ENVIRON

May 15, 2013

Overnight Delivery

Mr. Jeff Robinson
Chief, Air Permit Section
U.S. Environmental Protection Agency Region 6, 6PD
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733 USA

Re: Application for PSD Air Quality Permit – Greenhouse Gas Emissions
The Alpha Olefin Chemical Company LLC
Alpha Olefin Plant, Freeport, Texas

Dear Mr. Robinson:

On behalf of The Alpha Olefin Chemical Company ("AOCC"), ENVIRON is submitting the enclosed application for a Prevention of Significant Deterioration (PSD) air quality permit for greenhouse gas emissions. This PSD permit is requested to authorize construction of an alpha olefins (AO) plant near the city of Freeport, Brazoria County, Texas. The plant will manufacture a series of straight-chain alpha olefins.

A Nonattainment New Source Review (NNSR) and PSD permit application for other regulated pollutants has also been submitted to the Texas Commission on Environmental Quality (TCEQ). An electronic copy of the non-confidential version of this TCEQ application is included on the attached compact disk (CD).

AOCC and ENVIRON are both committed to working with EPA to facilitate the review of this permit application. Please contact me at +1 713.470.6657 or by email at sramsey@environcorp.com if you have any questions or need additional information.

Best Regards,

Steven H. Ramsey, PE
Principal Consultant

Enclosure - CD

10333 Richmond Avenue, Suite 910, Houston, Texas 77042 USA
Tel: +1 713.470.6546 Fax: +1 713.470.6547

Greenhouse Gas PSD Permit Application

The Alpha Olefin Chemical Company LLC
Alpha Olefins Plant
Freeport, Texas

Prepared for:
The Alpha Olefin Chemical Company LLC

Prepared by:
ENVIRON International Corporation
Houston, Texas

Date:
May 15, 2013

Project Number:
31-30190A

Contents

List of Appendices

1 Introduction

Project Overview

The Alpha Olefin Chemical Company LLC ("AOCC") is planning to build a new alpha olefins ("AO") manufacturing plant near the city of Freeport, Brazoria County, Texas. When constructed, the new AO plant will be located on land owned by The Dow Chemical Company (Dow) at its existing Freeport Chemical Manufacturing Complex, Plant "A". The Dow Freeport Chemical Complex is located on FM 1495, approximately 3 miles south of the intersection of Highway 332 and FM 523 (Figure 1).

Construction is scheduled to begin in the second quarter of 2014 and plant startup will commence in the second half of 2016.

The AOCC AO plant will use ethylene as its main raw material. The AO products will be distributed to customers via tanker trucks, railcars and ships. Some of the products and byproducts may be sent to the neighboring Dow Chemical plant.

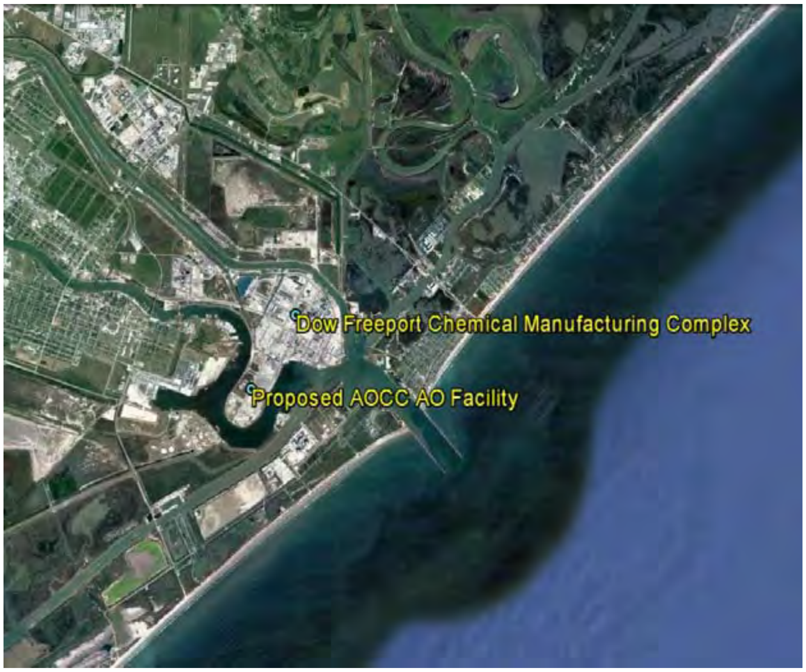

Figure 1. Location of Proposed AOCC AO Plant
(Map Created Using Google Earth)

Sources of Air Emissions

Activities and facilities at the proposed AOCC AO plant that will result in the emission of regulated air pollutants include:

- Heaters;
- Cooling tower;
- Storage tanks;
- Product loading;
- Process vents;
- Analyzer vents;
- Process fugitives;
- Flare;
- Routine maintenance, startup, and shutdown emissions.

Emissions of Volatile Organic Compounds ("VOCs") from the AOCC plant will exceed 25 tons/year ("tpy"). Therefore, the plant will be a new major source subject to Nonattainment New Source Review ("NNSR") for VOC. With respect to nitrogen oxides ("NO_X"), emissions will be less than 25 tpy and, thus, the plant will be a minor source and not subject to NNSR. As a new major source, the de minimis threshold test (netting) does not apply. Per 30 TAC §116.150(c), netting is required for modifications to existing major sources, not for new major sources.

In addition, the AO unit will be subject to federal Prevention of Significant Deterioration (PSD) review for PM less than 10 micrometers in diameter (PM_{10}), PM less than 2.5 micrometers in diameter ($PM_{2.5}$), and greenhouse gases (GHGs) quantified as carbon dioxide equivalents (CO_2e). Emissions of nitrogen oxides (NOx), carbon monoxide (CO), PM and sulfur dioxide (SO_2) are below the significance threshold for PSD permitting.

On June 3, 2010, the United States Environmental Protection Agency (EPA) published final rules for permitting sources of GHGs under the PSD and Title V air permitting programs, known as the GHG Tailoring Rule.[1] On December 23, 2010, EPA issued a Federal Implementation Plan (FIP) authorizing EPA to issue GHG permits in Texas until Texas submits the required State Implementation Plan (SIP) revision and this revision is approved by EPA.[2] Since the Texas Commission on Environmental Quality (TCEQ) has not submitted the required SIP revisions to EPA and has not implemented a PSD permitting program for GHGs, the purpose of this application is to obtain air quality permit authorization from EPA to authorize GHG emissions from the proposed new AO plant near Freeport, Texas. AOCC believes that this application has been prepared such that it contains all information necessary for processing the application as described in 40 CFR §52.21(b)(22). The proposed AO plant will not be located within 100 km of a designated Class I federal area and the emissions of GHGs from the plant will not affect air quality at any of these designated Class I areas.

A separate air preconstruction permit application has been submitted to the TCEQ to authorize emissions of all regulated air pollutants except for GHGs. This TCEQ permit application is consistent with the requirements in Title 30 of the Texas Administrative Code (30 TAC) Chapter 116, Subchapter B, Division 1. In addition, consistent with correspondence between TCEQ and EPA Region 6, the TCEQ has been requested by AOCC to review its applications for authorization of emissions of PM_{10} and $PM_{2.5}$ (pollutants below PSD major thresholds, but above PSD significance thresholds).[3]

Emissions from each of the sources in the AO plant will be addressed in the GHG Emissions Calculations and Best Available Control Technology (BACT) sections of this application for all GHGs.

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[1] 75 FR 31514 (June 3, 2010)

[2] 75 FR 81874 (December 29, 2010)

[3] Letter from Zak Covar, Executive Director, TCEQ to Samuel Coleman, Deputy Regional Administrator, EPA Region 6, dated February, 13, 2013; Letter from Samuel Coleman, Deputy Regional Administrator, EPA Region 6 to Zak Covar, Executive Director, TCEQ dated April 14, 2013.

2 General Application Information

2.1 TCEQ Form PI-1

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

Important Note: The agency requires that a Core Data Form be submitted on all incoming applications unless a Regulated Entity and Customer Reference Number have been issued and no core data information has changed. For more information regarding the Core Data Form, call (512) 239-5175 or go to www.tceq.texas.gov/permitting/central_registry/guidance.html.

I. Applicant Information		
A. Company or Other Legal Name: The Alpha Olefin Chemical Company LLC		
Texas Secretary of State Charter/Registration Number (if applicable):		
B. Company Official Contact Name: Yoshiaki Izawa		
Title: Chief Financial Officer		
Mailing Address: 3000 Town Center, Suite 2820		
City: Southfield	State: Michigan	ZIP Code: 48075
Telephone No.: 248-355-9590	Fax No.: 248-355-9330	E-mail Address: yoshiaki.izawa@idemitsu.com
C. Technical Contact Name: Danny Worrell		
Title: Attorney		
Company Name: Brown McCarroll, L.L.P.		
Mailing Address: 111 Congress Avenue, Suite 1400		
City: Austin	State: Texas	ZIP Code: 78701
Telephone No.: 512-472-5456	Fax No.: 512-479-1101	E-mail Address: dworrell@brownmccarroll.com
D. Site Name: Freeport Alpha Olefins Facility		
E. Area Name/Type of Facility: Manufacture of Alpha Olefins		☒ Permanent ☐ Portable
F. Principal Company Product or Business: Series of Alpha Olefins		
Principal Standard Industrial Classification Code (SIC): 2869		
Principal North American Industry Classification System (NAICS): 325110		
G. Projected Start of Construction Date: Second Quarter of 2014		
Projected Start of Operation Date: Second Half of 2016		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: FM 1495, approximately 3 miles south of the intersection of Hwy 332 and FM 523.		
City/Town: Freeport	County: Brazoria	ZIP Code: 77541
Latitude (nearest second): 28.940141	Longitude (nearest second): -95.324205	

I.	**Applicant Information (continued)**	
I.	Account Identification Number (leave blank if new site or facility):	
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):	
L.	Regulated Entity Number (RN):	
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, notice of violation, or enforcement action? If Yes, attach a copy of any correspondence from the agency and provide the RN in section I.L. above.	☐ YES ☒ NO
C.	Number of New Jobs: 25-100	
D.	Provide the name of the State Senator and State Representative and district numbers for this facility site:	
State Senator: Joan Huffman		District No.: 17
State Representative: Dennis Bonnen		District No.: 25
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):	
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 ☐ Plant-Wide Applicability Limit ☒ Prevention of Significant Deterioration ☐ Hazardous Air Pollutant Major Source ☐ 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)*

E. Is this application for a change of location of previously permitted facilities? If Yes, complete III.E.1 - III.E.4.0	☐ YES ☒ NO

1. Current Location of Facility (If no street address, provide clear driving directions to the site in writing.):

Street Address:

City:	County:	ZIP Code:

2. Proposed Location of Facility (If no street address, provide clear driving directions to the site in writing.):

Street Address:

City:	County:	ZIP Code:

3. Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions? If "NO", attach detailed information.	☐ YES ☐ NO
4. Is the site where the facility is moving considered a major source of criteria pollutants or HAPs?	☐ YES ☐ NO

F. Consolidation into this Permit: List any standard permits, exemptions or permits by rule to be consolidated into this permit including those for planned maintenance, startup, and shutdown.

List: None

G. Are you permitting planned maintenance, startup, and shutdown emissions? If Yes, attach information on any changes to emissions under this application as specified in VII and VIII.	☒ YES ☐ NO
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) Is this facility located at a site required to obtain a federal operating permit? If Yes, list all associated permit number(s), attach pages as needed).	☐ YES ☐ NO ☒ To be determined

Associated Permit No (s.):

1. Identify the requirements of 30 TAC Chapter 122 that will be triggered if this application is approved.

☐ FOP Significant Revision
☐ FOP Minor
☐ Application for an FOP Revision
☐ Operational Flexibility/Off-Permit Notification
☐ Streamlined Revision for GOP
☒ To be Determined
☐ None

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).	
List:	
E. Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E.3.	NO
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):***

Volatile Organic Compounds (VOC): 35.4

Sulfur Dioxide (SO2): 0.2

Carbon Monoxide (CO): 44.7

Nitrogen Oxides (NOx): 24.9

Particulate Matter (PM): 23.2

PM 10 microns or less (PM10): 23.2

PM 2.5 microns or less (PM2.5): 21.3

Lead (Pb): n/a

Hazardous Air Pollutants (HAPs): Hydrochloric acid (HCl) 0.04

Other speciated air contaminants not listed above: n/a

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

V. Public Notice Information *(complete if applicable)*

A. Public Notice Contact Name: Danny Worrell

Title: Attorney

Mailing Address: 111 Congress Avenue, Suite 1400

City: Austin | State: Texas | ZIP Code: 78701

B. Name of the Public Place: Freeport Library

Physical Address *(No P.O. Boxes)*: 410 N Brazosport Blvd.

City: Freeport | County: Brazoria | ZIP Code: 77541

The public place has granted authorization to place the application for public viewing and copying. ☒ YES ☐ NO

The public place has internet access available for the public. ☒ YES ☐ NO

C. Concrete Batch Plants, PSD, and Nonattainment Permits

1. County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.

The Honorable: Judge Milan Miller

Mailing Address: 210 A W First St

City: Freeport | State: TX | ZIP Code: 77541

2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? ***(For Concrete Batch Plants)*** ☐ YES ☐ NO

Presiding Officers Name(s):

Title:

Mailing Address:

City: | State: | ZIP Code:

3. Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located.

Chief Executive:

Mailing Address:

City: | State: | ZIP Code:

Name of the Indian Governing Body:

Mailing Address:

City: | State: | ZIP Code:

V.	**Public Notice Information *(complete if applicable) (continued)***	
C.	Concrete Batch Plants, PSD, and Nonattainment Permits	
3.	Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located. *(continued)*	
Name of the Federal Land Manager(s):		
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	
B.	Are any schools located within 3,000 feet of this facility?	☐ YES ☒ NO

VII. Technical Information

C. Maximum Operating Schedule:

Hour(s): 24	Day(s): 365	Week(s): 52	Year(s): 8,760

Seasonal Operation? If Yes, please describe in the space provide below.	☐ YES ☒ NO
D. Have the planned MSS emissions been previously submitted as part of an emissions inventory?	☐ YES ☒ NO
Provide a list of each planned MSS facility or related activity and indicate which years the MSS activities have been included in the emissions inventories. Attach pages as needed.	
E. Does this application involve any air contaminants for which a disaster review is required?	☐ YES ☒ NO
F. Does this application include a pollutant of concern on the Air Pollutant Watch List (APWL)?	☐ YES ☒ NO

VIII. State Regulatory Requirements

Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment. *The application must contain detailed attachments addressing applicability or non applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*

A. Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?	☒ YES ☐ NO
B. Will emissions of significant air contaminants from the facility be measured?	☒ YES ☐ NO
C. Is the Best Available Control Technology (BACT) demonstration attached?	☒ YES ☐ NO
D. Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?	☒ YES ☐ NO

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.*

A. Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?	☒ YES ☐ NO
B. Does 40 CFR Part 61, National Emission Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?	☐ YES ☒ NO

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.*	
C.	Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☐ YES ☒ NO
D.	Do nonattainment permitting requirements apply to this application?	☒ YES ☐ NO
E.	Do prevention of significant deterioration permitting requirements apply to this application?	☒ YES ☐ NO
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
Paid online?	☐ YES ☒ NO
Company name on check: Idemitsu Chemicals U. S. A. Corporation	
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

XII. Delinquent Fees and Penalties

This form will not be processed until all delinquent fees and/or penalties owed to the TCEQ or the Office of the Attorney General on behalf of the TCEQ is paid in accordance with the Delinquent Fee and Penalty Protocol. For more information regarding Delinquent Fees and Penalties, go to the TCEQ Web site at: www.tceq.texas.gov/agency/delin/index.html.

XIII. 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 to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7, Texas Clean Air Act (TCAA), as amended, or any of the air quality rules and regulations of the Texas Commission on Environmental Quality or any local governmental ordinance or resolution enacted pursuant to the TCAA I further state that I understand my signature indicates that this application meets all applicable nonattainment, prevention of significant deterioration, or major source of hazardous air pollutant permitting requirements. The signature further signifies awareness that intentionally or knowingly making or causing to be made false material statements or representations in the application is a criminal offense subject to criminal penalties.

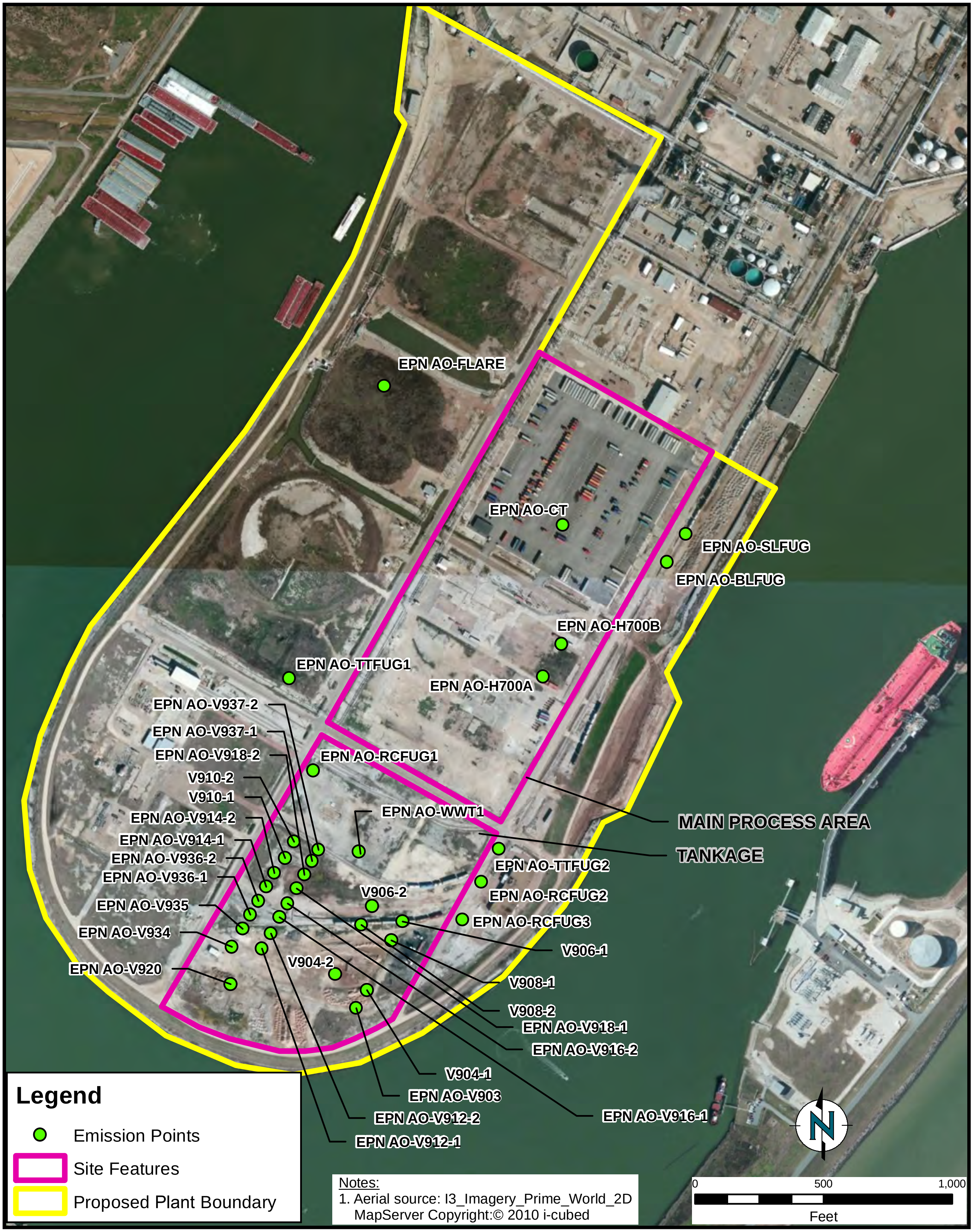
Name: Kazuo Maruyama

Signature: Kazuo Maruyama
Original Signature Required

Date: 4/15/2013

PRINT FORM   RESET FORM

2.2 Plot Plan



Notes:
1. Aerial source: I3_Imagery_Prime_World_2D
MapServer Copyright:© 2010 i-cubed

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PLOT PLAN

ALPHA OLEFIN CHEMICAL COMPANY LLC
FREEPORT ALPHA OLEFINS PLANT

Figure
3

DRAFTED BY: MRJ

Date: 5/7/2013

PROJECT: 31-30190A

2.3 Area Map

Legend

- ☐ Proposed Plant Boundary
- ☐ 3000 Feet Buffer

Notes:
1. Aerial source: I3_Imagery_Prime_World_2D
MapServer Copyright:© 2010 i-cubed

ENVIRON

DRAFTED BY: MRJ

Date: 4/1/2013

AREA MAP

ALPHA OLEFIN CHEMICAL COMPANY LLC
FREEPORT ALPHA OLEFINS PLANT

Figure
2

PROJECT: 31-30190A

3 Process Description and GHG Emission Sources

3.1 Overview

AOCC is planning to build a new alpha olefins plant near the City of Freeport in Brazoria County, Texas. This plant will use ethylene as its primary raw material. Ethylene will undergo reaction and distillation to produce a variety of alpha olefins. The sale of alpha olefins and other products will vary in response to marketplace and customer demands.

Major sections of the AO process at the proposed plant include:

- Preparation;
- Reaction;
- Deactivation;
- Distillation; and
- Support Operations such as unloading and storage of miscellaneous raw materials, product storage, product loading, hot oil heaters, cooling water system, flare, and routine maintenance, startup, and shutdown activities.

AOCC is submitting this GHG PSD permit application to authorize the construction of the AO plant and other associated activities as described above. AOCC will own, operate, and control the plant. Each part of the chemical manufacturing process and associated emissions are identified in the following discussion of the AO process.

3.2 Production Operations

The AOCC AO process is described in the following sections.

Preparation

Fresh catalyst along with cyclohexane is fed in to the reactors. Cyclohexane emissions due to leaks are the only emissions of concern during catalyst preparation. Emissions due to leaks are vented to the flare.

Reaction

Two reactors are used at the proposed plant. Cyclohexane is used as a recycle solvent during the reaction and is fed into the reactors along with the catalyst.

The formation reaction of AO from ethylene is an exothermic reaction. The heat of reaction is removed by using an external heat exchanger system comprised of water and steam. Steam generated is condensed at the air fin cooler (AFC) and recycled into the system.

Deactivation

Active catalyst remains in the effluent which is a mixture of AO and cyclohexane. The catalyst is deactivated and removed in the Deactivation Section. Effluent is fed into a deactivator with ammonia water to deactivate the catalyst.

Distillation

Effluent from the Deactivation Section is fed to the Distillation Section. In the Distillation Section, lighter alpha olefin product and cyclohexane are recovered from the initial distillation columns. The bottom stream from these initial distillation columns is fed into a series of distillation columns operating at different temperatures and pressures to recover the heavier AO products. The bottom stream of the last distillation column is C30+ which is used as fuel for the hot oil heaters. Light gas (off-gas) from the overhead stream is sent by pipeline to an existing plant for reprocessing.

Raw Material and Product Storage

Primary feeds to the AO process include ethylene among other components. Ethylene will be fed directly by pipeline from an existing plant and will not be stored on site. Catalysts will be stored at the proposed plant. Fresh cyclohexane will be stored in a process holding tank at the proposed plant.

AO products will be stored in either spheres or storage tanks, depending on the type of AO.

Raw Material and Product Loading/Unloading

Raw materials unloaded at the plant include catalysts and cyclohexane. At initial startup, cyclohexane will be loaded from a ship or barge to a vertical fixed roof tank. After start of operation, cyclohexane will be loaded from a tank truck to a vertical fixed roof tank.

AO products will be loaded into barges, railcars, ships and tank trucks. VOC emissions generated due to loading of lighter AOs will be vented to the flare. Emissions generated due to the loading of heavier AOs and AO blends are insignificant due to low vapor pressures associated with these products and will therefore be directly vented to the atmosphere.

Hot Oil Heaters (EPNs AO-H700A and AO-H700B)

Hot oil heaters will be used to provide heat to the process, storage vessels, etc. At this time, AOCC is planning on installing two hot oil heaters. The hot oil heaters will be fired primarily on two fuels: fuel gas (provided by pipeline from an existing plant) and residual alpha olefins (C30+). The fuel gas is composed primarily of methane. The proposed plant may also, at certain times, use off-gas from the distillation section as a fuel for the hot oil heaters.

Cooling Water System (EPN AO-CT)

The AO plant will utilize a single cooling tower. The cooling water system is considered to be a potential source of VOC emissions as well as particulate matter (PM) emissions.

Flare (EPN AO-FLARE)

The AO plant will utilize a multi-stage ground flare for the control of intermittent and continuous process vent streams; control of emissions due to loading and unloading operations at the proposed plant; and control of emergency releases. It will also be utilized during process clearing and venting for routine maintenance, startup and shutdown. The number of stages has yet to be determined.

Wastewater storage and treatment

The AO plant will generate one wastewater stream from the Deactivation Section. This wastewater stream will contain deactivated catalyst and will be hard-piped to an onsite wastewater holding tank before being routed by pipeline to an existing offsite wastewater treatment plant.

Routine maintenance, startup and shutdown activities (EPNs AO-MSSC and AO-MSSU)

Planned and predictable maintenance, startup and shutdown (MSS) activities at the AO plant will be conducted in a way that will minimize emissions to the atmosphere. This will generally be accomplished by clearing equipment before line openings or vessel opening. Where feasible, this equipment will be cleared back to the process or routed to the process flare.

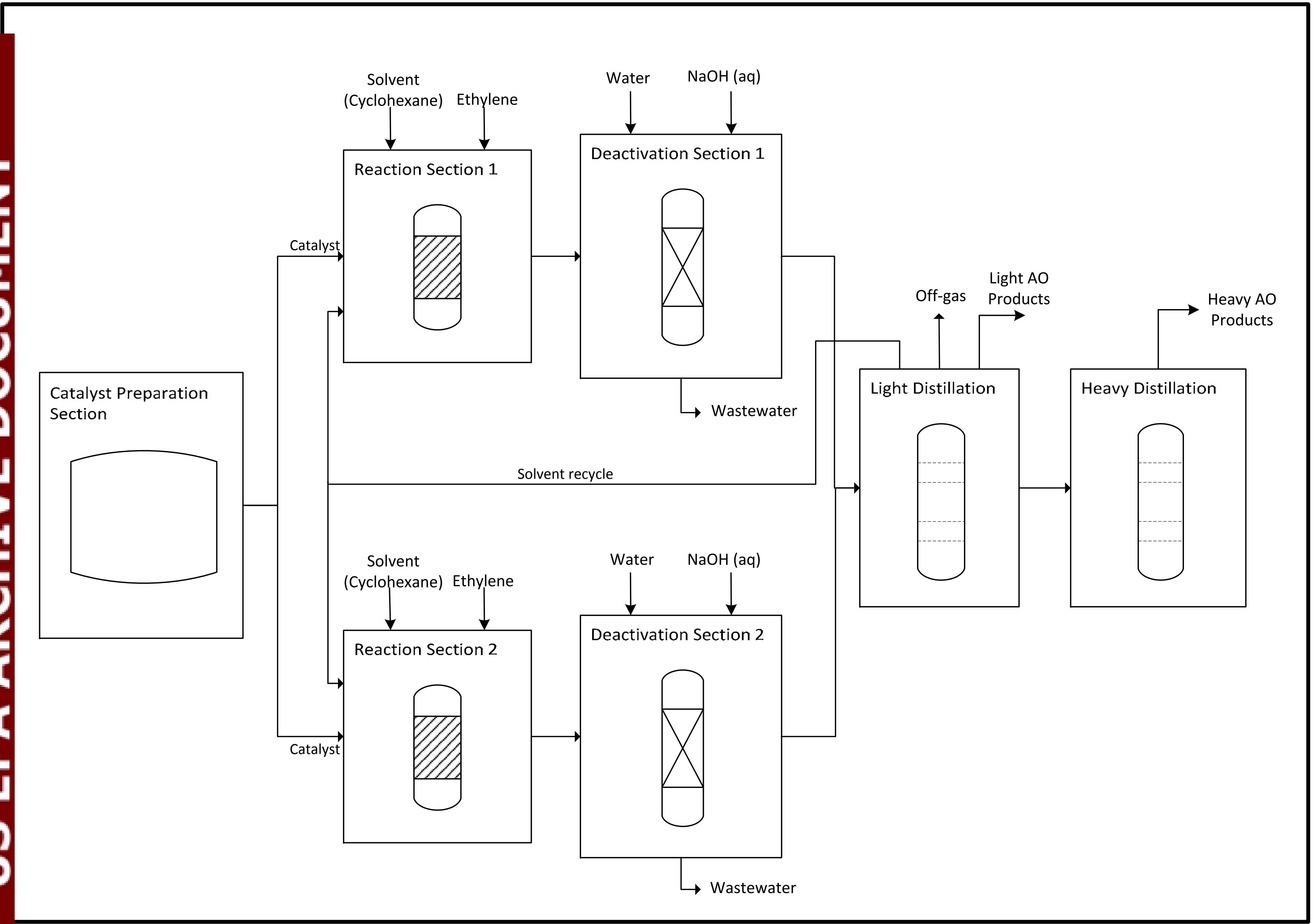

Figure 4 – Simplified Process Flow Diagram

4 GHG Emission Calculations

The following sections estimate annual emissions of GHGs from various activities in the AO plant. All backup documentation for these emission calculations are found in Appendix A of this permit application.

4.1 Hot Oil Heaters

The AO unit will utilize a combination of fuel gas, AO residuals and process off-gas for combustion. Annual emissions have been calculated using combustion of AO residuals and fuel gas, using a heat input ratio based on annual usage for each fuel.

These heaters will be a source of CO_2, CH_4, and N_2O emissions. These emissions are calculated in accordance with the procedures in the Mandatory Greenhouse Gas Reporting rules, 40 CFR 98, Subpart C – General Stationary Fuel Combustion Sources. Equation C-5 is used for calculating CO_2 emissions from fuel gas. Equation C-4 is used for calculating CO_2 emissions from AO residuals. CH_4 and N_2O are calculated using Equation C-8 and the emission factors (kg/MMBtu) for natural gas combustion and the default high heat value of the fuel from Table C-2 and C-1, respectively. Please note that default high heat values and fuel-specific emission factors for natural gas and residual fuel oil no. 6 have been used for calculating CH_4 and N_2O emissions from fuel gas and AO residuals. The global warming potential factors used to calculate carbon dioxide equivalent (CO_2e) emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules. Sample calculations for Hot Oil Heater No. 1 are shown below.

CO_2 Emissions (for fuel gas)

$$CO_2\ (metric\ tons) = \frac{44}{12}\,x\ Fuel\ x\ CC\ x\,\frac{MW}{MVC}\,x\ 0.001$$

Where:

CO_2 = Annual CO_2 mass emissions from combustion of the specific gaseous fuel (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
CC = Annual carbon content of the gaseous fuel (kg C per kg fuel)
MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole)
MVC = Molar volume conversion factor at standard conditions (836.6 scf per kg-mole)
44/12 = Ratio of molecular weights, CO_2 to carbon
0.001= Conversion factor from kg to metric tons

For Hot Oil Heater No. 1:

$$CO_2\ = \frac{44}{12}\,x\ 1{,}663{,}564{,}487\,\frac{scf}{yr}\,x\ 0.857\ x\ 0.738\ x\,\frac{16.94}{836.6}\,x\ 0.001 = 78{,}134\ metric\ tons$$

To convert to short tons, for Hot Oil Heater No. 1:

$$78{,}134\ metric\ tons\ x\ 1.1023\ \frac{short\ tons}{metric\ ton} = 86{,}127\ short\ tons/yr$$

0.857 in the sample calculation for fuel gas represents the heat input ratio for fuel gas on an annual basis.

CO_2 Emissions (for fuel oil)

$$CO_2\ (metric\ tons) = \frac{44}{12} x\ Fuel\ x\ CC\ x\ 0.001$$

Where:
CO_2 = Annual CO_2 mass emissions from combustion of the specific liquid fuel (metric tons)
Fuel = Annual volume of the liquid fuel combusted (gallons)
CC = Annual carbon content of the liquid fuel (kg C per gallon of fuel)
44/12 = Ratio of molecular weights, CO_2 to carbon
0.001= Conversion factor from kg to metric tons

For Hot Oil Heater No. 1:

$$CO_2 = \frac{44}{12} x\ 2{,}084{,}880 \frac{gal}{yr} x\ 0.858\ x\ 0.001 = 6{,}558\ metric\ tons$$

To convert to short tons, for Hot Oil Heater No. 1:

$$6{,}558\ metric\ tons\ x\ 1.1023\ \frac{short\ tons}{metric\ ton} = 7{,}229\ short\ tons/yr$$

Therefore, total CO_2 emissions from Hot Oil Heater No. 1 are,

$$86{,}127\ short\ tons/yr + 7{,}229\ short\ tons/yr = 93{,}357\ short\ tons/yr$$

CH_4 Emissions

$$\boldsymbol{CH_4\ (metric\ tons) = 1\ x\ 10^{-3}\ x\ Fuel\ x\ HHV\ x\ EF}$$

Where:
CH_4 = Annual emissions from the combustion (metric tons)
Fuel = Mass or volume of fuel combusted per year
HHV = Default high heat value from Table C-1, 0.00128 MMBtu/scf for natural gas and 0.150 MMBtu/gal for residual fuel oil no. 6
EF = Fuel-specific emission factor from Table C-2, 0.001 kg/MMBtu for natural gas and 0.003 kg/MMBtu for residual fuel oil No. 6

1×10^{-3} = Conversion factor from kilograms to metric tons

Fuel gas combustion, Hot Oil Heater No. 1:

$$CH_4 = 1\ x\ 10^{-3}\ x\ 1{,}663{,}564{,}487\,\frac{scf}{yr}\ x\ 0.857\ x\ 1.028\ x\ 10^{-3}\,\frac{MMBtu}{scf}\ x\ 0.001\,\frac{kg}{MMBtu} = 1.47\ metric\ tons/yr$$

To convert metric tons to short tons, for Hot Oil Heater No. 1:

$$1.47\ metric\ tons\ x\ \frac{1.1023\ short\ tons}{metric\ ton} = 1.62\ short\ tons/yr$$

Combustion of AO residuals, Hot Oil Heater No. 1:

$$CH_4 = 1\ x\ 10^{-3}\ x\ 2{,}084{,}880\,\frac{gal}{yr}\ x\ 0.150\ \frac{MMBtu}{gal}\ x\ 0.003\,\frac{kg}{MMBtu} = 0.94\ metric\ tons/yr$$

To convert metric tons to short tons, for Hot Oil Heater No. 1:

$$0.94\ metric\ tons\ x\ \frac{1.1023\ short\ tons}{metric\ ton} = 1.03\ short\ tons/yr$$

Therefore, total CH_4 emissions from Hot Oil Heater No. 1 are,

$$1.62\ short\ tons/yr + 1.03\ short\ tons/yr = 2.65\ short\ tons/yr$$

N_2O Emissions

$$\boldsymbol{N_2O\ (metric\ tons) = 1\ x\ 10^{-3}\ x\ Fuel\ x\ HHV\ x\ EF}$$

Where:
N_2O= Annual emissions from the combustion (metric tons)
Fuel = Mass or volume of fuel combusted per year
HHV = Default high heat value from Table C-1, 0.00128 MMBtu/scf for natural gas and 0.150 MMBtu/gal for residual fuel oil no. 6
EF = Fuel-specific emission factor from Table C-2, 0.0001 kg/MMBtu for natural gas and 0.0006 kg/MMBtu for residual fuel oil No. 6
1×10^{-3} = Conversion factor from kilograms to metric tons

Fuel gas combustion, Hot Oil Heater No. 1:

$$N_2O = 1 \; x \; 10^{-3} \; x \; 1{,}663{,}564{,}487 \frac{scf}{yr} \; x \; 0.857 \; x \; 1.028 \; x \; 10^{-3} \frac{MMBtu}{scf} \; x \; 0.0001 \frac{kg}{MMBtu}$$
$$= 0.15 \; metric \; tons/yr$$

To convert to short tons, for Hot Oil Heater No. 1:

$$0.15 \; metric \; tons \; x \; 1.1023 \; \frac{short \; tons}{metric \; ton} = 0.16 \; short \; tons/yr$$

Combustion of AO residuals, Hot Oil Heater No. 1:

$$N_2O = 1 \; x \; 10^{-3} \; x \; 2{,}084{,}880 \frac{gal}{yr} \; x \; 0.150 \; \frac{MMBtu}{gal} \; x \; 0.0006 \frac{kg}{MMBtu} = 0.19 \; metric \; tons/yr$$

To convert metric tons to short tons, for Hot Oil Heater No. 1:

$$0.19 \; metric \; tons \; x \; \frac{1.1023 \; short \; tons}{metric \; ton} = 0.21 \; short \; tons/yr$$

Therefore, total N_2O emissions from Hot Oil Heater No. 1 are,

$$0.16 \; short \; tons/yr + 0.21 \; short \; tons/yr = 0.37 \; short \; tons/yr$$

CO_2e Emissions

To determine CO_2e emissions, the annual rate of CO_2, CH_4, and N_2O emissions are multiplied by the Global Warming Potential for each compound.

$$CO_2e = (CO_2 \; emissions \; x \; GWP) + (CH_4 \; emissions \; x \; GWP) + (N_2O \; emissions \; x \; GWP)$$

Where:
GWP for CO_2 = 1
GWP for CH_4 = 21
GWP for N_2O = 310

For Hot Oil Heater No. 1:

$$CO_2e = (93{,}357 \; short \; tons \; x \; 1) + (2.65 \; short \; tons \; x \; 21) + (0.37 \; short \; tons \; x \; 310)$$
$$= 93{,}527 \; short \; tons/yr$$

4.2 Process Flare

The process flare will use natural gas for the flare pilots. Other routine combustion will include vent lines from storage tanks, cyclohexane seal pot vent and loading for control of VOC emissions from these routine operations. Non-routine combustion will include emissions due to combustion of startup and shutdown purge lines vented to the flare from reaction, light distillation and heavy distillation sections.

The AO plant process flare will be a source of CO_2, CH_4, and N_2O emissions. Emissions from this flare are calculated in accordance with the procedures in the Mandatory Greenhouse Gas Reporting rules, 40 CFR 98, Subpart Y – Petroleum Refineries. CO_2 emissions are calculated by using Equation Y-1a, CH_4 emissions calculated using Equation Y-4, and N_2O emissions calculated using Equation Y-5. The global warming potential factors used to calculate carbon dioxide equivalent (CO_2e) emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules. Sample calculations for the process flare are shown below.

CO_2 Emissions

$$CO_2 = 0.98\ x\ 0.001\ x\ \frac{44}{12}\ x\ \ Flare\ x\ \frac{MW}{MVC}\ x\ CC$$

Where:

CO_2 = CO_2 mass emissions, metric tons/yr
0.98 = Assumed combustion efficiency of the flare
0.001 = Unit conversion factor (metric tons/kilogram)
44/12 = Ratio of molecular weights, CO_2 to carbon
Flare = Volume of flare gas combusted, scf/yr
MW = Average molecular weight of the flare gas combusted (kg/kg-mole)
MVC = Molar volume conversion factor (836.6 scf/kg-mole)
CC = Average carbon content of the flare gas, kg C/kg flare gas

For routine emissions from the flare (purge gas and flare pilots):

$$CO_2 = 0.98\ x\ 0.001\ x \frac{44}{12} x\ 803{,}000\ x \frac{16.94}{836.6} x\ 0.738 = 43.1\ metric\ tons$$

To convert to short tons, for the process flare:

$$43.1\ metric\ tons\ x\ 1.1023\ \frac{short\ tons}{metric\ ton} = 47.51\ short\ tons$$

CH_4 Emissions

$$CH_4 = (CO_2 \ x \ EmF_{CH4}/EmF) + CO_2 \ x \ \frac{0.02}{0.98} \ x \ \frac{16}{44} \ x \ F_{CH4}$$

Where:

CH_4 = CH_4 mass emissions, metric tons/yr

CO_2 = CO_2 mass emissions, metric tons/yr

EmF_{CH4} = Default CH_4 emission factor for “Petroleum Products” from Table C-2 of subpart C of 40 CFR 98, kg CH_4/MMBtu

EmF = Default CO_2 emission factor for flare gas of 60 kg CO_2/MMBtu

0.02/0.98 = Correction factor for flare combustion efficiency

16/44 = Correction factor ration of the molecular weight of CH_4 to CO_2

F_{CH4} = Default weight fraction of carbon in the flare gas prior to combustion that is contributed by methane, 0.4 kg C in methane / kg C in flare gas

For routine emissions from the flare (purge gas and flare pilots):

$$CH_4 = (43.1 \ x \ 0.001/60) + 43.1 \ x \ \frac{0.02}{0.98} \ x \ \frac{16}{44} \ x \ 0.4 = 0.13 \ metric \ tons$$

To convert to short tons, for the process flare:

$$0.13 \ metric \ tons \ x \ 1.1023 \ \frac{short \ tons}{metric \ ton} = 0.14 \ short \ tons$$

N_2O Emissions

$$N_2O = CO_2 \ x \ EmF_{N2O}/EmF$$

Where:

N_2O = Nitrous oxide mass emissions, metric tons/yr

CO_2 = CO_2 mass emissions, metric tons/yr

EmF_{N2O} = Default N_2O emission factor for “Petroleum Products” from Table C-2 of subpart C of 40 CFR 98, kg N_2O/MMBtu

EmF = Default CO_2 emission factor for flare gas of 60 kg CO_2/MMBtu

For routine emissions from the flare (purge gas and flare pilots):

$$N_2O = 43.1 \ x \ \frac{0.0001}{60} = 7.2x10^{-5} \ metric \ tons$$

To convert to short tons, for the process flare:

$$7.2x10^{-5}\ metric\ tons\ x\ 1.1023\ \frac{short\ tons}{metric\ ton} = 7.9x10^{-5}\ short\ tons$$

CO_2e Emissions

To determine CO_2e emissions, the annual rate of CO_2, CH_4, and N_2O emissions are multiplied by the Global Warming Potential for each compound.

$$CO_2e = (CO_2\ emissions\ x\ GWP) + (CH_4\ emissions\ x\ GWP) + (N_2O\ emissions\ x\ GWP)$$

Where:
GWP for CO_2 = 1
GWP for CH_4 = 21
GWP for N_2O = 310
For the purge gas and pilots on the process flare:

$$CO_2e = (47.51\ short\ tons\ x\ 1) + (0.14\ short\ tons\ x\ 21) + (7.9x10^{-5}\ short\ tons\ x\ 310) = 50.5\ short\ \frac{tons}{yr}$$

4.3 Process Fugitives

AOCC has provided details pertaining to fugitive emissions components including:

- An estimated count of valves, pumps, compressors, flanges/connectors and sampling connections; and
- The service of those components.

TCEQ methodology is used to estimate fugitive emissions.[4] Specifically, average with ethylene and without ethylene SOCMI emission factors are used to estimate uncontrolled emissions. Controlled emissions are estimated using TCEQ-specified control efficiencies for the 28MID Leak Detection and Repair ("LDAR") program for components in gas and light liquid service. Controlled emissions for heavy liquids are estimated using TCEQ-specified control efficiencies for the Audio/Visual/Olfactory ("AVO") LDAR program. 99% of the valves in gas, light liquid and heavy liquid service will be monitored quarterly. The remainder 1% of these valves will be monitored annually since these are either difficult to reach or unsafe to monitor on a quarterly basis. The TCEQ 28MID program requires that all new pumps and compressors be "leak-less". Therefore, 100% control is applied to fugitive emissions from all pumps and compressors.

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[4] Texas Commission on Environmental Quality, "Emissions Factors for Equipment Leak Fugitive Components," Addendum to RG-360A, Table 3 (January 2008) (http://www.tceq.texas.gov/assets/public/implementation/air/ie/pseiforms/ef_elfc.pdf).

Flanges and connectors in gas/vapor and light liquid service that are monitored using an organic vapor analyzer ("OVA") at the same leak definition as valves may use the same control credit used for valves. AOCC will monitor flanges and connectors using an OVA at the same leak definition as valves. Therefore, 97% control is applied to fugitive emissions from all flanges and connectors.

The chemical composition and concentration of each process stream was obtained from proprietary process simulation provided by AOCC. The output from this process simulation was used to estimate the speciation of fugitive emissions.

Additionally, the plant will utilize a number of Pressure Safety Valves (PSVs) in the process. All PSVs in GHG service will relieve to the flare or will be equipped with a rupture disk and pressure sensing device to monitor for disk integrity. Consequently, 100% control for fugitive emissions from PSVs was applied.

CO2e emissions have been calculated for methane and R-22. Sample calculations for GHG emissions due to process fugitives are shown below.

CO_2e Emissions

$$CO_2e\ (short\ tons) = Component\ Fugitive\ Emission\ Rate\ (tpy) x\ Component\ GWP$$

Where:

Component fugitive emission rate is derived from the detailed fugitive emission calculations using SOCMI emission factors; and

Component GWP is the Global Warming Potential for each fugitive component with a global warming potential.

$$CO_2e\ = 0.02\ tpy\ x\ 21\ (GWP\ for\ Methane) = 0.33\ tpy$$

4.4 Routine Startup, Shutdown and Maintenance Emissions

Emissions due to scheduled MSS have been estimated using the total volume displaced when a particular unit is under MSS. For the reaction and distillation sections, emissions are based on the total volume purged to the flare, VOC content of the purged volume and physical parameters such as maximum operating pressure and temperature. Plant shutdown will likely occur every 24 months. For the purpose of estimating MSS emissions, it is conservatively assumed that one plant shutdown occurs per calendar year. During shutdown events, equipment will be cleared of all gas or liquids by returning to the process, de-pressured to the flare as feasible, and then opened to the atmosphere. TCEQ MSS Guidance document for petroleum refineries and chemical plants was used to calculate MSS emissions from storage tanks and piping. For these calculations, it is assumed that after all the liquid has been drained out of the storage tanks and piping under MSS, the vapor space is saturated with VOC.[5] All

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[5] http://www.tceq.texas.gov/permitting/air/guidance/newsourcereview/nsr-chem.html

equipment under MSS is purged to the flare until the VOC content falls below 10,000 ppmw. Uncontrolled MSS emissions are calculated using 10,000 ppmw VOC. It is also anticipated that routine maintenance of process analyzers, such as calibration, will be required. However, no emission calculations have been conducted for analyzer MSS.

The process flare for the AO unit will be used to control emissions due to MSS activities. During MSS, this flare will be a source of CO_2, CH_4, and N_2O emissions. Emissions from this flare are calculated in accordance with the procedures in the Mandatory Greenhouse Gas Reporting rules, 40 CFR 98, Subpart Y – Petroleum Refineries. CO_2 emissions are calculated by using Equation Y-1a, CH_4 emissions calculated using Equation Y-4, and N_2O emissions calculated using Equation Y-5. The global warming potential factors used to calculate carbon dioxide equivalent (CO_2e) emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules. For sample calculations, see the discussion of routine flare emissions.

5 Prevention of Significant Deterioration Applicability

The AOCC Plant will be a new stationary source. Emissions of GHGs will exceed 100,000 tons/year CO_2e; therefore, per federal rules it will be a PSD major stationary source. While emissions of all other pollutants will individually be less than 100 tpy, emissions of PM_{10} and $PM_{2.5}$ will exceed the respective PSD significant emission rates of 15 tpy and 10 tpy. Emissions of all other pollutants are below the PSD significant emission rates.

At this time, the Texas Commission on Environmental Quality ("TCEQ") does not regulate GHG emissions and, per the current State Implementation Plan ("SIP"), the proposed AOCC Plant will be a minor PSD source (emissions of all PSD pollutants individually less than 100 tpy). In accordance with the agreement in place between the TCEQ and EPA Region 6, however, AOCC has requested that the TCEQ determine compliance with PSD requirements and issue a PSD permit for PM_{10} and $PM_{2.5}$.[6] The permit application for the AOCC Plant was submitted to the TCEQ on May 7, 2013.

The purpose of this permit application being submitted to EPA is to obtain a PSD authorization for only the GHG emissions associated with the AOCC Plant.

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[6] Refer to letter dated February 13, 2013 from Mr. Zak Covar, Executive Director of the TCEQ, to Mr. Samuel Coleman, Deputy Regional Administrator, EPA Region 6, and the response letter from Mr. Coleman to Mr. Covar dated April 4, 2013.

6 Best Available Control Technology (BACT)

As required by 40 CFR §52.21(j), Best Available Control Technology (BACT) must be demonstrated for new and modified emission sources for which a significant net increase will occur. BACT is defined as follows:

> *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 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 entitled *PSD and Title V Permitting Guidance for Greenhouse Gases*, dated March 2011, EPA recommends the use of the Agency's five-step "top-down" process to determine BACT for greenhouse gases. This top-down process calls for the identification of all available control technologies for a given pollutant and the ranking of these technologies in descending order of control effectiveness. The applicant must then evaluate the highest-ranked option and the top-ranked option(s) should be established as BACT unless it is demonstrated that the technical considerations, or energy, environmental, or economic impacts and other costs justify a conclusion that the top-ranked technology is not achievable. If the most effective control strategy is eliminated, then the next most effective control should be evaluated until an option is selected as BACT. BACT cannot be less stringent than any applicable standard of performance under New Source Performance Standards (NSPS); however EPA has not promulgated any NSPS that contain emissions limits for GHGs.

EPA has divided the process of determining BACT into five steps:

Step 1: Identify all available control technologies
Step 2: Eliminate technically infeasible options
Step 3: Rank remaining control technologies
Step 4: Evaluate economic, energy and environmental impacts
Step 5: Select the BACT*

The five-step BACT process will be applied to each GHG emission source in the AO plant. These emission sources include:

- Hot oil heaters;
- Process flare; and
- Equipment fugitive emissions.

Since CH_4 and N_2O contribute insignificantly to the overall GHG emissions, the GHG BACT is focused on CO_2.

6.1 BACT for Hot Oil Heaters

As mentioned previously in this permit application, the process will include two hot oil heaters (EPNs: AO-H700A and AO-H700B), each rated at approximately 189.17 MMBTU/hr heat input. The fuels for these heaters will be:

- Fuel gas provided by The Dow Chemical Company.
- The residual alpha olefin ($C_{30=}$+) stream off the bottom of the last distillation column in the Heavy Distillation Section. Currently there is no market for this stream nor can it be reprocessed. Therefore, AOCC must dispose of it. Use of the residual AO as a fuel in the Hot Oil Heaters is considered the most environmentally and financially beneficial use. This approach not only disposes of this stream in an environmentally-responsible manner, it reduces the process fuel gas needs for the plant.
- Light Distillation Section off-gas (primarily ethylene and butylenes) when The Dow Chemical Company cannot accept this stream for reprocessing due to maintenance activities, turnarounds, etc.

6.1.1 Step 1: Identify All Available Control Technologies

Other than Carbon Capture and Sequestration (CCS) which is separately addressed in Appendix B, the primary GHG control options available for combustion units are the selection of energy efficient design to maximize thermal efficiency combined with the implementation of operation and maintenance procedures to ensure ongoing operation of the combustion source in an energy-efficient manner. The following lists those design elements and operating and maintenance practices considered to maximize energy efficiency of the process heaters.

- *Use of Low Carbon Fuels* – Selection of low carbon fuels in order to limit the amount of CO_2 emissions produced per unit of heat input.
- *Heater Design* – Good design measures in order to maximize equipment efficiency.
- *Oxygen Trim Control and Good Combustion Practices* – Continuous monitoring of oxygen concentration in the flue gas to be used to control excess air for optimal efficiency.

- *Periodic Tune-up* – Periodic tune-ups of the heaters to maintain maximum efficiency.

Presented in Appendix C is a summary of CO2 BACT determinations found for hot oil heaters in the EPA RACT/BACT/LAER Clearninghouse (“RBLC”). As shown, only one determination was found, with BACT being use of good combustion practices with an annual tune up.

6.1.2 Step 2: Eliminate Technically Infeasible Options

All of the options in Step 1 are considered technically feasible for controlling GHG emissions from the process heaters.

6.1.3 Step 3: Rank Remaining Control Technologies

The following reductions in GHG emissions can be achieved by the technologies listed below[7]:

- Use of Low Carbon Fuels – up to 100% for fuels containing no carbon
- Good Heater Design – 10%
- Good Combustion Control – 5-25%
- Periodic Tune-up – 2-10%

6.1.4 Step 4: Evaluate Economic, Energy and Environmental Impacts

- *Use of Low Carbon Fuels* – Combustion of any carbon containing fuel will produce GHG emissions. Of the fuels typically used by industrial processes (coal, fuel oil, natural gas, and process fuel gas), natural gas is the lowest carbon fuel that can be burned. Fuels used by the proposed AOCC Plant Hot Oil Heaters will include fuel gas (similar in composition to natural gas), AO residuals and, at times, off gas from the Light Distillation Section (mainly ethylene and butylenes). The CO_2 footprint for each of these fuels is as follows:

    - Fuel Gas ≈ 53.02 lb CO_2/MMBTU heat input
    - AO Residuals ≈ 75.10 lb CO_2/MMBTU heat input
    - LDS Off-Gas ≈ 67.43 lb CO_2/MMBTU heat input

    By comparison, the combustion of natural gas has a CO_2 footprint of approximately 118 lbs/MMBTU heat input (HHV). However, this value does not take into consideration the GHG emissions associated with the exploration, production and transmission of the natural gas. AOCC intends on using a locally-available fuel (process gas), a process waste stream (AO residuals) and, at times, process off-gas to fuel the Hot Oil Heaters. This eliminates the supply chain GHG emissions associated with use of natural gas supplied by an off-site 3rd party. Use of the AO residuals not only eliminates the need for the purchase and use of additional fuel gas, it eliminates GHG emissions that would be

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[7] EPA, *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy Plant Managers,* pg. 49-59 (June 2008).

associated with the transport and disposal of this material off-site. At projected AO residual production rates of approximately 476 gallons/hour, shipment off-site would require approximately 3 truckloads per day (5,000 gallons per truck), with associated GHG emissions while transporting the waste AO residuals to a disposal site. Proper disposal may very well include combustion (industrial incinerator, use as a fuel in a kiln, etc.) with resultant GHG emissions. With respect to LDS off-gas, use as a fuel in the Hot Oil Heaters (during times when Dow cannot take it for reprocessing) instead of flaring, reduces the need for fuel gas and eliminates the GHG emissions that would be associated with burning of the additional fuel gas.

- *Good Heater Design* – New heaters can be designed with a number features to improve efficiency by minimizing heat loss and increasing overall thermal efficiency. Operating a heater at near steady state conditions allows it to achieve maximum efficiency. Design features that improve overall thermal efficiency include efficient burners, and refractory and insulation materials on surfaces to minimize heat loss. Per the AOCC engineering team, the Hot Oil Heaters will be designed and operated to achieve a maximum thermal efficiency of 90% without SCR. If SCR is required in order to achieve the NO_X emission limits as stated in the TCEQ permit application, then overall thermal efficiency of the Hot Oil heaters is expected to be approximately 87%. The following table compares the anticipated thermal efficiency of the AOCC Plant Hot Oil Heaters with other hot oil heaters as represented in recently submitted applications.

Application	Description of Plant	Date of Permit Submittal	Heater Description	Represented Thermal Efficiency (%)
AOCC Plant	Alpha Olefins Plant	May 2013	378.34 MMBTU/hr Hot Oil Heaters	90%
Enterprise Products Operating, Mont Belvieu	NGL Fractionator & Debutanizer	May 2012	140 MMBTU/hr Hot Oil Heaters	89%
Flint Hills Resources	Crude Oil Expansion	December 2012	450 MMBTU/hr Hot Oil Heater	92%
ONEOK Hydrocarbon	NGL Fractionation Plant	September 2012	127 MMBTU/hr Hot Oil Heaters	91%
Targa Gas Processing	Natural Gas Processing Plant	February 2012, August 2012	98 MMBTU/hr Hot Oil Heater	Not Specified
Targa Midstream Services	NGL Fractionation Plant	March 2012, November 2012	144.45 MMBTU/hr Hot Oil Heaters	Not Specified

As shown, the thermal efficiency of the AOCC Plant Hot Oil Heaters will be comparable with other hot oil heaters as represented in recent GHG PSD permit applications.

- <u>*Good Combustion Control*</u> – The effect of excess air on furnace efficiency is due to the large percentage (79%) of nitrogen in the air. When excess air increases, more of the thermal energy from combustion of the fuel goes to heat the larger volume of combustion gases (the nitrogen) instead of the process fluid – in this case, hot oil. Thus, thermal efficiency drops and the combustion of more fuel is required to fulfill the energy needs of the process. Some excess air must be present to ensure complete combustion of the fuel. Complete combustion, however, can be achieved with the use of 2-3% excess oxygen. Controlling the air to fuel ratio to maintain this oxygen level in a heater is effective in reducing emissions from overuse of excess air. The AOCC design will include fuel gas composition and heating value analysis and flue gas oxygen analysis to optimize the fuel to air ratio continuously. This will enable AOCC to monitor the amount of excess air added to the heaters and optimize the excess air to provide both good combustion and maximum heater thermal efficiency.

- *Periodic Tune-up* – While it is difficult to directly quantify the efficiency benefits of furnace tune-ups and maintenance, the furnaces must be well-maintained to achieve the stated design thermal efficiencies. The heater operation will be closely monitored and the heater equipment routinely inspected :

  - Monitoring of flue gas temperature, excess oxygen, and carbon monoxide.
  - Monitoring and trending firing rate relative to feedstock and production rates.
  - Visual inspection of firebox seals at locations where tramp air can enter the box.
  - Thermal scans of the firebox walls for heat leakage.

  Routine maintenance and tune-up activities to make corrections on an as-needed basis will include, but not be limited to:

  - Cleaning, maintenance and/or replacement of burner tips.
  - Cleaning and, as necessary, replacement of tubes.
  - Maintenance and calibration of oxygen analyzers, temperature measurements, and flow measurements.
  - Inspect flame pattern and adjust burners to optimize flame pattern at least annually.

6.1.5 Step 5: Select BACT

AOCC will utilize all of the technologies listed in Step 4. Specifically:

- AOCC will use of a combination of low carbon fuels: fuel gas available on site (composition similar to natural gas), recovered AO residuals, and recovered LDS off-gas (at certain times). This will result in lower GHG emissions compared to burning 100% natural gas in the Hot Oil Heaters and shipping the AO Residuals off-site for destruction (most likely, thermal destruction in an incinerator or kiln) and flaring the LDS off-gas at times when it cannot be reprocessed.
- Good heater design to maximize heat transfer efficiency to evenly heat the feed and reduce heat loss. Insulating material such as ceramic fiber blankets will be used where feasible on all heater surfaces.
- Implementation of the monitoring and maintenance procedures and practices identified in the Step 4.

6.2 BACT for Flares

GHG emissions from the flare (EPN AO-FLARE) consist primarily of CO_2. Routine emissions are generated from the combustion of the natural gas pilots used to maintain the required minimum heating value and achieve adequate VOC destruction. Other routine vents to the process flare are from process analyzers and VOC storage tanks. The flare also controls VOC emissions from periodic MSS events that require degassing of process equipment and piping.

In addition to normal operation and MSS events, the flare is designed to control emissions from emergency releases. A thermal oxidizer is incapable of handling sudden large volumes of gas which occur during upset conditions, so has not been considered in this analysis.

6.2.1 Step 1: Identify All Available Control Technologies

The only GHG control options for flares or other such control devices are to minimize the quantity and duration of VOC material vented and to design and operate these devices to minimize the natural gas used to maintain the minimum heating value required to achieve adequate destruction. The following lists those design elements and operating practices considered to optimize flare performance and minimize GHG emissions.

- *Use of Low-Carbon Assist Gas* – Use of natural gas as assist is the lowest-carbon fuel available for the proposed project.
- *Good Combustion Practices* – Operate the flare using flow and composition monitors to optimize the amount of natural gas required for adequate VOC destruction and minimize GHG emissions from combustion.
- *Flare Minimization* – Minimize the quantity and duration of emissions routed to the flare.
- *Good Flare Design* – Good design measures in order to maximize equipment efficiency.

6.2.2 Step 2: Eliminate Technically Infeasible Options

Good combustion practices, flare minimization, and flare design are all considered to be technically feasible options.

6.2.3 Step 3: Rank Remaining Control Technologies

AOCC will utilize all design elements and operating practices described in Step 1.

6.2.4 Step 4: Evaluate Economic, Energy and Environmental Impacts

No BACT options are being eliminated in this step.

6.2.5 Step 5: Select BACT

AOCC will utilize all of the technologies listed in Step 1. The flare design and operating practices are described in further detail here.

- *Use of Low-Carbon Assist Gas* – AOCC proposes to use natural gas for the flare's pilot gas and as supplemental fuel, if needed, to maintain appropriate vent stream heating value as required by applicable air quality regulations.
- *Good Combustion Practices* – AOCC will use flow meters and gas composition monitors on the flare gas lines to improve flare gas combustion and optimize flare combustion efficiency. AOCC will also continuously monitor the flare pilot for the presence of a flame.
- *Flare Minimization* – AOCC will:
    - Utilize LDS off-gas as fuel for the Hot Oil Heaters as fuel for boilers and heaters instead of venting to the flare during times when Dow cannot take the off-gas for reprocessing.
    - Utilize process controls to minimize upset conditions
    - Clear equipment to storage as possible to minimize the quantity of VOC materials vented to the flare during MSS.
- *Flare Design* – At the time of submitting this application the flare design is still in the initial stages. However, for the purpose of estimating GHG emissions associated with the operation of the AO-FLARE at the proposed facility, the current application uses a ground flare with 11 stages, each with 2 pilots. Please note that the number of stages may change at a later stage in the flare design. It is assumed to achieve 98% destruction removal efficiency (DRE) for organic compounds. This flare will incorporate the latest burner design and combustion temperature control to minimize NO_X formation while, at the same time, maximizing VOC control efficiency.

6.3 BACT for Equipment Fugitives

6.3.1 Step 1: Identify All Available Control Technologies

GHG emissions from leaking piping components (process fugitives) from the AOCC Plant will consist of primarily ethylene, cyclohexane, methane from equipment in fuel gas service and in refrigerant (chlorodifluoromethane, or R22) service. These emissions will constitute a small portion of the overall GHG emissions from the AOCC Plant (approximately 360 tons/year). The following methods are available for reducing these fugitive emissions:

- *Installation of Leakless Technology Components* – Eliminates leaks which eliminates fugitive emissions.
- *Implementation of Instrument Leak Detection and Repair (LDAR) Programs* – Regular inspection programs, typically used for VOC control, identify and correct leaking components to minimize emissions.
- *Implementation of Audio/Visual/Olfactory (AVO) Monitoring Programs* – Regular inspection program, typically used for non-VOC control, identifies and corrects leaking components to minimize emissions.

- *Use of Remote Sensing Technology* – Remotely monitors emissions using technology such as infrared cameras to detect leaks, therefore making it possible to repair the leak quickly, reducing fugitive emissions.

6.3.2 Step 2: Eliminate Technically Infeasible Options

Leakless technology valves and other leakless approaches (such as welded piping) are used in situations where highly toxic or otherwise hazardous materials are present. These technologies cannot typically be repaired without a unit shutdown. Because fuel gas, natural gas and R22 are not considered to be highly toxic or hazardous materials, these fluids do not warrant the risk of unit shutdown for repair. Therefore leakless valves and welded piping for fuel and refrigerant lines are considered technically infeasible.

All other options identified in Step 1 are considered technically feasible for controlling process fugitive emissions.

6.3.3 Step 3: Rank Remaining Control Technologies

Instrument LDAR programs and the alternative work practice of remote sensing using an infrared camera have been determine by EPA to be equivalent methods of piping fugitive controls. However, in practice, passive infrared cameras have limitations with respect to the concentrations that they can detect. While very effective at “spotting” large leaks, small leaks are often not detectable using infrared cameras. The cameras also cannot provide information on the concentration of the leak or the mass being emitted by the leak.

Since pipeline-quality natural gas is odorized with very small quantities of mercaptan, olfactory observation is an effective method for identifying and correcting leaks in natural gas systems. However, the plant fuel gas is not odorized and, consequently, olfactory observation would not be as effective a method for detecting leaks relative to use of an instrument LDAR program. Additionally, R22 does not exhibit a strong odor and, thus, use of an olfactory detection program would be ineffective at finding leaks of R22.

In consideration of the above, an instrument LDAR program is considered the most effective method for detecting and fixing equipment fugitive leaks.

6.3.4 Step 4: Evaluate Economic, Energy and Environmental Impacts

AOCC will employ the TCEQ’s 28MID LDAR program for fugitive VOC emission control. As required by 28MID, new pumps, compressors, and agitators in VOC service will be equipped with a shaft sealing system that prevents or detects emissions of VOCs from the seal (i.e. “leakless”). In addition to quarterly monitoring of valves, AOCC will conduct quarterly instrument monitoring of flanges and connectors.

While not specifically designed for control of GHG fugitive emissions, this program will minimize GHG emissions while also controlling VOC emissions.

6.3.5 Step 5: Select BACT

AOCC’s proposed BACT for fugitive components is the TCEQ’s 28MID LDAR program.

7 Other PSD Requirements

7.1 Impacts Analysis

An impacts analysis is not being provided with this application in accordance with EPA's recommendations:

> *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 is 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.*[8]

7.2 GHG Preconstruction Monitoring

A preconstruction monitoring analysis for GHG is not being provided with this application in accordance with EPA's recommendations:

> *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.*[9]

7.3 Additional Impacts Analysis

The requirements for a PSD additional impact analyses are described in 40 CFR §52.21(o). A Biological and Cultural assessment of the impact of emissions from the proposed AOCC Plant will be submitted under separate cover to address the potential impairment to soils and vegetation having significant commercial or recreational value that might occur as a result of emissions from this plant. Refined dispersion modeling will also be submitted to the TCEQ to address PSD impacts of the project for other criteria pollutants. Additional PSD impacts analysis for GHG emissions are not being provided with this application in accordance with EPA's recommendations:

> *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*

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[8] EPA, PSD and Title V Permitting Guidance for Greenhouse Gases at 47-48.

[9] *Id.* at 48.

> *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.*[10]

7.4 Endangered Species, Essential Fish Habitat, and Cultural Resources

AOCC has retained ENVIRON, which in turn has retained the Whitenton Group, Inc. (http://whitentongroup.com/) to prepare the Biological Assessment ("BA"), Essential Fish Habitat ("EFH") Assessment and Cultural Resources Assessment documents in support of this project. AOCC anticipates these documents being completed and submitted to EPA for consideration in July 2013.

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[10] EPA, PSD and Title V Permitting Guidance for Greenhouse Gases

Appendix A

GHG Emission Calculations

Table A-1 - Greenhouse Gas Emissions Summary

Source	EPN	Estimated Greenhouse Gas Emissions (tpy)			
		CO_2	CH_4	N_2O	Total CO_2e
Hot Oil Heater No. 1	AO-H700A	93,357	2.6	0.4	93,527
Hot Oil Heater No. 2	AO-H700B	93,357	2.6	0.4	93,527
Flare - Routine	AO-FLARE	508	1.5	8.5E-04	540
Flare - MSS	AO-MSSC	96	0.3	1.6E-04	101.8
Process Fugitives	AO-FUG				333
TOTAL		**187,318**	**7**	**0.7**	**188,029**

Greenhouse Gas Emission Calculations - Hot Oil Heaters

Fuel Gas and AO Residuals - Annual Emissions

Source	EPN	Fuel Flow - AO Residuals (gal/yr)	Fuel Flow - Fuel Gas (scf/yr)	Avg. Heat Input Contribution (MMBTU/hr)			Heat Input (MMBTU/yr)	Annual GHG Emissions (tpy)			
				AO Residuals	Fuel Gas	Total		CO_2	CH_4	N_2O	Total GHG (CO_2e)
Hot Oil Heater No. 1	H700A	2,084,880	1,663,564,487	26.94	162.23	189.17	1,657,129	93,357	2.65	0.37	93,527
Hot Oil Heater No. 2	H700B	2,084,880	1,663,564,487	26.94	162.23	189.17	1,657,129	93,357	2.65	0.37	93,527
TOTAL		**4,169,760**	**3,327,128,974**	**53.89**	**324.45**	**378.34**	**3,314,258**	**186,714**	**5.30**	**0.74**	**187,054**

Fuel Type: Fuel Gas

Component	Composition	HHV (Btu/scf)	MW (kg/kgmol)	Carbon atoms/mole	Carbon Content
Nitrogen	0.0086	0	28	0	0
Methane	0.951	995	16	1	0.75
Ethane	0.0236	1743	30	2	0.80
Propane	0.0036	2481	44	3	0.82
Carbon Dioxide	0.0132	0	44	1	0.27
Total	**1**	**996**	**17**		**0.74**

Fuel Type: AO Residuals

Component	Composition	MW (kg/kgmol)	Carbon atoms/mole	Carbon Content
C26	0.001	364	26	0.86
C28	0.133	392	28	0.86
C30	0.186	420	30	0.86
C32	0.68	448	32	0.86
Total	**1**	**435**		**0.858**

Conversions & Emission Factors

8760	hr/yr
2000	lb/ton
0.0001	kg/MMBTU N_2O, from 40 CFR 98 Subpart C, Table C-2
0.001	kg/MMBTU CH_4, from 40 CFR 98 Subpart C, Table C-2
310	GWP for N_2O
21	GWP for CH_4
1	GWP for CO_2
0.1234	density of CO2 (lb/ft^3)at STP from http://www.engineeringtoolbox.com/gas-density-d_158.html
2.20462	lb/kg
0.001	conversion factor from kilograms to metric tons
1.1023	short tons/metric ton
35.31	ft^3/m^3
0.252	kcal/BTU
6.013	lb/gal (SG of AO Residuals is 0.72099), Density of AO Residuals
113,320	BTU/gal, Heat of Combustion of AO Residuals
1,297	kg/hr, AO Residuals Production
2,859	lb/hr, AO Residuals Production
476	gal/hr, AO Residuals Production

Greenhouse Gas Emission Calculations - Routine Flare Emissions

EPN	Description	Flow (scf/yr)	Annual GHG Emissions (tpy)			
			CO_2	CH_4	N_2O	Total GHG (CO_2e)
AO-FLARE	Storage Tank, V900	14,377	11.45	0.03	1.9E-05	12.2
	Storage Tank, V901	25	0.04	1.28E-04	7.2E-08	0.05
	Storage Tank, V902	11,629	3.97	0.01	6.6E-06	4.2
	Storage Tank, V906_1	36,606	12.49	0.04	2.1E-05	13.3
	Storage Tank, V906_2	36,606	12.49	0.04	2.1E-05	13.3
	Storage Tank, V908_1	61,254	27.87	0.08	4.6E-05	29.6
	Storage Tank, V908_2	61,254	27.87	0.08	4.6E-05	29.6
	Storage Tank, V910_1	5,584	3.18	0.01	5.3E-06	3.4
	Storage Tank, V910_2	5,584	3.18	0.01	5.3E-06	3.4
	Cyclohexane Seal Pot Vent	300,422	102.50	0.31	1.7E-04	109.0
	C6= Tank Truck Loading	738,019	251.81	0.75	4.2E-04	267.7
	C10= Tank Truck Loading	6,219	3.54	0.01	5.9E-06	3.8
	Fuel Gas	803,000	47.51	0.14	7.9E-05	50.5
TOTAL		2,080,581	**508**	**1.52**	**8.5E-04**	**540.0**

Vent Stream	Component	Composition	MW (kg/kgmol)	Carbon atoms/mole	Carbon Content
Storage Tank, V900	Off-spec	100%	196	14	0.858
Storage Tank, V901	Slop	100%	420	30	0.858
Storage Tank, V902	Cyclohexane	100%	84	6	0.858
Storage Tank, V906_1	C6=	100%	84	6	0.858
Storage Tank, V906_2	C6=	100%	84	6	0.858
Storage Tank, V908_1	C8=	100%	112	8	0.858
Storage Tank, V908_2	C8=	100%	112	8	0.858
Storage Tank, V910_1	C10=	100%	140	10	0.858
Storage Tank, V910_2	C10=	100%	140	10	0.858
Cyclohexane Seal Pot Vent	Cyclohexane	100%	84	6	0.858
C6= Tank Truck Loading	C6=	100%	84	6	0.858
C10= Tank Truck Loading	C10=	100%	140	10	0.858
Fuel Gas	Nitrogen	0.86%	28	0	0.000
Fuel Gas	Carbon Dioxide	1.32%	44	1	0.273
Fuel Gas	Methane	95.10%	16	1	0.749
Fuel Gas	Ethane	2.36%	30	2	0.799
Fuel Gas	Propane	0.36%	44	3	0.817
Total		**100%**	**16.94**		**0.738**

Conversions & Emission Factors

8760	hr/yr
2000	lb/ton
0.0001	kg/MMBTU N_2O, from 40 CFR 98 Subpart C, Table C-2
0.001	kg/MMBTU CH_4, from 40 CFR 98 Subpart C, Table C-2
310	GWP for N_2O
21	GWP for CH_4
1	GWP for CO_2
0.001	kh/metric tonnes
1.1023	short tons/metric ton
0.73024	R, ft^3 atm R^{-1} lb-mol^{-1}
1	atm

Greenhouse Gas Emission Calculations - Flare Emissions During Maintenance, Startup, and Shutdown

EPN	Description	Flow (scf/yr)	Annual GHG Emissions (tpy)			
			CO_2	CH_4	N_2O	Total GHG (CO_2e)
AO-FLARE	Startup - Reaction Section	300,500	34.18	1.02E-01	5.7E-05	36.34
	Startup - Distillation Section	142,420	16.20	4.84E-02	2.7E-05	17.22
	Shutdown - Reaction Section	11,230	1.28	3.81E-03	2.1E-06	1.36
	Shutdown - Light Distillation Section - V400	118,022	6.71	2.00E-02	1.1E-05	7.14
	Shutdown - Light Distillation Section - V410	46,545	10.59	3.16E-02	1.8E-05	11.26
	Shutdown - Light Distillation Section - V420	30,229	4.52	1.35E-02	7.5E-06	4.80
	Shutdown - Light Distillation Section - V430	116,962	13.30	3.97E-02	2.2E-05	14.14
	Shutdown - Light Distillation Section - V440	73,384	8.35	2.49E-02	1.4E-05	8.87
	Shutdown - Heavy Distillation Section - V500	470	0.11	3.19E-04	1.8E-07	0.11
	Shutdown - Heavy Distillation Section - V510	541	0.18	5.51E-04	3.1E-07	0.20
	Shutdown - Heavy Distillation Section - V520	320	0.11	3.26E-04	1.8E-07	0.12
	Shutdown - Heavy Distillation Section - V530	203	0.09	2.76E-04	1.5E-07	0.10
	Shutdown - Heavy Distillation Section - V540	160	0.07	2.18E-04	1.2E-07	0.08
	Shutdown - Heavy Distillation Section - V550	77	0.04	1.31E-04	7.3E-08	0.05
	Shutdown - Heavy Distillation Section - V560	52	0.04	1.05E-04	5.9E-08	0.04
	Shutdown - Heavy Distillation Section - V570	20	0.02	4.70E-05	2.6E-08	0.02
	Shutdown - Heavy Distillation Section - V600	20	0.02	5.37E-05	3.0E-08	0.02
TOTAL		839,762	**95.79**	**0.29**	**1.6E-04**	**101.8**

MSS Streams to the Flare

Vent Stream	Component	Composition	MW (kg/kgmol)	Carbon atoms/mole	Carbon Content
Startup - Reaction Section	Ethylene	100.00%	28	2	0.858
Startup - Distillation Section	Ethylene	67.18%	28	2	0.858
	Ethane	1.39%	30	2	0.801
	Methane	0.04%	16	1	0.751
	Butene	31.39%	56	4	0.858
	Total		*36.81*		*0.857*
Shutdown - Reaction Section	Ethylene	100%	28	2	0.858
Shutdown - Light Distillation Section	Ethylene	100%	28	2	0.858
	Butene	100%	56	4	0.858
	Hexene	100%	84	6	0.856
	Cyclohexane	100%	84	6	0.856
Shutdown - Heavy Distillation Section	C8=	100%	112	8	0.858
	C8=	100%	112	8	0.858
	C10=	100%	140	10	0.858
	C12=	100%	168	12	0.858
	C14=	100%	196	14	0.858
	C16=	100%	224	16	0.858
	C18=	100%	252	18	0.858
	C20=	100%	280	20	0.858
	C26=	100%	364	26	0.858

Conversions & Emission Factors

8760	hr/yr
2000	lb/ton
0.0001	kg/MMBTU N_2O, from 40 CFR 98 Subpart C, Table C-2
0.001	kg/MMBTU CH_4, from 40 CFR 98 Subpart C, Table C-2
310	GWP for N_2O
21	GWP for CH_4
1	GWP for CO_2
0.001	conversion factor from kilograms to metric tons
1.1023	short tons/metric ton

Greenhouse Gas Emission Calculations - Process Fugitive Emissions

EPN	Description	Emission Rate (tpy)	Annual GHG Emissions (tpy)
			CO_2e
	Methane	0.02	0.33
	R-22	0.20	333.05
TOTAL		0.21	**333**

Emission Factors

1700	GWP for R-22
21	GWP for CH_4
1	GWP for CO_2

Appendix B

CCS Detailed BACT Analysis and Supplemental Information

Best Available Control Technology for Carbon Capture and Sequestration

In the EPA guidance document entitled *PSD and Title V Permitting Guidance for Greenhouse Gases*, dated March 2011, EPA recommends the use of the Agency's five-step "top-down" process to determine BACT for greenhouse gases (GHGs). This top-down process calls for the identification of all available control technologies for a given pollutant and the ranking of these technologies in descending order of control effectiveness. The applicant must then evaluate the highest-ranked option and the top-ranked option(s) should be established as BACT unless it is demonstrated that the technical considerations, or energy, environmental, or economic impacts and other costs justify a conclusion that the top-ranked technology is not achievable. If the most effective control strategy is eliminated, then the next most effective control should be evaluated until an option is selected as BACT. BACT cannot be less stringent than any applicable standard of performance under New Source Performance Standards (NSPS); however EPA has not promulgated any NSPS that contain emissions limits for GHGs.

EPA has divided the process of determining BACT into five steps:

Step 1: Identify all available control technologies

Step 2: Eliminate technically infeasible options

Step 3: Rank remaining control technologies

Step 4: Evaluate economic, energy and environmental impacts

Step 5: Select the BACT

This five-step process is generally performed for each individual GHG emission source. As discussed in Section 6 of this permit application, Carbon Capture and Sequestration ("CCS") is a potential control technology for the two Hot Oil Heaters. It is not considered technically feasible to capture GHG emissions emitted by the process flare or to collect CO_2 emissions from leaking fugitive emission components. Therefore, the process flare and fugitive emissions have not been included in this evaluation of the feasibility of CCS.

Five-Step BACT Evaluation of CCS

Step 1: Identify All Available Control Technologies

In the guidance document *PSD and Title V Permitting Guidance for Greenhouse Gases*, EPA classifies CCS as an add-on pollution control technology available for large CO_2-emitting facilities. CCS is identified in Section 6 of the application as one of the alternatives for controlling GHG emissions from the two Hot Oil Heaters.

The emerging CCS technologies consist of processes for separation of CO_2 from combustion or process gases (i.e. capture), compression and transportation of this CO_2 (typically via pipeline), and then injection into suitable geologic formations (i.e. sequestration). These geologic formations include oil and gas reservoirs, unmineable coal seams, and underground saline formations.

Of the emerging CO_2 capture technologies, amine absorption is the only commercially available technology for the CO_2 separation process. Amine absorption has been utilized by processes in the petroleum refining and natural gas processing industries and for exhausts from gas-fired industrial boilers. The amine solvent used in these absorption units has been demonstrated to remove approximately 90% of the CO_2 from power plant exhaust streams, but is considered to be highly energy-intensive.[11] The GHG sources in the AOCC Plant will contain CO_2 in high volume, dilute concentration streams at low pressure. This will require that a large amount of energy be generated and consumed for the volume of gas treated to capture the CO_2. In addition, impurities in the GHG vent streams such as particulate matter, sulfur dioxide, and nitrogen oxides may degrade the amine sorbents and result in the reduced effectiveness of the CO_2 capture process.[12]

In order to be transported, the captured CO_2 must first be compressed. Compressor stations require large amounts of power, representing a significant cost and environmental impact due to the energy required to compress the gas. It is estimated that 70-90 percent of the cost per tonne of CO_2 is associated with capture and compression of the gas.[13] Transportation of CO_2 is typically done via pipeline. According to the *Report of the Interagency Task Force on Carbon Capture and Storage*, there are currently approximately 3,600 miles of existing CO_2 pipeline. Additional compression and pipeline infrastructure would be necessary for this project.

If CO_2 capture and compression can be achieved, it must then be routed to a suitable geologic formation for long-term storage. This geologic storage involves the injection of supercritical CO_2 into deep geologic formations under sealing zones or geologic traps that will prevent the CO_2 from escaping.[14] Some of the challenges associated with geological storage are the availability of storage capacity and the possible adverse impacts associated with the long-term storage of CO_2 (e.g. unanticipated migration and leakage of CO_2 and changes in subsurface pressures that could impact drinking water, human health and ecosystems).[15]

Step 2: Eliminate Technically Infeasible Options

According to the guidance documents for GHG permitting and for reducing CO_2 emissions, EPA has concluded that although CCS technologies exist, it does not necessarily mean CCS would be selected as BACT due to its technical and economic infeasibility. In addition, EPA supports the conclusion of the Interagency Task Force on Carbon Capture that current technologies could be used to capture CO_2 from new and existing plants, but are not ready for widespread

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[11] DOE-NETL, *Carbon Sequestration: FAQ Information Portal,* http://extsearch1.netl.doe.gov/search?q=cache:e0yvzjAh22cJ:www.netl.doe.gov/technologies/carbon_seq/FAQs/tech-status.html+emerging+R%26D&access=p&output=xml_no_dtd&ie=UTF-8&client=default_frontend&site=default_collection&proxystylesheet=default_frontend&oe=ISO-8859-1 (visited February 1, 2013)

[12] Ibid

[13] Report of the Interagency Task Force on Carbon Capture and Storage (http://www.epa.gov/climatechange/Downloads/ccs/ES-CCS-Task-Force-Report-2010.pdf)

[14] DOE-NETL, *Carbon Sequestration: Geologic Storage Focus Area,* http://www.netl.doe.gov/technologies/carbon_seq/corerd/storage.html (visited February 1, 2013)

[15] “Vulnerability Evaluation Framework for Geologic Sequestration of Carbon Dioxide” (EPA, July 2008)

implementation.[16] This is primarily because they have not been demonstrated at the scale necessary to establish confidence in their operations for high volume commercial deployment.

The goal of CO_2 capture is to concentrate the CO_2 stream from an emitting source for transport and injection at a storage site. CCS requires a highly concentrated, pure CO_2 stream for practical and economic reasons. The primary sources of CO_2 associated with the proposed AOCC Plant are exhaust gas from the Hot Oil Heaters. The exhaust gas streams from these sources have characteristics that make it technically difficult to employ CCS. These characteristics include:

- Multiple contaminants – PM, SO_2, NO_X and other products of combustion from the heaters.
- Low pressure – atmospheric.
- High temperature – 450^o F.
- High volume – approximately 87.5 MM actual ft^3/day for each heater.
- Low CO_2 concentrations – approximately 10%

The exhaust gases from combustion sources and process vents would require the installation and operation of additional equipment to capture, separate, cool, and pressurize the CO_2 for transportation. In addition, it would require compression to increase the pressure from atmospheric to a pressure required for efficient CO_2 separation. After separated, additional compression would be required to pressurize the CO_2 to that of the pipeline (estimated to be ~2000 psia). In practice, a series of compressors would be needed, which would increase the overall capital and operational cost. A cooling mechanism (e.g. complex heat exchangers) would also be required to reduce the temperature of the streams from 450^o F to less than 100°F prior to separation. To achieve separation, an amine unit or an equivalent would be required to capture the CO_2, therefore the equipment (including final compression) must be designed to handle acidic gases, which would result in additional cost. The entire system would require both high energy consumption and cost to compress, separate, and cool the exhaust gas for processing and transport requirements. The combination of all the additional equipment and operations described above would have an additional adverse impact on the environment.

Assuming that the CO_2 capture and compression is feasible, the CO_2 stream would need to be transported to a facility capable of long-term sequestration and storage. A pipeline would be required to transport the gas to the closest geologic formation capable of storing the CO_2. The closest site that is currently being field-tested to demonstrate its capacity for large-scale, long-term storage of CO_2 is the Southeast Regional Carbon Sequestration Partnership's (SECARB) Cranfield test site in Mississippi. This test site is over 320 miles away and would require a lengthy and sizable pipeline and numerous compression and recompression facilities if the CO_2 generated by the AOCC Plant were to be transported to Cranfield. The distance between the AOCC Plant and Cranfield makes the transportation infeasible.

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[16] PSD and Title V Permitting Guidance for Greenhouses Gases (EPA, March 2011)

As an alternative, it is possible that the CO_2 could be transported to the nearest pipeline planned by Denbury Green Pipeline – Texas. This pipeline is intended to provide CO_2 to support various enhanced oil recovery (EOR) operations in Southeast Texas. Construction of the Denbury pipeline is scheduled to begin in late 2013. Numerous logistical hurdles would be presented by this option that include construction of an inter-connecting pipeline, offsite land acquisition and easements, governmental regulatory approvals, and the timing of available transportation infrastructure. For the purposes of this evaluation, it is assumed that the Denbury pipeline would be used. However, it should be noted that none of the Southeast Texas EOR reservoirs or other local geologic formations have been demonstrated as viable options for large-scale, long-term storage of CO_2 and that there are no guarantees that the projected end users will use this CO_2 stream on a perpetual or long-term basis with sufficient demand.

In the Statement of Basis for GHG permits recently issued by EPA Region 6, EPA concludes that “while there are some portions of CCS that are technically infeasible, EPA has determined that overall CCS technologies are technologically feasible” at the permitted sources. Each CCS component, technology and the technical feasibility (or infeasibility) is noted. A summary of these components, technologies and their technical feasibility is summarized in Table B.1.

As indicated in EPA’s *PSD Permitting Guidance for Greenhouse Gases*, a permitting authority may conclude that CCS is not applicable to a particular source, and consequently not technically feasible, even if the type of equipment needed to accomplish the compression, capture and storage of GHGs are determined to be generally available from commercial vendors. Based on the information provided in this step, AOCC believes that the application of CCS for the heaters has not been demonstrated on similar sources and should be eliminated from any further consideration as a potential control technology for GHGs. It is clear that there are significant and overwhelming technical (including logistical) issues associated with the application of CCS for the type of source under review. The remainder of this evaluation will delineate the other reasons CCS is not considered to be a viable control technology for these emission sources.

Step 3: Rank Remaining Control Technologies

As documented in Step 2, implementation of CCS technology for the AOCC plant is not considered commercially available or technically feasible. The economic feasibility of CCS will be discussed in detail in Step 4.

Table B.1 – Step Two Summary for CCS from EPA Region 6

CCS Component	CCS Technology	Technical Feasibility
Capture	Post-combustion	Y
	Pre-combustion	N
	Oxyfuel combustion	N
	Industrial separation (natural gas processing, ammonia production)	N
Transportation	Pipeline	Y
	Shipping	Y
Geological Storage	Enhanced Oil Recovery	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*

*Both geologic storage and large scale CO_2 utilization technologies are in the research and development phase and currently commercially unavailable

Step 4: Evaluate Economic, Energy and Environmental Impacts

EPA considers CCS to be an available control option for high-purity CO_2 streams that merits initial consideration as part of the BACT review process, especially for new facilities. As noted in EPA's GHG Permitting Guidance, a control technology is "available" if it has a potential for practical application to the emissions unit and the regulated pollutant under evaluation. Thus, even technologies that are in the initial stages of full development and deployment for an industry, such as CCS, can be considered "available" as that term is used for the specific purposes of a BACT analysis under the PSD program. In 2010, the Interagency Task Force on Carbon Capture and Storage was established to develop a comprehensive and coordinated federal strategy to speed the commercial development and deployment of clean coal technology. As part of its work, the Task Force prepared a report that summarized the state of CCS and identified technical and non-technical challenges to implementation. EPA, which participated in the Interagency Task Force, supported the Task Force's conclusion that although current technologies could be used to capture CO_2 from new and existing plants, they were not ready for widespread implementation at all types of facilities. This conclusion was based primarily on the fact that the technologies had not been demonstrated on the scale necessary to establish confidence in their operations. Nothing has changed significantly in the industry since the August 2010 report, and there is no specific evidence supporting the feasibility and cost-effectiveness of a full scale carbon capture system for the project and emission sources proposed by AOCC.

In addition to the information provided in Step 2 of this evaluation, AOCC has also considered a number of other environmental and operational issues related to the operation of CCS. Operation of capture and compression units will require a substantial amount of additional electricity. For example, it has been reported that operation of carbon capture equipment at a typical natural gas fired combined cycle plant will reduce net efficiency of the plant from approximately 50% to approximately 42.7% (based on fuel higher heating value).[17] A similar loss in efficiency is anticipated for heaters.

For the purpose of this BACT analysis, AOCC has determined that the proposed Denbury pipeline is the nearest potentially available CO_2 pipeline (for EOR, rather than CCS). It will be approximately 47 miles from the AOCC Plant location and is scheduled to begin construction in late 2013 (although legal challenges may delay this schedule). The construction of a pipeline from the AOCC Plant to the Denbury pipeline would require the purchase of right-of-ways, planning, environmental studies and possible mitigation of environmental impacts from pipeline construction.

In addition to the technical and operational challenges described above, CCS will also result in considerable costs. AOCC has estimated these costs and summarized them in Table B.2. It should be noted that this cost estimate is conservatively low because it does not include all costs, such as piping for on-site gathering systems required to collect the vent gas, additional electricity required to power the capture and compression systems, and cost of obtaining right-of-ways and permits for pipeline construction. It also assumes that the pipeline will only be 47 miles (22.45 km), which is the distance to the proposed Denbury pipeline. If the proposed Denbury pipeline is not constructed or if the projected EOR customers do not continuously accept this CO_2 stream, pipeline costs incurred to transport CO_2 to undetermined alternate locations will be higher.

The CCS cost estimate in Table B.2, does not include the potential costs associated with long-term liability potentially arising from geologic storage of CO_2 in formations supporting EOR, rather than permanent sequestration. Nevertheless, the average annual cost associated with CCS for the AOCC Plant is approximately \$19.3 MM. Even though considered to be conservatively low, this demonstrates that CCS is economically unreasonable. Therefore, CCS is not considered a technically, economically, or commercially viable control option for this project.

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[17] US Department of Energy, National Energy Technology Laboratory, “Costs and Performance Baseline for Fossil Energy Plants, Volume 1 – Bituminous Coal and Natural Gas to Energy”, Revision 2, November 2010

Step 5: Select BACT

As demonstrated in Steps 2 and 4 of this BACT review, CCS is not commercially available, is technically infeasible, and is economically unreasonable. Therefore it is not considered BACT for the AOCC Plant.

Table B.2

Southeast Texas EOR Alternative

Range of Approximate Annual Costs for Installation and Operation of Capture, Transport, and Storage Systems for Control of CO_2 Emissions

Carbon Capture and Storage (CCS) Component System	Factors for Approximate 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)	Range of Approximate Annual Costs for CCS Systems ($)
Post-Combustion CO_2 Capture and Compression System	$103.42 / ton of CO_2 avoided [2]	169,226		$17,501,363
CO_2 Transport System				
Minimum Cost	$0.91 / ton of CO_2 transported per 100 km [2]	169,226	75.64	$116,481
Maximum Cost	$2.72 / ton of CO_2 transported per 100 km [2]	169,226	75.64	$348,162
Average Cost	$1.82 / ton of CO_2 transported per 100 km [3]	169,226	75.64	$232,322
CO_2 Storage System				
Minimum Cost	$0.51 / ton of CO_2 stored [2,4]	169,226		$86,305
Maximum Cost	$18.14 / ton of CO_2 stored [2,4]	169,226		$3,069,761
Average Cost	$9.33 / ton of CO_2 stored [3,4]	169,226		$1,578,033
Total Cost for CO_2 Capture, Transport, and Storage Systems				
Minimum Cost	$104.62 / ton of CO_2 removed	169,226		$17,704,149
Maximum Cost	$123.62 / ton of CO_2 removed	169,226		$20,919,287
Average Cost	$114.12 / ton of CO_2 removed [3]	169,226		$19,311,718

Notes:

[1] Assumes the maximum annual CO_2 emission rates from the Hot Oil heaters and that a capture system operates with 90% efficiency

[2] These cost factors are from *Report of the Interagency Task Force on Carbon Capture and Storage* , pp. 33, 34, 37, and 44 (Aug 2010)(http://www.epa.gov/climatechange/policy/ccs_task_force.html). The factors from the report in the form of $/tonne of CO_2 avoided, transported, or stored and have been converted to $/ton. Per the report, the factors are based on the increased cost of electricity (COE; in $/kW-h) of an "energy-generating system, including all the costs overs its lifetime: initial investment, operations and maintenance, cost of fuel, and cost of capital."

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

[4] "Cost estimates [for geologic storage of CO_2] are limited to capital and operational costs, and do not include potential costs associated with long-term liability." (from the *Report of the Interagency Task Force on Carbon Capture and Storage* , p. 44)

Appendix C

EPA RACT/BACT/LAER Clearninghouse

Hot Oil Heaters

Pollutant Information

Click on the Process Information button to see more information about the process associated with this pollutant.
Or click on the Process List button to return to the list of processes.

RBLC Home | New Search | Search Results | Facility Information | Process List | Process Information

Pollutant Information

Help

DRAFT

RBLC ID: SC-0142
Corporate/Company:
Facility Name: SHOWA DENKO CARBON, INC.
Process: HOT OIL HEATER

Pollutant: Carbon Dioxide
CAS Number: 124-38-9

Pollutant Group(s): Greenhouse Gasses (GHG),InOrganic Compounds,Acid Gasses/Mist,
Substance Registry System: Carbon Dioxide

Pollution Prevention/**A**dd-on Control Equipment/**B**oth/**N**o Controls Feasible: N
P2/Add-on Description: GOOD COMBUSTION PRACTICES, ANNUAL TUNE UP, LOW NOX BURNERS

Test Method: EPA/OAR Methods | All Other Methods

Percent Efficiency: 0
Compliance Verified:
EMISSION LIMITS:
- **Case-by-Case Basis:** BACT-PSD
- **Other Applicable Requirements:**
- **Other Factors Influence Decision:**
- **Emission Limit 1:** 3093.0000 T/YR (CO2E)
- **Emission Limit 2:** 0
- **Standard Emission Limit:** 0

COST DATA:
- **Cost Verified?** No
- **Dollar Year Used in Cost Estimates:**
- **Cost Effectiveness:** 0 $/ton
- **Incremental Cost Effectiveness:** 0 $/ton
- **Pollutant Notes:**