February 4, 2013

ELECTRONIC MAIL / FACSIMILE RETURN RECEIPT REQUESTED

Ms. Aimee Wilson
Air Permits Section, 6PD-R
U.S. EPA Region 6
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

RE: REPONSE TO QUESTIONS FOR THE BOILER HOUSE UNIT EXPANSION GREENHOUSE GAS (GHG) PERMIT APPLICATION
Rohm and Haas Texas Incorporated, A Subsidiary of The Dow Chemical Company
RN100223205 (Account # HG-0632-T)

Dear Ms. Wilson:

Purpose

This package is to provide response to your questions listed in a letter dated December 12, 2012 related to the Boiler House Unit Expansion Greenhouse Gas (GHG) permit application.

Attachments

The following attachments are included in this package:

- Updated Section 1.0 - Introduction.
- Updated Section 6.1 BACT For Gas Fired Boilers
- Updated Section 6.2 BACT For Piping Fugitives

Future Contact

For future correspondence or questions, please contact
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Sincerely,

Tim May
Responsible Care® Leader

CERTIFED MAIL
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GHG Permit Application, February 2013 Response to Questions

Overview

The purpose of this package is to respond to questions listed in the December 12, 2012 incompleteness letter related to the GHG permit application for the Boiler House Expansion project at the Rohm and Haas Deer Park, TX facility. The questions that were asked are shown below along with the responses directly below each question in bold.

Question 1

The application provides a five-step BACT analysis for the boilers. CCS is evaluated as a control technology, but is eliminated in Step-2 as technically infeasible. A general cost analysis is provided in Step 2. Please supplement the cost analysis with details indicating the equipment needed to implement CCS (if the CO_2 stream needs to be treated further before it can be sent to pipeline), the costs of any pretreatment of the CO_2 stream, and the size and length of the pipeline needed for transport. Provide site specific costs versus a range of approximate costs. Also, we are requesting a comparison of the cost of CCS to the current project's annualized cost. Also provide analysis of any associated energy penalty or environmental effects that may result from the implementation of CCS.

Rohm and Haas has revised Section 6.1 BACT For Gas Fired Boilers to address all the requested information. Please see Attachment A.

GHG Permit Application, February 2013 Response to Questions (Continued)

Question 2 The application indicates that emissions from piping fugitives are generated primarily from natural gas and absorber off-gas lines, and state in Step 2 of the BACT analysis that the use of leak detection and repair programs (LDAR) is technically feasible. The application then eliminates LDAR in Step 4 of the BACT analysis based on “the economic practicability of such programs cannot be verified” (pg. 24). 28 LAER states connectors should be checked for fugitive emissions weekly using auditory, visual, and olfactory (AVO) methods, and at least quarterly using an approved gas analyzer with a directed maintenance program. Did the BACT analysis consider 28 LAER as the highest control? The application states on page 1 that the proposed project “represents a major modification to an existing major source with respect to Nonattainment New Source Review (NNSR) for ozone precursors nitrogen oxide (NOx) and volatile organic compounds (VOC).” It is assumed that TCEQ would require the use of the 28 LAER LDAR program for control of VOC fugitive emission at the facility. Could the LDAR implemented to control VOC fugitive emissions not also be used to control fugitive greenhouse gas (GHG) emissions (methane) from the same components? If LDAR is already being used to control VOC emission is it economically feasible to implement LDAR for the natural gas and absorber off-gas lines that are primarily responsible for GHGs from piping fugitives? Please provide supporting documentation that led to the conclusion that the implementation of LDAR is not economically practicable for GHGs.

Response

The sentence in Section 1.0-Introduction that says “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 (PM10 and PM2.5).”, was incorrectly stated. The statement should read:

“The proposed Boiler House expansion project required a Nonattainment New Source Review (NNSR) netting analysis for the ozone precursors nitrogen oxide (NOx) and volatile organic compounds (VOC). The contemporaneous netting analysis indicated that the project does not constitute a major modification for ozone presursors NOx and VOC.” Therefore, LAER is not triggered for this project. Please see Attachment B for an updated Section 1.0 Introduction.

The Boiler House Unit is a utilities facility. There are no process lines in VOC service that feed the boilers. Fugitive piping components are only in natural gas and/or fuel gas (AOG) service. Existing piping components at the Boiler House Unit do not utilize a LDAR program; therefore to be consistent with existing fugitive monitoring, Rohm and Haas will implement AVO methods for detecting leaks in natural gas and fuel gas (AOG) service. Please see Attachment C for an updated Section 6.1 BACT For Piping Fugitives.

Attachment A

Updated Section 6.1 – BACT for Gas Fired Boilers

6.1 BACT FOR GAS FIRED BOILERS

6.1.1 Step 1 – Identify Available Control Technologies

The best way to minimize combustion related GHG emissions is through thermal efficiency achieved through design and operations. Good combustion practices are considered BACT. These practices are based on EPA guidance are summarized in Table 4-2.

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

- Energy efficiency
- Use of Low-Carbon Gaseous Fuels;
- Use of good operating and maintenance practices; and
- Carbon Capture and Storage (CCS) as an add-on control.

6.1.2 Step 2 – Eliminate Technically Infeasible Options

The technologies identified in Step 1 are all technically feasible.

6.1.3 Step 3 – Rank Remaining Control Technologies

Because thermal efficiencies include work practice standards, it is difficult to discriminate control efficiencies for ranking. For this reason, the technologies listed in Step 1 have not been ranked here, and are addressed in detail in Step 4.

6.1.4 Step 4 – Evaluate the Most Effective Controls

6.1.4.1 Energy and Thermal 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.

6.1.4.2 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.

6.1.4.3 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.

6.1.4.4 Carbon Capture and Storage

CO_2 capture from dilute CO_2 sources such as the gas fired boilers 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".*[1]

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, amine absorption is the most commercially developed for state-of-the-art large scale CO_2 separation processes. Amine absorption has been applied to processes in the petroleum refining and natural gas processing industries and for exhausts from furnaces. Other potential absorption and membrane technologies are being developed.

Rohm and Haas has evaluated CCS for the proposed project based on technological, environmental, and economic feasibility. The following table summarizes the current CCS technology and its associated components, which is based on the IPCC's *Carbon Dioxide Capture Storage* report[2]:

Table 6-1 Technical Feasibility of CCS Technologies

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	Y
	Saline Formations	Y
	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

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[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.

[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) as well as oxygen in the flue gas can degrade sorbents and reduce the effectiveness of certain CO_2 capture processes; and
- 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.[3]

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, 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*[4] has estimated that an energy penalty of as much as 15% would result from inclusion of CO_2 capture and would also result in an overall loss of energy efficiency.

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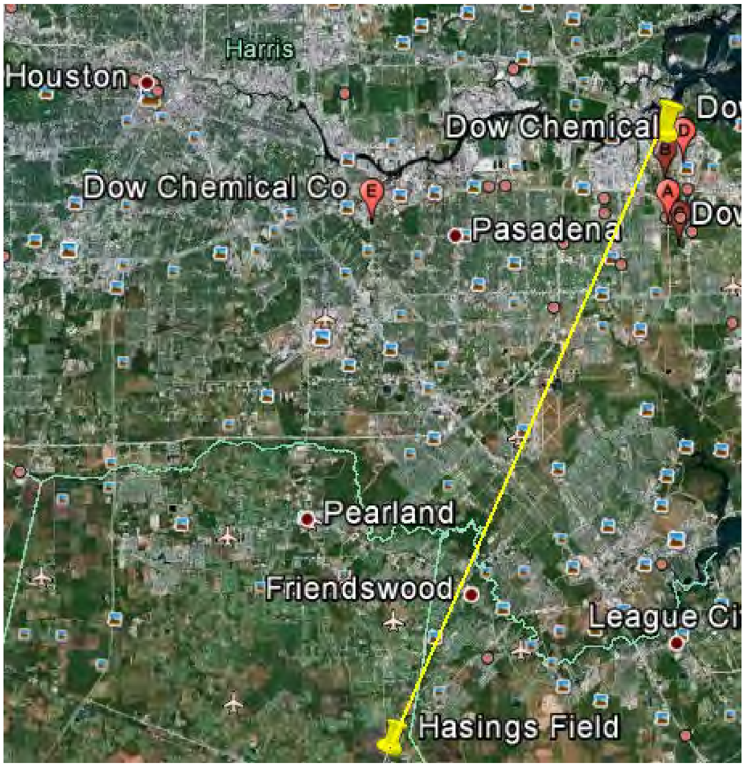
[3] DOE-NETL, Carbon Sequestration: FAQ Information Portal, http://www.netl.doe.gov/technologies/carbon_seq/faqs.html

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

CO_2 Transport

Once the CO_2 is segregated from the boilers exhaust, it will require compression to the pressure of the proposed CO_2 pipeline and the high volume stream would need to be transported via pipeline to a geologic formation capable of long-term storage. This would require significant additional input of energy as the CO_2 gas must be compressed to CO_2 liquid at a pressure of approximately 2,000 pounds per square inch absolute (psia).

The capabilities for CO_2 storage in the vicinity around Deer Park are in early development and are tenuous with regard to commercial viability and demonstration of large-scale, long-term storage; therefore, the capital and legal risks of building infrastructure solely for CO_2 storage from the boiler installation is unreasonable. However, if a pipeline was constructed, Denbury Resources owns and operates the Green Pipeline that crosses the Galveston Bay and has a terminus point at the Hastings Field[5]. The Hastings Field EOR site is approximately 30 miles from Deer Park; however, there is no existing connection to the pipeline for Hastings Field.



Other potential sequestration sites, which are presently commercially viable, are in the range of 400 to 500 miles from the proposed project site. Assuming it can be demonstrated that those sequestration sites could indefinitely store a substantial portion of the large volume of CO_2 generated by the proposed project, a very long and sizable pipeline would have to be constructed to transport the large volume of high-pressure CO_2 from the plant to the potential storage facility. Based on site specific estimates from the Dow Pipeline organization, typical pipeline costs for installation (including labor) in congested areas would be $2,000,000-$2,500,000 per mile. Thus, the high cost of CO2 transport via pipelines 50 miles or greater in length would render the project infeasible.

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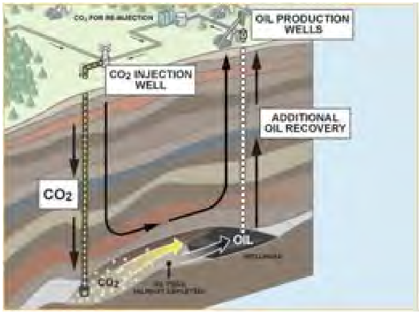
[5] Denbury, Green Pipeline Projects, available at http://www.denbury.com/Corporate-Responsibility/Pipeline-Projects/green-pipeline-project/default.aspx (last visited October 10, 2012).

CO_2 Storage

Once the CO_2 is captured and compressed it must be transported to a suitable sequestration site for storage. The Hastings Oil Field, located north of Alvin, Texas, is in the advanced stage of primary depletion. The field has been characterized for storage and Denbury Resources has been developing the field for CO_2-Enhanced Oil Recovery (EOR). CO_2 is injected into the well dissolving into the oil, causing it to swell. The swelling reduces the surface tension of the oil, allowing it to flow toward producing wells. The following diagram is a representation of how EOR works.[6]



There are other potential storage sites, including enhanced oil recovery (EOR) sites and saline formations that exist in Texas, Louisiana, and Mississippi. These reservoirs and other geologic formation sites are all in early development and are tenuous with regard to 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 storage from this Boiler Expansion project are economically challenging. There are salt dome caverns near the project 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. There are other potential sequestration sites in Texas that are commercially viable, such as the SACROC EOR unit in the Permian Basin. However that location is 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 Mississippi's Adams and Franklin Counties. Mississippi is over 400 miles away from the proposed project site. Therefore, both the Texas and Mississippi storage alternatives would be infeasible based on the distance from the project site.

In addition, there are potential environmental impacts that would still require assessment regarding storage in geologic formations:

- 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; and
- 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.

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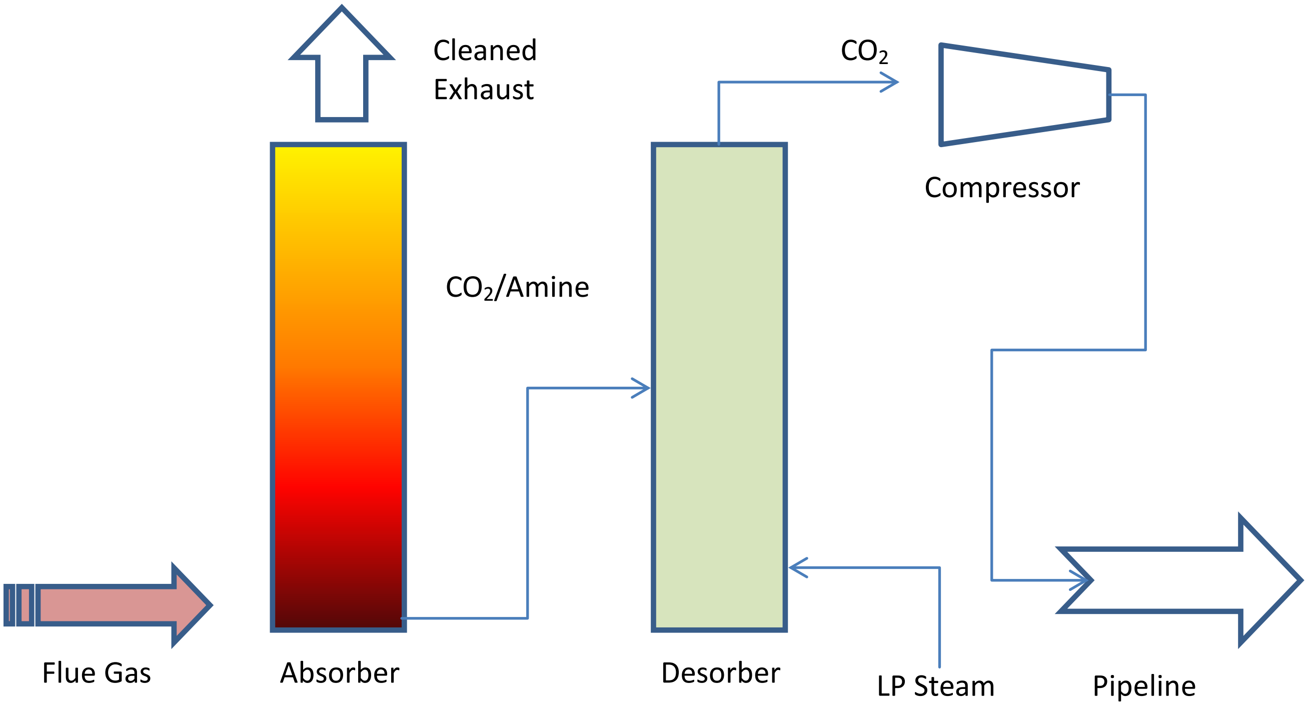
6 Clean Air Task Force, http://www.fossiltransition.org/

Economic Analysis

Rohm and Haas understands that CCS is considered to be technically feasible as an add-on control option for the proposed boilers. An economic feasibility analysis has been completed for a carbon capture and transport system. Rohm and Haas has worked to tailor an estimate based on site specific parameters. The CCS cost estimate is based on CO_2 generation of 515,000 ton/yr. The main elements of the cost analysis include capture, compression, pipeline and storage. The following figure depicts a simplified representation of a CCS system.



The cost estimate includes compression of CO_2 to pipeline pressure of 2000 psi and dry (<500ppm water) and a pipeline from Deer Park to the Hastings field. The pipe run is approximately 30 miles in length and based on transporting 515,000 tons/year of CO_2 in an 8” pipe. Based on site specific estimates from the Dow Pipeline organization, typical pipeline costs for installation (including labor) in congested areas would be $2,000,000-$2,500,000 per mile. The pipeline capital cost also includes a 15% contingency for Rights of Way (ROW), routing challenges, and variable labor rates. The CCS cost analysis below represents the capital, operating, and maintenance expenses for CCS expressed in annual cost of US dollars. The analysis assumes that the capture efficiency of the CCS system will be 90%.

Detailed CO_2 CCS Effectiveness Evaluation

Deer Park Gas Fired Boilers	Base Case
CO_2 Emissions tons/yr	514,818
Vol% CO_2 in Flue Gas	7%
Assumed % CO_2 Capture	90%

1) CCS Equipment/ Capital		Units	Base Case
Capture		USD 2012	$ 154,800,000
Tie-ins, duct work			$ 1,200,000
Cooling Tower			$ 9,600,000
Air compressor			$ 1,200,000
Site Development			$ 2,400,000
Additional Steam Capacity			$ 1,560,000
Total CO_2 Treating Related Capital			$ 170,760,000

2) Pretreatment

No pretreatment is specified at this time.

3) Pipeline Capital and Specifics

Distance to Injection		miles	30
Number Booster Pumps		number	0
Nominal Pipe Diameter		in	8
Pipeline Cost		$/Mi	2,500,000
Pipeline Capital		2012 USD	$ 86,250,000
(Includes 15% contingency for ROW, variable labor, and higher cost in congested areas)			

4) Site Specific Costs (e.g. Operational Costs)

Electricity Cost

compression, MW	5.0		$ 2,030,001
pumping & booster fan, MW	5.1		$ 2,059,209
air compressor, MW	0.2		$ 97,362
Steam required @ 90psig, MW	16.6		$ 6,806,392
SubTotal Electricty Cost	26.9	$/yr	$ 10,992,964

Chemical Costs & Services

Demin Water, Inst Air, Plant Air, Nitrogen, Caustic, Antifoam, TEG, Activated Carbon			$ 1,880,579
Waste Water treatment, $/mo	2500		$ 1,615,680
Amine make up, m^3	1500		$ 3,092,511
SubTotal Chemicals & Services Cost		$/yr	$ 6,588,770

Operations and Maintenance

Capture, Regenerate, Compress			$ 13,842,417
Pipeline			$ 511,853
Well			$ 316,251
Pore Space			$ 403,761
SubTotal Operations and Maintenance		$/yr	$ 15,074,283

Other

Tax and Insurance			$ 6,565,195
Measure, Monitor, Verify			$ 1,061,755
SubTotal Other		$/yr	$ 7,626,950

Total of Annual operating expense		$/yr	$ 40,282,966

Detailed CO_2 CCS Effectiveness Evaluation, continued

5) Energy Penalty

Total CCS Required Power		MW	26.9
Energy penalty			52%

6) Comparison of CCS Cost to Project Cost

CCS/ boiler Capital			367%

7) Avoided Cost

Cost to avoid emission via CCS, averaged over 20 yrs		$/ton	120
Avoided Cost, WITH selling CO_2, averaged over 20 yrs		$/ton	96

selling at $15/ton assumed

8) Associated CO_2

CO_2 generated from Power to capture CO_2			33%

The overall cost effectiveness of a CCS system is estimated to be $120/ton of CO_2 avoided, assuming the CO_2 is stored and not sold. This includes the capital cost for installation, operating cost, and maintenance expenses. In addition, as a result of the implementation of CCS the related energy penalty would be approximately 52%. This energy penalty would necessitate the increased operation of the plants power generation to fulfill the required steam and electrical energy to operate the plant. This would result in an increase in emissions of NOX, VOC, PM_{10}, $PM_{2.5}$, SO_2, CO, and ammonia. The proposed plant is located in a severe ozone nonattainment area, therefore additional increases of NO_X and VOC would be environmentally detrimental.

Although CCS is considered to be technically feasible, based on the high annualized cost for capture, transport, and storage of the CO_2, CCS as a combined technology is not considered economically feasible for reducing GHG emissions from the boilers. The extraordinarily high cost would render the proposed project economically unviable if selected. CCS is eliminated as a potential control option in this BACT analysis for CO_2 emissions and is not considered further in this analysis.

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.

Attachment B

Updated Section 1.0 – Introduction

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 planned for September 2014. The proposed Boiler House expansion project required a Nonattainment New Source Review (NNSR) netting analysis for the ozone precursors nitrogen oxide (NOx) and volatile organic compounds (VOC). The contemporaneous netting analysis indicated that the project does not constitute a major modification for ozone presursors NOx and VOC. 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 100,000 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.

Attachment C

Updated Section 6.2 – BACT For Piping Fugitives

6.2 BACT For 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 fuel gas (absorber off-gas (AOG)) 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 fuel gas (AOG) 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 fuel gas (AOG) service may be somewhat more effective than as-observed AVO methods, using these programs to monitor components in natural gas and fuel gas (AOG) service and control GHG emissions is not economically practical.

As indicated in the GHG emission calculations, without the use of a monitoring/control program the contribution of GHG CO_2e emissions from fugitives is less than 0.02% of the total proposed project GHG CO_2e emissions. The cost to implement an LDAR program or equivalent method for monitoring/controlling GHG emissions is approximately $84/ton of CO_2e. This cost makes implementing these programs economically impractical for monitoring/controlling GHG emissions from piping fugitives, which contribute less than 0.02% of the overall project GHG emissions.

As-observed AVO is economically and environmentally practicable for this project.

6.2.5 Step 5 – Select BACT

As-observed AVO is economically and environmentally practicable for this project. Therefore, Rohm and Haas proposes to utilize the as-observed AVO as BACT for the natural gas and fuel gas (AOG) fugitive piping components at the Boiler House Unit.

A table listing the GHG sources, GHG emission rates, and the proposed BACT for each source is provided at the end of this section.