From:	Warnement, Tom E
To:	Wilson, Aimee
Subject:	Olefins 1 and 2 Expansion Projects - Equistar Channelview
Date:	Tuesday, February 19, 2013 1:20:02 PM
Attachments:	OP-1 OP-2 GHG BACT FINAL.pdf

Aimee,

The following are responses to your questions regarding the Olefins 1 and 2 expansion projects at Equistar's Channelview facility. I am verifying the production numbers and the efficiency data and will send the information in a separate email.

1. Will the new cracking heater have SCR controls? Yes. There will be one heater in each of Olefins units and each will utilize SCR control.
2. What is the hourly firing rate for the new cracking heaters. The cracking heater design is for a maximum firing rate of 640 MMBtu/hr (HHV) per heater.
3. How many decoking events will be performed each year. The annual emission rates from decoking events are based on 26 events per heater per year.
4. Will hydrogen be used in the fuel? The units may combust H2 rich fuel gas as a secondary fuel when practicable and when available. The process produces H2 that may enter the commercial H2 market, offsetting on-purpose production of hydrogen by others which produces GHG emissions. If, for any reason, a portion of the produced hydrogen is not exported from the unit as a product, it may be used as a fuel to capture its heating value, thus offsetting some of the heat input that would otherwise come from natural gas or plant fuel gas. (See BACT discussion in May 2012 amended submittal)
5. How much would CCS increase the projected cost of the Olefins Expansion Projects? Capital cost for carbon capture is estimated to be more than $108-million, and for transportation is estimated at $21-million. The total cost for CCS is therefore estimated to be greater than $129-million. The project cannot adsorb the cost of CCS and remain financially viable. (See BACT discussion in May 2012 amended submittal)

Note: The BACT discussion from the May amended submittal has been attached for your reference.

Please let me know if you have any questions.

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BACT for GHGs

Executive Summary

Greenhouse Gas (GHG) Best Available Control Technology (BACT) for the facility has been evaluated via a "top-down" five-step approach. Each of those five steps is outlined in subsequent sections of this document. The analysis has been conducted on each source for each GHG gas emitted. The evaluation considered the OP-1 and OP-2 projects together. That analysis led to the conclusion that:

> BACT for cracking furnace GHG emissions is fuels management (limits CO_2, CH_4). The company also adopts an energy efficient design (limits CO_2, CH_4 and N_2O), and proper operational control (limits CO_2, CH_4).

> BACT for the decoking activity is the combination of furnace design, operation to minimize coke formation, and to follow established procedures for decoking (limits CO_2).

> BACT for fugitive emissions has been determined to be instrumented leak detection and repair (limits CH_4).

Introduction

GHG emissions increases from the OP-1/OP-2 unit furnace additions, expressed as carbon dioxide equivalents (CO_2e) are projected to be greater than 100,000 tons which triggers PSD permitting obligations as described in EPA's Greenhouse Gas Tailoring Rule. Emissions of GHGs are more than 99% carbon dioxide (CO_2) expressed as carbon dioxide equivalents (CO_2e). Pursuant to EPA regulation, the project is subject to regulation under PSD and the required BACT review has been conducted for each of the GHG pollutants individually from each of the emissions sources. In the proposed project, specified GHGs will be emitted from the following sources, and no other GHGs (i.e., SF_6, hydrofluorocarbons, perfluorocarbons) will be emitted from the Olefins units beyond those indicated below:

- Cracking Furnace (CO_2, N_2O and CH_4)
- Decoke vent (CO_2)
- Fugitive Emissions (CH_4)

CO_2, CH_4, and N_2O will be generated as a result of hydrocarbon combustion within the cracking furnaces. CO_2 will also be emitted from the decoke stacks. CH_4 will be emitted as fugitive emissions from components in process gas and fuel gas services.

Permitting of GHGs is a relatively new requirement and there is not yet much guidance specific to GHG BACT evaluations and determinations. The following US EPA guidance documents were utilized as resources in completing the GHG BACT evaluation for the proposed project:

PSD and Title V Permitting Guidance For Greenhouse Gases (hereafter referred to as General GHG Permitting Guidance)[1]

Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boiler (hereafter referred to as GHG BACT Guidance for Boilers)[2]

Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Petroleum Refining Industry (hereafter referred to as GHG BACT Guidance for Refineries)[3]

To complete the GHG BACT evaluation, Equistar also reviewed and/or relied on a number of other resources. Some of those resources form much of the basis for this BACT analysis. Examples of the variety of those resources which were consulted are listed below while others are indicated throughout this document:

NSR Workshop Manual (Draft), *Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting*, 1990[4]

RBLC database – Searching the newly enhanced RBLC database returned no results on permitting decisions for gaseous fuel and gaseous fuel mixture combustion in Process Code 11.300, synthetic organic chemical manufacturing industry (SOCMI), in Process Code 64.000, or flares in Process Code 19.300. [5]

Herzog, Meldon, Hatton, "*Advanced Post-Combustion CO2 Capture*," April 2009[6]

Report of the Interagency Task Force on Carbon Capture and Storage, August 2010.[7]

Mehlman, *Carbon Capture and Sequestration (via Enhanced Oil Recovery) from a Hydrogen Production Facility in an Oil Refinery*, Praxair, Inc., June 2010[8]

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[1] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: March 2011). http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf

[2] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: October 2010). http://www.epa.gov/nsr/ghgdocs/iciboilers.pdf

[3] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: October 2010). http://www.epa.gov/nsr/ghgdocs/refineries.pdf

[4] http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf

[5] http://cfpub.epa.gov/RBLC/

[6] http://web.mit.edu/mitei/docs/reports/herzog-meldon-hatton.pdf

[7] http://www.fe.doe.gov/programs/sequestration/ccstf/CCSTaskForceReport2010.pdf

The National Renewable Energy Laboratory publication, *Life Cycle Assessment of Hydrogen Production via Natural Gas Steam Reforming*, NREL/TP-570-27637, February 2001.[9]

Perry & Chilton, Chemical Engineer's Handbook, 5th Ed., c 1973

The National Energy Technology Laboratory guidance, *Estimating Carbon Dioxide Transport and Storage Costs*, DOE/NETL-400/2010/1447, March 2010.[10]

Al-Juaied and Whitmore, *Realistic Costs of Carbon Capture,* Discussion Paper 2009-08, Cambridge, Mass.: Belfer Center for Science and International Affairs, July 2009.[11]

David and Herzog, *The Cost of Carbon Capture*, Massachusetts Institute of Technology (MIT), Cambridge, MA, USA[12]

GHG Mitigation Strategies Database – The GHG Mitigation Strategies Database did not contain any information for emission sources presented in this analysis.[13]

Ordorica-Garcia, Wong, Faltinson, *CO2 Supply from the Fort McMurray Area, 2005-2020*, Alberta Research Council, Inc., 2009[14]

U.S. DOE, NETL, *The Cost of Carbon Dioxide Capture and Storage in Geologic Formations*, 2008[15]

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[8] http://www.osti.gov/bridge/servlets/purl/1014021-IesmBR/1014021.pdf

[9] http://www.nrel.gov/docs/fy01osti/27637.pdf

[10] http://www.netl.doe.gov/energy-analyses/refshelf/PubDetails.aspx?Action=View&PubId=338

[11] http://belfercenter.ksg.harvard.edu/files/2009_AlJuaied_Whitmore_Realistic_Costs_of_Carbon_Capture_web.pdf

[12] http://www.netl.doe.gov/publications/proceedings/01/carbon_seq_wksp/david-herzog.pdf

[13] Previously located at http://ghg.ie.unc.edu:8080/GHGMDB/

[14] http://www.assembly.ab.ca/lao/library/egovdocs/2009/alrc/173912.pdf

[15] http://www.netl.doe.gov/publications/factsheets/program/Prog065.pdf

BACT Top-down Approach

Step 1 - Identify Control Technologies

Available control technologies with the practical potential for application to the emission unit and regulated air pollutant in question are identified. The selected control technologies vary widely depending on the process technology and pollutant being controlled. The application of demonstrated control technologies in other similar source categories to the emission unit in question may also be considered. While identified technologies may be eliminated in subsequent steps in the analysis, control technologies with potential application to the emission unit under review are identified in this step.

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

1. EPA's Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) database;[16]

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

3. Engineering experience with similar control applications;

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

5. Review of literature from industrial, technical, government, academic and trade organizations.

However, since GHG BACT is a new and evolving requirement, these tools and platforms are of limited use in preparing the GHG BACT. Outside of the power generation industry, there are very few examples of operational GHG control technologies specifically targeting control of GHGs. Therefore, to establish BACT for GHGs, Equistar will rely primarily on items (3) through (5) above, and the aforementioned references. Those include references from the EPA BACT GHG Workgroup.

STEP 2 - ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

After the available control technologies have been identified, each technology is evaluated with respect to its technical feasibility in controlling the PSD-triggering pollutant emissions from the source in question. The first question in determining whether or not a technology is feasible is whether or not it is demonstrated. Whether or

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[16]   http://cfpub.epa.gov/RBLC/

not a control technology is demonstrated is considered to be a relatively straightforward determination. Demonstrated has specific meaning in this regard. Demonstrated "means that it has been installed and operated successfully elsewhere on a similar facility." *Prairie State*, slip op. at 45. "This step should be straightforward for control technologies that are demonstrated--if the control technology has been installed and operated successfully on the type of source under review, it is demonstrated and it is technically feasible."[17]

The US EPA Environmental Appeals Board (EAB) addressed how control technologies are considered in a BACT analysis in *In re Cardinal FG Co.*, 12 E.A.D. 153 (EAB 2005), upholding a permitting agency's decision that a technology was not demonstrated. The permitting authority, in the response to comments, concluded that although the technology was in use on other facilities in the industry, it was not widely adopted by facilities using the specific process planned for the proposed facility. The permitting authority explained the specific technical reasons why the technology would not work for the source in question and sufficiently distinguished the proposed facility from the other facilities that were using it.

One plant was distinguished on technical grounds, two other plants on grounds that the technology at issue resulted in higher emission limits than those specified for the proposed facility, and another plant on grounds that the two to three years' experience the plant had operating the technology was not sufficient to support that the technology was demonstrated. An argument that a technology would result in higher emissions by itself is not sufficient to exclude it at step 2. The issue of effectiveness of the technology should be dealt with in step 3, ranking of technologies. Because this comment was made in the response to comments, it appeared to be another reason to reject the technology, but not supportive of why the technology should be eliminated under step 2. As the EAB explained, even if a top-down step was not done exactly correctly, evidence that it would have made no difference in the BACT analysis is sufficient to justify not remanding the permit to redo that step.

An undemonstrated technology is only technically feasible if it is "available" and "applicable." A control technology or process is only considered available if it has reached the licensing and commercial sales phase of development and is "commercially available".[18] Control technologies in the R&D and pilot scale phases are not considered available. Based on EPA guidance, an available control technology is presumed to be applicable if it has been permitted or actually implemented by a similar source. Decisions about technical feasibility of a control option consider the physical or chemical properties of the emissions stream in comparison to emissions streams from similar sources successfully implementing the control alternative.

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[17] NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, page B.17.

[18] NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, page B.18.

The NSR Manual explains the concept of applicability as follows: "An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration."[19] Applicability of a technology is determined by technical judgment and consideration of the use of the technology on similar sources as described in the NSR Manual.

> *Technical judgment on the part of the applicant and the review authority is to be exercised in determining whether a control alternative is applicable to the source type under consideration. In general, a commercially available control option will be presumed applicable if it has been or is soon to be deployed (e.g., is specified in a permit) on the same or a similar source type. Absent a showing of this type, technical feasibility would be based on examination of the physical and chemical characteristics of the pollutant bearing gas stream and comparison to the gas stream characteristics of the source types to which the technology had been applied previously. Deployment of the control technology on an existing source with similar gas stream characteristics is generally sufficient basis for concluding technical feasibility barring a demonstration to the contrary.*
>
> *For process-type control alternatives the decision of whether or not it is applicable to the source in question would have to be based on an assessment of the similarities and differences between the proposed source and other sources to which the process technique had been applied previously. Absent an explanation of unusual circumstances by the applicant showing why a particular process cannot be used on the proposed source the review authority may presume it is technically feasible.[20]*

The EAB has relied on the NSR Manual for its decisions regarding applicability.

It is important to note that emerging control technologies whose installations are primarily for research and development, or as demonstration projects for a particular process unit, do not represent technologies that are necessarily both available and applicable to all similar process units.

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[19] NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, page B.18.

[20] NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, page B.18-B.20.

US EPA ARCHIVE DOCUMENT

STEP 3 - RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

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

In this BACT analysis, there are instances in which Equistar has chosen to employ multiple technologies for control of GHG emissions. In those cases, relative ranking of the individual control effectiveness is irrelevant and has not been done. Such relative ranking would have no effect on the decision making required by the BACT analysis. As an alternative, where technologies have been combined, Equistar has provided a "grouped" effectiveness. An example is that use of a low carbon primary fuel, use of hydrogen as a fuel, and use of plant produced fuel gases can be evaluated individually or as a grouped technology described as fuels selection.

Collateral effects are usually not considered until step four of the five step top-down BACT analysis and could result in rejection of a favorable control option at step 3. As a result, top-down BACT does not necessarily drive an integrated manufacturing site to lowest emissions of GHG, and particularly CO_2. For example, the OP-1/OP-2 units may produce waste gas streams that have high CO_2 generation potential when combusted. Some of those streams could be routed to a fuel gas system in lieu of being routed to a flare, and as a result the flue gas emissions of CO_2 would increase. In top down BACT analysis, the use of the fuel gas to reduce CO_2 emissions would be rejected because it would actually increase furnace CO_2 emissions. However, if not consumed as a fuel, those streams would be flared, converting essentially all of their carbon content into CO_2. At the same time, the furnace must be fueled with an equivalent heat value from another fuel, such a CH_4, which also produces CO_2. Equistar has identified several instances in which careful consideration of collateral effects are considered. Those instances are presented within this document to clearly indicate where the collateral effects have influenced the evaluation.

STEP 4 - EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

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

Please note that the GHG BACT assessment presents a unique challenge with respect to the evaluation of CO_2 and CH_4 emissions. The technologies that are most frequently used to control emissions of CH_4 in hydrocarbon-rich streams (e.g., flares and thermal oxidizers) actually convert CH_4 emissions to CO_2 emissions. Consequently, the reduction

of one GHG (i.e., CH_4) results in a simultaneous increase in emissions of another GHG (i.e., CO_2).

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

According to 40 CFR §52.21(b)(49)(ii), CO_2e emissions must be calculated by scaling the mass of each of the six GHGs by the gas' associated global warming potential (GWP), which is established in Table A-1 to Subpart A of 40 CFR Part 98. Therefore, to determine the most appropriate strategy for prioritizing the control of CO_2 and CH_4 emissions, Equistar considered each component's relative GWP. As presented in Table 1, the GWP of CH_4 is 21 times the GWP of CO_2. Therefore, one ton of atmospheric CH_4 emissions has the same predicted global warming effect of 21 tons of CO_2e emissions. On the other hand, one ton of CH_4 that is combusted to form CO_2 emissions prior to atmospheric release equates to 2.7 tons of CO_2e emissions. Since the combustion of CH_4 decreases GHG emissions by approximately 87 percent on a CO_2e basis, combustion of CH_4 is preferential to direct emission of CH_4.

BACT Table 1 provides the Global Warming Potential (GWP) for the three greenhouse gases expected to be emitted by the olefins unit at Equistar's Channelview plant. The GWP is based on a 100-year time horizon. These data are taken from Table A-1 of 40 CFR Part 98.

BACT TABLE 1 GLOBAL WARMING POTENTIALS

Pollutant[1]	GWP[2]
CO_2	1
CH_4	21
N_2O	310

STEP 5 - SELECT BACT

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

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

NAAQS have not been established for GHGs and a dispersion modeling analysis for GHG emissions is not a required element of a PSD permit application for GHGs. Since localized short-term health and environmental effects from GHG emissions are not recognized, this BACT evaluation relies on technical feasibility, control effectiveness, and determinations of collateral impacts and costs.

CRACKING FURNACE – GHG BACT

Greenhouse Gas (GHG) Best Available Control Technology (BACT) for the cracking furnaces has been evaluated via a "top-down" five-step approach. Each of those five steps is outlined below. The analysis has been conducted for each of the three GHGs emitted from the furnace stack. That analysis led to the conclusion that BACT for cracking furnace GHG combustion emissions is fuels selection (CO_2, CH_4). In addition, energy efficient design (CO_2, CH_4 and N_2O) and proper operational control (CO_2, CH_4) also limit CO_2 emissions.

CRACKING FURNACE – CO_2 BACT

IDENTIFICATION OF POTENTIAL CO_2 CONTROL TECHNOLOGIES (STEP 1)

Step 1 Summary

Equistar used a combination of published resources and general knowledge of industry practices to generate a list of six potential controls for carbon dioxide resulting from the cracking furnace operation. All are presented in Step 1 of this BACT analysis.

Potential CO2 Control Technologies

The following potential CO_2 control strategies for the cracking furnace were considered as part of this BACT analysis:

▲ Use hydrogen as the primary fuel for the cracking furnaces.

Hydrogen when burned has no potential for generation of CO_2 emissions.

▲ Carbon capture and storage (CCS)

CCS is a developing technology that captures CO_2 and permanently stores the CO_2 in lieu of it being emitted to the atmosphere.

▲ Fuels Selection

   o Selection of the lowest carbon fuel as the primary fuel

   Various fuels have differing potential for generation of CO_2 through combustion. Hydrogen has none. Methane will generate CO_2 through combustion; however ethane (C_2H_6) would produce more CO_2 than methane for the same heat release from combustion.

   o Use of plant produced fuel gas to fire the furnaces

   Equistar may use fuel gas containing hydrocarbons, primarily methane, and hydrogen, as a fuel for the furnace offsetting natural gas use.

▲ Installation of energy efficient options for the cracking furnace

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Fuel combustion in the furnace, which results in CO_2 generation, results in heat energy release to the furnace firebox. A highly energy efficient furnace will transfer a greater fraction of the heat into the process stream, the intended consequence, than will an inefficient furnace. This results in less fuel needing to be combusted, and less CO_2 generation for the same amount of process stream heating.

▲ Best Operational Practices

Best operational practices can be characterized as steps or actions taken by owners/operators of furnaces to maintain energy efficiency.

No other control technologies for CO_2 from the cracking furnace flue gas were identified.

ELIMINATE TECHNICALLY INFEASIBLE OPTIONS (STEP 2)

Step 2 Summary

In the evaluation of technical feasibility presented below, of the five listed control options, all but CCS are believed to be technically feasible for control of CO_2 emissions associated with the operation of the cracking furnaces. However, all five CO_2 control technologies, including CCS, are progressed to Step 3.

CCS technologies are developing, with several large scale demonstration projects underway at this time that may be relevant. The component elements of CCS (capture, transportation and storage) have all been demonstrated in various projects. However, Equistar has been unable to identify any olefins plant cracking furnace fitted with flue gas carbon capture. The determination of technical feasibility of CCS at this point for Equistar's project is largely subjective. Therefore Equistar has chosen to progress all five technologies, including CCS, to Step 3 in this five-step top-down BACT analysis without a determination that CCS is technically feasible or infeasible. More detailed discussion is provided below.

Use of Hydrogen as Primary Fuel for the Cracking

During combustion, hydrogen generates no CO_2. Hydrogen could be used as a fuel for the cracking furnaces provided that engineering and operational difficulties, such as flash back at the burner and flame stability and radiant heat distribution in the firebox, could be overcome. Hydrogen use as the primary fuel is progressed to Step 3 of this analysis.

Carbon Capture and Storage

Carbon capture and storage (CCS) involves separation and capture of CO_2 emissions from the flue gas prior to being emitted from the stack, compression of the captured CO_2, transportation of the compressed CO_2 via pipeline, and finally injection and long-term geologic storage of the captured CO_2. For CCS to be technically feasible, all three components needed for CCS must be technically feasible; carbon capture and compression, transport, and storage. Equistar has determined that CCS could be rejected at this stage in this top-down BACT analysis due to technical infeasibility. The current

stage of development of the related technologies falls short of having CCS being "demonstrated" for control of CO_2 from a large cracking furnace's flue gas where SCR is employed as a control for NOx. Because CCS as a control technology for CO_2 from the cracking flue gas is eliminated in Step 4 of this analysis, a detailed engineering evaluation of the technical feasibility of CCS has not been conducted. Although CCS is progressed to step 3 of this analysis, Equistar offers the following discussion of the feasibility aspects of CCS for this project.

The recently issued U.S. EPA guidance for PSD and Title V Permitting of Greenhouse Gases states:

> " *For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing). For these types of facilities, CCS should be listed in Step 1 of a top-down BACT analysis for GHGs."[21]*

It must be noted that the "industrial facilities with high-purity CO_2 stream" identified in the guidance document make reference to process streams and process vent streams that contain substantially higher CO_2 concentrations than cracking furnace flue gas. None of those "high-purity CO_2 streams" mentioned in this reference is generated from simple combustion of a fossil fuel. The flue gas produced by Equistar's cracking will contain a low concentration of CO_2, below 3% at the lower end of the predicted range, and therefore CCS may not qualify as an "available" add-on control technology for this flue gas stream. Many combustion streams discussed in literature, most associated with coal fired power plant, have CO_2 concentrations of 10% or higher, making CO_2 removal much more effective. This is especially true for the coal fired power plants with the combustion of large quantities of fuel, providing substantial economies of scale. Based on this EPA guidance, it may not have been necessary to list CCS as a potential control option in Step 1 of this BACT analysis.

Currently only two options appear to be feasible for capture of CO_2 from the cracking flue gas: Post-Combustion Solvent Capture and Stripping and Post-Combustion Membranes. In one 2009 M.I.T. study conducted for the Clean Air Task Force, it was noted that "To date, all commercial post-combustion CO_2 capture plants use chemical absorption processes with monoethanolamine (MEA)-based solvents."[22] Although absorption technologies are currently available that may be adaptable to flue gas streams of similar character to the cracking furnace flue gas, to Equistar's knowledge the

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[21] US EPA, Office of Air Quality Planning and Standards, "PSD and Title V Permitting Guidance for Greenhouse Gases", March 2011, p. 32.

[22] Herzog, Meldon, Hatton, Advanced Post-Combustion CO_2 Capture, April 2009, p 7, http://web.mit.edu/mitei/docs/reports/herzog-meldon-hatton.pdf

technology has never been commercially demonstrated for flue gas control in large scale industrial cracking furnace operation where the cracking furnace is equipped with selective catalytic reduction controls for NOx. In addition, the furnace fuel slate provides a wide variation in CO_2 concentrations in the flue gas with a predicted range of 2.7% to 8.7%. This means that the capture system would need to accommodate greater than a 3-to-1 turndown range at low concentrations while in continuous operation. In review of documents for preparation of this GHG BACT analysis, Equistar found that post-combustion capture systems were only installed on units that would be expected to have low variability in flue gas CO_2 concentrations with little variation in fuels being combusted, e.g. power plants firing only one type of coal, or for natural gas combined cycle units, firing only pipeline quality natural gas.

Various white papers for GHG reduction options were reviewed for the discussion of CCS BACT. In the GHG BACT Guidance for Boilers white paper, a brief overview of the CCS process is provided and the guidance cites the Interagency Task Force on Carbon Capture and Storage for the current development status of CCS technologies.[23,24] In the Interagency Task Force report on CCS technologies, a number of pre- and post-combustion CCS projects are discussed in detail; however, many of these projects are in formative stages of development and are predominantly power plant demonstration projects (and mainly slip stream projects). Capture-only technologies are technically available; however not yet commercially demonstrated.

Beyond power plant CCS demonstration projects, the report also discusses three industrial CCS projects that are being pursued under the Department of Energy (DOE) funded Industrial Carbon Capture and Storage (ICCS) program for the following companies/installations:

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

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

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

At present, these industrial deployments were selected for funding by DOE in June 2010 and are moving into construction/demonstration phases. Therefore, they are not yet demonstrated. More importantly, each of these three projects is capturing CO_2 from a process stream as opposed to a flue gas stream. Therefore these projects cannot be used

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[23] US EPA, "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial and Institutional Boilers," October 2010, p. 26, http://www.epa.gov/nsr/ghgdocs/iciboilers.pdf

[24] "Report of the Interagency Task Force on Carbon Capture and Sequestration," August 2010. http://fossil.energy.gov/programs/sequestration/ccstf/CCSTaskForceReport2010.pdf.

to represent a control technology available for Equistar's cracking furnace flue gas. They would remain irrelevant to this BACT analysis even if in operation.

Similarly, Equistar has identified one installation at Joffre, AB, Canada where CO2 generated by an olefins plant is captured and used for enhanced oil recovery. However, based on communications directly with that site, it has been learned that the CO2 is separated from feedstocks prior to cracking as opposed to being isolated from the flue gas. Therefore that example is also irrelevant.

Another, sometimes unrecognized demand associated with CCS is the greatly increased water use. At a time when availability of water resources along the Texas Gulf Coast is in question, any substantial increase in water withdrawal and consumption must be evaluated. An amine based collection system for these cracking furnaces would require large amounts cooling water as part of the amine regeneration stage. After the CO2 has been captured, it must be compressed to approximately 2,000 psig for transport. That compression introduces an additional significant demand for cooling water to remove the heat of compression. There are alternatives that would reduce or eliminate the need for cooling water; however the alternate methods, such as finned exchangers with fan induced air flow for cooling, are relatively inefficient and create a collateral demand for electrical power and the associated generation of additional CO2.

The next step in CCS is the transport of the captured and compressed CO2 to a suitable location for storage. This would typically be via pipeline, and that would be most suitable for the Equistar Olefins unit CO2 if it were captured. Pipeline transport is an available and demonstrated, although costly, technology.

Capture of the CO_2 stream and transport are not sufficient control technologies by themselves, but require the additional step of permanent storage. After separation and transport, storage could involve sequestering the CO_2 through various means such as enhanced oil recovery, injection into saline aquifers, and sequestration in un-minable coal seams, each of which are discussed below:

▲ *Enhanced Oil Recovery (EOR)*: EOR involves injecting CO_2 into a depleted oil field underground, which increases the reservoir pressure, dissolves the CO_2 in the crude oil (thus reducing its viscosity) and enables the oil to flow more freely through the formation with the decreased viscosity and increased pressure. A portion of the injected CO_2 would flow to the surface with the oil and be captured, separated, and then re-injected. At the end of EOR, the CO_2 would be stored in the depleted oil field.

▲ *Saline Aquifers*: Deep saline aquifers have the potential to store post-capture CO_2 deep underground below impermeable cap rock.

▲ *Un-Mineable Coal Seams*: Additional storage is possible by injecting the CO2 into un-mineable coal seams. This has been successfully used to recover coal bed methane. Recovering methane is enhanced by injecting CO_2 or nitrogen into the coal bed, which adsorbs onto the coal surface thereby releases methane.

There are additional methods of sequestration such as potential direct ocean injection of CO_2 and algae capture and sequestration (and subsequent conversion to fuel); however, these methods are not as widely documented in the literature for industrial scale applications. As such, while capture-only technologies may be technologically available at a small-scale, the limiting factor is the availability of a mechanism for the facility to permanently store the captured CO2.

To Equistar's knowledge, the Channelview facility is not located near a demonstrated permanent CO_2 storage option with a proven history of long term CO2 storage. However, the facility is located near numerous potential storage locations.

The Channelview facility is located approximately 30 miles from the Denbury Green Pipeline which will provide CO2 for EOR operations in the Hasting oil field in Brazoria County, TX. Denbury Resources is actively injecting CO2 for EOR in the Oyster Bayou Field in east Chambers County, Texas, and in the Hastings Oil Field in Brazoria County, TX. This option is the clear, lowest cost storage choice for the CO2 that would be captured and transported from Equistar's olefins unit. Also, the Frio Saline Aquifer underlies this part of the Texas Gulf Coast and could serve as storage for captured and compressed CO2. Finally, there are a number of salt domes around the Houston, TX area into which solution mining could create caverns for CO2 storage. Equistar is not aware of any un-mineable coal seams along the Texas Gulf coast suitable for CO2 storage. Each of the potential options has risks. Examples are provided below.

An evaluation of the Hastings field was conducted as part of a CCS demonstration project that was subsequently abandoned. That evaluation includes portions addressing risks of failures that could only be further evaluated as part of a demonstration project. The project was led by Praxair, Inc., with other project participants: BP Products North America Inc., Denbury Onshore, LLC (Denbury), and Gulf Coast Carbon Center (GCCC) at the Bureau of Economic Geology of The University of Texas at Austin. In a project update document titled "*Carbon Capture and Sequestration (via Enhanced Oil Recovery) from a Hydrogen Production Facility in an Oil Refinery*," risk factors were described, including uncertainty of the upward transmission of injected CO2. Although the excerpt below was taken from a section of the report relating to monitoring, verification and accounting (MVA), it speaks to routes of upward migration of injected CO2, and the methods for detection of that migration. [25] The MVA aspect is an essential element of a well-run EOR project. The lengthy excerpt below shows that there are various alternatives to detect upward migration of CO2, and that there were risk mitigation plans for upward migration that might be detected. Nevertheless, the identified risks raise concern regarding the viability of EOR in the Hasting Field.

> *The research MVA program will focus on areas of uncertainty in*
> *retention of fluids in the injection zone. As these oil fields have*

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[25] Carbon Capture and Sequestration (via Enhanced Oil Recovery) from a Hydrogen Production Facility in an Oil Refinery , Appendix D, Page D-21, http://www.osti.gov/bridge/servlets/purl/1014021-IesmBR/1014021.pdf

retained oil and gas for geologic time, we consider that it is documented the natural seal is adequate to support a significant CO_2 column with migration occurring possibly only at diffusion rates. Risk assessment and experience indicates that the most probable migration paths are (1) non-sealing well completions; (2) vertical migration up fault when reservoir pressure exceeds original pressure (3) off-structure or out of compartment migration of CO_2 or brine as a result of elevated pressure into areas not controlled as part of the flood. An MVA program is outlined for each of these risk areas and is linked to a mitigation or management process that can be implemented to result in adequate assurance that the CO_2 injected is permanently stored.

Non sealing well completions

Wells that penetrate the seal are potential weak points, especially during injection. This occurs because older wells have been completed under older regulatory schemes. Wells that perform adequately during extraction, when they are pressure sinks, have the possibility of becoming upwardly transmissive during injection when pressure of the reservoir is increased. Wells that are actively producing can be inspected via a logging program, however wells that have been plugged and abandoned (P&A) are prohibitively expensive to reenter to inspect and therefore do not provide viable candidates for monitoring. The research MVA program is intended to extend the commercial operations well integrity program, and test the effectiveness of the commercial operations program. Activities that will be considered for possible inclusion in the research MVA proposal:

(1) Additional logging program (e.g. temperature, radioactive tracers, high end wireline tools)
(2) Above zone pressure monitoring – ambient and introduced fluids
(3) Well deconstruction – possibly associated with workover.
(4) Soil gas, groundwater, or other near-surface monitoring.

In Hastings, water disposal into the Miocene overlying the Frio CO_2 injection zone has elevated pressure and perturbed geochemistry. In the short term, this elevated pressure provides a barrier to upward flow. It will be interesting to assess how long this pressure barrier will be sustained with respect to long term storage goals. (it should be noted that we are making efforts to restrict or eliminate Miocene water injection as it is creating several adverse problems in the field re-development, will be interesting to monitor how quickly the Miocene "bleeds" off if any with time once injection has been curtailed). It may add difficulties to above-zone detection methods.

Possible methods for looking for flawed wellbore migration are: Thermal anomalies (hot fluids expelled from depth, or cold areas in shallow zones where CO_2 flashes to gas). Can be done though casing

Noise anomalies - Can be done though casing
Pressure anomalies - requires perforations
Geochemical anomalies - requires perforations.
Soil gas methods near surface (methane, CO_2)
Augmented soil gas/aquifer surveillance methods (noble gases/isotopes,tracers)

Vertical Migration up faults

Faults related to salt structure are ubiquitous in the Gulf coast. Some faults are clearly vertically transmissive; others trap thick oil and gas columns and are therefore not transmissive at rates relevant to CO_2 storage. It is sometimes not clear how faults will perform when pressure is increased, and this uncertainty can be a block to use/storage of anthropogenic CO_2 in faulted settings. Technique development is needed to determine effective methods to document that faults are sealed to vertical flow. Hastings has a main growth fault that extends to surface as well as several cross faults. Production history suggest that cross faults maybe somewhat cross-fault transmissive, however the vertical performance has not been assessed.

Activities that will be considered for possible inclusion in the proposal:
(1) Natural fault performance - any near surface soil gas anomalies - methane , noble gasses
(2) Soil gas, groundwater, or other near-surface monitoring, same as above but focused on fault. Location - where master fault approaches surface.
(3) Logging program for wells that cut the fault (e.g. temperature, radioactive tracers, high end wireline tools) looking for changes (need before and after injection in wells that cut faults as CO_2 is injected).
(4) Above zone pressure and geochemical monitoring - any changes as CO_2 is introduced? may be impossible with water disposal in Miocene. Need to perforate one or more wells where they cut fault. Sample for PFT.
(5) Geophysical methods – design VSP or cross well acoustic array to look for changes along fault plane. Consider passive acoustic methods to determine if there is any viability in ductile rocks in Gulf Coast. Consider gravity methods.

For the CO_2 that will be generated by the Equistar Channelview cracking furnaces, storage may not be technically feasible even by the most reasonable method, EOR in the Hastings Field. While DOE funded demonstration projects will rely on the Hastings field for storage/sequestration, those demonstration projects are still in early stages. The MVA work done in association with those demonstration projects will add to understanding and quantification of risks of EOR in the Hastings Field. Until that time it would be unreasonable for Equistar to commit to storage of CO_2 in the Hastings Field in

association with this project where the entire cost of the project is provided by Equistar. EOR activities are being successfully carried out in west Texas; however the distance for pipeline transmission to the area may make this option impractical.

The Report of the Interagency Task Force on Carbon Capture and Storage includes Appendix H, Potential Causes of Long-Term Storage Risk and/or Liability. This list of eight risk areas are also cause for concern with any storage option and must be weighed in any decision for CO_2 storage. Those risks stated in verbatim from the Report include:

1. **Scientifically understood phenomena**. For example, migration of CO2 in scientifically understood ways as a result of high injection pressures.
2. **Scientific uncertainties or unknown phenomena** that would alter previous understandings about risks.
3. **Operator error**. For example, an operator misapplies monitoring technology and fails to detect migration of CO2, or an operator misuses injection equipment, which fails, and CO2 is released from the storage site.
4. **Regulatory mistake or oversight**. For example, a State or Federal agency reviewing a permit application fails to detect a geological feature, or fails to identify migration of CO2 in monitoring data.
5. **Falsification and illegal conduct**. For examples, a site operator falsifies geological data in order to obtain a permit; a site operator falsifies monitoring data in order to avoid the costs of remediation; or a site operator stores more CO2 than allowed under a permit to obtain the associated income stream.
6. **Policy changes**. For example, a subsequent Administration withdraws funding for CCS activities, or the relevant legal framework changes, or a State ceases funding for a storage site.
7. **Acts of God**. For example, an earthquake causes a release from a storage site.
8. **Judicial system error**. For example, groundwater contamination develops near a storage site. The harm is not in fact caused by the site, but would have occurred even without the storage activity. A court nevertheless erroneously holds the site operator liable, for example on an ultrahazardous activity theory.

The Frio Saline Aquifer has been the subject of sequestration modeling and actual field tests. One test was documented In a 2005 report by the Gulf Coast Carbon Center titled *"Gas-Water-Rock Interactions in Saline Aquifers Following CO2 Injection: Results from Frio Formation, Texas, USA"*[26]. In that report, representatives from the U.S. Geological Survey, Oak Ridge National Laboratory and the Alberta Research Council made the following observations:

> *To investigate the potential for the geologic storage of CO2 in saline sedimentary aquifers, ~16 million kg of CO2 were injected at ~1,500-m depth into a 24-m sandstone section of the Frio Formation—a regional*

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[26] http://www.beg.utexas.edu/gccc/forum/codexdownloadpdf.php?ID=24

brine and oil reservoir in the U. S. Gulf Coast. Fluid samples obtained from the injection and observation wells before, during and post CO_2 injection, show a Na-Ca-Cl type brine with 93,000 mg/L TDS and near saturation of CH_4 at reservoir conditions. As injected CO_2 became the dominant gas at the observation well, results showed sharp drops in pH (6.5 to 5.7), pronounced increases in alkalinity (100 to 3,000 mg/L as HCO_3) and Fe (30 to 1,100 mg/L), and significant shifts in the isotopic compositions of H_2O, DIC and CH_4. Geochemical modeling indicates that brine pH would have dropped lower, but for the buffering by dissolution of carbonate and iron oxyhydroxides. The low pH values resulting from CO_2 injection could cause rapid dissolution of carbonate and other minerals creating pathways for CO_2 and brine leakage. Dissolution of some minerals, especially iron oxyhydroxides could mobilize trace metals and other toxic components. Also, where residual oil and other organics are present, the injected CO_2 may mobilize organic compounds, some may be environmentally toxic. The $\delta^{18}O$ values for brine and CO_2 samples indicate that supercritical CO_2 comprises ~45% of fluid volume in Frio sandstone near injection well ~6 months after end of injection. Post-injection sampling, coupled with geochemical modeling, indicate the brine gradually returning to its pre-injection composition.

The injection of the CO_2 caused dissolution of surrounding formations, presenting additional risks which the authors summarized as follow:

The low pH values resulting from CO_2 injection could have important environmental implications:
a) Dissolution of minerals, esp. iron oxyhdroxidescould mobilize toxic components;
b) Dissolution of minerals may create pathways for CO_2 and brine leakage.

Equistar owns and operates salt dome caverns for storage of hydrocarbons at Markham, TX and at Mont Belvieu, TX. Equistar believes these are effective and safe methods for terminalling light hydrocarbons. Similar storage of CO_2 may be a viable option, however a thorough technical evaluation has not been conducted.

Based on the aforementioned technical challenges with capture and storage of CO_2, CCS could be determined to be technically infeasible as BACT for reducing CO_2 emissions from Equistar's cracking furnace flue gas. An acceptance of CCS as GHG BACT for this process would come with significant technical risks. Accordingly, CCS should be eliminated as a potential control option in this BACT assessment for CO_2 emissions due to technical infeasibility. Nevertheless, discussion of CCS as an option for control is carried forward from this step of the top-down BACT analysis. As mentioned previously, that progression in this analysis should not be considered Equistar's acceptance that CCS is technically feasible, but rather recognition that the prohibitive costs can be more easily presented in

Step 4 of this BACT analysis than to disprove the somewhat subjective aspects of *demonstrated, available and applicable*.

Fuels Selection

Equistar Channelview is a large chemical manufacturing complex with access to natural gas and plant produced fuel gases. The selection of which fuels to use for firing the furnaces has a direct impact on CO_2 emissions and is progressed to Step 3 of this BACT analysis. Fuels selection has two component parts; selection of lowest carbon fuel and use of plant produced fuel gas to fire the furnaces.

Selection of the Lowest Carbon Fuel

For GHG BACT analyses, low-carbon intensity (mass of carbon per MMBtu) fuel selection is a control option that can be considered a lower emitting process. The cracking furnace will be fired with natural gas and low carbon fuel gases as the primary fuels.

Use of plant produced fuel gas to fire the furnaces

Olefins plants may produce gas streams that are suitable for introduction to a fuel gas system with the only other reasonable option being flaring. These gases include primarily methane and hydrogen. Combustion of these streams further reduces CO_2 emissions.

Installation of Energy Efficiency Options on the Cracking Furnace

The manufacture of olefins begins with steam cracking in the furnaces. This step is energy intensive, and produces more than 99.9% of the CO_2 emissions associated with this project. During normal operation, the furnace designs target about 91.1% thermal efficiency (LHV) or 92% (HHV), with a minimum of 90.3% (LHV basis), which is equivalent to 91.2 efficiency on HHV basis. Thus, this energy efficient technology is feasible and is progressed to Step 3 of this analysis.

Best Operational Practices

Best Operational Practices include periodic furnace tune-up and oxygen trim control. These practices are technically feasible and have been demonstrated. Best Operational Practices are progressed to Step 3 of this BACT analysis.

RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

Summary of Step 3

Of the five control technologies that passed through Step 2, it is determined in Step 3 that use of hydrogen to fuel the furnaces would be 100% effective in reducing CO_2

emissions. CCS would be the next most effective control of CO_2 emissions at 90% control without consideration for impacts on other sources, but would provide about 57% control if increases elsewhere are considered. That is followed by fuel selection at a minimum of 12% effectiveness. Energy efficiency will be incorporated into the design, as industry standard practice with a maximum reasonable 2.4% control assigned. Adoption of best operational practices also is progressed as a CO_2 limiting technology, although these practices have 0% effectiveness. The options are presented in order of decreasing effectiveness in BACT Table 2 below.

BACT Table 2: Furnace CO_2 Control Effectiveness

Technology	Effectiveness	CO2 Emission w/ Control, TPY
Use of hydrogen as primary fuel	100%	0
Carbon Capture and Storage	90% (57%)	60,080 w/90% control
Fuels Selection**	>12%	600,800
Energy Efficiency**	2.4%	600,800
Best Operational Practices**	0%	600,800

* Control effectiveness is reduced to approximately 57% if collateral impacts are considered as described in Step 4.

** Assumes all three technologies are employed; fuels selection, energy efficiency and best operational practices.

Use of Hydrogen to as Primary Fuel

Hydrogen has no capacity to produce CO_2 when combusted. Provided that engineering and operational difficulties, such as flash back at the burner , flame stability, and radiant heat distribution in the firebox could be overcome, hydrogen would provide 100% effectiveness in control of CO_2 emissions from the cracking furnace. This option is progressed to Step 4 where it is rejected on the basis of collateral effects.

CO_2 emissions with hydrogen as primary fuel = 0 tons/year.

Carbon Capture and Storage

Almost universally, references cite CO_2 capture efficiencies for post-combustion control at 90%, including the study by Jeremy David and Howard Herzog, "*The Cost of Carbon Capture*," Massachusetts Institute of Technology (MIT), Cambridge, MA, USA in which the authors reviewed several projects.[27] For purposes of this analysis the capture efficiency is irrelevant because CCS is being considered the most effective control measure with an assumed 90% control effectiveness.

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[27] http://www.netl.doe.gov/publications/proceedings/01/carbon_seq_wksp/david-herzog.pdf

With an uncontrolled emission estimate of 600,800 TPY CO_2, the application of a 90% control would result in furnace emissions from both OP-1/OP-2 furnaces of 60,080 TPY CO_2. However, the generation of power to operate the carbon capture equipment and to compress the CO_2 prior to transport is significant. With consideration of that contribution of CO_2 elsewhere, the control effectiveness is estimated to be less than 57%.

An adjustment to overall efficiency must be applied due to collateral emissions increases. A term called "CO_2 Avoided" is often used when a source must produce energy to drive collection and compression equipment, thus reducing capacity to export power or increasing demand for overall power production so that the collection and compression equipment may be operated. In either case, the net effect is that more fossil fuel is combusted, generating more CO_2 prior to control. Where that CO_2 is generated by the very unit generating the power that is used by the capture and compression equipment, the created CO_2 for extra power generation is also captured by the collection and compression system. Where the power to operate a CO_2 collection and compression system, as would be the case for an Equistar installation, it cannot be assumed that the power generating facility is equipped with CO_2 controls.

The classic example of "CO_2 avoided" compares a plant with and without CO_2 capture and compression, showing that the CO_2 avoided is the difference between CO_2 emissions without capture and emissions with capture, but also showing the increased overall CO_2 emissions due to extra power generation. It has been estimated that power plants would experience up to a 30 percent penalty in power generation, meaning that 30% of the plant's output goes to powering the carbon capture and compression facilities.[28] BACT Figure 1 shows graphically how this is manifested at a power plant.

BACT Figure 1: Power Plant CO_2 Emissions versus CO_2 Avoided with Control
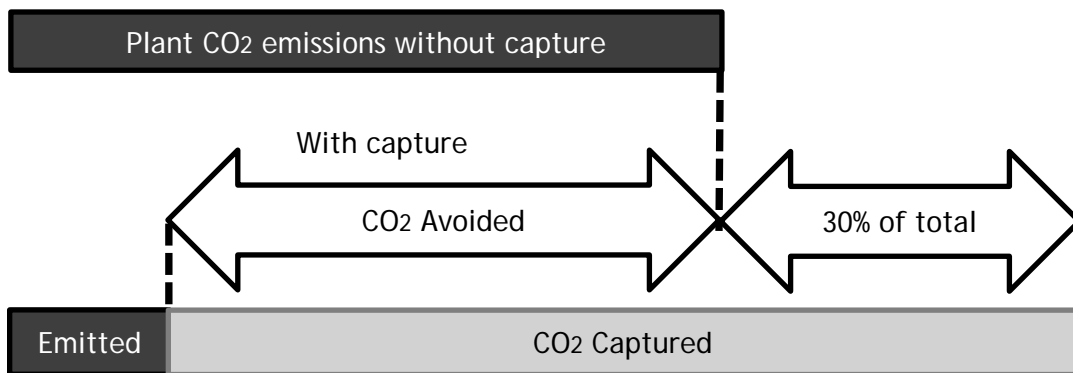

For an installation such as Equistar's, in which it is assumed that the external power needed to operate the CO_2 capture and compression systems is generated by a source without CCS, the graphical example in BACT Figure 2 is more complex. As a result, for

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28 Report of the Interagency Task Force on Carbon Capture and Storage, August 2010, Executive Summary, p 30.

essentially the same overall cost, the amount of CO_2 captured is appreciably lower. That translates into a lower effectiveness when an overall GHG emissions potential is considered.

BACT Figure 2: CO_2 Control with Power Generation by Others
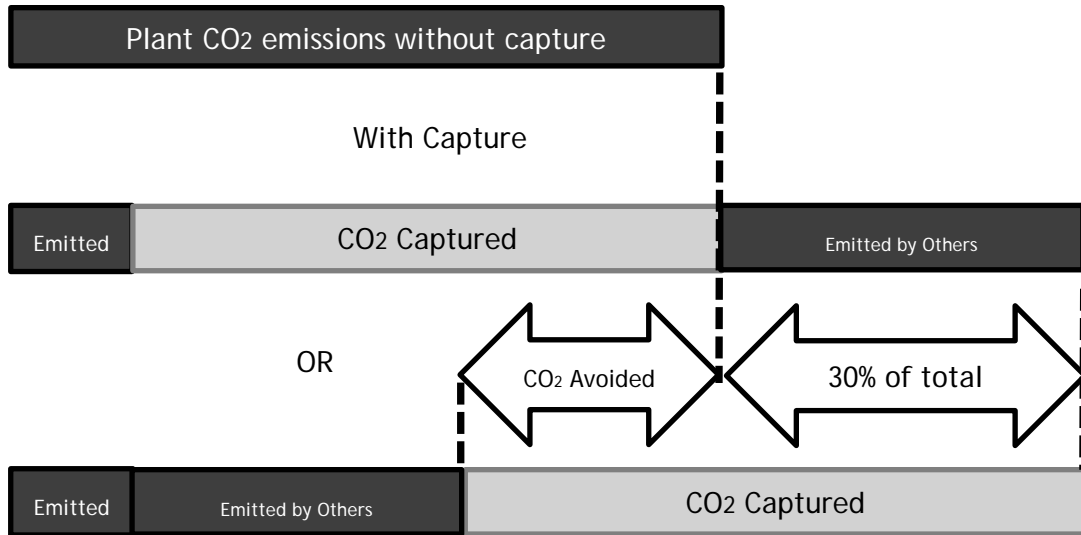
Equistar's uncontrolled CO_2 emissions from the cracking furnace flue are estimated to be approximately **600,800** tons per year. To avoid over-adjustment in the effectiveness, Equistar is assuming that the generation of energy by others accounts for only 25% of overall pre-control CO_2 emissions, as opposed to the average 30% presented by the Interagency Task Force on Carbon Capture and Storage.

Explanation   **600,800** tons per year CO_2 uncontrolled

    540,720 tons per year captured w/90% control
     60,080 tons per year emitted directly w/ 90% control.

    200,267 tons per year emitted by others to produce power for capture and control: 200,267/(200,267 + 600,800) = 0.25 or 25%

    90% control at furnaces = (540,720/600,800)
    57% control considering emissions by others =(540,720 - 200,267)/600,800

Fuels Selection

Fuels selection is presented in two parts, selection of the primary low carbon fuel and use of plant fuel gas, including hydrogen streams. The careful selection of fuels will limit CO_2 generation from the furnace and from the site as a whole due to collateral effects.

Selection of the Lowest Carbon Fuel

Natural gas is the lowest emitting GHG fuel on a direct carbon basis than all other typical fossil fuels. The CO_2 generating potential from methane is 12% lower than ethane, the next lowest CO_2 producing alkane. Thus, selection of CH_4 as the primary fuel, as opposed to another fossil fuel, has a minimum of 12% ($1-^1/_{1.14}$) control effectiveness.

Use of natural gas as the primary furnace fuel to limit of CO_2 emissions is technically feasible. Natural gas is the lowest emitting carbon fuel that could be relied upon for continuous fueling of the proposed operation. The next higher MW common carbon based fuel is ethane whose CO_2 emitting potential is 14% higher than that of methane on a carbon to heating value basis. The impact of carbon based fuel selection on CO_2 emissions is significant. BACT Table 3 shows the relative CO_2 emissions to heat release capacity for several hydrocarbons, including common fuels.

BACT Table 3: Carbon dioxide production related to fuel heating values.

Fuel	Btu/lb (HHV)	Lb CO2/lb fuel	Lb CO2/MMBtu *	Lb CO2/MMBtu v. CH4
Methane	23,861	2.75	115	1.00
Ethylene	21,625	3.14	145	1.26
Ethane	22,304	2.93	131	1.14
Propylene	21,032	3.14	149	1.30
Propane	21,646	3.00	139	1.21
Butylene	20,833	3.14	151	1.31
Butane	21,293	3.03	144	1.25

∗ Assuming complete combustion to form CO_2.

Combustion of natural gas, primarily methane, is technically feasible and effective for limiting emissions of CO_2.

Based on natural gas firing of the furnaces, the emissions from the OP-1/OP-2 furnaces are estimated to be **600,800** TPY CO_2. This includes incorporation of energy efficient design and adoption of best operational practices.

Use of plant produced fuel gas to fire the furnaces

As stated previously, olefins plants may produce gas streams that are suitable for introduction to a fuel gas system. The gases are primarily methane and hydrogen, along with occasional quantities of materials such as acetylene. The olefins plants, OP-1 and OP-2, each include a demethanizer, which is a distillation column that separates methane from the process stream of heavier components. This is one of the primary sources of plant produced fuel gas.

If flared as opposed to being used as fuel, essentially all carbon content of the gases would be converted to CO_2 with no beneficial use of the heating value of the flared gases. The consumption of fuels heavier than methane will produce more furnace flue gas CO_2 emissions than would methane firing alone. However those emissions would be offset pound-per-pound by the elimination of those CO_2 emissions at the flare. The net result is a reduction in site CO_2 emissions, because the burning of the fuel gas in the furnace offsets an equal amount (heating value basis) of methane burning.

Consider a 500 MMBtu/hour heater fired on methane alone with no fuel gas combustion, and an acetylene waste gas stream going to the flare capable of providing 10 MMBtu/hour of heat.

500 MMBtu/hr x 1 lb CH_4/23,861 Btu = 20,955 lb CH_4 / hr

20,955 lb CH_4/hr x 12 lb C/16 lb CH_4 x 44 lb CO_2 / 12 lb C = 57,265 lb CO_2/hr

10 MMBtu/hr x 1 lb C_2H_2 / 21,460 Btu = 466 lb C_3H_8

466 lb C_2H_2/hr x 24 lb C / 26 lb C_2H_2 x 44 lb CO_2 / 12 lb C = 1,577 lb CO_2/hr

Total = 57,265 + 1,577 = 58,842 lb CO_2/hr

Contrast that to the same furnace burning acetylene providing 10 MMBtu/hour and with CH_4 providing the balance for 500 MMBtu total firing. Flare emissions from the acetylene are entirely eliminated as that waste stream is directed to a fuel gas disposition.

490 MMBtu/hr x 1 lb CH_4/23,861 Btu = 20,536 lb CH_4/hr

20,536 lb CH_4/hr x 12 lb C/16 lb CH_4 x 44 lb CO_2 / 12 lb C = 56,473 lb CO_2/hr

10 MMBtu/hr x 1 lb C_2H_2 / 21,460 Btu = 466 lb C_2H_2/hr

466 lb C_2H_2/hr x 24 lb C / 26 lb C_2H_2 x 44 lb CO_2 / 12 lb C = 1,577 lb CO_2/hr

Total = 56,473 + 1,577 = 58,050 lb CO_2/hr

Thus, in this hypothetical example, the site CO_2 emissions, including those from the furnace, are reduced by 1.3%, from 58,842 lb/hour to 58,050 lb/hour, while the furnace CO_2 emissions are increased by 1.4%, from 57,265 lb/hour to 58,050 lb/hour. While the 792 lb/hour net reduction in site CO_2 emissions is not large, it is important to note that the change in site-wide CO_2 emissions will always be directionally downward when plant gases are being consumed as furnace fuel as opposed to being flared.

Note that in addition, the unit may combust H_2 rich fuel gas as a secondary fuel when practicable and when available. The process produces H_2 that may enter the commercial H_2 market, offsetting on-purpose production of hydrogen by others which produces GHG emissions. If, for any reason, a portion of the produced hydrogen is not exported from the unit as a product, it may be used as a fuel to capture its heating value, thus offsetting some of the heat input that would otherwise come from natural gas or plant fuel gas. As a result the use of high H_2 fuel gas, which has no potential for generation of CO_2 emissions, would further reduce the CO_2 emissions from this combustion source. Equistar views the hydrogen as a product and as a fuel gas component, and will select dispositions for any part of the produced hydrogen as business needs dictate. Burners will be designed to handle hydrogen / methane mole ratio of 5/95 to 85/15.

Based on the above considerations for fuel selection, Equistar proposes to (1) use natural gas as the primary fuel, and (2) use fuel gas containing hydrocarbons and/or hydrogen to the extent practicable and aligned with business needs. As compared to alternatives, the overall effectiveness in reducing or minimizing CO_2 emissions is estimated at 12% minimum. The minimum is set by combustion of natural gas alone with no further consideration of the reductions provided by use of fuel gases, including high hydrogen content fuel gases.

Based on natural gas firing of the furnaces, the emissions from the OP-1/OP-2 furnaces are estimated to be **600,800** TPY CO_2. This includes incorporation of energy efficient design and adoption of best operational practices.

Installation of Energy Efficiency Options on the Cracking Furnace

The first step in the production of olefins in the process known as steam cracking is energy intensive, and is the most significant source of GHG emissions in such an olefins manufacturing unit. This section describes the energy efficiencies incorporated in the design of Equistar's cracking furnaces. This information is provided to demonstrate that high efficiency is a critical design element of a cracking furnace. Equistar believes the furnace design and thermal efficiency target is comparable to the designs being proposed by others. The Equistar project is the addition of one furnace in each of two existing units which have established energy balances which dictate certain constraints in the design of the furnaces. The design of new furnaces as part of a new greenfield unit would likely have a different thermal efficiency that is integral to the energy balance of the new unit. The target efficiency is higher than 91% LHV or 92% HHV , meaning that more than 92% of the energy released through combustion is captured for beneficial use. This leaves little opportunity for additional energy improvements. A failure to incorporate those design features in the new furnaces could have substantial impacts on increased CO_2 emissions. As reported in a 2008 EPA Energy Star publication[29] related to the petrochemical industry:

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[29] Neelis, Worrell, Masanet, *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry, An ENERGY STAR ® Guide for Energy and Plant Managers*, June 2008, p.57 http://www.energystar.gov/ia/business/industry/Petrochemical_Industry.pdf

Approximately 30% of the fuel used in the chemical industry is used in fired heaters. The average thermal efficiency of furnaces is estimated at 75-90% (Petrick and Pellegrino, 1999). Accounting for unavoidable heat losses and dewpoint considerations the theoretical maximum efficiency is around 92% (HHV) (Petrick and Pellegrino, 1999).

Equistar's furnaces are projected to have energy efficiencies during operation ranging from 90.3 in worst case conditions to 91.1% as targeted design. These efficiencies approach the theoretical maximum presented in that EPA document. It must be noted that these furnaces are designed for cracking liquid feeds and their efficiencies should not be compared to the ethane cracking furnaces that Equistar and others are currently planning for installation elsewhere. The same Energy Star guidance document described several energy saving features, most of which are listed later in this discussion. Efficiencies described within that document that are specific to design features to be incorporated into Equistar's furnaces include, but are not limited to those listed in BACT Table 4.

BACT Table 4: CO_2 Control Effectiveness for Energy Efficiency Aspects

Design Feature	Cited Effectiveness
Air to fuel ratio control	5% – 25%
Heat containment (refractory & Insulation)	2% – 5%
Sealing openings	5%
Flue gas heat recovery	8% - 18%

This excerpt is taken from a 2005 scholarly article on olefins production furnaces written by Zimmermann and Walzl.[30]

Cracking furnaces represent the largest energy consumer in an ethylene plant; their thermal efficiency is a major factor in operating economics. New plants are designed for 93 - 95 % thermal efficiency, and revamping of older ones can increase efficiencies to 89 - 92 %.

With the lower end of efficiencies reasonably placed around 89% for older furnaces, and comparing that to Equistar's targeted 91.1% thermal efficiency LHV or 92% HHV, the maximum control that could be reasonable attributed to energy efficiency as a control is the change from 89% to 91.1%, or a 2.4% change.

$$(91.1-89)/89 = 0.024 = 2.4\%$$

For somewhat of an apples and oranges comparison of cracking furnace efficiencies (89% to 95%) with other combustion sources. one can reference these excerpts from the

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[30] http://onlinelibrary.wiley.com/doi/10.1002/14356007.a10_045/pdf

Council of Industrial Boiler Owners publication, *Energy Efficiency and Industrial Boiler Efficiency, An Industry Perspective*, March 2003.[31]

Table 1: Typical Efficiencies for New boilers [page 5]

Coal fired boilers	75-85%
Oil fired boilers	72-50%
Gas fired boilers	70-75%

Typical Electric Generation Facilities [page 6]

Gas Turbines	25 – 38%
Coal Boilers/Steam Turbines	25-40%
Gas Turbines/HRSG Steam Turbines	40-51%

Because operation of an olefins furnace is energy intensive, it is intentionally designed to maximize the energy efficiency in the various components of the furnace. In a typical olefins plant, more than 60% of energy consumption is in the olefins furnaces. The furnace addition by Equistar will maximize thermal efficiency as described in this document. Furnace design will incorporate the latest improvements in heat transfer and fluid flow to maximize the energy efficiency and energy recovery to provide a targeted 91.1% efficiency LHV or 92% HHV in transfer of heat into the process fluids.

The major components of a furnace are

- Firebox or Radiant Section

- Burners

- Convection Section

- Fan

- Stack

- Quench Exchangers and Steam Drum

The energy efficiency aspects of each of these components are discussed below to validate Equistar's claim of high energy efficiency.

Firebox or Radiant Section

The firebox of an olefins furnace is the heart of the furnace where the cracking reaction takes place to thermally break down hydrocarbon feeds allowing them to reform as ethylene, propylene and other by-products. The cracking process is highly endothermic, and high amounts of heat must be input to the process fluids to break down the hydrocarbon feed to lighter gases. The reaction takes place inside process tubes, commonly referred to as radiant tubes or the radiant coil, where radiant heat is provided

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[31] http://cibo.org/pubs/whitepaper1.pdf

for the thermal cracking process by burners which heat the tubes in the radiant section of the furnace.

The radiant tubes in the firebox will be located in the center of the box in a configuration to minimize the shadowing effect of adjacent radiant tubes, which allows for increased radiant heat transfer to the radiant tubes and high radiant transfer efficiency. The firebox is vertical with the radiant tubes supported vertically in the center of the firebox. Burner layout is carefully engineered to allow radiant heat to be transferred uniformly. This minimizes localized coke build-up inside the radiant tubes, reduces spots of overheating which reduce efficiency, and helps maintain high energy efficiency of radiant heat transfer.

Olefins cracking furnaces are known for extremely high operating temperatures. The temperature in an olefins furnace firebox will be on the order of 2000°F or higher. The higher the temperature of the object, the higher the radiant energy an object releases. Due to the high temperature in the firebox, the overwhelming majority of the heat transfer to the radiant tubes is through radiant heat transfer, as opposed to conductive or convective heat transfer. The hot firebox radiates heat to the relatively cold radiant tubes for thermal cracking. This radiant heat is similar to the heat one feels when standing a distance from a campfire where the air temperature is cold, but the heat can be clearly felt. In order to put this in context, the temperature range for basic petrochemical process heaters is typically less than to 1600°F, and they tend to have less corresponding potential heat loss. The olefin furnaces proposed in this application have a fuel firing rate up to 600 MMBtu/hour in each furnace. The typical petrochemical process heater generally has a firing rate less than 200 MMBtu/hour and often the firing rate is less than 100 MMBtu/hour. Since the firebox temperature in an olefins furnace is high it is important to minimize heat loss from the firebox and it is important to have sufficient insulation to reduce the external metal temperature to values recommended by American Petroleum Institute. A combination of high temperature brick and ceramic fiber insulation of sufficient thickness will be used along the walls of the firebox, to reduce firebox heat loss and to maximize reflection of radiant heat back to the radiant tubes.

Another feature that Equistar will be using to maximize efficiency in the firebox is to minimize air infiltration from the entry and exit of radiant tubes in the firebox. In this furnace design the number of penetrations through the radiant section walls, floor and roof is minimized so as to avoid unnecessary air in-take which reduces furnace efficiency. In addition, each opening where the radiant tubes enter and exit the firebox will be sealed to maintain high energy efficiency. Engineered insulation boots to cover the openings will be utilized to minimize air infiltration.

A typical olefins cracking furnace has multiple radiant tubes, with some approaching 300 tubes. If the process flow to each of the radiant tubes is not uniform, it will lead to uneven coke formation in different tubes. This will lead to higher heat requirement in tubes with coke build-up which decreases the heat transfer efficiency. The radiant tubes will be decoked as needed to maintain the heat transfer efficiency. In order to get

uniform feed flow to each radiant tube for maximum furnace efficiency, critical sonic flow venturis will be installed at the inlet of each radiant tube. The uniform distribution of the feed to the radiant tubes and the uniform heating of the tubes are critical to the successful thermal cracking of the feed.

Burners

High efficiency burners will be installed in the firebox and will be designed to handle the whole range of fuels combusted in the olefins plant cracking furnaces. In order to maintain the combustion efficiency the burner inspection and maintenance will be included in the preventative maintenance program. The burners will be inspected, while in service so the burner flame pattern can be observed, on a routine basis.

The burners will be located inside the firebox so as to maximize radiant heat transfer efficiency. State-of-the art computational flow dynamics modeling of the burner arrangement and burner flame pattern are utilized to ensure proper firebox operation. A predictable and even heat distribution profile along the length of the radiant tubes is critical to the thermal cracking process. The burner flame envelopes for floor mounted burners are long and thin, with long highly luminous portions in the infrared spectrum parallel to the process tubes, again maximizing efficiency. The burners that will be installed in Equistar olefins furnaces will be tested at the burner vendor facility prior to installation and burner design optimized for maximizing efficiency and operability.

Burners will be designed to operate with minimum excess air to maintain high combustion efficiency. The furnace will be equipped with an oxygen analyzer to provide data used in the control of the combustion process. Operation with more than optimum excess air causes energy inefficiency leading to more fuel gas consumption. Excess O2 in the firebox will typically be less than 2.5% during normal liquids cracking operation. The burners will be designed to operate under the range of fuel gases combusted in the plant, including natural gas, and plant produced fuel gases.

Convection Section

The hot flue gases from the firebox enter the convection section to maximize heat recovery for achieving the optimum thermal efficiency for the furnace. In this section, the heat transfer occurs primarily by convection, with hot flue gases transferring heat to the convection tubes which are located horizontally in the convection section.

In a process heater which operates at lower temperatures, the convection section will be located directly above the radiant section. Direct radiation could lead to localized overheating, reduced heat transfer and premature failure of tubes with more frequent start-ups and shutdowns. In order to avoid this direct radiation exposure of bottom convection tubes, a refractory pathway will be used as a shield and then the flue gas redistributed to maximize efficiency.

The firebox in a modern cracking furnace could be over 60 feet long and 40 feet tall and the convection section could be over 60 feet long, 10 feet wide and 90 feet tall.   The area between the radiant section and the convection section is called the transition section. The hot flue gases exiting the vertical firebox make a 90° horizontal turn over the entire firebox length and then another 90°F vertical turn to enter the convection section. In order to maximize heat transfer, the transition section will be designed carefully to minimize channeling of flue gas. In addition, the first row of convection section tubes will be located above the transition floor with sufficient distance to allow for fully developed flue gas flow across the tubes for maximum heat recovery.

The convection section will have refractory along the walls of sufficient thickness to minimize heat loss from the convection walls and to meet American Petroleum Institute recommendations for external skin temperature.   The convection tubes will be located in a triangular pattern between rows of tubes, or in triangular pitch, to maximize heat transfer to the tubes. In a triangular pattern, end tubes between alternating rows will have more gap between the tube and end wall.   These larger gaps will be filled with refractory flow diverters called corbels which will be used to keep the same distance between end tubes and end walls in all rows of tubes. The corbels near the end tubes in each row break up flow and minimize flue gas channeling, thus maximizing efficiency.

The heat recovery in the convection section can be divided into two services - process service tubes with hydrocarbon and steam flowing from the convection tubes into the radiant section and waste heat recovery service tubes with boiler feed water and very high pressure steam. In order to minimize fuel gas usage, the process feed gas will be preheated in the convection section to the maximum extent practicable before entering the radiant section. The remaining flue gas heat will be recovered by preheating boiler feed water before the feed water enters a steam drum and by superheating the high pressure saturated steam which is generated in the steam drum.

The selective catalytic reduction (SCR) catalyst bed, for reduction of NOx, will be an integral part of the convection section. When operating an SCR, there is an optimum temperature envelop for maximum NOx reduction across the catalyst.   There will be convection tube banks above and below the SCR catalyst bed. The heat in the flue gas is needed to heat other process fluids, as described above, and is the driving force in the NOx reduction reaction across the catalyst.

Heat recovery will be maximized for the range of operating conditions to get the flue gas exiting the convection section to the lowest temperature practicable.   The temperature will be sufficiently low that further heat recovery is impractical.

Fan

It is important to control the excess oxygen required for combustion in order to maximize thermal efficiency of the furnace.   An induced draft fan is located on top of the convection section to pull the flue gases up through the convection section. There is a stack damper located at the inlet to the fan. The draft is maintained at a minimum with

the stack damper opening or closing to minimize infiltration of any tramp or unnecessary air. The induced draft fan in combination with the stack damper allow for oxygen to be controlled at the desired low level for efficiency (as described above).

Stack

Flue gases will exit the furnace through a stack located on top of the fan. Stack design is important to furnace efficiency because it contributes to an organized even flow of gases through the furnace. The stack will be designed to have sufficient velocity for the wide range of operating conditions that the furnace will encounter.

Quench Exchangers & Steam Drum

In order to offset rising utility costs, rising fuel costs, and to increase overall furnace efficiency, integral quench exchangers / steam drum will be provided with the furnace. While not uncommon, this design is not ubiquitous to cracking furnaces. The radiant tubes exit the firebox and are close coupled to the quench exchangers. The cracked gas passes from the radiant tubes to the quench exchangers where the gas is rapidly cooled from about 1500°F to less than 900°F. With gas crackers, the quench exchanger process outlet temperature could be cooled to as low as 400°F to improve the efficiency further. Water from the steam drum is circulated by natural circulation on the shell side as the cooling fluid to produce very high pressure steam, which is beneficially used in compressor drivers, further reducing overall energy consumption.   The steam drum will be designed to produce high pressure steam at about 1550 psig that will be superheated in the convection section and used to drive the turbines serving various compressors in the plant.

Furnace Efficiency Summary

As discussed in the sections above, the cracking furnaces incorporate many energy efficiency elements in their design, providing a thermal efficiency targeting 91.1% LHV or 92% HHV. Little improvement in efficiency can be obtained with reasonable measures. Therefore Equistar contends that energy efficiency is a technically feasible and the chosen design will provide a maximum effectiveness of 2.4% control of CO_2 emissions.

Based incorporation of the design features presented above, the emissions from the OP-1/OP-2 furnaces are estimated to be 600,800 TPY CO_2. This includes firing on natural gas and adoption of best operational practices.

Best Operational Practices

Periodic Tune Up – The cracking furnace, to the extent practicable and in accordance with usual industry preventative maintenance practices, is kept in good working condition. These tune-ups include a variety of activities ranging from instrument calibration to cleaning of dirty or fouled mechanical parts. With respect to GHG

emissions potential, these activities maintain performance as opposed to enhancing performance.

Oxygen Trim Controls – The excess oxygen is measured post-combustion and those results are used to control inlet combustion air volume to maintain high efficiency. Introduction of too much excess air increases the mass in the furnace to be heated and reduces efficiency. Oxygen trim control allows the excess oxygen to be controlled to optimum levels, thus allowing the furnace to operate at continuous high levels of efficiency.

Best operational practices do not reduce GHG emissions but rather prevent performance degradation that would allow GHG emissions to increase. Therefore they are assigned a 0% control effectiveness.

Adoption of the best operational practices along with energy efficient design and use of natural gas to fire the furnaces, the emissions from the OP-1/OP-2 furnaces are estimated to be **600,800** TPY CO_2.

EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

Summary of Step 4

In Step 4 of this CO_2 BACT analysis, use of hydrogen as primary fuel is rejected due to collateral impacts. Those impacts are discussed below.

Carbon Capture and Storage (CCS) is rejected due to cost and collateral impacts. Those costs and collateral impacts are reviewed in detail below.

Fuels selection is determined to be the most appropriate CO_2 BACT for the furnace with a minimum reasonable control effectiveness of 12%. Energy efficient design at 2.4% maximum effectiveness and best operational practices with 0% effectiveness follow fuels selection in the hierarchy.

Use of Hydrogen as Primary Fuel for the Cracking Furnaces

Hydrogen could be used as the only fuel for the cracking furnaces, providing 100% elimination of CO_2 from the flue gas, provided it was available and that necessary firebox heat release and temperatures could be produced through hydrogen firing. Those aspects have not been further evaluated due to rejection on the basis of related impacts which show that collateral CO_2 emissions may be higher if hydrogen is burned as the primary fuel.

The National Renewable Energy Laboratory (NETL) has determined that the net effect of using hydrogen as a fuel when produced by the most common means, steam methane reforming, is an overall increased GHG emissions. [32] NETL concluded:

> *Although hydrogen is generally considered to be a clean fuel, it is important to recognize that its production may result in environmental consequences. Examining the resource consumption, energy requirements, and emissions from a life cycle point of view gives a complete picture of the environmental burdens associated with hydrogen production via steam methane reforming. The operation of the hydrogen plant itself produces very few emissions with the exception of CO_2. On a system basis, CO_2 is emitted in the largest quantity, accounting for 99 wt% of the total air emissions and 89% of the system GWP. Another air emission that effects the GWP of the system is CH_4, which primarily comes from the natural gas lost to the atmosphere during production and distribution. The energy balance of the system shows that for every 0.66 MJ of hydrogen produced, 1 MJ of fossil energy must be consumed (LHV basis).*

Therefore, while CO_2 emissions from the cracking furnaces may be reduced by use of H_2 as the primary fuel, the collateral effect is that the H_2 will be produced elsewhere and the most common means of production generates more CO_2 than is offset by the H_2 combustion. Equistar has the ability to sell hydrogen and market demands for H_2 continue to increase, primarily for use as a feedstock for hydrodesulfurization at refineries for low sulfur fuel production.

To quantify the impact of firing with hydrogen, one must compare the CO2 generation for a given heat release firing with methane, and compare that to the CO2 generation of a hydrogen production facility providing a quantity of hydrogen for that same heat value.

The heat of combustion of methane is 11,953.6 cal/gm. [33]

Direct combustion of CH_4 to produce 1 MJ heat energy would require combustion of 20 grams of CH_4:

1×10^6 joules x 0.239 cal/joule x 1 gm CH_4 / 11,953.6 cal = 20 gm CH_4

20 gm CH_4 with complete combustion produces 55 grams of CO_2:

20 gm CH_4 x 12 gm C / 16 gm CH_4 x 44 gm CO_2 / 12 gm C = 55 gm CO_2

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[32] NETL publication, *Life Cycle Assessment of Hydrogen Production via Natural Gas Steam Reforming*, Page 23, Conclusions. http://www.nrel.gov/docs/fy01osti/27637.pdf

[33] Perry & Chilton, *Chemical Engineer's Handbook*, 5th Ed., c 1973, p. 3-145, Heats of Combustion

Production of hydrogen to supply 1 MJ heat energy would require combustion of enough methane to produce 83 grams of CO_2:

1 MJ from hydrogen / (0.66 MJ from hydrogen / 1 MJ from fossil fuel)[20] = 1.51 MJ from fossil fuel.

Verification: 1.51×10^6 j x 0.239 cal/j x 1 gm CH_4/11,953.6 cal x 12 gm C/16 gm CH_4 * 44 gm CO_2/12 gm C = 83 gm CO_2

83 gm CO_2 / 55 gm CO_2 = 1.51

If one were to use methane, the lowest carbon common fossil fuel, to fire a steam methane cracking unit to produce hydrogen to be used as fuel, collateral CO_2 emissions from manufacture of that hydrogen, assuming identical manufacturing efficiencies, would be 51% higher than if the hydrogen had never been produced for use as a fuel.

In addition, the most common method of hydrogen production is steam methane reforming where the process parameters are adjusted to shift production to favor high concentrations of CO_2 in the synthesis gas for efficient separation of the hydrogen and CO_2. These units typically release the large volumes of CO_2 separated from the synthesis gas directly to the atmosphere. That is in addition to the CO_2 that is generated through combustion, making the collateral impacts much greater than the 51% demonstrated above.

Thus, it is technically infeasible to achieve a reduction in overall CO_2 emissions when collateral increases are considered. Use of hydrogen as a primary fuel is rejected due to collateral impacts on increased CO_2 emissions and overall GWP.

Carbon capture and Storage

As described below, carbon capture and storage (CCS) is not economically feasible for this project based on the combination of the capture and transportation costs alone. In addition, the effectiveness of CCS is estimated to be near 57% when collateral increased CO_2 emissions are considered.

Capital cost for carbon capture is estimated to be more than $108-million, and for transportation is estimated at $21-million. The total cost for CCS is therefore estimated to be greater than $129-million. The project cannot adsorb the cost of CCS and remain financially viable. In fact, a substantially lower calculated cost for CCS would kill this project. CCS is rejected as a viable alternative due to capital cost alone.

Carbon Capture

Several methods are available for carbon capture, none of which Equistar has determined to be technically feasible as presented earlier in Step 2 of this analysis. Equistar has been unable to locate cost data, or specific technology details for the capture of CO_2

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from flue gas generated by a similar sized furnace fired with natural gas and utilizing selective catalytic reduction technology for NOx control. Therefore, the cost data provided herein are based on ranges of costs provided in the cited references adjusted accordingly for differences between those projects and Equistar's facility.

Most carbon capture cost data that are available in literature are derived from power plant installations. Much of the data in literature are based on coal fired plants, including primarily integrated gasification combined cycle (IGCC) and pulverized coal (PC) plants. There are limited examples for natural gas combined cycle (NGCC) installations which would be more relevant to Equistar's cracking furnace, however remaining only distantly related. Power plants, with their relatively large fuel consumption when compared to the cracking furnace, and relatively high in stack CO_2 concentration (~10%vol CO_2 vs. <3%vol CO_2 minimum) could be reasonably expected to have much lower costs for CO_2 capture ($/ton basis) than would the cracking furnace.

It can be anticipated that a first of a kind (FOAK) installation, as one at Equistar's olefins plant would be, would have significantly higher costs than Nth of a kind (NOAK) installations where the technology is better developed. Where cost data are presented for a NOAK installation, those costs must be factored upward to reflect cost for a FOAK installation as Equistar's cracking carbon capture would be. One set of researchers estimated that costs could vary by a factor of 3 by stating:[34]

> *Based on these considerations a likely representative range of costs of abatement for capture (and excluding transport and storage) appears to be $100-150/tCO2 for first-of-a-kind plants and plausibly $30-50/tCO2 for nth-of-a-kind plants.*

For adjustment for coal fired plant examples, an understated upward adjustment of only 1.5x will be applied. Literature searches indicate CO_2 ranges in flue gas from coal fired plants ranges from roughly 7% to 14%. Equistar's cracking furnace flue gas will contain roughly 3% to 9% CO_2 depending on the fuel slate. At the lower concentrations, adsorption into amine solutions is much less effective than installation on coal fired units. With Equistar's flue gas having less than half the partial pressure of CO_2 at times as seen in coal fired plant fuel gas, the costs equivalent control at the Equistar facility would require scale up for the needed additional amine contact. In process design, it is necessary to design for the entire range of normal operating parameters, and in this case, a relevant aspect is the low CO_2 concentration that would be observed when firing with a high molar percentage of hydrogen in the fuel gas. One in depth 2009 study estimated the cost of capture ($CA/tonne CO_2) of a 3.5% CO_2 stream to be roughly twice as much as

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[34] Al-Juaied, Mohammed A and Whitmore, Adam, "*Realistic Costs of Carbon Capture*" Discussion Paper 2009-08, Cambridge, Mass.: Belfer Center for Science and International Affairs, July 2009, Abstract, p ii, http://belfercenter.ksg.harvard.edu/files/2009_AlJuaied_Whitmore_Realistic_Costs_of_Carbon_Capture_web.pdf

a stream containing 9.2% CO_2.[35]   For the purposes of cost estimation in this analysis, a factor of only 1.5 will be applied as opposed to 2.0 to account for the greater cost for capture of CO_2 from a dilute stream as opposed to a more concentrated flue gas stream that would be produced by a coal fired plant. The lower factor is chosen to avoid over-estimation of costs. Those estimates cited in the reference included both capture and compression, but did not include transportation or storage.

For adjusting cost for the size of the unit, in terms of CO_2 mass to be collected, the "0.6 factor model" or "0.6 factor rule," will be used. This is a commonly used model for roughly estimating relative capital costs of processing plants based on size of those plants. The cost adjustment is the ratio of Equistar's unit CO_2 generation divided by the reference case CO_2 generation, and that result is raised to the 0.6 power then multiplied by the reference model cost. This will be applied to each case analyzed to increase or decrease the estimated capital cost appropriately.

For this evaluation, Equistar has researched assorted references with cost data for CCS installations and academic papers that also provide cost data. Some of those data are provided below with indications of appropriate adjustment for the factors provided in the discussion above. The appropriate adjustments and the justifications for their use are provided in each case.

BACT Table 5: Slate of Adjustments for Capital Cost

Cost Factor	Data Source	Cost Adjustment for Equistar
Fuel type	Coal (IGCC or PC)	Upward 1.5x due to CO_2 partial pressure difference in the flue gas.
	Natural gas (NGCC)	No change (conservative)
Size of unit	CO_2 generation or firing rate	Usually downward (Equistar CO_2/Reference CO_2)^0.6
Temporal basis	FOAK or current operation	No change
	NOAK	Upward 1.5x to 3x due to higher FOAK basis

Based on referencing four cases, including coal and natural gas fired power plants, using factors to prevent any appearance of over-stating costs, the estimated cost for an Equistar FOAK facility for capture of CO_2 at 90% effectiveness, is between $108-million and $511-million. The highest estimate appears to be a clear outlier. It is likely that a more rigorous cost estimate for a capture unit specific to Equistar would result in a substantially higher cost range.

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[35]   Ordorica-Garcia , Wong, Faltinson, "CO2 Supply from the Fort McMurray Area , 2005-2020" Table 3.4. Estimate of CO2 cost for three CO2 concentrations of 3.5%, 9.2% and 18.6%.

CASE 1

This example is taken from a cost evaluation presented by Ahmed Aboudheir and Gavin McIntyre[36] on the cost for installation of a CCS system alone on a coal fired power plant. The CO_2 capture plant is designed to capture 3307 tons per day of CO2 at 90% recovery rate. This would be a FOAK installation. Because this is a capital cost alone, no adjustment is made for power to operate the recovery system, for CO_2 transportation or for storage.

Size of Unit: 3307 tons/per day
Fuel type: Coal   (12% CO_2 in flue gas)
Capital Cost: $165- million

Adjustments to cost estimate for Equistar case:

Size of unit: $(1480/3307)^{0.6} = 0.62$
Fuel type: 1.5

Capita; cost = $165-million x 0.62 x 1.5 = **$153-million**

CASE 2

Case 2 is also taken from Aboudheir and McIntyre's evaluation of capital costs. Case 2 is a Natural Gas Combines Cycle (NGCC) plant of the same size as the coal fired plant presented in case 1. Being a NGCC plant, no adjustment is made for fuel type (reported 4% CO2 in stack). This would also be a FOAK installation. Because this is a capital cost alone, no adjustment is made for power to operate the recovery system, for CO_2 transportation or for storage.

Size of Unit: 3307 tons/per day
Capital Cost: $227- million

Adjustments to cost estimate for Equistar unit:

Size of unit: $(1480/3307)^{0.6} = 0.62$

Capital cost = $227-million x 0.659 = **$141-million**

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[36] Aboudheir and McIntyre, Industrial Design and Optimization of CO2 Capture, Dehydration, and Compression Facilities.
http://www.bre.com/portals/0/technicalarticles/INDUSTRIAL%20DESIGN%20AND%20OPTIMIZATION%20OF%20CO2%20CAPTURE,%20DEHYDRATION,%20AND%20COMPRESSION%20FACILITIES.pdf

CASE 3

This case was presented by Al-Juaied and Whitmore[37] in 2009 and relates to a natural gas fired combined heat and power unit at the Mongstad, Bergen, Norway refinery. The unit is a FOAK unit, capturing a total of 1.2-million tonnes per year of CO_2 from the CHP unit. Being natural gas fired there is no adjustment for fuel type. 50% of the $1.75-billion is for the capture facilities associated with the CHP unit.

Size of Unit: 1.2-million tonnes x 1.102 ton/tonne / 365 day/yr = 3623 tpd

Capital cost: $1.75 billion x 0.50 = $875-million

Adjustments to cost estimate for Equistar unit:

Size of Unit: $(1480 /3623)^{0.6} = 0.58$

Capital cost = $875-million x 0.58 = **$511-million**

CASE 4

This case was also presented by Al-Juaied and Whitmore.[38] It is a Saudi Aramaco gas turbine installation, firing natural gas, capturing 1.3 million tonnes per year of CO_2 with a capital cost of $194-million.

Size of Unit: 1.3-million tonnes x 1.102 ton/tonne /365 day/yr = 3925 tpd

Capital cost: $194 million

Adjustments to cost estimate for Equistar unit:

Size of Unit: $(1480/3925)^{0.6} = 0.56$

Capital cost = $194-million x 0.56 = **$108-million**

Based on referencing these coal and natural gas fired power plants, the estimated costs for an Equistar FOAK facility for capture of CO_2 at 90% effectiveness, is likely between $115-million and 160-million.

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[37] Al-Juaied, Mohammed A and Whitmore, Adam, "Realistic Costs of Carbon Capture" Discussion Paper 2009-08, Cambridge, Mass.: Belfer Center for Science and International Affairs, July 2009. http://belfercenter.ksg.harvard.edu/files/2009_AlJuaied_Whitmore_Realistic_Costs_of_Carbon_Capture_web.pdf

Transportation

The CO2 emissions from the cracking furnaces have been estimated to be approximately 600,800 tons per year. With 90% capture, 540,700 tons per year or 1,480 tons per day would require transportation. The closest tie-in point to a CO2 transportation pipeline, regardless of the end-point destination of the CO2 is the Denbury Green pipeline. The logical tie-in point is approximately 30 miles south-southeast of Equistar's Channelview site, NEAR Dickinson, TX. NETL guidance[38] suggests that an 8″ diameter pipeline would be appropriate for this transport need. NETL guidance on pipeline costs yields a final total capital cost of $21-million and Operation and Maintenance costs of $260,000/year.

The following cost estimates in BACT Table 6 are based on formulae provided by NETL. [39]

BACT Table 6: Estimates for CO2 Transport from Equistar Channelview to Dickinson, TX Area.

Cost Type	Units	Cost		Est. Cost
		Pipeline Costs		
Materials	$ Diameter (inches) Length (miles)	$64,632 + $1.85 x L (330.5 x D^2 + 686.7 x D + 29,960) =		$ 3,039,743
Labor	$ Diameter (inches) Length (miles)	$341,627 + $1.85 x L x (343.2 x D^2 + 2,074 x D + 170,013) =		$ 11,917,251
Miscellaneous	$ Diameter (inches) Length (miles)	$150,166 + $1.58 x L x (8,417 x D + 7,234) =		$ 3,684,784
Right of Way	$ Diameter (inches) Length (miles)	$48,037 + $1.20 x L x (577 x D + 29,788) =		$ 1,286,581
		Other Capital		
CO2 Surge Tank	$	$1,150,636		$1,150,636
Pipeline Control System	$	$110,632		$110,632
		O&M		
Fixed O&M	$/mile/year	$8,632		$258,960

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[38] Figure 4: Pipe Diameter as a Function of CO2 Flow Rate, *Estimating Carbon Dioxide Transport and Storage Costs*, Page 11. http://www.netl.doe.gov/energy-analyses/pubs/QGESStransport.pdf

[39] Table 2: Pipeline Cost Breakdown [4,6,7], *Estimating Carbon Dioxide Transport and Storage Costs*, Page 5. http://www.netl.doe.gov/energy-analyses/pubs/QGESStransport.pdf

Storage

Equistar owns and operates salt dome caverns for storage of light hydrocarbons and that technology could possibly be employed for CO_2 storage. Due to familiarity with the technology and uncertainty of the other options, this storage option is further evaluated. Based Equistar's 2006 study of the total cost for a new 2.65-million barrel storage cavern, it is estimated that a storage cavern of sufficient size to store 20 years of captured CO_2 from the new furnaces would have a capital cost of more than $1-billion (2006 dollars). It is assumed that solution mining to produce a cavern for CO_2 storage is not substantially different in cost than for a hydrocarbon storage cavern.

Captured CO_2 = 540,700 tons per year

Captured CO_2 = 20 years x 540,700 tpy = 21,628,000,000 pounds

CO_2 density at supercritical conditions, well depth >3,000 ft. ~42 lb/ft^3

Volume needed = 21,628,000,000 lb / 42 lb/ft^3 = 515,000,000 ft^3

= 515,000,000 ft3 / 5.61 ft3/barrel = 92 million barrels.

Based on size alone, this project is 35 times larger than the project evaluated in 2006.

Development cost (fixed) $15-million
Well installation = 35 x $37-million = $1.3-billion.

Total cost is approximately $1.3-billion. (2006 dollars)

For storage alone, that cost is clearly prohibitive in comparison to the other options. For the purposes of this evaluation, it is assumed that CO_2, if used for enhanced oil recovery (EOR) would generate revenues that would at least partially offset the cost for storage and storage monitoring. If saline aquifer or un-mineable coal seam options were selected to complete the CCS strategy, additional costs would need to be added to the analysis for injection wells, storage rights, and long term monitoring.

Because EOR costs would be partially offset by revenues generated by recovered oil, the CCS analysis assumes zero cost for storage.

Fuels Selection

Equistar intends to employ fuels selection as described in Steps 2 and 3 of this Furnace CO_2 BACT evaluation.

Installation of Energy Efficiency Options on the Cracking Furnace

The new cracking furnaces at Equistar's Channelview Plant will incorporate the energy efficiencies described in Steps 2 and 3.

Best Operational Practices

The implementation of periodic tune-ups and the use of oxygen trim control do not reduce GHG emissions, but are useful in preventing degradation of performance that would allow GHG emissions to increase.

SELECTION OF CO_2 BACT (STEP 5)

With the rejection of hydrogen use as a primary fuel, and of CCS as an option for control of CO_2 emissions in step 4 of this BACT analysis, the remaining options include fuels selection, energy efficient design and adoption of best operational practices. Consistent with EPA guidance for selection of BACT, fuels selection is BACT for control of CO_2 emissions associated with furnace operation. Furthermore, Equistar has chosen to control CO_2 emissions using all three of these methods for limiting CO_2 emissions relating to operation of the olefins unit cracking furnaces.

Emissions from the two furnace combined with incorporation of the three technologies is estimated to be no more than 600,800 tons per year.

BACT Table 7: Summary of Furnace CO_2 Emissions w/ BACT Applied

Source	Description	TPY CO_2	TPY CO_2e
EF3419	Furnace EF3419	300,400	300,400
EF4419	Furnace EF4419	300,400	300,400

With respect to operational controls and best practices, Equistar proposes the following:

PREVENTATIVE MAINTENANCE AND TUNING/CALIBRATION	BEST PRACTICE
Excess O2 analyzer	Monthly calibration, check filters, etc.
CEMS (O2, NOx)	Daily automatic calibration
	Classify as environmentally critical instruments and thus receive an increased priority for preventative maintenance and repairs.
Fuel gas analyzer	Monthly calibration, check filters, etc.
Fuel gas flow meter	Biannual calibration
	Classify as environmentally critical instruments and thus receive an increased priority for preventative maintenance and repairs.
Burner condition	Visually check burner for flame pattern to maintain combustion efficiency
OPERATION	**BEST PRACTICE/CONTROL**
Convection section wash	As required to maintain thermal efficiency.
Oxygen control	Control O2 based on O2 analyzer output to assure high efficiency combustion.

CRACKING FURNACE - CH$_4$ BACT

IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Summary of Step 1

Control options for CH4 emissions from the cracking furnace stack include actual direct control, elimination of the capability to emit CH4, and steps to minimize the generation of CH4. Five methods were identified and were all carried to Step 2 in the process.

Available Controls

Available control options for minimizing CH$_4$ emissions from the cracking furnace include:

▲ Post-combustion catalytic oxidation

Post-combustion catalytic oxidation provides rapid conversion of a hydrocarbon into CO2 and water vapor in the presence of available oxygen. This is direct control of CH4, producing a second GHG, CO2 with a net decrease in CO2e emissions.

▲ Use hydrogen as the primary fuel for the cracking.

In its combustion, hydrogen produces no CH4. This method of control is elimination of the capacity to produce CH4 emissions.

▲ Burn low CH4 generating fuel.

CH4 emissions estimating methods published by EPA[40] indicate that different fuels produce varying amounts of CH4 that may be emitted. Selection of a low CH4 emitting fuel minimizes CH4 emissions.

▲ Installation of energy efficient options for the cracking furnace

Improved energy efficiency reduces overall fuel combustion demands for a given process production rate. By combusting less fuel, it is reasonably projected that less CH4 would be emitted.

▲ Best Operational Practices

Best operational practices preserve energy efficiency and thus maintain low overall fuel combustion demands for a given process production rate. By combusting less fuel, it is reasonably projected that less CH4 would be emitted.

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[40] 40 CFR Part 98, Subpart C.

ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

Summary of Step 2

In Step 2 of the five-step BACT evaluation for control of CH_4 emissions from the cracking furnace stack, post-combustion catalytic oxidation and use of hydrogen as the primary fuel are both rejected as technically infeasible. Use of low CH_4 generating fuel, energy efficiency and best operational practices are technically feasible and are carried forward to Step 3.

Post-Combustion Catalytic Oxidation

The cracking furnace flue gas temperature design temperature is 350° to 375°F (177°C to 191°C). It is expected to contain about 1 ppmv CH_4.

The temperature reflects the highly efficient furnace operation in which heat loss via furnace flue gas is minimized. However, this temperature is below the lowest operating temperature for catalytic oxidation found in literature research. Typical low ends of operating temperature ranges for catalytic oxidation are 250°C or higher. In addition, the flue gas CH_4 concentration is about two orders of magnitude below the lower end of VOC concentration in streams which would typically be fitted with catalytic oxidation for control.[41]

The cracking furnace is essentially a highly efficient thermal oxidizer, achieving destruction efficiencies of greater than 99.9% for the methane fuel. Addition of post-combustion catalytic oxidation on this cracking furnace for control of CH_4 is technically infeasible and will not be considered in subsequent steps of this analysis.

Use of hydrogen as the primary fuel

During combustion, hydrogen generates no CH_4. Hydrogen could be used as a fuel provided it was available and that necessary firebox heat release and temperatures could be produced through hydrogen firing. Those aspects have not been further evaluated due to subsequent rejection on the basis of collateral impacts as presented below.

Hydrogen combustion for its fuel value generates no CH_4 directly. However, the National Renewable Energy Laboratory (NETL) has determined that the net effect of using hydrogen as a fuel when produced by the most common means, natural gas steam reforming, is an overall increase global warming potential (GWP). NETL concluded:

> *Although hydrogen is generally considered to be a clean fuel, it is important to recognize that its production may result in environmental consequences. Examining the resource consumption,*

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[41] US EPA, APTI 415, Control of Gaseous Emissions, Chapter 6, P 6-14.
http://www.epa.gov/apti/Materials/APTI%20415%20student/415%20Student%20Manual/415_Chapter%206_final.pdf

energy requirements, and emissions from a life cycle point of view gives a complete picture of the environmental burdens associated with hydrogen production via steam methane reforming. The operation of the hydrogen plant itself produces very few emissions with the exception of CO_2. On a system basis, CO_2 is emitted in the largest quantity, accounting for 99 wt% of the total air emissions and 89% of the system GWP. Another air emission that effects the GWP of the system is CH_4, which primarily comes from the natural gas lost to the atmosphere during production and distribution. The energy balance of the system shows that for every 0.66 MJ of hydrogen produced, 1 MJ of fossil energy must be consumed (LHV basis). [42]

On-purpose hydrogen production through steam methane reforming, the most common process used for commercial production of hydrogen, will also generate CH_4 emissions. If one were to use methane, the lowest carbon common fossil fuel and coincidentally the fuel that produces the lowest CH_4 emissions, to fire a steam methane cracking unit to produce hydrogen to be used as fuel, collateral CH_4 emissions from manufacture of that hydrogen, assuming identical manufacturing efficiencies, would be roughly 50% higher than if the hydrogen had never been produced for use as a fuel.

Therefore, while CH_4 emissions from the subject source may be reduced by use of hydrogen as the primary fuel, the collateral effect is greater CH_4 emissions elsewhere. Given the global nature of GHG emissions this option is rejected due to the increased CH_4 emissions from the hydrogen generating source beyond the increase that would be seen if the cracking furnace was fired with natural gas alone. In addition, as presented in the CO_2 BACT discussion in this document, collateral CO_2 emissions also increase if hydrogen is used as the primary fuel. Use of hydrogen as the primary fuel for the cracking furnace would actually increase overall CO2e emissions and is not progressed beyond this step of the top-down BACT analysis.

Furthermore, the most common method of hydrogen production is steam methane reforming where the process parameters are adjusted to shift production to favor high concentrations of CO_2 in the synthesis gas for efficient separation of the hydrogen and CO_2. These units typically release the large volumes of CO_2 separated from the synthesis gas directly to the atmosphere, increasing the CO2e emissions even more.

Use of hydrogen as a primary fuel is rejected due to collateral impacts on increased CH_4 emissions and overall GWP.

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[42] NETL publication, *Life Cycle Assessment of Hydrogen Production via Natural Gas Steam Reforming*, Page 23, Conclusions. http://www.nrel.gov/docs/fy01osti/27637.pdf

Burn Low CH4 Generating Fuel.

Data collected by EPA and presented in Tables C-1 and C-2 of 40 CFR Part 98, Subpart C for purposes of estimating emissions of GHGs indicate that a switch from natural gas firing to another fuel would actually increase emissions of CO_2, CH4 and N2O. The GHG generation rates below are taken from the two emissions factor tables in 40 CFR Part 98, Subpart C, shown below as BACT Table 8.

BACT Table 8: Emissions factors from 40 CFR Part 98, Subpart C

Fuel	CO2 kg/MMBtu	CH4 kg/MMBtu	N2O Kg/MMBtu
Methane	53.02	1.0×10^{-3}	1.0×10^{-4}
Ethane	62.64	3.0×10^{-3}	6.0×10^{-4}

Because a switch to an available fuel other than natural gas would increase CH4 emissions, use of natural gas as a fuel results in minimized CH4 emissions. This is a feasible method to minimize CH4 emissions.

In addition, when hydrogen cannot be marketed, it may be routed to the furnace fuel system, thus further reducing CH4 emissions potential. However, the preferred disposition for the hydrogen would be in the commercial market.

Installation of energy efficient options for the cracking furnace

As presented in the discussion of CO2 BACT, minimization of GHG emissions through use of energy efficient design is effective and will be employed in the cracking furnaces. This will limit overall firing rate for a given production volume and corresponding emissions of CH4. This option is carried forward in the analysis.

Best Operational Practices

As presented in the discussion of CO2 control through use best operational practices, this method will be employed to prevent energy efficiency degradation of the cracking furnace, and thereby prevents CH4 emissions increase. This option is carried forward in the analysis.

Rank of Remaining Control Technologies (Step 3)

The three remaining technologies are linked in that the furnace is designed for natural gas combustion at peak energy efficiency and the employment of best operational practices assures that the energy efficiency is retained. All three methods of control will be employed and therefore ranking is unnecessary and irrelevant.

EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

The three remaining technologies are linked in that the furnace is designed for natural gas combustion at peak energy efficiency and the employment of best operational practices assures that the energy efficiency is retained. All three methods of control will be employed and therefore further evaluation is unnecessary and irrelevant.

SELECTION OF CH$_4$ BACT (STEP 5)

The combination of the three remaining technologies will be adopted as BACT.

Equistar will:

* Fire the cracking furnace with natural gas and/or hydrogen rich fuel gas,
* Use the existing energy efficient design, and
* Conform to Best Operational Practices.

BACT Table 9: Summary of Furnace CH4 Emissions w/ BACT Applied

Source	Description	TPY CH4	TPY CO2e
EF3419	Furnace EF3419	5.67	119
EF4419	Furnace EF4419	5.67	119

With respect to operational controls and best practices, Equistar proposes the following:

PREVENTATIVE MAINTENANCE AND TUNING/CALIBRATION	BEST PRACTICE
Excess O2 analyzer	Monthly calibration, check filters, etc.
CEMS (O2, NOx)	Daily automatic calibration
	Classify as environmentally critical instruments and thus receive an increased priority for preventative maintenance and repairs.
Fuel gas analyzer	Monthly calibration, check filters, etc.
Fuel gas flow meter	Biannual calibration
	Classify as environmentally critical instruments and thus receive an increased priority for preventative maintenance and repairs.
Burner condition	Visually check burner for flame pattern to maintain combustion efficiency
OPERATION	**BEST PRACTICE/CONTROL**
Convection section wash	As required to maintain thermal efficiency.
Oxygen control	Control O2 based on O2 analyzer output to assure high efficiency combustion.

CRACKING FURNACE - N$_2$O BACT

IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

▲ N2O catalysts to decompose N2O into nitrogen and oxygen.

▲ Low NOx burner selection to limit formation of NOx (including N2O) emissions.

▲ Energy efficient design and good operating practices to minimize firing necessary for a given production volume.

ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

N$_2$O catalysts have been used to reduce N2O emissions from adipic acid and nitric acid plants. [43] There is no indication that these catalysts have been used to control N$_2$O emissions from cracking furnace flue gas. In addition, the very low N$_2$O concentrations present in the exhaust stream would make installation of N$_2$O catalysts technically infeasible. In comparison, the application of a catalyst in the nitric acid industry sector has been effective due to the high (1,000-2,000 ppm) N$_2$O concentration in those exhaust streams. N$_2$O catalysts are eliminated as a technically feasible option for the proposed project.

With N$_2$O catalysts eliminated, low-NOx, efficient burner technology selection and energy efficient operating practices are the only available and technically feasible control options for N$_2$O reduction from the cracking furnace. Both are carried to Step 3.

RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

Low-NOx, efficient burner selection and energy efficient design and good operating practices will be adopted as BACT for N2O control from the cracking. No ranking is necessary.

EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

Low-NOx, efficient burner selection and energy efficient design and operating practices will be adopted as BACT for N2O control from the cracking. No further evaluation is necessary.

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[43] http://www.catalysts.basf.com/p02/USWeb-Internet/catalysts/e/content/microsites/catalysts/news/success-stories/reduce-emissions

SELECTION OF N2O BACT (STEP 5)

Equistar will select efficient natural gas burners that meet the design requirements for the proposed project. Furthermore, Equistar will use the existing energy efficient furnace design and adopt good operating practices.

N2O emissions from each of the furnaces are anticipated to be no more than 0.53 TPY based on 40 CFR Part 98 dated December 17, 2010, Table C-2 of Subpart C - Default CH4 and N2O Emission Factors for Various Types of Fuel. Emission factors for natural gas (unspecified heat value, weighted U.S. average) are used. In comparison to the total CO2e emissions associated with the project, the combined furnace N2O emissions represent less than 1/1000th of the unit CO2e emissions.

BACT Table 10: Summary of Furnace N2O Emissions w/ BACT Applied

Source	Description	TPY CH4	TPY CO2e
EF3419	Furnace EF3419	0.57	176
EF4419	Furnace EF4419	0.57	176

With respect to operational controls and best practices, Equistar proposes the following:

PREVENTATIVE MAINTENANCE AND TUNING/CALIBRATION	BEST PRACTICE
Excess O2 analyzer	Monthly calibration, check filters, etc.
CEMS (O2, NOx)	Daily automatic calibration
	Classify as environmentally critical instruments and thus receive an increased priority for preventative maintenance and repairs.
Fuel gas analyzer	Monthly calibration, check filters, etc.
Fuel gas flow meter	Biannual calibration
	Classify as environmentally critical instruments and thus receive an increased priority for preventative maintenance and repairs.
Burner condition	Visually check burner for flame pattern to maintain combustion efficiency
OPERATION	**BEST PRACTICE/CONTROL**
Convection section wash	As required to maintain thermal efficiency.
Oxygen control	Control O2 based on O2 analyzer output to assure high efficiency combustion.

DECOKING GHG BACT

The only GHG emitted from the decoke stacks is carbon dioxide (CO_2). Therefore this section addresses only CO_2 BACT associated with the furnace decking operation. Because the furnace is already designed to minimize coke formation, the selected CO_2 BACT for the decoking operation is careful operation of the furnaces to minimize formation of coke and thus minimize frequency and duration of decoking operations.

DECOKE STACK – CO2 BACT DISCUSSION

IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Decoking is a process of removing coke deposits from inside of process tubes in the furnace. This is a combustion process that occurs in the presence of stem-air mixture, with CO and CO_2 being the products of combustion. The gases are emitted via a drum that is used to remove coke particulates from the gaseous portion of the decoke stream.

Control of excess air in the decoking process to low levels in the steam-air mixture is necessary to prevent furnace tube overheating. This drives the reaction to produce both CO and CO_2 as opposed to more complete oxidation to almost exclusively CO_2 in a fuel gas combustion process. Thus, the normal decoking procedure that is used to prevent overheating of process tubes in the furnace also limits instantaneous CO_2 production.

Review of the RBLC identified no BACT level control for GHG emissions from decoking operations. Because coke deposits in furnace tubes reduce furnace efficiency, great effort is incorporated in the design and operation of furnaces to minimize the amount of coke that is formed and subsequently required to be removed. The design and operation alone are limits to CO_2 emissions. No methods have been identified for practical control of the CO_2 emissions other than to design and operate the furnaces to minimize the need for decoking. There are no known end-of-pipe control options for CO_2 from decoking operations.

ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

The current decoking operation, limiting air input into the furnace tubes, drives combustion kinetics to limit CO_2 emissions.

The proper design and operation of the furnaces to minimize the amount of coke to be burned is a technically feasible option for overall reduction of CO2 emissions.

RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

Only two options remain for control of CO_2 from decoking operation, those being the careful design and operation of the furnace to limit the need for decoking and its

associated emissions of CO2, and to follow good decoking practices which limit CO2 generation.

EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

Only two options remains for control of CO2 from decoking operation, those being the careful design and operation of the furnace to limit the need for decoking and its associated emissions of CO2, and to follow good decoking practices which limit CO2 generation. Both will be adopted and further evaluation is unnecessary for selection of CO2 BACT for the decoking operation.

SELECTION OF CO2 BACT (STEP 5)

Equistar will utilize a combination of design and furnace operation that limits build-up of coke in the process tubes, thus limiting the need for decoking. By minimizing decoking, CO2 emissions are also minimized. In addition, procedures for decoking that prevent overheating of furnace tubes will be utilized. Specifically there will be a limitation on excess oxygen and to control the rate of combustion, thus limiting CO2 emissions.

BACT Table 11: Summary of Decoke CO2 Emissions w/ BACT Applied

Source	Description	TPY CO2	TPY CO2e
EOP1DECOKE2	OP-1 Decoking Drum	281	281
EOP2DECOKE2	OP-2 Decoking Drum	281	281

FUGITIVE EMISSIONS GHG BACT

Greenhouse Gas (GHG) Best Available Control Technology (BACT) for fugitive emissions has been evaluated via a "top-down" five-step approach. Each of those five steps is outlined below. The analysis has been conducted for CH4, the only GHG emitted from fugitive sources. That analysis led to the conclusion that BACT for fugitive emissions is leak detection and repair program based on Method 21 monitoring for leaks.

STEP 1 – IDENTIFY ALL CONTROL TECHNOLOGIES

Summary of Step 1

Equistar has identified five common technologies and practices for control of fugitive emissions. All are carried forward to Step 2.

Identification of Control Technologies

In determining whether a technology is available for controlling GHG emissions from fugitive components, permits and permit applications and US. EPA's RBLC were consulted. Based on these resources, the following available control technologies were identified although not specific to GHGs:

▲ Installation of leakless technology components to eliminate fugitive emission sources.

▲ Instrumented Leak Detection (Method 21) and Repair (LDAR) Program;

▲ Leak Detection and Repair Program with Remote Sensing Technology.

▲ Audio, visual, and olfactory (AVO) detection of leaks followed by repair.

▲ Design and construct facilities with high quality components, with materials of construction compatible with the process.

STEP 2 – TECHNICAL FEASIBILITY ANALYSIS

Summary of Step 2

All methods identified in Step 1 of the BACT analysis for CH4 emissions from fugitive emissions sources are determined to be technically feasible, and are all carried forward to Step 3.

Leakless Technology

Leakless technology valves are available and in use in industry. In addition, welded connections in lieu of flanged or screwed connection provide leakless operation.

Instrumented Leak Detection (Method 21) and Repair Programs

LDAR programs based on EPA Method 21 leak detection are possible for streams containing combustible gases, including methane. Equistar currently applies this method of LDAR to components in certain VOC services.

Leak Detection and Repair Program with Remote Sensing Technology.

Remote sensing of leaks has been proven as a technology using sophisticated infrared cameras. The use of such devices has been approved by EPA as an alternative to Method 21 detection in certain instances. The remote sensing technology can detect CH_4 emissions.

Audio, visual, and olfactory (AVO) detection of leaks followed by repair

AVO methods of leak detection are technically feasible and some states have approved monitoring and repair credits for emissions estimation where this method of leak detection and repair is employed.

Design and construct facilities with high quality components, with materials of construction compatible with the process.

This technology to minimize leak frequency and severity is feasible.

STEP 3 – RANKING OF REMAINING CONTROL TECHNOLOGIES BY EFFECTIVENESS

Summary of Step 3

BACT Table 14 provides in order of decreasing effectiveness for control of fugitive emissions of CH_4 the potential technologies to be used.

BACT Table 14: Fugitive Emissions Control Technologies and their Effectiveness

Technology	Control Effectiveness (%)	CH₄ Emissions with Control (TPY)	CO2e Emissions with Control (TPY)
Leakless technologies	~100	0.00	0.00
Instrumented Leak Detection and Repair (28LAER)	97	1.2	26
Leak Detection & Repair w/ Remote Sensing	>75	8.7	182
Audio, Visual, Olfactory	<30	24.3	512
Design & Construct w/ High Quality Components	Undetermined	NA	NA

Leakless Technology

Leakless technologies are nearly 100% effective in eliminating leaks except when certain components of the technology suffer from a physical failure. These technologies do not, however, eliminate all leak interfaces, even when working perfectly. Those interfaces are typically stationary interfaces and therefore leak frequency at those interfaces of component parts (e.g., valve body to bonnet) would be expected to be low. The critical elements of leakless components include parts such as a bellows installed on a valve stem, or the diaphragm in a diaphragm valve. Following a failure of one of these parts, the component is most often not repairable online and may leak until the next unit shutdown. Nevertheless, this is the most effective of the controls.

Instrumented Leak Detection (Method 21) and Repair Programs

LDAR programs based on quarterly testing with EPA Method 21 leak detection, and repair of leaks greater than 500 ppm have been given a 97% control credit by some state agencies. Such detection is possible for streams containing combustible gases, unless simultaneously emitted noncombustible gases such as nitrogen are in too high of a concentration. The 97% allowed credit makes this the second most effective control.

Leak Detection and Repair Program with Remote Sensing Technology.

Remote sensing of leaks has been approved by EPA as a partial alternative to Method 21 detection in certain instances. EPAs approved alternate method allows use of remote sensing technology provided components are monitored at least annually using Method 21 for leak detection. Due to equivalency with Method 21 monitoring, is assumed to have no less than 75% control effectiveness.

Audio, visual, and olfactory (AVO) detection of leaks followed by repair

AVO methods of leak detection and repair are given credit for emission reduction, however that effectiveness is highly dependent on the system pressure (high pressure systems have higher potential for making noise, or creating a visible emission or condensation/ice at the leak) and on the odor of the leaking material. Effectiveness is also dependent on the frequency of AVO inspection. It is highly unlikely that AVO methods are more effective than EPA alternative procedure listed above for components in methane and fuel gas services that are the subject of this project. Some programs allow 30% control effectiveness for AVO monitoring.

Design and construct facilities with high quality components, with materials of construction compatible with the process.

A key element in control of fugitive emissions is the use of high quality equipment that is designed for the specific service in which it is employed. For example, a valve that has been manufactured under high quality conditions can be expected to have lower runout

on the valve stem and the valve stem is typically polished to a smoother surface. Both of these factors reduce the likelihood of leaking. The olefins unit at Equistar's Channelview plant utilizes such components, and materials of construction, including gasketing, that are determined to be compatible with the service in which they are employed.

A control effectiveness of design and construction of facilities with high quality components, and with materials of construction compatible with the process is unknown.

STEP 4 – TOP-DOWN EVALUATION OF CONTROL OPTIONS

Leakless Technology

While leakless technologies provide for the highest level of control of the five technologies initially identified, Equistar has determined that leakless technologies are not justified for CH4 service in consideration of the other control technologies to be employed. Leakless technologies have not been universally adopted as LAER, or even BACT. Leakless technologies are not required for toxic or extremely hazardous services for components covered by rules for Hazardous air pollutants. Therefore it is reasonable to state that these technologies are unwarranted for control of CH4 with no acute impact. Any further consideration of available leakless technologies for GHG controls is unnecessary.

Instrumented Leak Detection (Method 21) and Repair Programs

LDAR programs for which instrumented detection of leaks is an essential activity have traditionally been developed for control of VOC emissions. BACT determinations related to control of VOC emissions rely on economic reasonableness for these instrumented programs. The adverse impact of non-VOC fugitive emissions of CH_4 due to global warming potential has not been quantified, and no reasonable cost effectiveness has been assigned. Nevertheless, with 97% control effectiveness, and general acceptance for components in VOC service, Equistar proposes to use TCEQ method 28LAER for leak detection and repair.

Leak Detection and Repair Program with Remote Sensing Technology.

Remote sensing of fugitive components in CH4 service can provide an effective means to identify leaks. However, because the 28LAER program will be adopted for control of fugitive CH4 emissions, this option is rejected.

Audio, visual, and olfactory (AVO) detection of leaks followed by repair

Leaking components can be identified through AVO methods. However, because the 28LAER program will be adopted for control of fugitive CH4 emissions, this option is rejected.

STEP 5 – SELECT CH₄ BACT FOR FUGITIVE EMISSIONS

Equistar proposes to employ TCEQ's 28LAER leak detection and repair to components in CH4 service.

Technology	Control Effectiveness (%)	CH₄ Emissions with Control (TPY)	CO2e Emissions with Control (TPY)
Instrumented LDAR (28LAER)	97	7.65	161