Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for the voestalpine Texas LLC Portland Direct Reduced Iron (DRI) and Hot Briquette Iron (HBI) Portland Production Plant

Permit Number: PSD-TX-1344-GHG

This document serves as the statement of basis for the above-referenced draft permit, as required by 40 CFR 124.7. This document sets forth the legal and factual basis for the draft permit conditions and provides references to the statutory or regulatory provisions, including provisions under 40 CFR 52.21, that would apply if the permit is finalized. This document is intended for use by all parties interested in the permit.

I Executive Summary

On February 5, 2013, voestalpine Texas LLC (voestalpine) submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions for construction of a direct reduced iron (DRI) and hot briquette iron (HBI) production plant. In connection with the same proposed project, voestalpine also submitted a PSD permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on February 5, 2013. The TCEQ issued permit 108113/PSD-TX-1344 on March 18, 2014 for the source. voestalpine submitted a completely updated application on November 26, 2013 and updated the emissions calculations on 1/23/2014.

The facility will have the capacity to manufacture 360 tons per hour and 2,205,000 tons per year of direct reduced iron/hot briquetted iron (DRI/HBI). After reviewing the application, EPA Region 6 has prepared the following Statement of Basis (SOB) and draft air permit to authorize construction of air emission sources at the voestalpine Texas DRI/HBI Portland Production Plant.

This SOB documents the information and analysis EPA used to support the decisions EPA made in drafting the air permit. It includes a description of the proposed facility, the applicable air permit requirements, and an analysis showing how the applicant complied with the requirements.

EPA Region 6 concludes that voestalpine's application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable air permit regulations. EPA's conclusions rely upon information provided in the permit application, supplemental information requested by EPA and provided by voestalpine, and EPA's own technical analysis. EPA is making all this information available as part of the public record.

II. Applicant

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III. Permitting Authority

On May 3, 2011, EPA published a federal implementation plan that makes EPA Region 6 the PSD permitting authority for the pollutant GHGs. 75 FR 25178 (promulgating 40 CFR § 52.2305).

The GHG PSD Permitting Authority for the State of Texas is:

EPA, Region 6
1445 Ross Avenue
Dallas, TX 75202

The EPA, Region 6 Permit Writer is:
Brad Toups
Air Permitting Section (6PD-R)
(214) 665-7258

IV. Facility Location

The voestalpine Texas LLC DRI/HBI Portland Production Plant is located in San Patricio County, Texas. The geographic coordinates for this facility are as follows:

Latitude: 27º 53’ 19” North
Longitude: - 97º 16’ 40” West

San Patricio County is currently designated attainment for all pollutants. There is no Class I area within 300 kilometers of the proposed DRI/HBI plant.

Below, Figure 1 illustrates the facility location for this draft permit.

V. Applicability of Prevention of Significant Deterioration (PSD) Regulations

EPA concludes that voestalpine's application is subject to PSD review for the pollutant GHGs, because the project would result in an emissions increase of at least 75,000 tpy carbon dioxide equivalent (CO_2e) as described at 40 CFR § 52.21(b)(49)(iv)(a) based on voestalpine's estimated 1,824,731 tons per year of CO_2e emissions. As noted in Section III, EPA Region 6 implements a GHG PSD FIP for the Texas under the provisions of 40 CFR 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305.

voestalpine represents that TCEQ, the permitting authority for regulated NSR pollutants other than GHGs, has determined that voestalpine is also subject to PSD review for carbon monoxide (CO),particulate matter smaller than 10 and 2.5 microns, respectively (PM_{10}, $PM_{2.5}$), and nitrogen oxides (NO_x). Accordingly, under the circumstances of this project, the TCEQ has addressed the non-GHG portion of the project emissions and EPA will address the PSD permit for the GHG portion.[1]

EPA Region 6 follows the policies and practices reflected in the EPA document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases"[2]. In accordance with that guidance, we have not required the applicant to model or conduct ambient monitoring for GHGs, and we have not required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions. Instead, EPA has determined that compliance with BACT is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules as they relate to GHGs.

VI. Project Description

General Process Description

This facility will receive iron ore pellets and convert them in solid form to iron briquettes. Liquid metal is not produced in this process. The primary processes at the site are conversion of iron ore pellets into iron and forming the iron into iron briquettes.

The facility will be a direct reduced iron/hot briquetting (DRI/HBI) production plant. Pelletized iron ore (Fe_2O_3, between ¼ and ¾ inch in size,~60% by weight iron) will be transported to the facility via ship and off loaded via luffing crane onto a conveyor/screening/sizing system to enclosed stock piles. From the stockpiles the ore will be reacted in a tower reactor (shaft furnace) with a reducing gas manufactured on site by steam reformation of natural gas. The product of the DRI process is not liquid metal iron, but rather 'sponge iron', which is approximately 92% by weight iron. This sponge iron will then be pressed into pillow shaped briquettes of approximately 4.5" x 2" in size and stock piled before shipment via ship to other locations.

Greenhouse Gas Emissions associated with this project

The primary greenhouse gasses associated with this project are carbon dioxide, methane, and nitrous oxide (CO_2, CH_4, and N_2O, respectively). voestalpine states that virtually all (>99.98%) of the CO_2e emissions at the site originate from the use of pipeline quality natural gas in the

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[1] *See* EPA, Question and Answer Document: Issuing Permits for Sources with Dual PSD Permitting Authorities, April 19, 2011, http://www.epa.gov/nsr/ghgdocs/ghgissuedualpermitting.pdf

[2] PSD and Title V Permitting Guidance for Greenhouse Gases March 2011. US EPA. Available here: http://www.epa.gov/nsr/ghgpermitting.html

process, the remaining percentage is from the use of diesel fuel for the emergency generator and firewater pump.

Natural gas is used in two ways at the site: 1) as the raw material reformed into process gas rich in hydrogen (H_2) and carbon monoxide (CO) for use in the shaft furnace and 2) as fuel in two combustion devices: the reformer and the flare.

Carbon Dioxide (CO_2) emissions generally occur as a by-product of burning fossil fuels and biomass, as well as from land-use changes and other industrial processes. In this project, CO_2 originates from the combustion natural gas in the reformer, from the chemical reduction of iron ore to metallic iron in the furnace, from the combustion of natural gas in the flare pilot, and from combustion of diesel fuel in two emergency engines, one that drives a backup electrical generator and the other that drives a firewater pump.

Methane (CH_4) emissions result from incomplete combustion of carbon bearing fuels or they may be emitted by processes. In this project, methane emissions are generated by incomplete combustion in the reformer, in the flare pilot, in the diesel engines, and as fugitive emissions from the natural gas supply lines and components in natural gas service at the site.

Nitrous Oxide (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 (e.g., HCN) originating from fuel nitrogen, char nitrogen, and by heterogeneous reactions of nitrogen on the char surface. In this project, the combustion of natural gas and diesel fuel are the sources of N_2O.

Because of the way the process gas and spent process gas are routed through the plant, voestalpine states that virtually all of the natural gas that enters the site will be combusted, either in the reformer firebox (the vast majority) or in the flare. Therefore, with the exception of the minor amount of natural gas lost to atmosphere through equipment leaks (< 0.01%), all of the natural gas entering the plant will be combusted and will be emitted as natural gas products of combustion from one of six emissions points at the site. See Table 14 at the end of this document for a listing of these emissions points and the proposed authorized emissions limitations.

voestalpine estimates that CO_2 emissions make up 1,820,102 of the 1,824,731 tons per year (over 99.75%) of the CO_2e emissions at the site. Because the non-CO_2 GHGs are minimal, our BACT analysis below will focus on sources emitting CO_2.

Detailed process area description and GHG emissions associated with each area

The major elements/process areas of the DRI/HBI plant include the following:

- Iron oxide pellet receipt, handling, and preparation;
- The reformer- making the reducing gas;
- Shaft furnace- the reducing reactor and its seal gas;
- Spent reducing gas handling;
- The flare;
- Hot briquetting system;
- HBI handling and loading; and,
- Ancillary operations to include a cooling tower, a diesel fired emergency generator and fire pump, and methane leaks from piping and equipment in natural gas service.

Each of these areas will be discussed in detail below. While GHG emissions are not present in each of these areas, all of the steps are described in order to understand the overall site operations.

A. Iron oxide pellet receipt, handling, and preparation

No GHG emissions occur in this process. Direct Reduction (DR) grade pellets arrive by ship and are delivered in the surge bin at the port. After weighing the pellets, they move by conveyor to the enclosed pellet storage area. The pellet storage area is equipped with a stacker/reclaimer and will maintain a sufficient supply for one 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 exhausted to various baghouses for the control of particulate emissions. Iron pellets will be stored in enclosed storage areas. Iron ore operations will employ enclosed conveyors and water sprays at conveyor transfer points.

B. Reformer - making the reducing gas

GHG are produced in and emitted to atmosphere from the reformer at the reformer main flue ejector stack (EPN 29). The emissions of CO_2 from this point account for 92.3% of the sitewide emissions of CO_2.

The natural gas reformer is a refractory lined chamber containing alloy tubes filled with catalyst and fired by plant fuel gas. voestalpine has indicated that they have selected the Midrex Technologies, Inc. (Midrex) system for its reforming technology. According to voestalpine, Midrex designs and builds commercial high-temperature, near-stoichiometric reformers that produce a high-quality reformed gas that can be fed directly to a DRI shaft furnace.[3]

As the raw materials (natural gas, steam, and CO_2) pass thru the tubes, they are reformed into a hydrogen (H_2) and carbon monoxide (CO) rich reducing gas. The important reforming reactions are:

[3] See Attachment 3 of voestalpine's "response to (EPA's) Application Completeness Determination" dated November 7, 2013 for a complete description of the Midrex process and a comparison of the Midrex process to other means of producing DRI.

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

$CH_4 + H_2O \rightarrow CO + 3H_2$

An important property of the reducing gas is the gas "quality." The quality is a measure of the potential for the gas to reduce iron oxide in the shaft furnace (described below). 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)

According to the industry, the optimum gas quality for hot, fresh reducing gas is 10 or higher. Also, to obtain essentially complete reduction, the quality of the spent reducing gas exiting the DRI process should be at least 2. Another important property of the reducing gas is the H_2/CO ratio. The typical H_2/CO ratio produced by the reformer is about 1.55:1. The importance of this ratio will be discussed in the furnace section, below.

Both of the reforming reactions identified above are endothermic and therefore require energy in the form of heat input. Therefore, the reformer is fired at a maximum heat input of 1,591mmBtu/hr. The fuel used to fire the reformer is composed of 85% (heating value basis) recycled spent shaft furnace reactor gas that is rich in H_2 and CO and 15% natural gas.

To maximize the reformer's efficiency the spent reducing gas (process gas that has been used in the shaft furnace) is treated in the process gas system and recycled through the reforming process. The spent reducing gas contains $H_{2,}$ CO, $CO_{2,}$ and water vapor. The water vapor and CO_2 concentrations in the spent reducing gas are sufficiently great to impede the reforming reaction in the shaft furnace, and so the spent reforming gas must have the water and CO_2 content reduced (but not eliminated) prior to reuse. In order to prepare the spent reducing gas for reuse, the spent gas stream is partially dewatered. After being dewatered, 2/3 of the stream is then blended with fresh natural gas and recycled back to the reformer where it is transformed into fresh reducing gas. The remaining 1/3 of the spent reducing gas stream has significant heating value (approximately ¼ that of natural gas) and so is routed to the firebox where it is combined with supplemental natural gas to become fuel for the reformer.

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 process gas (between 840 and 1000°C) to the shaft furnace without quenching and reheating provide for a very efficient process.

C. Shaft furnace - the reactor and its seal gas

GHG emissions are produced in and emitted to atmosphere in this step. Emissions of seal gas, which contain CO_2e exit at the charge hopper vent (EPN 17) at the furnace top, through the bottom seal gas dust collector system exiting at EPN 8, with an additional fraction of the seal gas from the bottom of the furnace exiting the briquette dedusting scrubber vent at EPN 9..

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 (O_2) in the iron ore is removed at elevated temperatures by reaction with CO and H_2 contained in a reducing gas to produce metallic iron (Fe), while liberating CO_2 and water vapor (H_2O). The overall reduction reactions are:

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

To optimize the above reactions, hot (840-1000° C), fresh reducing gas should meet the reductant/oxidant gas quality molar ratio of 10 (as described in the reformer section, above), and a reducing gas molar ratio (H_2/CO) of 1.55:1. Control of the H_2/CO ratio affords thermally balanced reduction reactions because 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. Direct additions of natural gas into the shaft furnace can be accomplished to aid in maintaining the desired ratios in the shaft furnace.

According to voestalpine, the shaft furnace reactor design is patented. This furnace has a nominal 7.15-meter internal diameter, and is 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 in the furnace 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 (high in H_2 and CO) 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 sponge 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 through the top gas scrubber to remove particulates and is cooled and dewatered, and split, 2/3 to recycle through the reformer, 1/3 to be used as fuel in the reformer, as described in the 'reformer' section above.

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 base of the furnace 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 hot reduced material is discharged from the base of the furnace via a dynamic seal leg and a hydraulically driven variable speed hot wiper bar. The speed of the lower burden feeder is matched 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 limits the 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. The dynamic seal leg at the lower end of the discharge cone uses pressurized inert seal gas to keep the reducing gasses within the furnace.

Inert seal gas for the shaft furnace originates as a slip stream of the hot flue gas from the reformer firebox. voestalpine indicates that the design volumetric reformer stack vent rate is 464,300 Nm^3/hr The seal gas system takes 5.4% by volume of the total flue gas (25,000 of 464,300 Nm^3/hr) and cools it in a packed bed, direct contact type cooler 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 both the top gas and bottom seal gas legs of the shaft furnace.

In the case when seal gas may not be available (e.g., for the initial startup as well as after maintenance downtimes), a liquid nitrogen system will be used to supply inert seal gas as well as inert purge gas. Purge gas is used to purge the combustibles out of the system when needed (such as for a maintenance shutdown). Also, the liquid nitrogen system will be the source for impulse purge for some instruments. The liquid nitrogen system additionally serves as a back-up supply source of some seal gas users, such as the bottom seal gas for the bottom seal leg.

Because the process gas is at a slightly negative pressure relative to the seal gas, some seal gas is drawn into the process gas system while most of the seal gas exits at the charge hopper vent (EPN 17) at the furnace top, and from the furnace bottom through the bottom seal gas dust collector system exiting at EPN 8, and through the briquetting process dust collector vent, EPN 9. voestalpine estimates, for worst case emissions purposes, that the seal gas is divided across these three emission points as follows: 40% across the charge hopper scrubber vent(EPN 17), 40% through the bottom wet gas scrubber (EPN 8) and 20% through the briquette dedusting scrubber vent (EPN 9).

D. Spent reducing gas handling

The shaft furnace reducing (process) gas system operates at a slightly negative pressure compared to the shaft furnace seal gas legs, thus keeping the reducing gases from exiting to atmosphere from the furnace. The process gas originates in the reformer, enters the furnace through tuyeres at the furnace base and exits near the top of the furnace through the top gas scrubber. The spent top gas is direct contact scrubbed with water to remove entrained particulate and then dewatered (by cooling). Two thirds of the treated gas is recycled back to the reformer, where, together with additional natural gas, the reformer gas processing cycle is repeated.

As stated in the reformer section above, spent top gas should have a reductant to oxidant (or gas quality) ratio of at least 2, while ideal fresh reducing gas should have the molar ratio closer to 10. According to voestalpine, getting this ratio back up to 10 can be accomplished in two ways. voestalpine's represented method accomplishes this by separating approximately one third of the spent process gas flow and routing it to the reformer firebox where it is used, along with natural gas, to fire the reformer, thus recovering the heating value of the spent reducing gas while simultaneously reducing the CO_2 content of the remaining recycle process gas. The 2/3 portion of the original spent reducing gas stream is then supplemented by natural gas prior to entering the reformer.

A second method that could be used to reduce the CO_2 component of the spent shaft furnace gas stream before being recycled back to the reformer is by means of amine treatment of the dewatered gas stream to remove and concentrate a fraction of the CO_2. The captured, concentrated CO_2 stream could then be sold, transported to a sequestration site for long term storage, or, as was done in the past, vented to atmosphere. voestalpine has not chosen this method of operation, opting for the energy integration method previously described.

E. The flare

GHG emissions are produced in and emitted to atmosphere in this step at the flare, EPN 38. The shaft furnace is not normally directly vented to the atmosphere, but it does have a bypass that is routed to the flare. The continuously lit pilot flare is fired by natural gas. The bypass through the flare is needed to assure that the shaft furnace can be safely vented in the case of furnace startup, shutdown, or to assure that the furnace pressure does not exceed the seal gas pressure (at either end of the shaft furnace), and cause a potentially dangerous situation through the uncontrolled emissions of H_2 and CO rich process gas to atmosphere. Therefore, while the shaft furnace does not have a specific emission point associated with it, the flare is the point of venting for the shaft furnace and the remaining process gas system when shutdown, startup, malfunctions, or maintenance activities require de-inventorying the process gas system. The flare will be operated in accordance with the requirements for flares in the New Source Performance Standards (40 CFR §60.18) to assure a destruction efficiency of at least 98% for the contaminants to be controlled by it.

F. Hot briquetting system

GHG emissions are emitted at one point in this system. CO_2 emissions from the furnace bottom seal gas leg are emitted from the briquetting process dust collector vent, EPN 9.

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 startup 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 the briquetter dedusting stack (EPN 9).

G. HBI handling and loading

There are no GHG emissions from this process. 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 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 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.

H. Ancillary processes

GHG are emitted from four sources: the process water degasser vent (EPN 30), the emergency generator (EPN 34), the fire pump engine (EPN 35), and fugitive emissions from piping and components in natural gas service. (EPN: FUG)

*Degassing process water***.** Direct contact coolers provide much of the gas cooling in the DRI plant. The gases being cooled are under pressure, so some of the CO and CO_2 are absorbed into the cooling water. Due to the direct contact of process water with CO, CO_2, and process gasses, some gas constituents are dissolved in water at an elevated process gas pressure. This occurs in the process water that is in the top gas scrubber (in particular). In order to reduce the fugitive emissions at the clarifier and to reduce scaling in process water ducts, a forced degassing unit will be installed. The process water degasser will use pressurized air to strip the process water of the dissolved gasses prior to the clarifier. During this degassing process, CO and CO_2 are released. However, the flow and concentration of CO and CO_2 are irregular because entry to and from the pressurized DRI process is episodic in nature.

Emergency Generator and Firewater pump A 2500 KW diesel engine driven generator will be on site to provide emergency power. The engine will emit GHG as a result of combusting diesel fuel. In addition, a fire water pump powered by a 235 HP diesel engine will be on site for use during emergency conditions. The engine will emit GHG as a result of combusting diesel fuel.

Piping and Equipment Leaks in natural gas service. While a relatively minor source of GHG emissions, equipment fugitive emissions from piping and components in natural gas service is a source of emissions. voestalpine estimates that there are over 500 components, such as valves, flexible hoses, compressors, pipe fittings, and connectors planned for use at the site that are in natural gas service.

VII. BACT Analyses

A. Overview of Federal BACT Process

In preparing the BACT analyses for this draft permit, EPA Region 6 applied the concepts and policies described in EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011), which outlines the steps for conducting a "top-down" BACT analysis. Those steps are listed and described below.

(1) Identify all potentially available control options;

(2) Eliminate technically infeasible control options;

(3) Rank remaining control technologies;

(4) Evaluate the most effective controls and document the results; and

(5) Select BACT.

Please refer to pp. 17-46 of the EPA's March 2011 guidance for more discussion on each step of the top-down BACT process[4].

B. Applicable Federal Regulations

In accordance with 40 CFR 52.21(b)(12), an initial review of applicable New Source Performance Standards (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 iron making facilities. The NSPS for Stationary Compression Ignition Internal Combustion Engines, 40 CFR 60 Subpart IIII, does apply to some emission units at the proposed voestalpine facility; however, this rule contains no GHG-specific requirements. Thus, as of the date of this draft permit, the NSPS program does not establish a minimum level of stringency under BACT for the GHG emissions at the proposed voestalpine facility.

C. GHG Control Methodologies

The *PSD and Title V Permitting Guidance for Greenhouse Gases* identifies potentially applicable control alternatives for evaluation under BACT according to the three categories:

- inherently lower-emitting system designs, methods, processes, and management practices;
- add-on controls, and;
- a combination of the two.

A series of white papers have been developed by the EPA that summarizes 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

[4] PSD and Title V Permitting Guidance for Greenhouse Gases" March 2011. USEPA. Available here: http://www.epa.gov/nsr/ghgpermitting.html

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, the EPA 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*[5]. In addition to the items listed in this guidance, other guidance related to energy efficiency measures in mineral processing, such as that found in a similar guide related to the cement manufacturing sector [6] may be applicable in this sector as well.

1. **Available technologies for reducing CO_2, CH_4, and N_2O emissions in the iron and steel industry**

   By reviewing the Iron and Steel Industry and Cement Manufacturing Industry EPA GHG control papers, as well as process knowledge in the DRI field, the applicant identified the following design and operational control measures to be employed at the site[7]. The applicant has characterized them as energy efficiency measures:

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

   Table 1 on the following page shows possible energy efficiency improvements identified by voestalpine that result in reduced fuel consumption. It also indicates whether these technologies are potentially applicable to the voestalpine facility.

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

2. **Near term technologies for reducing CO_2, CH_4, and N_2O emissions in the iron and steel industry**

   Significantly, the EPA 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. The white paper also identifies carbon capture and storage as near term control measures for the iron and steel manufacturing industry. Another near term steel making process is the HIsarna process, which will also be discussed below.

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[5] *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Iron and Steel Industry.* Office of Air Quality Planning and Standards, Sector Policies and Programs Division, Research TrianglePark, NC, September 2012.

[6] *Available and Emerging Technologies for Reducing Greenhouse Gas: Emissions from the Portland Cement Industry.* Office of Air Quality, Planning and Standards, Sector Policies and Programs Division, Research Triangle Park, NC, October 2010.

[7] See response to Question 4 of voestalpine's "response to (EPA's) Application Completeness Determination" dated November 7, 2013 for details on the energy efficiency measures identified by voestalpine.

Table 1 Energy efficiency design and operation measures to be implemented		
Measures*	**Comment**	**Applicable at voestalpine facility?**
Material Handling Equipment	Mechanical conveyor systems typically use less energy than pneumatic systems.	Mechanical conveyors will be used where practical. Pneumatic conveyors will be used for fine materials where practical.
Process Control and Management Systems	Automated control systems can be used to maintain operating conditions at optimum levels.	Process control and management systems are planned and production planning will be optimized to reduce waste Automated 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.	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.
Insulation	Insulation is important to keep heat loses from equipment to a minimum.	The shaft furnace will be well insulated to reduce energy losses to the surroundings.
Heat Recovery	Exhaust streams with significant amounts of heat energy can be recovered for other heating purposes.	The reformer flue gas exits on both sides of the reformer and enters the parallel train heat recovery system where it is used to preheat natural gas for reforming and for fuel use, for combustion air preheat, and recycled process gas preheat. This heat recovery system increases the reformer capacity and reduces the net plant energy consumption by approximately 25-30%. 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.

* Measures are from the Cement Manufacturing and the Iron and Steel EPA GHG control guidance documents as well as from DRI industry knowledge.

Table 2 Energy efficiency improvements to reduce electricity use to be implemented		
Control Measure*	**Comment**	**Applicable at voestalpine facility?**
Preventive Maintenance	Training programs and good housekeeping programs can help to decrease energy consumption throughput the facility.	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.	Energy monitoring and management systems will be used.
High Efficiency Motors	The use of high efficiency motors as well as a motor management plan can reduce electricity use and save in energy and maintenance costs.	National Electrical Manufacturers Agency (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.	VSDs will be used for controlling and optimization of process.
High Efficiency Fans	High efficiency fans may reduce power consumption.	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.	A maintenance plan for compressed air systems and other efficiency improvements will be implemented.
Lighting System Efficiency Improvements	Automated lighting controls and lights with more efficient bulbs can reduce energy use.	Automated lighting controls and lights with more efficient bulbs will be used.

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

voestalpine compared overall energy efficiency of DRI production as follows:

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[8].*

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[9] or as a range from 10.5 to 14.5 GJ/t-DRI[10], while the energy consumption for coal-based DRI production is considerably higher (20 to 25 GJ/t-DRI). 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[11]. In comparison, blast furnace ironmaking produces emissions ranging from approximately 1.6 to 2.2 tons of* CO_2 *per ton of steel[12]. 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.[13]

Examples of DRI/EAF integrated steelmaking are presented in the 2012 EPA iron and steel white paper as follows:

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[8] European Integrated Pollution Prevention and Control Bureau (EIPPCB), 2012. *Best Available Techniques (BAT) Reference Document for Iron and Steel Production Industrial Emissions.* Directive 2010/75/EU (Integrated Pollution Prevention and Control). Joint Research Centre Institute for Prospective Technological Studies Sustainable Production and Consumption Unit, Brussels, Belgium, November 2012.

[9] *Tracking Industrial Energy Efficiency and CO2 Emissions.* page132. International Energy Agency, Head of Communication and Information Office, Paris, France, 2007.

[10] EIPPCB 2012 p534.

[11] *Ibid. p 132.*

[12] "Revisiting the Carbon Issue: Reducing the World Steel Industry's Carbon Footprint through Direct Reduction and CCS," in *Direct from Midrex*, 1st Quarter 2012. Available on-line at:http://www.midrex.com/handler.cfm/cat_id/152/section/company.

[13] page 17 of voestalpine GHG PSD permit application dated January 2013 received by EPA on February 5, 2013.

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 was to 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 DOE 2008 report claims a 41% reduction in CO_2 emissions relative to traditional steelmaking[14].

Nucor's DRI Iron and Steel Production Facility: In early 2011, Nucor Corporation began construction of an iron and steel complex in Louisiana that includes a DRI furnace. Initial production of DRI began in early 2014. It is the first GHG permitted DRI facility in the U.S.

3. Add on Controls for Reducing CO_2

Carbon capture and storage (CCS). CCS can make a contribution to the overall GHG reduction effort by reducing the emissions of CO_2 from the use of fossil fuels. 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:

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 have been 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.

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.

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[14] AISI/DOE Technology Roadmap Program for the Steel Industry, TRP 9941: A New Process for Hot Metal Production at Low Fuel Rate. Final Report. 2006 Dr. Wei-Kao Lu. Last accessed March 2014 here: http://steeltrp.com/finalreports/finalreports/9941NonPropFinalReport.pdf

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[15]. 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]: 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. voestalpine notes that that none of these projects are in the iron and steel sector. The US LSIPs are summarized in Table 3 below.

Adding CCS to any process is expected to increase capital costs, as well as ongoing operating and maintenance costs. For example:

Air Products' hydrogen plant in Port Arthur, Texas. Beginning operation in May of 2013, this project captures CO_2 and transports it via the Denbury Green Pipeline and makes use of it in an EOR project. The $430 million project retrofitted 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 eventually capture one million tons of CO_2 annually for use in enhanced oil recovery (EOR) operations in Texas oilfields.[17]

Leucadia's Lake Charles CCS Project. This is an industrial CCS 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.

Summit Power Group's Texas Clean Energy Project (TCEP). This project is a $2.9 billion, 400 MW 'polygen' IGCC plant being developed in 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 for a nearby EOR project.

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[15] *The Global Status of CCS: 2012.* Global CCS Institute, Canberra, Australia, September 2012
[16] *Ibid.*
[17] see DOE newsrelease at http://energy.gov/articles/breakthrough-industrial-carbon-capture-utilization-and-storage-project-begins-full-scale

Table 3. Large-Scale Integrated Projects for CO_2 CCS in the US[1]									
Project Name	**Industry**	**Capture Type[2]**	**Volume CO_2 (Mtpa)**	**Transport**	**Operator**	**State**	**Distance Miles**	**Storage Type[3]**	**Operation Date**
CURRENTLY OPERATING									
Val Verde Gas Plant	Natural gas processing	Pre-Comb	1.3	Val Verde Pipeline	Sandridge	TX	91-93	EOR	1972
Enid Fertilizer	Fertilizer production	Pre-Comb	0.68	Enid-Purdy Pipeline,	Merit	OK	130-156	EOR	1982
Shute Creek Gas Processing Facility	Natural gas processing	Pre-Comb	7	Schute Creek Pipeline	Exxon, Chevron, Texacio, Anadarko	WY	132	EOR	1986
Great Plains Synfuel Plant and Weyburn – Midale Project	Synthetic natural gas	Pre-Comb	3	Onshore to onshore pipeline			218	EOR	2000
Century Plant	Natural gas processing	Pre-Comb	5	Onshore to onshore pipeline			177	EOR	2010
CURRENTLY PLANNED									
Air Products Steam Methane Reformer	Hydrogen Production	Post-Comb	1	Green Line Pipeline	Denbury	LA to TX	104-284	EOR	2012
Lost Cabin Gas Plant	Natural gas processing	Pre-Comb	1	Greencore Pipeline	Denbury	MT to WY	258	EOR	2012
Illinois Industrial CCS Project	Chemical (ethanol) production	Industrial separation	1	Onshore to onshore pipeline				Saline	2013
Kemper County IGCC Project	Power Generation	Pre-Comb	3.5	Sonat Pipeline	Denbury	MS	52-63	EOR	2014
OTHER									
Coffeyville Gasification Plant	Fertilizer Production	Pre-Comb	0.88	Onshore to onshore pipeline		KS	77	EOR	2013
Lake Charles Gasification	Synthetic natural gas	Pre-Comb	4.5	Green Line	Denbury	LA to TX	284	EOR	2014

Table 3. Large-Scale Integrated Projects for CO_2 CCS in the US[1]

Project Name	Industry	Capture Type[2]	Volume CO_2 (Mtpa)	Transport	Operator	State	Distance Miles	Storage Type[3]	Operation Date
Medicine Bow	Coal to liquids	Pre-Comb	3.6	Greencore planned extension,	Denbury	WY		EOR	2015
NRG Energy Parish CCS Project	Power generation	Post-Comb	1.4-1.6	Onshore to onshore		TX		EOR	2015
Texas Clean Energy Project	Power generation	Pre-Comb	2.5	Central Basin Pipeline	Kinder-Morgan	TX	35-159	EOR	2015
Hydrogen Energy California Project (HECA)	Power generation	Pre-Comb	3	Onshore to onshore piJpeline		CA	4.4	EOR	2017
PurGen One	Power generation	Pre-Comb	2.6	Onshore to onshore pipeline		NJ	111	Offshore saline	2017
Taylorville Energy Center	Power generation	Pre-Comb	1.92	Onshore to onshore pipeline		IL	5.5	Onshore saline	2017
Cash Creek Generation	Power generation	Pre-Comb	2	Onshore to onshore pipeline		KY		EOR	2015
Indiana Gasification	Synthetic natural gas	Pre-Comb	4.5	Onshore to onshore pipeline		IN		EOR	2015
Mississippi Gasification (Leucadia	Synthetic natural gas	Pre-Comb	4	Free State Pipeline	Denbury	MS	95-122	EOR	2015
Riley Ridge Gas Plant	Natural gas processing	Pre-Comb	2.5	Onshore to onshore pipeline		WY		EOR	2015
FutureGen 2.0	Power generation	Oxyfuel combustio n	1.3	Onshore to onshore pipeline		IL	35	Onshore saline	2016
Kentucky NewGas	Synthetic natural gas	Pre-Comb	5	Onshore to onshore pipeline		KY			2018

1 Data source: The Global Status of CCS: 2012. Global CCS Institute, Canberra, Australia, September 2012.

2 Capture Type: Pre-Comb= Pre combustion,Post-Comb, is post combustion ; Oxy= Oxyfuel Combustion, Sep=Separation

3 Storage Type: EOR= Enhanced Oil Recovery, Sal=Saline; Oth=Other formation

For the global iron and steel industry, the following approaches are underway as pilot projects to control GHG emissions[18]:

- 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.

Carbon capture from the DRI process. Potential capture of CO_2 can be done through pre-combustion (coal/coke gasification) where solid fossil fuels are used, by 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.

4. 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.

5. N_2O Control Technologies

The control of N_2O emissions is primarily achieved through combustion controls. In addition, post combustion catalyst systems including Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR), 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 (< 0.01%) of the GHG emissions produced, installing controls for N_2O emissions alone would not be cost-effective.

[18] "CCS in Industry." Bellona Environmental CCS Team. Available on-line at: http://bellona.org/ccs/technology/ccs-in-industryplants.html.

D. Emission Units subject to BACT

The majority of the GHG emissions associated with the project are from combustion sources (i.e., reformer, reactor furnace, emergency generator, and emergency fire pump), but the process water degasser also emits GHGs. In addition, pipe and piping equipment can also leak, thus posing a source of methane GHG emissions (less than 0.005 %). These combustion sources primarily emit carbon dioxide (CO_2). The sources listed in Table 4 are subject to the requirements of the GHG PSD permit:

Table 4. Summary of Sources and Emission Point Numbers (EPNs) for voestalpine

Source Name	EPN	Brief Description
Reformer Main Flue Ejector Stack	29	Reformer firebox (Combustion Unit) has a maximum design heat input rate of 1591 MMBtu/hr and is limited to the combustion of pipeline quality natural gas and top gas.
Hot Pressure Relief Vent-Flare	38	Flare controlling emissions from the reactor furnace during startup and shutdown.
Charge Hopper Vent	17	Charge Hopper feeds iron oxide pellets to the reactor furnace. Seal gas exhausts from the top of the furnace through the charge hopper.
Bottom Seal Gas Vent	8	Shaft furnace bottom seal gas wet scrubber vent.
Briquetting Dedusting Wet Scrubber Vent	9	Scrubs particulate from briquetting exhaust gas which also contains seal gas from the furnace bottom seal gas leg.
Process Water Degasser Vent	30	Vent from process water used to cool various streams that have come into contact with elevated pressure process gas directly or indirectly, particularly the wet gas scrubbers such as the charge hopper scrubber. The EPN is the vent to the process water degassing tank.
Emergency Generator	34	2500 KW diesel engine driven generator.
Emergency Fire Pump	35	175 KW/240 HP diesel engine driven emergency firewater pump.
Fugitive Components	FUG	Natural gas and reducing gas piping.

A summary of the proposed voestalpine facility GHG emissions is presented in Table 14 located at the end of this document. The overall proposed monitoring strategy involves determining 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 based on a 12-month rolling total. Fuel analyses will be conducted as required to demonstrate practical enforceability.

E. BACT Analysis

In order to address BACT for emissions of CO_2e from the DRI facility, the EPA reviewed technologies technically applicable to the production equipment installed at the facility for manufacturing DRI/HBI. This section describes a detailed, step-by-step BACT analysis for control of CO_2e emissions from each of the facilities identified in Table 4 above.

1. Reformer Main Flue Ejector Stack (EPN 29) BACT Analysis

This EPN serves as the normal operations emission point for both the natural gas reformer as well as for the shaft furnace. While a detailed process description is found in Section VI above, a brief description is provided here. Natural gas is first reformed into the reducing gases CO and H_2 in the reformer. The reducing gasses are then used in the shaft furnace as process gas to reduce the iron ore into sponge iron (DRI). During the reduction of the iron ore (iron oxide) to metallic iron, oxygen in the form of both CO_2 and H_2O is liberated from the iron oxide. The hot spent shaft furnace gas (called top gas) has residual H_2 and CO content and so most of it is recycled back to the beginning of the reforming step, where natural gas additions are made and the cycle repeats.

For process efficiency reasons described in Section VI above, approximately one third of the hot spent top gas is routed to the reformer combustion chamber where, when mixed with additional natural gas, it is used as fuel in the reformer. This hot, spent reducing gas still has heating value from the residual H_2 and CO (about ¼ the heating value of natural gas) but it also has CO_2 and H_2O from the reduction reaction in the furnace. Consequently, when this stream is routed to the reformer firebox, it carries the CO_2 from the reduction reaction with it. This spent top gas supplies most of the heat energy needed to fire the reformer (about 85%), the balance of the heat energy needed to fire the reformer comes from natural gas. Heat is recovered from the reformer firebox flue gas prior to exiting to atmosphere at EPN 29.

Emission point number 29 accounts for over 92% of the CO_2e emitted at the site, and contains CO_2 formed both in the shaft furnace as DRI is being created and as part of the products of combustion as fuel is combusted in the firebox of the reformer to create the heat to drive the reforming of methane into reducing gasses.

Step 1 - Identify Potential Control Technologies

voestalpine's search of the EPA'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 Table 5 below.

Most of the existing authorized DRI facilities have controlled GHG emissions through the efficient use of energy and natural gas at the facility by the implementation of the methods identified in Tables 1 and 2 above. voestalpine has stated that they are incorporating all of the methods identified in Tables 1 and 2 above in the design of the facility.

None of the existing DRI facilities identified in Table 5 below have made use of the add-on control technology of carbon capture and sequestration.

TABLE 5: Summary of RBLC Data for GHG Emissions from DRI Plants			
RBLC ID Number Company, Date	**Process Description**	**Emission Limits**	**BACT Requirements**
Consolidated Environmental Management Inc. – Nucor St. James, LA 07/19/2012 Operating	Process Heater (to replace Reformer) (DRI-108 – DRI Unit #1)	BACT-PSD: GHG 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 Not operating	Indurating Furnace Stacks (Waste Gas and Hood Furnace)	BACT-PSD: GHGLimit -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 Operating	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: GHG 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 the facility on a 12-month rolling total.	Good combustion practices, acid gas separation system, energy integration.

We will evaluate the following control technologies, all of which were described as part of the process description in Section VI above and also in the general discussion on control techniques earlier in this section.

1. Energy efficient equipment. This involves the use of efficient material transportation systems such as mechanical material transfer equipment where possible, reserving pneumatic transfer to fines. Included in this is also the use of high efficiency motors, variable speed drives, efficient fans, and efficient lighting systems. Also included in this category the use of refractory material and insulation to allow the maximum amount of heat to remain as useful heat in the various parts of the system, as described in Tables 1 and 2 above.
2. Enhanced Process Control. The use of automated process control and management systems, preventive maintenance systems, energy monitoring and managing systems, including the optimization of the compressed air systems. These are described in Tables 1 and 2 above.

3. Low GHG emitting fuels and raw materials and good combustion practices. This includes the use of natural gas as compared with a solid fossil fuel such as coal to both provide the fuel and from which to produce the process gas, as described earlier in this section VII.C above, along with good combustion practices.
4. Heat recovery and energy integration. This includes the use of spent top gas as fuel to the reformer, and the use of reformer flue gas heat recovery to allow preheating of fuel, process gas raw material, and combustion air as described the detailed process description sections on the reformer, the shaft furnace, and the spent reducing gas handling system (Section VI.B, C., and D, above, respectively).
5. Add on controls. The use of carbon capture and sequestration.

<u>Step 2 - Eliminate Technically Infeasible Options</u>

The following options are technically feasible:

1. Energy Efficient Equipment. The use of energy efficient equipment is technically feasible, and is incorporated into the design of the voestalpine facility.
2. Enhanced Process Control. The use of automated process control and management systems, preventive maintenance systems, energy monitoring and managing systems, including the optimization of the compressed air systems.
3. Low GHG emitting fuels and raw materials and good combustion practices. Fuels and raw material such as natural gas as compared with a solid fossil fuel such as coal, is technically feasible. In the case of voestalpine, the purpose and design of the facility includes the use of natural gas exclusively as both the primary energy source to run the reformer and furnace and as the feedstock to produce the process gas.
4. Heat recovery and energy integration is technically feasible. This includes the use of spent top gas as fuel to the reformer, and the use of reformer flue gas heat recovery to allow preheating of fuel, process gas raw material, and combustion air as described the detailed process description sections on the reformer, the shaft furnace, and the spent reducing gas handling system (Section VI.B, C, and D, above, respectively). The use of such systems is part of the design of the voestalpine facility.

The following option has not been proven as technically feasible:

5. Add on controls. The use of carbon capture and sequestration. Carbon capture and storage has not been demonstrated in practice for any commercial scale DRI facility. As described in Section VI.D (discussing spent process gas treatment) and Section VII.C.2 (near-term use of CCS in iron and steel industry) above, voestalpine indicated that CO_2 capture and water removal is a possible way to treat the spent process gas to ensure high efficiency reduction reactions as it is recycled in the system. However, the only time the process gas stream is vented directly to atmosphere is due to startup and shutdown events, where this stream is routed through the flare, and this accounts for 1,593 tpy CO_2e of the flare's 2462, tpy CO_2e emissions, or about less than 0.2% of the total CO_2e emissions from the site.

It is also possible to apply CCS to the main reformer firebox flue gas steam (92% of the emissions at the site), but that stream, as the products of combustion of natural gas, has a CO_2 concentration of approximately 5%, too low to practically capture by CCS.

According to voestalpine, if CCS were to be applied at the site, then the composition of the two gas streams would necessitate separate systems to treat each stream, one for the process gas stream and one for the reformer flue gas stream.

EPA is evaluating whether there is sufficient information to conclude that CCS is technically feasible at this source and will consider public comments on this issue. However, because the applicant has provided a basis to eliminate CCS on other grounds, we have assumed, for purposes of this specific permitting action, that potential technical or logistical barriers do not make CCS technically infeasible for this project and have addressed the economic feasibility issues in Step 4 of the BACT analysis in order to assess whether CCS is BACT for this project.

Step 3 - Rank Remaining Technically Feasible Control Options

The efficiency measures are estimated by voestalpine[19] to be as follows:

Low GHG emitting fuels and raw materials and good combustion practices. - 41%

Heat recovery and energy integration. - 25-30%

Add on controls. CCS. – 15 to 28%, but may not be technically feasible on all CO_2 bearing streams or economically reasonable.

Energy efficient equipment – up to 5% .

Enhanced Process Control. – up to 0.5%

Step 4 - Evaluate Remaining Control Technologies

We have determined that all measures except the add on control are appropriate control technologies because all of them are current design elements of a modern DRI facility and comparable industrial facilities, as identified in the various studies referenced in this document (see description of each, above), these elements are represented as being implemented in the design of the voestalpine facility, and we would expect no adverse impacts on energy or the environment from their implementation.

Carbon capture with transport and sequestration
As previously described, process gas quality improvement using amine stripping of CO_2 has been demonstrated in industry as an effective measure to improvement process gas quality and hence iron ore to iron conversion.

The capital cost of incorporating amine CO_2 stripping technology on the process gas stream is offset by the reduced operational cost of natural gas consumption (less bleed off of the spent process gas stream to the reformer furnace). 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

[19] See response to Question 4 and also Attchment 3 of voestalpine's "response to (EPA's) Application Completeness Determination" dated November 7, 2013 for details on the energy efficiency measures identified by voestalpine.

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 from the process gas stream can be deemed effective considering potential adverse impacts. Compared to the proposed project, voestalpine had determined that an amine CO_2 stripping system could be employed to improve the quality of the process gas and would reduce overall CO_2 emissions sitewide by about 15%.

The process gas cleanup system so described does not include the emissions from the reformer firebox where 92 % of the CO_2 emissions from the site are vented to atmosphere. voestalpine indicated in their BACT analysis that a Midrex plant could be fitted with an amine based carbon capture system that could capture as much as 50% of the CO_2 emitted sitewide if it could be sold at the site (that is, not considering compression, transportation, and storage requirements). With the specifics of this site's location and design and implementation (including amine stripping and captured CO_2 compression) voestalpine estimates that amine stripping and CO_2 compression could result in CO_2 emissions being reduced by 512,574 tpy, or 28% of the sitewide total.

Despite the fact that CO_2 separation is technically feasible for the process gas stream, CO_2 transport (including compression) and sequester costs are dependent upon the availability of pipelines to transport the captured CO_2 to a suitable location for its permanent sequestration or for commercial use. 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 enhanced oil recovery (EOR). If use of the Denbury pipeline is considered in this project, the approximate cost for a post-combustion CCS system can be estimated based on site specific information from voestalpine and from the *Report of the Interagency Task Force on Carbon Capture* [20]. CCS is a three-step process that includes the capture of CO_2 from industrial sources, transport of the captured CO_2 (usually in pipelines), and storage of that CO_2 in suitable geologic reservoirs. In this study, site specific costs were provided by voestalpine for CO_2 capture. However, site specific costs are not available for CO_2 transport and CO_2 storage, so costs are estimated as follows:

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[20] *Interagency Task Force on Carbon Capture* (2010). *Report of the Interagency Task Force on Carbon Capture and Storage.* August 2010.

CO_2 capture - For a new CO_2 capture project at the voestalpine facility, site specific costs for a CO_2 removal plant are estimated as $164,100,000 (shown in Table 6 below) for capturing and producing approximately 512,574 tpy of CO_2, which is about 28% of the sitewide CO_2 emissions. This results in a source specific estimated cost of $320.15 per ton of CO_2 captured.

CO_2 transport – The *Report of the Interagency Task Force on Carbon Capture* cites studies showing that CO_2 pipeline transport costs for a 100-kilometer (62 mile) pipeline range from approximately $1.10 per ton of CO_2 to $3.30 per ton of CO_2 [21]. As mentioned earlier in this section, a pipeline length of approximately 220 miles would be needed to transport CO_2 from voestalpine to the Denbury pipeline.

CO_2 storage - The *Report of the Interagency Task Force on Carbon Capture* cites cites project costs associated with CO_2 storage have been estimated to be approximately $0.44 per ton of CO_2 to $22.05 per ton of CO_2[22].

TABLE 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, and Stored per Year	Total Annual Cost
CO_2 capture and compression facilities			
Capital equipment costs for CO_2 separation (such as heat exchangers, amine scrubber, and/or mole sieves) and purification equipment-			$72,800,000
Compression equipment to pipeline conditions (including H_2S removal after compression)			$62,200,000
Engineering and design costs to incorporate above equipment			$10,000,000
Operating costs: Scrubber media/sieves – initial; Scrubber media/sieves – annual replacement; and kW for system-			$15,000,000
Wastewater treatment plant modifications directly tied to CCS additions-			$3,500,000
Engineering and design costs to incorporate wastewater treatment plant modifications-			$500,000
Operating costs:Wastewater treatment plant-			$100,000
Subtotal CO_2 capture and compression facilities	$320	512,574 tpy	$164,100,000
CO_2 Transport Facilities (for a 220 mile pipeline)	$7.86	512,574 tpy	4,001,384
CO_2 storage facilities	$0.44	512,574 tpy	5,766,458
Total CCS System Cost	**$339.21**	512,574 tpy	$173,867,839

At approximately $339.21 per ton of CO_2 controlled (captured, compressed, transported and stored), the use of CCS at the voestalpine facility is found by the applicant to be economically prohibitive. Even if only the site specific costs for capture and compression are used, the applicant estimates the costs to be $320.15 per ton of CO_2, which they also assert is economically infeasible. EPA views these cost estimates as credible, and agrees that the expected CCS costs are high for BACT purposes. EPA also recognizes that there may be an energy penalty associated with the operation of a post combustion CO_2 capture system at the

[21] *Ibid, p 37.*
[22] *Ibid, p 44.*

proposed facility. While not quantified here, EPA expects this increased energy requirement to result in increases in criteria pollutants. In light of the costs of CCS, and the potential for increased energy requirements and the resultant criteria emission increases, EPA is rejecting CCS under Step 4 of the BACT review.

<u>Step 5 – Selection of BACT</u>

The following control technologies have been selected as BACT:

1. Energy efficient equipment.
2. Enhanced Process Control.
3. Low GHG emitting fuels and raw materials and good combustion practices.
4. Heat recovery and energy integration.

voestalpine estimated that the total CO_2 emissions from EPN 29 to be 1,679,829 tpy and total CO_2e emissions of 1,683,316 tpy for this unit with the forgoing control methods applied. We propose this value as the BACT limit for this emission unit. In addition to this emission unit specific limit, we also establish an additional key sitewide natural gas usage value of no more than 13 decatherms/tonne DRI (11.79 mmBtu/short ton of DRI produced) on a 12-month rolling average basis. The DRI produced for this limit is based on total DRI production (i.e., the sum of off spec and commercial quality production). Compliance with these two BACT requirements will be demonstrated in an ongoing manner through the use of fuel monitoring, flow rate monitoring, good combustion practices monitoring on the reformer firebox, and DRI production accounting.

2. Hot Pressure Relief Vent (EPN: 38, FLARE) BACT Analysis

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 reducing gases (H_2 and CO) from the system by combusting the reducing gas.

<u>Step 1 – Identify Potential Control Technologies</u>

Table 8 lists the technologies required in issued PSD permits for controlling GHG emissions from the flares at DRI plants.

TABLE 8: Technologies for controlling GHG emissions from flares at DRI plants

RBLC ID Number Company, Date	Process Description	Emission Limits CO_2e	Control Type and Efficiency
LA-0248 Consolidated Environmental Management Inc. – Nucor St. James, LA 07/19/2012 (Unit #1) and 1/27/2011 (Unit 2)	Hot Flares (to revise Hot Flare)(DRI-110 (Unit #1) and DRI-210 (Unit 2)	none.	Good combustion practices. No other control specified.

We will evaluate the following control technologies, all of which were described as part of the process description in Section VI above and also in the general discussion on control techniques earlier in this section.

1. Low carbon fuels. 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 relief vent (flare) will be equipped with a natural gas-fired pilot to provide a constant flame source to ignite the flare system.
2. Good combustion practices. Good combustion practices for flares are listed in 40 CFR §60.18 and 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 that is necessary to assure a minimum 98% destruction efficiency of the waste streams controlled by it. Using good combustion practices also results in longer life of the equipment and more efficient operation.
3. Carbon capture and sequestration.

Step 2 - Eliminate Technically Infeasible Options

The following options are technically feasible:

1. Low carbon fuels.
2. Good combustion practices.

The following options are not technically feasible:

3. Carbon capture and sequestration. As described in Section VI above, the emission of GHG from the flare, including emissions from the combustion of the natural gas fired flare pilot and from the control of the streams vented to the flare amount to 2463 tpy CO_2e, less than 0.2% of the sitewide total emissions. In addition, the total flows to this flare are variable, being dominated by emissions during an estimated 26 startup/shutdown events annually.

Step 3 – Rank Remaining Technically Feasible Control Options

It is not necessary to assign relative efficiency rankings to the flare control options as they are all technically required for the proper operation of the flare.

1. Low carbon fuels.
2. Good combustion practices.

Step 4 – Evaluate Remaining Control Technologies

1. Low carbon fuels. The fuel for the pilot will meet the minimum heating value required by 40 CFR §60.18 by firing only pipeline quality natural gas as both pilot flame fuel and, when needed, to meet the minimum btu value required by 40 CFR §60.18 to assure proper control of the vent stream air contaminants being controlled.
2. Good combustion practices. 40 CFR §60.18 includes requirements to assure that the flare will operate properly and achieve the minimum 98% destruction efficiency required to properly combust the vent streams sent to the flare.

Step 5 – Selection of BACT

Based on the top-down BACT analysis, the best available technology for controlling CO_2, CH_4, and N_2O emissions (GHG emissions) from the flare is to use natural gas as the pilot fuel and as a supplement to the vent gas stream to assure proper heating value. Compliance with the operational and design requirements for flares found in 40 CFR §60.18 will assure that the flare achieves 98% destruction efficiency. So designed and operated, the flare will be limited to a maximum of 2462 tpy of CO_2e on a rolling 12 month average basis. To assure this limit is met and the flare will achieve it required minimum destruction efficiency, compliance with 40 CFR §60.18 for flares, workpractice standards, pilot gas monitoring, and proper maintenance will be required in the permit.

3. Shaft furnace charge hopper vent, bottom seal gas wet scrubber vent, and briquetter vents (EPNs 17, 8, and 9, respectively) BACT analysis

The Charge Hopper scrubber vent, and bottom seal gas wet scrubber vent. (EPNs 17 and 8) As described in Section VI.C above, seal gas assures that the process gas in the furnace does not escape to atmosphere. The seal gas is allowed to escape the furnace (through the referenced EPNs) while the reducing gas is retained. Due to the higher seal gas pressure, a portion is also entrained into the process gas and combined with the spent reducing gas that travels back to the reformer. Seal gas, as stated in Section VI.C above, is merely a slipstream of cooled flue gas from the reformer firebox and primarily consists of products of combustion of natural gas, including atmospheric nitrogen, CO_2, and water vapor. Also as stated in Section VI.C above, voestalpine estimates that the seal gas is split between the three emissions point with 40% routed through the charge hopper vent on top of the furnace (EPN 17), 40% vented through the bottom seal gas wet scrubber (EPN 8) and 20% vented through the briquette dedusting scrubber vent (EPN 9). During startup operations, the seal gas system used is nitrogen, and so contains no carbon species.

The briquetter dedusting vent (EPN 9), as described in Section VI.F above, uses a wet scrubber to control the dust emissions from the briquetting of DRI, but it also catches residual seal gas from the bottom of the shaft furnace seal gas leg.

This section performs a detailed, step-by-step BACT analysis for control of CO_2 emissions from these three vents.

Step 1 – Identify Potential Control Technologies

Table 9 lists the technologies required in issued PSD permits for controlling GHG emissions from the seal gas and briquetting vents at DRI plants.

TABLE 9: Summary of RBLC Data for CO_2e Emissions from Seal Gas Vent at DRI Plant

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

The following list of control methods was first described in Section VII.E.1 above, in the discussion on Reformer main flue ejector stack (EPN 29) BACT discussion. This list represents technologies that are available for the control of CO_2 emissions from EPNs 17, 8, and 9:

1. Enhanced Process Control. Process control, which includes proper equipment maintenance, is the key option available to minimize CO_2 emissions from these three emissions points. Carefully monitoring and controlling the pressure and flow in the seal gas legs to assure that the process gas is retained in the furnace and that the furnace is operated to minimize over pressurization (and thus furnace process gas venting thru the flare) is the best way to minimize the amount of seal gas that will be vented to atmosphere from EPNs 17, 8, and 9.
2. Heat recovery and energy integration. Recalling that seal gas is simply dewatered and dehydrated reformer firebox flue gas, then the best way to minimize GHG emissions from the reformer firebox is to assure that the reformer is operating correctly, as is described in the BACT discussion on the reformer, above.

<u>Step 2 – Eliminate Technically Infeasible Options</u>

Both options are technically feasible.

<u>Step 3 – Rank Remaining Technically Feasible Control Options</u>

Both options are equally important for proper operation of the site.

<u>Step 4 – Evaluate Remaining Control Technologies</u>

We have determined that measures 1 and 2 are required for the proper operation of the site appropriately.

<u>Step 5 – Selection of BACT</u>

BACT for CO_2 will consist of enhanced process control and heat recovery and energy integration. When properly operated, EPNs 17 and 8 are each limited to emit no more than 54, 689 tons of CO_2e per 12 month rolling average, while EPN 9. is limited to no more than 27,402.04 tpy CO_2e on a 12-month rolling average. Specific monitoring of process parameters are required in the permit.

4. Process Water Degasser (EPN: 30) BACT Analysis

All streams from the process cooling water system (including direct cooling) are collected and treated at the process water treatment plant. Due to the required direct contact of process water with process gases (top gas scrubber in particular), some traces of gas constituents (CO_2, CO, etc.) are dissolved in water at elevated process gas pressure. The return water flow from the top gas scrubber weir (after depressurization) is routed to a degasser vessel where air (coming from a separate air fan) flows countercurrent to the hot return water. The majority of the dissolved gas constituents (CO_2, CO, etc.) are collected in the degasser vent gas flow and released to atmosphere at EPN 30. The process water from the degasser then flows to the clarifier.

The amount of CO_2, CO, etc. in the return water flow from direct contact of process water with process gas (e.g., gas scrubber systems) is a result of basic physics principles of gas wet treatment technology; the degassing of the return water flow has to operate because of industrial hygiene and safety reasons only. The CO_2 emissions at the degasser can be estimated via calculation using the theoretical absorption capacity (Henry`s Law) and the flow rates. Furthermore the flow and concentration of CO and CO_2 are irregular since entry to and from the pressurized DRI process is episodic in nature too. It should noted that emissions from this source account for less than 1700 tpy CO_2e, or < 0,06% of sitewide CO_2e emissions.

Step 1 – Identify Potential Control Technologies

voestalpine's search of EPA's RBLC database revealed no DRI plants with process water limits. Other industrial facilities that have similar process waters are listed in Table 10.

TABLE 10: Summary of RBLC Data for CO_2e Emissions from Process Water Degasser at DRI Plants

RBLC ID Number Company, Date	Process Description	Emission Limits CO_2e	Control Type and Efficiency
Formosa Plastics Corp. Point Comfort, TX November 2012 Permit Application	Process Water Stripper	none	Caustic/water wash tower.
IA-0206 CF Industries Nitrogen, LLC Port Neal Nitrogen Complex 07/12/2013	Condensate Steam Stripper	none	Good operating practices.
LA-0272 Dyno Nobel Louisiana Ammonia, LLC Ammonia Production Facility 03/27/2013	CO_2 Stripper Vent	none	Energy efficiency measures.

The following list of control technologies represent technologies that have been used for the control of CO_2 emissions from the process water degasser.

1. Caustic/Water Scrubber. A caustic/water scrubber can be used for the removal of acid gases (e.g., CO_2 and trace H_2S) from the process water degasser exhaust. A control efficiency of 95 to 99% can be attained depending on the type of reagent used (such as 20% caustic solution) and the scrubber design.
2. Enhanced Process Control. Enhanced Process Control includes include appropriate maintenance of equipment and operating within the operational parameters recommended by the manufacturer. Using good operating 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.

Step 2 – Eliminate Technically Infeasible Options

The identified control strategies are technically feasible and have not been eliminated.

Step 3 – Rank Remaining Technically Feasible Control Options

1. Caustic/Water Scrubber: 99% control efficiency.
2. Enhanced Process Control. Since this technology would not actually strip CO_2 from the process stream, then it has no specific control efficiency assignable.

Step 4 – Evaluate Remaining Control Technologies

1. Caustic/Water Scrubber: Although technically feasible, use of a caustic/water scrubber to control the small amount of GHG emissions that occur from process water degassing is very small (approximately 1636 tpy or 0.06% of site-wide CO_2e emissions), and the incremental increase in CO_2e emissions controlled by it is insignificant so this option is ruled out.
2. Enhanced Process Control. voestalpine will incorporate good operating practices and perform maintenance as recommended by the process water degassing manufacturer.

Step 5 – Selection of BACT

BACT for CO_2 emissions from the process water degasser (EPN 30) is determined to be 1,636 CO_2e tpy on a 12-month rolling average by performing enhanced process control that is implementing good operating practices and proper maintenance for the process water degasser. Specific monitoring of process parameters are required in the permit.

5. Emergency Generator and Fire Pump (EPNs: 34 and 35, respectively)

The Emergency Generator, Emission Source 34 is a diesel fired generator used to ensure the supply of electric power in case of failure of the main incoming supply. The fire pump is also fired by diesel fuel and is used solely to ensure the supply of water in case of fire. Neither of these sources is expected to operate more than 100 hours in a year, and that is for testing purposes.

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 Table 11 below.

TABLE 11: Summary of RBLC Data for CO_2e Emissions from Emergency Generators and Fire Pumps

RBLC ID Number Company, Date	Process Description	Emission Limits CO_2e	Control Type and Efficiency
LA-0256 Westlake Vinyls Company LP Ascension Parish, LA 12/06/11	Emergency Generator, 1818 HP, Natural Gas	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	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	Emergency Fire Pump Engine, Diesel	CO_2 2.4 tpy, 12-month rolling.	Use of good combustion practices, based on the current

TABLE 11: Summary of RBLC Data for CO_2e Emissions from Emergency Generators and Fire Pumps			
RBLC ID Number Company, Date	**Process Description**	**Emission Limits CO_2e**	**Control Type and Efficiency**
Company, Inc. Lloyd Ridge (OCS), FL 10/27/2011 *Draft Determination			manufacturer's specifications for this engine.
LA-0254 Entergy Louisiana LLC LA 08/16/11	Emergency Diesel Generator, 1250 HP	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	163 lb/MMBtu, 12-month rolling.	Proper operation and good combustion practices.

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. 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.
2. 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 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.

<u>Step 2: Eliminate Technically Infeasible Options</u>

1. 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.
2. Good Combustion Practices and Proper Maintenance are technically feasible.

<u>Step 3 – Rank Remaining Technically Feasible Control Options</u>

2. Good Combustion Practices and Proper Maintenance.

Step 4 – Evaluate Remaining Control Technologies

2. 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. The emergency generator will be limited to no more than 197.14 tpy CO_2e per rolling 12-month average. The firewater pump shall be limited to 12.83 tpy CO_2e per 12-month rolling average. The two engines will be limited to 100 hours of operation per year for testing purposes.

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.

6. Fugitive GHG emissions (EPN: FUG) BACT Analysis

Fugitive components for voestalpine will include: pipe joining components, valves, pressure relief valves, pump seals, compressor seals, and sampling connections. GHG emissions from leaking pipe components (fugitive emissions) from the proposed project will include both CO_2 and CH_4; however, the ratio of CO_2 to CH_4 in pipeline-quality natural gas is relatively low. For purposes of the GHG calculations, it was assumed all piping components will be in a rich CH_4 stream. Total emissions from equipment leaks is determined based on the number of components by type and emissions factors published by the US EPA.[23] Table 13, below, provides some of the control efficiencies identified by the TCEQ for various LDAR programs.

The following discussion presents a BACT evaluation of fugitive CO_2 and CH_4 emissions, and because the fugitive emission controls presented in this analysis will provide similar levels of emission reduction for both CO_2 and CH_4, the BACT evaluation has been combined into a single analysis.

Results of a search of EPA's RBLC database by voestalpine for the control of CO_2e from equipment leaks are presented in Table 12 below. Related permits and permit applications are also included in this listing.

[23] US EPA Emissions Inventory Improvement Program, Volume 2 Chapter 4: Preferred and Alterate Methods for Estimating Emissions from Equipment Leaks, 1996. Available here: http://www.epa.gov/ttnchie1/eiip/techreport/volume02/

TABLE 12: Summary of RBLC Data for CO_2e emissions from fugitive components			
RBLC ID Number Company, Date	**Process Description**	**Emission Limits CO_2e**	**Control Type and Efficiency**
Cheniere Corpus Christi Pipeline, Sinton Compressor Station 08/31/2013	Fugitive Emissions	none	Conduct annual GHG surveys in compliance with 40 CFR 60 Part 98.
Celanese, Ltd. – Clear Lake Plant August 2013	Fugitive Emissions	none	Implementation of 28LAER LDAR program; use of an AVO program to monitor for leaks in between instrumented checks; and use of high quality components and materials of construction.
LA-0271 Crosstex Processing Services, LLC - Plaquemine NGL Fractionation Plant 05/24/2013	Fugitive Emissions	none	Compliance with LDAR programs under 40 CFR 60 Subpart OOOO, LAC 33:III.2111, and LAC 33:III.2122.
LA-0266 Crosstex Processing Services, LLC - Eunice Gas Extraction Plant 05/01/2013	Process Fugitives	none	Compliance with LDAR programs: NSPS KKK and LAC 33:III.2121.
Dominion Cove Point LNG, LP March 2013	Fugitives	53.6 ton/yr 12-month rolling total.	Implementation of an LDAR program; implementation of an AVO monitoring program.
Corpus Christi Liquefaction, LLC August 2012 (*Permit Application)	Fugitives	38 ton/yr 12-month rolling total.	Use of leakless components (welded flanges) to the maximum extent possible; implementation of 28VHP LDAR program.
LA-0263 Phillips 66 Company – Alliance Refinery 07/25/2012	Hydrogen Plant Fugitives	BACT-PSD: CO_2e Limit – none.	Implementation of the Louisiana Refinery MACT leak detection and repair (LDAR) program; monitoring for total hydrocarbon content instead of VOC.
ETC Texas Pipeline – Jackson May 2012	Fugitive Emissions	none	Emissions shall be calculated annually based on the emission factors from Table W-1A of 40 CFR Part 98, Subpart W, Petroleum and Natural Gas Systems and using the reduction credit from 28LAER and calculations given in the TCEQ Technical Guidance Document for Equipment Leak Fugitives, dated 10/2000.
LA-0257 Sabine Pass LNG, LP and Sabine Pass Liquefaction, LLC – Sabine Pass LNG Terminal 12/06/2011	Fugitive Emissions	89,629 ton/yr annual maximum.	Conduct a leak detection and repair (LDAR) program.
Freeport LNG Development, LP December 2011 (*Permit Application)	Fugitives for Pretreatment Facility	none	Implementation of 28MID LDAR program (with quarterly monitoring) and AVO program in between LDAR checks.
Freeport LNG Development, LP December 2011 (*Permit Application)	Fugitives for Liquefaction Plant	none.	Implementation of 28MID LDAR program (with quarterly monitoring) and AVO program in between LDAR checks.
TX-0612 Lower Colorado River Authority – Thomas C. Ferguson Power Plant 11/10/2011	Fugitive Natural Gas Emissions	327.2 ton/yr 365-day rolling average. 16.2 ton/yr 365-day rolling average.	Because the emissions from this unit are calculated to be 96% methane (CH_4), the remaining pollutant emissions (CO_2) are not accounted for.

* RBLC data obtained from USEPA RBLC, Process Type 50.999, other petroleum and natural gas production and refining sources.

Step 1 – Identify Potential Control Technologies

The following technologies were identified as potential control measures for CO_2e emissions associated with fugitive components.

1. Installing leakless technology components. Emissions from pumps and valves can be reduced through the use of leakless valves (such as welded bonnet bellows valves and diaphragm valves) and sealless pumps (such as diaphragm, canned, and magnetic-driven pumps).
2. Implementing various LDAR programs. LDAR programs are required by a number of state and federal air regulations for the control of VOC emissions. BACT determinations related to control of VOC emissions rely on technical feasibility, economic reasonableness, reduction of potential environmental impacts, and regulatory requirements for these instrumented programs.
3. Implementing an alternative monitoring program. Alternate monitoring programs have proven to be effective in leak detection and repair. For example, the use of sensitive infrared camera technology has become widely accepted as a cost effective means for identifying leaks of hydrocarbons and may also be effective for identifying leaks of CO_2 and CH_4.
4. Implementing an Audio/Visual/Olfactory (AVO) monitoring program. Leaking fugitive components can be identified through audio, visual, or olfactory (AVO) methods. The fugitive emissions from piping components are expected to have a discernible odor, making them detectable by olfactory means. A large leak can be detected by sound and/or sight. The visual detection can be a direct viewing of leaking gases, or a secondary indicator such as condensation around a leaking source due to cooling of the expanding gas as it leaves the leak interface. AVO programs are commonly used in various industries.

Step 2: Eliminate Technically Infeasible Options

1. Installing leakless technology components. The use of leakless technology components to eliminate fugitive emission sources is an available option; however, these technologies are generally considered to be technically infeasible except for specialized service. Also, using leakless connectors can result in an inability to isolate small areas; therefore, requiring the clearance of a larger area or a full shutdown to perform maintenance. As a result, further consideration of leakless technology for GHG controls is unwarranted.

The remaining options are considered technically feasible.

Step 3 – Rank Remaining Technically Feasible Control Options

2-4. The various LDAR programs range in control effectiveness based on a number of factors, and are well documented in the literature and range from 75 to 99 percent[24].

[24] See Chapter 4 entitled "Preferred and Alternative Methods for Estimating Air Emissions from Equipment Leaks." November 1996. This chapter is in Volume 2, Part 1 of the Emissions Inventory Improvement Program published online by the US EPA at this website: http://www.epa.gov/ttn/chief/eiip/techreport/volume02/index.html

Step 4 – Evaluate Remaining Control Technologies

2. Implementing Various LDAR Programs. Conventional LDAR programs are designed to control VOC emissions and vary in stringency. CH_4 is not considered a VOC, so LDAR programs have not previously been required for streams containing a high CH_4 content. However, instrumented monitoring is effective for identifying leaking CH_4 emissions, and with CH_4 having a GWP greater than CO_2, instrumented monitoring of the fuel system for CH_4 would be an effective method for control of CO_2e emissions.

   Table 13 below is a summary of the Texas Commission on Environmental Quality's (TCEQ's) LDAR programs and the control efficiencies that may be achieved with each. The TCEQ's 28LAER program is one of the TCEQ's most stringent LDAR programs, which was developed to satisfy LAER requirements in ozone non-attainment areas. The voestalpine facility will be located in an attainment area, so LAER requirements are not applicable. Accordingly, the use of the 28 LAER LDAR program is not appropriate. The next most stringent LDAR program is TCEQ's 28MID program. The 28MID program requires quarterly instrumented monitoring with a leak definition of 500 ppmv, accompanied by intense directed maintenance, which is generally assigned a control effectiveness of 97%.

3. Although technically feasible, use of an alternative monitoring program to control the negligible amount of GHG emissions that occur as process fugitives does not require specialized alternative monitoring programs over existing program type, and so is rejected as overly complex for the need.

4. Implementing an Audio/Visual/Olfactory (AVO) monitoring program. When implemented at a source with an odorized gas stream, this is a very effective program due to the frequency of observation, which is typically carried out each day as personnel work in the plant area. Since all gas streams at this facility will be odorized, this method will be as effective as an instrumental monitoring program at this site.

Step 5: Select BACT

For CO_2e emissions from fugitive components, BACT is selected to be use of an AVO program to monitor for leaks.

TABLE 13: Summary of TCEQ Control Efficiencies for Leak Detection and Repair (LDAR) Programs[25]						
Equipment/Service	**28M**	**28RCT**	**28VHP**	**28MID**	**28LAER**	**Audio/Visual/ Olfactory[1]**
Valves						
Gas/Vapor	75%	97%	97%	97%	97%	97%
Light Liquid	75%	97%	97%	97%	97%	97%
Heavy Liquid[2]	0%[3]	0%[4]	0%[4]	0%[4]	0%[4]	97%
Pumps						
Light Liquid	75%	75%	85%	93%	93%	93%
Heavy Liquid[2]	0%[3]	0%[3]	0%[5]	0%[6]	0%[6]	93%
Flanges/Connectors						
Gas/Vapor[7]	30%	30%	30%	30%	97%	97%
Light Liquid[7]	30%	30%	30%	30%	97%	97%
Heavy Liquid	30%	30%	30%	30%	30%	97%
Compressors	75%	75%	85%	95%	95%	95%
Relief Valves (Gas/Vapor)	75%	97%	97%	97%	97%	97%
Open-ended Lines[8]	75%	97%	97%	97%	97%	97%
Sampling Connections	75%	97%	97%	97%	97%	97%

Notes:

1. Audio, visual, and olfactory walk-through inspections are applicable for inorganic/odorous and low vapor pressure compounds such as chlorine, ammonia, hydrogen sulfide, hydrogen fluoride, and hydrogen cyanide.

2. Monitoring components in heavy liquid service is not required by any of the 28 Series LDAR programs. If monitored with an instrument, the applicant must demonstrate that the VOC being monitored has sufficient vapor pressure to allow reduction.

3. No credit may be taken if the concentration at saturation is below the leak definition of the monitoring program (i.e. (0.044 psia/14.7 psia) x 106 = 2,993 ppmv versus leak definition = 10,000 ppmv).

4. Valves in heavy liquid service may be given a 97% reduction credit if monitored at 500 ppmv by permit condition provided that the concentration at saturation is greater than 500 ppmv.

5. Pumps in heavy liquid service may be given an 85% reduction credit if monitored at 2,000 ppmv by permit condition provided that the concentration at saturation is greater than 2,000 ppmv.

6. Pumps in heavy liquid service may be given a 93% reduction credit if monitored at 500 ppmv by permit condition provided that the concentration at saturation is greater than 500 ppmv.

7. If the applicant decides to monitor connectors using an organic vapor analyzer (OVA) at the same leak definition as valves, then the applicable valve reduction credit may be used instead of the 30% reduction credit. If this option is chosen, the applicant shall continue to perform the weekly physical inspections in addition to the quarterly OVA monitoring.

8. The 28 Series quarterly LDAR programs require open-ended lines to be equipped with an appropriately sized cap, blind flange, plug, or a second valve. If so equipped, open-ended lines may be given a 100% control credit.

[25] Control Efficiencies for TCEQ Leak Detection and Repair Programs Revised 07/11 (TCEQ document APDG 6129v2) available at:www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/control_eff.pdf

F. BACT Limits and Compliance

As a preliminary matter, the majority of all CO_2 at voestalpine is either generated from the consumption and combustion of natural gas within the reformer (92%) or the combustion of diesel in an emergency engines (<0.0.001%), we propose the following calculations to provide an ongoing method of assuring that the sitewide emissions limitations of GHG are met:

For Natural Gas:

$$X\ million\ cubic\ feet_{per\ time\ period} * \quad EF\ \frac{tons}{million\ cubic\ feet} = Y\ tons_{per\ time\ period}$$

For Diesel:

$$X\ gallons_{per\ time\ period} * \quad EF\ \frac{tons}{gallon} = Y\ tons_{per\ time\ period}$$

Where "X" is the monitored value and "EF" is the emission factor as suggested below:

Emissions Factors from Fuel combustion based on AP-42 factors[26]		
Greenhouse Gas	**Natural Gas (AP-42) (tons/mmcf)**	**Diesel (AP-42) (tons/gallon)**
CO_2	60	1.13E-02
Methane	0.00115	2.60E-08
Nitrous Oxide	0.00032	1.30E-07
CO_{2e}	60.12	1.13E-02

In addition, voestalpine will be required to comply with the limitations and other BACT workpractice standards identified in Table 14 at the end of this document.

VIII. Threatened and Endangered Species

Pursuant to Section 7(a)(2) of the Endangered Species Act (ESA) (16 U.S.C. 1536) and its implementing regulations at 50 CFR Part 402, EPA is required to insure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any federally-listed endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat.

To meet the requirements of Section 7, EPA is relying on a Biological Assessment (BA) prepared by the applicant, voelstalpine Texas LLC ("voelstalpine"), and its consultant, Environmental Resource Management ("ERM"), reviewed and adopted by EPA. Further, EPA designated voelstalpine and its consultant, ERM, as non federal representatives for purposes of preparation of the BA and for conducting informal consultation.

A draft BA has identified twenty-three (23) species as endangered or threatened in San Patricio and Nueces Counties, Texas by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS) and the Texas Parks and Wildlife Department (TPWD) and is listed in the table below:

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[26] AP 42, 5th Edition, Volume 1 Chapter 1: External Combustion available here:http://www.epa.gov/ttn/chief/ap42/ch01/index.html

Federally Listed Species for San Patricio and Nueces Counties by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS) and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Reptiles	
Green sea turtle	*Chelonia mydas*
Hawksbill sea turtle	*Eretmochelys imbriacata*
Kemp's ridley sea turtle	*Lepidochelys kempii*
Leatherback sea turtle	*Dermochelys coriaea*
Loggerhead sea turtle	*Caretta caretta*
Mammals	
Gulf coast jaguarundi	*Herpailurus yagouaroundi cacomitli*
Ocelot	*Leopardus pardalis*
Red Wolf	*Canis lupus rufus*
Birds	
Yellow-billed cuckoo	*Coccyzus americanus*
Northern aplomado falcon	*Falco femoralis septentrionalis*
Eskimo curlew	*Numenius borealis*
Piper plover	*Charadrius melodus*
Red knot	*Calidris canutus rufa*
Whooping crane	*Grus americana*
Plants	
South Texas ambrosia	*Ambroia cheiranthifolia*
Slender rush-pea	*Hoffmannseggia tenella*
Fish	
Smalltooth sawfish	*Pristis pectinata*
Marine Mammals	
West Indian manatee	*Trichechus manatus*
Blue whale	*Balaenoptera musculus*
Finback whale	*Balaenoptera physalus*
Humpback whale	*Megaptera novaeangliae*
Sei whale	*Balaenoptera borealis*
Sperm whale	*Physeter macrocephalus*

EPA has determined that issuance of the proposed permit to voelstalpine for a new direct reduced iron (DRI)/hot-briquetted iron (HBI) production facility will have no effect on thirteen (13) of the twenty-three (23) federally-listed species, specifically the the red wolf (*Canis rufus*), slender rush-pea (*Hoffmannseggia tenella*), Gulf coast jaguarundi (*Herpailurus yagouaroundi cacomitli*), ocelot (*Leopardus pardalis*), eskimo curlew (*Numenius borealis*), South Texas ambrosia (*Ambrosia cheiranthifolia*), smalltooth sawfish (*Pristis pectinata*), blue whale (*Balaenoptera musculus*), finback whale (*Balaenoptera physalus*), humpback whale (*Megaptera novaeangliae*), sei whale (*Balaenoptera borealis*), sperm whale (*Physeter macrocephalus*) and leatherback sea turtle (*Dermochelys coriacea*). These species are either thought to be extirpated from these counties or Texas or not present in the action area.

Six (6) of the twenty-three (23) federally-listed species are species that may be present in the Action Area and are under the jurisdiction of USFWS. As a result of this potential occurrence and based on the information provided in the draft BA, the issuance of the permit may affect, but is not likely to adversely affect the following species:

- Red knot (*Calidris canutus rufa*)
- Yellow-billed cuckoo (*Coccyzus americanus*)
- Northern Aplomado falcon (*Falco femoralis septentrionalis*)
- Piping plover (*Charadrius melodus*)
- Whooping crane (*Grus americana*)
- West Indian manatee (*Trichechus manatus*)

On April 3, 2014, EPA submitted the final draft BA to the Southwest Region, Corpus Christi, Texas Ecological Services Field Office of the USFWS for its concurrence that issuance of the permit may affect, but is not likely to adversely affect these six federally-listed species.

Four (4) of the twenty-three federally-listed species identified are marine species that may be present in the Action Area and are under the jurisdiction of NOAA. As a result of this potential occurrence and based on the information provided in the draft BA, the issuance of the permit may affect, but is not likely to adversely affect the following species:

- green sea turtle (*Chelonia mydas*)
- Kemp's ridley sea turtle (*Lepidochelys kempii*)
- loggerhead sea turtle (*Caretta caretta*)
- Hawksbill sea turtle (*Eretmochelys imbricate*)

On February 20, 2014, EPA submitted the final draft BA to the NOAA Southeast Regional Office, Protected Resources Division of NMFS for its concurrence that issuance of the permit may affect, but is not likely to adversely affect these four federally-listed species.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on listed species. The final draft BA can be found at EPA's Region 6 Air Permits website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

IX. Magnuson-Stevens Act

The 1996 Essential Fish Habitat (EFH) amendments to the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act) set forth a mandate for the National Oceanic Atmospheric Administration's National Marine Fisheries Service (NMFS), regional fishery management councils, and other federal agencies to identify and protect important marine and anadromous fish habitat.

To meet the requirements of the Magnuson-Stevens Act, EPA is relying on an EFH Assessment prepared by the ERM on behalf of voelstalpine and reviewed and adopted by EPA.

The facility is adjacent to tidally influenced portions of the La Quinta Channel that adjoins to the Corpus Christi Ship Channel leading to the Gulf of Mexico. These tidally influenced portions have been identified as potential habitats of postlarval, juvenile, subadult or adult stages of red drum (*Sciaenops ocellatus*), shrimp (4 species), and reef fish (43 species). The EFH information was obtained from the NMFS's website (http://www.habitat.noaa.gov/protection/efh/efhmapper/index.html).

Furthermore, these tidally influenced areas have also been identified by NMFS to contain EFH for neonate of the finetooth shark (*Carcharhinus isodon*); neonate and juvenile of the scalloped hammerhead shark (*Sphyrna lewini*), bull shark (*Carcharhinus leucas*), and spinner shark (*Carcharhinus brevipinna*); adult and neonate of lemon shark (*Negaprion brevirostris*); and neonate, juvenile, and adult of the blacktip shark (*Carcharhinus limbatus*), sharpnose shark (*Rhizoprionodon terraenovae*), and bonnet head shark (*Sphyrna tiburo*).

Based on the information provided in the EFH Assessment, EPA concludes that the proposed PSD permit allowing voelstalpine construction of a new DRI/HBI production facility will have no adverse impacts on listed marine and fish habitats. The assessment's analysis, which is consistent with the analysis used in the BA discussed above, shows the project's construction and operation will have no adverse effect on EFH.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on listed species. The final essential fish habitat report can be found at EPA's Region 6 Air Permits website at: http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

X. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties eligible or potentially eligible for inclusion in the National Register of Historic Places. To make this determination, EPA relied on a cultural resource report prepared by ERM, voelstalpine's consultant, submitted on July 24, 2013.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be approximately 475 acres of land that contains the construction footprint of the project. ERM performed a field survey, including shovel testing, and a desktop review on the archaeological background and historical records within a 1.0-mile radius of the facility's APE, which included a review of the Texas Historical Commission's online Texas Archaeological Site Atlas (TASA) and the National Park Service's National Register of Historic Places (NRHP). At least five archeological investigations have been conducted within and adjacent to the APE; these are listed in the report.

Based on the results of the field survey, one archaeological resource was found within the APE. However, it was recommended that the portion of the archeological site within the APE is not eligible for inclusion in the National Register. Based on the desktop review for the site, seven archaeological/historic sites were identified, all of which are outside of the APE.

On February 13, 2014, EPA sent letters to Indian tribes identified by the Texas Historical Commission as having historical interests in Texas to inquire if any of the tribes have historical interest in the particular location of the project and to inquire whether any of the tribes wished to consult with EPA in the Section 106 process. EPA received no requests from any tribe to consult on this proposed permit.

EPA will provide a copy of the report to the State Historic Preservation Officer for consultation and concurrence with its determination. Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties. A copy of the report may be found at http://yosemite.epa.gov/r6/Apermit.nsf/AirP

XI. Environmental Justice (EJ)

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive branch policy on environmental justice. Based on this Executive Order, the EPA's Environmental Appeals Board (EAB) has held that environmental justice issues must be considered in connection with the issuance of federal Prevention of Significant Deterioration (PSD) permits issued by EPA Regional Offices [See, e.g., In re Prairie State Generating Company, 13 E.A.D.1, 123 (EAB 2006); In re Knauf Fiber Glass, Gmbh, 8 E.A.D. 121, 174-75 (EAB 1999)]. This permitting action, if finalized, authorizes emissions of GHG, controlled by what we have determined is the Best Available Control Technology for those emissions. It does not select environmental controls for any other pollutants. Unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no National Ambient Air Quality Standard (NAAQS) for GHGs. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [PSD and Title V Permitting Guidance for GHGS at 48]. Thus, we conclude it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, we have determined an environmental justice analysis is not necessary for the permitting record.

XII. Conclusion and Proposed Action Based on the information supplied by voestalpine, our review of the analyses contained in the TCEQ PSD Permit Application and the GHG PSD Permit Application, and our independent evaluation of the information contained in our Administrative Record, it is our determination that the voestalpine LLC, Portland Production Plant would employ BACT for GHGs under the terms contained in the draft permit. Therefore, EPA is proposing to issue voestalpine a PSD permit for GHGs for the facility, subject to the PSD permit conditions specified therein. See Table 14, below, for the Annual Emissions and BACT requirements summary.

Table 14. Proposed Emissions Limitations and BACT Requirements Summary					
Facility Description	EPN	GHG Mass Basis		CO_2e TPY [1,2,3]	BACT Requirements Summary[4]
		Pollutant	TPY[1]		
Sitewide					Limit natural gas use to no more than 13 decatherms /tonne HBI (11.79 mmBtu/ton HBI) 12-month rolling annual average.
Reformer Main Flue Ejector Stack	29	CO_2	1,679,829	1,683,316	Energy efficient equipment. Enhanced Process Control. Natural gas for fuels and process gas raw material Heat recovery and energy integration.
		CH_4	32.20		
		N_2O	9.00		
Hot Pressure Relief Vent Flare	38	CO_2	2,236	2,462	Natural gas for pilot. Good combustion practices, design, operate, and maintain consistent with 40 CFR §60.18.
		CH_4	9.05		
		N_2O	0.01		
Charge Hopper	17	CO_2	54,689	54,802	Enhanced process control. Heat recovery and energy integration.
		CH_4	1.05		
		N_2O	0.29		
Bottom Seal Gas Wet Scrubber	8	CO_2	54,689	54,802	Enhanced process control. Heat recovery and energy integration.
		CH_4	1.05		
		N_2O	0.29		
Briquetter Dedusting	9	CO_2	27,345	27,403	Enhanced process control. Heat recovery and energy integration.
		CH_4	0.52		
		N_2O	0.15		
Process Water Degasser	30	CO_2	1,104	1,636	Enhanced process control (good operating practices and proper maintenance).
		CH_4	21.25		
		N_2O	Negligible		
Emergency Generator	34	CO_2	197	197	Good combustion practices and proper maintenance. Engine must comply with NSPS Subpart IIII based on manufacturer's specifications.
		CH_4	Negligible		
		N_2O	0.01		
Fire Pump	35	CO_2	13	13	Good combustion practices and proper maintenance. Engine must comply with NSPS Subpart IIII based on manufacturer's specifications.
		CH_4	Negligible		
		N_2O	Negligible		
Fugitive Components	FUG	CO_2	Negligible	100	Use of an AVO program to monitor for leaks.
		CH_4	4.01		
		N_2O	Negligible		
Sitewide[6]		**CO_2**	**1,820,102**	**1,824,731**	
		CH_4	**69.13**		
		N_2O	**9.73**		

1. Compliance with the annual emission limits (tons per year) is based on a 12 month rolling average unless otherwise specified.
2. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities
3. Annual CO_2e per facility is calculated by summing the product of the mass emission rate for the air pollutant by the Global Warming Potential (GWP) found in Table A-1 of Subpart A of 40 CFR Part 98 (78 FR 71904) for each pollutant. The relevant GWP values include: CO_2 =1; CH_4 = 25; N_2O = 298
4 Specific supporting BACT requirements are found in the permit in Section III. Permit Special Conditions.
5. Total fugitive emissions are and estimate, and not a BACT emissions limit. Compliance is through the AVO program workpractice.
6. Sitewide totals for informational purposes only.