show interior dimensions and features of the equipment necessary to calculate in performance.

*Standard Conditions: 70°F, 14.7 psia

TABLE B-1

FUEL SPECIFICATIONS
BOILER EXPANSION PROJECT
DEERPARK, TEXAS

1.1 Natural Gas Specification

Parameter	Typical Composition
Methane (wt%)	89.05
Ethane (wt%)	3.44
Propane (wt%)	1.04
n-Butane (wt%)	0.32
i-Butane (wt%)	0.22
n-Pentane (wt%)	0.22
i-Pentane (wt%)	0.21
Hexane (wt%)	0.37
Nitrogen (wt%)	1.24
Carbon Dioxide (wt%)	3.90
Typical High Heat Value	22,519.47 (Btu/lb)
	1,000.34 (Btu/scf)

1.2 N-Area Offgas (AOG) Specification

Parameter	Typical Composition
Hydrogen (wt%)	1.38
Methane (wt%)	0.37
Ethane (wt%)	0.09
Hydrogen Cyanide (wt%)	0.012
Nitrogen (wt%)	87.98
Carbon Monoxide (wt%)	6.46
Carbon Dioxide (wt%)	1.55
Oxygen (wt%)	0.12
Ammonia (wt%)	0.001
Water (wt%)	0.46
Inerts (wt%)	1.58
Typical High Heat Value	1,231.39 (Btu/lb)
	76.32 (Btu/scf)

Appendix D: Emission Calculations

Overview

In This Section The following calculations are included in this section:

Scenario	Emission Source	EPN	Page
Routine	Boiler No. 5 and Boiler No. 6	BH-2-5 and BH-2-6	D-2
	Piping Fugitives	BLR-FUG2	D-10
MSS	Boiler No. 5 MSS	BH-2-5_MSS	D-13
	Boiler No. 6 MSS	BH-2-6_MSS	D-16

FIN: BH-2-5 and BH-2-6
EPN: BH-2-5 and BH-2-6
Description: Boiler No. 5 and Boiler No. 6

Fuel Gas Analysis

Compound	VOC?	Typical Natural Gas (Wt%)	Typical AOG Offgas (Wt%)	MW (lb/lbmol)	HHV (Btu/lb)
Hydrogen (H_2)	NO		1.38	2.02	60,954.75
Methane (CH_4)	NO	89.05	0.37	16.04	23,858.59
Ethane (C_2H_6)	NO	3.44	0.09	30.07	22,301.69
Propane (C_3H_8)	YES	1.04		44.09	21,644.08
n-Butane (n-C_4H_{10})	YES	0.32		58.12	21,280.66
i-Butane (i-C_4H_{10})	YES	0.22		58.12	21,257.00
n-Pentane (n-C_5H_{12})	YES	0.22		72.14	20,911.40
i-Pentane (i-C_5H_{12})	YES	0.21		72.14	20,871.91
Hexane + (C_6H_{14}+)	YES	0.37		86.17	20,769.72
Hydrogen Cyanide (HCN)	YES		0.01	27.03	10,182.99
Nitrogen (N_2)	NO	1.24	87.98	28.01	0.00
Carbon Monoxide (CO)	NO		6.46	28.01	4,343.41
Carbon Dioxide (CO_2)	NO	3.90	1.55	44.01	0.00
Oxygen (O_2)	NO		0.12	32.00	0.00
Sulfur (S)	NO			32.07	11,462.03
Sulfur Dioxide (SO_2)	NO			64.06	2,043.79
Sulfur Trioxide (SO_3)	NO			80.06	876.70
Sulfuric Acid (H_2SO_4)	NO			98.08	
Ammonia (NH_3)	NO		0.001	17.03	9,671.61
Water (H_2O)	NO		0.46	18.02	0.00
Inerts	NO		1.58	39.95	0.00

Notes:

1. The boilers can operate on either Natural Gas (NG) or a combination of Natural Gas (NG) and N-Area Absorber Offgas (AOG Offgas).
2. The molecular weights (MW) and high heating values (HHV) are based on Dow's Physical Properties Data Sheets.
3. Inerts are assumed to have the properties of Argon.

FIN:	**BH-2-5 and BH-2-6**
EPN:	**BH-2-5 and BH-2-6**
Description:	**Boiler No. 5 and Boiler No. 6**

Natural Gas/AOG Offgas Operation

Natural Gas Fuel Flow

Compound	Typical Wt%	HHV (Btu/lb)	MW (lb/lbmol)	Fuel Flow (lb/hr)[1]	Fuel Flow (MMBtu/hr)	Fuel Flow (MMscf/hr)[2]
Methane (CH_4)	89.05	23,858.59	16.04	16,586.08	395.72	0.3985
Ethane (C_2H_6)	3.44	22,301.69	30.07	640.51	14.28	0.0082
Propane (C_3H_8)	1.04	21,644.08	44.09	192.83	4.17	0.0017
n-Butane (n-C_4H_{10})	0.32	21,280.66	58.12	60.06	1.28	0.0004
i-Butane (i-C_4H_{10})	0.22	21,257.00	58.12	41.73	0.89	0.0003
n-Pentane (n-C_5H_{12})	0.22	20,911.40	72.14	40.81	0.85	0.0002
i-Pentane (i-C_5H_{12})	0.21	20,871.91	72.14	38.46	0.80	0.0002
Hexane + (C_6H_{14}+)	0.37	20,769.72	86.17	68.43	1.42	0.0003
Nitrogen (N_2)	1.24	0.00	28.01	230.09	0.00	0.0032
Carbon Dioxide (CO_2)	3.90	0.00	44.01	725.83	0.00	0.0064
Total	**100.00**	**22,519.47**	**17.12**	**18,624.83**	**419.42**	**0.42**

Footnotes:

[1]Total Flow (lb/hr) = Maximum Boiler Capacity * 1,000,000 Btu/hr / Fuel HHV (Btu/lb)

[2]Fuel Flow (MMscf/hr) = Fuel Flow (lb/hr) / MW (lb/lbmol) * Standard Molar Volume (scf/lbmol) / 1,000,000

[3]Typical Natural Gas High Heat Value 1,000.34 Btu/scf

Natural Gas Emission Rates from Natural Gas/AOG Offgas Operation

Compound	Emission Factor	Unit	Emission Rates Max Hourly (lb/hr)	Emission Rates Annual (tpy)
Carbon Dioxide (CO_2)	53.02	kg/MMBtu[1]	123,724.23	541,912.13
Carbon Monoxide (CO)	50.00	ppmvd	1.52	6.67
Nitrogen Oxide (NO_x)	0.01	lb/MMBtu	4.19	18.37
Particulate Matter (PM/PM_{10}/$PM_{2.5}$)	6.00	lb/MMscf	2.52	11.02
Sulfur Dioxide (SO_2) (Hourly)	5.00	gr S/100scf	5.99	-
Sulfur Dioxide (SO_2) (Annual)	0.14	gr S/100scf	-	0.73
Volatile Organic Compounds (VOC)	5.50	lb/MMscf	2.31	10.10
Methane (CH_4)	1.0E-03	kg/MMBtu[1]	2.33	10.22
Ethane (C_2H_6)	3.10	lb/MMscf	1.30	5.69
Ammonia (NH_3)	10.00	ppmvd	0.19	0.81
Propane (C_3H_8)	---	---	1.01	4.40
n-Butane (n-C_4H_{10})	---	---	0.31	1.37
i-Butane (i-C_4H_{10})	---	---	0.22	0.95
n-Pentane (n-C_5H_{12})	---	---	0.21	0.93
i-Pentane (i-C_5H_{12})	---	---	0.20	0.88
Hexane + (C_6H_{14}+)	---	---	0.36	1.56
Sulfuric Acid (H_2SO_4) (Hourly)	SO_2 ---> SO_3 ---> H_2SO_4		0.37	-
Sulfuric Acid (H_2SO_4) (Annual)	SO_2 ---> SO_3 ---> H_2SO_4		-	0.20
Mercury (Hg)	0.0003	lb/MMscf	1.09E-04	4.77E-04
Lead (Pb)	0.0005	lb/MMscf	2.10E-04	9.18E-04

Footnote:

[1] Emissions calculated based on guidance per the EPA MRR, Subpart C (40 CFR § 98.30), dated October 30, 2009, Tier 1 Methodology. Default emission factors for combustion emissions of CO_2 and CH_4 per Tables C-1 and C-2 to Subpart C of Part 98.

FIN: BH-2-5 and BH-2-6
EPN: BH-2-5 and BH-2-6
Description: Boiler No. 5 and Boiler No. 6

Emission Rate Summary for Each Operating Scenario

Fuel Property	Natural Gas		Natural Gas/AOG Offgas	
Flow Rate (lb/hr) -->	45,738.21		514,470.20	
Flow Rate (MMscf/h) -->	1.03		8.42	
Compound	Max Hourly (lb/hr)	Annual (tpy)	Max Hourly (lb/hr)	Annual (tpy)
Carbon Dioxide (CO_2)	123,724.23	541,912.13	123,724.23	541,912.13
Carbon Monoxide (CO)	3.74	16.39	30.59	134.01
Nitrogen Oxide (NO_x)	10.30	45.11	10.30	45.11
Particulate Matter ($PM/PM_{10}/PM_{2.5}$)	6.18	27.06	6.11	26.75
Sulfur Dioxide (SO_2) (Hourly)	14.69	-	5.99	-
Sulfur Dioxide (SO_2) (Annual)	-	1.80	-	0.73
Volatile Organic Compounds (VOC)	5.66	24.80	5.60	24.52
Methane (CH_4)	2.33	10.22	2.33	10.22
Ethane (C_2H_6)	3.19	13.98	26.10	114.32
Ammonia (NH_3)	0.45	1.99	3.72	16.30
Propane (C_3H_8)	2.47	10.81	1.01	4.40
n-Butane (n-C_4H_{10})	0.77	3.37	0.31	1.37
i-Butane (i-C_4H_{10})	0.53	2.34	0.22	0.95
n-Pentane (n-C_5H_{12})	0.52	2.29	0.21	0.93
i-Pentane (i-C_5H_{12})	0.49	2.16	0.20	0.88
Hexane + (C_6H_{14}+)	0.88	3.84	0.36	1.56
Hydrogen Cyanide (HCN)	-	-	3.29	14.42
Sulfuric Acid (H_2SO_4) (Hourly)	0.90	-	0.37	-
Sulfuric Acid (H_2SO_4) (Annual)	-	0.11	-	0.20
Mercury (Hg)	0.0003	0.001	0.002	0.010
Lead (Pb)	0.0005	0.002	0.004	0.018

Maximum Emission Rate Summary

Compound	Emission Rates		Fuel
	Max Hourly (lb/hr)	Annual (tpy)	
Carbon Dioxide (CO_2)	123,724.23	541,912.13	NG or NG/AOG
Carbon Monoxide (CO)	30.59	134.01	NG/AOG
Nitrogen Oxide (NO_x)	10.30	45.11	NG or NG/AGO
Particulate Matter ($PM/PM_{10}/PM_{2.5}$)	6.18	27.06	NG
Sulfur Dioxide (SO_2)	14.69	1.80	NG
Volatile Organic Compounds (VOC)	5.66	24.80	NG
Methane (CH_4)	2.33	10.22	NG or NG/AGO
Ethane (C_2H_6)	26.10	114.32	NG/AGO
Ammonia (NH_3)	3.72	16.30	NG/AOG
Propane (C_3H_8)	2.47	10.81	NG
n-Butane (n-C_4H_{10})	0.77	3.37	NG
i-Butane (i-C_4H_{10})	0.53	2.34	NG
n-Pentane (n-C_5H_{12})	0.52	2.29	NG
i-Pentane (i-C_5H_{12})	0.49	2.16	NG
Hexane + (C_6H_{14}+)	0.88	3.84	NG
Hydrogen Cyanide (HCN)	3.29	14.42	NG/AOG
Sulfuric Acid (H_2SO_4)	0.90	0.20	NG
Mercury (Hg)	0.002	0.010	NG/AOG
Lead (Pb)	0.004	0.018	NG/AOG

Note:
1. Speciated emission rates for the boilers are conservatively based on the maximum emission rate from each operating scenario.

FIN: BH-2-5 and BH-2-6
EPN: BH-2-5 and BH-2-6
Description: Boiler No. 5 and Boiler No. 6

Example Calculations (continued)

Methane (CH_4) Emission Rates:

Maximum Hourly Emission Rate (lb/hr) = 1 x 10^-3 (metric ton/kg) * Hourly Fuel Usage (MMscf/hr) * Default High Heat Value (MMBtu/scf) * Default Emission Factor (kg/MMBtu) * 2,204.62 lb/metric ton * 10^6 scf/MMscf
lb/hr = 1 x 10^-3 metric ton/kg * 1.03 MMscf/hr * 1.028E-03 MMBtu/scf * 1.0E-03 kg/MMBtu * 2,204.62 lb/metric ton * 10^6 scf/MMscf
lb/hr = 2.33
Annual Emission Rate (tpy) = 1 x 10^-3 (metric ton/kg) * Annual Fuel Usage (MMscf/yr) * Default High Heat Value (MMBtu/scf) * Default Emission Factor (kg/MMBtu) * 2,204.62 lb/metric ton * 10^6 scf/MMscf / 2,000 lb/short ton
tpy = 1 x 10^-3 metric ton/kg * 9,020 MMscf/yr * 1.028E-03 MMBtu/scf * 1.0E-03 kg/MMBtu * 2,204.62 lb/metric ton * 10^6 scf/MMscf / 2,000 lb/short ton
tpy = 10.22

Ethane (C_2H_6) Emission Rates:

Maximum Hourly Emission Rate (lb/hr) = Natural Gas Fuel Flow (MMscf/hr) * Emission Factor (lb/MMscf)
lb/hr = 1.03 MMscf/hr * 3.10 lb/MMscf
lb/hr = 3.19
Annual Emission Rate (tpy) = Maximum Hourly Emission Rate (lb/hr) * 8,760 hr/yr / 2,000 lb/ton
tpy = 3.19 lb/hr * 8,760 hr/yr / 2,000 lb/ton
tpy = 13.98

Ammonia (NH_3) Emission Rates:

Maximum Hourly Emission Rate (lb/hr) = Natural Gas Fuel Flow (MMscf/hr) * 1,000,000 scf/MMscf / Standard Molar Volume (scf/lbmol) * NH3 Molecular Weight (lb/lbmol) * Emission Factor (ppmvd) / 1,000,000
lb/hr = 1.03 MMscf/hr * 1,000,000 scf/MMscf / 385.40 scf/lbmol * 17.03 lb/lbmol * 10.00 ppmvd / 1,000,000
lb/hr = 0.45
Annual Emission Rate (tpy) = Maximum Hourly Emission Rate (lb/hr) * 8,760 hr/yr / 2,000 lb/ton
tpy = 0.45 lb/hr * 8,760 hr/yr / 2,000 lb/ton
tpy = 1.99

Propane (C_3H_8) Emission Rates: (Note: Calculation methodology is the same for all speciated VOCs.)

Maximum Hourly Emission Rate (lb/hr) = VOC Emission Rate (lb/hr) * Normalized Propane Weight Percent (%)
lb/hr = 5.66 lb/hr VOC * 43.59 % Propane
lb/hr = 2.47
Annual Emission Rate (tpy) = Maximum Hourly Emission Rate (lb/hr) * 8,760 hr/yr / 2,000 lb/ton
tpy = 2.47 lb/hr * 8,760 hr/yr / 2,000 lb/ton
tpy = 10.81

Sulfuric Acid (H_2SO_4) Emission Rates:

Maximum Hourly Emission Rate (lb/hr) = Maximum Hourly SO2 Emission Rate (lb SO2/hr) * Percent Conversion of SO2 to SO3 (%) * Percent Conversion of SO3 to H2SO4 (%) * H2SO4 Molecular Weight (lb H2SO4/lbmol) / SO2 Molecular Weight (lb SO2/lbmol)
lb/hr = 14.69 lb SO2/hr * 4.00 % * 100.00 % * 98.08 lb H2SO4/lbmol / 64.06 lb SO2/lbmol
lb/hr = 0.90
Annual Emission Rate (tpy) = Annual SO2 Emission Rate (tpy) * Percent Conversion of SO2 to SO3 (%) * Percent Conversion of SO3 to H2SO4 (%) * H2SO4 Molecular Weight (lb H2SO4/lbmol) / SO2 Molecular Weight (lb SO2/lbmol)
tpy = 1.80 tpy SO2 * 4.00 % * 100.00 % * 98.08 lb H2SO4/lbmol / 64.06 lb SO2/lbmol
tpy = 0.11

Lead (Pb) Example Calculation: (Note: Calculation methodology is the same for all metals.)

Maximum Hourly Emission Rate (lb/hr) = Natural Gas Fuel Flow (MMscf/hr) * Emission Factor (lb/MMscf)
lb/hr = 1.03 MMscf/hr * 0.0005 lb/MMscf
lb/hr = 5.15E-04
Annual Emission Rate (tpy) = Maximum Hourly Emission Rate (lb/hr) * 8,760 hr/yr / 2,000 lb/ton
tpy = 5.15E-04 lb/hr * 8,760 hr/yr / 2,000 lb/ton
tpy = 2.25E-03

EPN: BLR-FUG2
FIN: BLR-FUG2
Description: Piping Fugitives

AOG Delivery System

Equipment	Service	Equipment Components	Factor (lb/hr-component)	AGO (Wt%)	Emission Rates (lb/hr)	Emission Rates (tpy)
Valves	Light Liquid	25	0.0035	100	0.09	0.38
Flanges	Light Liquid	65	0.0005	100	0.03	0.14
TOTAL					**0.12**	**0.53**

AOG Speciated Emissions

Compound	Typical Wt%	Emission Rates (lb/hr)	Emission Rates (tpy)
Hydrogen (H_2)	1.38%	0.0017	0.00725
Methane (CH_4)	0.37%	0.0004	0.00194
Ethane (C_2H_6)	0.09%	0.0001	0.00047
Hydrogen Cyanide (HCN)	0.01%	0.00001	0.00006
Nitrogen (N_2)	87.98%	0.1056	0.46241
Carbon Monoxide (CO)	6.46%	0.0078	0.03395
Carbon Dioxide (CO_2)	1.55%	0.0019	0.00815
Oxygen (O_2)	0.12%	0.0001	0.00063
Ammonia (NH_3)	0.001%	0.000001	0.00001
Water (H_2O)	0.46%	0.0006	0.00242
Inerts	1.58%	0.0019	0.00830
Total VOC	0.01%	0.00001	0.00006

Natural Gas Distillate

Equipment	Service	Equipment Components	Factor (lb/hr-component)	Natural Gas Content (Wt%)	Emission Rates (lb/hr)	Emission Rates (tpy)
Valves	Gas/Vapor	10	0.0089	100	0.09	0.39
Valves	Light Liquid	10	0.0035	100	0.04	0.15
Flanges	Gas/Vapor	30	0.0029	100	0.09	0.38
Flanges	Light Liquid	30	0.0005	100	0.02	0.07
Relief Valves		2	0.2293	100	0.46	2.01
TOTAL					**0.68**	**3.00**

Natural Gas Distillate Speciated Emissions

Compound	Typical Wt%	Emission Rates (lb/hr)	Emission Rates (tpy)
Methane (CH_4)	0.02%	0.0001	0.0005
Ethane (C_2H_6)	0.22%	0.0015	0.0065
Propane (C_3H_8)	3.45%	0.0236	0.1035
n-Butane (n-C_4H_{10})	12.21%	0.0836	0.3662
i-Butane (i-C_4H_{10})	2.75%	0.0188	0.0825
n-Pentane (n-C_5H_{12})	15.57%	0.1066	0.4668
i-Pentane (i-C_5H_{12})	11.77%	0.0806	0.3531
Hexane + (C_6H_{14}+)	54.01%	0.3697	1.6195
Total VOC	99.76%	0.68	2.99

FIN: BH-2-5_MSS
EPN: BH-2-5_MSS
Description: Boiler No. 5 MSS

Summary of Emission Rate

Compound	Emissions Rates[1]	
	Max Hourly (lb/hr)	Annual (tpy)
Carbon Dioxide (CO_2)	61,862.12	4,175.69
Carbon Monoxide (CO)	97.85	6.60
Nitrogen Oxides (NO_x)	72.08	4.87
Particulate Matter (PM)	3.09	0.21
Particulate Matter (PM_{10})	3.09	0.21
Particulate Matter ($PM_{2.5}$)	3.09	0.21
Sulfur Dioxide (SO_2)	7.35	0.50
Volatile Organics (VOC)	2.83	0.19
Methane (CH_4)	1.17	0.08
Ethane (C_2H_6)	1.60	0.11
Mercury (Hg)	0.0001	0.00001
Lead (Pb)	0.0003	0.00002

Assumptions:

Parameter	Value	Unit
Typical Heat Value of Natural Gas	1,000.34	Btu/scf
Heat Input per Boiler	515.00	MMBtu/hr
	0.51	MMscf/hr
Number of Startup Events	5.00	Events
Number of Hours per Startup event	24.00	Hours/Event
Duration of Startup Events	120.00	Hours/ Year
Number of Shutdowns	5.00	Events
Number of Hours per Shutdown Event	3.00	Hours/Event
Duration of Shutdown Events	15.00	Hours/ Year
Molecular Weight of Sulfur (S)	32.07	lb/lbmol
Molecular Weight of Sulfur Dioxide (SO_2)	64.06	lb/lbmol

Compound	Emission Factors	Units
Carbon Dioxide (CO_2)[2]	53.02	kg/MMBtu
Carbon Monoxide (CO)[3]	0.19	lb/MMBtu
Nitrogen Oxides (NO_x)[4]	140.00	lb/MMscf
Particulate Matter (PM Total)[5]	6.00	lb/MMscf
Sulfur Dioxide (SO_2)[6]	5.00	grain S/100 scf
Volatile Organics (VOC)[7]	5.50	lb/MMscf
Methane (CH_4)[2]	0.001	kg/MMBtu
Ethane (C_2H_6)[7]	3.10	lb/MMscf
Mercury (Hg)[7]	0.0003	lb/MMscf
Lead (Pb)[7]	0.0005	lb/MMscf

FIN: BH-2-5_MSS
EPN: BH-2-5_MSS
Description: Boiler No. 5 MSS

Shutdown

Compound	Emission Rates	
	lb/hr	tpy
Carbon Dioxide (CO_2)	61,862.12	463.97
Carbon Monoxide (CO)	97.85	0.73
Nitrogen Oxides (NO_x)	72.08	0.54
Particulate Matter ($PM/PM_{10}/PM_{2.5}$)	3.09	0.02
Sulfur Dioxide (SO_2)	7.35	0.06
Volatile Organics (VOC)	2.83	0.02
Methane (CH_4)	1.17	0.01
Ethane (C_2H_6)	1.60	0.01
Propane (C_3H_8)[8]	1.23	0.01
n-Butane (n-C_4H_{10})[8]	0.38	0.003
i-Butane (i-C_4H_{10})[8]	0.27	0.002
n-Pentane (n-C_5H_{12})[8]	0.26	0.002
i-Pentane (i-C_5H_{12})[8]	0.25	0.002
Hexane + (C_6H_{14}+)[8]	0.44	0.003
Mercury (Hg)	0.0001	0.000001
Lead (Pb)	0.0003	0.000002

Footnotes

[1] MSS hourly emission rates are based on the maximum emission rates from startup or shutdown activities. MSS annual emission rates are based on the total annual emissions from boiler startups and shutdowns. Startup and shutdown emission rates are calculated using the maximum hours required for each event and the average number of MSS events that will occur each year.

[2] CO_2 and CH_4 emission factors are from Table C-1 in Subpart C of Part 98.

[3] CO emission factor is from historical boiler data.

[4] NO_x emission factor is from AP-42 Chapter 1, Section 1.4, Table 1.4-1 for large boilers with low NOx burners.

[5] PM emission factor is based on vendor data. This emission factor is also used to calculate emissions for PM_{10} and $PM_{2.5}$.

[6] SO_2 emission factor is based on the maximum potential sulfur content in natural gas.

[7] Emission factors for PM, VOC, methane, ethane, mercury, and lead are from AP-42, Chapter 1, Section 1.4.

[8] The speciated VOC emission rates are calculated using the normalized VOC composition of natural gas and multiplying that percent by the calculated VOC emission rate.

[9] There are no NH_3 and HCN emissions during planned startup and shutdown events, because the absorber off-gas line and SCR are shut-off during these events.

[10] Rohm and Hass will minimize the frequency and duration of the boiler MSS activities.

FIN:	BH-2-6_MSS
EPN:	BH-2-6_MSS
Description:	Boiler No. 6 MSS

Typical Natural Gas Speciation

Compound	Typical Wt%
Methane (CH_4)	89.05%
Ethane (C_2H_6)	3.44%
Propane (C_3H_8)	1.04%
n-Butane (n-C_4H_{10})	0.32%
i-Butane (i-C_4H_{10})	0.22%
n-Pentane (n-C_5H_{12})	0.22%
i-Pentane (i-C_5H_{12})	0.21%
Hexane + (C_6H_{14}+)	0.37%
Nitrogen (N_2)	1.24%
Carbon Dioxide (CO_2)	3.90%

Emission Rate Calculations

Startup

Compound	Emissions	
	lb/hr	tpy
Carbon Dioxide (CO_2)	61,862.12	3,711.73
Carbon Monoxide (CO)	97.85	5.87
Nitrogen Oxides (NO_x)	72.08	4.32
Particulate Matter ($PM/PM_{10}/PM_{2.5}$)	3.09	0.19
Sulfur Dioxide (SO_2)	7.35	0.44
Volatile Organics (VOC)	2.83	0.17
Methane (CH_4)	1.17	0.07
Ethane (C_2H_6)	1.60	0.10
Propane (C_3H_8)[8]	1.23	0.07
n-Butane (n-C_4H_{10})[8]	0.38	0.02
i-Butane (i-C_4H_{10})[8]	0.27	0.02
n-Pentane (n-C_5H_{12})[8]	0.26	0.02
i-Pentane (i-C_5H_{12})[8]	0.25	0.01
Hexane + (C_6H_{14}+)[8]	0.44	0.03
Mercury (Hg)	0.0001	0.00001
Lead (Pb)	0.0003	0.00002