Greenhouse Gas Permit Application to Construct a DRI/HBP Plant at La Quinta

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1.0 INTRODUCTION AND BACKGROUND

voestalpine proposes to build a direct reduced iron (DRI) plant in Corpus Christi in San Patricio County in Texas. A site location map showing the location of the plant with respect to the surrounding vicinity is included in this document.

For greenhouse gases (GHGs), a process overview is presented in the remainder of Section 1. Emission calculations used in this best available control technology (BACT) analysis are presented in Section 2. A regulatory review of potentially applicable federal, state, and local regulations related to GHG emissions is presented in Section 3. The details of the BACT analysis are presented in Section 4. Additional information is provided in appendices as follows:

- Appendix A – Emission Rate Calculations;
- Appendix B – Figures.
- Appendix C – Recently Issued Permits and Pending Applications; and

1.1 PROCESS OVERVIEW

1.1.1 General Process Description

The Direct Reduction Iron (DRI) process consists of two main components, a Reformer (to produce the reducing agent) and the DRI reactor (where the reaction occurs). The DRI process converts pre-processed iron oxide pellets into highly metallized iron in the form of direct reduced iron (DRI) or hot briquetted iron (HBI), which are ideal feed materials for high quality steelmaking.

Reformer:
The primary raw material source to produce the reducing gas for the reactor is natural gas. Natural gas is reacted with carbon dioxide and water vapor across a proprietary catalyst to produce a reducing gas rich in carbon monoxide and hydrogen.

The important reforming reactions are:

$$CH_4 + CO_2 \rightarrow 2CO + 2H_2$$
$$CH_4 + H_2O \rightarrow CO + 3H_2$$

Both of these reforming reactions are endothermic and therefore require energy in the form of heat input. All heat input into the system will solely be from natural gas combusted on the heat side of the reformer.

Reduction:
Most naturally occurring iron oxide has the chemical composition of hematite, Fe_2O_3, and contains about 30 percent oxygen by weight. In the DRI - process, the chemically bonded oxygen in the iron ore is removed at elevated temperatures by

reaction with carbon monoxide (CO) and hydrogen (H_2) contained in a reducing gas to produce metallic iron (Fe), while liberating carbon dioxide (CO_2) and water vapor (H_2O). The overall reduction reactions are:

$Fe_2O_3 + 3H_2 \rightarrow 2Fe + 3H_2O$
$Fe_2O_3 + 3CO \rightarrow 2Fe + 3CO_2$

An important property of the reducing gas is the reductant/oxidant ratio, or "gas quality." The quality is a measure of the potential for the gas to reduce iron oxide. The quality is defined as the ratio of reductants to oxidants contained in the gas:

Quality = reductant/oxidant ratio = moles (H_2 + CO)/moles (H_2O + CO_2)

Experience has found that the optimum gas quality for hot, fresh reducing gas should be 10 or higher. Also, to obtain essentially complete reduction, the quality of the spent reducing gas exiting the process should be at least 2. Another important property of the reducing gas is the H_2/CO ratio. Control of the H_2/CO ratio affords thermally balanced reduction reactions since reduction with carbon monoxide is exothermic, and reduction with hydrogen is endothermic. That is, the heat required by the hydrogen reaction is balanced by the heat supplied by the carbon monoxide reaction. Therefore, proper reduction temperatures can be maintained without significant additional heat input from fuel combustion. The typical H_2/CO ratio produced by the reformer is about 1.55:1.

A description of the individual process areas is provided below and the Process Flow Diagrams for the facility are included in Appendix D.

1.1.2 *Iron Oxide Storage and Handling*

Direct Reduction (DR) grade pellets are delivered in the surge bin at the port. After weighing the pellets, a conveyor transports the pellets to the pellet pile. The pellet pile is equipped with a stacker/reclaimer and will maintain a sufficient supply for one (1) month of operation. The pellets are weighed and transferred to the oxide day bins. The day bins act as a buffer of prepared oxide that is fed to the shaft furnace.

The day bins then discharge to a screening operation to separate the off-specification fractions from the desired 6-20 mm oxide fractions. The desired oxide fractions are discharged on the oxide transfer conveyor. The off specification material is screened further to identify usable fractions. Unusable material is discarded.

The material on the oxide transfer conveyor is weighed and discharged onto the furnace feed conveyor. The furnace feed conveyor is a vertical, pocket type conveyor with flexible sidewalls that deliver material to the top of the shaft furnace structure. The closed furnace feed conveyor discharges through a riffler to the charge hopper at the top of the shaft furnace. The oxide coating station enables feeding of coating directly to the charge hopper of the shaft furnace. The coating is a solid material consisting of cement, burnt lime, hydrated lime, and hydrated dolomite to assist in the reaction process. These materials are maintained in individual silos. A weight indicator in the charge hopper keeps the operator informed of the quantity of feed in the charge hopper.

All process operations within the Iron Oxide Storage and Handling system are routed to various baghouses for the control of particulate emissions. The storage pile and associated operations are controlled with fugitive suppressants.

1.1.3 Reduction Reactor

The reduction reactor is a patented furnace with a nominal 7.15-meter internal diameter refractory, lined with abrasion resistant and insulating brickwork/castables to minimize heat loss. Iron ore pellets enter the reactor through the upper dynamic seal leg and are uniformly distributed on the stockline by symmetrical feed pipes. A dynamic seal is created by a small flow of inert seal gas into the upper seal leg of the furnace. This small flow of inert seal gas into the furnace through the seal leg prevents the escape of furnace gases to the atmosphere, while still allowing the free flow of material by gravity into the furnace without the use of lockhoppers.

The iron ore pellets are reduced to metallic iron in the upper portion of the furnace (reduction zone) by contact with hot hydrogen and carbon monoxide gases that are generated in the reformer and flow counter current to the descending iron oxide. The temperature of the reducing gas is typically 840 – 1,000 °C, depending on the specific reactor operating conditions. Specially designed inlet ports (tuyeres) ensure that the reducing gases flow uniformly to the furnace burden. Spent reducing gas exits near the top of the reactor and enters the process gas system. The product material typically spends 3-4 hours in the reactor in order to achieve the desired product metallization and is then discharged from the furnace cone at temperatures above 700 °C. The discharge zone consists of the refractory lined furnace cone equipped with hydraulically operated burden feeders and a flow aid insert to aid the flow of the material within the cone.

The reduction reactor is not directly vented to the atmosphere so it does not have a specific emission source associated with it. Seal gas (described below) is used to pressurize both the top and bottom of the reactor so that the system reducing gases do not vent to the atmosphere. Furthermore, the reactor does not produce a melted product; the product remains in solid form throughout the reaction process. However, during startup and shut down the system vents through the top gas scrubber to a flare; but, this is to deal with safety issues arising from high hydrogen concentrations associated with the startup and shutdown processes.

1.1.4 Hot Discharge System

The hot reduced material is discharged from the furnace via a dynamic seal leg and a hydraulically driven variable speed hot wiper bar. The speed of the lower burden feeder is ratioed to the average discharge rate of the furnace to achieve a uniform flow of the material from the lower cone to the lower seal leg. The hot material flows across the wiper bar and then passes through a set of hydraulically driven screens, which limit the maximum size of the product passing into the surge hopper of the product discharge chamber. The material is discharged from the surge hopper into one or more of several feed legs. These feed legs connect directly to either a briquette machine or the bypass feed screw. For safety, each leg is isolated from its respective discharge device by a slide gate and ball valve.

1.1.5 *Hot Briquetting System*

The briquetting section includes briquette machines with individual grease lubrication stations, briquette strand separators, HBI cooling conveyors, and one bypass line. Hot DRI is supplied to each briquette machine by a screw feeder. The briquette machines are roll type machines which produce "pillow" shaped briquettes about 6 mm by 120 mm. Each roll contains dies which form the briquettes. One of the rolls is forced toward the other roll by means of a hydraulic pressure system, which ensures a uniform pressing force. The continuous briquette strand that exits the briquetting machine is fed to the strand separators to break the strands into individual briquettes, which are then fed to the HBI cooling system for slow cooling and discharge to the product handling system. Off-specification product (remet) produced during plant start-up or process upset bypasses the briquette machines and is discharged through a bypass feed leg to the bypass discharge feeder and then to the HBI cooling system.

The HBI cooling conveyors will spray water to cool the HBI and will be equipped with vapor hoods to remove steam created by the process. Most of the mist will vaporize on contact with the hot HBI and the vapor will be exhausted to the atmosphere via vapor exhaust fans. The vapor removal system consists of ducts and fans designed to capture and minimize the release of steam into the briquette area. Outside air ducts will be directly connected to each vapor hood and vapor removal fans will supply the required amount of unheated outside air directly into the vapor hoods. Spray cooling water that does not vaporize will drain into collection pans and be routed to a sump and then to the waste water facility.

The dust collection system is designed to minimize the escape of dust at the briquette machines. The system consists of an exhaust fan, a cyclone, an additional air valve, a dust collection scrubber, a sump, an exhaust stack, and associated ducts, hoods, pumps and valves. Dusty air and seal gas are collected and conveyed at a sufficient velocity to prevent settling and accumulation within the ducts. The gas stream then enters a venturi scrubber where water is sprayed onto the dust particles to create a slurry. The slurry is discharged from the scrubber and pumped to the basin upstream of the clarifier. Cleaned gases are pulled from the dust collection system by the exhaust fan and discharged into the atmosphere through a stack.

1.1.6 *Product Material Handling*

The material is transferred from the briquette cooling conveyors to the HBI conveyors, which are equipped with product scales. The HBI product is transported to the product screening station 1 where it is separated into product fines (0-6.35mm) and HBI (6.35-120mm). The fines are fed into a ground floor product fines bunker, while the HBI is weighed and transported on the product collection conveyor to the stacker conveyor for storage. The HBI product storage has a capacity of 100,000 tons per pile.

The HBI is reclaimed from the HBI product storage and transported via conveyor to the product screening station 2, where it is screened; the HBI is weighed and transported via conveyor to the port.

All process operations within the Product Material Handling system are routed to various baghouses for the control of particulate emissions. The storage pile and associated operations are controlled with fugitive suppressants.

1.1.7 Process Gas System

Spent reducing gas (top gas) exits the reduction zone of the reactor through the refractory lined top gas duct and enters the top gas scrubber to be cleaned and cooled. Inside the top gas scrubber, the gas passes through two distinct processing zones. First the gas flows through the venturi portion of the scrubber where it is rapidly cooled and the particulate matter is wetted and removed. Then the warm gas is split into two streams that pass through two parallel packed beds (for additional cooling) and two sets of spin vanes (to remove water droplets) within the scrubber.

After scrubbing and cooling, approximately two-thirds of the clean top gas (now called process gas) flows through a second set of mist eliminators and then to the inlet of the first stage process gas compressor, followed by a second compressor. These compressors are centrifugal type machines designated as first stage and second stage process gas compressors. After compression, the process gas is mixed with natural gas and preheated to form the feed gas for the reformer. The other one-third of the cleaned top gas (now called top gas fuel) is mixed with a small amount of natural gas and then passed through a mist eliminator to remove water droplets before fueling the reformer main burners.

It is important to note that the Top Gas Scrubber is not a control device but a process device. The process gas system does not vent directly to the atmosphere during regular operation.

1.1.8 Reformer

The reformer generates the hot reducing gas (H_2 and CO) required to reduce the iron oxide in the shaft furnace. It has a proprietary tubular style design that reforms natural gas across a proprietary catalyst with both the water vapor and CO_2 in the feed gas. Heat for the reforming reactions is supplied by floor fired (burners are on the floor) main burners, which are located on the bottom of the reformer box between tube rows and between the outside tube rows and the reformer wall. The air required for combustion is preheated in the heat recovery system before being directed to the burners with the main air blower. The reformer box is thermally insulated with refractory material. Natural gas-fired auxiliary burners maintain the reformer box temperature during plant idle conditions to minimize both restart time and thermal cycling of the reformer tubes.

Each reformer bay has a separate sized flue gas port to each of the flue gas headers to ensure uniform heat distribution along the reformer length. The flue gas headers are refractory lined and expansion joints are provided between the single sections of the headers to compensate for thermal expansion. The flue gas exiting the reformer box via the flue gas headers flows to the heat recovery system where the waste heat is recovered.

1.1.9 Heat recovery system

The reformer flue gas exits on both sides of the reformer and enters the parallel train heat recovery system. Each parallel system contains combustion air pre-heaters and feed gas pre-heaters, all of which consist of alloy bundle type heat exchangers suspended in the refractory lined heat recovery ducts. The combustion air pre-heaters are designed to preheat the combustion air to about 600 °C in two stages. The feed gas pre-heaters located downstream of the combustion air pre-heater heat the feed gas to approximately 600 °C as well.

The flue gas exits the parallel trains through a common ejector stack which generates the required draft with a single ejector stack fan. The ejector stack is an induced draft (venturi type) flue gas stack. It uses the ejector stack fan to generate sufficient suction to pull the flue gases out of the reformer and through the heat recovery system. The heat recovery system increases the reformer capacity and reduces the net plant energy consumption by approximately 25-30 percent over the first generation designed in the 1960's.

1.1.10 Seal gas and purge gas system

Inert seal gas for the plant, which is used primarily for sealing the top and bottom of the furnace, is provided by the seal gas generation system. This system takes hot reformer flue gas and cools it in a seal gas cooler. The seal gas cooler is a packed bed, direct contact type cooler which cools the reformer flue gas to near ambient temperature. The cooled seal gas is then compressed by a positive displacement type compressor and then cooled in a shell and tube aftercooler to remove the heat of compression. The cooled seal gas passes through a mist eliminator and seal gas dryer. The seal gas dryer is a refrigerant type unit equipped with a stand-by compressor that removes moisture from the wet seal gas. This dry seal gas is then distributed to various plant users.

Part of the dry seal gas is compressed by the purge gas compressors and dried in a desiccant dryer. The dry purge gas is stored in tanks to be used for emergency plant shutdown situations and for small high pressure requirements during normal operation.

1.1.11 Bottom seal gas system

The furnace bottom seal gas system consists of a compressor, a dilution hood, a dust collection scrubber, a fan, and a stack to supply and exhaust seal gas for sealing the bottom of the shaft furnace. The bottom seal gas compressor, a positive displacement run dry type, supplies dry seal gas to the lower seal leg of the shaft furnace at the required pressure. The bottom seal gas is vented through a vent line and collected in the dilution hood, which captures sufficient air to maintain a mixture of gases that remains below minimum explosive limits in the dust collection system. The mixture passes to the dust collection scrubber where entrained dust particles are removed and then the seal gas/air mixture is exhausted through the bottom seal dust collection fan and stack. In the event of an interruption in the seal gas supply, the inert gas generator or the purge gas system supply bottom seal gas while the problem is corrected.

1.1.12 *Inert gas system*

An inert gas system supplies seal gas for the plant in the event that the reformer combustion system is not in operation. This system consists of an inert gas generator where natural gas and air are burned at close to the stoichiometric ratio, so that the product of combustion yields a suitable inert gas with a very low oxygen content. This system is not used under normal operations.

1.1.13 *Machinery and process cooling water system*

The water system consists of a machinery cooling water circuit and a process cooling water circuit. Water system equipment is located outside the Core Plant Area.

The machinery cooling water is a closed circuit that supplies cooling water to all indirect coolers such as burden feeders, rotating equipment lubrication oil, heat exchangers, etc. It consists of circulation pumps, a sump, plate and frame heat exchangers, and a scaling/corrosion inhibitor dosing system. Circulation pumps circulate hot water from the machinery cooling water sump through the heat exchanger on one side while cold process water is pumped through on the other side to cool the machinery cooling water. A head tank is used to supply cooling water to the water cooled furnace equipment.

The process cooling water circuit supplies cooling water to the direct contact coolers and the process users, such as the top gas scrubber and the dust collection systems. It also provides the cooling water for the machinery cooling water heat exchangers. The process cooling water system consists of a sump, circulation pumps, process water cooling towers, and a clarifier system. Dirty, hot process water flows from the users to the clarifier. A dosing system injects a flocculating agent into the clarifier causing particulate matter to settle. Underflow from the clarifier is sent as a slurry to settling ponds for de-watering and overflow is sent to the process water sump. Clean, hot process water flows directly from the users to the process water sump, where it is mixed with the clarifier overflow. The water in the process water sump is cooled by passing through the process water cooling towers.

2.0 EMISSIONS ANALYSIS

This section summarizes the methodologies and emission factors used to calculate GHG emissions for each emission source type included in this project. As outlined in the USEPA document, *PSD and Title V Permitting Guidance for Greenhouse Gases* (USEPA, 2011), GHGs are a regulated NSR pollutant under the PSD major source permitting program. The six GHG pollutants are:

- Carbon dioxide (CO_2);
- Nitrous oxide (N_2O);
- Methane (CH_4);
- Hydrofluorocarbons (HFCs);
- Perfluorocarbons (PFCs); and
- Sulfur hexafluoride (SF_6).

The voestalpine facility will not use or process HFCs, PFCs, or SF_6 in the manufacturing process and does not believe these three compounds will be emitted as a result of the manufacturing process. Therefore, only emissions of CO_2, CH_4, and N_2O were examined for comparison to the PSD thresholds. Emission calculations are included in Appendix A.

For this BACT analysis, total GHG, on a carbon dioxide equivalent (CO_2e) basis has been used. The amounts of CO_2, CH_4, and N_2O were converted to tons of CO_2e using the Global Warming Potential (GWP) factors from Subpart A of Part 98, Table A-1, as shown in the table below.

Table 2-1: Global Warming Potentials [100-Year Time Horizon] from Table A-1 to Subpart A of 40 CFR Part 98

Name	CAS Number	Chemical Formula	Global Warming Potential (100 yr)
Carbon dioxide	124-38-9	CO_2	1
Methane	74-82-8	CH_4	21
Nitrous oxide	10024-97-2	N_2O	310

TABLE 2-2: Summary of voestalpine Facility Emissions Compared to PSD Significant Emission Rates

Pollutant	PSD Significant Emission Rate (TPY)	Facility-Wide Emission Rate (TPY)	Significant Source
Greenhouse Gases (GHG) as CO_2e	100,000	1,814,144	Yes

3.0 REGULATORY REVIEW

The proposed project will be subject to federal and state regulatory requirements as outlined in the following sections. Only those regulations that are potentially applicable to the proposed project were reviewed in this application. The USEPA promulgated a Federal Implementation Plan (FIP) for Texas assuming the PSD permitting authority for large GHG-emitting sources in Texas in accordance with the thresholds established under the Tailoring Rule published on June 3, 2010. All other pollutants are regulated by the Texas Commission on Environmental Quality (TCEQ) under the State Implementation Plan (SIP) and are beyond the scope of this application.

3.1 FEDERAL REGULATIONS

3.1.1 GHG Tailoring Rule

On June 3, 2010, the US Environmental Protection Agency (USEPA) issued a final rule addressing GHG emissions from stationary sources under the Clean Air Act (CAA) permitting programs. This final rule set thresholds for GHG emissions that defined when permits under the Prevention of Significant Deterioration (PSD)/New Source Review (NSR) and Title V Operating Permit programs are required for new and existing industrial facilities.

The GHG PSD Tailoring rule defined a major new source of GHG emissions as emitting 100,000 short tons of CO_2 equivalent (CO_2e) and 100 tons per year (tpy)/250 tpy (depending on the source category) on a mass basis. A major modification under the rule was defined as an emission increase and net emissions increase of 75,000 tpy or more of GHGs on a CO_2e basis and greater than zero tpy of GHGs on a mass basis. For the second phase of the Tailoring Rule, which began on July 1, 2011, PSD requirements for GHGs are triggered for new construction projects that have the potential to emit GHG emissions of at least 100,000 tpy. PSD requirements are triggered for modifications at existing sources only if the existing source's GHG emissions are equal to or greater than 100,000 tpy on a CO_2e basis and equal to or greater than 100 tpy/250 tpy on a mass basis, and the emission increase and net emission increase of GHGs from the modification would be equal to or greater than 75,000 tpy on a CO_2 basis and greater than zero tpy on a mass basis. This application has been prepared because the CO_2e emissions from the voestalpine facility (new construction) will exceed 100,000 tpy.

3.1.2 Mandatory Reporting Rule

Under the Mandatory Reporting Rule (40 CFR Part 98), beginning in 2010, facilities with fuel burning equipment with actual CO_2e emissions greater than or equal to 25,000 metric tpy must submit an annual GHG report that must cover all source categories and GHGs for which calculation methodologies are provided in subparts of the rule. The voestalpine facility will report GHG emissions under 40 CFR Part 98 as applicable.

4.0 BEST AVAILABLE CONTROL TECHNOLOGY (BACT) ANALYSIS

This application presents a full "top-down" BACT analysis. Under Title 30 of the Texas Administrative Code (TAC) Chapter 116, BACT shall be applied to reduce or eliminate air emissions from a new or modified facility. The TCEQ utilizes a tiered BACT analysis in implementing PSD and state BACT requirements. PSD BACT is applicable to all pollutants that are subject to PSD review. State-only BACT is applicable to all other pollutants which are emitted from a new or modified facility.

Federal BACT is defined in 30 TAC 116.160 and 40 CFR 52.21(b)(12) as:

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

State BACT is defined in 30 TAC 116.10(1) as:

> *"An air pollution control method for a new or modified facility that through experience and research, has proven to be operational, obtainable, and capable of reducing or eliminating emissions from the facility, and is considered technically practical and economically reasonable for the facility. The emissions reduction can be achieved through technology such as use of add-on control equipment or by enforceable changes in production processes, systems, methods or work practice."*

The USEPA guidance document, *PSD and Title V Permitting Guidance for Greenhouse Gases* (EPA 457/B-11-001), recommends the use of the five-step "top-down" BACT process established in the 1990 draft guidance *New Source Review Workshop Manual* to evaluate and select BACT for GHG. This process requires identification and consideration of available control technologies. The applicant must then demonstrate control technologies that are infeasible due to engineering constraints. All remaining technologies are ranked in order of descending order of control effectiveness. The top-ranked control option must be selected unless the applicant can demonstrate that it is not viable due to adverse economic or environmental impacts. If the most effective technology is not selected, then the most effective alternative should be evaluated until an option is selected as BACT.

4.1 KEY STEPS IN A TOP-DOWN BACT ANALYSIS

The five basic steps of a "top-down" BACT analysis are listed below:

Step 1: Identify potential control technologies;
Step 2: Eliminate technically infeasible options;
Step 3: Rank remaining control technologies by control effectiveness;
Step 4: Evaluate the most effective controls and document results; and
Step 5: Select BACT.

These steps are discussed in more detail below.

Step 1 – Identify Potential Control Technologies

The first step is to identify potentially "available" control options for each emission unit and for each pollutant under review. Available options should consist of a comprehensive list of those technologies with a potentially practical application to the emissions unit in question. The list should include lowest achievable emission rate (LAER) technologies, innovative technologies, and controls applied to similar source categories.

For this analysis, the following types of information were researched:

- USEPA's RACT/BACT/LAER Clearinghouse (RBLC) database;
- Federal and state air quality permits;
- Technical books and articles; and
- Guidance documents.

Step 2 – Eliminate Technically Infeasible Options

The second step is to eliminate technically infeasible options from further consideration. To be considered feasible, a technology must be both available and applicable. It is important in this step that any presentation of a technical argument for eliminating a technology from further consideration be clearly documented based on physical, chemical, engineering, and source-specific factors related to safe and successful use of the controls.

Step 3 – Rank Remaining Technically Feasible Control Options

The third step is to rank the technologies not eliminated in Step 2 in order of descending control effectiveness for each pollutant of concern. If the highest ranked technology is proposed as BACT, it is not necessary to perform any further technical or economic evaluation, except for the environmental analyses.

Step 4 – Evaluate Remaining Control Technologies

The fourth step entails an evaluation of energy, environmental, and economic impacts for determining a final level of control. The evaluation begins with the most stringent control option and continues until a technology under consideration cannot be eliminated based on adverse energy, environmental, or economic impacts.

Step 5 – Selection of BACT

The fifth and final step is to select as BACT the most effective of the remaining technologies under consideration for each pollutant of concern. BACT must, as a minimum, be no less stringent than the level of control required by any applicable New Source Performance Standard (NSPS) and National Emission Standard for Hazardous Air Pollutants (NESHAP) or state regulatory standards applicable to the emission units included in the PSD permit application.

This BACT analysis provides background information on potential control technologies, a summary of technology determinations contained in the RBLC database for similar emission units, a discussion of other potential control options that may be applicable to the emission units, and descriptions of proposed BACT emission limits.

Each of the steps listed above have been evaluated in detail for each project-related emissions source combination in the following sections.

In accordance with 40 CFR 52.21(b)(12), an initial review of applicable NSPS regulations was performed in order to ensure that no technology or process less stringent than an applicable NSPS could be identified as BACT. Currently, there are no NSPS rules that apply specifically to direct reduction ironmaking facilities. The NSPS for Stationary Compression Ignition Internal Combustion Engines, 40 CFR 60 Subpart IIII, does apply to sources in the voestalpine facility; however, this rule does not contain limitations that would effectively reduce GHG emissions. Thus, the NSPS program does not create a technology floor for the review of BACT for emissions of GHG gases.

A review of applicable NESHAP regulations was also performed in order to ensure that no technology or process less stringent than an applicable maximum achievable control technology (MACT) standard could be identified as BACT. Currently, there are no MACT rules that apply specifically to direct reduction ironmaking facilities. The NESHAP for Stationary Reciprocating Internal Combustion Engines (RICE) (40 CFR 63 Subpart ZZZZ) will apply to sources at the voestalpine facility; however, this rule does not contain limitations that would effectively reduce GHG emissions. Thus, the NESHAP and MACT program do not create a technology floor for the review of BACT for emissions of GHG gases.

4.2 *GREENHOUSE GAS EMISSIONS*

CO_2 emissions occur as a by-product of burning fossil fuels and biomass, as well as from land-use changes and other industrial processes. CO_2 is formed through the complete oxidation of organic material. All fossil fuels contain significant amounts of carbon, and during combustion, the fuel carbon is oxidized into carbon monoxide (CO) and CO_2. Full oxidation of fuel carbon to CO_2 is desirable because CO has long been a regulated pollutant with established adverse health impacts, and because full combustion releases more useful energy within the process, maximizing energy conservation and efficiency.

CH_4 emissions result from incomplete combustion. Incomplete combustion can also result in emissions of PM, CO, and organic hazardous air pollutants (HAP). CH_4 emissions can be reduced by operating combustion processes with higher flame temperatures and higher excess oxygen levels. Available control technologies for the control of CH_4 emissions are the same as for the control of CO and VOC emissions, and include good combustion practices, oxidation catalysts, and thermal oxidation. Unfortunately, techniques for reducing CH_4 emissions can increase NO_x emissions. Consequently, achieving low CH_4 and low NO_x emission rates is a balancing act in combustion process design and operation. Because CH_4 emissions are a small fraction of the GHG emissions produced at the voestalpine facility, installing controls for CH_4 emissions alone would not be cost-effective.

N_2O emissions result primarily from low temperature combustion (between temperatures of 900 to 1,700°F). N_2O is formed from volatile nitrogen species (HCN) originating from fuel nitrogen, char nitrogen, and by heterogeneous reactions of nitrogen on the char surface. Therefore, the amount of char and the amount of fuel nitrogen have a significant effect on N_2O emissions. N_2O emissions are usually higher for geologically older fuels. Other sources of N2O emissions include NO_x control systems, such as conventional selective catalytic reduction (SCR) systems and selective non-catalytic reduction (SNCR) systems, which may produce N_2O emissions. Therefore, N_2O emissions may be reduced by not using these systems for the control of NO_x emissions. Because N_2O emissions are a small fraction of the GHG emissions produced at the voestalpine facility, installing controls for N_2O emissions alone would not be cost-effective.

4.3 *DESCRIPTION OF GHG CONTROL TECHNOLOGIES*

Potential control options are addressed for CO_2 below. Because the primary GHG emitted by the voestalpine facility will be CO_2, the control technologies and measures presented in this section focus on CO_2 control technologies.

4.3.1 *CO_2 Control Technologies*

In the USEPA document, *PSD and Title V Permitting Guidance for Greenhouse Gases* (USEPA, 2011), potentially applicable control alternatives have been identified and evaluated according to the following three categories: inherently lower-emitting processes/management practices and methods/system designs; add-on controls; and combinations of inherently lower emitting processes/practices/designs and add-on controls. The BACT analysis should consider potentially applicable control techniques from these three categories in order to capture a broad array of potential options for pollution control. However, USEPA has recognized that:

> "*a ... list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant.*" (USEPA, 2011, p. 26)

A series of white papers have been developed by the USEPA that summarize readily available information on control techniques and measures to mitigate GHG emissions from specific industrial sectors. These white papers are intended to provide basic information on GHG control technologies and reduction measures in order to assist regulatory agencies and regulated entities in implementing technologies or measures to reduce GHGs under the CAA, particularly in permitting under the PSD program and the assessment of BACT. Of interest for this BACT analysis, USEPA has developed a white paper for iron and steel manufacturing, *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Iron and Steel Industry* (USEPA, 2012).

4.3.2 *Available Technologies for Reducing GHG Emissions in the Iron and Steel Industry*

The available control measures that are identified in the USEPA iron and steel white paper for reducing GHG emissions from iron and steel manufacturing can be categorized under the following energy efficiency measures:

- Reductions in fuel consumption, which reduce the direct emissions of GHG from the facility; and
- Reductions in electricity usage, which reduce the indirection emissions of GHG (i.e., power plant emissions).

Table 4-1 shows possible energy efficiency improvements that can be made to reduce fuel consumption and also indicates whether these technologies are potentially applicable to the voestalpine facility.

Table 4-1 Possible Energy Efficiency Improvements (Reduced Fuel Consumption) at voestalpine

Control Measure*	Comment	Applicable at voestalpine facility?
Transport System Efficiency Improvements	Mechanical conveyor systems typically use less energy than pneumatic systems.	Yes, mechanical conveyors will be used where practical. Pneumatic conveyors will be used for fine materials.
Process Control and Management Systems	Automated control systems can be used to maintain operating conditions at optimum levels.	Yes, process control and management systems are planned. Yes, production planning will be optimized to reduce waste. Yes, controls will be used for temperature regulation in process equipment.
Refractory Material Selection	The refractory material lining the shaft furnace is the primary insulating material.	Yes, shaft furnace will be lined on the inside with abrasion resistant and insulating brickwork / castables thereby keeping the heat losses at a minimum. The discharge zone consists of the refractory lined shaft furnace cone equipped with hydraulically operated burden feeders and a flow aid insert, to aid the flow of the material within the cone.
Insulation	Insulation is important to keep heat loses from equipment to a minimum.	Yes, the shaft furnace will be well insulated to reduce energy losses to the surroundings.
Heat Recovery from Process Streams and Waste-Heat Recovery from Cooling Water	Exhaust streams with significant amounts of heat energy can be recovered for other heating purposes.	Yes, the reformer flue gas exits on both sides of the reformer and enters the parallel train heat recovery system. The heat recovery system increases the reformer capacity and reduces the net plant energy consumption by approximately 25-30%. Each parallel system contains combustion air preheaters and feed gas preheaters. The preheaters consist of alloy bundle type heat exchangers suspended in the refractory lined heat recovery ducts. The combustion air preheaters are designed to preheat the combustion air to about 600 °C in two stages. The feed gas preheaters are located downstream from the hot combustion air preheaters.
Use of Preheaters	Preheaters allow higher energy transfer efficiency and lower fuel requirements.	Yes, Feed Gas is preheated prior to entering the reformer.

* List of control technologies is adapted from USEPA's white paper for the Portland cement industry (USEPA, 2010).

Additional energy efficiency improvements can be made by effectively managing the electricity used in facility operations. Table 4-2 lists the possible energy efficiency improvements that are potentially applicable to the voestalpine facility.

Table 4-2: Possible Energy Efficiency Improvements (Reduced Electricity Usage) at voestalpine

Control Measure*	Comment	Applicable at voestalpine facility?
Preventive Maintenance	Training programs and good housekeeping programs can help to decrease energy consumption throughput the facility.	Yes, a preventive maintenance program will be implemented, along with training and good housekeeping programs.
Energy Monitoring and Management System	Energy monitoring and management systems provide for optimal energy recovery and distribution between processes.	Yes, energy monitoring and management systems will be used.
High Efficiency Motors	Energy efficiency opportunities for all motor systems can optimize overall performance. A motor management plan can reduce electricity use and save in energy and maintenance costs.	Yes, NEMA motors will be used for all motors over 50 hp.
Variable Speed Drives (VSDs)	Variable speed drives can reduce energy consumption and therefore reduce CO_2 emissions.	Yes, VSDs will be used for controlling and optimization of process.
High Efficiency Fans	High efficiency fans may reduce power consumption.	Yes, potentially applicable for other fans.
Optimization of Compressed Air Systems	Implementing a comprehensive maintenance plan for compressed air systems and other efficiency improvements can reduce energy consumption.	Yes, voestalpine plans to implement a maintenance plan for compressed air systems and other efficiency improvements.
Lighting System Efficiency Improvements	Automated lighting controls and lights with more efficient bulbs can reduce energy use.	Yes, voestalpine plans to use automated lighting controls and lights with more efficient bulbs.

* List of control technologies is based on USEPA's white paper for iron and steel manufacturing (USEPA, 2012).

Some of these control technologies are technically feasible, though high capital costs could outweigh the expected energy savings. The voestalpine facility will implement energy efficient processes and will use energy efficient electric equipment (motors and fans) and controls where feasible and practical to reduce energy consumption.

4.3.3 *Emerging Technologies for Reducing GHG Emissions in the Iron and Steel Industry*

Significantly, the USEPA white paper for the iron and steel industry identifies integrated DRI/EAF steelmaking as a "near-term" technology for GHG reduction because this approach provides a considerable reduction in CO_2 emissions relative to traditional steelmaking. Examples of DRI/EAF integrated steelmaking are presented in the white paper as follows:

> *Essar's Integrated DRI/EAF Steelmaking:* The Essar Group acquired Minnesota Steel in late 2007 and was constructing a steel-making facility in Minnesota that will convert iron ore to steel product at the mine site;

however, construction has been halted due to economic reasons. This new plant will produce DRI pellets, most of which will be processed in electric arc furnaces (EAF) to produce steel slabs. This DRI/EAF integrated steel-making route requires less energy and produces lower emissions than traditional integrated iron and steelmaking. A DOC 2008 report claims a 41% reduction in CO_2 emissions relative to traditional steelmaking.

Nucor's DRI Iron and Steel Production Facility: In early 2011, Nucor Corporation began construction of an iron and steel complex in Louisiana that will include a pig iron operation utilizing a DRI furnace, along with a pellet operation, blast furnace, coke ovens, and a steel mill. Upon start-up, this facility will be the first DRI facility in the U.S. The PSD permit for this facility was the first to go through the GHG BACT review process in the US (in 1st quarter 2011).

Energy consumption in iron and steel making is considerable, and CO_2 is generated when energy is consumed. Emissions of CO_2 in iron and steel processes are related to three main factors: providing sufficient temperatures in order to carry out chemical reactions and physical treatment needed; providing a reductant (mainly CO) in order to reduce iron oxide; and providing power and steam necessary to run the steelworks.

DRI (also known as sponge iron) offers an alternative steel production route. In the DRI process, iron ore is reduced in its solid state, without forming a liquid metal during reduction. DRI can then be transformed to steel in electric arc furnaces (EAFs). DRI production is common in the Middle East, South America, India, and Mexico. The main benefit of a DRI plant (compared to a blast furnace or other traditional approach) is that a DRI plant uses natural gas (or possibly coal) as a fuel instead of coke, which significantly reduces emissions. To a certain extent, direct reduction (DR) can be an option to reduce CO_2 emissions (IPPC, 2012, p. 15).

Natural gas and coal are the two main fuels used in global DRI production. Most of the global DRI plants (more than 90% in 2007) use (lower grade) natural gas, but coal is primarily used at DRI plants in India. Typical energy consumption for natural gas-based DRI production has been reported as 10.4 GJ/t-DRI (IEA, 2007, p. 132-133) or as a range from 10.5 to 14.5 GJ/t-DRI (IPPC, 2012, p. 534), while the energy consumption for coal-based DRI production is considerably higher (20 to 25 GH/t-DRI) (IEA, 2007, p. 132-133). Natural gas-based DRI production results in lower CO_2 emissions than coal-based DRI production, with emissions ranging from 0.77 to 0.92 ton of CO_2 per ton of steel, depending on the type of electricity used (IEA, 2007, p. 132). In comparison, blast furnace ironmaking produces emissions ranging from approximately 1.6 to 2.2 tons of CO_2 per ton of steel (Midrex, 2012). Therefore, use of the DRI process results in far lower CO_2 emissions than conventional methods.

The most common technologies (83% of the market in 2007) used for natural gas-based DRI production are Midrex and HYL III (IEA, 2007. p.132). At this time, voestalpine has not selected a reformer supplier. Brief summaries of the Midrex and HYL DR processes are provided below.

Midrex Technologies, Inc. (Midrex) designs and builds commercial high-temperature, near-stoichiometric CO_2 reformers that produce a high-quality reformed gas that can be fed directly to a DR shaft furnace. In the past 40 years, Midrex has supplied more than 70 MIDREX Reformers for projects around the world (http://www.midrex.com). To maximize the reformer's efficiency, offgas from the shaft furnace is recycled and blended with fresh natural gas, which is then fed to the reformer (a refractory-lined chamber containing alloy tubes filled with catalyst), where it is heated and reformed as it passes through the tubes. The newly reformed gas, containing 90-92 percent H_2 and CO (dry basis), is then fed hot directly to the shaft furnace as reducing gas. The thermal efficiency of the MIDREX® Reformer is greatly enhanced by a heat recovery system in which heat is recovered from the reformer flue gas to preheat the feed gas mixture and the burner combustion air. The use of recycled gas and the ability to feed hot reformed gas to the shaft furnace without quenching and reheating provide for a very efficient process.

Tenova HYL has developed the ZR process with no external gas reformer. This innovative DR technology represents the most advanced state of the art in DR plant design, operation, environmental friendliness, and economy. In the past 50 years, Tenova HYL has supplied more than 40 DR modules worldwide (http://www.tenovagroup.com).

4.3.4 *Long-Term Opportunities for Reducing GHG Emissions in the Iron and Steel Industry*

Other "long-term opportunities" are identified in the USEPA white paper as possible emerging techniques to reduce CO_2 emissions in the iron and steel industry as follows: electrolysis; HIsarna with carbon capture and storage (CCS); and carbon capture and storage (CCS). Of these, only CCS could be an applicable control option for DRI plants.

CCS can make a contribution to the overall GHG reduction effort by reducing the emissions of CO_2 from the use of fossil fuels. Most of the technologies needed for CCS are being used in a variety of industries, but are yet to be widely applied to power generation and industry at a commercial scale. There are also certain industries, such as iron and steel manufacturing and cement production, where CCS is often the only solution for substantial emission reductions (Global CCS Institute, 2012). CCS is the long-term isolation of fossil fuel CO_2 emissions from the atmosphere through capturing and storing the CO_2 deep in the subsurface of the Earth. CCS is made up of three key stages:

1. Capture: Carbon capture is the separation of CO_2 from other gases produced when fossil fuels are combusted to generate power and in other industrial processes. Three main processes are being developed to capture CO_2 from power plants that use coal or gas. These are: pre-combustion capture; post-combustion capture; and oxyfuel combustion capture.

   Pre-combustion capture is mainly applicable to gasification plants, where coal is converted into gaseous components by applying heat under pressure in the presence of steam and sub-stoichiometric O_2. This technology has not been demonstrated for DRI plants.

   Post-combustion capture of CO_2 using solvent scrubbing, typically using monoethanolamine (MEA) as the solvent, is a commercially mature technology; however, this technology has not been demonstrated for DRI plants.

   Oxy-combustion is the process of burning a fuel in the presence of pure or nearly pure oxygen instead of air. Fuel requirements for oxy-combustion are reduced because there is no nitrogen component to be heated, and the resulting flue gas volumes are significantly reduced. This technology has not been demonstrated for DRI plants.

   In industries such as steel mills and cement plants, capture processes have not been developed at a large scale, but an existing capture method could be tailored to suit the particular production process. For instance, collection of CO_2 from cement plants uses post-combustion capture, and collection from modified steel manufacturing processes uses a type of oxyfuel combustion.

2. Transport: After separation, CO_2 is compressed to make it easier to transport and store. It is then transported to a suitable geologic storage site. Today, CO_2 is being transported by pipeline, by ship, and by road tanker.

3. Storage: At a storage site, CO_2 is injected into deep underground rock formations, often at depths of 1 km or more. Appropriate storage sites include depleted oil fields, depleted gas fields, or rock formations which contain a high degree of salinity (saline formations). These storage sites generally have an impermeable rock above them, with seals and other geologic features to prevent CO_2 from returning to the surface. (Global CCS Institute, 2012) Monitoring, reporting, and verification are important to demonstrate that CO_2 is safely stored.

The Global CCS Institute identified 75 large-scale integrated projects (LSIPs) world-wide as of September 2012: 16 projects are currently in construction or operating; and 59 projects are in planning stages. This reflects a net change in the number of projects from the 2011 report (Global CCS Institute, 2011) of one: nine new projects were identified in 2012, while eight were cancelled or put on hold or restructured. These large-scale projects involve the capture, transport, and storage of greater than 800,000 tonnes of CO_2 annually for coal-fired power plants or greater than 400,000 tonnes of CO_2 annually for emission-intensive industrial facilities (Global CCS Institute, 2012). The majority of these projects are in the power generation industry, with 40 LSIPs totaling more than 70 million tonnes per annum (Mtpa) in potential CO_2 capture capacity. However, it should be noted that none of these projects are in the iron and steel sector. The US LSIPs are summarized in Table 4-3 below.

Table 4-3. Large-Scale Integrated Projects for CO_2 Carbon Capture and Storage in the US

Project Name and Industry*	Capture Type	Volume CO2 (Mtpa)	Transport	Storage Type	Date of Operation
CURRENTLY OPERATING					
Val Verde Gas Plant Natural gas processing	Pre-combustion	1.3 Mtpa	Val Verde Pipeline, operated by Sandridge TX, 132-134 km	EOR	1972
Enid Fertilizer CO_2-EOR Project Fertilizer production	Pre-combustion	0.68 Mtpa	Enid-Purdy Pipeline, operated by Merit OK, 188-225 km	EOR	1982
Shute Creek Gas Processing Facility Natural gas processing	Pre-combustion	7 Mtpa	Schute Creek Pipeline, operated by Exxon, Chevron Texaco, Andarko WY, 190 km	EOR	1986
Great Plains Synfuel Plant and Weyburn – Midale Project Synthetic natural gas	Pre-combustion	3 Mtpa	Onshore to onshore pipeline 315 km	EOR	2000
Century Plant Natural gas processing	Pre-combustion	5 Mtpa (+3.5 Mtpa in construction)	Onshore to onshore pipeline 256 km	EOR	2010
CURRENTLY PLANNED					
Air Products Steam Methane Reformer EOR Project Hydrogen production	Post-combustion	1 Mtpa	Green Line Pipeline, operated by Denbury LA to TX, 101-150 or 411 km	EOR	2012

Project Name and Industry*	Capture Type	Volume CO2 (Mtpa)	Transport	Storage Type	Date of Operation
Lost Cabin Gas Plant Natural gas processing	Pre-combustion	1 Mtpa	Greencore Pipeline, operated by Denbury MT to WY, 373 km	EOR	2012
Illinois Industrial CCS Project Chemical production (ethanol)	Industrial separation	1 Mtpa	Onshore to onshore pipeline	Onshore deep saline formations	2013
Kemper County IGCC Project Power generation	Pre-combustion	3.5 Mtpa	Sonat Pipeline, operated by Denbury MS, 75-80 km	EOR	2014
OTHER					
Coffeyville Gasification Plant Fertilizer production	Pre-combustion	0.85 Mtpa	Onshore to onshore pipeline KS, 112 km	EOR	2013
Lake Charles Gasification Synthetic natural gas	Pre-combustion	4.5 Mtpa	Green Line Pipeline operated by Denbury LA to TX, 441 km	EOR	2014
Medicine Bow Coal-to-Liquids Facility Coal to liquids (CTL)	Pre-combustion	3.6 Mtpa	Greencore Pipeline planned extension, operated by Denbury WY	EOR	2015
NRG Energy Parish CCS Project Power generation	Post-combustion	1.4-1.6 Mtpa	Onshore to onshore pipeline TX	EOR	2015
Texas Clean Energy Project Power generation	Pre-combustion	2.5 Mtpa	Central Basin Pipeline, operated by Kinder Morgan TX, 50-230 km	EOR	2015
Hydrogen Energy California Project (HECA) Power generation	Pre-combustion	3 Mtpa	Onshore to onshore pipeline CA, 6.4 km	EOR	2017
PurGen One Power generation	Pre-combustion	2.6 Mtpa	Onshore to onshore pipeline NJ, 160 km	Offshore deep saline formations	2017

Project Name and Industry*	Capture Type	Volume CO2 (Mtpa)	Transport	Storage Type	Date of Operation
Taylorville Energy Center Power generation	Pre-combustion	1.92 Mtpa	Onshore to onshore pipeline IL, 8 km	Onshore deep saline formations	2017
Tenaska Trailblazer Energy Center Power generation	Post-combustion	5.75 Mtpa	Onshore to onshore pipeline TX, 201-250 km	EOR	Not specified
Cash Creek Generation Power generation	Pre-combustion	2 Mtpa	Onshore to onshore pipeline KY	EOR	2015
Indiana Gasification Synthetic natural gas	Pre-combustion	4.5 Mtpa	Onshore to onshore pipeline IN	EOR	2015
Mississippi Gasification (Leucadia) Synthetic natural gas	Pre-combustion	4 Mtpa	Free State Pipeline, operated by Denbury MS, 138-176 km	EOR	2015
Riley Ridge Gas Plant Natural gas processing	Pre-combustion	2.5 Mtpa	Onshore to onshore pipeline WY	EOR	2015
FutureGen 2.0 Oxy Combustion Large Scale Test Power generation	Oxyfuel combustion	1.3 Mtpa	Onshore to onshore pipeline IL, <50 km	Onshore deep saline formations	2016
Quintana South Heart Project Power generation	Pre-combustion	2.1 Mtpa	Onshore to onshore pipeline ND	EOR	2017
Kentucky NewGas Synthetic natural gas	Pre-combustion	5 Mtpa	Onshore to onshore pipeline KY	Various options being considered	2018

Of course, adding CCS to any process increases capital costs, as well as ongoing operating and maintenance costs. The costs and status of a few large US projects are summarized below:

- For the Air Products' new hydrogen plant in Port Arthur, Texas, which will capture CO_2 and transport it via the Denbury Green Pipeline, construction began in August 2011, and the plant is expected to become operational by the end of 2012. The **$430 million** project will retrofit CO_2 capture technology onto two steam methane reformers used to produce hydrogen at a Valero Energy Corp. refinery in Port Arthur, Texas, and will capture one million tons of CO_2 annually for use in enhanced oil recovery (EOR) operations in Texas oilfields (GHG Monitor, 2012).

- Archer Daniels Midland's CCS Project in Decatur, IL, is expected to be operational by the second half of 2013. This **$208 million** project will capture one million tons of CO_2 annually from ADM's currently existing ethanol plant for sequestration in the Mount Simon sandstone formation. This project will incorporate knowledge gained from a nearby sister CO_2 injection project (managed through one of USDOE's regional partnerships) that has been in operation since November 2011 (GHG Monitor, 2012a).
- Leucadia's Lake Charles CCS Project is an industrial project being funded by the USDOE. The **$436 million** project will construct a greenfield petroleum coke-to-chemicals gasification plant with carbon capture that will produce methanol near Lake Charles, LA. The project will then be linked up to Denbury Resource's existing Green CO_2 pipeline, which will transport more than four million tons of CO_2 captured annually to EOR operations in Texas' West Hastings oil field.
- The Texas Clean Energy Project (TCEP) is a 400 MW 'polygen' IGCC plant being developed by Summit Power Group, LLC, which is currently in negotiations with a Chinese bank for financing of the **$2.9 billion** project set for west Texas. Progress on the project has been steady since a long-term CO_2 sales agreement was signed with Whiting Petroleum Corporation last year. This plant and potentially two others (GHG Monitor, 2012b) will be built in close proximity to depleted oilfields, eliminating the need for long pipelines that can often run as much as $2 million per mile.

For the global iron and steel industry, the following approaches are underway as pilot projects to control GHG emissions (Bellona, 2012):

- In Europe, 48 companies and organizations from 15 countries have launched a co-operative R&D project under the Ultra-Low CO_2 Steelmaking (ULCOS) consortium. One of them is the ArcelorMittal & ULCOS joint project on steel-CCS, where post-combustion CO_2 capture will be applied on a steel plant. The project has applied for NER300 funding and was submitted by the French Government to the European Investment Bank in May 2011;
- Small-scale demonstrations of CO_2 capture from processes such as DRI, HIsarna, and oxyfuel are being developed in France, Germany, the Netherlands, Sweden, and the United Arab Emirates.

The DRI process involves conversion of iron ore to iron through the use of a reduction gas (usually natural gas) chemically converted to hydrogen and CO. Potential capture of CO_2 can be done through pre-combustion (gasification), PSA (pressure swing absorption) or VPSA (Vacuum PSA) or chemical absorption.

The HIsarna steelmaking process combines twin screw reactors, smelting and cyclone converter furnace technologies. It operates using pure oxygen instead of air, resulting in a top gas that is nitrogen-free and has a high concentration of CO_2. HIsarna equipped with CCS could capture approximately 80% of the CO_2 process from producing liquid iron from iron ore and coal. Capture technologies are PSA or VPSA. A HIsarna pilot plant is under construction in IJmuiden, the Netherlands (Bellona, 2012).

4.3.5 *CH_4 Control Technologies*

Available control technologies for the control of CH_4 emissions are the same as for the control of CO and VOC emissions, and include good combustion practices, oxidation catalysts, and thermal oxidation. Techniques for reducing CH_4 emissions can increase NO_x emissions. Consequently, achieving low CH_4 and NOx emission rates is a balancing act in combustion process design and operation. Because CH_4 emissions will be a small fraction of the GHG emissions produced, installing controls for CH_4 alone would not be cost-effective.

4.3.6 *N_2O Control Technologies*

The control of N_2O emissions is primarily achieved through combustion controls. In addition, post combustion catalyst systems including SCR, and NCSR, and thermal destruction control systems may reduce N_2O emissions. However, NO_x control systems including conventional SCR systems and SNCR systems, may produce N_2O emissions. Therefore, N_2O emissions may be reduced by not using these systems for the control of NO_x emissions. Because N_2O emissions will be a small fraction of the GHG emissions produced, installing controls for N_2O emissions alone would not be cost-effective.

4.4 *SUMMARY OF PROPOSED BACT*

A summary of the proposed voestalpine facility GHG emissions is presented in Table 4-4. Proposed monitoring strategy is to determine compliance based on total natural gas consumption divided by total HBI production (including regular and off-spec DRI product). voestalpine proposes to monitor CO_2e emissions on the basis of a 12-month rolling total. Fuel analyses will be conducted as required to demonstrate practical enforceability.

TABLE 4-4: Summary of Proposed GHG BACT Determinations for voestalpine

Company, Date	Process Description	Emission Limits	Control Type and Efficiency
voestalpine 2013	Facility-Wide	Proposed BACT-PSD CO_2e Limit – 1,814,144 tpy facility-wide.	No add-on controls.
voestalpine 2013	Reformer Main Flue Ejector Stack, Emission Source 29	Proposed BACT-PSD: CO_2e Limit – no more than 13 MMBtu (decatherms) of natural gas/tonne HBI	Energy integration through combustion of spent reducing gas. Use of low-carbon fuel (natural gas). Limit total quantity of natural gas

Company, Date	Process Description	Emission Limits	Control Type and Efficiency
		produced. Compliance based on total natural gas consumption divided by total production (including regular and off-spec DRI product) of the facility on a 12-month rolling total.	consumption per metric ton of product.
voestalpine 2013	Hot Pressure Relief Vent (Flare), Emission Source 38	Proposed BACT-PSD: CO_2e Limit – included in 13 MMBtu (decatherms) of natural gas/tonne HBI produced limit.	Use of natural gas fuel for the flare's pilot and as supplemental fuel (if needed). Good combustion practices and proper maintenance.
voestalpine 2013	Seal Gas Vent, Emission Source 37	Proposed BACT-PSD: CO_2e Limit – included in 13 MMBtu (decatherms) of natural gas/tonne HBI produced limit.	No additional controls feasible.
voestalpine 2013	Emergency Generator, Emission Source 34	Proposed BACT-PSD: CO_2e Limit – 194 tons CO_2e/yr (based on 100 hrs).	Good combustion practices and proper maintenance. Engines must comply with NSPS Subpart IIII based on manufacturer's specifications.
voestalpine 2013	Fire Pump, Emission Source 35	Proposed BACT-PSD: CO_2e Limit –13.8 tons CO_2e/yr (based on 100 hrs).	Good combustion practices and proper maintenance. Engines must comply with NSPS Subpart IIII based on manufacturer's specifications..
voestalpine 2013	Facility-wide	Proposed BACT-PSD: implement energy efficient operations.	Utilize mechanical conveyors, heat recovery, and other energy efficiencies as appropriate to the facility's design.
voestalpine 2013	Facility-wide	Proposed BACT-PSD: implement energy efficient equipment.	Utilize preventive maintenance, energy monitoring and management, high efficiency motors, variable speed drives, high efficiency fans, optimized compressed air systems, and efficient lighting systems as appropriate to the facility's design.

4.5 REFORMER MAIN FLUE EJECTOR STACK

Emission Sources and Process Descriptions

Emission Source	Description
Reformer Main Flue Ejector Stack, Emission Source 29	Spent shaft furnace gas is combusted as fuel in the reformer in order to recover the remaining chemical energy in the gas. Top gas has a low fuel value, about one-fourth that of natural gas, so the fuel is mixed with natural gas to maintain stable combustion by increasing the BTU content of the top gas and to provide enough energy to run the reforming process.

In order to address BACT for emissions of CO_2e from the DRI facility, voestalpine reviewed technologies technically applicable to the production equipment installed at the facility for manufacturing DRI. This section describes a detailed, step-by-step BACT analysis for control of CO_2e emissions from the reformer main flue ejector stack at the voestalpine facility.

Emissions from the reformer main flue ejector stack result from two main processes, the DRI shaft furnace and the reformer.

4.5.1 *CO_2e Emissions from the Reformer Main Flue Ejector Stack – Shaft Furnace*

The shaft furnace is a countercurrent shaft reactor where the reducing gas generated by the reformer reacts with the iron ore to form metallized iron. Although it is called a furnace, combustion does not actually occur within the reactor. The CO and H_2 of the reducing gas scavenge oxygen from the iron oxides in the iron oxide pellets, reducing the oxygenation state of the ores. The resulting products of the reduction process are pure iron, CO_2, and water.

$$Fe_2O_3 + 3\ CO \dashrightarrow 2\ Fe + 3\ CO_2$$

$$Fe_2O_3 + 3\ H_2 \dashrightarrow 2\ Fe + 3\ H_2O$$

The rate at which these reactions occur determines the residence time needed to metallize the iron oxide pellets into DRI product, which typically takes several hours. In the shaft furnace, fresh reducing gas, rich in CO (5%) and H_2 (95%) from the reformer, enters at the bottom of the furnace, while iron oxide pellets are fed from the top, so that the gas flow is countercurrent to the descending iron oxide pellets. As the reduction reaction progresses, CO_2 and water vapor are formed in the gas stream as reaction products. The spent reducing gas then exits the furnace at the top of the furnace and is ducted for recycle to the reformer.

Current DRI process designs release CO_2 from the process gas loop by off-taking a stream of spent reducing gas (also known as top gas) prior to recycle back to the reformer and using this stream as fuel in the reformer. At the top of the shaft furnace, the partially spent reducing gas exits and is recompressed, enriched with natural gas, preheated, and transported back to the gas reformer as follows: After scrubbing and cooling, approximately two-thirds of the clean top gas (now called process gas) flows through a second set of mist eliminators and then to the inlet of the first stage process gas compressor. The process gas compressors are centrifugal type machines specifically selected for the process. These machines are designated the first stage and second stage process gas compressors. After compression, the process gas is mixed with natural gas to form the feed gas for the reformer. Feed gas is preheated prior to entering the reformer. The reformer "reforms" the mixture back to CO and 95% H_2, which is then ready for re-use by the shaft furnace. (This loop is called the process gas loop.)

Although CO_2 is not vented from the reactor directly, it is generated by the reduction reactions in the furnace. Therefore, the efficiency of the reactions in the furnace may have an impact on the overall efficiency of the facility, including combustion sources, and thus an impact on total GHG emissions. Recent EPA guidance for GHG BACT indicates that efficiency improvements of the source should be considered in any determination of BACT, and are in fact likely to be primary controls in many cases. BACT considerations for the process gas loop are discussed below.

Step 1 - Identify Potential Control Technologies

A search of USEPA's RBLC database revealed the following entries for the control of CO_2e emissions from the DRI manufacturing process. Documentation compiled in this research is presented in the table below.

TABLE 4-5: Summary of RBLC Data for CO_2e Emissions from DRI Plants

RBLC ID Number Company, Date	Process Description	Emission Limits	Control Type and Efficiency
Consolidated Environmental Management Inc. – Nucor St. James, LA 07/19/2012	Process Heater (to replace Reformer) (DRI-108 – DRI Unit #1)	BACT-PSD: CO_2e Limit – no more than 13 MMBtu (decatherms) of natural gas per metric tonne of DRI (11.79 MMBtu/ton of DRI). Compliance based on total natural gas consumption divided by total production (including regular and off-spec DRI product) of the facility on a 12-month rolling total.	Good combustion practices, acid gas separation system, energy integration.
MN-0085 Essar Steel Minnesota LLC Itasca, MN 05/10/2012	Indurating Furnace Stacks (Waste Gas and Hood Furnace)	BACT-PSD: CO_2e Limit - 710,000 ton/yr 12-month rolling sum.	Energy efficiency measures, such as heat recovery, use of preheaters, etc. Use of lower emitting processes. Good design/ operating practices for furnace. Use of natural gas fuel. CCS deemed technically infeasible.
LA-0248 Consolidated Environmental Management Inc. – Nucor St. James, LA 01/27/2011	Reformer Main Flue Stack (DRI-108 – DRI Unit #1) Reformer Main Flue Stack (DRI-208 – DRI Unit #2) Package Boiler (DRI-109) Package Boiler (DRI-209)	BACT-PSD: CO_2e Limit – no more than 13 decatherms of natural gas per tonne of DRI (11.79 MMBtu/ton of DRI). Compliance based on total natural gas consumption divided by total production (including regular and off-spec DRI product) of	Good combustion practices, acid gas separation system, energy integration.

RBLC ID Number Company, Date	Process Description	Emission Limits	Control Type and Efficiency
		the facility on a 12-month rolling total.	
MN-0070 Minnesota Steel Industries, LLC 09/07/2007	DRI Plant	BACT-PSD: CO_2e Limit – None.	No requirement for GHG controls.

The following technologies and innovative processes were identified as potential control measures for CO_2e emissions associated with the shaft furnace.

1. Process Gas Carbon Capture with Dedicated Sequestration
2. Process Gas Carbon Capture with Transport and Sequestration

A description of each of the identified technologies or processes is presented below.

Process Gas Carbon Capture with Dedicated Sequestration

In evaluating the use of natural gas as a raw material, an inefficient DRI process will consume large volumes of natural gas for each ton of DRI produced, while an efficient process will operate closer to theoretical limits of DRI/natural gas ratios. These theoretical limits are based upon the stoichiometry of the reduction reaction.

One means of reducing natural gas consumption is to remove the oxygen that is being freed from the iron oxide ore from the process gas loop of the reducing gas. This oxygen, in the form of CO_2 and water vapor, inhibits the reaction of CO and H_2 with the oxygen of the ore when either or both are present at high levels. While some CO_2 and water vapor are necessary in the reactions of the reformer, the removal of excess CO_2 and water vapor in the system will improve overall efficiency.

Current DRI process designs release CO_2 and water vapor from the process gas loop by off-taking a stream of spent reducing gas (prior to recycle back to the reformer) and using this stream as fuel in the reformer. The DRI process inherently removes water vapor from the spent reducing gas being recycled to the reformer in a quench step. As the gas is cooled, its capacity to hold water is reduced, and the water is captured in the process water system.

As an acid gas, CO_2 can be separated from certain gas streams with the use of an amine absorber system. Amine absorption has been in use for many years on smaller scales, typically for the treatment of hydrogen sulfide (H_2S, also an acid gas) from gases in the petroleum and natural gas industry. These amine absorber systems, when scaled-up to the flow requirements of the DRI process, have the ability to separate CO_2 from the spent reducing gas leaving the shaft furnace. When this treated tail gas is recycled back to the reformer (and ultimately the shaft furnace), the reducing gas is more efficient in the metallization of iron oxides due to the lower concentration of CO_2. Removing CO_2 from the spent reducing gas used as fuel in the reformer also has the additional benefit of increasing combustion efficiency incrementally.

The amine solution used to absorb CO_2 must be regenerated through heating, typically using a steam reboiler. After treatment for the removal of sulfur compounds such as H_2S, the resulting gas is nearly pure CO_2. This gas stream should require little additional treatment effort to produce pipeline-quality, commercial grade CO_2.

Separating CO_2 from the process gas must be paired with some form of storage, or sequestration, in order for the technology to provide any reduction in CO_2 emissions. In fact, CO_2 separation without storage actually results in an increase in total CO_2 generation, since the separation system has an energy demand as well, in the form of a reboiler for regenerating amine solution rich in CO_2, and electrical needs for system equipment.

Dedicated sequestration involves the injection of CO_2 into an on-site or nearby geological formation, such an active oil reservoir (enhanced oil recovery), a brine aquifer, an unmined coal seam, basalt rock formation, or organic shale bed. Geologic sequestration is being studied in several locations and geologies, with varying results and predictions. Clearly, in order for geologic sequestration to be a feasible technology, a promising geological formation must be located at or very near to the facility location.

Process Gas Carbon Capture with Transport and Sequestration

As described above, CO_2 can be separated from certain gas streams with the use of an amine absorber system. Separating CO_2 from the process gas must be paired with some form of storage, or sequestration, in order for the technology to provide any reduction in CO_2 emissions. In fact, CO_2 separation without storage actually results in an increase in total CO_2 generation, since the separation system has an energy demand as well, in the form of a reboiler for regenerating amine solution rich in CO_2, and electrical needs for system equipment.

Off-site CO_2 sequestration involves utilization of a third-party CO_2 pipeline system in order to transport CO_2 to distant geologic formations that may be more conducive to sequestration than sites in the immediate area. Building such a pipeline for dedicated use by a single facility will almost certainly make any project economically infeasible, from both an absolute and BACT-review perspective. However, such an option may be effective only if both adequate storage capacity exists downstream and reasonable transportation prices can be arranged with the pipeline operator.

Step 2 - Eliminate Technically Infeasible Options

Process Gas Carbon Capture with Dedicated Sequestration

As discussed above, dedicated geological sequestration of CO_2 requires close proximity to a favorable geologic formation. According to the US Department of Energy's (USDOE) National Energy Technology Laboratory (NETL), no basalt formations exist near the project site. The Barnett Shale (Coal Seam) is approximately 360 miles from Corpus Christi based on the distance from Corpus Christi, TX, to Hill, TX, which is included in the 2007 Eastern Extension of the Barnett Shale project.

Saline formations are layers of porous rack that are saturated with brine. The Frio Brine Pilot Experiment is approximately 250 miles from Corpus Christi based on the distance from Corpus Christi, TX, to Dayton, TX. (This project is complete, but it is not known if there will be an expansion or a similar project in the area on a larger scale.) As described by NETL, "less is known about saline formations because they lack the characterization experience that industry has acquired through resource recovery from oil and gas reservoirs and coal seams. Therefore there is an amount of uncertainty regarding the suitability of saline formations for CO_2 storage." Due to the high degree of uncertainty in utilizing saline formations for dedicated CO_2 storage, this type of sequestration has been deemed technically infeasible.

Texas is well known as a major producer of oil and natural gas, and voestalpine researched the sequestration of CO_2 in oil and gas reservoirs through enhanced oil recovery (EOR) techniques. Without a nearby active oil reservoir, or depleted natural gas reservoir, this option becomes technically infeasible.

Step 3 - Rank Remaining Technically Feasible Control Options

1. Process Gas Carbon Capture (15%) with Transport and Sequestration (99%)

The reaction efficiency improvement strategy of removing CO_2 and water vapor from the process gas loop has the potential to reduce overall GHG emissions (almost exclusively CO_2) by 15% or more, on an equal production basis. However, this CO_2 gas stream would have to be transported and sequestered for reducing GHG emissions.

Step 4 - Evaluate Remaining Control Technologies

Process Gas Carbon Capture with Transport and Sequestration

Process gas CO_2 separation has been demonstrated in industry as an effective efficiency improvement measure. The capital cost of incorporating this technology in a new facility is offset by the reduced operational cost of natural gas consumption. The amine solution used to absorb CO_2 and other acid gases from the process stream is regenerable for use over many cycles, and thus does not create an adverse environmental impact. Finally, total energy consumption of the facility is reduced, removing the concern of an adverse energy penalty. Thus, process gas CO_2 separation and water removal can be deemed effective considering potential adverse impacts.

Utilizing a long-distance pipeline to deliver captured CO_2 to sequestration sites would virtually eliminate CO_2 emissions from this source. However, the economic feasibility of transporting CO_2 for sequestration at a distant storage site depends on whether a long-distance pipeline exists within a reasonable distance of the facility in order to make a connection to the system. At this time, there are less than 4,000 miles of CO_2 pipelines currently constructed in the US.

Denbury Resources operates a dedicated CO_2 pipeline -- Green Pipeline –that extends from Louisiana to near Houston, Texas. The nearest branch of this pipeline is approximately 220 miles away from Corpus Christi. The Denbury Resources pipeline system stretches from Jackson Dome in Mississippi, to Donaldsonville, Louisiana, and west to the West Hastings oil field south of Houston, Texas. Naturally occurring CO_2 is extracted from a geologic formation near Jackson Dome and used for EOR in several fields along the pipeline route. Additionally, Denbury has sought out planned industrial projects along the pipeline route to from which to purchase additional CO_2 volumes. The nearest branches of this pipeline system are approximately 220 miles away from the voestalpine facility. Pipeline connections at this distance would cost on the order of millions of dollars, plus the additional cost of compression equipment, and on-going electricity and maintenance requirements.

Denbury has entered into contracts with several industrial projects along its pipeline route which, if constructed, will deliver CO_2 from these industrial sources to the pipeline system for EOR. At least 6,000,000 tons of CO_2 per year will theoretically be sequestered in this fashion, should all of these projects come to fruition. However, it should be noted that these are voluntary contracts entered into by for-profit companies without any sort of regulatory driver. An agreement of value can therefore be reached by the parties, since the option to walk away from the contract remains to both sides. The imposition of operating permit requirements to this sort of negotiation would fundamentally alter the relationship between the parties, and the economics of the transaction being negotiated.

An operating permit requirement, such as a BACT determination, requiring a facility to contract with a single third-party for specific services places the facility in an untenable economic position. Denbury is a for-profit, publically traded company, which has a fiduciary responsibility to obtain the best return for its shareholder as possible, just like any other for-profit enterprise. A BACT requirement conditioning the voestalpine facility's operation on the use of the Green Line pipeline would place Denbury in the position of being a natural monopoly such as a utility, upon whose services voestalpine would depend for the operation of the DRI facility. However, Denbury's pipeline operations are not currently considered to be such a utility and are not regulated. Without regulation as a utility, Denbury could exact any price it wished to allow access to the pipeline and use denial of such access rights as a tool in any negotiations. These facts make the use of this third-party pipeline economically infeasible. Even if an equitable contract could be agreed to in the short term, the supply/demand relationship imposed by a permit requirement would make the voestalpine project completely unviable as a long-term investment. Therefore, the use of a third-party pipeline for transport of CO_2 to distant sequestration sites is deemed to be economically infeasible.

If use of the Denbury pipeline is considered, the approximate cost for a post-combustion carbon capture and sequestration system can be estimated from the *Report of the Interagency Task Force on Carbon Capture* (August, 2010). CCS is a three-step process that includes the capture of CO_2 from power plants or industrial sources, transport of the captured CO_2 (usually in pipelines), and storage of that CO_2 in suitable geologic reservoirs. Technologies exist for all three components of CCS, but they have not yet been deployed at the scale necessary to help achieve GHG reduction targets. Cost estimates of current technology for CCS in power production range between $60 and $114 per tonne of CO_2 avoided. In this study, costs were provided for CO_2 capture, CO_2 transport, and CO_2 storage as follows:

- CO_2 capture - For a new post-combustion project, costs are estimated at $95/tonne of CO_2.
- CO_2 transport – Recent studies have shown that CO_2 pipeline transport costs for a 100-kilometer (62 mile) pipeline transporting 5 million tonnes per year range from approximately $1 per tonne to $3 per tonne.
- CO_2 storage -Costs associated with CO_2 storage have been estimated to be approximately $0.4 per tonne to $20 per tonne of CO_2.

TABLE 4-6: Approximate Cost for Construction and Operation of a Post-Combustion CCS System at voestalpine

CCS System Component	**Cost ($/ton of CO_2 Controlled)**	**Tons of CO_2 Controlled, Transported, or Stored per Year**	**Total Annual Cost**
CO_2 Capture and Compression Facilities	$86	1,812,279 * 0.90 = 1,631,051	$140,270,395
CO_2 Transport Facilities (per 100 km of pipeline)	$0.91	1,812,279 * 0.90 = 1,631,051	$1,484,256
CO_2 Storage Facilities	$0.36	1,812,279 * 0.90 = 1,631,051	$587,178
Total CCS System Cost	**$87**	**1,631,051**	**$142,341,829**

At approximately $87 per tonne of CO_2 controlled, CCS at the voestalpine facility is found to be economically infeasible.

Step 5 – Selection of BACT

None of the identified technologies remain, having been deemed technically or economically infeasible. BACT is selected as no add-on control.

4.5.2 *CO_2e Emissions from the Reformer Main Flue Ejector Stack – Reformer*

Reducing gas is generated initially from natural gas, which is heated and reformed in the reformer at an elevated temperature. At this elevated temperature, the natural gas dissociates into a reducing gas rich in CO and hydrogen (H_2), which are the primary reductants for the DRI process:

$$CH_4 + CO_2 \rightarrow 2\,CO + 2\,H_2$$

$$CH_4 + H_2O \rightarrow CO + 3\,H_2$$

The reformer generates the hot reducing gas (CO and H_2) required to reduce the iron oxide in the shaft furnace. It has a proprietary tubular style design in which natural gas dissociates into a reducing gas rich in CO and H_2, which are the primary chemicals used to remove the oxygen (O_2) from the iron ore. Heat for the reforming reactions is supplied by floor-fired (burners are on the floor) main burners, which are located on the bottom of the reformer box between tube rows and between the outside tube rows and the reformer wall. The air required for combustion is preheated in the heat recovery system before being directed to the burners with the main air blower. Natural gas-fired auxiliary burners maintain the reformer box temperature during plant idle conditions to minimize both restart time and thermal cycling of the reformer tubes.

CO_2 is born in the fuel gas and simply passes through the combustion process as an inert. Current DRI process designs release CO_2 from the process gas loop by off-taking a stream of spent reducing gas (prior to recycle back to the reformer) and using this stream as fuel in the reformer. After scrubbing and cooling, the other one-third of the cleaned top gas from the scrubber (now called top gas fuel) is mixed with a small amount of natural gas to become the fuel mixture for the reformer main burners. The fuel mixture passes through a mist eliminator to remove water droplets and it is used by the reformer main burners.

This arrangement serves to both allow for an outlet of CO_2 from the process gas and increase the energy efficiency of the reformer through energy integration. While this increases the energy efficiency of the reformer by providing more gases to surround the reformer tubes for heat transfer, the CO_2 is still released to the atmosphere. CO_2 released from the reformer in this manner is mixed with products of combustion and other inert gases, and is not suitable for sequestration. BACT considerations for the flue gas loop are discussed below.

Step 1 - Identify Potential Control Technologies

The following technologies and innovative processes were identified as potential control measures for GHG emissions associated with the reformer.

1. Flue Gas Carbon Capture with Dedicated Sequestration
2. Flue Gas Carbon Capture with Transport and Sequestration
3. Energy Integration through Combustion of Spent Reducing Gas

4. Low-Carbon Fuel (Natural Gas Combustion)
5. Maximized Combustion Efficiency

A description of each of the identified technologies or processes is presented below.

Flue Gas Carbon Capture with Dedicated Sequestration

Flue gas CO_2 separation differs from process gas CO_2 separation, in that the remaining gas is primarily water vapor and nitrogen (N_2) from the combustion air. These gases are both undesirable in the reducing gas used in the shaft furnace, to which the process gas is recycled after CO_2 separation. Therefore, it is inherently necessary to operate separate and distinct systems for separating CO_2 from flue gas and process gas, so that flue gas water vapor and N_2 could be released to the atmosphere instead of mixing with the process gas return.

Flue Gas Carbon Capture with Transport and Sequestration

Flue gas CO_2 separation differs from process gas CO_2 separation, in that the remaining gas is primarily water vapor and N_2 from the combustion air. These gases are both undesirable in the reducing gas used in the shaft furnace, either inhibiting the reduction reaction (water), creating the potential for generating unnecessary criteria pollutant emissions (N_2 converting into NO_X), or increasing energy demand in order to heat unnecessary constituents in the process gas (both). Therefore, it is inherently necessary to operate separate and distinct systems for separating CO_2 from flue gas and process gas, so that flue gas water vapor and N_2 could be released to the atmosphere instead of mixing with the process gas return.

Energy Integration through Combustion of Spent Reducing Gas

Minimizing the use of natural gas fuel is naturally the primary method of reducing GHG emissions from combustion. Energy integration has the most potential for reducing fuel consumption, by reducing wasted energy as much as possible. The DRI process design includes the use of spent reducing gas from the process (known as top gas) as fuel for the process. Top gas contains a large fraction of CO, which retains a residual fuel value. This top gas fuel is mixed with the fuel natural gas, replacing a portion of the needed heat input to the process. This design integrates the energy cycle of the process in order to capture as much residual chemical energy from the shaft furnace gases as possible.

Low-Carbon Fuel (Natural Gas Combustion)

The use of natural gas as a combustion fuel, in preference over other fossil fuels such as oil or coal, results in fewer GHG emissions per unit of energy output. This property has been well documented, and is reflected in 40 CFR Part 98,

Table C-1 (the Mandatory Reporting Rule for Emissions of Greenhouse Gases), where natural gas is ranked as having one of the lowest CO_2 generation rates of any of the fuels listed. Natural gas also has benefits over other fossil fuels from the perspective of other criteria pollutant emissions, such as sulfur oxides (SO_x).

Maximized Combustion Efficiency

Maximizing combustion efficiency reduces the consumption of fuel by optimizing the quantity of usable energy transferred from the fuel to the process. Combustion efficiency is maximized when the combustion zone is provided the best possible mix of fuel and air conditions, such as fuel/air ratio, fuel temperature, combustion air temperature, combustion zone pressure, heat transfer area, and the like.

Step 2 - Eliminate Technically Infeasible Options

voestalpine has evaluated the technical feasibility/infeasibility of each control strategy identified under Step 1 of the BACT analysis. The evaluation of these technologies must review whether the specific technology is available for the application and is effective at reducing CO_2 emissions.

Flue Gas Carbon Capture with Dedicated Sequestration

As discussed above, CO_2 released from the reformer is mixed with products of combustion and other inert gases, and is not suitable for sequestration. Therefore, carbon capture with dedicated sequestration is not technically feasible and has been eliminated.

Flue Gas Carbon Capture with Transport and Sequestration

As discussed above, CO_2 released from the reformer is mixed with products of combustion and other inert gases, and is not suitable for sequestration. Therefore, carbon capture with transport and sequestration is not technically feasible and has been eliminated.

Step 3 - Rank Remaining Technically Feasible Control Options

1. Energy Integration through Combustion of Spent Reducing Gas (60%)
2. Low-Carbon Fuel (Natural Gas Combustion) (40%)
3. Maximized Combustion Efficiency (10%)

Step 4 - Evaluate Remaining Control Technologies

Energy Integration through Combustion of Spent Reducing Gas

By combusting spent reducing gas instead of flaring it, a great deal of residual energy is reclaimed back to the process. Natural gas is then only needed to supplement approximately 40% of the total energy input to the reformer. The combustion of spent reducing gas has become integral to the design of DRI plants world-wide.

In order to measure the overall GHG effectiveness of the process, the most relevant parameter that can be measured is natural gas consumption. This is due to the fact that the DRI process uses natural gas as both a fuel for energy input into the process, and also as a raw material, generating reducing gas that reacts with the iron oxide content of iron ore to remove oxygen and produce metallic iron. Both routes of natural gas consumption ultimately result in the formation of CO_2. Thus, reducing the total quantity of natural gas consumed by the facility, both fuel and raw material natural gas streams, is the most effective means of reducing GHG generation. This approach is consistent with the output-based metric approach outlined in the GHG BACT Guidance recently published by EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases*, USEPA, OAQPS, Nov. 2010.

In order for the measurement of natural gas consumption to be meaningful, it must be evaluated on an equal production basis. Thus, the proper metric for measuring the natural gas consumption of the process, and thus the GHG efficiency, is in units of natural gas consumed per ton of DRI product. The consumption of natural gas is considered to be the sum of natural gas consumed as fuel and as a raw material, so that all sources of natural gas consumption are accounted for in the metric. Due to production rate and product quality variability in any production process, production rates should be inclusive of all production at the facility, both of regular and off-spec materials.

Low-Carbon Fuel (Natural Gas Combustion)

Natural gas combustion results in significantly less CO_2 generation per unit of energy when compared to most other fuels. When compared with pulverized coal combustion, natural gas can be expected to generate as much as 40% less CO_2 per unit of energy. Since natural gas is an essential raw material in creating the reducing gas needed for the process chemistry, it is also the natural selection for fueling combustion sources such as the reformer.

Maximized Combustion Efficiency

Maximizing combustion efficiency reduces the consumption of fuel by optimizing the quantity of usable energy transferred from the fuel to the process. Combustion efficiency is maximized when the combustion zone is provided the best possible mix of fuel and air conditions, such as fuel/air ratio, fuel temperature, combustion air temperature, combustion zone pressure, heat transfer area, and the like.

Step 5 - Selection of BACT

For GHG emissions generated by combustion at the reformer, BACT is selected to be energy integration through the combustion of spent reducing gas, combined with natural gas combustion for supplemental energy needs. The BACT selection represents inherent design aspects of the DRI process, and as such, these are not add-on controls.

voestalpine is proposing a BACT limit from the reformer main flue ejector stack of 13 MMBtu natural gas per tonne HBI produced. This limit will be achieved with the use of good combustion practices to minimize the CO_2e emissions that occur during the combustion of natural gas and top gas in the reformer.

TABLE 4-7: Summary of BACT for CO_2e Emissions from Reformer Main Flue Ejector Stack at voestalpine

Company, Date	Process Description	Emission Limits	Control Type and Efficiency
voestalpine 2013	Reformer Main Flue Ejector Stack, Emission Source 29	Proposed BACT-PSD: CO_2e Limit –no more than 13 MMBtu (decatherms) of natural gas/tonne HBI produced. Compliance based on total natural gas consumption divided by total production (including regular and off-spec DRI product) of the facility on a 12-month rolling total.	Energy integration through combustion of spent reducing gas. Use of low-carbon fuel (natural gas). Limit total quantity of natural gas consumption per metric ton of product.

4.6 HOT PRESSURE RELIEF VENT (FLARE)

Emission Sources and Process Descriptions

Emission Source	Description
Hot Pressure Relief Vent (Flare), Emission Source 38	The hot pressure relief vent (flare) prevents an uncontrolled release of CO from the system by combusting the reducing gas.

The shaft furnace must run as close to steady state operation as possible in order to produce DRI product of acceptable quality. Due to the nature of the reducing gas recycle system, periodic shifts in pressure may occur. The pressure of the reducing gas must be maintained below that of the seal gas system or an uncontrolled release of reducing gas will result from the top seal and bottom seal. To maintain this condition, the reducing gas is occasionally flared to prevent a rise in pressure. The hot pressure relief vent (flare) prevents an uncontrolled release of CO from the system by combusting the reducing gas.

4.6.1 CO_2e Emissions from the Hot Pressure Relief Vent (Flare)

This section describes a detailed, step-by-step BACT analysis for control of CO_2e emissions from the hot pressure relief vent (flare) at the voestalpine facility.

Step 1 – Identify Potential Control Technologies

A search of USEPA's RBLC database revealed the following entries for the control of CO_2e emissions from the hot pressure relief vent (flare) at DRI plants. Documentation compiled in this research is presented in the table below.

TABLE 4-8: Summary of RBLC Data for CO_2e Emissions from Hot Pressure Relief Vent (Flare) at DRI Plants

RBLC ID Number Company, Date	Process Description	Emission Limits	Control Type and Efficiency
Consolidated Environmental Management Inc. – Nucor St. James, LA 07/19/2012	Hot Flare (to revise Hot Flare) (DRI-110 – DRI Unit #1)	BACT-PSD: CO_2e Limit – none.	Good combustion practices. No other control specified.
IN-1035 Hoosier Energy REC INC. – Merom Generating Station Sullivan County, IN 11/10/2011	Coal Bed Methane-Fired Standby Flare w/Propane-Fired Pilot	BACT-PSD: CO_2e Limit – 3,235 lb/MW-hr, 4,852 tpy (12-month consecutive period).	Good combustion practices and proper maintenance.
LA-0248 Consolidated Environmental Management, Inc. – Nucor St. James, LA 01/27/2011	Hot Flare (DRI-110, Unit No. 1)	BACT-PSD: CO_2e Limit – none.	Good combustion practices. No other control specified.
LA-0248 Consolidated Environmental Management, Inc. – Nucor St. James, LA 01/27/2011	Hot Flare (DRI-210, Unit No. 2)	BACT-PSD: CO_2e Limit – none.	Good combustion practices. No other control specified.

The following list of control technologies represent technologies that have been used for the control of CO_2 emissions from the hot pressure relief vent (flare) and from similar sources in other industries.

1. Carbon Capture with Dedicated Sequestration
2. Carbon Capture with Transport and Sequestration
3. Low-Carbon Fuel (Natural Gas Combustion)
4. Good Combustion Practices and Proper Maintenance

Carbon Capture with Dedicated Sequestration

CO_2 released from the hot pressure vent (flare) is mixed with products of combustion and other inert gases, and is not suitable for sequestration. Therefore, carbon capture with dedicated sequestration is not technically feasible and has been eliminated.

Carbon Capture with Transport and Sequestration

CO_2 released from the hot pressure vent (flare) is mixed with products of combustion and other inert gases, and is not suitable for sequestration.

Therefore, carbon capture with dedicated sequestration is not technically feasible and has been eliminated.

Low-Carbon Fuel (Natural Gas Combustion)

Use of fuels containing lower concentrations of carbon generate less CO_2 than other higher carbon fuels. Typically, gaseous fuels such as natural gas contain less carbon, and thus lower CO_2 potential, than liquid or solid fuels such as diesel or coal. The hot pressure vent (flare) will be equipped with a natural gas-fired pilot to provide a constant flame source to ignite the flare system.

Good Combustion Practices and Proper Maintenance

Good combustion practices for flares include appropriate maintenance of equipment (such as periodic flare tip maintenance) and operating within the recommended heating value and flare tip velocity as specified by its design. Using good combustion practices results in longer life of the equipment and more efficient operation. Therefore, such practices indirectly reduce GHG emissions by supporting operation as designed and with consideration of other energy optimization practices incorporated into the voestalpine facility.

Step 2 – Eliminate Technically Infeasible Options

The Hot Pressure Relief Vent flare is not a process flare, but an intermittent use MSS flare to control pressure of the reducing gas in the shaft furnace. Therefore, no continuous stream (other than pilot gas) is being combusted, and add on controls are not technically feasible. Periodic maintenance will help maintain the efficiency of the flare.

Carbon Capture with Dedicated Sequestration

As discussed above, carbon capture with dedicated sequestration is not technically feasible and has been eliminated.

Carbon Capture with Transport and Sequestration

As discussed above, carbon capture with transport and sequestration is not technically feasible and has been eliminated.

Step 3 – Rank Remaining Technically Feasible Control Options

1. Low-Carbon Fuel (Natural Gas Combustion) (40%)
2. Good Combustion Practices and Proper Maintenance (50%)

Step 4 – Evaluate Remaining Control Technologies

Low-Carbon Fuel (Natural Gas Combustion)

voestalpine proposes to use natural gas for the flare's pilot and as supplemental fuel, if needed, to maintain appropriate vent stream heating value as required by applicable air quality regulations. Liquid and solid fossil fuels are not proposed for use with the flare.

Good Combustion Practices and Proper Maintenance

voestalpine will incorporate good combustion practices and proper maintenance as recommended by the flare manufacturer. Further, voestalpine will minimize maintenance, startup, and shutdown events that can increase CO_2e emissions. Good combustion practices include the following:

- Operator practices - based on written operating procedures incorporating good combustion practices including startup, shutdown, and malfunction;
- Maintenance knowledge – equipment maintained by personnel with training specific to equipment;
- Maintenance practices – based on written site specific procedures for best/optimum maintenance practices;
- Fuel quality (analysis) – periodic fuel sampling and analysis where composition could vary;
- Use of clean fuel – use of pipeline quality natural gas;
- Combustion air distribution – including routine and periodic adjustments and checks of air distribution system;
- Good engineering design – maintain records of manufacturer's specifications and maintenance guidelines; and
- Visible emissions monitoring – maintain records of visible emissions observations.

Step 5 – Selection of BACT

Based on the top-down BACT analysis, the best available technology for controlling CO_2e emissions from the natural gas pilot for the hot pressure relief vent (flare) is use of natural gas for the flare's pilot and as supplemental fuel (if needed), good combustion practices, and proper maintenance. voestalpine will install a natural gas-fired flare tip.

TABLE 4-9: Summary of BACT for CO_2e Emissions from Hot Pressure Relief Vent (Flare) at voestalpine

Company, Date	Process Description	Emission Limits	Control Type and Efficiency
voestalpine 2013	Hot Pressure Relief Vent (Flare), Emission Source 38	Proposed BACT-PSD: CO_2e Limit – included in 13 MMBtu (decatherms) of natural gas/tonne HBI produced limit. Compliance based on total natural gas consumption divided by total production (including regular and off-spec DRI product) of the facility on a 12-month rolling total.	Use of natural gas fuel for the flare's pilot and as supplemental fuel (if needed). Good combustion practices and proper maintenance.

4.7 SEAL GAS VENT

Emission Sources and Process Descriptions

Emission Source	Description
Seal Gas Vent, Emission Source 37	Bottom seal gas exits the shaft furnace with a high particulate concentration from fines generated during the action of the pellets passing through the shaft furnace.

In order to prevent the reducing gas from escaping the furnace, a higher pressure gas called seal gas is applied at both the charging and discharging opening. The seal gas is allowed to escape the furnace while the reducing gas is retained. Due to the higher seal gas pressure, a portion is also entrained into the reactor and combined with the spent reducing gas travels back to the reformer. This seal gas is merely a small amount of cooled flue gas from the reformer combustion side, and primarily consists of atmospheric nitrogen, CO_2, and water vapor.

4.7.1 CO_2e Emissions from the Seal Gas Vent

CO_2 is present in seal gas that is emitted from the seal gas vent because it is simply reformer flue gas diverted for the purpose of retaining the reducing gas within the shaft furnace. Control of CO_2 from the seal gas vent is most appropriately addressed at combustion within the reformer. This section performs a detailed, step-by-step BACT analysis for control of CO_2 emissions from the seal gas vent at the voestalpine facility.

Step 1 – Identify Potential Control Technologies

A search of USEPA's RBLC database revealed the following entries for the control of CO_2e emissions from the seal gas vent at DRI plants. Documentation compiled in this research is presented in the table below.

TABLE 4-10: Summary of RBLC Data for CO_2e Emissions from Seal Gas Vent at DRI Plants

RBLC ID Number Company, Date	Process Description	Emission Limits	Control Type and Efficiency
Consolidated Environmental Management Inc. – Nucor St. James, LA 07/19/2012	Removed Upper Seal Gas Vent (DRI-106, Unit No. 1)	BACT-PSD: CO_2e Limit – none.	N/A
LA-0248 Consolidated Environmental Management – Nucor St. James, LA 01/27/2011	Upper Seal Gas Vent (DRI-106, Unit No. 1)	BACT-PSD: CO_2e Limit – none.	No controls feasible.
LA-0248 Consolidated Environmental Management – Nucor St. James, LA 01/27/2011	Upper Seal Gas Vent (DRI-206, Unit No. 2)	BACT-PSD: CO_2e Limit – none.	No controls feasible.

The following list of control technologies represent technologies that have been used for the control of CO_2 emissions from the seal gas vent (reformer).

1. Good Combustion Practices and Proper Maintenance

Good Combustion Practices and Proper Maintenance

Good combustion practices include appropriate maintenance of equipment and operating within the recommended air to fuel ratio recommended by the manufacturer. Using good combustion practices in conjunction with proper maintenance results in longer life of the equipment and more efficient operation. Therefore, such practices indirectly reduce GHG emissions by supporting operation as designed and with consideration of other energy optimization practices incorporated into the voestalpine facility. voestalpine will incorporate such combustion practices and proper maintenance as recommended by the reformer manufacturer.

Step 2 – Eliminate Technically Infeasible Options

The identified control strategy is technically feasible and has not been eliminated.

Step 3 – Rank Remaining Technically Feasible Control Options

1. Good Combustion Practices and Proper Maintenance (50%)

Step 4 – Evaluate Remaining Control Technologies

Good Combustion Practices and Proper Maintenance

voestalpine will incorporate good combustion practices and perform maintenance as recommended by the reformer manufacturer.

Step 5 – Selection of BACT

BACT for CO_2 was already determined as good combustion practices for the reformer flue gas, and no additional control is feasible for the use of a small portion of this flue gas as seal gas.

TABLE 4-11: Summary of BACT for CO_2e Emissions from Seal Gas Vent at voestalpine

Company, Date	Process Description	Emission Limits	Control Type and Efficiency
voestalpine 2013	Seal Gas Vent, Emission Source 37	Proposed BACT-PSD: CO_2e Limit – included In 13 MMBtu (decatherms) of natural gas/tonne HBI produced limit. Compliance based on total natural gas consumption divided by total production (including regular and off-spec DRI product) of the facility on a 12-month rolling total.	Good combustion practices and proper maintenance.

4.8 EMERGENCY GENERATOR AND FIRE PUMP

Emission Sources and Process Descriptions

Emission Source	Description
Emergency Generator, Emission Source 34	To ensure the supply of electric power in case of failure of the main incoming supply, an emergency diesel generator is provided for powering selected electrical consumers.
Fire Pump, Emission Source 35	To ensure the supply of water in case of fire, an emergency diesel fire pump is provided for fire protection.

4.8.1 CO_2e Emissions from the Emergency Generator and Fire Pump

The three GHGs—CO_2, CH_4, and N_2O—are emitted during the combustion of fossil fuels. CO_2 accounts for the majority of the GHG emissions from stationary combustion sources. This section performs a detailed, step-by-step BACT analysis for control of CO_2 from the engines for the emergency generator and fire pump at the voestalpine facility.

Step 1 – Identify Potential Control Technologies

A search of USEPA's RBLC database revealed the following entries for the control of CO_2e emissions from emergency engines. Documentation compiled in this research is presented in the table below.

TABLE 4-12: Summary of RBLC Data for CO_2e Emissions from Emergency Generators and Fire Pumps

RBLC ID Number Company, Date	Process Description	Emission Limits	Control Type and Efficiency
LA-0256 Westlake Vinyls Company LP Ascension Parish, LA 12/06/11	Emergency Generator, 1818 HP, Natural Gas	BACT-PSD: GHG limit – CO_2e 1,509.23 lb/hr, 39.24 tpy.	USE OF NATURAL GAS AS FUEL AND GOOD COMBUSTION PRACTICES.
FL-0328* ENI U.S. Operating Company, Inc. Lloyd Ridge (OCS), FL 10/27/2011 *Draft Determination	Emergency Engine, Diesel	BACT-PSD: GHG Limit – CO_2 14.6 tpy, 12-month rolling.	Use of good combustion practices, based on the current manufacturer's specifications for this engine.
FL-0328* ENI U.S. Operating Company, Inc. Lloyd Ridge (OCS), FL 10/27/2011 *Draft Determination	Emergency Fire Pump Engine, Diesel	BACT-PSD: GHG Limit – CO_2 2.4 tpy, 12-month rolling.	Use of good combustion practices, based on the current manufacturer's specifications for this engine.
LA-0254 Entergy Louisiana LLC LA 08/16/11	Emergency Diesel Generator, 1250 HP	BACT-PSD: GHG Limit – 163 lb/MMBtu, 12-month rolling.	Proper operation and good combustion practices.
LA-0254 Entergy Louisiana LLC LA 08/16/11	Emergency Fire Pump, 350 HP, Diesel	BACT-PSD: GHG Limit – 163 lb/MMBtu, 12-month rolling.	Proper operation and good combustion practices.
TX-0481 Air Products LP Baytown, TX 11/02/04	Emergency Generator	BACT-PSD: CO2 Limit - 2.24 lb/hr, 0.99 tpy.	No control specified.

The RBLC database did not identify any add-on CO_2 control technologies for emergency engines; only good combustion practices were identified in the RBLC as BACT for emergency engines. However, the following list of control technologies represent technologies that could be used for the control of GHG emissions from emergency engines.

1. Carbon Capture with Dedicated Sequestration
2. Carbon Capture with Transport and Sequestration
3. Low-Carbon Fuel
4. Good Combustion Practices and Proper Maintenance

Carbon Capture with Dedicated Sequestration

Carbon Capture with Dedicated Sequestration

CO_2 released from the emergency engines is mixed with products of combustion and other inert gases, and is not suitable for sequestration.

Carbon Capture with Transport and Sequestration

CO_2 released from the emergency engines is mixed with products of combustion and other inert gases, and is not suitable for sequestration.

Low-Carbon Fuel

Using fuels containing lower concentrations of carbon generates less CO_2 than other higher carbon fuels. Typically, gaseous fuels such as natural gas contain less carbon, and thus lower CO_2 potential, than liquid or solid fuels such as diesel or coal.

The use of natural gas as a combustion fuel, in preference over other fossil fuels such as diesel, results in fewer GHG emissions per unit of energy output. This property has been well documented, including through USEPA's GHG Reporting Rule, which lists natural gas as having the lowest CO_2 emission factor of any primary fossil fuel. Natural gas also has benefits over the use of diesel fuel, from the perspective of emissions from other pollutants, such as sulfur dioxide and particulate matter.

Good Combustion Practices and Proper Maintenance

Good combustion practices for compression ignition engines include appropriate maintenance of equipment (such as periodic testing as will be conducted weekly) and operating within the recommended air to fuel ratio recommended by the manufacturer. Using good combustion practices in conjunction with proper maintenance results in longer life of the equipment and more efficient operation. Therefore, such practices indirectly reduce GHG emissions by supporting operation as designed and with consideration of other energy optimization practices incorporated into the voestalpine facility.

Step 2: Eliminate Technically Infeasible Options

Carbon Capture with Dedicated Sequestration

CO_2 released from the emergency engines is mixed with products of combustion and other inert gases, and is not suitable for sequestration. Therefore, carbon capture with dedicated sequestration is not technically feasible and has been eliminated. Also, because the emergency generator and fire pump will normally operate 100 hours per year or less and because their stack gases are low in volume and CO_2 mass rate, the capture, and segregation of CO_2 for sequestration is considered a technically infeasible control option for the emergency engines at the voestalpine facility.

Carbon Capture with Transport and Sequestration

CO_2 released from the emergency engines is mixed with products of combustion and other inert gases, and is not suitable for sequestration. Therefore, carbon capture with transport and sequestration is not technically feasible and has been eliminated. Also, because the emergency generator and fire pump will normally operate 100 hours per year or less and because their stack gases are low in volume and CO_2 mass rate, the capture, transport, and segregation of CO_2 for sequestration is considered a technically infeasible control option for the emergency engines at the voestalpine facility.

Low-Carbon Fuel

Because the emergency generator and fire pump are intended for emergency use, these engines must be designed to use non-volatile fuel such as diesel fuel. Use of volatile (low-carbon) natural gas in an emergency situation could exacerbate a potentially volatile environment that could be present under certain conditions, resulting in unsafe operation. Therefore, non-volatile fuel is appropriate and necessary for emergency equipment. Therefore, use of low-carbon fuel is considered technically infeasible for emergency engine operation.

Step 3 – Rank Remaining Technically Feasible Control Options

1. Good Combustion Practices and Proper Maintenance (50%)

Step 4 – Evaluate Remaining Control Technologies

Good Combustion Practices and Proper Maintenance

voestalpine will incorporate good combustion practices and perform maintenance as recommended by the emergency generator and fire pump manufacturers.

Step 5: Select BACT

A top-down BACT analysis was performed for emissions of CO_2e from emergency engines. voestalpine will maintain good combustion practices and proper maintenance for the emergency generator and fire pump to control CO_2e emissions.

Further, these new engines will be subject to the NSPS for Stationary Compression Ignition Internal Combustion Engines (40 CFR 60 Subpart IIII), and specific emissions standards for various pollutants must be met during normal operation, such that the engines will meet or exceed BACT.

TABLE 4-13 Summary of BACT for CO_2e Emissions from Emergency Generator and Fire Pump at voestalpine

Company, Date	Process Description	Emission Limits	Control Type and Efficiency
voestalpine 2013	Emergency Generator, Emission Source 34	Proposed BACT-PSD: CO_2e Limit –194 tons CO_2e/yr (based on 100 hrs).	Good combustion practices and proper maintenance. Engines must comply with NSPS Subpart IIII based on manufacturer's specifications.
voestalpine 2013	Fire Pump, Emission Source 35	Proposed BACT-PSD: CO_2e Limit –13.8 tons CO_2e/yr (based on 100 hrs).	Good combustion practices and proper maintenance. Engines must comply with NSPS Subpart IIII based on manufacturer's specifications..

4.9 OTHER MEASURES

Terrestrial sequestration involves the fixation of the CO_2 into vegetative biomass and soils. For example, trees use CO_2 as they grow, and some agricultural practices, such as no-till farming, keep CO_2 in the soil (rather than releasing it when the land is tilled). This type of approach is being used in some states, such as Mississippi and other Lower Mississippi Valley states by the US Fish and Wildlife Service (USFWS). The USFWS, in conjunction with company partners and other conservation agencies, has added 40,000 acres of restored habitat to its national wildlife refuges and more than 80,000 acres to native habitats (USFWS, 2010). However, as summarized by the Southwest Regional Partnership for Carbon Sequestration (SWP):

> *"… terrestrial carbon capacity in the Southwest region is limited by low average annual precipitation and yearly variability in precipitation. Even in systems managed for carbon storage, wet years followed by a series of dry years may result in a net carbon flux out of the system. Opportunity to increase carbon storage on range lands is limited because most areas are at a relatively stable equilibrium given land use history and management. Much of the desert grassland and shrub land areas with less than 12 inches of annual precipitation are subject to loss of cover and exposure to wind and water erosion. Retaining soil carbon levels in these ecosystems will require active restoration practices that are challenging, given current technologies"* (SWP, 2012).

Because terrestrial sequestration is unlikely to be effective in Texas, this technology was not evaluated further in this application.

The use of solar collectors or wind turbines to generate energy at DRI plants is potentially feasible, but the existing infrastructure may not be sufficient to supply extra power to the grid. This technology was not evaluated further in this application.

5.0 ADDITIONAL REQUIREMENTS UNDER PSD

An analysis of ambient air quality impacts is not provided with this application as there are no National Ambient Air Quality Standards (NAAQS) or PSD increments established for GHG (per EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases*).

Since there are no NAAQS or PSD increments for GHGs, the requirements in sections 52.21(k) and 51.166(k) of EPA's regulations to demonstrate that a source does not cause contribute to a violation of the NAAQS are not applicable to GHGs. Therefore, there is no requirement to conduct dispersion modeling or ambient monitoring for CO_2 or GHGs. Additionally, an analysis of Air Quality Related Values (AQRV) is not provided because GHGs do not contribute to regional haze or terrestrial/aquatic acid deposition.

A pre-construction monitoring analysis for GHG is not being provided with this application in accordance with EPA's recommendations (per EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases*). EPA does not consider it necessary for applicants to gather monitoring data to assess ambient air quality for GHGs under 40 CFR 52.21(m)(1)(ii), 40 CFR 51.166(m)(1)(ii), or similar provisions that may be contained in state rules based on EPA's rules. GHGs do not affect "ambient air quality" in the sense that EPA intended when these parts of EPA's rules were initially drafted. Considering the nature of GHG emissions and their global impacts, EPA does not believe it is practical or appropriate to expect permitting authorities to collect monitoring data for purpose of assessing ambient air impacts of GHGs

A PSD application for the criteria pollutants is being submitted to the Texas Commission for Environmental Quality (TCEQ) under separate cover. Impact evaluations related to the Federal Endangered Species Act (biological assessment) and the National Historic Preservation Act (cultural assessment) are being submitted to USEPA under separate cover.

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Appendix A

Emission Rate Calculations

SUMMARY TABLE: voestalpine Direct Reduction Iron Facility Emissions Totals

Emission Point ID	Modeling Stack No.	Air Emission Source Description	TSP Emissions		PM_{10} Emissions		$PM_{2.5}$ Emissions		NO_x Emissions	
			Average lb/hr	Average tons/yr	Average lb/hr	Average tons/yr	Average lb/hr	Average tons/yr	Average lb/hr	Average tons/yr
1	1	Dock Ore Unloading / Product Loading Gantry Crane	0.42	1.84	0.20	0.87	0.03	0.13		
4	4	Oxide Unloading Bin & Dedusting	0.11	0.49	0.11	0.49	0.08	0.36		
5	5	Oxide Pellet Pile Transfer & Dedusting (Pre Pile)	0.25	1.10	0.25	1.10	0.19	0.83		
2	2	Oxide Pellets Piles 1	2.00	8.75	0.51	2.23	0.09	0.38		
6	6	Oxide Transfer & Dedusting (Post Pile)	0.11	0.49	0.11	0.49	0.08	0.36		
7	7	Oxide & Remet Screening & Dedusting	0.71	3.09	0.71	3.09	0.53	2.32		
16	16	Furnace Charge Hopper Loading Silos	0.01	<0.01	0.01	<0.01	0.01	<0.01		
29	29	Reformer Main Flue Ejector Stack	7.41	32.46	7.41	32.46	7.41	32.46	81.52	357.06
38	38	Hot Pressure Relief Vent (Flare)	0.51	0.08	0.51	0.08	0.51	0.08	20.26	2.96
37	37	Seal Gas Vent	0.37	1.61	0.37	1.61	0.37	1.61	4.22	18.48
8	8	Furnace Dedusting (BSG Dust Collection)	2.50	10.95	2.50	10.95	2.25	9.86		
9	9	Briquetter Dedusting	3.97	17.38	3.97	17.38	3.57	15.64		
12	12	Transfer & Product Screening Station No. 1 (Pre Pile)	0.40	1.77	0.40	1.77	0.36	1.59		
14	14	Product Storage Piles	1.48	6.50	0.44	1.91	0.07	0.30		
13	13	Transfer & Product Screening Station No. 2 (Post Pile)	0.40	1.77	0.40	1.77	0.36	1.59		
36	36	Remet / Fines Storage	0.17	0.74	0.04	0.20	0.01	0.02		
33	33	Salt Water Cooling Tower	2.61	11.44	0.08	0.34	0.08	0.34		
39	39	Paved Road Fugitive Dust	0.25	1.08	0.05	0.21	0.01	0.03		
34	34	Emergency Generator	0.47	0.02	0.47	0.02	0.47	0.02	32.09	1.60
35	35	Fire Pump	0.03	<0.01	0.03	<0.01	0.03	<0.01	2.25	0.11
		TOTAL EMISSIONS	**24.18**	**101.54**	**18.57**	**76.95**	**16.51**	**67.93**	**140.33**	**380.22**

SUMMARY TABLE: voestalpine Direct Reduction Iron Facility Emissions Totals

			SO_2 Emissions		**CO Emissions**		**VOC Emissions**		**Benzene**	
Emission Point ID	**Modeling Stack No.**	**Air Emission Source Description**	**Average lb/hr**	**Average tons/yr**	**Average lb/hr**	**Average tons/yr**	**Average lb/hr**	**Average tons/yr**	**Average lb/hr**	**Average tons/yr**
1	1	Dock Ore Unloading / Product Loading Gantry Crane								
4	4	Oxide Unloading Bin & Dedusting								
5	5	Oxide Pellet Pile Transfer & Dedusting (Pre Pile)								
2	2	Oxide Pellets Piles 1								
6	6	Oxide Transfer & Dedusting (Post Pile)								
7	7	Oxide & Remet Screening & Dedusting								
16	16	Furnace Charge Hopper Loading Silos								
29	29	Reformer Main Flue Ejector Stack	2.76	8.46	109.98	481.72	7.20	31.54	<0.01	<0.01
38	38	Hot Pressure Relief Vent (Flare)	0.02	<0.01	248.93	33.02	0.04	0.02		
37	37	Seal Gas Vent	0.14	0.60	5.44	23.85			<0.01	<0.01
8	8	Furnace Dedusting (BSG Dust Collection)								
9	9	Briquetter Dedusting								
12	12	Transfer & Product Screening Station No. 1 (Pre Pile)								
14	14	Product Storage Piles								
13	13	Transfer & Product Screening Station No. 2 (Post Pile)								
36	36	Remet / Fines Storage								
33	33	Salt Water Cooling Tower								
39	39	Paved Road Fugitive Dust								
34	34	Emergency Generator	0.04	<0.01	3.80	0.19	0.99	0.05		
35	35	Fire Pump	<0.01	<0.01	0.27	0.01	0.07	<0.01		
		TOTAL EMISSIONS	**2.96**	**9.06**	**368.42**	**538.80**	**8.30**	**31.61**	**<0.01**	**<0.01**

SUMMARY TABLE: voestalpine Direct Reduction Iron Facility Emissions Totals

			Dichlorobenzene		**Formaldehyde**		**n-Hexane**		**Naphthalene**	
Emission Point ID	**Modeling Stack No.**	**Air Emission Source Description**	**Average lb/hr**	**Average tons/yr**	**Average lb/hr**	**Average tons/yr**	**Average lb/hr**	**Average tons/yr**	**Average lb/hr**	**Average tons/yr**
1	1	Dock Ore Unloading / Product Loading Gantry Crane								
4	4	Oxide Unloading Bin & Dedusting								
5	5	Oxide Pellet Pile Transfer & Dedusting (Pre Pile)								
2	2	Oxide Pellets Piles 1								
6	6	Oxide Transfer & Dedusting (Post Pile)								
7	7	Oxide & Remet Screening & Dedusting								
16	16	Furnace Charge Hopper Loading Silos								
29	29	Reformer Main Flue Ejector Stack	<0.01	<0.01	0.01	0.05	0.28	1.24	<0.01	<0.01
38	38	Hot Pressure Relief Vent (Flare)								
37	37	Seal Gas Vent	<0.01	<0.01	<0.01	<0.01	0.01	0.06	<0.01	<0.01
8	8	Furnace Dedusting (BSG Dust Collection)								
9	9	Briquetter Dedusting								
12	12	Transfer & Product Screening Station No. 1 (Pre Pile)								
14	14	Product Storage Piles								
13	13	Transfer & Product Screening Station No. 2 (Post Pile)								
36	36	Remet / Fines Storage								
33	33	Salt Water Cooling Tower								
39	39	Paved Road Fugitive Dust								
34	34	Emergency Generator								
35	35	Fire Pump								
		TOTAL EMISSIONS	**<0.01**	**<0.01**	**0.01**	**0.05**	**0.30**	**1.30**	**<0.01**	**<0.01**

SUMMARY TABLE: voestalpine Direct Reduction Iron Facility Emissions Totals

			Toluene		PAH		Lead		Total HAPs	
Emission Point ID	Modeling Stack No.	Air Emission Source Description	Average lb/hr	Average tons/yr	Average lb/hr	Average tons/yr	Average lb/hr	Average tons/yr	Average lb/hr	Average tons/yr
1	1	Dock Ore Unloading / Product Loading Gantry Crane							0.00	0.00
4	4	Oxide Unloading Bin & Dedusting							0.00	0.00
5	5	Oxide Pellet Pile Transfer & Dedusting (Pre Pile)							0.00	0.00
2	2	Oxide Pellets Piles 1							0.00	0.00
6	6	Oxide Transfer & Dedusting (Post Pile)							0.00	0.00
7	7	Oxide & Remet Screening & Dedusting							0.00	0.00
16	16	Furnace Charge Hopper Loading Silos							0.00	0.00
29	29	Reformer Main Flue Ejector Stack	<0.01	<0.01	<0.01	<0.01	<0.01	0.01	0.30	1.30
38	38	Hot Pressure Relief Vent (Flare)					<0.01	<0.01	<0.01	<0.01
37	37	Seal Gas Vent	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01	0.01	0.06
8	8	Furnace Dedusting (BSG Dust Collection)							0.00	0.00
9	9	Briquetter Dedusting							0.00	0.00
12	12	Transfer & Product Screening Station No. 1 (Pre Pile)							0.00	0.00
14	14	Product Storage Piles							0.00	0.00
13	13	Transfer & Product Screening Station No. 2 (Post Pile)							0.00	0.00
36	36	Remet / Fines Storage							0.00	0.00
33	33	Salt Water Cooling Tower							0.00	0.00
39	39	Paved Road Fugitive Dust							0.00	0.00
34	34	Emergency Generator							0.00	0.00
35	35	Fire Pump							0.00	0.00
		TOTAL EMISSIONS	**<0.01**	**<0.01**	**<0.01**	**<0.01**	**<0.01**	**0.01**	**0.31**	**1.37**

Emission Point Source Calculations

Case: **1**
Description: **Dock Ore Unloading / Product Loading Gantry Crane**

Inputs	Value	Units
Annual hours of operation	8,760	hrs/yr
Maximum Loading Rate (Conveyor Capacity)	1,500	tons/hr
Average wind speed	12.0	mph
Loading control efficiency	90.0%	%
Unloading control efficiency	90.0%	%
Annual throughput - iron ore	3,197,250	tons/yr
Excess Receiving Capacity (Annual)	110%	%
Conveyor System Service Factor (Hourly)	115%	%
Material moisture content-iron ore	3.20	%

Emissions Summary

Source Description	Pollutant	Average Emission Rate	Annual Emission Rate
		(lbs/hr)	(tpy)
Barge/Ship Unloading (Dock 1)	TSP*	0.419	1.84
	PM_{10}	0.198	0.868
	$PM_{2.5}$	0.0300	0.131

* Per AP-42 (Table 13.2.2-2), PM-30 is assumed equivalent to total suspended particle matter (TSP)

Calculation Basis:

Loading emissions: (1) conveyor to ship/barge (i.e., 1 drop)
Unloading emiss er, (2) hopper to receiving conveyor (2 drops)

$$Emission\ factor\,(lb/ton) = k * (0.0032) * \frac{\left(\frac{U}{5}\right)^{1.3}}{\left(M\ \right)^{1.4}}$$

Emission Factor

$$\left(\frac{M}{2}\right)$$

Aerodynamic Particle Size Multiplier (k)	
< 30 micrometers	**0.74**
< 15 micrometers	0.48
< 10 micrometers	**0.35**
< 5 micrometers	0.2
< 2.5 micrometers	**0.053**

where U = Mean wind speed (mph) for the area[1]
M = Material moisture content (%)[2]
k = Particle size multiplier[3]

Note:
1. Corpus Christi average wind speed (previous 60 years) http://www.ncdc.noaa.gov/oa/climate/online/ccd/avgwind.html
2. From AP-42 (11/06), Section 13.2.4.2, Table 13.2.4-1 and process experience
3. From AP-42 (11/06), Section 13.2.4.3

* Calculation methodology derived from Section 13.2.4 "*Aggregate Handling and Storage Piles*," AP-42 (11/06).

Emission Calculations

Average Controlled Emission Rate (tons/yr) = Material Throughput (tons/yr) * EF (lb PM/ton) * (Number of drops) * (1-Control efficiency)
Average Controlled Emission Rate (lb/hr) = Average Controlled Emission Rate (tons/yr)* (2000 lb/ton)/8760 hrs/yr

Particulate Emissions from Barge Loading/Unloading @ Dock # 1

Pollutant	Annual Throughput	Emission Factor	Number of Drops	Uncontrolled Emissions	Overall Control Efficiency	Excess Receiving Capacity	Conveyor Service Factor	Average Emission Rate	Annual Emission Rate
	(tons/yr[1])	(lb/ton)		(lb/yr)	%	%	%	(lb/hr$_{avg}$)	(tpy)
TSP	3,197,250	0.00383	3.00	36,710	90.0%	110%	115%	0.419	1.84
PM10	3,197,250	0.00181	3.00	17,363	90.0%	110%	115%	0.198	0.868
PM2.5	3,197,250	0.000274	3.00	2,629	90.0%	110%	115%	0.0300	0.131

[1] Capacity converted to US tons

[2] Pig iron has no intrinsic silt content, and is assumed to be non-emitting.

Emission Point Source Calculations

Emission Point Identifier: **4**
Description: **Oxide Unloading Bin & Dedusting**

Inputs

Description	Value	Units
Annual Hours of Operation	8,760	hr/yr
Iron Oxide Consumption Rate	3,197,250	tons/yr
Design Volmetric Vent Rate	11,000	Nm^3/hr
Clean Gas Concentration	4.57	mg/Nm^3
PM_{10} Mass Fraction	100%	%
$PM_{2.5}$ Mass Fraction (uncontrolled 15%, AP-42)	75.0%	%

Emissions Summary

Pollutant	Average Emission Rate (lb/hr)	Annual Emission Rate (tpy)
TSP	0.111	0.485
PM_{10}	0.111	0.485
$PM_{2.5}$	0.0831	0.364

Calculate Emissions

Pollutant	Normal Dedusting Airflow Rate	Maximum Clean Gas Concentration	Mass Fraction of Total PM	Average Emission Rate	Annual Emission Rate
	(Nm^3/hr)	**(mg/Nm^3)**	**%**	**(lb/hr)**	**(tons/yr)**
TSP	11,000	4.57	100%	0.111	0.485
PM_{10}	11,000	4.57	100%	0.111	0.485
$PM_{2.5}$	11,000	4.57	75.0%	0.0831	0.364

Emission Point Source Calculations

Emission Point Identifier: **5**
Description: **Oxide Pellet Pile Transfer & Dedusting (Pre Pile)**

Inputs

Description	Value	Units
Annual Hours of Operation	8,760	hr/yr
Iron Oxide Consumption Rate	3,197,250	tons/yr
Design Volmetric Vent Rate	25,000	Nm^3/hr
Clean Gas Concentration	4.57	mg/Nm^3
PM_{10} Mass Fraction	100%	%
$PM_{2.5}$ Mass Fraction (uncontrolled 15%, AP-42)	75.0%	%

Emissions Summary

Pollutant	Average Emission Rate (lb/hr)	Annual Emission Rate (tpy)
TSP	0.25	1.10
PM_{10}	0.25	1.10
$PM_{2.5}$	0.19	0.83

Calculate Emissions

Pollutant	Normal Dedusting Airflow Rate	Maximum Clean Gas Concentration	Mass Fraction of Total PM	Average Emission Rate	Annual Emission Rate
	(Nm^3/hr)	(mg/Nm^3)	%	(lb/hr)	(tons/yr)
TSP	25,000	4.57	100%	0.25	1.10
PM_{10}	25,000	4.57	100%	0.25	1.10
$PM_{2.5}$	25,000	4.57	75.0%	0.19	0.83

Emission Point Source Calculations

Case: **2**
Description: **Oxide Pellets Piles 1**

Inputs	**Value**	**Units**
Material storage time	8,760	hrs
Storage duration	365	days
Average wind speed	12.0	mph
Number of dry days per year	288	days
Percentage of time wind speed > 12 mph	50.0%	% (actual)
Annual Material Throughput	3,197,250	tons/yr
Excess Receiving Capacity (Annual)	110%	%
Transfer rate-stacker	1,500	tons/hr
Transfer rate-reclaimer	1,500	tons/hr
Wind Erosion Chemical Suppression	95.0%	%
Control efficiency -stacker	90.0%	%
Control efficiency -reclaimer	75.0%	%
Material moisture content	3.00	%
Material silt content	15.00	%
Storage area ground surface silt content	6.00	%
Percentage PM 10 in material	6.0%	%
Pile maintenance/traffic hours	365	days
Dozer miles per day	2	mi
Dozer average weight	20	tons
Front end loader miles per day	10	mi
Front end loader average weight	20	tons
Control efficiency - maintenance/traffic	70.0%	%

Corpus Christi average wind speed (previous 60 years) http://www.ncdc.noaa.gov/oa/climate/online/ccd/avgwind.html, 7/27/12
Corpus Christi mean number of days with precipitation .01" or more (previous 63 years) http://lwf.ncdc.noaa.gov/oa/climate/online/ccd/prcpdays.html, 7/27/12
http://www.ncdc.noaa.gov/oa/climate/online/ccd/avgwind.html

Emissions Summary

Total Suspended Particles (TSP)

Source Description	**Average Emission Rate (lbs/hr)**	**Annual Emission Rate (tpy)**
Material Transfers In/Out of Storage	0.371	1.63
Equipment Traffic in Storage Area	1.17	5.12
Wind Erosion	0.457	2.003
TOTAL	**2.00**	**8.75**

Total Particulate Matter < 10 um (PM_{10})

Source Description	Average Emission Rate	Annual Emission Rate
	(lbs/hr)	**(tpy)**
Material Transfers In/Out of Storage	0.170	0.745
Equipment Traffic in Storage Area	0.311	1.36
Wind Erosion	0.0274	0.1202
TOTAL	**0.509**	**2.23**

Total Particulate Matter < 2.5 um ($PM_{2.5}$)

Source Description	Average Emission Rate	Annual Emission Rate
	(lbs/hr)	**(tpy)**
Material Transfers In/Out of Storage	0.0526	0.230
Equipment Traffic in Storage Area	0.0311	0.136
Wind Erosion	0.00412	0.0180
TOTAL	**0.0878**	**0.385**

[1] Per AP-42 (Table 13.2.2-2), PM-30 is assumed equivalent to toal suspended particle matter (TSP)

Material Stacking and Reclaiming

Calculation Basis:

Calculation methodology derived from Table 12.5-4 "*Pile Formation, Stacker, Pellet Ore,*" AP-42 (10/86).
Transfer Locations: (1) stacker/dump to pile; (2) reclaimer/loader out of pile onto conveyor; (3) equipment traffic within pile area.

Emission Calculations

Average Annual Particulate (TSP) Emissions from Material Storage Pile Transfers

Transfer Location	Annual Throughput	Emission Factor	Number of Drops	Uncontrolled Emissions	Overall Control Efficiency	Controlled Emission Rates	
	(tons/yr[1])	**(lb/ton)**		**(lb/yr)**	**%**	**(lb/hr_{avg})**	**(tpy)**
Storage Pile (stacker)	3,517,327	0.00240	1.00	8,442	90.0%	0.0964	0.422
Storage Pile (reclaimer)	3,517,327	0.00240	1.00	8,442	75.0%	0.241	1.055
TOTAL						**0.337**	**1.477**

Average Annual Particulate (PM_{10}) Emissions from Material Storage Pile Transfers

Transfer Location	Annual Throughput	Emission Factor	Number of Drops	Uncontrolled Emissions	Overall Control Efficiency	Controlled Emission Rates	
	(tons/yr[1])	**(lb/ton)**		**(lb/yr)**	**%**	**(lb/hr_{avg})**	**(tpy)**
Storage Pile (stacker)	3,517,327	0.00110	1.00	3,869	90.0%	0.0442	0.193
Storage Pile (reclaimer)	3,517,327	0.00110	1.00	3,869	75.0%	0.1104	0.484
TOTAL						**0.1546**	**0.677**

Average Annual Particulate ($PM_{2.5}$) Emissions from Material Storage Pile Transfers

Transfer Location	Annual Throughput	Emission Factor	Number of Drops	Uncontrolled Emissions	Overall Control Efficiency	Controlled Emission Rates	
	(tons/yr[1])	(lb/ton)		(lb/yr)	%	(lb/hr_{avg})	(tpy)
Storage Pile (stacker)	3,517,327	0.000340	1.00	1,196	90.0%	0.01365	0.0598
Storage Pile (reclaimer)	3,517,327	0.000340	1.00	1,196	75.0%	0.0341	0.1495
TOTAL						**0.0478**	**0.209**

[1] capacity converted to US tons

Equipment Traffic in Storage Areas

Calculation Basis:

Calculation methodology derived from Section 13.2.2, "*Unpaved Roads,*" dated AP-42 (11/06) (in accordance with guidance from Section 13.2.4)
Accounts for bulldozer (on pile) and front-end loader (between piles)

$$\textit{Emission factor (lb/VMT)} = k(s/12)^{a}(W/3)^{b}$$

where:

s = silt content of aggregate (%)[1]
W = mean vehicle weight [2]
k, a, b = empirical constants for industrial roads [3]

Empirical Constants for Industrial Roads			
	PM-2.5	**PM-10**	**PM-30**
k	**0.15**	**1.5**	**4.9**
a	**0.9**	**0.9**	**0.70**
b	**0.45**	**0.45**	**0.45**

Note:

1. From AP42, Section 13.2.2, Table 13.2.2-1, Dated 11/06
2. From AP42, Section 13.2.2, Table 13.2.2-3, Dated 11/06
3. From AP42, Section 13.2.2, Table 13.2.2-2, Dated 11/06

Calculation of Average Annual Controlled Emission Rate

Average Annual Controlled Emission Rate (tons/yr) = Vehicle Miles traveled in an day (VMT/day) * EF (lb PM / VMT) * (number of days per year)* (1-control efficiency) / (2000 lb/ton)
Average Controlled Emission Rate (lb/hr) = Average Controlled Emission Rate (tons/yr)* (2000 lb/ton)/8760 hrs/yr

Emission Calculations:

Average Annual Particulate Emissions (TSP) from Equipment Traffic in Storage Areas

Vehicle Type	Vehicle Miles Traveled	Emission Factor	Uncontrolled Emission Rate	Overall Control Efficiency	Controlled Emission Rates	
	(VMT/day)	(lb/VMT)	(lb/day)	%	(lb/hr$_{avg}$)	(tpy)
Dozers	2	7.08	14.2	70.0%	0.177	0.776
Front-end loaders	10	7.08	70.8	70.0%	0.885	3.88
TOTAL					**1.06**	**4.65**

Average Annual Particulate Emissions (PM10) from Equipment Traffic in Storage Areas

Vehicle Type	Vehicle Miles Traveled	Emission Factor	Uncontrolled Emission Rate	Overall Control Efficiency	Controlled Emission Rates	
	(VMT/day)	(lb/VMT)	(lb/day)	%	(lb/hr$_{avg}$)	(tpy)
Dozers	2	1.89	3.78	70.0%	0.0472	0.207
Front-end loaders	10	1.89	18.9	70.0%	0.236	1.03
TOTAL					**0.283**	**1.24**

Average Annual Particulate Emissions ($PM_{2.5}$) from Equipment Traffic in Storage Areas

Vehicle Type	Vehicle Miles Traveled	Emission Factor	Uncontrolled Emission Rate	Overall Control Efficiency	Controlled Emission Rates	
	(VMT/day)	(lb/VMT)	(lb/day)	%	(lb/hr$_{avg}$)	(tpy)
Dozers	2	0.189	0.378	70.0%	0.00472	0.0207
Front-end loaders	10	0.189	1.89	70.0%	0.0236	0.103
TOTAL					**0.0283**	**0.124**

Wind Erosion

Calculation Basis:

Calculation methodology derived from EPA documents:
"Fugitive Emissions from Integrated Iron and Steel Plants", Section 2.2.4, Figure 3-9 (March 1978) and
"*Iron and Steel Plant Open Source Fugitive Emission Evaluation*", Section 2.1.3 and Table 2-1, Equation (8) (August 1978)
Climatological data NOAA Website for Corpus Christi TX

Emission factor (lb/ton) = *0.05(s/1.5)(D/90)(d/235)(f/15)*

where:
s = silt content of aggregate (%)[1]
D = duration of storage (days)
d = dry days per year[2]
f = percentage of time wind speed exceeds 12 mph

Note:
1. From AP42, Section 13.2.2, Table 13.2.2-1, Dated 11/06
2. From AP42, Section 13.2.2, Table 13.2.2-1, Dated 11/06

Calculation of Average Annual Controlled Emission Rate

Average Annual Controlled Emission Rate (tons/yr) = tons of aggregate through storage cycle (tons) * EF (lb PM / VMT) * (1 - Control efficiency)
Average Controlled Emission Rate (lb/hr) = Average Controlled Emission Rate (tons/yr)* (2000 lb/ton)/8760 hrs/yr

Emission Calculations:

Average Annual Particulate Emissions (TSP) from Wind Erosion from Storage Piles

Aggregate	Throughput[1]	Emission Factor	Uncontrolled Rate	Overall Control Efficiency	Controlled Emission Rate	
	(tons/yr)	(lb/ton)	(lb/yr)	%	(lb/hr$_{avg}$)	(tpy)
Iron Ore Pellets	879,332	0.0828	72,841.1	95.0%	0.416	1.821

Average Annual Particulate Emissions (PM_{10}) from Wind Erosion from Storage Piles

Aggregate	TSP Controlled Emission Rate		% PM 10	Controlled Emission Rate	
	(lb/hr$_{avg}$)	(tpy)	%	(lb/hr$_{avg}$)	(tpy)
Iron Ore Pellets	0.416	1.821	6.0%	0.0249	0.1093

Average Annual Particulate Emissions ($PM_{2.5}$) from Wind Erosion from Storage Piles

Aggregate	TSP Controlled Emission Rate		% $PM_{2.5}$[2]	Controlled Emission Rate	
	(lb/hr$_{avg}$)	(tpy)	%	(lb/hr$_{avg}$)	(tpy)
Iron Ore Pellets	0.416	1.821	0.90%	0.00374	0.0164

[1] Assume 3-month supply onsite at all times
[2] Per an EPA document showing that PM2.5/PM10 for metallic ore and coal piles is 0.15- www.epa.gov/ttn/chief/conference/ei15/session14/cowherd.pdf

Emission Point Source Calculations

Emission Point Identifier: **6**
Description: **Oxide Transfer & Dedusting (Post Pile)**

Inputs

Description	Value	Units
Annual Hours of Operation	8,760	hr/yr
Iron Oxide Consumption Rate	3,197,250	tons/yr
Design Volmetric Vent Rate	11,000	Nm^3/hr
Clean Gas Concentration	4.57	mg/Nm^3
PM_{10} Mass Fraction	100%	%
$PM_{2.5}$ Mass Fraction (uncontrolled 15%, AP-42)	75.0%	%

Emissions Summary

Pollutant	Average Emission Rate (lb/hr)	Annual Emission Rate (tpy)
TSP	0.111	0.485
PM_{10}	0.111	0.485
$PM_{2.5}$	0.0831	0.364

Calculate Emissions

Pollutant	Normal Dedusting Airflow Rate	Maximum Clean Gas Concentration	Mass Fraction of Total PM	Average Emission Rate	Annual Emission Rate
	(Nm^3/hr)	**(mg/Nm^3)**	**%**	**(lb/hr)**	**(tons/yr)**
TSP	11,000	4.57	100%	0.111	0.485
PM_{10}	11,000	4.57	100%	0.111	0.485
$PM_{2.5}$	11,000	4.57	75.0%	0.0831	0.364

Emission Point Source Calculations

Emission Point Identifier: **7**
Description: **Oxide & Remet Screening & Dedusting**

Inputs

Description	Value	Units
Annual Hours of Operation	8,760	hr/yr
Designed Production Rate	3,197,250	tons/yr
Design Volmetric Vent Rate	70,000	Nm^3/hr
Clean Gas Concentration	4.57	mg/Nm^3
PM_{10} Mass Fraction	100%	%
$PM_{2.5}$ Mass Fraction (uncontrolled 15%, AP-42)	75.0%	%

Emissions Summary

Pollutant	Average Emission Rate (lb/hr)	Annual Emission Rate (tpy)
TSP	0.705	3.09
PM_{10}	0.705	3.09
$PM_{2.5}$	0.529	2.32

Calculate Emissions

Pollutant	Normal Dedusting Airflow Rate	Maximum Clean Gas Concentration	Mass Fraction of Total PM	Average Emission Rate	Annual Emission Rate
	(Nm^3/hr)	(mg/Nm^3)	%	(lb/hr)	(tons/yr)
TSP	70,000	4.57	100%	0.705	3.09
PM_{10}	70,000	4.57	100%	0.705	3.09
$PM_{2.5}$	70,000	4.57	75.0%	0.529	2.32

Emission Point Source Calculations

Emission Point Identifier: **16**
Description: **Furnace Charge Hopper Loading Silos**

Inputs

Description	Value	Units
Annual Hours of Operation	364	hr/yr
Designed Production Rate	3,197,250	tons/yr
Design Volmetric Vent Rate	1,400	Nm^3/hr
Gas Dust Loading	4.57	mg/Nm^3
PM_{10} Mass Fraction	100%	%
$PM_{2.5}$ Mass Fraction (uncontrolled 15%, AP-42)	75.0%	%

Emissions Summary

Pollutant	Average Emission Rate (lb/hr)	Annual Emission Rate (tpy)
TSP	0.0141	0.00257
PM_{10}	0.0141	0.00257
$PM_{2.5}$	0.0106	0.00193

Calculate Emissions

Pollutant	Normal Dedusting Airflow Rate	Maximum Clean gas Dust Loading	Mass Fraction of Total PM	Average Emission Rate	Annual Emission Rate
	(Nm^3/hr)	(mg/Nm^3)	%	(lb/hr)	(tons/yr)
TSP	1,400	4.57	100%	0.0141	0.00257
PM_{10}	1,400	4.57	100%	0.0141	0.00257
$PM_{2.5}$	1,400	4.57	75.0%	0.0106	0.00193

Emission Point Source Calculations

Emission Point Identifier: **29**
Description: **Reformer Main Flue Ejector Stack**

Inputs

Description	**Value**	**Units**	Comments
Annual Hours of Operation	8,760	hr/yr	
Designed Production Rate, Annual	2,205,000	tons/yr	Manfacturer
Designed Production Rate, Hourly	360	ton HBI / hr	Manfacturer
Maximum Production Rate Ratio	110%	%	Design Maximum
Total Reformer Vented Rate, wet @ 1.49% O2	424,000	Nm^3/hr	Design Maximum
Seal Gas System Off-take	20,000	Nm^3/hr	Manfacturer
Normal Reformer Firing Rate	1,402	MMBtu/hr	Main and Aux burners plus Top Gas
Nominal Natural Gas Supplement Rate	12.0%	%	Maufacturer
Total PM Emission Factor, dry @3%O2	10.0	mg/Nm^3	Vendor Guarantee, total
Filterable PM Emission Factor	25.0%	%	AP-42, Chapter 1, Section 4
NO_X Uncontrolled Concentration, dry at 3% O2	110.0	mg/Nm^3	Vendor Guarantee, total
PM_{10} Filterable Mass Fraction	100%		Worst case
$PM_{2.5}$ Filterable Mass Fraction	100%		Worst case
CO Emission Factor	84.0	lbs / $mmft^3$	AP-42, Chapter 1, Section 4, Table 1.4-1
CO2 Emission Factor	120,000	lbs / $mmft^3$	AP-42, Chapter 1, Section 4, Table 1.4-2
SO_2 Emission Factor	0.600	lbs / $mmft^3$	AP-42, Chapter 1, Section 4, Table 1.4-2
VOC Emission Factor	5.50	lbs / $mmft^3$	AP-42, Chapter 1, Section 4, Table 1.4-2
Natural Gas, fuel and reduction gas raw materials	380	Nm^3/ton HBI	Manfacturer, total

Emissions Summary

Pollutant	Average Emission Rate (lb/hr)	Annual Emission Rate (tpy)
TSP	7.41	32.5
PM_{10}	7.41	32.5
$PM_{2.5}$	7.41	32.5
NO_x	81.5	357
SO_2	2.76	8.5
CO	110	482
CO2	552,385	1,691,680
CO2e	552,510	1,692,060
VOC	7.20	31.5
Lead (Pb)	2.30E-03	7.05E-03
Benzene	3.30E-04	1.44E-03
Dichlorobenzene	1.88E-04	8.25E-04
Formaldehyde	0.0118	0.0516
n-Hexane	0.282	1.24
Naphthalene	9.57E-05	4.19E-04
Toluene	5.34E-04	2.34E-03
PAH	1.32E-05	5.77E-05

Calculate Emissions
Via Outlet Concentrations (Manufacutrer)

Pollutant	Normal Vented Flue Flow Rate	Dry Vented Flue Flow Rate	Component Concentration @ 3% O2	Control Efficiency	Average Emission Rate	Annual Emission Rate
	(Nm^3/hr)	(dNm^3/hr)	(mg/dNm^3)	%	(lb/hr)	(tons/yr)
NO_x	404,000	316,696	110.0	0%	81.5	357
TSP	404,000	316,696	10.0	0%	7.41	32.5
PM_{10}	404,000	316,696	10.0	0%	7.41	32.5
$PM_{2.5}$	404,000	316,696	10.0	0%	7.41	32.5

Emission rate correction to 3% O2: dNm^3 * mg/dNm^3 / 453600 * ((20.9-1.9)/(20.9-3))

Via AP-42 Emission Factor, Chapter 1, Section 4, Tables 1.4-1 and 1.4-2

Pollutant	Normal Reformer Firing Rate	Emission Factor	Control Efficiency	Seal Gas Compensation	Average Emission Rate	Annual Emission Rate
	(MMBtu/hr)	(lbs/mmBtu NG)	%	-	(lb/hr)	(tons/yr)
CO	1,402	0.0824	0%	0.953	110.0	482
VOC	1,402	0.00539	0%	0.953	7.20	31.5

Via Reducing Gas and Fuel Maximum

Pollutant	Total NG as Fuel and Raw Material	Max HBI output		Emission Factor	Control Efficiency	Seal Gas Compensation	Average Emission Rate	Annual Emission Rate
	(Nm^3/ton)	(ton HBI/hr)	(ton HBI/yr)	(lbs/mmcf NG)	%	-	(lb/hr)	(tons/yr)
SO2	380	360	2,205,000	0.600	0%	0.953	2.76	8.5
CO2	380	360	2,205,000	120,000	0%	0.953	552,385	1,691,680
CO2e	380	360	2,205,000	120,027	0%	0.953	552,510	1,692,060
Lead (Pb)	380	360	2,205,000	5.00E-04	0%	0.953	2.30E-03	0.0070

Calculate HAP Emissions

Pollutant	Normal Reformer Firing Rate	AP-42 Emission Factor	Nominal Natural Gas Supplement Rate	Seal Gas System Compensation	Average Emission Rate	Annual Emission Rate
	(MMBtu/hr)	(lb/MBtu)	%	(-)	(lb/hr)	(tons/yr)
Benzene	1,402	2.06E-06	12.0%	0.953	3.30E-04	1.44E-03
Dichlorobenzene	1,402	1.18E-06	12.0%	0.953	1.88E-04	8.25E-04
Formaldehyde	1,402	7.35E-05	12.0%	0.953	1.18E-02	5.16E-02
n-Hexane	1,402	1.76E-03	12.0%	0.953	2.82E-01	1.24E+00
Naphthalene	1,402	5.98E-07	12.0%	0.953	9.57E-05	4.19E-04
Toluene	1,402	3.33E-06	12.0%	0.953	5.34E-04	2.34E-03
PAH	1,402	8.24E-08	12.0%	0.953	1.32E-05	5.77E-05
Arsenic	1,402	1.96E-07	12.0%	0.953	3.14E-05	1.37E-04
Barium	1,402	4.31E-06	12.0%	0.953	6.91E-04	3.02E-03
Beryllium	1,402	1.18E-08	12.0%	0.953	1.88E-06	8.25E-06
Cadmium	1,402	1.08E-06	12.0%	0.953	1.73E-04	7.56E-04
Chromium	1,402	1.37E-06	12.0%	0.953	2.20E-04	9.62E-04
Cobalt	1,402	8.24E-08	12.0%	0.953	1.32E-05	5.77E-05
Copper	1,402	8.33E-07	12.0%	0.953	1.33E-04	5.84E-04
Manganese	1,402	3.73E-07	12.0%	0.953	5.96E-05	2.61E-04
Mercury	1,402	2.55E-07	12.0%	0.953	4.08E-05	1.79E-04
Molybdenum	1,402	1.08E-06	12.0%	0.953	1.73E-04	7.56E-04
Nickel	1,402	2.06E-06	12.0%	0.953	3.30E-04	1.44E-03
Selenium	1,402	2.35E-08	12.0%	0.953	3.77E-06	1.65E-05
Vanadium	1,402	2.25E-06	12.0%	0.953	3.61E-04	1.58E-03
Zinc	1,402	2.84E-05	12.0%	0.953	4.55E-03	1.99E-02

Emission Point Source Calculations

Source ID: **38**
Description: **Hot Pressure Relief Vent (Flare)**
Startup, Shutdown and Malfunction estimates

Inputs	**Value**	**Units**
Pilot Natural Gas Flowrate (Average)	459	scf/hr
Operation Hours	8,760	hr/yr
Higher Heating Value, Natural Gas	1,000	Btu/scf
Number of Startup/Shutdown Events	26	events/yr
Startup Venting Duration	8.00	hours
Startup Venting Volume	160,000	Nm^3
Startup Venting Heating Value	94	Btu/scf
Shutdown Venting Duration	0.500	hours
Shutdown Venting Volume	15,000	Nm^3
Shutdown Venting Heating Value	272	Btu/scf
Maximum Venting Rate	100%	%
Control Efficiency	98%	%

Emissions Summary

Pollutant	**Average Hourly Emissions (lb/hr)**	**Annual Emission Rate (tpy)**
TSP[1]	0.51	0.0763
PM_{10}[1]	0.51	0.0763
$PM_{2.5}$[1]	0.51	0.0763
NO_x	20.3	2.96
SO_2	0.0189	0.00360
CO	249	33.0
VOC	0.042	0.0152
CO2e	15,932	2,315
Lead (Pb)	2.30E-07	1.01E-06

[1] Assume $PM_{10}=PM_{2.5}=TSP$

Start Up Venting Emission Calculations

Calculate Flue Gas Components

Component	Concentration (ppmv)	Partial Volumetric Flow Rate* (Nm^3/hr)	Molar Vent Rate (kg-mol/hr)	Molecular Weight (kg/kg-mol)	Average Flow Rate (kg/hr)	Average Flow Rate (lb/hr)	Maximum Flow Rate (lb/hr)
CO_{2e}	46,300	926	41.3	44.0	1,818.30	4,008.66	4,008.66
H_2O	6,300	126	5.62	18.0	101.25	223.21	223.21
N_2	515,300	10,306	460	28.0	12,881.35	28,398.48	28,398.48
CO	60,800	1,216	54.3	28.0	1,519.70	3,350.36	3,350.36
H_2	263,300	5,266	235	2.02	473.62	1,044.16	1,044.16
CH_4	108,000	2,160	96	16.0	1,546.09	3,408.53	3,408.53
Total	**1,000,000**	**20,000**	**892**	**-**	**18,340.31**	**40,433.41**	**40,433.41**

* - Assumes ideal gas behavior.

Startup Concentrations estimate from Manufacturer

Calculate Flue Gas Emissions

Component	Emission Factor (lb/MMBtu)	Venting Heat Value (MMBtu/hr)	Average Flow Rate (lb/hr)	Maximum Flow Rate (lb/hr)	Control Efficiency	Average Emission Rate (lb/hr)	Annual Emission Rate (tpy)
CO_{2e}	-	-	4,008.66	4,008.66	0%	4,008.66	417
CO			3,350.36	3,350.36	98%	67.0	6.97
CH_4	-	-	3,408.53	3,408.53	98%	68.2	7.09
TSP	0.00760	66	-	-	-	0.50	0.0525
NOx	0.0700	66	-	-	-	4.6	0.483
SO_2	0.0000648	66	-	-	-	0.00	4.47E-04
VOC	5.94E-04	66	-	-	-	0.04	4.10E-03

* - Assumes ideal gas behavior.

Shut Down Venting Emission Calculations

Calculate Flue Gas Components

Component	Concentration (ppmv)	Partial Volumetric Flow Rate* (Nm^3/hr)	Molar Vent Rate (kg-mol/hr)	Molecular Weight (kg/kg-mol)	Average Flow Rate (kg/hr)	Average Flow Rate (lb/hr)	Maximum Flow Rate (lb/hr)
CO_2	184,015	3,680	164	44.0	7,226.66	15,932.04	15,932.04
H_2O	70,632	1,413	63.0	18.0	1,135.13	2,502.53	2,502.53
N_2	5,576	112	4.98	28.0	139.39	307.31	307.31
CO	225,836	4,517	202	28.0	5,644.80	12,444.64	12,444.64
H_2	478,625	9,572	427	2.02	860.95	1,898.07	1,898.07
CH_4	35,316	706	31.5	16.0	505.57	1,114.59	1,114.59
Total	**1,000,000**	**20,000**	**892**	**-**	**15,512.51**	**34,199.18**	**34,199.18**

* - Assumes ideal gas behavior.
Shutdown Concentrations estimate from Manufacturer

Calculate Flue Gas Emissions

Component	Emission Factor (lb/MMBtu)	Venting Heat Value (MMBtu/hr)	Average Flow Rate (lb/hr)	Maximum Flow Rate (lb/hr)	Control Efficiency	Average Emission Rate (lb/hr)	Annual Emission Rate (tpy)
CO_{2e}	-	-	15,932.04	15,932.04	0.00%	15,932.04	1,657
CO	-	-	12,444.64	12,444.64	98.0%	249	25.9
CH_4	-	-	1,114.59	1,114.59	98.0%	22.3	2.32
TSP	2.68E-04	288.2	0.00441	0.00441	0.00%	0.082	0.00850
NOx	7.00E-02	288.2	-	-	-	20.2	2.10
SO_2	6.48E-05	288.2	-	-	-	0.0187	0.00194
VOC	0.00	288.2	0.00	0.00	98.0%	0.00	0.00

* - Assumes ideal gas behavior.

Pilot Lights Emission Calculations

Flare pilot emission calculations are based on AP-42 Section 1.4 (07/98) Natural Gas Combustion, Table 1.4-1 and Table 1.4-2 factors for Large Wall-Fired Boilers, Uncontrolled (Post-NSPS)

(1) Calculate average/maximum heat input values (MMBtu/hr) based on natural gas flowrate

Fuel Component	Natural Gas Flowrate (Average)[1]	Natural Gas Flowrate (Maximum)[1]	Gross Heating Value	Average Hourly Heat Input	Maximum Hourly Heat Input
	(scf/hr)	(kg/hr)	(BTU/scf)	(MMBtu/hr)	(MMBtu/hr)
Natural Gas	459	459	1,000	0.459	0.459

(2) Calculate average (lb/hr and tons/yr) and maximum hourly (lb/hr) emissions

Pollutant	Emission Factor[2]	Emission Factor	Average Hourly Heat Input	Average Emission Rate	Annual Emission Rate
	(lb/ 10^6 scf)	(lb/MMBtu)	(MMBtu/hr)	(lb/hr)	(tpy)
TSP[1]	7.60	0.00760	0.459	0.00349	0.0153
NO_x	190	0.190	0.459	0.0872	0.382
SO_2[3]	0.600	6.00E-04	0.459	2.75E-04	1.21E-03
CO	84.0	0.0840	0.459	0.0386	0.169
VOC	5.50	5.50E-03	0.459	2.52E-03	1.11E-02
CO2e	120,027.00	1.20E+02	0.459	5.51E+01	2.41E+02
Lead (Pb)	5.00E-04	5.00E-07	0.459	2.30E-07	1.01E-06

[1] Assume PM_{10}=$PM_{2.5}$=TSP

[2] Emission Factors from AP-42 Table 1.4-1 and Table 1.4-2

[3] SO_2 AP-42 emission factor adjusted for typical natural gas Sulfur content

Emission Point Source Calculations

Emission Point Identifier: **37**
Description: **Seal Gas Vent**

Inputs

Description	Value	Units
Annual Hours of Operation	8,760	hr/yr
Designed Production Rate	2,205,000	tons/yr
Designed Production Rate, Hourly	360	ton HBI / hr
Total Reformer Volumetric Vent Rate	424,000	Nm^3/hr
Seal Gas System Off-take	20,000	Nm^3/hr
Normal Reformer Firing Rate	1,402	MMBtu/hr
Nominal Natural Gas Supplement Rate	12.0%	lb/MMBtu
Total PM Emission Factor, dry @3%O2	10.0	mg/Nm^3
Filterable PM Emission Factor	25.0%	%
NO_X Uncontrolled Concentration, dry at 3% O2	115.0	mg/Nm^3
PM_{10} Filterable Mass Fraction	100%	
$PM_{2.5}$ Filterable Mass Fraction	100%	
CO Emission Factor	84.0	lbs / $mmft^3$
SO_2 Emission Factor	0.600	lbs / $mmft^3$
VOC Emission Factor	5.50	lbs / $mmft^3$
Natural Gas, fuel and reduction gas raw materials	380	Nm^3/ton HBI

Emissions Summary

Pollutant	Average Emission Rate (lb/hr)	Annual Emission Rate (tpy)
TSP	0.367	1.61
PM_{10}	0.367	1.61
$PM_{2.5}$	0.367	1.61
NOx	4.22	18.5
SO_2	0.137	0.599
CO	5.44	23.8
CO2	27,346	119,775
CO2e	27,352	119,802
VOC	0.356	1.56
Lead (Pb)	1.14E-04	4.99E-04
Benzene	1.63E-05	7.15E-05
Dichlorobenzene	9.32E-06	4.08E-05
Formaldehyde	5.83E-04	2.55E-03
n-Hexane	1.40E-02	6.13E-02
Naphthalene	4.74E-06	2.08E-05
Toluene	2.64E-05	1.16E-04
PAH	6.53E-07	2.86E-06

Calculation Basis: Seal Gas Vent

Seal gas consists of Reformer Flue Gas. Emissions for the Upper Seal Gas Vent are calculated in the exact same manner as total emissions from the Reformer, and then adjusted by the ratio of flue gas diverted to the seal gas system.

Calculate Emissions
Via Outlet Concentrations (Manufacutrer)

Pollutant	Normal Vented Flue Flow Rate	Dry Vented Flue Flow Rate	Component Concentration @ 3% O2	Control Efficiency	Average Emission Rate	Annual Emission Rate
	(Nm^3/hr)	(dNm^3/hr)	(mg/dNm^3)	%	(lb/hr)	(tons/yr)
NO_x	20,000	15,678	115	0.00%	4.22	18.5
TSP	20,000	15,678	10.0	0.00%	0.367	1.61
PM_{10}	20,000	15,678	10.0	0.00%	0.367	1.61
$PM_{2.5}$	20,000	15,678	10.0	0.00%	0.367	1.61

Emission rate correction to 3% O2: dNm^3 * mg/dNm^3 / 453600 * ((20.9-1.9)/(20.9-3))

Via AP-42 Emission Factor, Chapter 1, Section 4, Tables 1.4-1 and 1.4-2

Pollutant	Normal Reformer Firing Rate	Emission Factor	Seal Gas Compensation	Control Efficiency	Average Emission Rate	Annual Emission Rate
	(MMBtu/hr)	(lbs/mmBtu NG)	-	%	(lb/hr)	(tons/yr)
CO	1,402	0.0824	0.0472	0.00%	5.44	23.8
VOC	1,402	0.00539	0.0472	0.00%	0.356	1.56

Via Reducing Gas and Fuel Maximum

Pollutant	Total NG as Fuel and RM	Max HBI output	Emission Factor	Control Efficiency	Seal Gas Compensation	Average Emission Rate	Annual Emission Rate
	(Nm^3/ton)	(ton HBI/hr)	(lbs/mmcf NG)	%	-	(lb/hr)	(tons/yr)
SO2	380	360	0.600	0.00%	0.0472	0.137	0.599
CO2	380	360	120,000	0.00%	0.0472	27346	119775
CO2e	380	360	120,027	0.00%	0.0472	27352	119802
Lead (Pb)	380	360	5.00E-04	0.00%	0.0472	1.14E-04	4.99E-04

Calculate HAP Emissions

Pollutant	Normal Reformer Firing Rate (MMBtu/hr)	AP-42 Emission Factor (lb/MBtu)	Nominal Natural Gas Supplement Rate %	Seal Gas System Compensation (-)	Average Emission Rate (lb/hr)	Annual Emission Rate (tons/yr)
Benzene	1,402	2.06E-06	12.0%	0.0472	1.63E-05	7.15E-05
Dichlorobenzene	1,402	1.18E-06	12.0%	0.0472	9.32E-06	4.08E-05
Formaldehyde	1,402	7.35E-05	12.0%	0.0472	5.83E-04	2.55E-03
n-Hexane	1,402	1.76E-03	12.0%	0.0472	1.40E-02	6.13E-02
Naphthalene	1,402	5.98E-07	12.0%	0.0472	4.74E-06	2.08E-05
Toluene	1,402	3.33E-06	12.0%	0.0472	2.64E-05	1.16E-04
PAH	1,402	8.24E-08	12.0%	0.0472	6.53E-07	2.86E-06
Arsenic	1,402	1.96E-07	12.0%	0.0472	1.55E-06	6.81E-06
Barium	1,402	4.31E-06	12.0%	0.0472	3.42E-05	1.50E-04
Beryllium	1,402	1.18E-08	12.0%	0.0472	9.32E-08	4.08E-07
Cadmium	1,402	1.08E-06	12.0%	0.0472	8.55E-06	3.74E-05
Chromium	1,402	1.37E-06	12.0%	0.0472	1.09E-05	4.76E-05
Cobalt	1,402	8.24E-08	12.0%	0.0472	6.53E-07	2.86E-06
Copper	1,402	8.33E-07	12.0%	0.0472	6.60E-06	2.89E-05
Manganese	1,402	3.73E-07	12.0%	0.0472	2.95E-06	1.29E-05
Mercury	1,402	2.55E-07	12.0%	0.0472	2.02E-06	8.85E-06
Molybdenum	1,402	1.08E-06	12.0%	0.0472	8.55E-06	3.74E-05
Nickel	1,402	2.06E-06	12.0%	0.0472	1.63E-05	7.15E-05
Selenium	1,402	2.35E-08	12.0%	0.0472	1.86E-07	8.17E-07
Vanadium	1,402	2.25E-06	12.0%	0.0472	1.79E-05	7.83E-05
Zinc	1,402	2.84E-05	12.0%	0.0472	2.25E-04	9.87E-04

Emission Point Source Calculations

Emission Point Identifier: **8**
Description: **Furnace Dedusting (BSG Dust Collection)**

Inputs

Description	Value	Units
Annual Hours of Operation	8,760	hr/yr
Iron Oxide Consumption Rate	2,205,000	tons/yr
Design Volmetric Vent Rate	63,000	Nm^3/hr
Clean Gas Concentration	18.0	mg/Nm^3
PM_{10} Mass Fraction	100%	%
$PM_{2.5}$ Mass Fraction (Process Experience)	90.0%	%

Emissions Summary

Pollutant	Average Emission Rate (lb/hr)	Annual Emission Rate (tpy)
TSP	2.50	11.0
PM_{10}	2.50	11.0
$PM_{2.5}$	2.25	9.86

Calculate Emissions

Pollutant	Normal Dedusting Airflow Rate	Maximum Clean Gas Concentration	Mass Fraction of Total PM	Average Emission Rate	Annual Emission Rate
	(Nm^3/hr)	(mg/Nm^3)	%	(lb/hr)	(tons/yr)
TSP	63,000	18	100%	2.50	11.0
PM_{10}	63,000	18	100%	2.50	11.0
$PM_{2.5}$	63,000	18	90.0%	2.25	9.86

Emission Point Source Calculations

Emission Point Identifier: **9**
Description: **Briquetter Dedusting**

Inputs

Description	Value	Units
Annual Hours of Operation	8,760	hr/yr
Designed Production Rate	2,205,000	tons/yr
Design Volmetric Vent Rate	100,000	Nm^3/hr
Clean Gas Concentration	18.0	mg/Nm^3
PM_{10} Mass Fraction	100%	%
$PM_{2.5}$ Mass Fraction	90.0%	%

Emissions Summary

Pollutant	Average Emission Rate (lb/hr)	Annual Emission Rate (tpy)
TSP	3.97	17.4
PM_{10}	3.97	17.4
$PM_{2.5}$	3.57	15.6

Calculate Emissions

Pollutant	Normal Dedusting Airflow Rate	Maximum Clean Gas Concentration	Mass Fraction of Total PM	Average Emission Rate	Annual Emission Rate
	(Nm^3/hr)	**(mg/Nm^3)**	**%**	**(lb/hr)**	**(tons/yr)**
TSP	100,000	18.0	100%	3.97	17.4
PM_{10}	100,000	18.0	100%	3.97	17.4
$PM_{2.5}$	100,000	18.0	90.0%	3.57	15.6

Emission Point Source Calculations

Emission Point Identifier: **12**
Description: **Transfer & Product Screening Station No. 1 (Pre Pile)**

Inputs

Description	Value	Units
Annual Hours of Operation	8,760	hr/yr
Designed Production Rate	2,205,000	tons/yr
Design Volmetric Vent Rate	40,000	Nm^3/hr
Cleaned Gas Particulate Concentration	4.57	mg/Nm^3
PM_{10} Mass Fraction	100.0%	%
$PM_{2.5}$ Mass Fraction	90.0%	%

Emissions Summary

Pollutant	Average Emission Rate (lb/hr)	Annual Emission Rate (tpy)
TSP	0.40	1.77
PM_{10}	0.40	1.77
$PM_{2.5}$	0.36	1.59

Notes:
Transfer & Product Screening Station No. 1 (Pre Pile)

Basis:
The Screening Scrubber captures particulate emissions from the screening operations. This includes two transfer operations.

Calculations:

Calculate Emissions

Pollutant	Normal Dedusting Airflow Rate	Clean Gas Concentration	Mass Fraction of Total PM	Average Emission Rate	Annual Emission Rate
	(Nm^3/hr)	**(mg/Nm^3)**	**%**	**(lb/hr)**	**(tons/yr)**
TSP	40,000	4.6	100%	0.40	1.77
PM_{10}	40,000	4.6	100%	0.40	1.77
$PM_{2.5}$	40,000	4.6	90%	0.36	1.59

Emission Point Source Calculations

Case: **14**
Description: **Product Storage Piles**

Inputs	Value	Units
Material storage time	8,760	hrs
Storage duration	365	days
Average wind speed	12.0	mph
Number of dry days per year	288	days
Percentage of time wind speed > 12 mph	50%	% (actual)
Annual Material Throughput	2,205,000	tons/yr
Excess Receiving Capacity (Annual)	110%	%
Conveyor System Service Factor (Hourly)	115%	%
Transfer rate-stacker	1,500	tons/hr
Transfer rate-reclaimer	1,500	tons/hr
Wind Erosion Chemical Suppression	95%	%
Control efficiency -stacker	90%	%
Control efficiency -reclaimer	75%	%
Material moisture content	3.2	%
Material silt content	4.3	%
Storage area ground surface silt content	6.0	%
Percentage PM 10 in material	13.0%	%
Pile maintenance/traffic hours	365	days
Dozer miles per day	2	mi
Dozer average weight	20	tons
Front end loader miles per day	10	mi
Front end loader average weight	20	tons
Control efficiency - maintenance/traffic	70%	%

Corpus Christi average wind speed (previous 60 years) http://www.ncdc.noaa.gov/oa/climate/online/ccd/avgwind.html, 7/27/12
Corpus Christi mean number of days with precipitation .01" or more (previous 63 years) http://lwf.ncdc.noaa.gov/oa/climate/online/ccd/prcpdays.html, 7/27/12

Emissions Summary

Total Suspended Particles (TSP)

Source Description	Average Emission Rate	Annual Emission Rate
	(lbs/hr)	(tpy)
Material Transfers In/Out of Storage	0.26	1.12
Equipment Traffic in Storage Area	1.17	5.12
Wind Erosion	0.06	0.26
TOTAL	**1.48**	**6.50**

Total Particulate Matter < 10 um (PM_{10})

Source Description	Average Emission Rate	Annual Emission Rate
	(lbs/hr)	(tpy)
Material Transfers In/Out of Storage	0.12	0.51
Equipment Traffic in Storage Area	0.31	1.36
Wind Erosion	0.01	0.03
TOTAL	**0.44**	**1.91**

Total Particulate Matter < 2.5 um ($PM_{2.5}$)

Source Description	Average Emission Rate	Annual Emission Rate
	(lbs/hr)	(tpy)
Material Transfers In/Out of Storage	0.04	0.16
Equipment Traffic in Storage Area	0.03	0.14
Wind Erosion	0.00	0.01
TOTAL	**0.07**	**0.30**

[1] Per AP-42 (Table 13.2.2-2), PM-30 is assumed equivalent to toal suspended particle matter (TSP)

Material Stacking and Reclaiming

Calculation Basis:

Calculation methodology derived from Table 12.5-4 "*Pile Formation, Staacker, Pellet Ore,* " AP-42 (10/86).
Transfer Locations: (1) stacker/dump to pile; (2) reclaimer/loader out of pile onto conveyor.

Emission Calculations

Average Annual Particulate (TSP) Emissions from Material Storage Pile Transfers

Transfer Location	Annual Throughput	Emission Factor	Number of Drops	Uncontrolled Emissions	Overall Control Efficiency	Controlled Emission Rates	
	(tons/yr^1)	(lb/ton)		(lb/yr)	%	(lb/hr$_{avg}$)	(tpy)
Storage Pile (stacker)	2,425,743	0.0024	1.0	5,822	90.00%	0.07	0.29
Storage Pile (reclaimer)	2,425,743	0.0024	1.0	5,822	75.00%	0.17	0.73
TOTAL						**0.23**	**1.02**

Average Annual Particulate (PM$_{10}$) Emissions from Material Storage Pile Transfers

Transfer Location	Annual Throughput	Emission Factor	Number of Drops	Uncontrolled Emissions	Overall Control Efficiency	Controlled Emission Rates	
	(tons/yr^1)	(lb/ton)		(lb/yr)	%	(lb/hr$_{avg}$)	(tpy)
Storage Pile (stacker)	2,425,743	0.0011	1.0	2,668	90.00%	0.03	0.13
Storage Pile (reclaimer)	2,425,743	0.0011	1.0	2,668	75.00%	0.08	0.33
TOTAL						**0.11**	**0.47**

Average Annual Particulate (PM$_{2.5}$) Emissions from Material Storage Pile Transfers

Transfer Location	Annual Throughput	Emission Factor	Number of Drops	Uncontrolled Emissions	Overall Control Efficiency	Controlled Emission Rates	
	(tons/yr^1)	(lb/ton)		(lb/yr)	%	(lb/hr$_{avg}$)	(tpy)
Storage Pile (stacker)	2,425,743	0.00034	1.0	825	90.00%	0.01	0.04
Storage Pile (reclaimer)	2,425,743	0.00034	1.0	825	75.00%	0.02	0.10
TOTAL						**0.03**	**0.14**

[1] capacity converted to US tons

Equipment Traffic in Storage Areas

Calculation Basis:

Calculation methodology derived from Section 13.2.2, "*Unpaved Roads,*" dated AP-42 (11/06) (in accordance with guidance from Section 13.2.4)
Accounts for bulldozer (on pile) and front-end loader (between piles)

$$\text{Emission factor (lb/VMT)} = k(s/12)^{a}(W/3)^{b}$$

where:

s = silt content of aggregate (%)[1]
W = mean vehicle weight [2]
k,a,b = empirical constants for industrial roads [3]

Empirical Constants for Industrial Roads			
	PM-2.5	**PM-10**	**PM-30**
k	0.15	1.5	4.9
a	0.9	0.9	0.70
b	0.45	0.45	0.45

Note:

1. From AP42, Section 13.2.2, Table 13.2.2-1, Dated 11/06
2. From AP42, Section 13.2.2, Table 13.2.2-3, Dated 11/06
3. From AP42, Section 13.2.2, Table 13.2.2-2, Dated 11/06

Calculation of Average Annual Controlled Emission Rate

Average Annual Controlled Emission Rate (tons/yr) = Vehicle Miles traveled in an day (VMT/day) * EF (lb PM / VMT) * (number of days per year)*
(1-control efficiency) / (2000 lb/ton)
Average Controlled Emission Rate (lb/hr) = Average Controlled Emission Rate (tons/yr)* (2000 lb/ton)/8760 hrs/yr

Emission Calculations:

Average Annual Particulate Emissions (TSP) from Equipment Traffic in Storage Areas

Vehicle Type	Vehicle Miles Traveled	Emission Factor	Uncontrolled Emission Rate	Overall Control Efficiency	Controlled Emission Rates	
	(VMT/day)	(lb/VMT)	(lb/day)	%	(lb/hr$_{avg}$)	(tpy)
Dozers	2	7.08	14.2	70.00%	0.18	0.78
Front-end loaders	10	7.08	70.8	70.00%	0.89	3.88
TOTAL					**1.06**	**4.65**

Average Annual Particulate Emissions (PM10) from Equipment Traffic in Storage Areas

Vehicle Type	Vehicle Miles Traveled (VMT/day)	Emission Factor	Uncontrolled Emission Rate	Overall Control Efficiency	Controlled Emission Rates	
		(lb/VMT)	(lb/day)	%	(lb/hr$_{avg}$)	(tpy)
Dozers	2	1.89	3.8	70.00%	0.05	0.21
Front-end loaders	10	1.89	18.9	70.00%	0.24	1.03
TOTAL					**0.28**	**1.24**

Average Annual Particulate Emissions (PM$_{2.5}$) from Equipment Traffic in Storage Areas

Vehicle Type	Vehicle Miles Traveled (VMT/day)	Emission Factor	Uncontrolled Emission Rate	Overall Control Efficiency	Controlled Emission Rates	
		(lb/VMT)	(lb/day)	%	(lb/hr$_{avg}$)	(tpy)
Dozers	2	0.189	0.4	70.00%	0.00	0.02
Front-end loaders	10	0.189	1.9	70.00%	0.02	0.10
TOTAL					**0.03**	**0.12**

Wind Erosion

Calculation Basis:

Calculation methodology derived from EPA documents:
"Fugitive Emissions from Integrated Iron and Steel Plants", Section 2.2.4, Figure 3-9 (March 1978) and
"*Iron and Steel Plant Open Source Fugitive Emission Evaluation*", Section 2.1.3 and Table 2-1, Equation (8) (August 1978)
Climatological data from New Orleans Regional Airport Weather Station (Jan-Dec 2007)

Emission factor (lb/ton) = $0.05(s/1.5)(D/90)(d/235)(f/15)$

where:

s = silt content of aggregate (%)[1]
D = duration of storage (days)
d = dry days per year[2]
f = percentage of time wind speed exceeds 12 mph

Note:

1. From AP42, Section 13.2.2, Table 13.2.2-1, Dated 11/06
2. From AP42, Section 13.2.2, Table 13.2.2-1, Dated 11/06

Calculation of Average Annual Controlled Emission Rate

Average Annual Controlled Emission Rate (tons/yr) = tons of aggregate through storage cycle (tons) * EF (lb PM / VMT) * (1 - Control efficiency)
Average Controlled Emission Rate (lb/hr) = Average Controlled Emission Rate (tons/yr)* (2000 lb/ton)/8760 hrs/yr

Emission Calculations:

Average Annual Particulate Emissions (TSP) from Wind Erosion from Storage Piles

Aggregate	Throughput[1]	Emission Factor	Uncontrolled Emissions Rate	Overall Control Efficiency	Controlled Average Emission Rate	
	(tons/yr)	(lb/ton)	(lb/yr)	%	(lb/hr_{avg})	(tpy)
Iron Ore Pellets	404,290	0.02	9,601	95.00%	0.05	0.24

Average Annual Particulate Emissions (PM_{10}) from Wind Erosion from Storage Piles

Aggregate	TSP Controlled Avg. Emission Rate		% PM 10	Controlled Average Emission Rate	
	(lb/hr_{avg})	(tpy)	%	(lb/hr_{avg})	(tpy)
Iron Ore Pellets	0.05	0.24	13.00%	0.01	0.03

Average Annual Particulate Emissions ($PM_{2.5}$) from Wind Erosion from Storage Piles

Aggregate	TSP Controlled Avg. Emission Rate		% $PM_{2.5}$[2]	Controlled Average Emission Rate	
	(lb/hr_{avg})	(tpy)	%	(lb/hr_{avg})	(tpy)
Iron Ore Pellets	0.05	0.24	1.95%	0.00	0.00

[1] Assume 2-month supply onsite at all times

[2] Per an EPA document showing that PM2.5/PM10 for metallic ore and coal piles is 0.15- www.epa.gov/ttn/chief/conference/ei15/session14/cowherd.pdf

Emission Point Source Calculations

Emission Point Identifier: **13**
Description: **Transfer & Product Screening Station No. 2 (Post Pile)**

Inputs

Description	**Value**	**Units**
Annual Hours of Operation	8,760	hr/yr
Designed Production Rate	2,205,000	tons/yr
Design Volmetric Vent Rate	40,000	Nm^3/hr
Cleaned Gas Particulate Concentration	4.57	mg/Nm^3
PM_{10} Mass Fraction	100.0%	%
$PM_{2.5}$ Mass Fraction	90.0%	%

same as iron oxide consumption rate?

Emissions Summary

Pollutant	**Average Emission Rate (lb/hr)**	**Annual Emission Rate (tpy)**
TSP	0.40	1.77
PM_{10}	0.40	1.77
$PM_{2.5}$	0.36	1.59

Notes:
Transfer & Product Screening Station No. 2 (Post Pile)

Basis:
The Screening Scrubber captures particulate emissions from the screening operations. This includes two transfer operations.

Calculations:

Calculate Emissions

Pollutant	Normal Dedusting Airflow Rate (Nm^3/hr)	Nominal Clean Gas Concentration (mg/Nm^3)	Mass Fraction of Total PM %	Average Emission Rate (lb/hr)	Annual Emission Rate (tons/yr)
TSP	40,000	4.57	100%	0.40	1.77
PM$_{10}$	40,000	4.57	100%	0.40	1.77
PM$_{2.5}$	40,000	4.57	90%	0.36	1.59

Emission Point Source Calculations

Case: **36**
Description: **Remet / Fines Storage**

Inputs	Value	Units
Material storage time	8,760	hrs
Storage duration	365	days
Average wind speed	12.0	mph
Number of dry days per year	288	days
Percentage of time wind speed > 12 mph	50%	% (actual)
Annual Material Throughput[1]	130,000	tons/yr
Excess Receiving Capacity (Annual)	110%	%
Conveyor System Service Factor (Hourly)	100%	%
Transfer rate-stacker	50	tons/hr
Transfer rate-reclaimer	50	tons/hr
Wind Erosion Chemical Suppression	95%	%
Control efficiency -stacker	90%	%
Control efficiency -reclaimer	75%	%
Material moisture content	3.2	%
Material silt content	4.3	%
Storage area ground surface silt content	6.0	%
Percentage PM 10 in material, estimate as screened material	20.0%	%
Pile maintenance/traffic hours	365	days
Dozer miles per day	0.5	mi
Dozer average weight	20	tons
Front end loader miles per day	1	mi
Front end loader average weight	20	tons
Control efficiency - maintenance/traffic	70%	%

http://www.ncdc.noaa.gov/oa/climate/online/ccd/avgwind.html
Corpus Christi mean number of days with precipitation .01" or more (previous 63 years) http://lwf.ncdc.noaa.gov/oa/climate/online/ccd/prcpdays.html, 7/27/12
http://www.ncdc.noaa.gov/oa/climate/online/ccd/avgwind.html
Estimated maximum reject of ore or product combined

[1] Across multiple remet and storage piles and bunkers, facility annual total

Emissions Summary

Total Suspended Particles (TSP)

Source Description	Average Emission Rate	Annual Emission Rate
	(lbs/hr)	**(tpy)**
Material Transfers In/Out of Storage	0.00	0.02
Equipment Traffic in Storage Area	0.15	0.64
Wind Erosion	0.02	0.08
TOTAL	**0.17**	**0.74**

Total Particulate Matter < 10 um (PM_{10})

Source Description	Average Emission Rate	Annual Emission Rate
	(lbs/hr)	(tpy)
Material Transfers In/Out of Storage	0.00	0.01
Equipment Traffic in Storage Area	0.04	0.17
Wind Erosion	0.00	0.02
TOTAL	**0.04**	**0.20**

Total Particulate Matter < 2.5 um ($PM_{2.5}$)

Source Description	Average Emission Rate	Annual Emission Rate
	(lbs/hr)	(tpy)
Material Transfers In/Out of Storage	0.001	0.00
Equipment Traffic in Storage Area	0.004	0.02
Wind Erosion	0.001	0.00
TOTAL	**0.005**	**0.02**

[1] Per AP-42 (Table 13.2.2-2), PM-30 is assumed equivalent to toal suspended particle matter (TSP)

Material Transfers In/Out of Storage

Calculation Basis:

Calculation methodology derived from Table 12.5-4 "*Pile Formation, Stacker, Pellet Ore,*" AP-42 (10/86).
Transfer Locations: (1) stacker/dump to pile; (2) reclaimer/loader out of pile onto conveyor; (3) equipment traffic within pile area.

Emission Calculations

Average Annual Particulate (TSP) Emissions from Material Storage Pile Transfers

Transfer Location	Annual Throughput	Emission Factor	Number of Drops	Uncontrolled Emissions	Overall Control Efficiency	Controlled Emission Rates	
	(tons/yr[1])	(lb/ton)		(lb/yr)	%	(lb/hr_{avg})	(tpy)
Storage Pile (drop point)	143,014	0.0024	1.0	343	90.00%	0.004	0.017
TOTAL						**0.004**	**0.017**

Average Annual Particulate (PM_{10}) Emissions from Material Storage Pile Transfers

Transfer Location	Annual Throughput	Emission Factor	Number of Drops	Uncontrolled Emissions	Overall Control Efficiency	Controlled Emission Rates	
	(tons/yr[1])	(lb/ton)		(lb/yr)	%	(lb/hr_{avg})	(tpy)
Storage Pile (drop point)	143,014	0.0011	1.0	157	90.00%	0.002	0.008
TOTAL						**0.002**	**0.008**

Average Annual Particulate ($PM_{2.5}$) Emissions from Material Storage Pile Transfers

Transfer Location	Annual Throughput	Emission Factor	Number of Drops	Uncontrolled Emissions	Overall Control Efficiency	Controlled Emission Rates	
	(tons/yr[1])	(lb/ton)		(lb/yr)	%	(lb/hr_{avg})	(tpy)
Storage Pile (drop point)	143,014	0.00034	1.0	49	90.00%	0.001	0.002
TOTAL						**0.001**	**0.002**

[1] capacity converted to US tons

Equipment Traffic in Storage Areas

Calculation Basis:

Calculation methodology derived from Section 13.2.2, "*Unpaved Roads,*" dated AP-42 (11/06) (in accordance with guidance from Section 13.2.4)
Accounts for bulldozer (on pile) and front-end loader (between piles)

$$\text{Emission factor (lb/VMT)} = k(s/12)^{a}(W/3)^{b}$$

where:

s = silt content of aggregate (%)[1]
W = mean vehicle weight [2]
k, a, b = empirical constants for industrial roads [3]

Empirical Constants for Industrial Roads			
	PM-2.5	**PM-10**	**PM-30**
k	**0.15**	**1.5**	**4.9**
a	**0.9**	**0.9**	**0.70**
b	**0.45**	**0.45**	**0.45**

Note:

1. From AP42, Section 13.2.2, Table 13.2.2-1, Dated 11/06
2. From AP42, Section 13.2.2, Table 13.2.2-3, Dated 11/06
3. From AP42, Section 13.2.2, Table 13.2.2-2, Dated 11/06

Calculation of Average Annual Controlled Emission Rate

Average Annual Controlled Emission Rate (tons/yr) = Vehicle Miles traveled in an day (VMT/day) * EF (lb PM / VMT) * (number of days per year)* (1-control efficiency) / (2000 lb/ton)

Average Controlled Emission Rate (lb/hr) = Average Controlled Emission Rate (tons/yr)* (2000 lb/ton)/8760 hrs/yr

Emission Calculations:

Average Annual Particulate Emissions (TSP) from Equipment Traffic in Storage Areas

Vehicle Type	Vehicle Miles Traveled	Emission Factor	Uncontrolled Emission Rate	Overall Control Efficiency	Controlled Emission Rates	
	(VMT/day)	(lb/VMT)	(lb/day)	%	(lb/hr_{avg})	(tpy)
Dozers	1	7.08	3.5	70.0%	0.044	0.19
Front-end loaders	1	7.08	7.1	70.0%	0.089	0.39
TOTAL					**0.13**	**0.58**

Average Annual Particulate Emissions (PM10) from Equipment Traffic in Storage Areas

Vehicle Type	Vehicle Miles Traveled	Emission Factor	Uncontrolled Emission Rate	Overall Control Efficiency	Controlled Emission Rates	
	(VMT/day)	(lb/VMT)	(lb/day)	%	(lb/hr_{avg})	(tpy)
Dozers	1	1.89	0.9	70.0%	0.012	0.05
Front-end loaders	1	1.89	1.9	70.0%	0.024	0.10
TOTAL					**0.035**	**0.16**

Average Annual Particulate Emissions ($PM_{2.5}$) from Equipment Traffic in Storage Areas

Vehicle Type	Vehicle Miles Traveled	Emission Factor	Uncontrolled Emission Rate	Overall Control Efficiency	Controlled Emission Rates	
	(VMT/day)	(lb/VMT)	(lb/day)	%	(lb/hr_{avg})	(tpy)
Dozers	1	0.189	0.1	70.0%	0.0012	0.005
Front-end loaders	1	0.189	0.2	70.0%	0.0024	0.010
TOTAL					**0.0035**	**0.016**

Wind Erosion

Calculation Basis:

Calculation methodology derived from EPA documents:
"*Fugitive Emissions from Integrated Iron and Steel Plants*", Section 2.2.4, Figure 3-9 (March 1978) and
"*Iron and Steel Plant Open Source Fugitive Emission Evaluation*", Section 2.1.3 and Table 2-1, Equation (8) (August 1978)
Climatological data from New Orleans Regional Airport Weather Station (Jan-Dec 2007)

$$\text{Emission factor (lb/ton)} = 0.05(s/1.5)(D/90)(d/235)(f/15)$$

where:
s = silt content of aggregate (%)
D = duration of storage (days)
d = dry days per year^{2}
f = percentage of time wind speed exceeds 12 mph

Note:
1. From AP42, Section 13.2.2, Table 13.2.2-1, Dated 11/06
2. From AP42, Section 13.2.2, Table 13.2.2-1, Dated 11/06

Calculation of Average Annual Controlled Emission Rate

Average Annual Controlled Emission Rate (tons/yr) = tons of aggregate through storage cycle (tons) * EF (lb PM / VMT) * (1 - Control efficiency)
Average Controlled Emission Rate (lb/hr) = Average Controlled Emission Rate (tons/yr)* (2000 lb/ton)/8760 hrs/yr

Emission Calculations:

Average Annual Particulate Emissions (TSP) from Wind Erosion from Storage Piles

Aggregate	Throughput	Emission Factor	Uncontrolled Emissions Rate	Overall Control Efficiency	Controlled Average Emission Rate	
	(tons/yr)	**(lb/ton)**	**(lb/yr)**	**%**	**(lb/hr$_{avg}$)**	**(tpy)**
Remet / Fines	130,000	0.024	3,087.1	95.00%	0.018	0.077

Average Annual Particulate Emissions (PM$_{10}$) from Wind Erosion from Storage Piles

Aggregate	TSP Controlled Avg. Emission Rate		% PM 10	Controlled Average Emission Rate	
	(lb/hr$_{avg}$)	**(tpy)**	**%**	**(lb/hr$_{avg}$)**	**(tpy)**
Remet / Fines	0.018	0.077	20.00%	0.004	0.015

Average Annual Particulate Emissions (PM$_{2.5}$) from Wind Erosion from Storage Piles

Aggregate	TSP Controlled Avg. Emission Rate		% PM$_{2.5}^{2}$	Controlled Average Emission Rate	
	(lb/hr$_{avg}$)	**(tpy)**	**%**	**(lb/hr$_{avg}$)**	**(tpy)**
Remet / Fines	0.018	0.077	3.00%	0.0005	0.0023

Per an EPA document showing that PM2.5/PM10 for metallic ore and coal piles is 0.15- www.epa.gov/ttn/chief/conference/ei15/session14/cowherd.pdf

Emission Point Source Calculations

Case: **33**
Description: **Cooling Tower**

Inputs	**Value**	**Units**
Annual operating hours	8,760	hrs
Cooling tower circulating water rate	20,000	gal/min
Percent drift	0.0005%	%
Total Dissolved Solids Content	35,000	ppm
Percent of Total PM that is PM_{10}[1]	3.0%	%

[1] Based upon document "Calculating PM_{10} Emissions from Cooling Towers" by Joel Reisman and Gordon Frisbie (Abstract No. 316, Session No. AM-1b)

Emissions Summary

Pollutant	**Average Emission Rate**	**Annual Emission Rate**
	(lbs/hr)	**(tpy)**
TSP	2.61	11.44
PM_{10}	0.08	0.34
$PM_{2.5}$	0.08	0.34

[1] Assume TSP=PM_{10}=$PM_{2.5}$

Calculation Basis:

Calculation methodology based upon a conservative mass balance approach.

Calculation of Average Annual Emission Rates

Emission Rate (lb/hr_{avg}) = Drift rate (gal/min)*TDS content (ppm)/1,000,000*60min/hr*0.13368 ft^3/gallon *62 lb/ft^3*1.5 Cycles

Emission Rate (tpy) = Average Controlled Emission Rate (lb/hr_{avg}) * annual operating hours (hrs/yr) / (2000 lb/ton)

Emission Calculations

Pollutant	Cooling Tower Circulating Water Rate	% Drift	Drift Rate	Total Dissolved Solids Content	Average Emission Rate	Annual Emission Rate
	(gal/min)	%	(gal/min)	(ppm)	(lb/hr_{avg})	(tpy)
TSP	20,000	0.0005%	0.10	35,000	2.61	11.44
PM_{10}	20,000	0.0005%	0.10	35,000	0.08	0.34
$PM_{2.5}$[1]	20,000	0.0005%	0.10	35,000	0.08	0.34

[1] Assuming PM_{10} = $PM_{2.5}$

Emission Point Source Calculations

Case: **39**
Description: **Paved Road Fugitive Dust**

Inputs	Value	Units
Days of Operation per year	365	days/yr
Average road surface silt loading	9.7	%
Fleet Average Weight	10.50	tons
Vehicle Miles Travelled - Heavy Duty	50	miles/day
Number of Days with > 0.01 inches of rain	77	days/yr
Control efficiency - Sweeping	90%	%

Corpus Christi mean number of days with precipitation .01" or more http://lwf.ncdc.noaa.gov/oa/climate/online/ccd/prcpdays.html, 7/27/12

Emissions Summary

Source Description	Pollutant	Average Emission Rate	Annual Emission Rate
		(lbs/hr)	(tpy)
Paved Road Fugitive Emissions	TSP[1]	0.25	1.08
	PM_{10}	0.05	0.21
	$PM_{2.5}$	0.01	0.03

[1] Per AP-42 (Table 13.2.2-2), PM-30 is assumed equivalent to total suspended particle matter (TSP)

Calculation Basis:

Calculation methodology derived from Section 13.2.1, "*Paved Roads,* " dated AP-42 (11/06)
Accounts for fall vehicular traffic on paved roads (assumes 1 mile ot paved road at facility)

$$Emission\,factor(lb/vehicle\,mile\,traveled) = k * \left(\frac{sL}{2}\right)^{0.65} * \left(\frac{W}{3}\right)^{1.5} - C$$

where:
sL = road surface silt loading, g/m^2 [1]
W = average vehicle weight, tons [2]
k = particle size multiplier, lb/VMT [3]
C - emission factor for 1980's vehicle fleet exhaust, brake wear, and tire wear, lb/VMT [4]

Note:
1. From AP42, Section 13.2.1, Table 13.2.1-4, Dated 11/06
2. From AP42, Section 13.2.2, Table 13.2.2-3, Dated 11/06
3. From AP42, Section 13.2.1, Table 13.2.1-1, Dated 11/06
4. From AP42, Section 13.2.1, Table 13.2.1-2, Dated 11/07

Particle Size Range	*k*	*C*
< 30 micrometers	0.082	0.00047
< 15 micrometers	0.02	0.00047
< 10 micrometers	0.016	0.00047
< 2.5 micrometers	0.0024	0.00036

Emission factor extrapolated for natural mitigation (lb/VMT) $E_{ext} = E\,[1 - (P/365)]$

where:
E = Uncontrolled emission factor
P = Number of days with > 0.01 inches of precipitation

<u>Emission Calculations:</u>

<u>Calculation of Average Annual Controlled Emission Rate</u>

Average Annual Controlled Emission Rate (tons/yr) = Vehicle Miles travelled in an day (VMT/day) * EF (lb PM / VMT) * (number of days per year)* (1-control effciency) / (2000 lb/ton)

Average Controlled Emission Rate (lb/hr) = Average Controlled Emission Rate (tons/yr)* (2000 lb/ton)/8760 hrs/yr

Average Annual Particulate Emissions (TSP) from Vehicular Traffic on Paved Roads

Emission Point	Vehicle Miles Travelled	Emission Factor	Uncontrolled Emission Rate	Overall Control Efficiency	Controlled Emission Rate	
	(VMT/day)	(lb/VMT)	(lb/day)	%	(lb/hr$_{avg}$)	(tpy)
All Vehicular Traffic	50	1.182	59.1	90%	0.25	1.08
TOTAL					**0.25**	**1.08**

Average Annual Particulate Emissions (PM_{10}) from Vehicular Traffic on Paved Roads

Vehicle Type	Vehicle Miles Travelled	Emission Factor	Uncontrolled Emission Rate	Overall Control Efficiency	Controlled Emission Rate	
	(VMT/day)	(lb/VMT)	(lb/day)	%	(lb/hr$_{avg}$)	(tpy)
All Vehicular Traffic	50	0.230	11.5	90%	0.05	0.21
TOTAL					**0.05**	**0.21**

Average Annual Particulate Emissions ($PM_{2.5}$) from Vehicular Traffic on Paved Roads

Vehicle Type	Vehicle Miles Travelled	Emission Factor	Uncontrolled Emission Rate	Overall Control Efficiency	Controlled Emission Rate	
	(VMT/day)	(lb/VMT)	(lb/day)	%	(lb/hr$_{avg}$)	(tpy)
All Vehicular Traffic	50	0.034	1.7	90%	0.01	0.03
TOTAL					**0.01**	**0.03**

Emission Point Source Calculations

Case: **34**
Description: **Emergency Generator**

Given:

1) 2500kWe Diesel Emergency Power Generator
2) Nominal Emissions data provided by a NSPS Certified manufacturer

Mechanical	kWm	2500
	Load %	100
NOx	g/kWh	5.822
HC	g/kWh	0.179
CO	g/kWh	0.689
PM	g/kWh	0.085

3) Fuel: 15ppm (0.0015%) Sulfur Diesel
4) SO2 emission factor: AP42 Chapter 3, Section 4: 8.09E-3*S = 8.09E-3*.0015 = 1.2E-5 lb/hph = 0.0077 g/kWh
5) NSPS IIII Hours based on Readiness and Maintenance limit of 100 hours (emergency use not limited)

Nominal Emissions Calculation - Requested Limit

Pollutant	100% Load (g/kWh)	100% Hourly Per Unit (lbs/hr)	100% Annual Emission Rate (tpy)
NOx	5.822	32.09	1.60
HC	0.179	0.99	0.049
CO	0.689	3.80	0.190
PM	0.085	0.47	0.023
SO2	0.0077	0.04	0.002

Hours	Per Unit
100%	100

Emission Point Source Calculations

Case: **35**
Description: **Fire Pump**

Given:

1) 175kWe Diesel Emergency Power Generator
2) Nominal Emissions data provided by a NSPS Certified manufacturer

Mechanical		
	kWm	175
	Load %	100
NOx	g/kWh	5.822
HC	g/kWh	0.179
CO	g/kWh	0.689
PM	g/kWh	0.085

3) Fuel: 15ppm (0.0015%) Sulfur Diesel
4) SO2 emission factor: AP42 Chapter 3, Section 4: 8.09E-3*S = 8.09E-3*.0015 = 1.2E-5 lb/hph = 0.0077 g/kWh
5) NSPS IIII Hours based on Readiness and Maintenance limit of 100 hours (emergency use not limited)

Nominal Emissions Calculation - Requested Limit

Pollutant	100% Load (g/kWh)	100% Hourly Per Unit (lbs/hr)	100% Annual Emission Rate (tpy)
NOx	5.822	2.25	0.112
HC	0.179	0.07	0.003
CO	0.689	0.27	0.013
PM	0.085	0.03	0.002
SO2	0.0077	0.00	1.49E-04

Hours	Per Unit
100%	100

Appendix B

Figures

General Layout
M 1:7500

Wind direction
Ingleside Naval Station

Overview
M 1:150 000

0 500m
Scale

29.10.2012

SAP techn. Platz Ebene 1	Konzeption Horizontale Erweiterung Technical Investment
Ebene 2	
Ebene 3	
Ebene 4	
Ebene 5	
Projekt	GO WEST
Maßstab	1:7500
Ersatz für (SAP-ZDM Dokumentennummer):	
Gehört zu (SAP-ZDM Dokumentennummer):	
Ersetzt durch (SAP-ZDM Dokumentennummer):	

voestalpine
EINEN SCHRITT VORAUS.

voestalpine Stahl GmbH
voestalpine-Straße 3
4020 Linz, Austria

Beschreibung
GENERAL LAYOUT:Texas/Corpus Christi - La Quinta DRI/HBI - Plant 1 (2,0 Mio.t/a) - MIDREX

	Datum	Name	Telefon
Ersteller	31.08.2012	Durstberger	73546
Prüfer			

Erstellerfirma (Name und Anschrift)
Engineering TSI
voestalpine Stahl GmbH

Diese Zeichnung wurde mit CAD erstellt und darf nur mit CAD geändert werden.
Erstellt mit CAD-Programm (+Version): AutoCAD

Firmen-Zeichnungsnummer
(nur wenn nicht voestalpine Stahl GmbH))

voestalpine Stahl GmbH
Zeichnungsnummer

SAP-Zuordnung zum technischen Platz: KON-GOWE

SAP-ZDM Dokumentennummer: 1004251

Dokumenttyp: LAY

Blatt 1
Folgeblatt 2

Format: A

Version

FILE:

Diese Zeichnung bleibt unser Eigentum und darf ohne unsere schriftliche Genehmigung weder vervielfältigt noch dritten Personen auf irgend eine Weise zugänglich gemacht werden.

General Layout
M 1:2500

Wind direction
Ingleside Naval Station

Overview
M 1:150 000

0 100m 200m

Scale 1:2500

LEGEND DRI-PLANT 1:

1	OXIDE UNLOADING WHARF
2	OXIDE TRANSFER TOWER 1 AND DEDUSTING
3	OXIDE TRANSFER TOWER 2
4	OXIDE STACKER
5	OXIDE STORAGE YARD
6	OXIDE RECLAIMER
7	OXIDE TRANSFER TOWER 3 AND DEDUSTING
8	OXIDE SCREENING STATION
9	DEDUSTING OXIDE SCREENING
10	OXIDE FINES HANDLING
11	REMET HANDLING
12	OXIDE COATING PLANT
13	VAPOR REMOVAL FAN & STACK
14	REDUCTION FURNACE
15	TOP GAS SCRUBBER
16	PROCESS GAS COMPRESSOR BUILDING
17	BLOWER HOUSE
18	HEAT RECOVERY SYSTEM
19	REFORMER
20	BRIQUETTE COOLER
21	HBI EMERGENCY STORAGE YARD
22	HBI TRANSFER TOWER 1
23	HBI STACKER
24	HBI STORAGE YARD
25	HBI RECLAIMER
26	PRODUCT SCREENING STATION
28	PRODUCT FINES HANDLING
29	SPACE FOR FINES BRIQUETTING
30	HBI TRANSFER TOWER 2
31	HBI LOADING WHARF
32	NATURAL GAS MEASURING AND REDUCTION STATION
33	FLARE
34	AIR COMPRESSOR STATION
35	DIESEL GENERATOR BUILDING
36	TRANSFORMER
37	MAIN SUBSTATION AND CONTROL BUILDING
38	SUBSTATION MATERIAL HANDLING
39	SUBSTATION SEAPORT
40	SEAWATER SUPPLY
41	RAW WATER TREATMENT
42	FIRE WATER RESERVOIR
43	WASTE WATER TREATMENT
44	CLARIFIER
45	COOLING TOWER
46	PUMP HOUSE
47	SETTLING PONDS
48	PROCESS CLASSIFIER
49	CHEMICAL AGENT STORAGE FACILITY
50	GATE HOUSE
51	ADMINISTRATION BUILDING, LABORATORY, FIRST AID STATION, BUILDING FOR TECHNOLOGICAL STAFF
52	EQUIPMENT STORAGE WAREHOUSE, REFRACTORY STORAGE, OIL AND LUBRICANT STORAGE, ENERGETIC WORKSHOP, HYDRAULIK AND MECHANICAL SERVICE SHOP
53	MOBILE EQUIPMENT FILLING & SERVICE STATION
54	ANALYZER CONTAINER
55	SPACE FOR WASTE HEAT RECOVERY
56	SEAL GAS STATION
57	INERT GAS STATION
58	BRIQUETTER AND BSG DEDUSTING
59	FLUE GAS HOT FAN
60	NATURAL GAS DISTRIBUTION
61	PURGE GAS TANKS
62	BLOWER AREA SUMP
63	SEAL GAS SUMP
64	PROCESS GAS MIST ELIMINATOR

29.10.2012

SAP techn. Platz Ebene 1 Konzeption Horizontale Erweiterung
Technical Investment
Ebene 2
Ebene 3
Ebene 4
Ebene 5
Projekt GO WEST

Maßstab 1:2500
Ersatz für (SAP-ZDM Dokumentennummer):
Gehört zu (SAP-ZDM Dokumentennummer):
Ersetzt durch (SAP-ZDM Dokumentennummer):

voestalpine
EINEN SCHRITT VORAUS.
voestalpine Stahl GmbH
voestalpine-Straße 3
4020 Linz, Austria

Beschreibung GENERAL LAYOUT:Texas/Corpus Christi - La Quinta
DRI/HBI - Plant 1 (2,0 Mio.t/a) - MIDREX

	Datum	Name	Telefon
Ersteller	31.08.2012	Durstberger	73546
Prüfer			

Erstellerfirma (Name und Anschrift)
Engineering TSI
voestalpine Stahl GmbH

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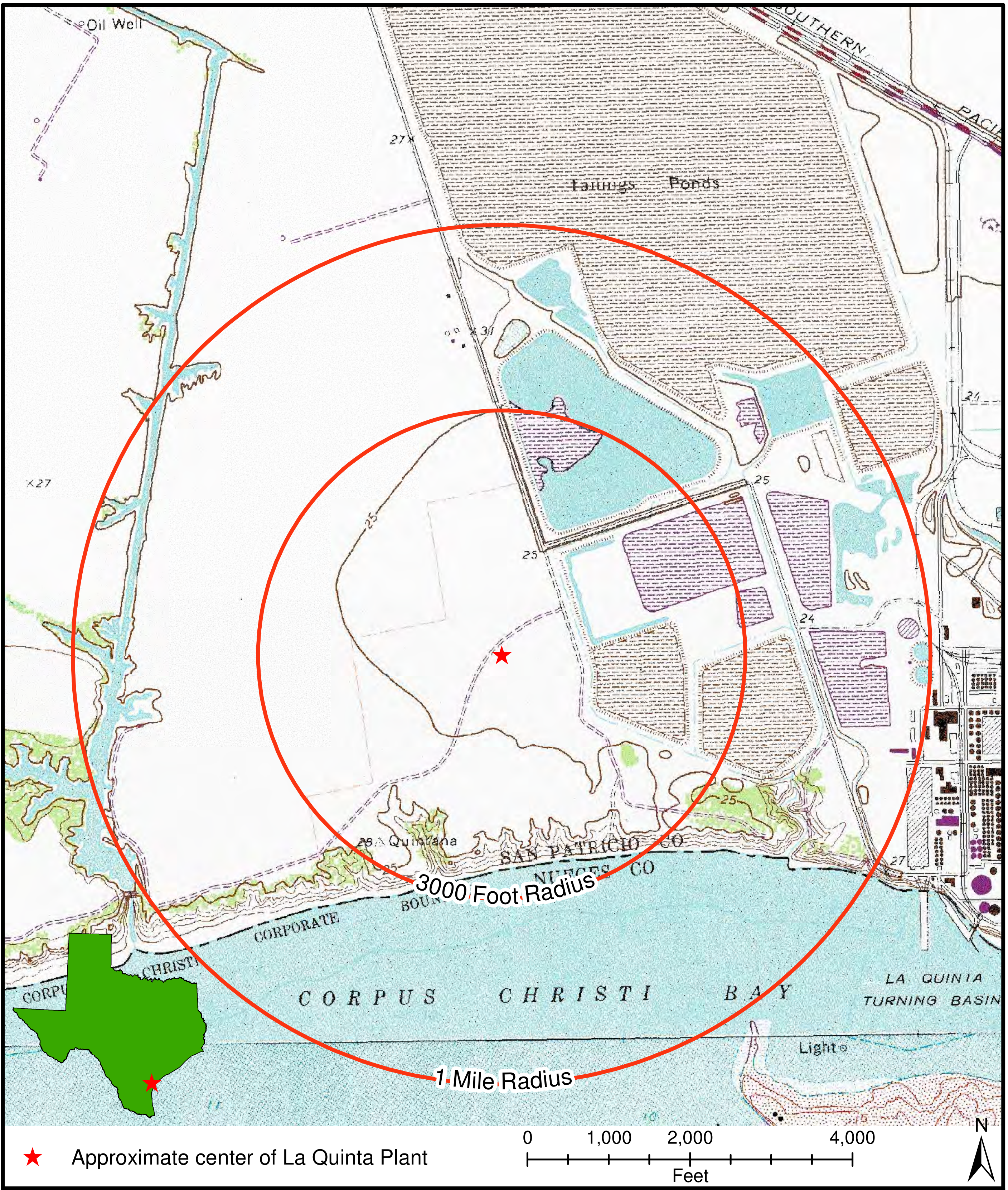


CHS 8/3/12 NAD83 UTM Zone 14N

Environmental Resources
Management NC, Inc.

FIGURE 2-1
3000 FOOT AND 1 MILE RADII MAP
Voestalpine La Quinta Plant
Corpus Christi, Texas

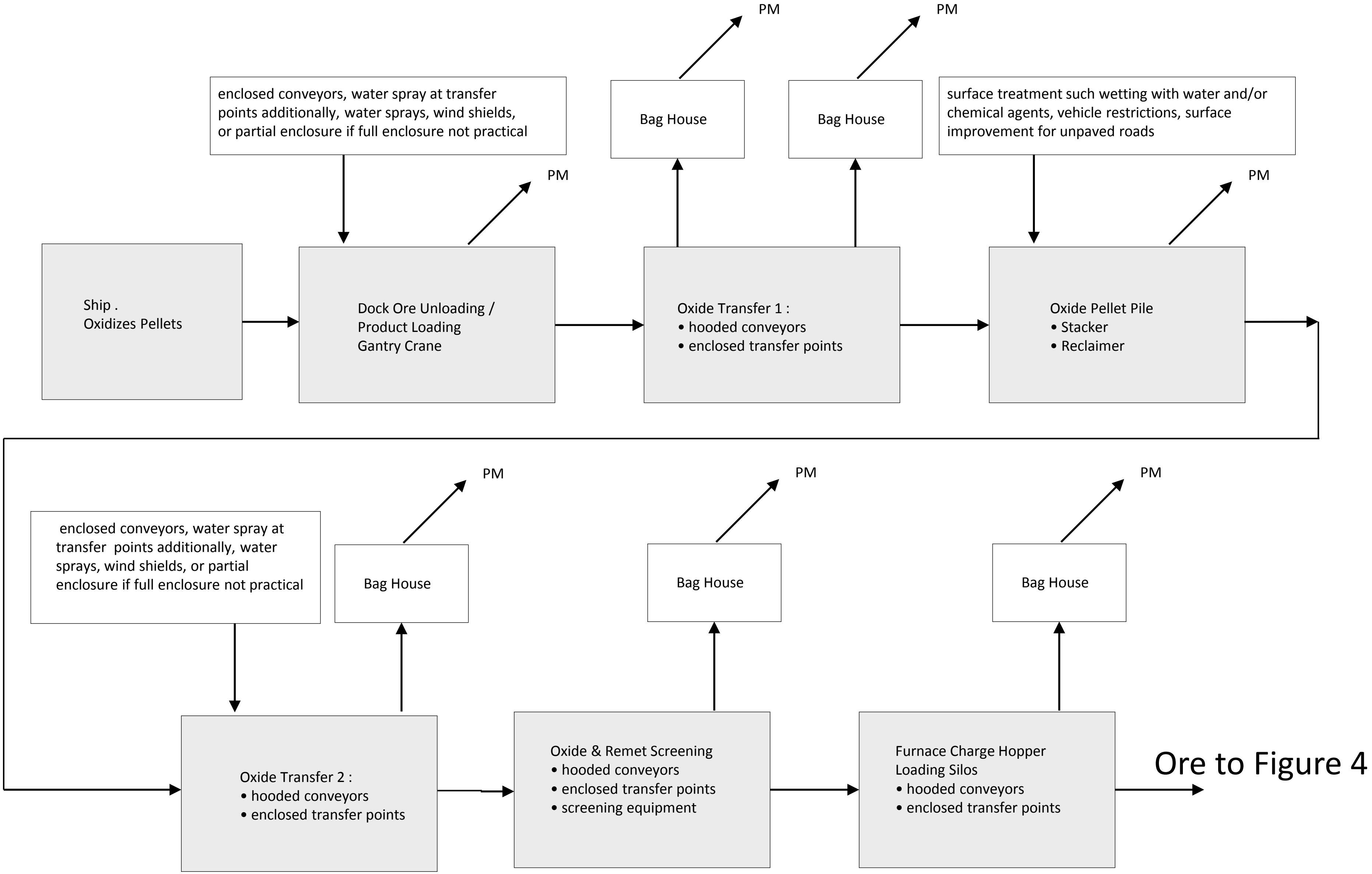
ERM

CHS 8/3/12 NAD83 UTM Zone 14N

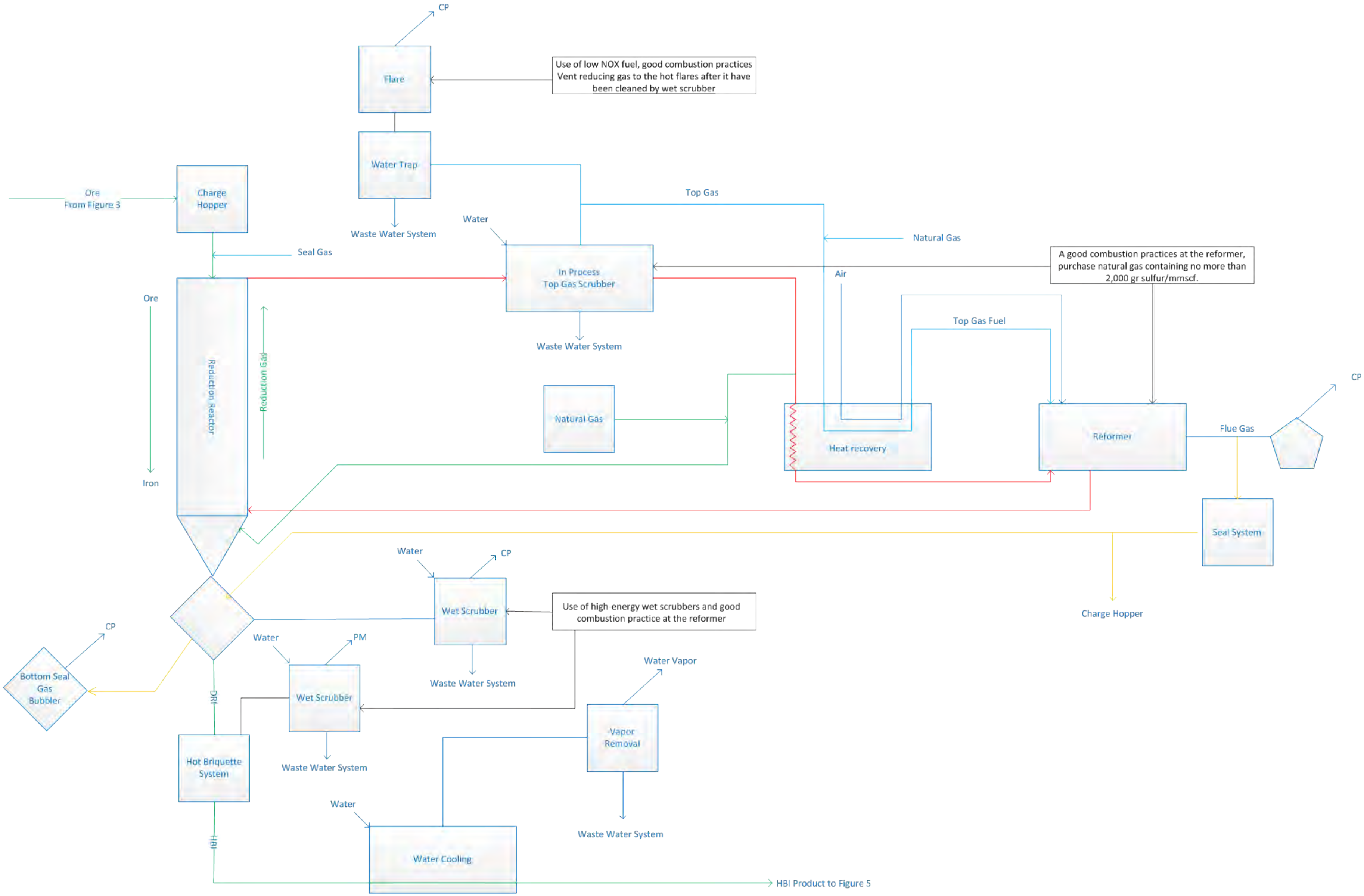
Environmental Resources Management NC, Inc.

FIGURE 2-2
3000 FOOT AND 1 MILE RADII MAP
Voestalpine La Quinta Plant
Corpus Christi, Texas

ERM



Process Flow Diagram Ore Handling / Figure 3

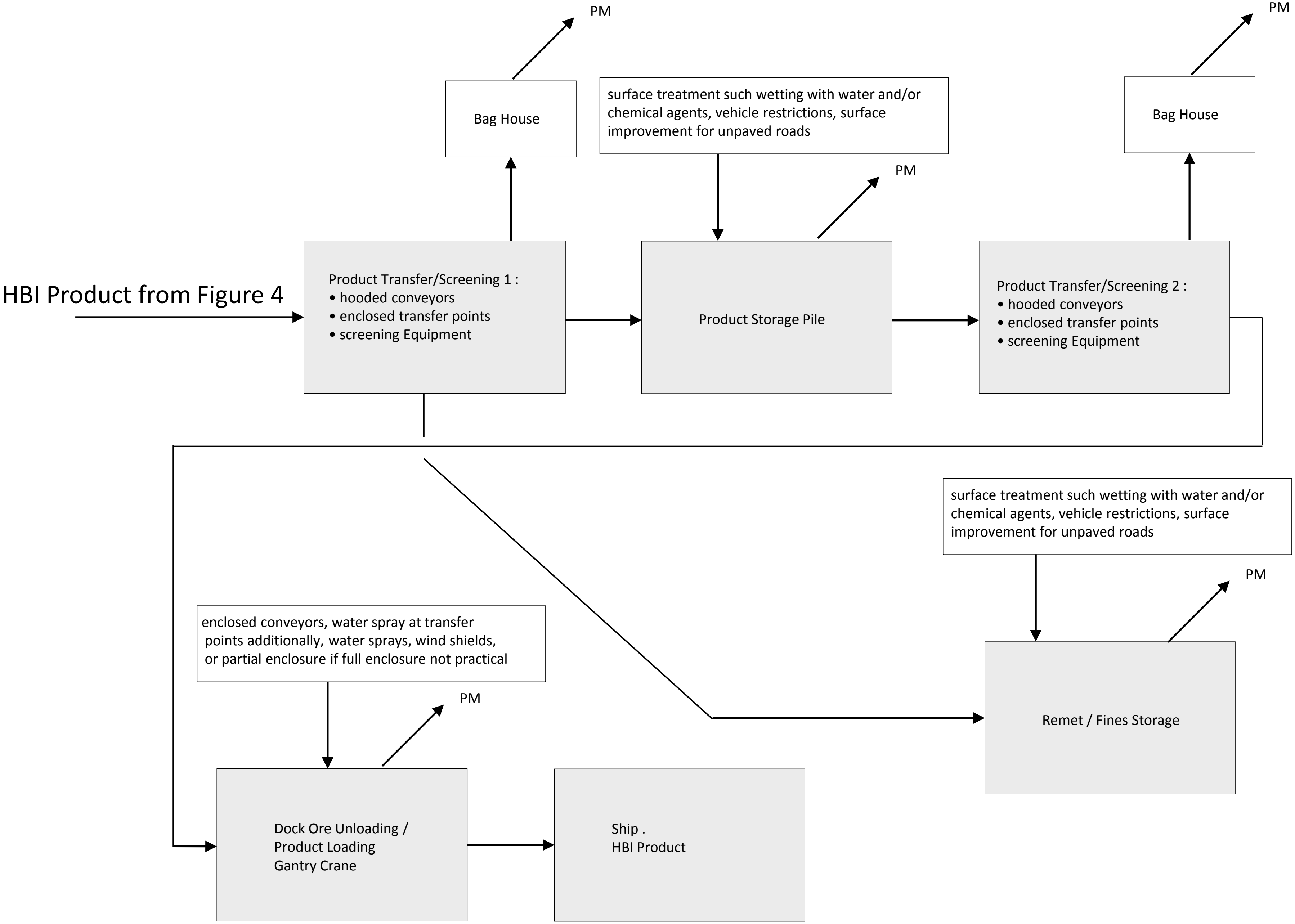


Use of low NOX fuel, good combustion practices
Vent reducing gas to the hot flares after it have
been cleaned by wet scrubber

A good combustion practices at the reformer,
purchase natural gas containing no more than
2,000 gr sulfur/mmscf.

Use of high-energy wet scrubbers and good
combustion practice at the reformer

Process Flow Diagram Reduction, Reformer, Hot Briquetting Figure 4



Process Flow Diagram Product Handling Figure 5

Appendix C

GHG BACT Decisions

Company (RBLC ID Number)	Process Description	Emission Limits	Control Type and Efficiency
AK-0076 Exxon Mobil Corporation North Slope, AK 08/20/2012	Combustion of Fuel Gas	BACT-PSD: No numerical emission limits available.	DLN with inlet heating and good combustion practices.
	Combustion of Diesel	BACT-PSD: No numerical emission limits available.	DLN with inlet air heating, good combustion practices, and waste heat recovery.
	Combustion of Diesel by ICEs	BACT-PSD: No numerical emission limits available.	Good combustion practices and compliance with 40 CFR 60 Subpart IIII requirements.
	Combustion (Flares)	BACT-PSD: No numerical emission limits available.	Good combustion practices.
	Combustion of Diesel by Boilers	BACT-PSD: No numerical emission limits available.	Good combustion practices.
LA-0263 Phillips 66 Company Plaquemines, LA 07/25/2012	Steam Methane Reformer	BACT-PSD: CO_2e Limit – 183,784 tpy. Standard Emission Limit – 0.05 lb/scf H_2 production.	Selection of most efficient H_2 process – pressure swing absorption, heat recovery, air preheater, adiabatic pre-reformer, maintenance and fouling control, combustion air and feed/stream preheat, combustion air controls (limiting excess air), process integration, furnace controls (good combustion practices), and new burner designs.
	Hydrogen Plant Fugitives	BACT-PSD: No numerical emission limits available.	Implement the Louisiana Refinery MACT Leak Detection and Repair Program; monitoring for total hydrocarbon instead of VOC.
MN-0085 Essar Steel Minnesota, LLC Itasca, MN 05/10/2012	Indurating Furnace	BACT-PSD: CO_2 Limit – 710,000 tpy.	Energy efficiency, lower emitting processes – SO_2 removal reagent, and use of clean fuel (natural gas).
SC-0113 Pyramex Ceramics, LLC Allendale, SC 02/08/2012	Pelletizer	BACT-PSD: CO_2e Limit – 44,446 tpy.	Energy efficient design and operation, waste heat recovery design, natural gas/propane.
	Calcining/Sintering Kiln	BACT-PSD: CO_2e Limit – 0.218 lb/ton.	Energy efficient design and operation, waste heat recovery design, natural gas/propane
	Boilers	BACT-PSD: No numerical emission limits available.	Good design and combustion practices.
IA-0101 Interstate Power & Light Wapello, IA 01/12/2012	Boiler	BACT-PSD: CO_2 Limit – 2,927.1 lbs/MW-hr.	Good combustion practices.
		BACT-PSD: CO_2e Limit – 8,000,325 tpy on a 12 mo. rolling basis.	Good combustion practices.

Company (RBLC ID Number)	Process Description	Emission Limits	Control Type and Efficiency
Universal Cement Chicago, IL 12/20/2011	Portland Cement Manufacturing Facility	BACT-PSD: CO_2 Limit – 1,860 lbs CO_2e/ton clinker on a 12-month rolling average basis, 0.93 tpy CO_2e.	Multi-stage preheater/ precalciner kiln with selection of refractory and a kiln seal management program and a third generation reciprocating clinker cooler.
MN-0084 United States Steel Corp. Itasca, MN 12/06/2011	Grate Kiln – Down Draft Drying Zone	BACT-PSD: CO_2 Limit – 114,000 tpy on a 12 mo. rolling basis.	Fuel efficiency via heat recovery from pellet coolers. Use of a primary fuel mix of 50% biomass and 50% natural gas.
		BACT-PSD: CO_2e Limit – 186,400 tpy on a 12 mo. rolling basis.	Fuel efficiency via heat recovery from pellet coolers. Use of a primary fuel mix of 50% biomass and 50% natural gas.
FL-0330 Port Dolphin Energy, LLC Hillsborough, FL 12/01/2011	Boilers	BACT-PSD: CO_2 Limit – 117 lbs/MMBtu on 8 hour rolling average.	Tuning, optimization, instrumentation and controls, insulation, and turbulent flow.
	Power Generator Engines	BACT-PSD: CO_2 Limit – 181 g/kw-hr on 8 hour rolling average (natural gas), 253 g/kw-hr on 8 hour rolling average (low sulfur fuel oil).	Use of efficient engine design and use of primarily natural gas.
	Fugitive Emissions	BACT-PSD: No numerical emission limits available.	A gas leak detection system will be used for CO_2.
GA-0143 JM Huber Corp. Jackson, GA 11/10/2011	Wellons Furnace	BACT-PSD: No numerical emission limits available.	The combustion of biomass and the use of good combustion/operating practices to control GHGs. *No control has been established to minimize N_2O emissions based on adverse NO_X impacts.
	Dryer System	BACT-PSD: No numerical emission limits available.	The combustion of biomass and the use of good combustion/operating practices to control GHGs. *No control has been established to minimize N_2O emissions based on adverse NO_X impacts.
IN-0135 Hoosier Energy Rec. Inc. – Merom Generating Station Sullivan, IN 11/10/2011	Coal Bed Methane-Fired Standby Flare w/ Propane Fired Pilot	Case-by-Case: CO_2 Limit - 3,235 lbs/MW-hr, 4,852 tpy on a 12 mo. rolling basis.	Good combustion practices and proper maintenance.
		Case-by-Case: CH_4 Limit – 0.06 lbs/MW-hr, 0.08 tpy on a 12 mo. rolling basis.	Good combustion practices and proper maintenance.

Company (RBLC ID Number)	Process Description	Emission Limits	Control Type and Efficiency
		Case-by-Case: N_2O Limit – 0.05 lbs/MW-hr, 0.08 tpy on a 12 mo. rolling basis.	Good combustion practices and proper maintenance.
	Coal Bed Methane CBM Dehydrator Units	Case-by-Case: CO_2 Limit – 59.36 lbs/hr, 260 tpy.	Proper maintenance.
	4-Stroke Lean Burn Coal Bed Methane – Fired RICE	Case-by-Case: CO_2 Limit – 1,100 lbs/MW-hr on a 3 hour avg. basis, 16,030 tpy.	Good combustion practices and proper maintenance.
		Case-by-Case: CH_4 Limit – 9.57 lbs/MW-hr on a 3 hour avg. basis, 139.4 tpy.	Good combustion practices and proper maintenance.
		Case-by-Case: N_2O Limit – 0.23 lbs/MW-hr, 3.35 tpy.	Good combustion practices and proper maintenance.
FL-0328 ENI U.S. Operating Company, Inc. Lloyd Ridge (OCS), FL 10/27/2011 *Draft Determination	Main Propulsion Engines	BACT-PSD: CO_2 Limit – 700 g/kw-hr on 24 hour rolling basis.	Use of good combustion practices based on the current manufacturer's specifications, and additional enhanced work practice standards including an engine performance management system and the Diesel Engines with Turbochargers (DEWT) measurement system.
	Crane Engines	BACT-PSD: CO_2 Limit – 722 tpy on a 12 mo. rolling basis.	Use of certified EPA Tier 1 engines and good combustion practices based on the current manufacturer's specifications for this engine.
	Crane Engines	BACT-PSD: CO_2 Limit – 687 tpy on a 12 mo. rolling basis.	Use of good combustion practices, based on the current manufacturer's specifications for this engine.
	Emergency Engine	BACT-PSD: CO_2 Limit – 14.6 tpy on a 12 mo. rolling basis.	Good combustion practices based on manufacturer's specifications.
	Emergency Fire Pump Engine	BACT-PSD: CO_2 Limit – 2.4 tpy on a 12 mo. rolling basis.	Good combustion practices based on manufacturer's specifications.
	Boiler	BACT-PSD: CO_2 Limit – 565 tpy on a 12 mo. rolling basis.	Use of good combustion and maintenance practices, based on the current manufacturer's specifications for this boiler.
LA-0254 Entergy Louisiana, LLC	Auxiliary Boiler	BACT-PSD: CO_2 Limit – 117 lbs/MMBtu.	Proper operation and good combustion practices.

Company (RBLC ID Number)	Process Description	Emission Limits	Control Type and Efficiency
Jefferson, LA 08/16/2011		BACT-PSD: CH_4 Limit – 0.0022 lbs/MMBtu.	Proper operation and good combustion practices.
		BACT-PSD: N_2O Limit – 0.0002 lbs/MMBtu.	Proper operation and good combustion practices.
	Emergency Diesel Generator	BACT-PSD: CO_2 Limit – 163.0 lbs/MMBtu.	Proper operation and good combustion practices.
		BACT-PSD: CH_4 Limit – 0.0061 lbs/MMBtu.	Proper operation and good combustion practices.
		BACT-PSD: N_2O Limit – 0.0014 lbs/MMBtu.	Proper operation and good combustion practices.
	Emergency Fire Pump	BACT-PSD: CO_2 Limit – 163.0 lbs/MMBtu.	Proper operation and good combustion practices.
		BACT-PSD: CH_4 Limit – 0.0061 lbs/MMBtu.	Proper operation and good combustion practices.
		BACT-PSD: N_2O Limit – 0.0014 lbs/MMBtu.	Proper operation and good combustion practices.
Carolinas Cement Company LLC Castle Hayne, NC 07/08/2011 *Draft Determination	Portland Cement Manufacturing Facility	BACT-PSD: CO_2e Limit - 0.91 tons CO_2e / ton clinker on a 12 mo. rolling basis.	Proposed work practices for electric efficiency: using vertical roller mills with high efficiency separators; installing variable frequency drives for motors that require less than 75% of nominal output; using NEMA premium efficiency motors for 200 HP or less applications; installing efficiency fans when practical; using bucket elevators and other mechanical systems wherever practical.
Lafarge Building Materials, Inc. Ravena, NY 05/11/2011 *Draft Determination	Ravena Plant Modernization Project	BACT-PSD: CO_2e Limit – 0.95 tons CO_2e / ton clinker	Modern preheater/ precalciner kiln system, vertical roller mills, high efficiency separators, modern multi-channel burners, and mechanical rather than pneumatic transport of kiln feed. Increase energy efficiency by reducing fuel use per ton of clinker produced (4.62 MMBTU/short tons per year to 2.74 MMBTU/short tons per year).
PacifiCorp Lake Side Power Plant Utah Co., UT 05/04/2011 *Draft Determination	Combined Cycle Turbine	BACT-PSD: CO_2e Limit – 950 lbs/MW-hr on a 12-month rolling avg. basis.	Energy efficiency/ heat recovery system.

Company (RBLC ID Number)	Process Description	Emission Limits	Control Type and Efficiency
Hyperion Energy Center Union County, SD 05/02/2011 *Draft Determination	Process Heaters	BACT-PSD: CO_2e Limit – 33.0 tons/Mbbl crude oil received.	Good combustion practices, energy efficiency, and low-carbon fuel.
	Combined Cycle Gas Turbine	BACT-PSD: CO_2e Limit – 23.9 tons/Mbbl crude oil received.	Good combustion practices, energy efficiency, low-carbon fuel, and oxidation catalyst.
	Acid Gas Removal System	BACT-PSD: CO_2e Limit – 58.6 tons/Mbbl crude oil received.	Efficient design.
	Small Combustion Sources	BACT-PSD: CO_2e Limit – 0.2 tons/Mbbl crude oil received.	Proper design.
	Coke Drum Steam Vents	BACT-PSD: CO_2e Limit – 9,320 lbs CO_2e/drum/cycle.	Comply with work practice standards.
Wolverine Power Supply Cooperative, Inc. Rogers City, MI 04/13/2011 *Draft Determination	600 MW Coal and Biomass-Fired Unit Consisting of Two 300 MW Circulating Fluidized Bed (CFB) Boilers	BACT-PSD: CO_2e Limit – 2.1 pounds/kW-hr gross energy output, 6,024,107 tpy on a 12-mo. rolling avg.	Combust at least 5% biomass on a heat input basis (12-mo. rolling avg.), use of variable speed motors for all system components with a motor over 100 HP, and follow the manufacturer's guidelines on O&M of plant components. Thermal performance components shall be designed to mazimize energy efficiency; where practical energy efficiency of fans and motors shall be optimized.
WE Energies Rothschild, WI 03/28/2011	Biomass-Fired Boiler	BACT-PSD: CO_2 Limit – 185 lbs/ 1,000 pounds of steam produced, or 508 lbs/MW-hr of steam produced per month, averaged over any consecutive 12-month period.	Use of energy efficient boiler.
	Natural Gas-Fired Boiler	BACT-PSD: CO_2 Limit – 3,050 lbs/MW-hr of gross output, averaged over any consecutive 12-month period.	Use of energy efficient boiler.

Company (RBLC ID Number)	Process Description	Emission Limits	Control Type and Efficiency
Palmdale Hybrid Power Project Palmdale, CA 10/18/2011	Two Natural Gas-Fired Combined Turbine Generators with Heat Recovery Steam Generators	BACT-PSD: CO_2 Limit – 744 lb/MWh source-wide net output; 117 lb/MMBtu heat input for each turbine and duct burner at ISO standard conditions, based on a 30-day rolling average.	Use of thermally efficient units.
	Natural Gas-Fired Auxiliary Boiler and Heater	BACT-PSD: No numerical emission limits available. Boiler limited to 110 MMBtu/hr & 500 hr/yr. Heater limited to 40 MMBtu/hr & 1,000 hr/yr.	Purchase thermally efficient units, conduct annual boiler tune-ups, limit heat input and hours of operation.
	SF_6 Circuit Breaker	BACT-PSD: CO_2e Limit – 9.56 tpy; 0.5% annual leakage rate.	Enclosed SF_6 circuit breakers with leak detection.
Abengoa Bioenergy Biomass of Kansas, LLC Hugoton, KS 9/16/2011	HV Circuit Breaker	BACT-PSD: CO_2e Limit – 4.9 tpy.	Install an enclosed-pressure circuit breaker with leak detection to maintain fugitive SF_6 emissions below 0.5% per year (by weight); implement an LDAR program; use a density monitor alarm system set to 4 psi drop.
	Biomass-Fired Stoker Boiler	BACT-PSD: CO_2e Limit – 0.34 lb/lb steam produced, avg. over 30 day rolling periods. Includes periods of SSM.	Restricted fuel type to biomass that is otherwise considered to have low to no economic value or benefit, and/or is lower impacting crops; and lower GHG-emitting processes and practices through an energy-efficient design, incorporating co-generation, process integration, combustion of co-products, heat recovery, and operational and maintenance monitoring.
	EH Fermentation CO_2 Scrubber	BACT-PSD: CO_2e Limit – 5.89 lbs/gal anhydrous EtOH produced, avg. over 30 day rolling periods. Includes periods of SSM.	Monitoring enzymatic hydrolysis process efficiency, incorporating monitoring CO_2 production during fermentation, energy efficient heat integration, water recycling, and co-product production.

Company (RBLC ID Number)	Process Description	Emission Limits	Control Type and Efficiency
	Product Load-out Vapor Recovery/ Biogas Flare	BACT-PSD: CO_2e Limit – 20,166 tpy during any 12 mo. consecutive period.	Restricted fuel type to primarily biogas and pipeline-grade natural gas in the pilot; use most efficient flare that can perform to the specification required by the facility's process.
	Firewater Pump Engine	BACT-PSD: CO_2e Limit – 24.0 tpy during any 12 mo. consecutive period.	Install a fuel-efficient NFPA-20 certified firewater pump engine with an EPA Tier 3 emission rating.
LA-0248 Consolidated Environmental Management Inc – Nucor St. James, LA 01/27/2011	Reformer Main Flue Stack (DRI-208 – DRI Unit #2)	BACT-PSD: CO_2 Limit - 11.79 MMBtu/ton of DRI. Limit natural gas usage to 13 decatherms per tonne of DRI.	Good combustion practices, acid gas separation system, and energy integration.
	Reformer Main Flue Stack (DRI-108 – DRI Unit #1)	BACT-PSD: CO_2 Limit - 11.79 MMBtu/ton of DRI. Limit natural gas usage to 13 decatherms per tonne of DRI.	Good combustion practices, acid gas separation system, and energy integration.
TX-0550 BASF Fina Petrochemicals LP Jefferson, TX 02/10/2010	Refinery Catalyst Regeneration Unit Effluent	BACT-PSD: No numerical emission limits available.	Good combustion practices.
	Reactor Regeneration Effluent	BACT-PSD: No numerical emission limits available.	Good combustion practices.
	Decoking Drum	BACT-PSD: No numerical emission limits available.	Good combustion practices.
Russell City Energy Hayward, CA 02/03/2010	Two Gas Turbines & Heat Recovery Steam Generators (HRSG)	BACT-PSD: CO_2e Limit – 1,928,182 metric tpy (for turbines and HRSG.	Energy efficiency. Use of combined cycle turbine design with HRSG. Implement an O&M schedule.
	Fire Pump Diesel Engine	BACT-PSD: CO_2e Limit - 7.6 metric tpy.	Good combustion practices and energy efficiency. Use of NFPA rated engine. Implement O&M schedule.
	SF_6 Circuit Breakers	BACT-PSD: CO_2e Limit – 39.3 metric tpy.	Use of enclosed system with leak detection. Implement O&M schedule.
OK-0135 Pryor Plant Chemical Co. Mayes, OK 02/23/2009	Carbon Dioxide Vent	BACT-PSD: CO_2 Limit - 3.65 lbs/hr (1-hr and 8-hr).	Good management practices

Company (RBLC ID Number)	Process Description	Emission Limits	Control Type and Efficiency
LA-0148 Red River Environmental Products LLC Red River, LA 05/28/2008	Multiple Hearth Furnaces/Afterburners	BACT-PSD: CO_2 Limit - 37.6 lbs/hr (3-hr).	Afterburner and good combustion practices.
AL-0231 Nucor Corporation Morgan, AL 06/12/2007	Vacuum Degasser Boiler	BACT-PSD: CO_2 Limit - 0.0610 lbs/MMBTU 5.8 lbs/hr.	No controls feasible.
TX-0481 Air Products LP Harris, TX 11/02/2004	Emergency Generator	BACT-PSD: CO_2 Limit - 2.24 lbs/hr, 0.99 tpy.	No controls feasible.
TX-0347 BP Amoco Chemical Co. Brazoria, TX 10/16/2001	Decoke Stack	BACT-PSD: CO_2 Limit - 36.5 lbs/hr, 7.2 tpy.	No controls feasible.
	Regeneration Heater	BACT-PSD: CO_2 Limit - 2.1 lbs/hr, 9.3 tpy.	No controls feasible.
TX-0361 Equistar Chemicals, LP Nueces, TX 10/08/1998	Two USC Furnaces	BACT-PSD: CO_2 Limit - 0.05 lbs/MMBTU each, 14.1 lbs/hr each, 61.8 tpy each.	No controls feasible.
NM-0028 Southwestern Public Service Co./ Cunningham Station Lea, NM 11/04/1996	Combustion Turbine, Natural Gas	BACT-PSD: No numerical emission limits available.	Good combustion practices.
AL-0175 Mobil Oil Exploration and Producing Southeast, Inc. Mobile, AL 09/29/1993	Sulfur Recovery Unit	BACT-PSD: CO_2 Limit - 12.8 lbs/hr.	High thermal oxidizer temperature.