

Prevention of Significant Air Quality Deterioration Review

Preliminary Determination

November 2010

Facility Name: Osceola Steel Company

City: Adel

County: Cook

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Review Conducted by:

State of Georgia - Department of Natural Resources

Environmental Protection Division - Air Protection Branch

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SUMMARY

The Environmental Protection Division (EPD) has reviewed the application submitted by Osceola Steel Company for a permit to construct and operate a micro steel mill with the capability of producing approximately 430,000 tons of steel per year to be located in Adel, Georgia. The proposed project consists of a melt shop containing a 24 million British Thermal Units per hour (10^6 Btu/hr) electric arc furnace; a reheat furnace with a heat input of 75×10^6 Btu/hr, horizontal ladle preheaters, a vertical ladle heating stack, Tundish preheaters, casting machine torches, cooling towers, continuous casting, a lime silo and a carbon silo. All fuel burning equipment associated with the proposed project will fire natural gas.

A Prevention of Significant Deterioration (PSD) analysis was performed for the facility for all pollutants to determine if any increase was above the “significance” level. The facility will emit more than 100 tons per year (tpy) of a single criteria air pollutant; therefore the facility is classified as a major stationary source under the PSD program since it is one of the 28 listed source categories. The construction of the Osceola Steel Mill will result in an emissions increase in Nitrogen Oxides (NO_x), Sulfur Dioxide (SO_2), Carbon Monoxide (CO), Particulate Matter with an aerodynamic size equal to or less than 2.5 microns ($\text{PM}_{2.5}$) and Particulate Matter with an aerodynamic size equal to or less than ten microns (PM_{10}) above the Prevention of Significant Deterioration (PSD) significance levels (SLs).

The Osceola Steel Company is located in Cook County, which is classified as “attainment” or “unclassifiable” for SO_2 , $\text{PM}_{2.5}$ and PM_{10} , NO_x , CO, and ozone (VOC).

The EPD review of the data submitted by Osceola Steel Company related to the proposed modifications indicates that the project will be in compliance with all applicable state and federal air quality regulations.

It is the preliminary determination of the EPD that the proposal provides for the application of Best Available Control Technology (BACT) for the control of NO_x , SO_2 , CO, PM_{10} , and $\text{PM}_{2.5}$, as required by PSD regulation 40 CFR 52.21(j) and 40 CFR 51.165 (for $\text{PM}_{2.5}$).

It has been determined through approved modeling techniques that the estimated emissions will not cause or contribute to a violation of any ambient air standard or PSD increment in the area surrounding the facility or in Class I areas located within 200 km of the facility. It has further been determined that the proposal will not cause impairment of visibility or detrimental effects on soils or vegetation. Any air quality impacts produced by project-related growth should be inconsequential.

This Preliminary Determination concludes that an Air Quality Permit should be issued to Osceola Steel Company for the construction and operation of a micro steel mill. A copy of the draft permit is included in Appendix A.

1.0 INTRODUCTION – FACILITY INFORMATION AND EMISSIONS DATA

On March 15, 2010, Osceola Steel Company (hereafter Osceola Steel Company) submitted an application for an air quality permit to construct a micro steel mill. Application No. 19537 was assigned to the facility, which will be located at 475 Osceola Road in Adel, Cook County.

Table 1-1: Title V Major Source Status

Pollutant	Is the Pollutant Emitted?	If emitted, what is the facility's Title V status for the Pollutant?		
		Major Source Status	Major Source Requesting SM Status	Non-Major Source Status
PM	Y	✓		
PM ₁₀	Y	✓		
SO ₂	Y	✓		
VOC	Y			✓
NO _x	Y	✓		
CO	Y	✓		
TRS	N	N/A	N/A	N/A
H ₂ S	N	N/A	N/A	N/A
Individual HAP	Y			✓
Total HAPs	Y			✓

Table 1-2: Facility-Wide Emissions

Pollutant	Potential Emissions (tpy)
PM	37.1
VOC	34.6
NO _x	111
CO	451
SO ₂	43.3
HF	2.8
Pb	0.44

Through its new source review procedure, EPD has evaluated Osceola Steel Company's proposal for compliance with State and Federal requirements. The findings of EPD have been assembled in this Preliminary Determination.

2.0 PROCESS DESCRIPTION

Osceola Steel Company has proposed to construct a micro steel mill capable of processing approximately 430,000 short tons per year of carbon steel rebar, rounds, squares, flats and angle iron. Scrap steel will be brought on site by truck and rail to the scrap receiving, storage and handling area. Each batch of steel (also called a "heat") is loaded into a charge bucket via overhead crane, lime and/or carbon in the form of chopped tires or petroleum coke is added to remove impurities from the heat. The loaded charge bucket is then positioned above the open Electric Arc Furnace (EAF) located in the melt shop. Upon obtaining accurate positioning, the charge bucket loads the scrap steel into the EAF. An electric arc furnace consists of a refractory-lined vessel, covered with a retractable roof, and through which one or more carbon or graphite electrodes enter the furnace. The furnace is primarily split into three sections: the *shell*, which consists of the sidewalls and lower steel 'bowl', the *hearth*, which consists of the refractory that lines the lower bowl and the *roof*, which may be refractory-lined or water-cooled. The roof also supports the refractory delta in its center, through which one or more electrodes enter.

Melting of the scrap steel is achieved through a combination of both electric and chemical energy. The chemical energy is supplied through oxy-fuel burners that provide a mix of natural gas and oxygen, as well as through oxygen lances and carbon injection into the slag. After the scrap is dropped, the charging bucket is raised, the top of the EAF is closed, and carbon/graphite electrodes are lowered into the furnace, which provide the electrical energy. The electrical current that passes between the electrodes is in the form of an arc, which melts the scrap steel. Arc furnaces differ from induction furnaces in that the charge material is directly exposed to an electric arc, and the current in the furnace terminals passes through the charged material. After the charge is partially melted the foamy slag process begins where oxygen and carbon are injected into the liquid steel to agitate the slag into a frothy consistency. Petroleum coke or crushed coal may also be injected into the slag to foam it as well. The lime and additives form the slag layer, which serves to remove impurities from the steel. Once the temperature and chemistry are correct, the steel is tapped out into a preheated ladle through tilting the furnace. The furnace is built on a tilting platform so that the liquid steel can be poured into another vessel for transport. The operation of tilting the furnace to pour molten steel is called "tapping". Modern EAFs have an eccentric bottom tap-hole (EBT) to reduce inclusion of nitrogen and slag in the liquid steel.

For plain-carbon steel furnaces, as soon as slag is detected during tapping the furnace is rapidly tilted back towards the deslagging side, minimizing slag carryover into the ladle. For some special steel grades, including stainless steel, the slag is poured into the ladle as well, to be treated at the ladle furnace to recover valuable alloying elements. During tapping some alloy additions are introduced into the metal stream, and some more lime is added on top of the ladle to begin building a new slag layer. Often, a few tons of liquid steel and slag is left in the furnace in order to form a 'hot heel', which helps preheat the next charge of scrap and accelerate its meltdown. During and after tapping, the furnace is 'turned around': the slag door is cleaned of solidified slag, repairs may take place, and electrodes are inspected for damage or lengthened through the addition of new segments; the tap hole is filled with sand at the completion of tapping.

Additional oxygen is then injected to cause the steel to boil from the formation of CO and CO₂, which facilitates the removal of the slag and impurities from the steel. The Direct Exhaust Control (DEC) system evacuates fumes from the EAF and ladle metallurgical station (LMS) by maintaining a negative pressure inside the furnaces, directly from the "fourth hole" exhaust duct located on the top (or roof) of the EAF (so named the fourth hole because the EAF includes three holes for the arc electrodes that extend into the EAF) and the ladle furnace. The fourth hole exhaust has an air gap in the duct to allow for furnace tilting during tapping of the EAF as well as EAF roof movement to allow for the opening and charging of the EAF. Air is drawn into this gap by the induced draft (ID) fan during system operation to provide sufficient oxygen within the EAF evacuation duct for burning of combustible gases (CO and hydrogen) exiting the EAF. The gases collected by the DEC are water cooled, then mixed with the high volume of cooler gases from the building canopy prior to entering the baghouse. The majority of the gases from the EAF are collected directly through the fourth hole, however, during periods of charging when the roof is

off the EAF the gases will exhaust into the building that houses the EAF (referred to as the melt shop). The melt shop is designed to contain these gases, which are then collected by a canopy above the EAF, and routes them to a baghouse for the control of particulate matter emissions.

Several factors impact the heat cycle of an electric arc furnace, however the whole process will usually take anywhere from less than 60 minutes to approximately 90 minutes from the tapping of one heat to the tapping of the next (the tap-to-tap time).

Slag formed during this process is poured into a concrete containment area under the EAF. Water is applied to the slag for cooling which will allow for the handling of the slag. The slag is then removed from the containment area with a front-end loader and transported to an outdoor processing area for reclamation. After being transported to the outdoor processing area, the slag will be quenched with water and large metallic pieces will be removed from the slag stockpile by magnet and returned to the scrap yard for reuse in the EAF. The final aggregate is sized into three fractions with a set of screens, then sold as a by-product, or used on-site for fill or road building. Any fugitive air emissions generated from handling and processing of the slag will be controlled through the use of water sprays. No stacks will be associated with this process.

Once melting of the scrap is completed, samples of the melt are analyzed for chemical composition, the EAF is tapped and the molten metal flows into a ladle, which has been preheated with natural gas. Ferro alloys are added to the ladle during the tapping process. The ladle is moved by transfer car to the ladle furnace (also referred to as the ladle metallurgical station (LMS)) where final chemistry and temperature adjustments to the heat are made. The ladle furnace also has 3 electrodes and a separate power supply from the EAF, which similarly heats up the steel in the ladle. A second DEC fume collection system will collect gases from the ladle furnace, which is also routed, to the melt shop baghouse.

The lime and carbon used in the process is stored in silos, which have filters for the collection of any dust generated during storage and transfer of material to the silos. A third silo will store the dust collected in the baghouse, prior to being shipped off site by rail. This silo along with the conveyor feeding the silo is vented back into the main EAF baghouse and will not therefore vent to the atmosphere.

When the steel is at the proper temperature and composition at the LMS, the ladle containing the steel is moved to the continuous caster via an overhead crane. The molten steel is poured from the ladle into the tundish. The tundish is a vessel that acts as a reservoir of metal to feed the casting machine while ladles are switched, thus acting as a buffer of hot metal, regulating metal feed to the molds. In the caster, two streams of liquid steel flow from the tundish into water-cooled molds to form the solid steel outer shell of the steel billets. The outer shell of the caster is continuously cooled with water sprays. The billets will be cut to specified lengths when solidification is complete using oxy-natural gas torches. The fumes from the torches are open vented into the melt shop building. The billets are then conveyed to a transfer table and allowed to cool further to approximately 1100 °F. Osceola will employ a hot charging system which is designed to load the hot billets directly into the reheat furnace, unlike the conventional practice of storing the billets in a billet yard where they are further cooled and reloaded back into the reheat furnace at a later time. The continuous caster will have a separate vent for the release of steam formed from the use of the direct-sprayed cooling water.

The steel then enters the natural gas-fired reheat furnace, where it is heated to approximately 2000 °F and then conveyed to the rolling mill. The rolling mill consists of a series of rollers that forms the steel to the appropriate thickness and shape. Scale is recovered from the water used in the continuous caster and the rolling mill and is sold as a by-product.

The Osceola Steel Company permit application and supporting documentation are included in Appendix A of this Preliminary Determination and can be found online at www.georgiaair.org/airpermit.

3.0 REVIEW OF APPLICABLE RULES AND REGULATIONS

State Rules

Georgia Rule for Air Quality Control (Georgia Rule) 391-3-1-.03(1) requires that any person prior to beginning the construction or modification of any facility which may result in an increase in air pollution shall obtain a permit for the construction or modification of such facility from the Director upon a determination by the Director that the facility can reasonably be expected to comply with all the provisions of the Act and the rules and regulations promulgated thereunder. Georgia Rule 391-3-1-.03(8)(b) states that no permit to construct a new stationary source or modify an existing stationary source shall be issued unless such proposed source meets all the requirements for review and for obtaining a permit prescribed in Title I, Part C of the Federal Act [i.e., Prevention of Significant Deterioration of Air Quality (PSD)], and Section 391-3-1-.02(7) of the Georgia Rules (i.e., PSD).

Georgia Rule 391-3-1-.02(2)(b) Emission Limitations and Standards Visible Emissions limits opacity to less than forty (40) percent, except as may be provided in other more restrictive or specific rules or subdivisions of *Georgia Rule 391-3-1-.02(2)*. This limitation applies to direct sources of emissions such as stationary structures, equipment, machinery, stacks, flues, pipes, exhausts, vents, tubes, chimneys or similar structures. This regulation is applicable to the Electric Arc Furnace (Source Code: EAF), Horizontal Ladle Pre-Heaters (Source Codes: HLP1 and HLP2), Vertical Ladle Heating Stack (Source Code: VLP1), Tundish Preheaters (Source Codes: TPH1 and TPH2), Reheat Furnace (Source Code: RHF), Casting Machine Torches (Source Code: CMT1 and CMT2), Cooling Towers (Source Codes: CT1, CT21, CT22 and CT3) Silos (Source Codes: LSF and CSF) and other supporting equipment with the capability of emitting particulates.

Georgia Rule 391-3-1-.02(2)(e) Emission Limitations and Standards Particulate Emission from Manufacturing Processes limits particulate emissions from manufacturing processes as follows:

$$E = 4.1 P^{0.67} \text{ ; for process input weight rate up to and including 30 tons per hour.}$$

$$E = 55 P^{0.11} - 40 \text{ ; for process input weight rate above 30 tons per hour.}$$

This regulation is applicable to the Cooling Towers (Source Codes: CT1, CT21, CT22 and CT3) Silos (Source Codes: LSF and CSF) and other supporting equipment with the capability of emitting particulates.

Georgia Rule 391-3-1-.02(2)(g)2 Emission Limitations and Standards Sulfur Dioxide requires all fuel burning sources below 100 million BTUs of heat input per hour shall not burn fuel containing more than 2.5 percent sulfur, by weight. Notwithstanding the limitations on sulfur content of fuels stated in paragraph 2 in *Georgia Rule 391-3-1-.02(2)(g)*, sulfur content can be allowed to be greater than that allowed in paragraph 2. in *Georgia Rule 391-3-1-.02(2)(g)*, provided that the source utilizes sulfur dioxide removal and the sulfur dioxide emission does not exceed that allowed by paragraph 2. in *Georgia Rule 391-3-1-.02(2)(g)*, utilizing no sulfur dioxide removal. This limit is applicable to the Electric Arc Furnace (Source Code: EAF), Horizontal Ladle Pre-Heaters (Source Codes: HLP1 and HLP2), Vertical Ladle Heating Stack (Source Code: VLP1), Tundish Preheaters (Source Codes: TPH1 and TPH2), Reheat Furnace (Source Code: RHF), Casting Machine Torches (Source Code: CMT1 and CMT2).

Georgia Rule 391-3-1-.02(2)(n) Emission Limitations and Standards Fugitive Dust requires Osceola to take all reasonable precautions to prevent such dust from becoming airborne for any operation, process, handling, transportation or storage facility which may result in fugitive dust. This regulation also limits opacity from such sources to less than 20 percent.

This limit applies to paved and unpaved plant roads, slag piles, parking areas, and material handling equipment.

Georgia Rule 391-3-1-.02(2)(4) Emission Limitations and Standards Ambient Air Standards

This regulation limits the quantities of sulfur dioxide, particulate matter, carbon monoxide, ozone, lead, and nitrogen dioxide from the Osceola Steel Company facility, which would cause the ambient air concentrations, listed to be exceeded. The limits are as follows:

- Sulfur Dioxide.
 - The concentration of sulfur dioxide at ground level for any three-hour period shall not exceed 1300 micrograms per cubic meter for more than one such three-hour period per year.
 - The concentration of sulfur dioxide at ground level for any twenty-four hour period shall not exceed 365 micrograms per cubic meter for more than one such twenty-four hour period per year.
 - The concentration of sulfur dioxide at ground level for any one-hour period shall not exceed 196 micrograms per cubic meter for more than one such one-hour period per year. The 1-hour SO₂ standard became effective June 22, 2010. The 140 ppb 24-hour and the 30 ppb annual standards were revoked on the same date but remain in effect for one year after the new attainment designation. The reported 1-hour value for each respective year is the 99th percentile value of the daily maximums (typically the 4th high value of the daily maximum if all days are monitored), not the overall maximum 1-hour value. See 40CFR Part 50 Appendix T.
 - The annual arithmetic mean concentration of sulfur dioxide at ground level shall not exceed 80 micrograms per cubic meter.
 - Standard conditions for sulfur dioxide measurements shall be considered to be 25 degrees Centigrade (°C) and 760 millimeters in mercury (mm Hg). The specific standard procedure for measuring ambient air concentrations for all sulfur dioxide will be West-Gaeke or equivalent method.
- Particulate Matter.
 - PM₁₀
 - The concentration of PM₁₀ in the ambient air for any 24-hour period shall not exceed 150 micrograms per cubic meter for more than one such 24-hour period per year. The standard is attained when the expected number of days per calendar year with a 24-hour average concentration above 150 micrograms per cubic meter, as determined in accordance with Appendix K of 40 CFR Part 50 is equal to or less than 1.
 - PM₁₀ shall be measured in the ambient air as PM₁₀ (particles with an aerodynamic diameter less than or equal to a nominal ten micrometers) by a reference method based upon 40 CFR Part 50, Appendix J.

- $PM_{2.5}$
 - The 98th percentile 24-hr $PM_{2.5}$ (particles with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers) concentration shall not exceed 35 microgram per cubic meter. The 98th percentile 24-hour concentration is as determined in accordance with Appendix N of 40 CFR part 50.
 - The annual arithmetic mean concentration of $PM_{2.5}$ in the ambient air shall not exceed 15 microgram per cubic meter. The standard is attained when the expected annual arithmetic mean concentration, as determined in accordance with Appendix N of 40 CFR part 50 is less than or equal to 15 micrograms per cubic meter.
 - $PM_{2.5}$ shall be measured in the ambient air as $PM_{2.5}$ by reference method based upon 40 CFR Part 50, Appendix L.
- Carbon Monoxide.
 - Carbon monoxide concentration, at ground level, shall not be allowed to exceed 40 milligrams per cubic meter for a one-hour average or 10 milligrams per cubic meter for an eight-hour average. Standard conditions for carbon monoxide measurements shall be considered to be 25 °C and 760 mm Hg.
 - The specified standard procedure for measuring ambient air concentrations of carbon monoxide shall be the non-dispersive infrared or equivalent method.
- Ozone.
 - The 8-hour ambient air standard for ozone is 0.075 parts-per-million, daily maximum 8-hour average. The standard is attained when the average of the annual fourth-highest daily maximum 8-hour average ozone concentration is less than or equal to 0.075 parts per million, as determined in accordance with appendix I of 40 CFR Part 50.
 - The specific standard procedure for measuring ambient air concentrations of ozone shall be the Chemiluminescence or equivalent method.
- Lead.
 - The mean concentration of lead at ground level shall not exceed 0.15 micrograms per cubic meter averaged over a calendar quarter.
 - The specified standard procedure for measuring ambient air concentrations of lead shall be those required to comply with Federal law or other Federal authority.
- Nitrogen Dioxide.
 - The annual arithmetic mean concentration of nitrogen dioxide at ground level shall not exceed 100 micrograms per cubic meter. Standard conditions for nitrogen dioxide considered to be 25 °C and 760 mm Hg.

- o The mean concentration of nitrogen dioxide at ground level shall not exceed 188 micrograms per cubic meter averaged over a period of one hour. The reported 1-hour value for each respective year is the 98th percentile value of the daily maximums (typically the 8th high value of the daily maximums if all days are monitored) , not the overall maximum 1-hour value. See 40 CFR Part 50 Appendix N.
- o The specified standard procedure for measuring ambient air concentrations of nitrogen dioxide shall be the Chemiluminescence or equivalent method.

This does not exempt Osceola Steel from controlling its emissions to a point equal to or lower than the levels required to comply with a specific emission standard enumerated in other sections of the Georgia Rules.

Federal Rule - PSD

The regulations for PSD as codified in 40 CFR 52.21 require that any new major source or modification at an existing major source be reviewed to determine if the new construction or modification is subject to regulations under the Clean Air Act. The PSD review requirements apply to any new or modified source that belongs to one of 28 specific source categories having potential emissions of 100 tons per year or more of any regulated pollutant, or to all other sources having potential emissions of 250 tons per year or more of any regulated pollutant. They also apply to any modification at a major stationary source which results in a significant net emission increase of any regulated pollutant.

Georgia has adopted a regulatory program for PSD permits, which the United States Environmental Protection Agency (EPA) has approved as part of Georgia's State Implementation Plan (SIP). This regulatory program is located in the Georgia Rules at 391-3-1-.02(7). This means that Georgia EPD issues PSD permits for new major sources pursuant to the requirements of Georgia's regulations. It also means that Georgia EPD considers, but is not legally bound to accept EPA comments or guidance. A commonly used source of EPA guidance on PSD permitting is EPA's Draft October 1990 New Source Review Workshop Manual for Prevention of Significant Deterioration and Nonattainment Area Permitting (NSR Workshop Manual). The NSR Workshop Manual is a comprehensive guidance document on the entire PSD permitting process.

The PSD regulations require that any major stationary source or major modification subject to the regulations meet the following requirements:

- Application of BACT for each regulated pollutant that would be emitted in significant amounts;
- Analysis of the ambient air impact;
- Analysis of the impact on soils, vegetation, and visibility;
- Analysis of the impact on Class I areas; and
- Public notification of the proposed plant in a newspaper of general circulation

Definition of BACT

The PSD regulation requires that BACT be applied to all regulated air pollutants emitted above the significant amounts. Section 169 of the Clean Air Act defines BACT as an emission limitation reflecting the maximum degree of reduction that the permitting authority (in this case, EPD), on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such a facility through application of production processes and available methods, systems, and techniques. In all cases BACT must establish emission limitations or specific design characteristics at least as stringent as applicable New Source Performance Standards (NSPS). In addition, if EPD determines that there is no economically reasonable or technologically feasible way to control the emissions, and hence to impose and enforceable emissions standard, it may require the source to use a design, equipment, work practice or operations standard or combination thereof, to reduce emissions of the pollutant to the maximum extent practicable.

EPA's NSR Workshop Manual includes guidance on the 5-step top-down process for determining BACT. In general, Georgia EPD requires PSD permit applicants to use the top-down process in the BACT analysis. The five steps of a top-down BACT review procedure per BACT guidelines are listed below:

- Step 1: Identification of all control technologies;
- Step 2: Elimination of technically infeasible options;
- Step 3: Ranking of remaining control technologies by control effectiveness;
- Step 4: Evaluation of the most effective controls and documentation of results; and
- Step 5: Selection of BACT.

The following is a discussion of the applicable federal rules and regulations pertaining to the equipment that is the subject of this preliminary determination, which is then followed by the top-down BACT analysis.

New Source Performance Standards

Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 60) New Source Performance Standards (NSPS) Subpart A – General Provisions

Except as provided in Subparts B and C of 40 CFR Part 60, the provisions of this regulation apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility [40 CFR 60.1(a)]. Osceola Steel Mill is a new facility with several pieces of equipment and/or processes subject to this regulation. Any new or revised standard of performance promulgated pursuant to Section 111(b) of the Clean Air Act apply to Osceola Steel Mill's applicable equipment and/or processes and any applicable source/equipment for which the construction or modification of is commenced after the date of publication in 40 CFR Part 60 of such new or revised standard (or, if earlier, the date of publication of any proposed standard) applicable to that equipment and/or processes [40 CFR 60.1(b)].

Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 60) New Source Performance Standards (NSPS) Subpart AAa- "Standards of Performance for Steel Plants: Electric Arc Furnaces and Argon-Oxygen De-carburization Vessels Constructed After August 17, 1983."

The provisions of this subpart are applicable to the following affected facilities in steel plants that produce carbon, alloy, or specialty steels: electric arc furnaces, argon-oxygen decarburization vessels, and dust-handling systems [40 CFR 60.270(a)]. The provisions of this subpart apply to each affected facility identified in paragraph (a) of this section that commences construction, modification, or reconstruction after August 17, 1983 [40 CFR 60.270(b)]. The Electric Arc Furnace (EAF) (Source Code: EAF) at Osceola Steel Mill is subject to all applicable provisions within the New Source Performance Standards for Steel Plants contained in 40 CFR 60, Subpart AAa.

Emission Standards

Particulate Matter (PM)

On and after the date of which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from an EAF or an AOD vessel any gases which:

[40 CFR 60.272(a)]

- (1) Exit from a control device and contain particulate matter in excess of 12 mg/dscm (0.0052 gr/dscf);
- (2) Exit from a control device and exhibit 3 percent opacity or greater; and
- (3) Exit from a shop and, due solely to the operations of any affected EAF(s) or AOD vessel(s), exhibit 6 percent opacity or greater.

On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from the dust-handling system any gases that exhibit 10 percent opacity or greater [40 CFR 60.272(b)].

National Emissions Standards For Hazardous Air Pollutants

Part 63, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 63) National Emissions Standards For Hazardous Air Pollutants (NESHAP) Subpart A—General Provisions

This regulation contains national emission standards for hazardous air pollutants (NESHAP) established pursuant to section 112 of the Act as amended November 15, 1990. These standards regulate specific categories of stationary sources that emit (or have the potential to emit) one or more hazardous air pollutants listed in this part pursuant to section 112(b) of the Act. The standards in this part are independent of NESHAP contained in 40 CFR Part 61. The NESHAP in part 61 promulgated by signature of the Administrator before November 15, 1990 (i.e., the date of enactment of the Clean Air Act Amendments of 1990) remain in effect until they are amended, if appropriate, and added to 40 CFR Part 63 [40 CFR 63.1(a)(1) and (2)]. No emission standard or other requirement established under 40 CFR Part 63 shall be interpreted, construed, or applied to diminish or replace the requirements of a more stringent emission limitation or other applicable requirement established by the Administrator pursuant to other authority of the Act (section 111, part C or D or any other authority of this Act), or a standard issued under State authority. The Administrator may specify in a specific standard under this part that facilities subject to other provisions under the Act need only comply with the provisions of that standard [40 CFR 63.1(a)(3)]. Osceola Steel Mill is a new facility with applicable units subject to this regulation.

Part 63, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 63) National Emissions Standards For Hazardous Air Pollutants (NESHAP) Subpart YYYYYY- National Emission Standards for Hazardous Air Pollutants for Area Sources: Electric Arc Furnace Steelmaking Facilities

This regulation applies to the owner and operator of an electric arc furnace (EAF) steelmaking facility that is an area source of hazardous air pollutant (HAP) emissions [40 CFR 63.10680(a)].

This subpart applies to each new or existing affected source. The affected source is each EAF steelmaking facility [40 CFR 63.10680(b)].

(1) An affected source is existing if you commenced construction or reconstruction of the affected source on or before September 20, 2007.

(2) An affected source is new if you commenced construction or reconstruction of the affected source after September 20, 2007.

This subpart does not apply to research and development facilities, as defined in section 112(c)(7) of the Clean Air Act (CAA) [40 CFR 63.10680(c)].

If you own or operate an area source subject to this subpart, you must have or obtain a permit under 40 CFR Part 70 or 40 CFR Part 71 [40 CFR 63.10680(d)].

Osceola Steel Mill is subject to all applicable provisions within the National Emission Standards for Hazardous Air Pollutants for Area Sources: Electric Arc Furnace Steelmaking Facilities (NESHAP) contained within 40 CFR 63, Subpart YYYYYY.

Compliance and Emission Standards

Chlorinated plastics, lead, and free organic liquids

For metallic scrap utilized in the EAF at the facility, the owner or operator must comply with the requirements in either paragraph (a)(1) or (2) of 63.10685. Certain scrap at the facility may be subject to paragraph (a)(1) of 63.10685 and other scrap subject to paragraph (a)(2) of 40 CFR 63.10685 provided the scrap remains segregated until charge make-up.

Pollution prevention plan For the production of steel other than leaded steel, Osceola Steel Mill must prepare and implement a pollution prevention plan for metallic scrap selection and inspection to minimize the amount of chlorinated plastics, lead, and free organic liquids that is charged to the furnace. For the production of leaded steel, a pollution prevention plan for scrap selection and inspection must be prepared and implemented to minimize the amount of chlorinated plastics and free organic liquids in the scrap that is charged to the furnace. The scrap pollution prevention plan must be submitted to the permitting authority for approval. Osceola Steel Mill must operate according to the plan as submitted during the review and approval process, operate according to the approved plan at all times after approval, and address any deficiency identified by the permitting authority within 60 days following disapproval of a plan. Osceola Steel Mill may request approval to revise the plan and may operate according to the revised plan unless and until the revision is disapproved by the permitting authority. You must keep a copy of the plan onsite, and you must provide training on the plan's requirements to all plant personnel with materials acquisition or inspection duties. Each plan must include the information in paragraphs (a)(1)(i) through (iii) of 40 CFR 63.10685 [40 CFR 63.10685(a)].

Restricted metallic scrap For the production of steel other than leaded steel, Osceola Steel Mill must not charge to a furnace metallic scrap that contains scrap from motor vehicle bodies, engine blocks, oil filters, oily turnings, machine shop borings, transformers or capacitors containing polychlorinated biphenyls, lead-containing components, chlorinated plastics, or free organic liquids. For the production of leaded steel, you must not charge to the furnace metallic scrap that contains scrap from motor vehicle bodies, engine blocks, oil filters, oily turnings, machine shop borings, transformers or capacitors containing polychlorinated biphenyls, chlorinated plastics, or free organic liquids. This restriction does not apply to any post-consumer engine blocks, post-consumer oil filters, or oily turnings that are processed or cleaned to the extent practicable such that the materials do not include lead components, chlorinated plastics, or free organic liquids. This restriction does not apply to motor vehicle scrap that is charged to recover the chromium or nickel content if the requirements in paragraph (b)(3) of 40 CFR 63.10685 are met [40 CFR 63.10685(b)].

Recordkeeping and reporting requirements In addition to the records required by §63.10, you must keep records to demonstrate compliance with the requirements for your pollution prevention plan in paragraph (a)(1) of this section and/or for the use of only restricted scrap in paragraph (a)(2) of 40 CFR 63.10685 and for mercury in paragraphs (b)(1) through (3) of 40 CFR 63.10685 as applicable. You must keep records documenting compliance with paragraph (b)(4) of 40 CFR 63.10685 for scrap that does not contain motor vehicle scrap [40 CFR 63.10685(c)].

Particulate Matter (PM)

The facility must install, operate, and maintain a capture system that collects the emissions from each EAF (including charging, melting, and tapping operations) and argon-oxygen decarburization (AOD) vessel and conveys the collected emissions to a control device for the removal of particulate matter (PM) [40 CFR 63.10686(a)].

Except as provided in paragraph (c) of 40 CFR 63.10686, you must not discharge or cause the discharge into the atmosphere from an EAF or AOD vessel any gases which [40 CFR 63.10686(b)]:

- (1) Exit from a control device and contain in excess of 0.0052 grains of PM per dry standard cubic foot (gr/dscf); and
- (2) Exit from a melt shop and, due solely to the operations of any affected EAF(s) or AOD vessel(s), exhibit 6 percent opacity or greater.

If you own or operate a new or existing affected source that has a production capacity of less than 150,000 tons per year (tpy) of stainless or specialty steel (as determined by the maximum production if specified in the source's operating permit or EAF capacity and maximum number of operating hours per

year), you must not discharge or cause the discharge into the atmosphere from an EAF or AOD vessel any gases which [40 CFR 63.10686(c)]:

- (1) Exit from a control device and contain particulate matter (PM) in excess of 0.8 pounds per ton (lb/ton) of steel. Alternatively, the owner or operator may elect to comply with a PM limit of 0.0052 grains per dry standard cubic foot (gr/dscf); and
- (2) Exit from a melt shop and, due solely to the operations of any affected EAF(s) or AOD vessel(s), exhibit 6 percent opacity or greater.

Except as provided in paragraph (d)(6) of 40 CFR 63.10686, you must conduct performance tests to demonstrate initial compliance with the applicable emissions limit for each emissions source subject to an emissions limit in paragraph (b) or (c) of 40 CFR 63.10686 [40 CFR 63.10686(d)].

State and Federal – Startup and Shutdown and Excess Emissions

Excess emission provisions for startup, shutdown, and malfunction are provided in Georgia Rule 391-3-1-.02(2)(a)7. Excess emissions from the equipment associated with the proposed project would most likely results from a malfunction of the associated control equipment. The facility cannot anticipate or predict malfunctions. However, the facility is required to minimize emissions during periods of startup, shutdown, and malfunction.

Limits established under PSD apply at all times including periods of startup, shutdown and malfunction.¹ A PSD BACT limit, which is the equivalent of NSPS and/or NESHAP limit, subsumes that limit. Therefore, if a PSD BACT limit subsumes any NSPS or NESHAP requirements, excess emissions of the short term (ppm or lb/10⁶Btu) during startup, shutdown and malfunction are not subject to the provisions in Georgia Rule 391-3-1-.02(2)(a)7. As a result, Osceola Steel Company must comply with applicable BACT limitations for applicable pollutants during all periods of operation, including startup, shutdown, and malfunction.

Federal Rule – 40 CFR 64 – Compliance Assurance Monitoring

Under 40 CFR 64, the *Compliance Assurance Monitoring* Regulations (CAM), facilities are required to prepare and submit monitoring plans for certain emission units with the Title V application. The CAM Plans provide an on-going and reasonable assurance of compliance with emission limits. Under the general applicability criteria, this regulation applies to units that use a control device to achieve compliance with an emission limit and whose pre-controlled emissions levels exceed the major source thresholds under the Title V permitting program. Osceola Steel Mill is required to address 40 CFR Part 64 applicability in its initial Title V Operating Permit application and will be subject to CAM upon renewal of the Title V Operating Permit.

¹ <http://www.epa.gov/region07/programs/artd/air/nsr/nsrpg.htm> - accessed May 25, 2010.

PM_{2.5} Surrogacy Policy

Particulate matter," also known as particle pollution or PM, is a complex mixture of extremely small particles and liquid droplets. Particle pollution is made up of a number of components, including acids (such as nitrates and sulfates), organic chemicals, metals, and soil or dust particles.

Particles less than 10 micrometers in diameter (PM₁₀) pose a health concern because they can be inhaled into and accumulate in the respiratory system. Particles less than 2.5 micrometers in diameter (PM_{2.5}) are referred to as "fine" particles and are believed to pose the largest health risks. Because of their small size (less than one-seventh the average width of a human hair), fine particles can lodge deeply into the lungs.

Health studies have shown a significant association between exposure to fine particles and premature mortality. Other important effects include aggravation of respiratory and cardiovascular disease (as indicated by increased hospital admissions, emergency room visits, absences from school or work, and restricted activity days), lung disease, decreased lung function, asthma attacks, and certain cardiovascular problems such as heart attacks and cardiac arrhythmia. Individuals particularly sensitive to fine particle exposure include older adults, people with heart and lung disease, and children.

Sources of fine particles include combustion activities and certain industrial processes. Particles with diameters between 2.5 and 10 micrometers are referred to as "coarse." Sources of coarse particles include crushing or grinding operations, and dust from paved or unpaved roads. EPA established annual and 24-hour NAAQS for PM_{2.5} for the first time in 1997, and revised the 24-hour NAAQS for PM_{2.5} in 2006.

In 1997, EPA established a policy regarding permitting decisions regarding PM_{2.5} emissions. The policy was to assume that if the permit procedures for PM₁₀ were followed that would suffice for addressing PM_{2.5}, presuming that controls for one would match the other. This was called the "surrogate approach", because PM₁₀ served as a surrogate for PM_{2.5}. This policy was put in place at the time because little was known about how to measure and model PM_{2.5} and there was insufficient emissions data on PM_{2.5} emissions for the various industries being permitted.

On August 12, 2009, EPA issued an order addressing issues identified in petitions filed in 2006 and 2008 by environmental groups requesting that EPA object to Title V permits issued by the Kentucky Division for Air Quality (KDAQ) to Louisville Gas and Electric Company (LG&E) for a new 750 megawatt supercritical pulverized coal (SPC) boiler (and other associated modifications) at the Trimble County Generating Station located in Bedford (Trimble County), Kentucky. Among several issues within the order, the adequacy of BACT for the auxiliary boiler and emergency diesel generator and failure of the permit to adequately consider particulate matter with a diameter less than 2.5 micrometers (PM_{2.5}) were the most pertinent issues addressed.

Petitioners had argued that: 1) LG&E may not meet its obligations for PM_{2.5} under the Prevention of Significant Deterioration (PSD) Program by using PM₁₀ as a surrogate, 2) the Trimble County permit cannot be lawfully issued without quantification of PM_{2.5} emissions, 3) the permit failed to contain an air quality analysis for PM_{2.5}, and 4) the permit failed to contain a BACT determination for PM_{2.5}.

EPA's response in the Order is limited to a discussion of the use of PM₁₀ as a surrogate for PM_{2.5} and does not address any of the other aspects to the PM_{2.5} issue. EPA states that case law on the topic of surrogates suggests that "any person attempting to show that PM₁₀ is a reasonable surrogate for PM_{2.5} would need to address the differences between PM₁₀ and PM_{2.5}" and identifies an example two step approach for conducting an evaluation of these differences (the cited case law is, however, based on litigation of regulations derived from other sections of the CAA and not the CAA section addressing PSD).

- First there must be a strong statistical relationship between PM₁₀ and PM_{2.5} emissions both before and after the control device. A single stack test or factor from AP-42 is insufficient. There should be an analysis of how the ratio of PM₁₀: PM_{2.5} may vary with source conditions.
- A demonstration that the degree of control proposed is at least as effective for PM_{2.5} as it is for PM₁₀. To make this demonstration a BACT analysis needs to be completed for PM_{2.5} and the resulting proposed controls compared to that of PM₁₀.

On February 11, 2010, EPA proposed (75 Fed Reg 6827-6836) two actions that would end it's 1997 policy that allows sources and permitting authorities to use a demonstration of compliance with the prevention of significant deterioration (PSD) requirements for particulate matter less than 10 micrometers (PM₁₀) as a surrogate for meeting the PSD requirements for particulate matter less than 2.5 micrometers (PM_{2.5}). First, EPA is proposing to repeal the "grandfathering" provision for PM_{2.5} contained in the Federal PSD program. Second, EPA is proposing to end early the PM₁₀ Surrogate Policy applicable in States that have an approved PSD program in their State Implementation Plan (SIP-approved States)².

The Osceola permit application utilizes the surrogacy approach and therefore does not include calculations of PM_{2.5} and only addresses PM₁₀, however the application does address the two aforementioned points of contention made by EPA for the Trimble County Generating Station.

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Below is a listing of particulate emission sources proposed for Osceola along with the proposed particulate emissions and the controls deemed as meeting BACT for each unit regarding particulate emissions.

Table 3.1: PM₁₀ Emissions from Combustion Sources at Osceola Steel

Source	PM ₁₀ Emission Rate (tpy)	Proposed Particulate Controls
EAFLMS	31	Fabric Filter (baghouse)
Reheat Furnace	2.5	N/A
Other Natural Gas Combustion Sources	1.9	N/A

The primary source of PM from the reheat furnace and miscellaneous heaters are the combustion products resultant from natural gas burning. EPA standards classify particulate matter emissions in two categories; filterable and condensable. Filterable particulate consists of particles that are directly emitted by a source as a solid or liquid at stack or release conditions and captured on the filter of a stack test train.

Condensable particulate are compounds that forms from condensing gases or vapors. It forms by chemical reactions as well as by physical phenomena³.

The majority of primary emissions from combustion are often found to be the PM_{2.5} or smaller size range, especially for devices equipped with particulate emission control equipment and for clean burning fuels such as gas. The predominant gaseous precursors of secondary particulate sulfates and nitrates are: sulfur dioxide (SO₂) and sulfur trioxide (SO₃); oxides of nitrogen (NO and NO₂), the sum of which is designated

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<http://www.epa.gov/scram001/Official%20Signed%20Modeling%20Proc%20for%20Demo%20Compli%20w%20PM2.5.pdf> - Official Signed Modeling Procedure for Demonstrating Compliance with PM_{2.5}

³ <http://www.epa.gov/apti/bces/glossary/index.htm#C> - Condensable Particulate Matter definition accessed on July 30, 2010

NO_x); and ammonia (NH₃). Secondary organic aerosols formed from volatile organic carbon compounds also may be very significant in some areas, especially during the summertime when photochemical activity is high⁴.

After performing a detailed review of available data (EPA guidance documents, trade journals, permits from other states and technical papers), it was determined no other data outside of AP-42 was available for use in spite of EPA's determination that AP-42 data for the electric arc furnace is insufficient due to non-specificity to the proposed project, the data provided being of the lowest quality rating (rated: E; poor) and does not address the other combustion or fugitive emissions associated with the facility. At this time, EPA has not established testing procedures and policy associated with testing PM_{2.5} emissions in addition to the fact there are no testing requirements associated with PM_{2.5} for similar sources in other states, which could contribute to the inability to locate representative data for PM_{2.5} emissions. The Osceola Steel Company application is for a Greenfield site in which the facility has yet to be constructed, this is the first steel mill Osceola Steel Company will be constructing; therefore they have no plant in which they can obtain representative testing data.

Based on reviews from data sources for natural gas and refinery gas-fired boilers it was shown that most of the particulate leaving the boiler is in the form of condensable particulate. One cited study, "*Dilution Based Emissions Sampling from Stationary Sources*" England et al Journal of the Air & Waste Management Association Jan. 2007 has listed eight different data sources where PM was measured for both filterable and condensable forms. Test data for the fine particulate matter (PM_{2.5}) emissions are provided for comparison with U.S. Environment Protection Agency (EPA) Conditional Test Method 040 for filterable particulate matter (FPM) and the EPA Method 202 for condensable particulate matter. This comparison showed important differences between methods, depending on whether a comparison is done between in situ FPM determinations or the sum of such values with condensable PM from liquid filled impingers chilled in an ice bath. That study showed that the amount of condensable PM varies from 71% to 98%⁵. This condensable particulate is comprised primarily of organic carbon compounds or sulfate compounds that come from sulfur odorant compounds that is added to the natural gas being combusted in the boiler. Because of the nature of condensable particulate matter and the means in which it is collected (condensed in the back half of a sampling train), it is not possible to determine the size of the particles when they do condense in the atmosphere. These results are considered applicable to the combustion operations at Osceola. The particulate coming from each of these combustion units is likely organic carbon compounds that would show up in the condensable portion of the test. Since most of the particulate is in the form of condensable PM, which is common to both PM_{2.5} and PM₁₀, using PM₁₀ as a surrogate for PM_{2.5} is acceptable because for the most part the emission total is primarily condensable matter.

⁴ http://www.anl.gov/PCS/acsfuel/preprint%20archive/Files/45_1_SAN%20FRANCISCO_03-00_0066.pdf PM_{2.5} Emission Characterization for Stationary Source Gas Combustion-accessed August 5, 2010

To address EPA's concern about PM_{2.5} data, Osceola is assuming PM_{2.5} is equal to PM₁₀, which gives a worst-case scenario for PM_{2.5}. The modeling results for PM₁₀ would be the same as PM_{2.5}. The average of the maximum results for these 5 years modeled 2.39 µg/m³. EPA guidance calls for each receptor to be averaged for all five years and the highest of these averages to be added to the background to be compared with the NAAQS standard. By averaging the highest from each model assumes that the maximum value occurs at the same receptor, thereby making it a worse case-scenario. If this value is added to the expected PM_{2.5} background for Valdosta, GA, the value will be below the NAAQS standard as shown in the table below. At this point a current value for the PM_{2.5} background was not available, Osceola Steel Company used background data from years 2006-2008.

Table 3.2: NAAQS Comparison

Averaging Period	Modeled Concentration (µg/m³)	Background Concentration (µg/m³)	Maximum Modeled Value plus Background Concentration (µg/m³)	NAAQS (µg/m³)
24-hour	3.21	25.0	28.21	35
Annual	0.35	10.5	10.85	15

Greenhouse Gas (GHG) Emissions (40 CFR 98)⁶

In response to the FY2008 Consolidated Appropriations Act (H.R. 2764; Public Law 110–161), EPA has issued 40 CFR Part 98, which requires reporting of greenhouse gas (GHG) emissions from large sources and suppliers in the United States. 40 CFR Part 98 is intended to collect accurate and timely emissions data to inform future policy decisions.

Under Part 98, suppliers of fossil fuels or industrial GHGs, manufacturers of vehicles and engines, and facilities that emit 25,000 metric tons or more per year of GHG emissions are required to submit annual reports to EPA. Part 98 was published in the *Federal Register* on October 30, 2009 under Docket ID No. EPA-HQ-OAR-2008-0508-2278. Part 98 became effective December 29, 2009. This action included reporting requirements for 31 of the 42 emission sources listed in the April 10, 2009 proposed rule.

On April 12, 2010, EPA issued four new proposed rules that amend Part 98. These proposals would require reporting of emissions data from oil and natural gas systems, industries that emit fluorinated GHGs, and facilities that inject and store carbon dioxide (CO₂) underground for the purposes of geologic sequestration or enhanced oil and gas recovery. In addition, EPA has proposed to add three new reporting requirements to the General Provisions (subpart A). EPA plans to finalize all four of these proposals this year so that they would become effective starting in 2011.

On May 13, 2010, the U.S. Environmental Protection Agency (EPA) issued a final rule that establishes an approach to addressing greenhouse gas emissions from stationary sources under the Clean Air Act (CAA) permitting programs. This final rule sets thresholds for greenhouse gas (GHG) emissions that define when permits under the New Source Review Prevention of Significant Deterioration (PSD) and title V Operating Permit programs are required for new and existing industrial facilities.

The CAA permitting program emissions thresholds for criteria pollutants such as lead, sulfur dioxide and nitrogen dioxide, are 100 and 250 tons per year (tpy). While these thresholds are appropriate for criteria pollutants, they are not feasible for GHGs because GHGs are emitted in much higher volumes.

The final rule addresses emissions of a group of six GHGs:

1. Carbon dioxide (CO₂)
2. Methane (CH₄)
3. Nitrous oxide (N₂O)
4. Hydrofluorocarbons (HFCs)
5. Perfluorocarbons (PFCs)
6. Sulfur hexafluoride (SF₆)

Some of these GHGs have a higher global warming potential than others. To address these differences, the international standard practice is to express GHGs in carbon dioxide equivalents (CO₂e). Emissions of gases other than CO₂ are translated into CO₂e by using the gases' global warming potentials. Under this rule, EPA is using CO₂e as the metric for determining whether sources are covered under permitting programs. Total GHG emissions will be calculated by summing the CO₂e emissions of the six aforementioned constituent GHGs.

EPA will phase in the CAA permitting requirements for GHGs in two initial steps.

Step1 pertains only to sources currently subject to the PSD permitting program (i.e., those that are newly-constructed or modified in a way that significantly increases emissions of a pollutant other than GHGs) would be subject to permitting requirements for their GHG emissions under PSD.

⁶ <http://www.epa.gov/NSR/documents/20100413fs.pdf>, Final Rule: Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, Accessed September 17, 2010

For these projects, only GHG increases of 75,000 tpy or more of total GHG, on a CO_{2e} basis, would need to determine the Best Available Control Technology (BACT) for their GHG emissions. Similarly for the operating permit program, only sources currently subject to the program (i.e., newly constructed or existing major sources for a pollutant other than GHGs) would be subject to title V requirements for GHG. During this time, no sources would be subject to Clean Air Act permitting requirements due solely to GHG emissions.

Step 1 of this final rule will take effect on January 2, 2011. The final rule asks states to inform EPA whether they must make rule changes to implement the new GHG emissions thresholds, and when such changes will be adopted. If there are cases where this cannot happen by January 2, 2011, EPA will take appropriate action to ensure that the existing CAA permitting rules do not apply to sources excluded by the Tailoring rule.

Currently, CO_{2e} emissions from the Osceola Steel Company PSD project have the potential to exceed the 75,000 tpy CO_{2e} threshold outlined in Step 1 of the GHG Emissions Tailoring Rule, however the likelihood of the facility exceeding the 75,000 tpy CO_{2e} threshold is minimal. EPD proposed a GHG limit of 74,900 tpy of CO_{2e}, therefore Osceola Steel Company is not required to determine the Best Available Control Technology (BACT) for their GHG emissions. Similarly for the operating permit program, only sources currently subject to the program (i.e., newly constructed or existing major sources for a pollutant other than GHGs) would be subject to Title V requirements for GHG, therefore Osceola Steel Company is not subject to the Title V requirements for GHG.

4.0 CONTROL TECHNOLOGY REVIEW

The proposed project will result in emissions that are significant enough to trigger PSD review for the following pollutants: PM, PM₁₀, PM_{2.5}, CO, NO_x, SO₂

Electric Arc Furnace (EAF)- Background

The Electric Arc Furnace (Source Code EAF) has a proposed construction and installation date of 2011. According to Application 19537, the electric arc furnace will fire natural gas with a design capacity of 24MMBtu/hr input and processes 60 ton/hr of steel. The EAF furnace is a cylindrical vessel with a diameter in the range of 15 to 40 feet, and heights from 12 to 30 feet⁷. The walls of the furnace are comprised of refractory and water-cooled panels. The hearth or bottom of the furnace is thick refractory, and the roof is usually water-cooled. Carbon electrodes pass through openings at the top of the furnace and can be up to 24 inches in diameter. Electric current is carried from a transformer, through support arms, and into the electrodes where the scrap completes the electric circuit and melts. The electrodes deliver the power to the furnace in the form of an electric arc between the electrode and the furnace charge. The arc itself is a plasma of hot, ionic gasses in excess of 6,000°F⁸. Burners are often mounted around the interior of the furnace walls to increase the rate of energy input. Burners consume natural gas, oxygen, and/or air. The burners may operate at stoichiometric mixtures of natural gas and oxygen, but can be operated with excess oxygen to help eliminate CO and hydrogen in the freeboard.

After the charge is partially melted, the foamy slag process begins, where oxygen and carbon are injected into the liquid steel to agitate the slag into a frothy consistency. Slag usually consists of metal oxides, and acts as a destination for oxidized impurities, as a thermal blanket (stopping excessive heat loss) and helps to reduce erosion of the refractory lining. Steel by definition is an alloy of iron and carbon, of which carbon is the primary element that controls strength and ductility. Carbon contained in the steel scrap, along with other oxidizable metals such as silicon must be partially removed from the liquid steel in the EAF. Lime, additives and additional oxygen are added to cause the steel to boil, forming CO. The CO combines with excess oxygen from the injection process and oxygen in the furnace atmosphere to form CO₂, which is captured along with the fumes and particulate, in which the gas bubbles and their formation flush out non-metallic inclusions, which is essential to producing a quality product. For a furnace with basic refractories, which includes most carbon steel-producing furnaces, the usual slag formers are calcium oxide (CaO, in the form of burnt lime) and magnesium oxide (MgO, in the form of dolomite and magnesite). These slag formers are either charged with the scrap, or blown into the furnace during meltdown. Another major component of EAF slag is iron oxide from steel combusting with the injected oxygen. Later in the heat, carbon (in the form of coke or coal) is injected into this slag layer, reacting with the iron oxide to form metallic iron and carbon monoxide gas, which then causes the slag to foam, allowing greater thermal efficiency, and better arc stability and electrical efficiency. The slag blanket also covers the arcs, preventing damage to the furnace roof and sidewalls from radiant heat.

⁷ http://cfpub.epa.gov/ncer_abstracts/index.cfm/fuseaction/display.abstractDetail/abstract/957/report/F – accessed May 19, 2010.

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<http://www.steel.org/AM/Template.cfm?Section=Articles3&TEMPLATE=/CM/HTMLDisplay.cfm&CONTENTID=21169> – accessed May 27, 2010.

Electric Arc Furnace (EAF) – CO Emissions

CO is emitted as a byproduct of incomplete combustion from the following potential sources – charged and injected carbon, scrap steel, electrodes and “foaming slag” operating practice. EAF’s generate CO as a result of oxidation of carbon introduced into the furnace charge to refine the steel and as a result of sublimation/oxidation of the carbon electrode. Several operating parameters impact CO emissions, including amount of carbon, temperature within the EAF, oxygen composition within the EAF, rate in which carbon is added, quantity of foaming slag to reduce melt heat loss, the use of lancing (injection of oxygen) and the use oxy-fuel burners.

Applicant’s Proposal

Step 1: Identify all control technologies

In Application 19537, Osceola Steel Company evaluated the following control technologies to act in conjunction with the DEC system on the EAF. The test for technical feasibility of any control option is whether it is both available and applicable to reducing CO emissions from the EAF. The alternatives available to control CO emissions from the EAF include the following:

- Flaring of CO emissions
- Post Combustion Reaction Chamber
- CO oxidation catalysts and catalytic incineration
- Oxygen Injection
- DEC Controls
- EFSOP (Expert Furnace System Optimization Process)

Step 2: Eliminate Technically Infeasible Options

The next step in the top-down BACT analysis is to evaluate the technical feasibility of each control option, as it would apply to the Osceola project.

Flaring of CO Emissions

Flaring of blast furnace gases, and Basic Oxygen Furnace (BOF) gases is quite common, but based on a review of several information resources, there is no known application of flaring EAF exhaust gases, other than the excess air introduction (2:1 dilution) at the adjustable air gap between the fourth hole elbow and the DEC duct, followed by the gas expansion and volume reduction in the drop-out box, which provides enough time (approximately 1 second) to complete the CO burning (temperature permitting)

Flaring of emissions for CO destruction would require raising the exhaust gas temperature to 1300 degrees Fahrenheit at a residence time of 0.5 second. The exhaust gas stream at the baghouse will be approximately 350,000 dry standard cubic feet per minute (dscfm) at approximately 100 degrees Centigrade.

Thus, based on the large gas volumetric flow at a substantial temperature differential, the auxiliary fuel requirements needed to operate the flare would be overwhelmingly large. It is questionable whether the flare would actually decrease CO emissions. Also, the flare would increase NO_x emissions resulting from combustion of auxiliary fuel. Consequently, this control alternative is not considered viable for EAF exhausts and, thus is precluded from further consideration in this BACT analysis.

Post Combustion Reaction Chambers

The principle of destruction in post combustion chambers is to raise the EAF exhaust gases with auxiliary fuel firing to a sufficiently high temperature for a minimum time to facilitate oxidation. The combustion

chamber configuration must provide effective mixing in the chamber with an acceptable residence time. Recuperative heat exchangers can be used with these systems to recover a portion of the exhaust gas heat and reduce the auxiliary fuel consumption.

Based on a review of listed resources, this type of technology has limited application for EAFs in the United States; also, the feasibility of these units to significantly reduce CO emissions, without resulting in severe operation problems, is unknown. Such units are expected to consume large quantities of natural gas and oxygen, resulting in excessive annual operating costs and increased NO_x emissions.

The amount of CO that could be oxidized with post combustion systems is uncertain. Precise performance guarantees are difficult to obtain from equipment manufacturers because of the lack of operating experience. Further, due to the heat and particulate loading, the burners that supply the auxiliary fuel would have a short life expectancy, and may sustain severe maintenance and reliability problems. Additionally, a single or multiple duct burner system would not be able to heat the relatively cool gases from the EAF during cold cycling.

Potentially, there are two locations where post combustion chambers can be installed, (i.e. upstream or downstream of an EAF baghouse). Locating a post combustion chamber upstream of the baghouse would take advantage of the slightly elevated temperatures in the exhaust gas stream. However, at this location, the post combustion chamber would be subject to high particulate loading. The units would be exposed to foul frequently from the particulate accumulation, and the burners would have severe maintenance and reliability problems. Thus, the installation of the post combustion chamber could be installed downstream of the EAF baghouse. However, even at this location, fouling due to PM could occur and more importantly, cooler exhaust temperatures would be encountered. These cooler temperatures would greatly increase the auxiliary fuel requirements. The associated combustion of additional fuel will result in increases in NO_x emissions to the atmosphere.

In the USEPA RBLC database, six permits are listed in the table below that refer to the use of post combustion or duct combustion. Of these six permits, two (Chaparral Steel (Virginia) and Ameristeel (North Carolina)) have CO limits much higher than the 2.00 lb/ton CO limit proposed by Osceola. Two permits (IPSCO, Alabama and SDI Indiana) have the same CO limits proposed by Osceola, but higher NO_x limits. The other two permits are for IPSCO Steel (Iowa), and Keystone Steel (Illinois). The IPSCO Steel permit was issued in April 1996. The original CO limit was listed as 0.91 lb/ton, but was revised to 1.93 lb/ton in July 2002 based on test data. At the same time, the NO_x permit limit has to be raised from 0.27 lb/ton to 0.8 lb/ton; the post combustion chamber could be contributing to the elevated NO_x levels. The Keystone facility has a CO limit of 1.34 lb/ton, but the corresponding NO_x limit is 0.51 lb/ton.

Table 4-1: RBLC Comparison Summary for NO_x and CO Emission Limits for the Electric Arc Furnace (Source Code EAF)

Facility Name	Date of Issuance	Control Technology	CO Emission Limit (lb/ton)	NO _x Emission Limit (lb/ton)
Chaparral Steel	4/1998	Ducting/External Combustion Chamber at 12 MMBtu/hr; Work Practices	4.00	0.70
Ameristeel (North Carolina)	4/1999	Direct Evacuating Control System	6.00	N/A
IPSCO Steel (Iowa)	3/1996	Slot and Post Combustion Chamber DEC/Elbow Slot/Post Combustion/Water Cooled Duct	0.913* (revised to 1.93 lb/ton in 7/2002)	0.27 *raised to 0.8 in 7/2002

Facility Name	Date of Issuance	Control Technology	CO Emission Limit (lb/ton)	NOx Emission Limit (lb/ton)
IPSCO Steel (Alabama)	10/1998	DEC with Post-Combustion	2.00	0.40
Steel Dynamics Inc (Indiana)	7/1999	DEC, Air Gap and Combustion Chamber	2.00	0.35
Keystone Steel (Illinois)	6/2000	DEC, Oxy/Fuel Burners, Combustion Chamber and Work Practices	1.34	0.51

Although post combustion maybe a technically feasible control option, there is no data to indicate that it would reduce CO emissions beyond the levels already proposed, and there are indications that NOx levels would increase. Therefore, the post combustion chamber is precluded from further consideration in this BACT analysis.

Catalytic Incineration and Oxidation Catalysts

Based on a review of listed information resources, there is no known application of a catalytic incineration or an oxidation catalyst to control CO emissions from EAFs.

Catalytic incinerators or oxidizers use a bed of catalyst that facilitates the overall combustion of combustible gases. The catalyst increases the reaction rate and allows the chemical conversation at lower temperatures than a thermal incinerator. The catalyst is typically a porous noble metal material, which is supported in individual compartments in the unit. An auxiliary fuel-fired burner ahead of the bed heats the entering exhaust gases to approximately 600 degrees F to maintain proper bed temperature. Recuperative heat exchangers are used to recover some of the exhaust gas heat and reduce the auxiliary fuel consumption. Secondary energy recovery is typically 70%.

The temperature of the exhaust gases from the EAF will vary significantly during the various stages of the heat (100-700 degrees C). Thus, the temperature will be below the minimum 500 degrees Fahrenheit threshold for effective operation of the catalysts during much of its operation. In addition, the wide variation in temperature would make operation of a catalyst impractical. Lastly, the particulate loading in the exhaust gas stream is anticipated to be too high. Masking effects, such as plugging and coating of the catalyst surface, would almost certainly result in impractical maintenance requirements, and would significantly degrade the performance of the catalyst. Lead and other trace metals that could occasionally be present in the exhaust stream are generally considered poisons to catalysts and deactivate the available reaction sites on the catalyst surface. PM can also build up on the catalyst, effectively blocking the porous catalyst matrix and rendering the catalyst inactive. In cases of significant levels of poisoning compounds and particulate loading, catalyst replacement costs are significant.

As in the thermal incineration (post-reaction chamber) discussion, there are two potential locations where the catalyst bed could be installed, i.e. upstream or downstream of the EAF baghouse. For the same reasons discussed earlier (e.g., fouling due to PM), the upstream location is considered technically infeasible. Alternatively, the catalyst could be installed downstream of the EAF baghouse, however, even at this location, fouling due to PM could occur, and further, the exhaust would be at a lower temperature. These cooler temperatures would greatly increase the auxiliary fuel requirements. The associated combustion of additional auxiliary fuel would result in an unacceptable increase in operating costs. Further, the combustion of additional fuel would result in increases in emissions (especially NOx) to the atmosphere.

Based on a review of the previously listed information resources, there is no known application of oxidation catalysts to control CO emissions from an EAF. Based on the adverse technology applicability

issues, this control alternative is not considered technically feasible and is precluded from further consideration in this analysis.

Oxygen Injection

A theoretical means of reducing CO would be oxygen injection at the entrance of the ductwork to increase oxidation of the available CO to CO₂. (Furthermore, no documentation was found to quantify the reduction of CO formation.) Oxygen injection directly into the furnace to reduce CO emission levels (in addition to oxygen lancing for carbon removal) is an experimental operating practice in Europe used to increase the heat input to the melt, but the practice has not been demonstrated to reduce CO emissions.

Typically, the DEC system draws air into the duct, creating an oxygen-rich mixture of EAF exhaust gases where CO is naturally oxidized. The addition of oxygen is expected to convert little if any CO to CO₂. The capability is also limited due to the cyclic operating schedule (i.e., hot-cold cycling). Thermal oxidation of CO to CO₂ requires temperatures above 1200 degrees F. Exhaust gas temperatures will fluctuate during each melt and, at times drop below 1200 degrees F. It is estimated that this would occur for 5 to 10 minutes during each melt. The minimum temperature that would be encountered is estimated to be approximately 350 degrees Fahrenheit. Thus, during these periods, the thermal destruction efficiency would be expected to decrease significantly, resulting in elevated CO emissions. Consequently, this control alternative is not considered efficient and is precluded from further consideration in this analysis.

DEC Controls

In the steel industry, two principal capture systems are generally employed during EAF operation to control the process emissions generated during melting and refining. One is the DEC system, and the other is the side draft hood system. Side draft hoods require higher airflow rates than a DEC system and are not widely used. Based on a review of the previously listed information resources, DEC controls (i.e., fourth-hole furnace control system) continue to be the primary technology for controlling CO emissions from an EAF.

A DEC system is comprised of a water-cooled duct connected to the EAF via the furnace roof's "fourth hole". The duct is connected to the melt shop canopy collector system. During melting and refining, a slight negative pressure is maintained in the furnace to withdraw exhaust gases through the DEC. Where the DEC duct meets the "fourth hole", an adjustable gap exists that allows combustion air to enter, providing oxygen to oxidize CO and VOC. The DEC system allows excellent emissions capture, promotes combustion of CO and VOC, and requires the lowest air volume compared to other EAF capture devices. The DEC system also eliminates potential explosions that could result from CO created in the EAF.

EFSOP (Expert Furnace System Optimization Process)

EFSOP, is a burner optimization label that Tenova (Techint) uses to sell their burner and control systems, usually as part of their Consteel process. The consteel process itself suffers from excessive CO and VOC emissions because of low temperature fuming and combustion in the scrap preheating process. The Consteel process is employed at 4 facilities in the US: namely Gerdau NJ, Gerdau-Knoxville, Gerdau-Charlotte, and CMC-Arizona. All have had issues with high CO and VOC emissions. Tenova is also a competitor to companies that Osceola Steel Company has approached in reference to supplying the EAF; all of which have burner control and post-combustion packages. The limitations of all these EFSOP systems to date is getting a reliable gas probe to operate in the DEC system close enough to the EAF to do any good. The problems have related to dust plugging, slag entrainment in the gas stream, temperatures up to 3000F, and even flying scrap." Osceola has given consideration to EFSOP technology but has found it not to be a successfully demonstrated technology.

Step 3: Rank Remaining Technically Feasible Control Options

Various control alternatives were reviewed for technical feasibility on controlling CO emissions from the EAF. All options other than the DEC had technical problems and uncertainties with controlling CO emissions from the EAF or provided no additional or marginal degree of control. In addition, flaring, catalytic oxidation, the post combustion reaction chamber, and oxidation catalysts would all require added fuel. The additional fuel would increase the NO_x generated by this melting process and would be environmentally unacceptable, since NO_x is a precursor to ozone. Except for DEC controls, the applicability of the identified control options was determined to be technically infeasible or not appropriate for the Osceola project.

Step 4: Evaluate Remaining Control Technologies

Not applicable-DEC is the only viable control for this project.

*Step 5: Selection of BACT****Process Variability***

AP-42 has several listings of emissions factors of CO from EAFs that range from 1.0 to 3.8 lb/ton. Similarly there is a large variation in listings of the amount of NO_x generated from the heat ranging from 0.13 to 0.48 lb/ton. There is no explanation provided in AP-42 that explains this wide variation, but it is likely a result of many factors including:

1. The amount of carbon that is in the raw material and the amount charged or injected,
2. Control of oxygen in the burners,
3. The amount of arc drawn into the EAF,
4. The efficiency/effectiveness of the foaming slag practice,
5. The number of charges,
6. Temperature in the EAF, and
7. The productivity rate

In our review of the RACT/BACT/LAER Clearinghouse (RBLC) database we did note sources with lower CO emission factors from an EAF. However, upon further review it was determined that these sources had not substantiated the emission factors through stack compliance testing. Specifically, Arkansas Steel Associates presented a CO emission factor of 0.60 lb/ton. Upon review of the facility's Title V permit, the CO emission factor was identified to be 6.0 lb/ton. The IPSCO Steel facility had an indirect CO emission factor of 0.913 lb/ton derived from an hourly limitation and theoretical production rate. The facility does not have a lb/ton limit. A review of the permit for the J&L Specialty mill found that the CO limit actually applied to a reheat furnace and not an EAF.

Table 4-2: RBLC Summary for CO Emissions Limits for the Electric Arc Furnace (Source Code EAF)

Facility Name	Date of Issuance	Control Technology	CO Emission Limit (lb/ton)
Arkansas Steel Company	9/1998	Ducting/External Combustion Chamber	0.60 *Review of Title V Permit identifies limit as 6.0 lb/ton.
J&L Specialty Steel (Pennsylvania)	4/2003	N/A	0.037 * limit was for a reheat furnace not an EAF.
IPSCO Steel (Iowa)	3/1996	Slot and Post Combustion Chamber DEC/Elbow Slot/Post Combustion/Water Cooled Duct	0.913* (revised to 1.93 lb/ton in 7/2002)

Some emission factors were also a combination of an EAF with other processes, including LMF's. Emissions from the ladle metallurgical station along with sources of combustion such as the ladle and tundish pre-heaters and cutting torches which vent fugitively in the melt shop will be captured by the canopy system and therefore be included in the EAF exhaust. But again, the primary difference between individual mills is the type of steel being produced.

MACTEC, on behalf of Osceola Steel Company reviewed the information in the RBLC database and other recent projects in addition to State BACT determinations were used to evaluate BACT limits for CO emissions from an EAF. Telephone conversations with the state agency confirm that Nucor Steel in Indiana has tested and is in compliance with a CO emission rate of 2.0 lb/ton of steel. Osceola is proposing a CO emission limit of 2.0 lb/ton of steel as BACT. This factor is based on input from potential furnace vendors on achievable emission rates given the type of steel to be produced and the corresponding NOx emission rate. A review of the RBLC shows that this is one of the lowest levels permitted for modern EAF furnaces. The facility (Keystone Steel, Illinois) with the lowest CO emissions rate (1.34 lb/ton) has a much higher corresponding NOx emission limit of 0.51 lb/ton. The Keystone Steel & Wire Co. emission factor of 1.34 lb/ton has not been tested or verified, as the project has not been completed, according to Jason Schapp of Illinois EPA.

The Gerdau Cartersville plant has undergone a PSD analysis for CO on its EAF, which resulted in a CO limit of 1.34 lb/ton. This value is based on the EAF located at the Keystone Steel and Wire Company (Illinois). The Gerdau plant completes quarterly sampling of CO to demonstrate compliance with its 1.34 lb/ton CO limit, but as is the case with NOx, this testing is done for 30 minutes and because of the short duration of the sampling it is unknown if this sampling would capture the peak CO emission rate for the process. Furthermore, the Gerdau permit does not require simultaneous sampling of the NOx and CO emissions. It is expected that CO would track with the amount of CO₂, which in the Kirschen study is found to be negligible at the period of peak NOx (first application of power), which it peaks when oxygen and or fuels are being burned.

As noted previously, the Gerdau plant in Cartersville, Georgia does have a CO limit that matches the 1.34 lb/ton value for the Keystone Steel plant. As noted in the NOx BACT analysis, the Gerdau plant

conducts quarterly CO sampling; however, the length of the sampling would not ensure that the stack sampling captures the peak CO condition.

Generally, many of the more recent (2003-2009) permits, some of which may have not yet entered the database such as Thyssen Krupp Steel (Alabama), The Bluewater Project (Arkansas) and ECO Steel Recycling (Mississippi) have been permitted at the proposed level of 2.0 lb/ton. These more recent permits tend to reflect a CO level that is more achievable under the various operating conditions that an EAF must operate under that impact CO emission.

Since NO_x is considered to be a pollutant of higher concern by EPA than CO, Osceola is proposing a much lower NO_x level along with a slightly higher CO level. The DEC system that allows CO to oxidize along with a scrap management plan to minimize oil or other volatile carbon sources to be introduced in the furnace is the chosen control technology for BACT for CO emissions. In conclusion, BACT for controlling CO emissions from the EAF is the use of a DEC control system to meet a CO emission rate of 2.0 lb/ton of steel produced. This value is consistent with other recent BACT determinations.

EPD Review – CO Control

Step 1: Identify all control technologies

The alternatives available to control CO emissions from the EAF include the following:

- Flaring of CO emissions
- Post Combustion Reaction Chamber
- CO oxidation catalysts and catalytic incineration
- Oxygen Injection
- DEC Controls
- EFSOP (Expert Furnace System Optimization Process)

Step 2: Eliminate Technically Infeasible Options

In addition to the proposed technologies listed earlier, the Division reviewed the following technology:

EFSOP (Expert Furnace System Optimization Process)

The Internet in addition to the RBLC database was searched to ascertain what CO Control Technology is available to reduce CO emissions. The EFSOP (Expert Furnace System Optimization Process) technology created by Goodfellow Technologies (now Tenova) was discovered as an available control technology. It is an off-gas based process control system which measures off-gas from the melting process on a continuous basis and uses the output in conjunction with a computer model to optimize furnace operations and reduce overall conversion costs. A rugged conditioning system cleans the offgas sample and a portion of it is analyzed for carbon monoxide (CO), carbon dioxide (CO₂), hydrogen (H₂) and oxygen (O₂).

This technology has been established and the Tenova Technology (formerly Goodfellow) has ten installations and operating worldwide, which have measured and analyzed data from over 200,000 heats as of 2007.⁹ Typical combustion efficiency of CO conversion to CO₂ varies from 25-70% for the heat cycle.

The EFSOP system provides on-line measurements in real-time of what is occurring as the furnace emissions are exhausted. An added advantage is that the system can be used to control post-combustion systems. This optimizes furnace combustion, increases production and saves energy. Steelmakers have reported energy savings of 20 kWh/ton of steel and tap-to-tap time reductions of 2 to 3 minutes with EFSOP. Where plants are operating with inadequate DEC/canopy hood systems, EFSOP can quantify the amount of heat being released to the DEC system and determine what shortfalls exist in the system. Specific upgrades can then be identified.

The EFSOP system analyses the furnace off-gas just before the combustion gap to quantify the amount of carbon monoxide (CO) in the off-gas. The CO results from the incomplete combustion of oxygen and fuel in the furnace shell. Some furnace practices and scrap mixes also cause high levels of hydrogen (H₂) in the off-gas streams. Together, these combustible gases can make up over 30 per cent of the furnace off-gas and they represent a tremendous loss of energy.

⁹Development of the Goodfellow EFSOP Technology for Combustion Intensive Industries, October, 2007, Iron and Steel Review-accessed June 30, 2010.

This loss and the high temperature of the off-gas can mean a waste of more than 2,000,000 BTU/min (over 500 kWh/min) at peak points in the melts. This represents over 50 per cent of the electrical energy used by the furnace. In addition, CO and H₂, oxygen and carbon dioxide are measured in the gas sample. The flow and temperature of the off-gas stream and process parameters from the furnace operating system also are monitored to give a complete real-time picture of the inputs and outputs of the process¹⁰.

The EFSOP system allows the steelmaker to tailor the operation of the DEC system to match the actual requirements of the process. The continuous fume analysis of the furnace off-gas allows the steelmaker to conduct controlled post-combustion and to capture some of the energy that is being lost in the off-gas in the furnace, before it escapes into the DEC system.

Once profiles of the off-gas have been established, alternative practices to optimize the operation of the furnace can be evaluated. This makes it possible to set operating parameters for the fume system, which match the existing and anticipated heat load, profiles. By monitoring process data from existing furnace control systems, these set points can be adjusted in real-time to match the actual furnace practice and to accommodate process upsets.

The EFSOP technology has been used at a major Canadian steelmaker since 2007 and the data has yielded some valuable information such as:

- The CO and H₂ levels in the off-gas are significant for long periods of the heat. Maximum CO levels can exceed 25 per cent while maximum H₂ levels can be more than 20 per cent;
- Measurements are highly variable which indicates that the process is complex and that many factors interact to affect the off-gas chemistry; and
- The furnace loses significant amounts of heat while the system is idle.

It was determined by the Division that EFSOP would not be a viable control technology due to lack of available data establishing a direct contribution to the reduction of carbon monoxide emissions from the EAF through the use of EFSOP technology. Few plants within the US are currently using Expert Furnace System Optimization Process (EFSOP_{TM}). The facilities that have a lengthy history of using EFSOP are located outside of the United States where requirements to limit CO emissions at the stack aren't present, therefore companies weren't required to have additional technology for CO emission reduction or destruction.

Nucor Steel-Seattle is one of the few facilities located within the US currently using the EFSOP Technology on the electric arc furnace. The Division contacted Puget Sound Clean Air Agency to request stack test emissions data for Nucor Steel-Seattle. Tests performed in 2008 found CO to be emitted at 1.44 lbs/ton, and the 2009 testing found CO emitted at 1.64 lbs/ton. The emission rates for CO and NO_x were quantified simultaneously during the operation of the Nucor electric arc furnace at the Wheelabrator baghouse inlet duct and the BAUMCO baghouse inlet duct; however, the role EFSOP has in obtaining the measured emissions is undetermined at this time.

It is likely if this type of system were added to an uncontrolled EAF, there would be any further reductions in CO emissions. Based on the established inversely proportional relationship between NO_x and CO, the potential of an increase in NO_x emissions becomes a factor for consideration. GTI (now Tenova) argues that NO_x values would be lower due to higher fuel efficiency, thus requiring the use of less fuel, however no empirical data has been made available to verify the claim, therefore it is unlikely that this monitor will be technically feasible to install at this time.

¹⁰ Technology Study- Electric Arc Furnace Fume Systems and Control Technologies- Ontario Ministry of the Environment http://www.archive.org/stream/technologystudye00ontauoft/technologystudye00ontauoft_djvu.txt

Indiana Department of Environmental Management (IDEM) reviewed the EFSOP technology for Steel Dynamics, Inc. – Engineered Bar Products Division for a PSD issued January 2009¹¹, and were unable to receive empirical data to determine whether EFSOP would be a viable technology to constitute BACT, thus IDEM rendered the use of EFSOP as a control technology infeasible.

Step 3: Rank Remaining Technically Feasible Control Options

The Division agrees with Osceola Steel Company's assessment that DEC is the only remaining viable control technology for use.

Step 4: Evaluate Remaining Control Technologies

Not applicable-DEC is the only viable control for this project.

BACT Conclusion for CO

The Division has determined that Osceola Steel Company's proposal to use a DEC control system constitutes BACT.

Because of the inversely proportional relationship between NO_x and CO, an issue that arises is when one pollutant becomes the focus of control, the other pollutants emission rate increases. Ultimately, a balance must be achieved in which a control technology can be used that would effectively control NO_x emissions, but not at the expense of increasing CO emissions. By directing complete focus on controlling CO emissions through the use of post combustion means would in turn reduce CO emissions, however, emissions of NO_x and CO₂ would increase due to the additional fuel needs which creates additional environmental concerns. By shifting focus to primarily the control of NO_x would cause a spike in CO emissions, which is a pollutant of concern as well, however, in order of pollutant priority, the control of NO_x and CO₂ ranks greater than the control of CO, therefore a slightly higher NO_x would not be environmentally acceptable at the expense of CO.

In conjunction with the use of the DEC system, Osceola Steel Company is required to install low NO_x burners and engage in good combustion practices and work standard requirements that will prevent the excess generation of CO, to reduce or eliminate CO through oxidation and draft a scrap management plan to ensure the minimization of oil or other volatile carbon sources to be introduced into the furnace to meet the CO BACT limit of 2.00 lb/ton. In addition to reducing or eliminating CO emissions through the use of use of a scrap management plan, the Division also proposes simultaneous testing of both CO and NO_x to ensure both BACT limits are able to be achieved during peak operation of the EAF, because the limits are interdependent. The proposed limit of 2.00 lb/ton of steel meets the requirements of BACT. This CO BACT limit applies during all periods of the EAF heat cycle, including startup, shutdown and malfunction. The DEC system must be operating during all times the electric arc furnace is in operation.

Table 4-3: BACT Summary for CO Emissions on the Electric Arc Furnace (Source Code EAF)

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
CO	DEC	2.00 lb/ton	3 hours	Performance Test

¹¹ <http://permits.air.idem.in.gov/27230p.pdf> – IDEM PSD Permit for Steel Dynamics Inc (SDI)

Electric Arc Furnace (EAF) – NOx Emissions

Scrap steel is melted in electric arc furnaces (EAFs) where radiant heat from an electric arc established between the electrodes (usually powered from a three-phase utility-based supply) and the scrap or molten steel bath is used to bring the charge to pouring temperature. Heating due to the electric current passing through the scrap or molten bath is a minor part of the total heat input. The use of electricity for steel melting transfers the generation of NO from the iron and steel mill to a utility generating plant. However, oxygen and natural gas are sometimes used to preheat the charge making EAFs a source of NOx emissions¹².

NOx emissions from EAFs come from two primary mechanisms: NOx formed in the electric arc plasma during the startup period of the melting process where nitrogen in the air is converted to NOx (thermal) and from the post-combustion of natural gas in the furnace (fuel). The amount of NOx from each mechanism will vary widely depending on numerous variables unique to the respective EAF. Such variables include: the number and length of the charges for each heat, the frequency of the charges, how well the furnace is insulated (which impacts the availability of nitrogen from the air), the type and use of secondary fuels, use of oxygen lances and several other factors.

Applicant's Proposal

Step 1: Identify all control technologies

The USEPA RACT-BACT-LAER Clearinghouse (RBLC) indicates that EAFs have no add-on control technology for NOx emissions. Also, USEPA's "Alternative Control Technologies Document-NOx Emissions from Iron and Steel Mills" states, "*There is no information to suggest that EAFs have NOx emission controls or that suitable controls are available*". Therefore, technology transfer of NOx control used on other sources is the only control technologies that were evaluated as part of this BACT analysis. Control of NOx is mainly practices in the power generation industry, which generates large quantities of NOx. Therefore, based on controls used for combustion sources and a review of the previously identified information sources, a list of potential NOx control technologies was developed. The following potential NOx control technology options are included in the BACT analysis.

- Low NOx combustion controls
- Selective Catalytic Reduction (SCR)
- Non-Selective Catalytic Reduction (NSCR)
- Selective Non-Catalytic Reduction (SNCR)

Step 2: Eliminate Technically Infeasible Options

The next step in the top-down BACT analysis is an evaluation of the technical feasibility of each control option, as it would apply to the Osceola project.

Low NOx combustion controls

Various mechanisms referred to as Low NOx Combustion Control are used to reduce NOx emissions from conventional combustion systems. These NOx control strategies include overfire air (OFA), low excess air (LEA), burners out of service (BOOS), low NOx/oxyfuel burners, FGR and reburning. Most NOx control techniques are not technically feasible for application to EAFs. Only low-NOx/oxyfuel

¹²U.S. Environmental Protection Agency-Office of Air and Radiation-Office of Air Quality Planning and Standards
Alternative Control Techniques Document -NOx Emissions from Iron and Steel Mills
http://www.epa.gov/ttn/catc/dir1/iron_act.pdf

burners are considered technically feasible for the NO_x formed from combustion. This would improve only the combustion portion of the NO_x emissions and not those associated with the electric charge.

Oxy-fuel burners reduce NO_x emissions from the natural gas combustion by replacing the ambient air used to support natural gas combustion with oxygen-enriched air. Oxygen from liquid typically runs over 99 percent pure, compared to ambient air that contains 79% nitrogen (by volume). The use of oxy-fuel burners will, however, produce less NO_x as compared to standard natural gas burners.

Selective Catalytic Reduction (SCR)

SCR systems involve the post combustion removal of NO_x from flue gas in a catalytic reactor. These systems selectively reduce NO_x by injecting NH₃ into the exhaust gas stream upstream in the presence of a metal catalyst. NO_x, NH₃ and oxygen react on the surface of the catalyst to form molecular nitrogen (N₂) and water.

An SCR system is composed of an NH₃ storage tank, NH₃ injection grid, and a reactor that contains the catalyst. An injection grid disperses NH₃ through nozzles into the EAF flue gas upstream of the catalyst. In the presence of the catalyst, the NH₃ and NO_x are reduced to N₂ and water. This control technique reduces both thermal NO_x and fuel NO_x in the exhaust streams.

In honeycomb-type catalysts, the size of the catalyst openings (i.e., pitch) is important. Smaller pitch equates to large surface area, and thus greater NO_x removal efficiency by maximizing of the surface area on which the reactions take place. However, if the catalyst openings are too small, there is potential for clogging from contaminants in the gas stream. The residence time of the exhaust gases in the presence of the catalyst must be sufficient for the reactions to take place. The longer the exposure time of exhaust with the catalyst, the greater the resulting NO_x removal.

Depending on system design, NO_x removal of 90% and higher is achievable under optimum conditions. The reaction of NH₃ and NO_x is favored by the presence of excess oxygen. Another variable affecting NO_x reduction is exhaust gas temperature. The greatest NO_x reduction occurs within a reaction window at catalyst bed temperatures between 600 degrees F and 750 degrees F for conventional (vanadium or titanium-based) catalysts, and 470 degrees F and 510 degrees F for platinum-based catalysts.

Performance for a given catalyst depends largely on the temperature of the exhaust gas stream being treated. A given catalyst performs optimally when the temperature of the exhaust gas stream is at the midpoint of the reaction temperature window for applications where exhaust gas oxygen concentrations are greater than 1%. Below the optimum temperature range, the catalyst activity is greatly reduced, potentially allowing unreacted NH₃ (referred to as “ammonia slip”) to be emitted directly to the atmosphere.

For an SCR system to effectively reduce NO_x emissions, the exhaust gas stream must have relatively stable gas flow rates, NO_x concentration, and temperature profile. In addition, certain elements such as iron, nickel, chrome and zinc can react with platinum catalysts to form compounds of alloys that are not catalytically active. The reactions are termed “catalytic poisoning”, and can result in premature replacement of the expensive catalyst. Also, any solid material in the gas stream can form deposits and result in fouling or masking of the catalytic surface.

Fouling occurs when solids obstruct the cell openings in the catalyst. Masking occurs when a film forms on the surface of catalyst over time. The film prevents contact between the catalytic surface and the flue gas. Both conditions can result in frequent cleaning and/or replacement requirements. Lastly, any SCR on the EAF system must be operated between 500 and 600 degrees Fahrenheit to prevent SO₂ from reacting with NH₃ to form ammonia sulfate (NH₄SO₄) that would contaminate the catalyst. The exhaust gas temperature delivered to the baghouse from the melt shop is well below this temperature.

For several reasons, SCR is considered infeasible for this source. The SCR reaction requires a stable gas flow rate, temperature range and NO_x concentration. As previously discussed, the EAF exhaust temperature ranges from 100 degrees C to 700 degrees C and NO_x concentrations are highly variable, making the SCR process ineffective. NO_x emissions appear to be close to zero during most of the operation of the EAFs with brief spikes of approximately 2 minutes in length occurring with the start of each charge. This suggests that the bulk of the NO_x emissions associated with a given heat occurred during a period that represents only 4-10% of the operating time of the furnace. The variation in exhaust temperature makes it impractical to maintain the consistent exhaust stream required for a catalyst to be effective.

The result of attempting to utilize an SCR on an EAF would be poor to minimal NO_x removal and excessive NH₃ slip dependent on exhaust conditions. Another problem in implementing SCR is the high concentration of EAF dust that would blind or erode the catalyst. Therefore, the reasons that SCR is considered infeasible include:

- The EAF exhaust gas stream is extremely variable, caused by the furnace going through several cycles compromising: tap and charge, and the charge melt. The fluctuations and wide range of variables include exhaust flow rate, temperature, and NO_x concentration.
- The exhaust temperature would often be outside the operating range of the catalyst including those periods when NO_x emissions are at their greatest.
- Metals, silicon and other dust load would blind and erode the catalyst.

For these reasons, SCR is considered infeasible for an EAF and was not further evaluated.

Non-Selective Catalytic Reduction (NSCR)

NSCR processes use a catalyst (platinum/rhodium) to reduce NO_x to nitrogen and water under near-stoichiometric conditions. NSCR has been used on certain types of combustion sources such as automobiles and reciprocating engines that operate in a fuel-rich mode-i.e., very low (1%-2%) oxygen levels. For NSCR to operate properly, the combustion process must be near stoichiometric. Research could not verify that this process has ever been installed on an EAF or the control ductwork. Because of the near stoichiometric conditions required during the process and the potential problems of plugging and fouling of catalyst, NSCR was not considered technically feasible for this application. Therefore, NSCR will not be evaluated further.

Selective Non-Catalytic Reduction (SNCR)

SNCR technology involves using NH₃ or urea injection in a fashion similar to SCR technology, but at higher temperatures of 1600 to 2200 degrees F. The operating temperature can be lowered to 1300 degrees F by injecting hydrogen with the NH₃. However, beyond the upper temperature limit, the NH₃ is converted to NO_x resulting in increased NO_x emissions.

For many of the same reasons as SCR, SNCR is also believed to be infeasible for application at an EAF/melt shop. SNCR requires a more stable gas condition than SCR. The highly variable NO_x concentration would make it impossible to maintain the proper stoichiometric ratio of reagent to NO_x, which in many cases could result in a significant NH₃ slip or reduced efficiency. To operate at these temperatures, the SNCR would have to be installed upstream of the baghouse and would, therefore, subject the reagent injection heads to high mechanical wear and poor dispersal of the fluids. There is also the potential for the NH₃ or urea to adsorb onto the particulates, where they could later be released as gas to the atmosphere while the exhaust cools. If the temperature falls below 1400 degrees F, NH₃ will be released. If the temperature exceeds 2000 degrees F, additional NO_x formation occurs. The temperature of the exhaust gas can vary widely over a melt cycle and often produces an exhaust gas stream outside the operating temperature ranges. Also, varying gas flow rates during the melt cycle would affect residence time and removal efficiencies. GAEPD is not aware of SNCR ever being applied or considered feasible.

on an EAF. Because of these technical problems, SNCR is considered technically infeasible and will not be considered further.

Step 3: Rank Remaining Technically Feasible Control Options

The only viable option for controlling NO_x emissions from an EAF is the use of low NO_x/oxyfuel burners for the reduction of NO_x from combustion. The approach of employing add-on NO_x controls is technically infeasible for application to EAFs. There are no other documented alternative approaches. Review of previous BACT and LAER determinations referenced on the RBLC maintained by USEPA and additional correspondence with various state permitting agencies and facilities not appearing on the RBLC confirm that no other approaches have been applied to EAFs.

Step 4: Evaluate Remaining Control Technologies

The low NO_x oxyfuel burner is the only technology remaining. This technology would only apply to the NO_x formation associated with fuel combustion and would not impact the NO_x emissions associated with the application of the electrical charge which appears to be the greater mechanism for NO_x formation.

Step 5: Selection of BACT

Proposed BACT Level

RBLC provides NO_x emission listings for EAFs, which shows NO_x emissions rates ranging from 0.1 to 1.32 lb/ton, with a large group of recently permitted units at the 0.35 lb/ton level. Considering these factors Osceola is proposing a NO_x factor of 0.35 lb/ton (and a corresponding proposed CO factor of 2.0 lb/ton). This factor is based on input from potential furnace vendors on achievable emission rates given the type of steel to be produced and the corresponding CO emission rate.

Process Variability

As noted in the Kirschen study the peak NO_x occurs over a short time period of time during the start-up period of the charging process when power is first applied to the electrodes. NO_x from individual EAFs will therefore be largely dependant upon the number of charges per heat. The second component of NO_x emissions (from combustion) will be dependent upon the use of natural gas or other supplemental fuels as well as the type and amount of combustibles contained in the scrap that feeds the EAF. The Osceola EAF will employ oxy-fuel burners therefore it will have more NO_x as compared to an EAF that does not utilize supplemental fuels. Furthermore, the Osceola mill will also utilize other sources of carbon (crushed coal, petroleum coke, coal and tires), which would also add nitrogen to the system, and therefore result in NO_x emissions from fuel bound nitrogen.

The economic viability of the proposed micro steel mill is highly dependent upon the cost of transportation of scrap steel (the primary raw material) to the mill and the transportation of the finished product to the end user. Transportation costs are the third largest variable cost to the mill (behind scrap and electrical energy), therefore success for the proposed project will hinge upon procuring local scrap and meeting the local demands for finished steel products. The mill will therefore need to utilize locally available scrap steel (including scrap grades with varying amounts of oils and other contaminants including residual metals). Osceola's will need to make adjustment for those many operational variants, which also impact emissions.

Review of BACT/LAER Listed Units

There were several units with limits below the proposed NOx BACT level for Osceola EAF. The specifics for some of these permits are as follows:

- Nucor Steel Marion, Ohio, had a 12-month rolling limit of 0.0036 lb/ton; however, the NOx emission limit has not been verified and likely refers to fugitive emissions out the roof vent.
- Charter Steel-A review of their permit found the correct NOx limit is 0.51 lb/ton
- Republic Technologies International, Ohio has a lower limit of 0.100 lb/ton; however, the NOx emission limit has not been verified.
- CF&I Steel-Rocky Mountain Steel, Colorado-A review of the Title V for this facility indicates that the EAFs at the mill vent to “baghouses that are connected to canopies constructed above the furnace... The canopies had to be constructed at a considerable distance from the top of the furnaces in order to allow the furnace tops to be opened, and the over-head crane to have access for depositing materials. As a consequence, the canopies are somewhat ineffective in capturing the emissions. The emissions that escape the canopies are discharged through openings (cupolas) in the roof of the building. The escaping emissions have a significant particulate matter content and create opacity in the atmosphere.” Because the unit isn’t capturing a large part of its emissions the unit could practical test to demonstrate compliance with its NOx limit.
- Co-Steel Raritan in New Jersey was purchased by Gerdau Ameristeel but the plant is no longer operating.
- Gerdau Ameristeel Wilton is permitted at a lower NOx limit of 0.19 lb/ton, however, its CO limit of 4.75 lb/ton is more than twice the proposed limit for the Osceola mill (2.00 lb/ton). Based on these levels it appears that the lower NOx levels are being achieved by operating at lower oxygen levels, which will contribute to higher CO.
- The Timken Company-Faircrest plant in Ohio has demonstrated compliance with its NOx limit of 0.2 lb/ton; however, this was a single one time test completed in 2006. The limit is not therefore thought to represent long-term compliance over process variations. Timken also produces the highest quality alloy steels, which require the use of select low residual scrap.
- Hoeganses Corporation in Tennessee has demonstrated compliance with its 0.2 lb/ton NOx limit, however the unit is only required to conduct stack testing once every five years. The limit is not therefore thought to represent long-term compliance over process variations. The plant produces powdered steel, which is a significantly different product than the steel to be produced by Osceola.
- Griffin Wheel Company-The unit is permitted at an equivalent emission rate of 0.2 lb/ton, but the permit limit is not on a lb/ton basis therefore it is unclear that the unit would be permitted at a NOx level equivalent to the proposed EAF.
- J&L Specialty, Pennsylvania is permitted at 16.62 lb/hr. This is an hourly limit and not a lb/ton limit, therefore it is unclear what levels the unit can achieve on a lb/ton basis.
- Nucor Auburn Steel, New York- The 0.27 lb/ton limit is based on a 30 day rolling average, therefore it is unknown if the level can be achieved on a short term basis for stack testing purposes (3 hour average).
- Charter Steel-Ohio-The unit has only a single stack test that shows compliance with its 0.33 lb/ton limit. The limit is not therefore thought to represent long-term compliance over process variations.
- Gerdau Ameristeel-Georgia- In addition to a review of the BACT/LAER clearinghouse, a review of Georgia permits was completed, which included the recently permitted Gerdau Ameristeel, plant in Cartersville, Georgia. The EAF at the Gerdau mill has a NOx emission limit of 0.15 lb/ton. This limit was implemented as part of Reasonable Achievable Control Technology (RACT) analysis for the site and not as part of a BACT analysis. This RACT limit was implemented because the Gerdau site is located in an area that impacts the Atlanta ozone non-attainment area. Osceola will be located in Cook County which is in attainment with the ground level ozone standard therefore this higher level of NOx control is not considered warranted for

this plant. The Gerdau Cartersville, Georgia plant produces a different product mix than the proposed facility. Osceola will produce rebar (60%-70% of product range) and angle iron and other merchant products while the Gerdau site produces medium sections and light structural steel products which are produced from a higher quality, more expensive scrap.

Table 4-4: RBLC Summary for NOx Emission Limits for the Electric Arc Furnace (Source Code EAF)

Facility Name	Date of Issuance	Control Technology	NOx Emission Limit (lb/ton)
Nucor Steel (Ohio)	8/2005	--	0.0036
Charter Steel (Ohio)	4/2003	DEC and Low NOx Oxy Fuel Burners	0.3299
Republic Technologies International (Ohio)	1/1999	--	0.3500
CF&I Steel-Rocky Mountain Steel (Colorado)	6/2004	Good Combustion Practices	0.1500
Co-Steel Raritan (New Jersey)	12/1996		0.1812
Gerdau Ameristeel-Wilton (Iowa)	5/2007	DEC and Oxy Fuel Burners	0.1900
Timken Company-Faircrest (Ohio)	2/2003	Low NOx Burners	0.2000
Hoeganses Corporation (Tennessee)	2/2000	Low NOx Burners	0.2000
Griffin Wheel Company (Oklahoma)	10/1999	--	0.2000
J&L Specialty Steel Inc (Pennsylvania)	4/2003	Low NOx Burners	0.2022
Nucor Steel-Auburn (New York)	6/2004	--	0.2700
Charter Steel (Ohio)	4/2003	DEC and Low NOx Burners	0.5100
Gerdau Ameristeel (Georgia)	9/2001(as Birmingham Southeast, LLC)	DEC and Low NOx Burners	0.1500
Thyssen Krupp Steel (Alabama)	8/2007	DEC and Low NOx Burners	0.3500
Nucor Steel (Indiana)	11/2003	Oxy Fuel Burners and CEMS	0.3500

Facility Name	Date of Issuance	Control Technology	NOx Emission Limit (lb/ton)
Corus Tuscaloosa (Alabama)	6/2003	--	0.3500
Bluewater Project (Arkansas)	7/2004	Low NOx Burners	0.3500
ECO Steel Recycling-Armory (Mississippi)	currently in draft	DEC and Low NOx Burners	0.3500

Generally, many of the more recent permits (2003-2009) (Thyssen Krupp Steel-Alabama, Nucor Steel-Indiana, Corus Tuscaloosa-Alabama, the Bluewater Project-Arkansas, and ECO Steel Recycling-Armory, Mississippi) have been permitted at the proposed level of 0.35 lb/ton. These recent permits tend to reflect a NOx level that is more achievable under the various operating conditions that an EAF must operate under that impact NOx emissions.

NOx Reduction Techniques to be Employed by Osceola

The Kirschen study identified several operational techniques that could potentially be employed to reduce NOx emissions. These techniques along with how they are expected to be employed by Osceola are outlined below:

- *Oxy fuel burner control and design* – Osceola will use low NOx burners and operate as close to stoichiometric as practical without excess generation of CO.
- *Minimize the number of charges per heat*- Instead of the typical 2 to 3 charge heats the Osceola furnace will be built with an extended sidewall height to facilitate a single charge practice when possible. This will reduce overall emissions and increase productivity. The final number of charged required will, however be dependent upon process variables tied to scrap steel availability and final product mix.
- *Minimum use off-gas volume during the starting phase (use of direct exhaust control)*- Osceola will be employing a DEC system. Excessive negative pressure draws air in through the furnace door and electrode ports and pressure will be maintained as close to neutral as practical to avoid the draw in of nitrogen.
- *Maximize air tightness of EAF (e.g. closed slag door)* – Osceola intends to employ a design that minimizes air leaks into the EAF, which in turn will reduce the available oxygen for NOx formation.
- *Improved foamy slag practice to shield the electric arc*- Osceola will be employing the foaming slag practice in its operation during the majority of the power on time. This practice shields the arc from nitrogen.

With the application of these techniques, it is expected that the unit will be able to consistently achieve a NOx limit of 0.35 lb/ton, which allows for the process variations under which the site will need to operate under.

EPD Review – NOx Control

Step 1: Identify all control technologies

Control techniques for NOx emissions can be placed into one of two basic categories: techniques designed to minimize NOx generation and techniques to remove previously generated NOx from the waste effluent stream. Combustion modification techniques such as low-NOx burners (LNB), low excess air (LEA) and LNB plus flue gas recirculation (FGR) fit into the first category. Add-on flue gas treatment techniques such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) are examples of the second⁷. The Division reviewed the control technologies for the reduction of NOx emissions outlined in Application 19507. Control technologies mentioned were: low-NOx burners, Selective Catalytic Reduction (SCR), Non-Selective Catalytic Reduction (NSCR) and Selective Non-Catalytic Reduction (SNCR).

Step 2: Eliminate Technically Infeasible Options

Next, RBLC Listings for NOx emission limits from EAF projects were queried, searched and verified. It was determined there were over 150 projects in which NOx emission limits were available. Of those projects, many facilities had no mechanical or other forms of control technology in practice, thus eliminating those facilities from the initial review. The Division reviewed the control technologies for the reduction of NOx emissions outlined in Application 19507, and the Division agrees with Osceola's decision to render the use of technologies such as: Selective Catalytic Reduction (SCR), Non-Selective Catalytic Reduction (NSCR) and Selective Non-Catalytic Reduction (SNCR) as technically infeasible due to lack of precedence being established for the use of control technology on a basis outside of experimentation⁷, instability of the gas flow rate, temperature range and NOx concentration associated with operation.

Step 3: Rank Remaining Technically Feasible Control Options

Of the projects that had control technology associated, the majority of the facilities listed oxy-fuel burners or low NOx burners as their primary mechanism for controlling NOx emissions in addition to good combustion and operational practices. While the listed combustion modification NOx control techniques, LEA, LNB, and LNB plus FGR, may increase CO and unburned hydrocarbon (HC) emissions. The NOx reduction mechanisms inherent in these modification techniques are the reduction of peak flame temperatures, which is exponentially related to the formation of thermal NOx and the reduced availability of excess oxygen needed to form NOx. Reducing the availability of oxygen to the combustion process increases the likelihood that some HC will not be burned and that some CO will not be oxidized to CO₂. However, if the control is properly designed and applied, NOx control can be achieved without increasing CO or HC emissions. The combination of low-NOx/oxyfuel burners plus a flue gas recirculating system (FGR) combined with good operational and combustion practices was the only technology identified for use in EAFs via the RBLC and additional reviewed, there were no additional technically infeasible options to eliminate.

Step 4: Evaluate Remaining Control Technologies

Not applicable- the combination of low-NOx/oxyfuel burners with flue gas recirculating (FGR) combined with good operational and combustion practices is the only viable control for this project.

Conclusion – NOx Control

The Division has determined that the combination of low-NOx/oxyfuel burners with flue gas recirculating (FGR) technology in addition to good operational and combustion practices, as a means to control NOx emissions constitutes BACT. In addition to reducing or eliminating NOx emissions through the use good

operational and combustion practices, the Division also proposes simultaneous performance testing of both CO and NOx to ensure both BACT limits are able to be achieved during peak operation of the EAF, because the limits are interdependent. This NOx BACT limit applies during all periods of the EAF heat cycle, including startup, shutdown and malfunction. The Good Operating practices proposed by Osceola Steel Company, derived from the Kirschen study such as:

- *Oxy fuel burner control and design* – Osceola will use low NOx burners and operate as close to stoichiometric as practical without excess generation of CO.
- *Minimize the number of charges per heat*- Instead of the typical 2 to 3 charge heats the Osceola furnace will be built with an extended sidewall height to facilitate a single charge practice when possible. This will reduce overall emissions and increase productivity. The final number of charges required will, however be dependent upon process variables tied to scrap steel availability and final product mix.
- *Minimum use off-gas volume during the starting phase (use of direct exhaust control)*- Osceola will be employing a DEC system. Excessive negative pressure draws air in through the furnace door and electrode ports and pressure will be maintained as close to neutral as practical to avoid the draw in of nitrogen.
- *Maximize air tightness of EAF (e.g. closed slag door)* – Osceola intends to employ a design that minimizes air leaks into the EAF, which in turn will reduce the available oxygen for NOx formation.
- *Improved foamy slag practice to shield the electric arc*- Osceola will be employing the foaming slag practice in its operation during the majority of the power on time. This practice shields the arc from nitrogen.

These good operation practices must be observed during all times the electric arc furnace is in operation. The good operation practices will also be included within the permit. The BACT selection for the Electric Arc Furnace (EAF) is summarized below in Table 4-4:

Table 4-5: BACT Summary for NOx Emissions on the Electric Arc Furnace (Source Code EAF)

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
NOx	Low NOx Burners with FGR technology and Good Combustion/Operation Practices	0.35 lb/ton	3 hours	Performance Test

Electric Arc Furnace (EAF) – PM Emissions

Particulate Matter (PM) may be generated in each of the steps, and may contain varying concentrations of mineral oxides, metals (e.g. arsenic, cadmium, mercury, lead, nickel, chromium, zinc, manganese), and metal oxides. Sources include melting and refining activities and heating furnaces (depending of type of fuels used); mechanical actions (e.g. scarfing and grinding); and handling of materials (e.g. raw materials, additive, recycled and waste materials, and by-products). Additional sources of particulate matter (PM) emissions include coal storage, conveying, charging, coking, pushing, and quenching gas emissions); and charging / tapping (secondary off-gas emissions). In the casting area (ingots and continuous casting), particulate matter and metals arise from the transfer of molten steel to the mold and from the cutting to length of the product by oxy-fuel torches during continuous casting. Exhausts should be fitted to filters and other relevant abatement equipment, especially in the casting and rolling, and finishing shops, where relevant¹³. EAF Furnace is the largest source of emissions from the steel mill, hence is the focus of the discussion here.

Applicant Proposal

Step 1: Identify all control technologies

The potentially available to reduce PM emissions from the EAF include the following:

- Electrostatic Precipitator
- High-Energy Wet Scrubbers
- Fabric Filters (i.e. baghouses)

Step 2: Eliminate Technically Infeasible Options

The test for technical feasibility of any control device is whether it is both available and applicable to reducing PM emissions from the EAF. The previously listed information sources (USEPA RBL Clearinghouse and various Air Quality Permits not listed in the RBLC) were consulted to determine the extent of applicability of each identified control alternative.

Electrostatic Precipitator

Electrostatic Precipitators (ESPs) use an electrostatic field to charge PM contained in the gas stream. The charged particles then migrate to a grounded collection surface. The collected particles are then periodically dislodged from the collection surface by vibrating or rapping the collection surface. The dislodged particles are then collected in a hopper at the bottom of the ESP.

Although an ESP is capable of very high (99% or higher) particulate removal, several factors preclude their application to EAF control. A key parameter is the consumption of the particles to be collected. Iron compounds adhere very strongly to the collection plate of the ESP (due to their electromagnetic properties). They are, therefore very difficult to remove and thus reduce ESP efficiency. Zinc and other compounds tend to foul ESP electrodes, also reducing effectiveness. In addition, ESPs are greatly affected by sensitivity to the variations in flow rate, solids loading and temperature fluctuations inherent in batch EAF operations. For the reasons explored above, ESPs have not been used on EAFs and are considered technically infeasible.

¹³ International Finance Group (IFG)-April 30, 2007-*Environmental, Health, and Safety Guidelines for Integrated Steel Mills*

High energy Wet Scrubbers

High Energy Wet Scrubbers are technically feasible, but have many disadvantages compared to fabric filters, which can achieve better levels of particulate control. Scrubber systems have very high-pressure drops that result in high system operating costs. They also require water treatment and sludge disposal, which are not necessary with the other PM control options. Osceola is not aware of any application of a wet scrubber to control particulates from an EAF. Based on the operational energy and environmental issues, this technology though viable is not fully considered in this application and for the economic analysis was not reopened for this application.

Fabric Filters (Baghouses)

A fabric filter (also known as a baghouse) is one of the most efficient means of separating particles from a gas stream. The advantage of fabric filters is that the efficiency is largely insensitive to the physical characteristics of the gas stream and changes in the dust loading. Baghouse installations are the industry standard for EAF particulate controls.

Both the positive and negative pressure baghouses have been used in the steel industry. Positive pressure baghouses operate at an internal pressure greater than atmospheric. In this configuration, the exhaust fans are located before the baghouse (i.e. on the “dirty side”) and pull the air from the EAF, then push the air through the baghouse. These systems vent to ambient air through a continuous ridge vent instead of a stack. Negative pressure baghouses operate at an internal pressure less than atmospheric. In this configuration, the exhaust fans are located after the baghouse (i.e. on the “clean side”), pull the air from the EAF through the baghouse, and exhaust to the ambient air through a central stack.

Step 3: Rank Remaining Technically Feasible Control Options

Various control alternatives were reviewed from technical feasibility in controlling PM emissions from the EAF. The highest-ranking control option was the baghouse, which is the control option proposed by Osceola.

Step 4: Evaluate Remaining Control Technologies

Baghouse technology is the only cost-effective and environmentally friendly method of control.

Step 5: Selection of BACT

The lowest limit identified in the RBLC for particulate matter was 0.0014 gr/dscf. This limit is for the New Steel International facility in Ohio, which has not yet been constructed. Therefore, no compliance determinations for this limit have yet been conducted. The next highest limit identified in the RBLC database is 0.0018 gr/dscf. In conclusion, BACT for controlling PM emissions from the EAF is the use of a baghouse with an emission factor of 0.0018 gr/dscf based on the USEPA Reference Method 5 testing procedure, meaning filterable particulate emissions only.

Most of the information available in the RBLC database does not clearly indicate that this limit is for filterable PM. This qualifier is justified as most of the test data on EAFs was developed from USEPA Reference Method 5 that at the time only accounted for filterable PM emissions.

Table 4-6: RBLC Summary for PM Emissions for the Electric Arc Furnace (Source Code EAF)

Facility Name	Date of Issuance	Control Technology	PM Emission Limit (gr/dscf)
New Steel International (Ohio)	5/6/2008	Baghouse and Direct Evacuation Control w/ 100% Capture Efficiency	0.0014
V & M Star (Ohio)	9/23/2008	Canopy Hood Fume Collection with Direct Evacuation Control System and Fabric Filter	0.0018
Nucor Yamato Steel (Arkansas)	1/31/2008	Baghouse	0.0018
Minnesota Steel Industries (Minnesota)	9/7/2007	Baghouse	0.0018
Quanex Corporation-Macsteel Division	2/1998	Positive Pressure Multicompartment Baghouse	0.0018
Nucor Steel (Indiana)	11/2003	Baghouses 1 & 2. Each Baghouse can sufficiently control emissions independently. Compliance Method: Stack Testing and Bag Leak Detection System.	0.0018
Nucor Steel (Alabama)	9/2003	Baghouse BH-01	0.0018
Bluewater Project (Arkansas)	7/2004	Fabric Filter	0.0018
Keystone Steel & Wire Company (Illinois)	6/2000	Baghouse	0.0018
Nucor Yamato Steel (Armored) (Arkansas)	10/2001	Baghouse/Fabric Filter	0.0018
C.F & I Steel L.P. DBA Rocky Mountain Steel Mills (Colorado)	6/2004	High Efficiency Filter Baghouse	0.0018
Chaparrel Steel Company (Virginia)	4/1998	Positive Pressure Baghouse	0.0018

Some of the particulate matter emitted from the EAF would be expected to be in the form of condensable particulate matter; however, it is expected to be a minimum because of the very high temperature at which the EAF is operated. Very little is known about the amount of condensable particulate matter from EAFs and very little sampling data is available. The proposed total BACT PM emission level for the EAF is 0.0026 gr/dscf which is based on the proposed BACT level for filterable particulate matter (0.0018 gr/dscf) and the AP-42 emission factor for condensable particulate matter of 0.039 lb/ton (aqueous and organic condensable PM), which is equivalent to 0.0008 gr/dscf.

EPD Review – PM Control

Step 1: Identify all control technologies

The Division agrees with Osceola Steel Company's discovery of available technology to control particulate matter from the EAF. Sources such as: *Operation and Maintenance of Particulate Control Devices on Selected and Ferroalloy Processes* by USEPA's Industrial Environmental Research Laboratory Office of Research and *Development and Electric Arc Furnace Fume Systems and Control Technologies* by the Ontario Department of the Ministry cite fabric filters, Venturi scrubbers and electrostatic precipitators (ESPs) as control technology available for use on EAFs.

Step 2: Eliminate Technically Infeasible Options

The criteria in which the Division used to verify feasibility of the control technology was based on the following parameters:

- Particle size to be collected,
- Particle loading,
- Stack gas flow rate,
- Stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials),
- Desired collection efficiency.

Based on research performed, the Division was able to eliminate the following control technologies:

Dry Electrostatic Precipitator

As previously mentioned, Electrostatic Precipitators (ESPs) use an electrostatic field to charge PM contained in the gas stream. Charged particles then migrate to a grounded collection surface and the collected particles are periodically dislodged from the collection surface by vibrating or rapping the collection surface. The dislodged particles are then collected in a hopper at the bottom of the ESP.

ESPs have one of the highest removal efficiency rates (99% or greater) of control technology to remove particulate matter. An additional benefit to the high removal efficiency was the flexibility of the dry ESP design. Dry ESPs can be designed to operate in many different stream conditions, temperatures, and pressures. While electrostatic precipitators were installed in a few plants but they had high capital costs and decreased efficiency in particulate matter collection became an issue once the ESP was designed and installed, sensitivity to fluctuations in operating conditions became the likely cause of performance degradation¹⁴. The composition of the fine dust consists mainly of alkali and lead chlorides, may limit the efficiency of ESPs. Conditioning the flue gas with additional moisture can usually reduce the problem. However, plate ESPs that are rapped or sprayed with water to remove dust from collection plates are commonly installed on BOFs¹⁵.

High energy Wet Scrubbers

A wet scrubber is an air pollution control device that removes PM from waste gas streams primarily through the impaction, diffusion, interception and/or absorption of the pollutant onto droplets of liquid.

¹⁴ www.epa.gov/ttncaaa1/t1/reports/sect5-2.pdf- accessed July 15, 2010.

¹⁵

[http://yosemite.epa.gov/oaqps/eogtrain.nsf/ae20ef1becae534385256b4100770781/3cf51317b4891fcb85256b66004e90e/\\$FILE/12bles5.pdf](http://yosemite.epa.gov/oaqps/eogtrain.nsf/ae20ef1becae534385256b4100770781/3cf51317b4891fcb85256b66004e90e/$FILE/12bles5.pdf)- Industrial Application of ESPs-accessed July 9, 2010

The liquid containing the pollutant is then collected for disposal. There are numerous types of wet scrubbers that remove PM. Collection efficiencies for wet scrubbers vary with the particle size distribution of the waste gas stream. In general, collection efficiency decreases as the PM size decreases. Collection efficiencies also vary with scrubber type. Collection efficiencies range from greater than 99% for Venturi scrubbers to 40-60% (or lower) for simple spray towers. Wet scrubbers are particularly useful in the removal of PM with the following characteristics:

- (1) Sticky and/or hygroscopic materials (materials that readily absorb water);
- (2) Combustible, corrosive and explosive materials;
- (3) Particles which are difficult to remove in their dry form;
- (4) PM in the presence of soluble gases; and
- (5) PM in waste gas streams with high moisture content.

While Venturi Scrubbers are a technically feasible option and can achieve desirable particulate collection efficiency (90% or better), this is achieved through a significant pressure drop (ranging from 6 - 20 inches of water). Wet scrubbers have low capital costs and require small spaces to install. They can be used to treat high temperature and high humidity air streams and have the capability to capture both air and sticky particulates. However they have high operating costs, require a pre-cleaner for heavier dust loadings, cause water pollution and are likely to erode at high velocities ¹⁶. There are some properties of the particulate generated in the EAF that are not characteristics of the particulate which yields greater efficiency in the high energy scrubbers, therefore it is not guaranteed the high-energy scrubber would yield a desired efficiency.

Fabric Filters (Baghouses)

As mentioned above, a fabric filter (also known as a baghouse) is one of the most efficient means of separating particles from a gas stream. The advantage of fabric filters is that the efficiency is largely insensitive to the physical characteristics of the gas stream and changes in the dust loading. Searches of permits via the RBLC yielded that both positive and negative pressure baghouses are used at various facilities in the steelmaking industry. Baghouses are technically feasible for collecting fine particulate matter emissions associated with metals from EAFs that have high particulate emissions. They can also achieve the highest control efficiency, among other particulate control devices, as applied to EAFs. Moreover, baghouses are good at removing PM_{2.5}.

¹⁶ <http://www.dustcollectorexports.com/scrubber/> -Standard Design of a Spray Tower or Packed Bed Wet Scrubber for Steel Mills-accessed July 9, 2010

Step 3: Rank Remaining Technically Feasible Control Options

Control Technology	Percent Efficiency	Rank
High Energy Wet Scrubber	40-60% (spray towers) 92-98% (Venturi)	3
Electrostatic Precipitator	Approximately 99% (on clean plates)	2
Fabric Filter (baghouse)	98%-99%	1

Step 4: Evaluate Remaining Control Technologies

The ESP met the criteria of being able to attain the desired collection efficiency, flexibility in control technology design allowing it to be operational, however the inflexibility of operation and challenges such as iron compound removal from the plates. Dry ESPs can be designed to operate in many different stream conditions, temperatures, and pressures. While electrostatic precipitators were installed in a few plants but they had higher capital costs and decreased efficiency in particulate matter collection became an issue once the ESP was designed and installed, sensitivity to fluctuations in operating conditions became the likely cause of performance degradation¹⁷. There were also concerns in the large fluctuation in efficiency; therefore the Division determined this control technology would not be operationally feasible.

The high energy wet scrubber, namely the Venturi scrubber met the criteria of being able to attain the desired collection efficiency, it also met the criteria to handle stack gases of higher velocities and temperatures, however the Venturi scrubber was unable to meet the adaptability quotient, whereas control efficiency is compromised by differences in gas flowrate and temperature as gases from EAF charges are not batch operations. Therefore, the Division determined this control technology would not be operationally feasible.

As mentioned above, baghouses are technically feasible for collecting fine particulate matter emissions associated with metals from EAFs that have high particulate emissions. Based on the criteria used to determine technical and operational feasibility, the baghouse was able to accommodate the particulate size to be collected, the particle loading and the changes in stack gas flow rate in addition to the presence of reactive materials within the composition of the stack gas as well as achieved the desired collection efficiency. Based on meeting those criteria in addition to not having to address additional environmental or economic concerns resulting from use of electricity like one would have to do with a high energy wet scrubber, the baghouse is technically and operationally feasible, plus baghouse installations are the industry standard for EAF particulate controls.

Conclusion – PM Control

The Division has determined that the installation of high-temperature baghouses as a means to control PM emissions constitutes BACT. This PM BACT limit applies during all periods of the EAF heat cycle, including startup, shutdown and malfunction. The baghouse must be in use during all times the electric arc furnace is in operation. Bag leak detectors are required for baghouses to detect an increase in PM emissions.

¹⁷ www.epa.gov/ttncaaa1/t1/reports/sect5-2.pdf- accessed July 15, 2010.

The BACT selection for the Electric Arc Furnace (EAF) is summarized below in Table 4-6:

Table 4-7: BACT Summary for PM Emissions for the Electric Arc Furnace (Source Code EAF)

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
PM (condensable and filterable)	Fabric filter (baghouse)	0.0026 gr/dscf with 0.0008 gr/dscf (condensable) 0.0018 gr/dscf (filterable)	3 hours	Performance Test

Electric Arc Furnace (EAF) – SO₂ Emissions

Sulfur dioxide (SO₂) emissions are mainly associated with combustion of sulfur compounds charged in the EAF. SO₂ is attributable to the sulfur content of the scrap, carbon electrode, the sulfur in the raw material charged in the EAF and to a lesser extent, the sulfur content of the oil on the scrap steel, in addition to the sulfur-content in the available fuel.

Applicant's Proposal

Step 1: Identify all control technologies

The alternatives that are potentially available to control SO₂ emissions from the EAF include the following:

- Charge substitution
- Flue gas desulfurization (FGD) options, including wet scrubbing, spray dryer absorption (SDA), and dry sorbent injection (DSI)
- Inclusion of additives to the charge to adsorb SO₂ (lime addition)

Step 2: Eliminate Technically Infeasible Options

The test for technical feasibility of any control option is whether it is both available and applicable to reducing SO₂ emissions from the EAF. The previously listed information resources were consulted to determine the extent of applicability of each identified control alternative.

Charge Substitution

SO₂ emissions are directly related to the amount of sulfur charged to the EAF. Types of material used in the charge that contain sulfur are: scrap, directed reduced iron, pig iron, injection carbon, carbon charge, chipped, tired, coal and petroleum coke. Scrap metal has inherently low sulfur content (0.003 to 0.07%), whereas injection coal, tired and petroleum which will be used by Osceola can have sulfur contents in the 2.5 to 3% range and potentially higher.

Flue Gas Desulfurization

FGD systems currently in use for SO₂ abatement can be classified as wet or dry systems. Review of the RBLC database and discussions with various individuals knowledgeable about steel mill operations indicate that control technologies for SO₂ abatement have not been successfully implemented for EAFs. However, FGD operations have been successfully applied to utility boilers. Therefore, the application of these technologies to the EAF is examined further.

In reviewing the following FGD options it is important to remember that the concentration of SO₂ in the exhaust gases is in the 10 ppm range as opposed to the 1,000 ppm range for coal-fired power plants. This greatly reduces the potential removal effectiveness for any type of scrubbing system.

Wet Scrubbing

Wet scrubbers are regenerative processes that are designed to maximize contact between the exhaust gas and an absorbing liquid. The exhaust gas is scrubbed with a 5% to 15% slurry, composed of lime (CaO) or limestone (CaCO₃) in suspension. The SO₂ in the exhaust gas reacts with the CaO or CaCO₃ to form calcium sulfite (CaSO₃) and calcium sulfate (CaSO₄). The scrubbing liquor is continuously recycled to the scrubbing tower after fresh CaO or CaCO₃ has been added.

The types of scrubbers that can adequately disperse the scrubbing liquid include packed towers, plate or tray towers, spray chambers, and venturi scrubbers. In addition to CaSO_3 or CaSO_4 , numerous other absorbents are available including sodium solutions and NH_3 -based solutions.

Various operating problems are associated with the use of wet scrubbers to control SO_2 emissions from an EAF. Particulates can plug spray nozzles, packing plates, and trays. Wet scrubbers also require handling, treatment, and disposal of a sludge by-product. In this case, air emissions would be exchanged for a large-scale water treatment requirement. The volumetric exhaust gas flow rate from the EAF would be approximately 350,000 dscfm. When coupled with the relatively low SO_2 emission rate, a relatively small SO_2 concentration in the exhaust would result. The SO_2 concentration would also vary widely over the EAF cycle. This would preclude efficient application of wet scrubbing. Osceola is not aware of any wet scrubbing system used on an EAF due to the technical difficulties with this type of installation. In view of the above limitations, the wet scrubber option is precluded from further consideration in this BACT analysis.

Spray Dryer Absorption

An alternative to wet scrubbing is a process known as dry scrubbing, or SDA. As in wet scrubbing, the gas-phase SO_2 is removed by intimate contact with the suitable absorbing media. Typically, this may be an aqueous solution of sodium carbonate (NaCO_3) or slaked lime [$\text{Ca}(\text{OH})_2$]. In SDA systems the solution is pumped to atomizers, which create a spray of very fine droplets. The droplets mix with the incoming SO_2 -laden EAF exhaust gas in a very large chamber, and subsequent absorption leads to the formation of sulfites and sulfates in the droplets. Almost simultaneously, the sensible heat of the exhaust gas that enters the chamber evaporates the water in the droplets, forming a dry powder before the gas leaves the spray dryer. The temperature of the desulfurized gas stream leaving the spray dryer then approaches its dew point. For this application, the exhaust gas temperature would be approximately 150 degrees F before entry to the baghouse. This temperature is too low for the effective operation of an SDA system.

The exhaust gas from the SDA system contains a particulate mixture that includes reacted products. Typically, baghouses employing Teflon-coated fiberglass bags (to minimize bag corrosion) are used to collect the precipitated particulates.

Although the SDA process would not have the wastewater treatment and disposal problems associated with the wet scrubbing systems, the SO_2 concentrations would be very low and would vary widely over the EAF cycle, precluding efficient application of SDA systems. Also, the temperature of the exhaust gas stream would be too low for effective operation. In view of the above limitations, the SDA dry scrubbing option is technically not feasible and is precluded from further consideration in this BACT analysis.

Dry Sorbent Injection (DSI)

This control option typically involves the injection of dry powders into either the furnace or post-furnace region of utility sized boilers. This process was developed as a lower-cost option to conventional FGD technology. Because the sorbent is injected directly into the exhaust gas stream, the mixing offered by the dry scrubber tower is not achieved. The maximum efficiency realized for this SO_2 control technology is estimated to be less than 50%.

As in SDA technology, DSI would not result in wastewater treatment and disposal problems associated with the wet scrubbing systems. However, because of the very low SO_2 emission concentrations in the exhaust gas and the fact that the SO_2 concentration will vary widely over the EAF cycle, it would not be feasible to design an efficient application of DSI systems. In view of the above limitations, the DSI option is technically not feasible and is precluded from further consideration in this BACT analysis.

Chemical Additives

One function of the CaO that is added to the charge is that it combines and reacts with various contaminants such as sulfur compounds, and this sulfur is then adsorbed into the slag layer of the melt. This slag is then poured off and handled as solid material. Osceola will use the proper amount of CaO addition to optimize sulfur capture.

Step 3: Rank Remaining Technically Feasible Control Options

Various control alternatives were reviewed for technical feasibility in controlling SO₂ emissions from the EAF. Each of the potential control options was considered technically infeasible except for chemical addition.

Step 4: Evaluate Remaining Control Technologies

Not applicable because the addition of chemicals is the only technically feasible control technology.

Step 5: Selection of BACT

The existing SO₂ limits range from 0.07 to 1.8 lb/ton. These limits are derived based on the product to be produced, which dictates the type of material charged to the EAF. Osceola is proposing one of the lower limits for SO₂ emissions from an EAF at 0.2 lb/ton. The USEPA RBLC database and state BACT determinations have been summarized in Table 4.8.

Table 4-8: RBLC Summary for SO₂ Emission Limits for the Electric Arc Furnace (Source Code EAF)

Facility Name	Date of Issuance	Control Technology	SO ₂ Emission Limit (lb/ton)
Nucor Steel (Ohio)	8/2005	--	0.0571
Nucor Yamato Steel Company (Arkansas)	6/2004	Low sulfur coke usage	0.1500
Charter Steel Division (Wisconsin)	6/2000	Limit to Avoid PSD	0.1760
Timken Company-Faircrest (Ohio)	7/2004	--	0.1500
Thyssen Krupp Steel (Alabama)	8/2007	--	0.1500
Hoegannes Corp, (Tennessee)	2/2000	Low Sulfur Content fuel limited to 0.25%	12.6 lb/hr
Republic Technologies International (Ohio)	1/1999	--	0.0700

Facilities with listed limits lower than those proposed by Osceola are discussed as follows:

Republic Technologies, Ohio-The SO₂ rate was given in lb/hr and estimated at 0.07 lb/ton. According to the notes in the RBLC, the permit modification was for NO_x only; therefore this SO₂ limit is not a BACT determination and believed to be in error. Because the facility does not have to verify compliance with a lb/ton value, it is difficult to compare.

Charter Steel, Wisconsin- Has a limit of 0.176 lb/ton. This limit is not BACT but was taken to be synthetic minor for SO₂.

Hoegannes Corp, Tennessee-A review of the Title V Permit for the facility found the unit is not limited to 0.07 lb/ton, but instead is limited to an hourly emission rate of 12.6 lb/hr. The permit does not require any compliance testing for SO₂ limit.

Roanoke Steel, Virginia-The SO₂ rate was given in lb/hr and estimated at 0.168 lb/ton. Again, the permit does not list a lb/ton value; therefore the unit does not have to test to verify this as a limit.

Nucor Utah, Nucor-Yamato Arkansas and Timken, Ohio-All have estimated SO₂ rate of 0.15 lb/ton. For the Ohio and Utah facilities, these values are not based on BACT, but state imposed permit limits. Also, the Nucor facility has limits listed in lb/hr only.

Osceola is proposing an SO₂ emission rate of 0.2 lb/ton of steel produced. This limit is based on the type of materials that will be charged to the EAF and lime, which will provide for the capture of much of the sulfur entering the system through the steel or sources of carbon. This value is comparable and/or less than limits for several recent permits issued as BACT in the RBLC database. For example, SDI, Hendricks, Beta Steel ECO Steel Recycling-Armory MS and Nucor-Indiana were issued permits in 2003 or later with SO₂ limits above the level proposed for this project. More recently Thyssen Krupp Steel-Alabama and the Bluewater Project-Arkansas were issued permits at the proposed level.

In conclusion, BACT for controlling SO₂ emissions from the EAF is an SO₂ emission rate of 0.20 lb/ton of steel produced. This value is consistent with other recent BACT determinations.

EPD Review – SO₂ Control

Step 1: Identify all control technologies

General recommended techniques to prevent and control the generation of SO₂ emissions include the following:

- Selection of raw feed with low sulfur content;
- Minimizing the sulfur content of the fuel;
- Addition of absorbents such as hydrated lime [Ca(OH)₂], calcium oxide (CaO), or fly ashes with high CaO content injected into the exhaust gas outlet before filtration;
- Use of a wet-scrubber injection of a slurry mix containing calcium carbonate (CaCO₃), CaO, or Ca(OH)₂;
- Use of a dry scrubber

Step 2: Eliminate Technically Infeasible Options

Selection of raw feed with low sulfur content:

Scrap metal has inherently low sulfur content (0.003 to 0.07%), According to Application 19507, Osceola Steel Company plans to use injection coal, tires and petroleum materials containing sulfur content between 2.5 to 3% range and potentially higher. Osceola Steel Mill provided no additional reasoning behind not selecting alternative raw feed materials with lower sulfur content such as:

- Anthracite Coal (which can be found in numerous locations throughout the US and world)

In the USA the majority of commercially available Anthracite Coal is found in Pennsylvania. The Fixed Carbon Content of Pennsylvania Anthracite Coal is 66 – 87%, Volatile Content is 5 – 9% and Sulfur Content is 0.5 – 1%. There are 8 sizes that are of interest to the Steel Industry ranging in size from 2 5/8” down to – 16 mesh.

- Metallurgical Coke

It is porous with good strength, the smaller size $< \frac{3}{4}$ ” is what is known as Coke Breeze and this is the product used in EAF steelmaking. It has a fixed Carbon Content 80 – 90%, Volatile Content 1 – 5% and Sulfur Content 0.5 – 1.5%, however it is a more abrasive material compared to other carbons.

The technique of Foaming Slag (Injection-based Carbon) in the EAF is used to increase productivity; lower operating costs and increases the quality of steel produced. The Foamy Slag Practice using carbon has become standard practice for most EAF melting. Carbon combines with oxygen in the slag or in the molten steel (introduced via lance) and generates CO and CO₂. This is an exothermic reaction, which generates heat. The evolved gasses cause the viscous slag to boil and expand dramatically in volume.

Both anthracite and metallurgical coke have a low cost per lb of fixed carbon and have sulfur contents less than the 2.5-3.0% or greater proposed sulfur content of materials claimed by Osceola Steel Company.

No additional information was provided by Osceola Steel Company justifying the high sulfur content for materials to be used for charging the EAF as opposed to seeking a mixture of charging materials that had a lower sulfur content than 2.5-3.0% and information and data is readily available supporting the use of low-sulfur charging materials, therefore the Division cannot find this option technically infeasible.

Minimizing the sulfur content of the fuel:

Osceola Steel Company proposes to use natural gas to fire the EAF; therefore the sulfur content in natural gas is negligible.

Addition of absorbents into the exhaust gas outlet before filtration:

EAF slag performs a variety of functions: insulates the steel bath to reduce heat losses; absorbs the products of oxidation from the steel (FeO, Al₂O₃, SiO₂, P₂O₅, etc); covers the electrical arc to facilitate the transfer of electrical energy to the bath and protects the lining or the panels on the furnace sides and roof; and protects the steel bath from picking up undesired gases such as hydrogen and nitrogen.

It has been determined that the key to improved performance for electric arc furnace steel producers has been the optimization of foamy slag practices, these practices provide benefits such as saving electrical energy, improved arc stability, reduced noise, improved productivity, lower nitrogen levels and increased refractory life in the furnace. As previously mentioned, a function of the adsorbant that is added to the charge is that it combines and reacts with various contaminants such as sulfur compounds, and this sulfur is then adsorbed into the slag layer of the melt. The slag is poured off and handled as solid material allowing for easier disposal or reuse.

Models and slag calculators were developed under the auspices of the SMA and various suppliers to the steel industry as an aid to steelmakers for a scientific approach in slagmaking and monitoring of foamy slag performance instead of the “sight and sound” only that was used by operators. These models allows the steelmaker to consider the changes in the steelmaking process by input of data relating to mass balance concepts, utilizing real time slag analysis, and scientific recommended changes in flux to achieve optimum foamy slag conditions. Examples of these efforts can be seen in work achieved by the Albany

Research Center, Dr. David Schroeder of Schroeder and Associates, and LWB Refractories efforts through Helmut Oltmann and Eugene Pretorius. Electrode manufacturers and several steel industries have offered equipment suppliers instruments and software to monitor foamy slag in real time. This technology is commonly used in the steelmaking industry with continuous success, thus the Division finds this option technically feasible.

Flue gas desulfurization (FGD) options, including wet scrubbing, spray dryer absorption (SDA), and dry sorbent injection (DSI)

Scrubbers are capable of reduction efficiencies in the range of 50%-98%. The highest removal efficiencies occur with wet scrubbers with greater than 90% efficiency and the lowest occurs with dry scrubbers with a removal efficiency of less than 80%, however newer dry scrubbers have been able to achieve removal efficiencies of around 90%.

Scrubber technology has typically been used in coal-powered and oil fired combustion sources such as: utility and industrial boilers, as well as other industrial combustion units such as medical and waste incinerators, cement and lime kilns, metal smelters, petroleum refineries, glass furnaces and H₂SO₄ manufacturing facilities. Approximately 85% of the FGD systems installed in the U.S. are wet systems, 12% are spray dry systems and 3% are dry systems.

While FGD options are a highly efficient technology that can prove to be useful in removing SO₂ from the flue gas, there are certain characteristics of flue gases the FGD technology would require in order to effectively remove SO₂ from the gas stream. These characteristics aren't limited to:

- Combustion Unit Size
- Temperature
- Pollutant Loading
- Composition of Flue Gas

While scrubbers have been applied to units ranging from 50MMBtu/hr to 3,000MMBtu/hr, wet scrubbers have a typical gas inlet temperature of approximately 300-700 degrees F, which is significantly less than the gas inlet temperature on the gas inlet stream for the EAF, dry sorbent injection (DSI) has a wider temperature range of 300 to 1800 degrees F, depending on the properties of the sorbent injected. The temperature range for the use of DSI would fall into the operating temperature of the EAF, however reliability becomes an issue because SO₂ scrubbers are limited to dilute streams containing a concentration of SO₂ around 2000ppm, where the concentration of SO₂ emission in the exhaust gas is significantly lower and the fact that the SO₂ concentration will vary widely over the EAF cycle, the Division agrees with Osceola Steel it would not be feasible to design an efficient application of DSI systems for this process within pursuing further investigation of the control technology.

Step 3: Rank Remaining Technically Feasible Control Options

<u>Control Technology</u>	<u>Percent Efficiency</u>	<u>Rank</u>
Selection of raw feed with low sulfur content	Baseline	3
Minimizing the sulfur content of the fuel	Baseline	2*
Addition of absorbents into the exhaust gas outlet before filtration	Baseline	1

* This is ranked as a sole means of controlling SO₂ emissions, not in conjunction with other control technologies.

Step 4: Evaluate Remaining Control Technologies

The selection of a raw feed with low sulfur content is a viable technology, in the respect that the technology has been used in the steelmaking process and there is data available to determine the rate of

SO₂ emissions from changing to feed material with lower sulfur content. This control technology was ranked third due to the limitations that arise when preferred materials are unavailable or it is economically prohibitive to acquire low-sulfur feed materials for the EAF.

Minimizing the sulfur content of the fuel used to fire the EAF is also a technically viable means of controlling SO₂ emissions, however SO₂ emissions from combustion would only be the only SO₂ emissions that would be controlled. The SO₂ emissions from the charging of the EAF are left unaccounted. This technology was ranked second due to the fact that unlike modifying the feed composition, it is less cost prohibitive as well as low sulfur fuels are more readily available than locating finite resources like low sulfur content feed. This control technology was ranked second because minimizing the sulfur content in the fuel only addresses SO₂ emissions from combustion and not SO₂ emissions from actual charging of the EAF which constitutes the majority of the SO₂ emissions from the EAF.

The addition of adsorbents such as calcium oxide (CaO) into the slag layer thus improving the foaming slag process is a technically viable means of controlling SO₂ emissions from the EAF, because of the reactivity with various contaminants such as sulfur compounds, and this sulfur is then adsorbed into the slag layer of the melt. This slag is then poured off and handled as solid material. This technology was ranked first because it addresses the SO₂ emissions associated with the charging process within the EAF, which constitutes the majority of the SO₂ emissions. However, the same issue arises with the addition of adsorbents as it did for minimizing the sulfur content of the fuel, which is only one of the two sources of SO₂ emissions from the EAF are addressed, therefore the Division proposes to incorporate both the minimization of the fuel sulfur content in addition to the addition of a determined ratio of CaO to the slag layer to increase the absorption of SO₂ during the charge process.

Conclusion – SO₂ Control

The Division has determined that the combination of minimizing the sulfur content of the fuel through the use of natural gas to fuel the EAF and the addition of adsorbants such as CaO to react with sulfur compounds, which pulls the sulfur into the slag layer as a means to control SO₂ emissions, constitutes BACT. This SO₂ BACT limit applies during all periods of the EAF heat cycle, including startup, shutdown and malfunction. The Division disagrees with Osceola Steel Company's proposal for a 0.20 lb/ton SO₂ limit for the EAF because insufficient reasoning behind the disregard of Chaparral Steel of Wisconsin's BACT limit of 0.176 lb/ton in addition to the disregard Nucor Utah, Nucor-Yamato Arkansas and Timken, Ohio which all have estimated SO₂ rates of 0.15 lb/ton. Even though the Ohio and Utah facilities, have values that are not based on BACT, but state imposed permit limits. Although this limit is not a BACT limit, the limit has been verified and compliance with the limit has been demonstrated, therefore precedent has been established for this limit.

Table 4-9: BACT Summary for SO₂ Emissions for the Electric Arc Furnace (Source Code EAF)

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
SO ₂	Use of low sulfur containing feed materials	Sulfur content of 2.0%	N/A	Vendor Certification or Fuel Analysis
SO ₂	Use of low-sulfur containing fuels	0.1500 lb/ton	24 hours	Performance Test

Reheat Furnace (RHF)- Background

The Reheat Furnace (Source Code RHF) has a proposed construction and installation date of 2011. According to Application 19537, the reheat furnace will fire natural gas with a design capacity of 75 MMBtu/hr heat input. Osceola will operate a reheat furnace to reheat the steel before entering the rolling mill. The reheat furnace will employ a hot charge system, which will allow the reheat furnace to process steel as soon as it exits the continuous casting machine and thereby reduce the amount of fuel required. The function of the reheat furnaces is to heat the steel billets to the correct temperature so that they can be rolled into longer bars through a series of reduction rolling mills. The reheat furnaces must be able to handle all sizes and grades. The steel must be heated to a specific temperature so that it will assume the properties that will allow it to be rolled into the proper shape. The furnace will have very distinct radiant and convection heating zones. The length of time that the steel will spend in each zone of a furnace and the temperature to which the steel will be exposed depends on many variables such as entry billet temperature, casting rate, and rolling rate. The quantity and concentration of emissions leaving the furnaces will vary, depending on the steel characteristics and desired properties. The furnaces will be fueled only with natural gas; therefore, because of the use of this clean fuel particulate, and SO₂ emissions are proposed to be negligible.

Reheat Furnace (RHF) – CO Emissions

Reheat furnaces also are subject to significant variability in emissions. One reason for this is the type of burners employed (*e.g.*, low NO_x, ultra-low NO_x). In addition, there are other major factors that influence emissions from reheat furnaces. For example, the physical size of the reheat furnace and the type of product (*e.g.*, rod, bar, beam, plate) manufactured by the facility influence emissions. Some products require large doors to allow the product to be inserted into and ultimately extracted from the reheat furnace. The larger door openings typically will result in greater emissions of various pollutants. The configuration of burners (*i.e.*, the number, location and relative firing rate) within the furnace also has an effect on emissions and is dictated by the product being manufactured.

Applicant's Proposal

Step 1: Identify all control technologies

CO is a result of incomplete combustion; therefore, it can typically be minimized through the use of good combustion practices including assurance of sufficient air to fuel ratios. Good combustion practices can be enhanced using staged combustion, which involves the injection of combustion air at different areas of the burners. Beyond combustion controls, the remaining CO could be oxidized to carbon dioxide (CO₂) in a second downstream control device. Installing an oxidizer or afterburner downstream of the device could reduce large quantities of CO. This is practiced whenever CO levels are elevated above 1,000 ppm, such as in certain chemical processes or combustion units that have a wet fuel or for some reason promote incomplete combustion. In the case of a gas fired burner, an afterburner or downstream oxidizer would be of no benefit because CO emissions typically are less than 100 ppm, and further oxidation would generate more NO_x emissions and have little impact on the CO. One add-on technology that potentially reduces CO emissions is the addition of a catalytic oxidizer, which would allow the oxidation process to occur at a lower temperature by moving the gases across a bed of catalyst material (usually consisting of a precious metal such as palladium).

Step 2: Eliminate Technically Infeasible Options

Other than good combustion practices, CO emissions could be further reduced through the addition of an oxidation technology such as a catalytic oxidizer. This is a transfer technology from industrial boiler control, but has never been attempted on a reheat furnace. Judging from the results of trials with SCRs, which are also catalytic units, the expected operation of such a bed would not approach its stated control

efficiency of 80% reduction. In addition, if this technology were feasible, the exhaust gas stream temperature would be significantly higher for an oxidation catalyst to be effective. At exhaust gas temperatures below 800oF, the oxidation catalyst becomes ineffective. The exhaust temperature of the reheat furnaces would range from 380oF to 600 oF depending on the phase of the process and the type of charge (hot or cold) and will also vary depending on the amount of heat recovery achieved (the exhaust gases are used to preheat the inlet air). An oxidation catalyst would, therefore, be ineffective at reducing CO emissions unless the exhaust gas temperature was raised considerably by reheating. Raising the temperature of the gases would require significant additional fuel firing or through reducing the amount of heat recovery which in effect increase fuel usage (and therefore emissions) on the furnace. The resulting increases of a higher priority pollutant such as NO_x would not justify the reduction in CO that would result. Based on these energy and environmental costs, oxidation alone or with a catalyst is not considered feasible or beneficial.

Step 3: Rank Remaining Technically Feasible Control Options

Good combustion operations practices are considered the only feasible control method.

Step 4: Evaluate Remaining Control Technologies

The RBLC database was searched to find CO emissions limits and controls that are currently in place for the reheat furnaces. As discussed, the only technology in use for minimizing CO emissions from reheat furnaces is good combustion operation practices. The lowest confirmed CO emission limit is 0.035 lb/MMBtu. One listing lower than this was for 0.0114 lb/MMBtu, but a check of the permit for this unit found this listing to be in error; it should have read 0.084 lb/MMBtu.

Table 4-10: RBLC Summary for CO Emissions Limit for the Reheat Furnace (Source Code RHF)

Facility Name	Date of Issuance	Control Technology	CO Emission Limit (lb/MMBtu)
Charter Steel Division (Wisconsin)	2/1997	Good combustion practices	0.114 *permit states limit is 0.084
Nucor Steel Division (Nebraska)	6/2004	--	0.0350
Nucor Steel Division (Nebraska)	6/2004	--	0.0350

Step 5 – Selection of BACT

Osceola will be installing ultra-low NO_x burners (ULNBs) with good combustion operating practices to meet the CO BACT of 0.035 lb/MMBtu.

EPD Review – CO Control

Step 1: Identify all control technologies

Internet Searches and verification of searches in the RBLC, the only control technology that could be used to control CO emissions from a reheat furnace is the use of good combustion practices, ensuring the fuel is burned at the appropriate stoichiometric ratio (air to fuel) to ensure a complete combustion.

Step 2: Eliminate Technically Infeasible Options

No other technology directly used on reheat furnaces was discovered during technical paper reviews, Internet searches and review of the RBLC, there are no options to eliminate.

Step 3: Rank Remaining Technically Feasible Control Options

The Division agrees that good combustion practices are considered the only technologically feasible control method.

Step 4: Evaluate Remaining Control Technologies

Not applicable

Conclusion – CO Control

Based on searches in the RBLC and verification of the Charter Steel Division permit's CO emission limit of 0.114 lb/MMBtu which was erroneously entered into the RBLC, the correct value is 0.084 lb/MMBtu as stated by Osceola Steel, therefore the Division accepts the proposed BACT limit of 0.035 lb/MMBtu

Table 4-11: BACT Summary for the Reheat Furnace (Source Code RHF)

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
CO	Good Combustion Practices	0.035 lb/MMBtu	N/A	Vendor Specifications or Fuel Analysis

Reheat Furnace (RHF) – NO_x Emissions

Most reheat furnaces are either recuperative- or regenerative fired, (i.e., they preheat the combustion air in order to increase fuel efficiency). Some reheating furnaces use cold combustion air. The temperature of the combustion air has a large impact on uncontrolled NO_x emissions. Increasing the combustion air temperature from 38 EC (100 EF) to 540E C (1,000 EF), for example, will increase uncontrolled NO_x emissions by a factor of about 6¹⁸. Combustion air preheated in regenerators has a much higher temperature than air preheated in recuperators. While the higher combustion air temperature increases furnace fuel efficiency, it also increases NO_x generation and NO_x emissions. Consequently, regenerative-firing is not usually practiced without combustion modifications for NO_x control, but there may be exceptions.

Control techniques for NO_x emissions can be placed into one of two basic categories: techniques designed to minimize NO_x generation and techniques designed to remove previously generated NO_x from the waste effluent stream. Combustion modification techniques, including low NO burners (LNB's) and flue gas recirculation (FGR), fit into the first category. Add-on flue gas treatment techniques such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) are examples of the second.

Applicant's Proposal

Step 1: Identify all control technologies

Nitrogen oxides (NO_x) are products of combustion in the reheat furnace. Because there is little fuel bound nitrogen in the natural gas fuel, NO_x is generally formed in combustion processes by a process known as thermal NO_x. Thermal NO_x is the direct conversion of the nitrogen in the combustion air to NO_x due to the high temperatures within the flame region. The volume of thermal NO_x being formed is largely dependent on temperatures in the flame zone of the burner.

NO_x control technologies include combustion control techniques such as operating with low excess air or operating staged combustion technologies to reduce combustion temperatures in the flame zone. Low NO_x burners use staged combustion; in the first stage, the fuel is burned in an oxygen-lean environment to reduce combustion temperature, which is then followed by a more oxygen rich stage to complete the combustion process. The net effect of this is to reduce temperatures in the hottest portion of the flame zone and thereby reduce thermal NO_x. The ultra-low NO_x levels will be achieved by combining air staging with fuel pre-mixing to minimize dependency on excess air levels, a common problem on other staged "low NO_x" burners. This results in a reduction of the temperatures in the combustion zone and in turn reduces thermal NO_x.

Flue Gas Recirculation (FGR) is also a common technology used to reduce NO_x emissions in some combustion operations. FGR, which also lowers flame temperature, is typically practiced in boiler operations but generally is not feasible in a reheat furnace. In a boiler, there are a small number of burners that exhaust out of a single stack, which makes it easy to recirculate the exhaust from the flue to the intake of the burner. However, in a reheat furnace, there are many burners located in numerous different areas surrounding the entire furnace volume (floor, walls and ceiling) to provide a specific temperature for each zone in the furnace. That temperature setting may vary, depending on the grade of steel. The exhaust from all burners in the furnace vent through a common flue. The resulting exhaust gas leaving the furnace is then an average exhaust from all the burners that would have to be manifolded back to each

¹⁸ U.S. Environmental Protection Agency-Office of Air and Radiation-Office of Air Quality Planning and Standards
Alternative Control Techniques Document -NO_x Emissions from Iron and Steel Mills
http://www.epa.gov/ttn/catc/dir1/iron_act.pdf

burner. The operation of each burner would then have to be compensated differently to meet the specific temperature setting for the burner required.

In addition to these combustion controls, a few add-on control technologies have been successful in controlling NO_x from some combustion operations. These include selective non-catalytic reduction (SNCR), selective catalytic reduction (SCR), and oxidation/reduction scrubbing. In SNCR, urea or ammonia (NH₃) is injected into the furnace in the combustion zone so that the urea or NH₃ mixes with the combustion gases where the temperatures are between 1,600 to 1,900 °F. When injected, the NH₃ and NO_x that was formed at higher temperatures breaks down to form nitrogen and water. This reaction can only occur within the temperature ranges found within the combustion chamber. How effective the process is at reducing NO_x depends on how well the gases mix and the temperature. Reduction efficiencies for this process vary from 20 to 70% depending on the application.

SCR also uses NH₃/urea injection to complete the same reaction, but the reaction occurs in a large catalytic bed downstream of the combustion device. The flue gases must be within a certain temperature range (typically between 500 to 800 °F) for the process to work, depending on the specific catalyst. SCR units have been able to reduce NO_x emissions from boiler applications by as much as 90%. Both of these technologies have been successfully used to control NO_x emissions from boilers but, due to the geometry of the reheat furnace, SNCR is not a viable control technology. The injection of NH₃ or urea at each burner would not likely result in lower NO_x because the furnace will be a large open volume (compared to a combustion chamber in a boiler), so the potential for NH₃ mixing with the NO_x at the right temperature is unlikely. Therefore, SNCR is not a viable technology, but SCR in which the entire exhaust stream is treated is a viable technology. One negative impact of this technology is NH₃ emissions. Some unreacted NH₃ will always leave the process and vent out the stack. Concentrations of NH₃ in the exhaust gas typically are less than 10 ppm.

One other add-on control technology that has been successful in reducing NO_x in certain specialized applications is a NO_x scrubber. In an oxidation/reduction scrubber the gases are cooled to dew point temperature, and ozone is injected into the exhaust stream to oxidize the NO_x further to form nitrogen pentoxide (N₂O₅) that can be absorbed in a wet scrubber. The resulting scrubbant becomes a weak nitric acid solution, which can be neutralized with sodium hydroxide (NaOH). Such a scrubber would also control CO and SO₂ with the same mechanism. These scrubbers have a very limited application and their success is limited to exhausts with highly concentrated NO_x as in the chemical process industry, but are less successful when the stream contains relatively low concentrations, such as those from combustion processes such as the reheat furnace. This technology is not therefore considered viable for the reheat furnace.

Step 2 – Eliminate Technically Infeasible Options

The technologies deemed applicable in step 1 are low NO_x burners, ULNBs, and SCR technologies. Of these technologies, SCR is deemed infeasible. One reheat furnace that has an SCR in operation is the Beta Steel mill in Portage, Indiana, which manufactures hot-rolled coiled steel strip (band) carbon steel. The mill has a reheat furnace that is natural gas-fired with maximum heat input capacity for the burners of 264.6 MMBtu per hour (MMBtu/hr). When first permitted in the 1990s, the NO_x emissions were permitted to be 14.7 pounds per million standard cubic feet (lb/MMSCF) of natural gas burned or 0.015 lb/MMBtu, which was similar to what permitted boilers equipped with SCRs had been achieving at that time. This transfer technology seemed to be a direct application of a similar operation; however, on startup these low levels were never achieved. As much as seven times more NO_x than anticipated was emitted from the SCR. After much study and numerous attempts at process changes, Beta Steel and the state environmental agency concluded that SCR was not as successful as hoped for the following reasons:

1. The reheat furnace operation is a non-steady state operation; emission rates vary depending on the heat input rate and material being heated. This not only affects the emissions sent to the SCR but it also impacts the quantity and temperature of the exhaust gas sent to the unit. A catalytic bed is

designed for a certain distribution of reactant across the surface of the bed at a certain temperature. The more variations there are in these factors, the less effective the control technology becomes.

2. Varying flue gas temperature at the inlet of SCR caused fluctuations in the catalyst performance. The flue gas temperature drops to 750 oF, well beyond the optimum performance range for the catalyst near 800 oF.
3. The catalyst performance is affected due to deposition of PM from the flue gas stream. Some scale leaves the furnace that tends to plug the catalytic bed. Because it is not possible to run the gas through any kind of add-on control before the SCR, this deleterious operating factor is inherent to this application of SCR.

Because of these issues, the unit was repermited with a much higher NO_x emission limit of 0.077 lb/MMBtu based on one specific stack test. It is yet to be seen whether this level of performance can be achieved consistently. Because this emission rate is equivalent to or higher than the other comparable technologies, SCR is not considered further in this BACT analysis.

In addition to the technical hurdles with operating SCRs on reheat furnaces, there would be significant energy, cost, and environmental implications as well. The reheat furnaces utilize heat recovery, which allows for a significant amount of energy savings and reduces the overall energy consumption at the mill. SCRs, however, require a minimum inlet temperature of 500 °F in order to be effective. As the temperature drops below this level, the effectiveness will dropped significantly. The reheat furnace would, therefore, in effect need to have reduced energy efficiencies in order to have exhaust temperatures in the required temperature window. This derating would result in increased energy consumption at the furnace, which would correlate to increased operating costs and increased NO_x emissions as well as other products of combustion. The only alternative to this approach would be a complete reengineering of the furnace design to allow for the recovery of energy after the SCR.

As indicated previously, the SCR applications on reheat furnaces have had catalyst fouling because of scale from the steel. It is therefore expected that a baghouse would need to be operated after the reheat furnace, but prior to the SCR in order to prevent fouling of the catalyst bed. A cost analysis was completed for the installation of an SCR on the reheat furnaces. The installation and operating cost for an SCR were based on the EPA cost manual for SCR controls. These costs were proportioned to the reheat furnace application based on the estimated airflow rate through the SCR system. This is considered reasonable because both the capital and operating costs for the SCR would be expected to be proportional to air flow rate. The cost for the baghouse was based on the EPA cost estimation spreadsheets. The estimated emission level that can be achieved with ultra-low NO_x burners in this application is 0.08 lb/MMBtu. Based on the estimated costs for installing the SCR and the expected NO_x emission reductions, the installation of an SCR on the Reheat Furnace would reduce NO_x at a cost of roughly \$21,500/ton of NO_x respectively. Table 1 provides the basis for these cost estimates. This cost would not be considered cost effective, when compared to the typically accepted maximum cost effective value of \$10,000/ton of pollutant reduced. This high cost along with the associated increase in energy consumption, and increase in emissions from losses in energy recovery would make the application of SCR on the reheat furnace unreasonable.

Step 3 – Rank Remaining Technically Feasible Control Options

Low-NO_x burners and ULNBs that rely on staged combustion and premixing of air and fuel combustion techniques are the only remaining NO_x control techniques. Therefore, the control technology is limited to the type of burner that can achieve the performance necessary for this application.

Step 4 – Evaluate Remaining Control Technologies

A listing generated from the RBLC of NO_x emissions from reheat furnaces was consulted to determine the lowest emission rate permitted. Not all the emission limits have been demonstrated. The lowest listing is 0.064 lb/MMBtu, which is for a Nucor Steel furnace in Stanton, Nebraska. The control technology stated is ULNBs. The listing is for reheat furnace numbered NNII. When contacted about this listing, the state agency indicated that the furnace has not yet been constructed. The first furnace (source ID: NNI) was constructed in 2005 and was permitted at 0.096 lb/MMBtu (as listed on Table 5-5). The control method for this furnace is also listed as ULNBs. When asked about the permitting of these two emissions levels, the state permitting contact stated that the permitting concept was to have a second furnace built sometime in the future that would benefit from improved performance over the first one. NNI (listed at 0.096 lb/MMBtu) has been demonstrated to meet its permitted level of NO_x.

The second lowest listing is 0.07 lb/MMBtu for Nucor Steel Yamato in Blytheville, Arkansas, which also lists ULNBs for control technology. This level of emission has been verified from a single stack test. This Nucor Steel Yamato reheat furnace is used for heating billets to produce structural beams in the roll mill. This type of product and raw material tend to be a relatively consistent operation, because the grades of steel being heated are generally uniform. This is very different from the proposed Osceola reheat furnace that will process merchant based products which could involve small batches of specialty orders, which may require adjustments to the natural gas burners to compensate for the varying products. The impact on emissions due to this variation is unknown. The proposed BACT level of 0.075 lb/MMBtu matches the next lowest permitted level of 0.075 lb/MMBtu as permitted at Nucor Steel in Tuscaloosa, Alabama, and North American Stainless in Ghent, Kentucky.

Table 4-12: RBLC Summary for NO_x Emissions Limit for the Reheat Furnace (Source Code RHF)

Facility Name	Date of Issuance	Control Technology	NO _x Emission Limit (lb/MMBtu)
Nucor Steel Division (Nebraska)	6/2004	Ultra Low NO _x Burners	0.064
Nucor-Yamato Steel Company (Arkansas)	4/2005	Ultra Low NO _x Burners	0.07
Nucor Steel Tuscaloosa, Inc. (Alabama)	6/2006	Ultra Low NO _x Burners	0.075
North American Stainless (Kentucky)	12/2003	Low NO _x Burners	0.075
Beta Steel Corporation (Indiana)	5/2003	Low NO _x Burners and SCR	0.0755

Step 5 – Selection of BACT

The control technology that meets BACT is ULNBs. The add-on control technology of SCR, which is used for boiler operations, was found to be incompatible with the variable operation of a reheat furnace and therefore not technically achievable. In addition the application of this technology would be uneconomical if the additional controls were added to compensate for the technical flaws. Osceola proposes to use ULNBs in the furnace to the maximum extent possible. A serious concern is the large variation in the temperature of the billets entering the reheat furnace (from ambient to 1200 °F). This variation (which will occur on an hourly basis) along with different casting/rolling rates will create

nonsteady state conditions. It is expected that this variation will affect the NO_x emissions from the unit due to the throttling of the burners and the variation in heat patterns necessary to accommodate the grade changes. For this reason, a variability factor is being incorporated into the proposed BACT emission limit. Osceola is proposing 0.075 lb/MMBtu as a BACT emission level, which allows for process variability due to the daily grade changes of the steel entering the furnace.

The reheat furnace will employ a hot charge system, which will allow steel to enter the reheat furnace directly after leaving the continuous casting machine before the steel is allowed to cool down. This will allow the furnace to burn a minimum amount of natural gas as compared to processing a cold charge which would require the operation of the burners at a much high rate although the emission rate in lb/MMBtu will remain the same. This reduction in fuel usage will result in a corresponding reduction in total mass of NO_x emissions from the furnace; however, it will not reduce emissions on a lb/MMBtu basis.

EPD Review – NOx Control

Step 1: Identify all control technologies

Low NOx combustion controls (Ultra Low Nox Burner)

Ultra-low NOx burners refer to a class of burners recently developed to meet the South Coast Air Quality Management District (SCAQMD) Rule 1109 NO emission requirements. These burners may incorporate a variety of techniques including internal or self-recirculating flue gas (IFGR), steam injection, or a combination of techniques. These burners are designed to recirculate hot, O₂-depleted flue gas from the flame or firebox back into the combustion zone. This reduces the average O₂ concentration within the flame without reducing the flame temperature below temperature necessary for optimal combustion efficiency.

Selective Catalytic Reduction (SCR)

The SCR process chemically reduces the NOx molecule into molecular nitrogen and water vapor. A nitrogen-based reagent such as ammonia or urea is injected into the ductwork, downstream of the combustion unit. The waste gas mixes with the reagent and enters a reactor module containing catalyst. The hot flue gas and reagent diffuse through the catalyst. The reagent reacts selectively with the NOx within a specific temperature range and in the presence of the catalyst and oxygen.

Catalyst activity is a measure of the NOx reduction reaction rate. Catalyst activity is a function of many variables including catalyst composition and structure, diffusion rates, mass transfer rates, gas temperature, and gas composition. Catalyst deactivation is caused by:

- Poisoning of active sites by flue gas constituents,
- Thermal sintering of active sites due to high temperatures within reactor,
- Blinding/plugging/fouling of active sites by ammonia-sulfur salts and particulate matter, and
- Erosion due to high gas velocities.

Selective Non-Catalytic Reduction (SNCR)

SNCR is based on the chemical reduction of the NOx molecule into molecular nitrogen (N₂) and water vapor (H₂O). A nitrogen-based reducing agent (reagent), such as ammonia or urea, is injected into the post combustion flue gas. The reduction reaction with NOx is favored over other chemical reaction processes at temperatures ranging between 1600°F and 2100°F (870°C to 1150°C), therefore, it is considered a selective chemical process (EPA, 2002).

Both ammonia and urea are used as reagents. Urea-based systems have advantages over ammonia-based systems. Urea is non-toxic, less volatile liquid that can be stored and handled more safely. Urea solution droplets can penetrate farther into the flue gas when injected into the boiler, enhancing the mixing with the flue gas, which is difficult in large boilers. However, urea is more expensive than ammonia. The Normalized Stoichiometric Ratio (NSR) defines the ratio of reagent to NOx required to achieve the targeted NOx reduction. In practice, more than the theoretical amount of reagent needs to be injected into the boiler flue gas to obtain a specific level of NOx reduction.

In the SNCR process, the combustion unit acts as the reactor chamber. The reagent is generally injected within the boiler superheater and reheater radiant and convective regions, where the combustion gas temperature is at the required temperature range. The injection system is designed to promote mixing of

the reagent with the flue gas. The number and location of injection points is determined by the temperature profiles and flow patterns within the combustion unit.

Certain applications are more suited for SNCR due to the combustion unit design. Units with furnace exit temperatures of 1550°F to 1950°F (840°C to 1065°C), residence times of greater than one second, and high levels of uncontrolled NO_x are good candidates.

Step 2: Eliminate Technically Infeasible Options

The reheat furnace imposes constraints on the SCR unit, which are not typically encountered in the utility industry. Due to downstream requirements, it is not uncommon for production to come to a stop from full production, and production turndown can be as low as five to one. As a result, the waste gas flow can go from 100% of the design flow rate to as low as 15% in a few minutes. As production changes, the air preheat and waste gas temperature also vary.

Different production rates can result in waste gas temperatures either too high or too low for SCR to work effectively. This requires installation of both a dilution air system for those situations when the gas is too hot and a recuperator bypass for when the gas is too cold. Since air preheat and firing rate both have a significant effect on emissions factors, the concentration of NO_x in the waste gases varies greatly. Thus, control of ammonia flow requires a two level system considering both waste gas flow and NO_x concentration in the waste gases. This can be achieved to some extent through instrumentation, but control response times are such that some form of predictive control of ammonia may be required.

The use of SCR imposes additional restrictions on the reheat furnace. New furnace designs often have waste gas temperatures below 600F after the recuperator. These temperatures are too low for SCR to work effectively. While an auxiliary burner can be utilized to increase the waste gas temperature, this is not typically the best approach. Auxiliary burners add to the installation cost and themselves contribute to NO_x emissions. The alternative is to limit the furnace length so that the waste gases exit the recuperator at a temperature in the appropriate range for SCR. This lowers the system capital cost while providing the same system fuel efficiency¹⁹. Therefore, the use of SCR to control NO_x emissions is not considered a viable control technology.

According to *Alternative Control Techniques Document --NO_x Emissions from Iron and Steel Mills*, SNCR technology had not been applied to iron and steel mill process facilities, however, in other SNCR applications, controlling the ammonia to NO_x molar ratio controls ammonia slip to acceptable levels. These levels are similar to ammonia emissions from SCR applications, e.g., 10 ppm. Some of the disadvantages to using SNCR technology include: Lower NO_x reductions than Selective Catalytic Reduction (SCR). It may require downstream equipment cleaning. Use of the reagent can Result in ammonia in the waste gas stream, which may impact plume visibility, and resale or disposal of ash.

An advantage of the SNCR is that it can operate efficiently at a higher temperature range, but temperatures in the reheat furnace can fluctuate greatly. While the SNCR specified temperature range is higher than the SCR's optimal temperature range, the process temperature impacts the level of efficiency in the SNCR. SNCRs also tend to be less effective at lower levels of uncontrolled NO_x. SNCR is also better suited for applications with high levels of PM in the waste gas stream than SCR. Therefore, SNCR control technology is ineffective for sources with low NO_x concentrations like the concentration within reheat furnace.

¹⁹ <http://www.netl.doe.gov/publications/proceedings/01/scr/debski.pdf> - Cost and Design Implications of SCR Applied to Reheat Furnaces by Paul D. Debski, P.E.-accessed July 21, 2010

Step 3: Rank Remaining Technically Feasible Control Options

The remaining technology is the installation of ultra low NOx burners.

Combustion modifications such as LNB, ULNB and FGR inhibit NOx formation by controlling the combustion process. Staging techniques are usually used by LNB and ULNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNB's create a lean primary combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures. The secondary combustion zone is fuel-rich.

Ultra-low-NOx burners use staging techniques similar to staged-fuel LNB in addition to internal flue gas recirculation. Flue gas recirculation returns a portion of the flue gas to the combustion zone through ducting external to the firebox that reduces flame temperature and dilutes the combustion air supply with relatively inert flue gas.

Step 4: Evaluate Remaining Control Technologies

Not applicable because the installation of ultra low NOx burners is the only control technology.

Conclusion – NOx Control

Based on searches in the RBLC and independent Internet research of NOx control technologies for reheat furnaces. It is determined that the use of ultra-low NOx burners constitute BACT and the Division accepts the proposed BACT limit of 0.075 lb/ton. The reheat furnace will also employ a hot charge system, which will allow the steel to directly enter the reheat furnace at a higher temperature after leaving the casting machine to reduce the amount of natural gas required to process a charge. Although the emission rate remains unchanged, more fuel is required to heat a cold charge than a pre-heated charge that cuts down on fuel usage, thus reducing the amount of NOx produced.

Table 4-13: BACT Summary for the Electric Arc Furnace (Source Code EAF)

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
NOx	Ultra Low NOx Burner and Good Operating Practices	0.075 lb/ton	N/A	Vendor Specifications or Fuel Analysis

Reheat Furnace (RHF) – PM Emissions**Applicant Proposal***Step 1: Identify all control technologies*

The BACT analysis began with identifying all technically feasible control technologies. Because the emissions from the reheat furnace will be products of combustion of natural gas (a clean burning fuel), no add-on control technologies for particulate emissions will be incorporated. The only potential control technology will be to ensure good combustion to prevent soot. Particulate leaving natural gas fired units is predominantly in condensable form and not filterable.

Step 2: Eliminate Technically Infeasible Options

Good combustion techniques will be the only applicable control technology.

Step 3: Rank Remaining Technically Feasible Control Options

Good combustion techniques will be the only applicable control technology.

Step 4: Evaluate Remaining Control Technologies

Table 4-13 lists the PM emission limits and controls that are currently in place for reheat furnaces in the USEPA RBLC database. As indicated, only good combustion techniques will be applicable, and it is doubtful that particulate emissions have ever been tested coming from a gas-fired furnace. Therefore, it is likely that the emission limits listed have their origin in natural gas combustion emission factors listed in AP-42 for boilers. The lowest emission factor listed in the table is 0.003 lb/MMBtu, but it has not been verified by testing. Nor are the next lowest limits verified (0.004, 0.0051 lb/MMBtu). Earlier versions of AP-42 listed particulate matter emission factors for natural gas fired boilers at lower levels than the current version and it is expected that these lower levels are based on these previous versions of AP-42.

Table 4-14: RBLC Summary for PM Emissions Limit for the Reheat Furnace (Source Code RHF)

Facility Name	Date of Issuance	Control Technology	PM Emission Limit (lb/MMBtu)
Qualtech Steel Corporation (Indiana)	10/1996	Fuel Spec. Combust Natural Gas Only	0.0030
IPSCO Steel Incorporated (Alabama)	2/2001	Fuel Spec. Combust Natural Gas Only	0.0040
Republic Technologies International (Nebraska)	1/1999	--	0.0051
Griffin Wheel Company (Oklahoma)	10/1999	--	0.0075
Bluewater Project (Arkansas)	7/2004	Fuel Spec. Combust Natural Gas Only	0.0076

Step 5 – Selection of BACT

Because none of the emission limits have been verified through testing, Osceola is proposing 0.0076 lb/MMBtu as BACT, which is equivalent to the current emission factor listed in AP-42 for natural gas-firing in boilers. Osceola will periodically verify that the natural gas burners on the furnaces will be tuned to manufacturer specifications for proper combustion.

EPD Review – PM Control**Step 1: Identify all control technologies**

Particulate matter emissions from the reheat furnace are a result of the combustion of natural gas. An Internet search of technical papers and trade journals, review of various state permits and a RBLC search was performed for post combustion (add-on) control technology for PM. Based on the results of the search, the only available control technology was the use of good combustion practices and the use of cleaner fuel to control particulate emissions from the reheat furnace.

Step 2: Eliminate Technically Infeasible Options

Not applicable because good combustion practices and fuel selection are the only available control technology.

Step 3: Rank Remaining Technically Feasible Control Options

Not applicable because good combustion practices and fuel selection are the only available control technology

Step 4: Evaluate Remaining Control Technologies

Not applicable

Conclusion – PM Control

Osceola Steel Company proposes to burn natural gas, a particularly clean fuel in the reheat furnace. After performing careful research, information regarding the testing of particulate emissions from the reheat furnace was unavailable. The RBLC was reviewed to determine the basis of the emissions limit for particulate matter from the reheat furnace and to determine whether performance testing was conducted to verify the limit. After independent Internet research, it was determined that use of the AP-42 emission rate for natural-gas fired boilers and process heaters would be an acceptable substitution and more than likely the basis for previous BACT emission limits. Currently, the emission factor according to USEPA's AP-42 for natural gas fired boilers is 0.0076 lb/MMBtu, therefore the Division agrees with Osceola Steel Company's proposed BACT limit. This limit is applicable at all times, including startup and shutdown.

Table 4-15: BACT Summary for the Reheat Furnace (Source Code RHF)

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
PM	Fuel Selection (natural gas fired)	0.0076 lb/MMBtu	N/A	Vendor Specifications or Fuel Certification

Reheat Furnace (RHF) – SO₂ Emissions**Applicant Proposal***Step 1: Identify all control technologies*

Because the emissions from the furnaces are products of combustion and only natural gas (a clean burning fuel) is being used as a fuel, no add-on control technologies to reduce SO₂ exist nor are they needed. If oil or other non-clean burning fuel were used, then add-on controls such as alkaline scrubbing might be appropriate. The only emission of SO₂ from burning gas would be due to the combustion of the minor amounts of odorant in natural gas.

Step 2: Eliminate Technically Infeasible Options

Clean fuel already has been chosen, so no other technology is evaluated.

Step 3: Rank Remaining Technically Feasible Control Options

Clean fuel already has been chosen, so no other technology is evaluated.

Step 4: Evaluate Remaining Control Technologies

Reviews of the RBLC listing of the SO₂ emissions from reheat furnaces revealed essentially the same emission limit of 0.0006 lb/MMBtu, which is the AP-42 emission factor for burning natural gas.

Step 5 – Selection of BACT

Osceola is proposing 0.0006 lb/MMBtu as BACT, which is the equivalent of the emission factor listed in AP-42 for natural gas firing in boilers.

EPD Review – SO₂ Control*Step 1: Identify all control technologies*

- Fuel Selection

Step 2: Eliminate Technically Infeasible Options

Not applicable because fuel selection is the only option to control SO₂ emissions from the reheat furnace

Step 3: Rank Remaining Technically Feasible Control Options

The only remaining option is fuel selection for effectively controlling SO₂ emissions from the reheat furnace.

Step 4: Evaluate Remaining Control Technologies

Because none of the emission limits have been verified through testing, Osceola is proposing 0.0006 lb/MMBtu as BACT, which is equivalent to the current emission factor listed in AP-42 for natural gas-firing in boilers. Osceola will periodically verify that the natural gas burners on the furnaces will be tuned to manufacturer specifications for proper combustion.

Conclusion – SO₂ Control

Because the emissions from the furnaces are products of combustion and only natural gas is being used as a fuel, and sulfur dioxide emissions are very low, there was no need to evaluate control technologies. After performing careful research, information regarding the testing of sulfur dioxide emissions from the reheat furnace was unavailable. The RBLC was reviewed to determine the basis of the emissions limit for particulate matter from the reheat furnace and to determine whether performance testing was conducted to verify the limit. After independent Internet research, it was determined that use of the AP-42 emission rate for natural-gas fired boilers and process heaters would be an acceptable substitution. Currently, the emission factor according to USEPA's AP-42 for natural gas fired boilers is 0.0006 lb/MMBtu, therefore the Division agrees with Osceola Steel Company's proposed BACT limit. This limit is applicable at all times, including startup and shutdown.

Table 4-16: BACT Summary for the Reheat Furnace (Source Code RHF)

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
SO ₂	Fuel Selection (equipment fires natural gas)	0.0006 lb/MMBtu	N/A	Fuel Receipts or Vendor Specification

Small Combustion Sources Background

Osceola Steel Mill proposes to operate several small combustion sources (less than 10MMBTU/hr). The small combustion sources include: two horizontal ladle pre-heaters (Source IDs HLP1 and HLP2), a vertical ladle pre-heater (Source ID VLP), two Tundish pre-heaters (Source ID TP1 and TP2) and two casting machine torches (Source ID CMT1 and CMT2). Below is a table of the proposed small combustion sources, fuel combusted and heat input for each unit.

Source ID	Fuel Combusted	Heat Input (MMBTU/hr)
HLP1	Natural Gas	8.0
HLP2	Natural Gas	8.0
VLP	Natural Gas	6.0
TP1	Natural Gas	1.5
TP2	Natural Gas	1.5
CMT1	Natural Gas	0.6
CMT2	Natural Gas	0.6

Emissions of PM, NO_x, CO, and SO₂ are associated with the combustion of natural gas in these units. The BACT analysis for the aforementioned pollutants will be consolidated into one section for the small combustion sources.

Applicant Proposal

The Osceola mill will operate several small (<8MMtu/hr) miscellaneous combustion sources (ladle preheaters, Tundish pre-heaters, and cutting torches) throughout the plant. Emissions of PM, NO_x, CO, and SO₂ are associated with the combustion of natural gas in these units. The BACT analysis for these pollutants for these sources is presented below.

Step 1: Identify all control technologies

Because of the nature of these operations these units are used very intermittently. These gas burners are used to pre-heat the vessels storing the hot melt and therefore are not in use when the ladle is transferring metal. They are also vent fugitively inside the melt shop, which makes emission controls difficult. Lastly the small amount of emissions involved would make any emission controls cost prohibitive. The use of good combustion practices which ensure good mixing of the fuel and combustion air will insure all pollutants impacted will be kept at low levels.

Step 2: Eliminate Technically Infeasible Options

Filterable PM emissions from natural gas combustion are very low; therefore, it is considered technically infeasible to collect PM from natural gas combustion. PM from natural gas combustions is usually from large-molecular-weight hydrocarbons that are not fully combusted; therefore PM can be best controlled through good combustion practices. NO_x and CO are similarly best controlled through properly air/ fuel mixing and good combustion practices.

NO_x and CO emissions from these miscellaneous burners are slightly higher than a typical low NO_x burner, however, these burners will utilize radiant heat and as a result will likely operate at significantly higher temperatures than those on a typical boiler that uses a convection heat transfer mechanism. Because of their radiant/ high temperature design the ultra low NO_x burner technology could not be applied to these small burners.

Any SO₂ emissions formed are results of sulfur contained in the fuel and therefore are a direct result of the oxidation of the sulfur compounds. These levels are however very low because of the very low sulfur

content of the natural gas. Any SO₂ emission controls would be impractical because the units vent fugitively and because of the low level of emission involved with natural gas combustion.

Step 3: Rank Remaining Technically Feasible Control Options

Good combustion control is considered the only remaining technology for the natural gas combustion sources.

Step 4: Evaluate Remaining Control Technologies

Good combustion control is considered the only remaining technology for the natural gas combustion sources.

Step 5 – Selection of BACT

Good combustion control is considered BACT for the pre-heaters. The proposed BACT emission limit for PM is 7.6 lb/MMscf, which is obtained from AP-42 in Table 1.4-2, and is equivalent to 0.0076 lb/MMBtu. BACT for NO_x, CO, and SO₂ are based on 0.1 lb/MMBtu, 0.082 lb/MMBtu, and 0.0006 lb/MMBtu which are also based on AP-42 Table 1.4-2.

EPD Review – Small Combustion Sources Criteria Pollutant Control

Filterable PM

Because natural gas is a gaseous fuel, filterable PM emissions are typically low. Particulate matter from natural gas combustion has been estimated to be less than 1 micrometer in size and has filterable and condensable fractions. Particulate matter in natural gas combustion typically has a larger molecular weight of hydrocarbons that are not fully combusted. Increased PM emissions may result from poor air/fuel mixing or maintenance problems.

NO_x

Thermal NO_x formation increases rapidly at temperatures exceeding 1540 degrees C (2800 degrees F) and is the primary source of NO_x in natural gas- and refinery fuel gas-fired heaters. Refinery fuel gas firing generally yields a higher thermal NO_x formation than natural gas firing due to the higher flame temperatures caused by the higher hydrogen content of the refinery fuel gas.

Prompt NO_x, occurs through early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NO_x reactions occur within the flame and are usually negligible when compared to the amount of NO_x formed through the thermal NO_x mechanism. However, prompt NO_x levels may become significant with ultra-low-NO_x burners.

Fuel NO_x formation is minimal in heaters that fire natural gas and refinery fuel gas, which contain little or no fuel-bound nitrogen. Although NO_x emissions would be somewhat higher in these sources than if they used LNB or ULNB, the size of these combustion sources have a potential yield less than 3tpy NO_x each.

CO

The rate of CO emissions from boilers depends on the efficiency of natural gas combustion. Improperly tuned boilers and boilers operating at off-design levels decrease combustion efficiency resulting in increased CO emissions.

SO₂

Emissions of SO₂ from natural gas-fired combustion equipment are low because pipeline quality natural gas typically has sulfur levels of 2,000 grains per million cubic feet. However, sulfur-containing odorants are added to natural gas for detecting leaks, leading to small amounts of SO₂ emissions. Boilers combusting unprocessed natural gas may have higher SO₂ emissions due to higher levels of sulfur in the natural gas. For these units, a sulfur mass balance should be used to determine SO₂ emissions.

Step 1: Identify all control technologies

PM

- Fuel Selection

NO_x

- Low-NO_x burners (LNBs)
- Ultra-low NO_x burners (ULNBs)
- Selective Non-Catalytic Reduction (SNCR)
- Selective Catalytic Reduction (SCR).
- Also, LNB's in combination with flue gas recirculation (FGR), SNCR, and SCR.

- Good Combustion Practices

CO

- Good Combustion Practices
- Fuel Selection

SO₂

- Fuel Selection

Step 2: Eliminate Technically Infeasible Options

Based on the size and limited use of the aforementioned combustion sources with a heat input of less than 10MMBtu/hr, the use of LNBs, UNLBs, SNCR, SCR and any combination of LNBs with FGR, SNCR and SCR are all technically feasible control technologies, however, based on the size of the equipment (<10MMBtu/hr) and the infrequency of use, which results in a small value of NO_x generated, the costs associated with operation of the control technology versus ton of NO_x removed far exceeds the \$10,000 per ton typically accepted maximum cost effective value of pollutant reduced., thus the use of LNBs, UNLBs, SNCR, SCR and the combination of LNBs with FGR, SNCR and SCR will not be investigated further.

Step 3: Rank Remaining Technically Feasible Control Options

The remaining technically feasible control options are good combustion practices, which will be used in conjunction with fuel selection.

Step 4: Evaluate Remaining Control Technologies

Non-Applicable because good combustion practices in conjunction with fuel selection is the only viable means of controlling PM, NO_x, SO₂ and CO emissions from the small combustion sources.

Conclusion – Small Combustion Sources Criteria Pollutant Control

Good combustion control is considered BACT for the small combustion sources. The proposed BACT emission limits are obtained from AP-42 in Table 1.4-2 and are equivalent to. BACT for PM, NO_x, CO, and SO₂:

Table 4-17: BACT Summary for the Small Combustion Sources Criteria Pollutants

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
CO	Good Combustion Practices/Fuel Selection	0.082 lb/MMBtu	N/A	Fuel Receipts or Vendor Specification
NO _x	Good Combustion Practices/Fuel Selection	0.1 lb/MMBtu	N/A	Fuel Receipts or Vendor Specification
PM	Good Combustion Practices/Fuel Selection	0.0076 lb/MMBtu	N/A	Fuel Receipts or Vendor Specification
SO ₂	Good Combustion Practices/Fuel Selection	0.0006 lb/MMBtu	N/A	Fuel Receipts or Vendor Specification

Slag Handling and Road Dust Fugitives Background

Applicant's Proposal

Top-Down BACT Steps 1 through 4

The only emission associated with slag handling is the generation of fugitive dust emissions during the transporting, crushing, and screening of the slag. These operations occur outside in an area west of the main plant operations. Table 2 lists the PM emissions limits and controls for slag handling processes at various recently permitted steel mills. Each facility lists no add-on technology. The control method is source control, either through minimizing drop height or wet suppression of the material. In addition, roadways and stockpiles of slag to be processed will also be treated in this manner.

Step 5 – Selection of BACT

Osceola is not proposing an emission limit for BACT, but instead is proposing a work practice of wet suppression of dust generating sources. The slag handling operations and main haul roads which transfer slag, raw materials, and finished steel will be watered as needed to suppress dust generation. Osceola does not anticipate large stockpiles of slag, but, if any are generated, those piles will be kept damp as well.

EPD Review- Slag Handling and Road Dust Fugitives Background Control

The proposed handling of emissions associated with crushing, screening, slag handling and transportation is not subject to requirements under BACT, therefore the Division reviewed the proposed handling of slag operations.

Fugitive particulate emissions occur from wind-blown dust, storage piles, raw material transfer, and paved and unpaved surfaces. Control measures include watering, chemical stabilization, reducing surface wind speed with windbreaks or source enclosures, clean up of spillage, vehicle restrictions (limiting speed, weight, number of vehicles), and surface improvements such as paving or adding gravel or slag to a dirt road. However, increased monitoring of fugitive emissions (e.g., monitoring on days when there is no precipitation) can be useful in providing additional control if control measures are applied when dusty conditions are observed (in addition to the regularly scheduled controls required by the permit). When spikes in opacities are observed (e.g., 10 percent or more), the cause of the event should be investigated and corrective actions taken.

Based on review of similar sources through the RBLIC, it has been determined the control methods commonly used are: water sprays on transfer points, minimizing drop heights and water suppression on material piles.

Conclusion-Slag Handling and Road Dust Fugitives Background Control

Based upon review of the proposed operating conditions associated with the slag handling and road dust fugitive control, the Division has determined based upon the quantity of particulate emissions associated with the slag handling and road dust fugitives, no emission limit is proposed, however good housekeeping practices will be required in order to ensure emissions don't exceed those outlined in Application 19507.

Based on calculations provided by Osceola Steel Company and verified by the Division, the amount of scrap transported to the facility via truck should not exceed 233,694 tons per year, which accounts for 50% of the amount of scrap brought in via truck, and the facility does not expect to transport more than 215, 000 tons of steel annually. The slag handling operations and main haul roads, which transfer slag, raw materials, and finished steel, will be watered at a minimum of once per week to suppress dust generation. Daily inspection of the slag handling operations and main haul roads will be required to ensure the roads are adequately watered and fugitive emissions are being controlled.

The slag pile is another area that serves as a source of fugitive emissions and careful monitoring of the slag piles to ensure raw material transfer is reduced. Wet suppression of raw material transfer and dust will be used to control particulate emissions from the slag pile. The drop height of the slag pile will be minimized to 25 feet stationary and 5 feet mobile to reduce the transfer of materials causing fugitive emissions and slag piles should not exceed an area of 75'x75'.

Cooling Towers Background

The cooling towers on site are heat exchangers that are used to dissipate heat loads from plant condensate to the atmosphere. Because wet cooling towers operate on the principal of evaporative cooling there is direct contact between the cooling water and the air passing through the tower. Some of the liquid water may be entrained in the air stream and can be carried out of the tower as "drift" droplets. As the droplet evaporates in the atmosphere, any suspended or dissolved water will solidify as particulate matter.

Applicant's Proposal

The only control method available for wet cooling towers is drift eliminators. The design of the drift eliminators dictates their control efficiency. The efficiencies range from 0.05 to 0.0005 percent (gallons of drift per gallons of cooling water).

The proposed BACT for this project is the use of drift eliminators with an efficiency of 0.0005 percent. The proposed method of compliance for the drift eliminators is use of a manufacturer's guarantee. This drift limit is consistent with recent BACT evaluations for cooling towers, and the RBLC database confirms BACT levels of 0.0005 percent. A review of the literature and the RBLC database indicates that this is the highest level of control at this time, as indicated in Table 3.

EPD Review – Cooling Towers PM Control

Step 1: Identify all control technologies

- Use of Dry Cooling (no water circulation) Heat Exchanger Units
- High-Efficiency Drift Eliminators, as low as 0.0005% of circulating flow
- Limitations on TDS concentrations in the circulating water
- Combinations of Drift Eliminator efficiency rating and TDS limit

Step 2: Eliminate Technically Infeasible Options

Non-evaporative cooling towers (dry cooling) for heat rejection from combined-cycle power plants has been adopted in dry climates with little rainfall or scarce water supply, this measure is usually a means to reduce the water consumption of the plant, instead of BACT for PM₁₀ emissions. There is a very substantial capital cost penalty in adopting this technology, in addition to the process changes (e.g., operating pressures) necessary to condense water at the ambient dry bulb temperature, rather than at ambient wet bulb temperature.

Step 3: Rank Remaining Technically Feasible Control Options

The Division verified that a form of drift eliminator is a control technology for cooling towers to control particulate emissions. In order to reduce the drift from cooling towers, drift eliminators are usually incorporated into the tower design to remove as many droplets as practical from the air stream before exiting the tower.

The drift eliminators used in cooling towers rely on inertial separation caused by direction changes while passing through the eliminators. Types of drift eliminator configurations include herringbone (blade-type), wave form, and cellular (or honeycomb) designs. The cellular units generally are the most efficient. Drift eliminators may include various materials, such as ceramics, fiber reinforced cement, fiberglass, metal, plastic, and wood installed or formed into closely spaced slats, sheets, honeycomb assemblies, or tiles. The materials may include other features, such as corrugations and water removal channels, to enhance the drift removal further.

In addition to the use of high efficiency drift eliminators, consideration must be granted to the composition, specifically the concentration of total dissolved solids (TDS) in the cooling water. By controlling the concentration of dissolved solids in the cooling water particulate emissions can be reduced. Dissolved solids accumulate in the cooling water due to increasing concentration of dissolved solids in the make-up water as the circulating water evaporates, and, secondarily, the addition of anti-corrosion, anti-biocide additives. However, to maintain reliable operation of the tower without the environmental impact of frequent acid wash cleanings, the water balance must be considered.

Therefore, in order to address the reduction of drift and reducing TDS in the cooling water, both feasible technologies should be combined.

Step 4: Evaluate Remaining Control Technologies

Not applicable- The combination of TDS reduction and elimination of drift is the only remaining technology.

Conclusion –Cooling Tower Criteria PM Control

In addition to the use of high efficiency drift eliminators, management of the tower water balance to control the concentration of dissolved solids in the cooling water can also reduce particulate emissions. Dissolved solids accumulate in the cooling water due to increasing concentration of dissolved solids in the make-up water as the circulating water evaporates, and, secondarily, the addition of anti-corrosion, anti-biocide additives. However, to maintain reliable operation of the tower without the environmental impact of frequent acid wash cleanings, the water balance must be considered.

Table 4-18: BACT Summary for the Cooling Towers (Source Code CT1, CT21, CT22 and CT3)

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
PM	High Efficiency Mist Eliminators/TDS limit in circulating water	0.0005% drift as percent of circulating water; limit of 1,000 mg/L of TDS in water	N/A	Vendor Certification and Specification

Opacity

Applicant Proposal

No significant visible opacity is expected from any of the processes. All furnaces and combustion operations utilize the cleanest fuel possible (natural gas) so opacity is not expected to be an issue for those units. For other process emissions for the most part specially designed baghouses are employed to minimize the amount of particulate in the exhaust gas. These controls are discussed in detail in the particulate BACT section for each process. Osceola is proposing a 10% opacity limit on a six-minute average for those operations not already covered by an opacity standard. Compliance with this level will be maintained by:

- Monitoring of furnace operations to ensure proper combustion
- Proper control device maintenance and operation
- Wet Suppression Techniques to minimize fugitive emissions

EPD Review

The Division agrees with Osceola Steel Company's proposal for an opacity limit of 10% on a 6-minute average for any processes that aren't covered under a more stringent standard. Compliance with the opacity limit will be maintained by wet suppression techniques to minimize fugitive emissions, proper maintenance and operation of all associated control devices and monitoring of operations to ensure complete and proper combustion.

Table 4-19: Facility-Wide BACT Summary and Emission Limits for Osceola Steel Company

Emission Unit	Pollutant	Control Technology	BACT Limit	Units
Electric Arc Furnace (Source Code: EAF)	CO	Direct Evacuation Control (DEC)	2.00	lb/ton
	NO _x	Low NO _x Burners with FGR Technology and Good Combustion/Operating Practices	0.35	lb/ton
	PM/PM ₁₀	Fabric Filter (Baghouse)	0.0026 (total) 0.0008 (condensable) 0.0018 (filterable)	gr/dscf
	SO ₂	Use of low-sulfur containing feed materials	2.0%	--
		Use of low-sulfur containing fuels.	0.176	lb/ton
Reheat Furnace (Source Code: RHF)	CO	Good Combustion/Operating Practices	0.0035	lb/MMBtu
	NO _x	Ultra Low NO _x Burners and Good Combustion/Operating Practices	0.075	lb/ton
	PM	Fuel Selection (firing natural gas exclusively)	0.0076	lb/MMBtu
	SO ₂	Fuel Selection (firing natural gas exclusively)	0.0006	lb/MMBtu
Small Combustion Sources (Source Codes: HLP1, HLP2, VLP, TPH1, TPH2, CMT1, CMT2)	CO	Good Combustion/Operating Practices and Fuel Selection (firing natural gas exclusively)	0.082	lb/MMBtu
	NO _x		0.1	lb/MMBtu
	PM		0.0076	lb/MMBtu
	SO ₂		0.0006	lb/MMBtu
Slag Handling and Road Dust Fugitive Emissions	PM (opacity)	Wet suppression of raw material transfer and dust from the roadways, limit slag pile drop height and size of slag pile area.	10% on a 6-minute average	--
Cooling Towers (CT1, CT21, CT22, CT33)	PM	High Density Mist Eliminators/Limit TDS in circulating water	0.0005% drift	--
			1,000	Mg/L
Facility-Wide	PM	--	10% on a 6 minute average unless otherwise covered by a more stringent standard	--

5.0 TESTING AND MONITORING REQUIREMENTS

Testing Requirements:

Part 52.21, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 52.21) Prevention of Significant Deterioration

The proposed electric arc furnace is subject to parallel sets of requirements. In this case, results in testing and monitoring requirements are redundant and unnecessary as a practical matter, even though the requirements still legally apply to the source. In EPA's Part 70 White Paper #2²⁰,

"In cases where compliance with a single set of requirements effectively assures compliance with all requirements, compliance with all elements of each of the overlapping requirements may be unnecessary and could needlessly consume resourcesThe streamlined monitoring, record keeping, and reporting requirements would generally be those associated with the most stringent emissions limit, providing they would assure compliance to the same extent as any subsumed monitoring. Thus, monitoring, record keeping, or reporting to determine compliance with subsumed limits would not be required where the source implements the streamlined approach."

The table below illustrates the individual applicable testing requirements for the proposed project:

Table 5-1: Applicable Testing Requirements for the Electric Arc Furnace

Pollutant/Parameter	40 CFR 52.21	40 CFR 63 Subpart YYYYY	40 CFR 60 Subpart AAa
Traverse Points	Method 1 or 1A of Appendix A-1 of 40 CFR Part 60	Method 1 or 1A of Appendix A-1 of 40 CFR Part 60	Not Applicable
Velocity and Volumetric Flow	Method 2, 2A, 2C, 2D, 2F, or 2G of Appendix A-1 of 40 CFR Part 60	Method 2, 2A, 2C, 2D, 2F, or 2G of Appendix A-1 of 40 CFR Part 60	Not Applicable
O ₂ and CO ₂ Concentrations	Method 3, 3A, or 3B of Appendix A-3 of 40 CFR Part 60	Not Applicable	Not Applicable
Dry Molecular Weight of the Stack Gas	Method 3, 3A, or 3B of Appendix A-3 of 40 CFR Part 60	Method 3, 3A, or 3B of Appendix A-3 of 40 CFR Part 60	Not Applicable
Moisture Content	Method 4 of Appendix A-3 of 40 CFR Part 60	Method 4 of Appendix A-3 of 40 CFR Part 60	Not Applicable

²⁰ *White Paper # 2 for Improved Implementation of the Part 70 Operating Permits Program*, EPA, Office of Air Quality Planning and Standards, March 5, 1996.

Table 5-1 con't: Applicable Testing Requirements for the Electric Arc Furnace

Pollutant/Parameter	40 CFR 52.21	40 CFR 63 Subpart YYYYY	40 CFR 60 Subpart AAa
PM Concentration	Method 5 or 5D of appendix A–3 of 40 CFR Part 60 to determine the PM concentration. For EAF, sample only when metal is being melted and refined.	Method 5 or 5D of appendix A–3 of 40 CFR Part 60 to determine the PM concentration. For EAF, sample only when metal is being melted and refined.	Method 5 shall be used for negative-pressure fabric filters and other types of control devices and Method 5D shall be used for positive-pressure fabric filters to determine the particulate matter concentration and volumetric flow rate of the effluent gas.
PM Emission Rate	Method 19 of appendix A of 40 CFR Part 60 to must be used to convert particulate matter, as determined using other methods specified in this section, to emission rates.	Method 19 of appendix A of 40 CFR Part 60 to must be used to convert particulate matter, as determined using other methods specified in this section, to emission rates.	Method 19 of appendix A of 40 CFR Part 60 to must be used to convert particulate matter, as determined using other methods specified in this section, to emission rates.
Opacity	Method 9 and the procedures of §60.11 shall be used to determine opacity. To demonstrate compliance with §60.272a(a) (1), (2), and (3), the Method 9 test runs shall be conducted concurrently with the particulate matter test runs.	Method 9 and the procedures of §60.11 shall be used to determine opacity. To demonstrate compliance with §60.272a(a) (1), (2), and (3), the Method 9 test runs shall be conducted concurrently with the particulate matter test runs.	Method 9 and the procedures of §60.11 shall be used to determine opacity. To demonstrate compliance with §60.272a(a) (1), (2), and (3), the Method 9 test runs shall be conducted concurrently with the particulate matter test runs.

Pollutant/Parameter	40 CFR 52.21	40 CFR 63 Subpart YYYYY	40 CFR 60 Subpart AAa
NO _x Concentration	Methods 7, 7A, 7C, 7D or 7E in Appendix A-4 to Part 60, as applicable, are the reference methods for determining NO _x Method 7 of appendix A of 40 CFR Part 60 shall be used to determine the NO _x concentration at the same location as the NO _x monitor pollutant concentrations. The Method 7 test runs shall be conducted concurrently with the CO test runs.	Not Applicable	Not Applicable
NO _x Emission Rate	Method 19 of Appendix A of 40 CFR Part 60 to must be used to convert nitrogen oxides as determined using other methods specified in this section, to emission rates.	Not Applicable	Not Applicable

Table 5-1 con't: Applicable Testing Requirements for the Electric Arc Furnace

Pollutant/Parameter	40 CFR 52.21	40 CFR 63 Subpart YYYYY	40 CFR 60 Subpart AAa
NO _x Emission Rate	Methods 7, 7A, 7C, 7D, or 7E in appendix A-4 to Part 60 must be used to measure total NO _x emissions, both NO and NO ₂ , for purposes of this part. The owner or operator shall not use the sections, exceptions, and options of method 7E in Appendix A-4 to Part 60 as specified in 75.22(a)(5).	Not Applicable	Not Applicable
Backup monitoring system to provide quality-assured monitor data for NO _x concentrations	Method 7E in Appendix A of Part 60	Not Applicable	Not Applicable
Carbon Monoxide Concentration	Method 10 or Method 10B of 40 CFR Part 60 Appendix A. The Method 10 test runs shall be conducted concurrently with the NO _x test runs.	Not Applicable	Not Applicable
Carbon Monoxide Emission Rate	Method 19 F-Factor methodology in Appendix A of Part 60	Not Applicable	Not Applicable

Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 60) New Source Performance Standards (NSPS) Subpart AAa- "Standards of Performance for Steel Plants: Electric Arc Furnaces and Argon-Oxygen De-carburization Vessels Constructed After August 17, 1983."

In conducting the performance tests required under §60.8, Osceola Steel Company must use the methods and procedures in Appendix A (including fuel certification and sampling) of 40 CFR Part 60 or the methods and procedures as specified in 40 CFR 60. During performance tests required in §60.8, the owner or operator shall not add gaseous diluents to the effluent gas stream after the fabric in any pressurized fabric filter collector, unless the amount of dilution is separately determined and considered in the determination of emissions [60.275(d)].

When emissions from any EAF(s) or AOD vessel(s) are combined with emissions from facilities not subject to the provisions of this subpart but controlled by a common capture system and control device, the owner or operator shall use either or both of the following procedures during a performance test (see also §60.276a(e)) [60.275(b)]:

- Determine compliance using the combined emissions.
- Use a method that is acceptable to the Administrator and that compensates for the emissions from the facilities not subject to the provisions of this subpart.

Compliance with the PM emission standards under §60.272a shall be determined through performance testing as described in paragraph (e) of 40 CFR 60.275a. To determine compliance with the PM emission limits and opacity limits under §60.272a, Osceola Steel Company must conduct an initial performance test as required under §60.8, and shall conduct subsequent performance tests as requested by the Division, using the following procedures and reference methods [40 CFR 60.275(e)(1) through (e)(4)]:

- Method 5 shall be used for negative-pressure fabric filters and other types of control devices and Method 5D shall be used for positive-pressure fabric filters to determine the particulate matter concentration and volumetric flow rate of the effluent gas. The sampling time and sample volume for each run shall be at least 4 hours and 4.50 dscm (160 dscf) and, when a single EAF or AOD vessel is sampled, the sampling time shall include an integral number of heats [60.275(e)(1)].
- Method 9 and the procedures of §60.11 shall be used to determine opacity [60.275a(e)(3)].
- To demonstrate compliance with §60.272a(a) (1), (2), and (3), the Method 9 test runs shall be conducted concurrently with the particulate matter test runs, unless inclement weather interferes [60.275a(e)(4)].

Where emissions from any EAF(s) or AOD vessel(s) are combined with emissions from facilities not subject to the provisions of this subpart but controlled by a common capture system and control device, Osceola Steel Company may use any of the following procedures during a performance test [60.275a(h)]:

- Base compliance on control of the combined emissions;
- Use of a Division-approved method that compensates for the emissions from the facilities not subject to the provisions of this subpart, or;

Any combination of the criteria of paragraphs 60.275a(h)(1) and 60.275a(h)(2) of this section may be used with prior Division approval.

Emissions Standards For Hazardous Air Pollutants (NESHAP) Subpart YYYYY- National Emission Standards for Hazardous Air Pollutants for Area Sources: Electric Arc Furnace Steelmaking Facilities

Except as provided in 40 CFR 63.10686(d)(6) of this section, Osceola Steel Company must conduct performance tests to demonstrate initial compliance with the applicable emissions limit for each emissions source subject to an emissions limit in paragraph (b) or (c) of 40 CFR 63.10686.

Osceola Steel Company must conduct each PM performance test for an EAF vessel according to the procedures in §63.7 and 40 CFR 60.275a using the following test methods in 40 CFR Part 60, Appendices A–1, A–2, A–3, and A–4 [63.10686(d)(1)]:

- Method 1 or 1A of Appendix A–1 of 40 CFR Part 60 to select sampling port locations and the number of traverse points in each stack or duct. Sampling sites must be located at the outlet of the control device (or at the outlet of the emissions source if no control device is present) prior to any releases to the atmosphere.
- Method 2, 2A, 2C, 2D, 2F, or 2G of Appendix A–1 of 40 CFR Part 60 to determine the volumetric flow rate of the stack gas.
- Method 3, 3A, or 3B of Appendix A–3 of 40 CFR Part 60 to determine the dry molecular weight of the stack gas. You may use ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses” (incorporated by reference—see §63.14) as an alternative to EPA Method 3B.
- Method 4 of Appendix A–3 of 40 CFR Part 60 to determine the moisture content of the stack gas.
- Method 5 or 5D of appendix A–3 of 40 CFR Part 60 to determine the PM concentration. Three valid test runs are needed to comprise a PM performance test. For EAF, sample only when metal is being melted and refined. For AOD vessels, sample only when the operation(s) are being conducted.

Osceola Steel Company must conduct each opacity test for a melt shop according to the procedures in §63.6(h) and Method 9 of Appendix A–4 of 40 CFR Part 60. When emissions from any EAF vessel are combined with emissions from emission sources not subject to this subpart, you must demonstrate compliance with the melt shop opacity limit based on emissions from only the emission sources subject to this subpart [63.10686(d)(2)].

During any performance test, you must monitor and record the information specified in 40 CFR 60.274a(h) for all heats covered by the test [63.10686(d)(3)].

Osceola Steel Company must notify and receive approval from the Division for procedures that will be used to determine compliance for an EAF or AOD vessel when emissions are combined with those from facilities not subject to this subpart [63.10686(d)(4)].

Osceola Steel Company may certify initial compliance with the applicable emission limit for one or more emissions sources based on the results of a previous performance test for that emissions source in lieu of the requirement for an initial performance test provided that the test(s) were conducted within 5 years of the compliance date using the methods and procedures specified in paragraph (d)(1) or (2) of 40 CFR 63.10686; the test(s) were for the affected facility; and the test(s) were representative of current or anticipated operating processes and conditions. Should the permitting authority deem the prior test data unacceptable to demonstrate compliance with an applicable emissions limit, the owner or operator must conduct an initial performance test within 180 days of the compliance date or within 90 days of receipt of the notification of disapproval of the prior test, whichever is later [63.10686(d)(6)].

Reheat Furnace

The reheat furnace is subject to 40 CFR 52.21 and 40 CFR 63 Subpart YYYYYY. Testing is described above for requirements under 40 CFR 52.21 of which the reheat furnace is subject. The reheat furnace is subject to emission limits under 40 CFR 52.21 and must demonstrate compliance with BACT limits for NO_x and CO limits through vendor certification or fuel analysis. The Reheat Furnace (RHF) is not subject to testing under 40 CFR 63 Subpart YYYYYY.

Small Combustion Sources

There is no required performance testing for this equipment under 40 CFR Part 52.21.

Cooling Tower

There is no required performance testing for this equipment under 40 CFR Part 52.21.

Monitoring Requirements:

Monitoring, record keeping, and reporting as described by 40 CFR 52.21, 40 CFR 60 Subpart AAa, 40 CFR 63 and Subpart YYYYYY for applicable pollutants shall be applied as specified, ensuring that monitoring, record keeping, and reporting for both these regulations are satisfied. Osceola Steel Company is also required to monitor, create records, and submit reports for any emission limit and/or operating limit established under 40 CFR Part 52.21, 40 CFR 60 Subpart AAa and 40 CFR 63 Subpart YYYYYY. Any other applicable regulation monitoring, record keeping, and reporting requirements not specifically cited in this section as also required.

To demonstrate compliance with the fuel composition limit for SO₂ established through BACT, Osceola Steel Company must maintain fuel composition records for each fuel shipment or statement confirming the natural gas used is pipeline grade natural gas, and must be maintained for a period of five years from the date they were generated.

Combustion controls monitoring, record keeping, and reporting as shall consist of the following for the electric arc furnace to demonstrate compliance with established BACT limits²¹:

- Good Combustion Technique: Operator Practices – Maintenance of a written site specific operating procedures manual in which operating procedures, including startup, shutdown, and malfunction are well documented in accordance with the manufacturer's specifications. The operating procedures must be updated as applicable with any equipment or operating practice changes. The procedures shall contain operating logs documenting such changes and any deviations from the operating procedures. The operating procedures manual shall be maintained in an area allowing easy access to the furnace's operator and made available for Division review and inspection upon request. The Good Operating practices should include and not be limited to practices such as:
 1. *Minimize the number of charges per heat*- Instead of the typical 2 to 3 charge heats the Osceola furnace will be built with an extended sidewall height to facilitate a single charge practice when possible. This will reduce overall emissions and increase productivity. The final number of charges required will, however be dependent upon process variables tied to scrap steel availability and final product mix.

²¹ Good Combustion Practices-Accessed on September 1, 2010 <http://www.epa.gov/ttn/atw/iccr/dirss/gcp.pdf>

2. *Minimum use off-gas volume during the starting phase (use of direct exhaust control)*- Osceola will be employing a DEC system. Excessive negative pressure draws air in through the furnace door and electrode ports and pressure will be maintained as close to neutral as practical to avoid the draw in of nitrogen.
 3. *Maximize air tightness of EAF (e.g. closed slag door)* – Osceola intends to employ a design that minimizes air leaks into the EAF, which in turn will reduce the available oxygen for NOx formation.
 4. *Improved foamy slag practice to shield the electric arc*- Osceola will be employing the foaming slag practice in its operation during the majority of the power on time. This practice shields the arc from nitrogen.
- Good Combustion Technique: Maintenance Knowledge – The electric arc furnace and reheat furnaces must be maintained in accordance with manufacturer's specifications by personnel with training specific to the individual furnaces and operating procedures.
 - Good Combustion Technique: Maintenance Practices – Maintenance of a written site-specific procedures manual for best/optimum maintenance practices in accordance to the manufacturer's specifications for each furnace. Periodic evaluations, inspections, and overhauls as appropriate of the furnaces must be conducted in accordance with manufacturer's specifications. The maintenance practices must be updated as applicable with any equipment or operating practice changes. The modification of these practice changes, scheduled periodic evaluation inspections and overhaul, as appropriate, and any deviations from the prescribed maintenance practices shall be well documented in maintenance logs. The maintenance practices manual shall be maintained in an area allowing easy access to the furnace's operator and made available for Division review and inspection upon request.
 - Good Combustion Technique: Fuel Quality Analysis – Osceola Steel Company will be required to monitor the fuel quality of the fuel (natural gas) combusted in the electric arc and reheat furnaces. Osceola Steel Company must obtain fuel quality certification from natural gas suppliers to ensure that the fuel is of an acceptable standard to reduce emissions. These certifications should certify sulfur content, heating value, and moisture content, as applicable. Such fuel sampling results and/or vender certifications must be submitted for review during the quarterly reporting period.

Osceola Steel Company is required to submit the results of all initial and required periodic performance testing and fuel analysis within 90 days from the date of the performance test. Any excess emissions, exceedances, or excursions as described in the permit of the proposed emission limits and/or operating parameter limitations shall be reported during the quarterly reporting period.

Any owner or operator who constructs or operates a source or modification not in accordance with the application submitted pursuant to this section or with the terms of any approval to construct, or any owner or operator of a source or modification subject to this section who commences construction after the effective date of these regulations without applying for and receiving approval hereunder, shall be subject to appropriate enforcement action [40 CFR 52.21(r)(1)].

Upon issuance of its PSD permit, Osceola Steel Company must commence construction within 18 months after receipt of the permit, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time then the permit is invalid [40 CFR 52.21(r)(2)].

The owner or operator shall monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any emissions unit identified in 52.21 (r)(6)(i)(b) and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 5

years following resumption of regular operations after the change, or for a period of 10 years following resumption of regular operations after the change if the project increases the design capacity or potential to emit of that regulated NSR pollutant at such emissions unit.

Per 40 CFR Part 52.21, all of the required reporting must be submitted on a quarterly basis, subsuming any semiannual or annual reporting established by applicable regulations.

The first quarterly report must cover the period beginning on the compliance date and ending on March 31, June 30, September 30, or December 31, whichever date is the first date that occurs at the end of the quarter in which initial startup is completed. The quarterly report must be post marked or delivered no later by the 30th day following the end of each reporting period, April 30, July 30, October 30, and January 30, respectively. Each subsequent report must cover the preparing period from January 1 through March 31, April 1 through June 30, July 1 through September 30, or October 1 through December 31 and must be post marked or delivered no later than April 30, July 30, October 30, and January 30, respectively, which date is the first date following the end of the quarterly reporting period. Such report shall be submitted to the Administrator within 60 days after the end of such year. At minimum, the report shall contain the following [40 CFR 52.21(r)(6)(v)]:

The name, address and telephone number of the major stationary source;

The annual emissions as calculated pursuant to paragraph (r)(6)(iii) of this section; and

Any other information that the owner or operator wishes to include in the report (e.g., an explanation as to why the emissions differ from the preconstruction projection).

40 CFR 60 Subpart AAa

Except as provided under paragraphs (b) and (c) of 60.273a, a continuous monitoring system for the measurement of the opacity of emissions discharged into the atmosphere from the control device(s) shall be installed, calibrated, maintained, and operated by the owner or operator subject to the provisions of this subpart.

No continuous monitoring system shall be required on any control device serving the dust-handling system.

A continuous monitoring system for the measurement of the opacity of emissions discharged into the atmosphere from the control device(s) is not required on any modular, multi-stack, negative-pressure or positive-pressure fabric filter if observations of the opacity of the visible emissions from the control device are performed by a certified visible emission observer; or on any single-stack fabric filter **if** visible emissions from the control device are performed by a certified visible emission observer and the owner installs and continuously operates a bag leak detection system according to paragraph (e) 60.273a.

Visible emission observations shall be conducted at least once per day for at least three 6-minute periods when the furnace is operating in the melting and refining period. All visible emissions observations shall be conducted in accordance with Method 9. If visible emissions occur from more than one point, the opacity shall be recorded for any points where visible emissions are observed. Where it is possible to determine that a number of visible emission sites relate to only one incident of the visible emission, only one set of three 6-minute observations will be required. In that case, the Method 9 observations must be made for the site of highest opacity that directly relates to the cause (or location) of visible emissions observed during a single incident. Records shall be maintained of any 6-minute average that is in excess of the emission limit specified in §60.272a(a).

A furnace static pressure monitoring device is not required on any EAF equipped with a DEC system **if** observations of shop opacity are performed by a certified visible emission observer as follows: Shop opacity observations shall be conducted **at least** once per day when the furnace is operating in the meltdown and refining period. Shop opacity shall be determined as the arithmetic average of 24 consecutive 15-second opacity observations of emissions from the shop taken in accordance with Method 9. Shop opacity shall be recorded for any point(s) where visible emissions are observed. Where it is possible to determine that a number of visible emission sites relate to only one incident of visible emissions, only one observation of shop opacity will be required. In this case, the shop opacity observations must be made for the site of highest opacity that directly relates to the cause (or location) of visible emissions observed during a single incident [60.273a(d)].

Osceola Steel Company must develop and implement a written startup, shutdown, and malfunction plan (SSMP) for the bag leak detection system for the electric arc furnace that will be available for the Division's review upon request.

The bag leak detection system must be installed and continuously operated on all single-stack fabric filters if Osceola Steel Company elects not to install and operate a continuous opacity monitoring system as provided for under paragraph (c) of 60.273a. In addition, Osceola Steel Company shall meet the visible emissions observation requirements in paragraph (c) of this section. The bag leak detection system must meet the specifications and requirements of paragraphs (e)(1) through (8) of 60.273a.

For each bag leak detection system installed according to paragraph (e) of 60.273a, the owner or operator shall initiate procedures to determine the cause of all alarms within 1 hour of an alarm. Except as provided for under paragraph (g) of 60.273a, the cause of the alarm must be alleviated within 3 hours of the time the alarm occurred by taking whatever corrective action(s) are necessary [60.273a(f)].

Upon approving the site-specific monitoring plan required in paragraph (e)(4) of 60.273a, the Division may allow Osceola Steel Company more than 3 hours to alleviate specific conditions that cause an alarm if the Osceola Steel Company identifies the condition that could lead to an alarm in the monitoring plan, adequately explains why it is not feasible to alleviate the condition within 3 hours of the time the alarm occurred, and demonstrates that the requested additional time will ensure alleviation of the condition as expeditiously as practicable [60.273a(g)].

Osceola Steel Company is required to check and record on a once-per-shift basis the furnace static pressure (if DEC system is in use, and a furnace static pressure gauge is installed according to 60.274a(f)) and either: check and record the control system fan motor amperes and damper position on a once-per-shift basis; install, calibrate, and maintain a monitoring device that continuously records the volumetric flow rate through each separately ducted hood; or install, calibrate, and maintain a monitoring device that continuously records the volumetric flow rate at the control device inlet and check and record damper positions on a once-per-shift basis. The monitoring device(s) may be installed in any appropriate location in the exhaust duct such that reproducible flow rate monitoring will result. The flow rate monitoring device(s) shall have an accuracy of 10 percent over its normal operating range and shall be calibrated according to the manufacturer's instructions. The Division may require Osceola Steel Company to demonstrate the accuracy of the monitoring device(s) relative to Methods 1 and 2 of Appendix A of Part 60 [60.274a(b)].

If Osceola Steel Company proposes to control particulate emissions during the heat time by the use of a DEC system and not use a certified visible emissions observer to monitor emissions, it is required to install, calibrate, and maintain a monitoring device that allows the pressure in the free space inside the EAF to be monitored. The pressure shall be recorded as 15-minute integrated averages. The monitoring device may be installed in any appropriate location in the EAF or DEC duct prior to the introduction of ambient air such that reproducible results will be obtained. The pressure-monitoring device shall have an accuracy of plus or minus 5 mm of water gauge over its normal operating range and shall be calibrated according to the manufacturer's instructions [60.274a(f)].

During any performance test required under 60.8, and for any report thereof required by 60.276a(f) of 40 CFR 60 Subpart AAa, or to determine compliance with 60.272a(a)(3) of 40 CFR 60 Subpart AAa, Osceola Steel Company shall monitor the following information for all heats covered by the test:

- Charge weights and materials, and tap weights and materials;
- Heat times, including start and stop times, and a log of process operation, including periods of no operation during testing and the pressure inside an EAF when direct-shell evacuation control systems are used;
- Control device operation log; and
- Continuous opacity monitor or Method 9 data.

40 CFR 63 Subpart YYYYY

For the production of steel other than leaded steel, Osceola Steel Company must prepare and implement a pollution prevention plan for metallic scrap selection and inspection to minimize the amount of chlorinated plastics, lead, and free organic liquids that is charged to the furnace. The scrap pollution prevention plan must be submitted to the Division for approval. The Permittee must operate according to the plan as submitted during the review and approval process, operate according to the approved plan at all times after approval, and address any deficiency identified by the permitting authority within 60 days following disapproval of a plan. A copy of the plan must be available onsite at all times and training on the plan's requirements must be provided to all plant personnel with materials acquisition or inspection duties. Each plan must include the information in paragraphs (a)(1)(i) through (iii) of 63.10685:

- Specifications that scrap materials must be depleted (to the extent practicable) of undrained used oil filters, chlorinated plastics, and free organic liquids at the time of charging to the furnace.
- A requirement in the scrap specifications for removal (to the extent practicable) of lead-containing components (such as batteries, battery cables, and wheel weights) from the scrap.
- Procedures for determining if the requirements and specifications in paragraph (a)(1) of 63.10685 are met (such as visual inspection or periodic audits of scrap providers) and procedures for taking corrective actions with vendors whose shipments are not within specifications.
- The requirements of paragraph (a)(1) of this section do not apply to the routine recycling of baghouse bags or other internal process or maintenance materials in the furnace. These exempted materials must be identified in the pollution prevention plan.

Osceola Steel Company does not propose to produce leaded steel, therefore, Osceola Steel Company must not charge to a furnace metallic scrap that contains scrap from motor vehicle bodies, engine blocks, oil filters, oily turnings, machine shop borings, transformers or capacitors containing polychlorinated biphenyls, lead-containing components, chlorinated plastics, or free organic liquids. Osceola Steel Company must certify in the notification of compliance status and maintain records of documentation that the scrap does not contain motor vehicle scrap. Osceola Steel does not propose to process steel containing motor vehicle scrap, therefore a site-specific plan for mercury switches is not required under 40 CFR 63 Subpart YYYYY.

In addition to the records required by §63.10, Osceola Steel Company must keep records to demonstrate compliance with the requirements for the pollution prevention plan outlined in paragraph (a)(1) of 63.10685 and retain records documenting compliance with paragraph (b)(4) of 63.10685 for steel that does not contain motor vehicle scrap.

Small Combustion Sources

In order to demonstrate compliance with the emission limits for NO_x, PM, CO, and SO₂ for small combustion sources, Osceola Steel Company must maintain fuel composition records for each fuel shipment or statement confirming the natural gas used is pipeline grade natural gas, and must be maintained for a period of five years from the date they were generated.

Combustion controls monitoring, record keeping, and reporting as shall consist of the following for the small combustion sources²²:

- Good Combustion Technique: Operator Practices – Maintenance of a written site specific operating procedures manual in which operating procedures, including startup, shutdown, and malfunction are well documented in accordance with the manufacturer's specifications. The operating procedures must be updated as applicable with any equipment or operating practice changes. The procedures shall contain operating logs documenting such changes and any deviations from the operating procedures. The operating procedures manual shall be maintained in an area allowing easy access to the furnace's operator and made available for Division review and inspection upon request.
- Good Combustion Technique: Maintenance Knowledge – The electric arc furnace and rehear furnaces must be maintained in accordance with manufacturer's specifications by personnel with training specific to the individual furnaces and operating procedures.

Slag Handling

Osceola Steel Company is required to monitor, create records, and submit reports for any emission limit and/or operating limit established under 40 CFR Part 52.21. Any other applicable regulation monitoring, record keeping, and reporting requirements not specifically cited in this section are also required.

Monitoring for the slag handling pile will consist of records demonstrating that wet suppression of the slag pile and roads will be performed "as warranted" for adequate dust control. "As warranted" is defined in the permit as dust control sufficient to keep visible emissions below the PSD opacity limit. Wet suppression of raw material transfer and dust will be used to control particulate emissions from the slag pile and the roads. The drop height of the slag pile will be minimized to 25 feet stationary and 5 feet mobile to reduce the transfer of materials causing fugitive emissions and slag piles should not exceed an area of 75'x75'. Daily observations for any visible emissions will be required as described within the PSD permit. Any deviation of the required monitoring shall be reported as part of the required quarterly report.

Cooling Towers

Compliance with the PSD limit shall consists of maintenance of records documenting that the drift eliminator has been designed to meet the applicable limit. Such records shall be submitted for review during the first quarterly report.

CAM Applicability:

Osceola Steel Mill is required to address 40 CFR Part 64 applicability in its initial Title V Operating Permit application and will be subject to CAM upon renewal of the Title V Operating Permit. Therefore, no CAM provisions are being incorporated into the facility's permit.

²² Good Combustion Practices-Accessed on September 1, 2010 <http://www.epa.gov/ttn/atw/iccr/dirss/gcp.pdf>

6.0 AMBIENT AIR QUALITY REVIEW

An air quality analysis is required to determine the ambient impacts associated with the construction and operation of the proposed modifications. The main purpose of the air quality analysis is to demonstrate that emissions emitted from the proposed modifications, in conjunction with other applicable emissions from existing sources (including secondary emissions from growth associated with the new project), will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment in a Class I or Class II area. NAAQS exist for NO₂, CO, PM_{2.5}, PM₁₀, SO₂, Ozone (O₃), and lead. PSD increments exist for SO₂, NO₂, and PM₁₀.

The proposed project at Osceola Steel Company triggers PSD review for CO, NO_x, SO₂ and PM (PM₁₀ and PM_{2.5}). An air quality analysis was conducted to demonstrate the facility's compliance with the NAAQS and PSD Increment standards for CO, NO_x, SO₂ and PM. An additional analysis was conducted to demonstrate compliance with the Georgia air toxics program. This section of the application discusses the air quality analysis requirements, methodologies, and results. Supporting documentation may be found in the Air Quality Dispersion Report of the application and in the additional information packages.

Modeling Requirements

The air quality modeling analysis was conducted in accordance with Appendix W of Title 40 of the Code of Federal Regulations (CFR) §51, *Guideline on Air Quality Models*, and Georgia EPD's *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions (Revised)*.

The proposed project will cause net emission increases of CO, NO_x, SO₂ and PM that are greater than the applicable PSD Significant Emission Rates. Therefore, air dispersion modeling analyses are required to demonstrate compliance with the NAAQS and PSD Increment. The southeast is generally NO_x limited with respect to ground level ozone formation.

Significance Analysis: Ambient Monitoring Requirements and Source Inventories

Initially, a Significance Analysis is conducted to determine if the CO, NO_x, SO₂ and PM emissions increases at Osceola Steel Company would significantly impact the area surrounding the facility. Maximum ground-level concentrations are compared to the pollutant-specific U.S. EPA-established Significant Impact Level (SIL). The SIL for the pollutants of concern are summarized in Table 6-1.

If a significant impact (i.e., an ambient impact above the SIL) does not result, no further modeling analyses would be conducted for that pollutant for NAAQS or PSD Increment. If a significant impact does result, further refined modeling would be completed to demonstrate that the proposed project would not cause or contribute to a violation of the NAAQS or consume more than the available Class II Increment.

Under current U.S. EPA policies, the maximum impacts due to the emissions increases from a project are also assessed against monitoring *de minimis* levels to determine whether pre-construction monitoring should be considered. These monitoring *de minimis* levels are also listed in Table 6-1. If either the predicted modeled impact from an emission increase or the existing ambient concentration is less than the monitoring *de minimis* concentration, the permitting agency has the discretionary authority to exempt an applicant from pre-construction ambient monitoring. This evaluation is required for CO, NO_x, SO₂ and PM.

If any off-site pollutant impacts calculated in the Significance Analysis exceed the SIL, a Significant Impact Area (SIA) would be determined. The SIA encompasses a circle centered on the facility with a radius extending out to (1) the farthest location where the emissions increase of a pollutant from the project causes a significant ambient impact, or (2) a distance of 50 km, whichever is less. All sources

within a distance of 50 km of the edge of a SIA are assumed to potentially contribute to ground-level concentrations within the SIA and would be evaluated for possible inclusion in the NAAQS and PSD Increment analyses. $PM_{2.5}$ does not yet have established SILs (3 options proposed on 9/12/07)

On March, 2010 Osceola Steel Company submitted a PSD Air Permit Application for the construction of a micro steel mill in Adel, Cook County, GA. The proposed facility comprises an electric arc furnace and a reheat furnace, plus additional associated equipment like cooling towers, silos, etc. The proposed facility was subject to PSD review due to its emissions of CO, NO_x, PM_{10} , and SO₂. A modeling analysis was submitted to demonstrate compliance with NAAQS, PSD Increment regulations, and GA's Toxic Air Pollutants regulations. In such analysis, compliance with $PM_{2.5}$ was demonstrated with the PM_{10} surrogate policy by assuming that all PM_{10} emissions are equal to $PM_{2.5}$ emissions, then modeling PM_{10} emissions and comparing the results with the $PM_{2.5}$ NAAQS.

However, on August 18, 2010, EPA Region IV submitted a letter in which they raised objections to this interpretation of the PM_{10} surrogate policy suggesting that additional analysis is required to demonstrate compliance with the $PM_{2.5}$ NAAQS. In addition, EPA also requested that 1-hr SO₂ modeling be submitted to demonstrate compliance with this new Standard.

Table 6-1: Summary of Modeling Significance Levels

Pollutant	Averaging Period	PSD Significant Impact Level ($\mu\text{g}/\text{m}^3$)	PSD Monitoring Deminimis Concentration ($\mu\text{g}/\text{m}^3$)
PM_{10}	Annual	1	--
	24-Hour	5	10
SO ₂	Annual	1	--
	24-Hour	5	13
	3-Hour	25	--
NO _x	Annual	1	14
CO	8-Hour	500	575
	1-Hour	2000	--

NAAQS Analysis

The primary NAAQS are the maximum concentration ceilings, measured in terms of total concentration of pollutant in the atmosphere, which define the "levels of air quality which the U.S. EPA judges are necessary, with an adequate margin of safety, to protect the public health." Secondary NAAQS define the levels that "protect the public welfare from any known or anticipated adverse effects of a pollutant." The primary and secondary NAAQS are listed in Table 6-2 below.

Table 6-2: Summary of National Ambient Air Quality Standards

Pollutant	Averaging Period	NAAQS	
		Primary / Secondary ($\mu\text{g}/\text{m}^3$)	Primary / Secondary (ppm)
PM_{10}	Annual	*Revoked 12/17/06	*Revoked 12/17/06
	24-Hour	150 / 150	--
$PM_{2.5}$	Annual	15 / 15	--
	24-Hour	35 / 35	--
SO ₂	Annual	80 / None	0.03 / None
	24-Hour	365 / None	0.14 / None
	3-Hour	None/1300	None / 0.5
NO _x	Annual	100 / 100	0.053 / 0.053
CO	8-Hour	10,000 / None	9 / None

Pollutant	Averaging Period	NAAQS	
		Primary / Secondary ($\mu\text{g}/\text{m}^3$)	Primary / Secondary (ppm)
	1-Hour	40,000 / None	35 / None

If the maximum pollutant impact calculated in the Significance Analysis exceeds the SIL at an off-property receptor, a NAAQS analysis is required. The NAAQS analysis would include the potential emissions from all emission units at Osceola Steel Company, except for units that are generally exempt from permitting requirements and are normally operated only in emergency situations. The emissions modeled for this analysis would reflect the results of the BACT analysis for the modified emission unit. Facility emissions would then be combined with the allowable emissions of sources included in the regional source inventory. The resulting impacts, added to appropriate background concentrations, would be assessed against the applicable NAAQS to demonstrate compliance. For an annual average NAAQS analysis, the highest modeled concentration among five consecutive years of meteorological data would be assessed, while the highest second-high impact would be assessed for the short-term averaging periods.

NAAQS ANALYSIS FOR PM_{2.5}

This modeling analysis was conducted under the PM₁₀ surrogate policy and therefore only the permitted facility's emissions were modeled. PM_{2.5} emissions are assumed to be equal to those of PM₁₀, hence the existing PM₁₀ significance modeling results can be used, ruling out this way the need to submit additional modeling.

To account for the contribution from the relevant nearby sources, background concentrations representative of the local conditions were added to the modeling results. Moreover, ambient concentrations of PM_{2.5} are comprised of the contribution of the direct emissions from the stacks plus the secondary formation in the atmosphere due to the chemical reaction of other pollutants such as SO₂ and NO_x. Therefore, background concentrations representative of the local conditions also account for secondary PM_{2.5}.

The values used for background concentrations are 25 $\mu\text{g}/\text{m}^3$ for the 24-hour averaging period and 10.5 $\mu\text{g}/\text{m}^3$ for the annual period. They were extracted from the Valdosta, GA ambient monitoring station, located approximately 36 km SE from the project's site and operated by GA EPD. These values were calculated in the terms of the corresponding standard. Results show that all predicted concentrations of PM_{2.5} plus the corresponding background are below the NAAQS.

Table 6.3: PM_{2.5} NAAQS Assessment.

Pollutant	Averaging Period	Maximum Predicted Concentration* ($\mu\text{g}/\text{m}^3$)	Background Concentration ($\mu\text{g}/\text{m}^3$)	Total Impact** ($\mu\text{g}/\text{m}^3$)	NAAQS ($\mu\text{g}/\text{m}^3$)	Receptor Location UTM Zone 16		Model Met Data Period yyymmddhh
						X (m)	Y (m)	
PM _{2.5}	Annual	0.35	10.5	10.85	15	269648.00	3442642.00	1988
	24 Hour	3.21	25.0	28.21	35	269549.00	3442651.00	88121924

* Highest concentration for both annual and 24 hour averaging period.

** Total impact is the sum of the predicted concentration plus the background concentration.

PSD Increment Analysis

The PSD Increments were established to “prevent deterioration” of air quality in certain areas of the country where air quality was better than the NAAQS. To achieve this goal, U.S. EPA established PSD Increments for certain pollutants. The sum of the PSD Increment concentration and a baseline concentration defines a “reduced” ambient standard, either lower than or equal to the NAAQS that must be met in an attainment area. Significant deterioration is said to have occurred if the change in emissions occurring since the baseline date results in an off-property impact greater than the PSD Increment (i.e., the increased emissions “consume” more than the available PSD Increment).

U.S. EPA has established PSD Increments for NO_x, SO₂, and PM₁₀; no increments have been established for CO or PM_{2.5} (however, PM_{2.5} increments are expected to be added soon). Since no PSD Increment limits exist for PM_{2.5} and 1-hour SO₂, no analysis was required. The PSD Increments are further broken into Class I, II, and III Increments. The Osceola Steel Company is located in a Class II area. The PSD Increments are listed in Table 6-3.

Table 6-4: Summary of PSD Increments

Pollutant	Averaging Period	PSD Increment	
		Class I (ug/m ³)	Class II (ug/m ³)
PM ₁₀	Annual	4	17
	24-Hour	8	30
SO ₂	Annual	2	20
	24-Hour	5	91
	3-Hour	25	512
NO _x	Annual	2.5	25

To demonstrate compliance with the PSD Increments, the increment-affecting emissions (i.e., all emissions increases or decreases after the appropriate baseline date) from the facility and those sources in the regional inventory would be modeled to demonstrate compliance with the PSD Class I increment for any pollutant greater than the SIL in the Significance Analysis. For an annual average analysis, the highest incremental impact will be used. For a short-term average analysis, the highest second-high impact will be used.

The determination of whether an emissions change at a given source consumes or expands increment is based on the source classification (major or minor) and the time the change occurs in relation to baseline dates. The major source baseline date for NO_x is February 8, 1988, and the major source baseline for SO₂ and PM₁₀ is January 5, 1976. Emission changes at major sources that occur after the major source baseline dates affect Increment. In contrast, emission changes at minor sources only affect Increment after the minor source baseline date, which is set at the time when the first PSD application is completed in a given area, usually arranged on a county-by-county basis. The minor source baseline dates have been set for PM₁₀ and SO₂ as January 30, 1980, and for NO₂ as April 12, 1991.

The NO₂ 1-hour standard of 100 ppb (188 µg/m³) was recently promulgated on January 22nd 2010. With the proposed standard, the EPA did not, however, establish either a SIL or a significant monitoring threshold. For the purpose of this permit application 5% of the standard was chosen as a SIL. This proposed SIL was based on the SIL set for CO, which is the only other pollutant with a 1-hour standard. For CO, the 1-hour SIL (2,000 µg/m³) is 5% of the 1-hour NAAQS standard (40,000 µg/m³). We are not proposing a level for a significant monitoring concentration since the standard was primarily written for concerns in major urban areas with large vehicular traffic within 50 meters of major roadways.

Modeling Methodology

Details on the dispersion model, including meteorological data, source data, and receptors can be found in EPD's PSD Dispersion Modeling and Air Toxics Assessment Review in Appendix C of this Preliminary Determination and in Section 6.1 of the permit application.

Modeling Results

The Class II area significant impact analysis was conducted for PM₁₀, NO₂, SO₂, and CO. An ambient air boundary was defined with receptors spaced 100 meters from each other, and a 20x20 kilometer receptor grid was used for the significance modeling, being this grid comprised of two different segments. The first one extended approximately 2 kilometers from the location of the main stacks with 100-meter spaced

receptors, excluding the area within the boundary line. The second segment extended from the edge of the first segment for eight additional kilometers with 500-meter spaced receptors.

It was stated in the application that the ambient air boundary will not be completely fenced, and that those parts without a fence would be controlled to prevent public access through patrols and visual observation.

Table 6-5 shows that the proposed project will not cause ambient impacts of CO, NO_x, SO₂ and PM above the appropriate SIL. The 1-hr SO₂ Standard became effective on August 23, 2010, but to present date, no corresponding Significant Impact Level (SIL) has been established. The applicant proposed the use of the interim SIL provided by EPA on an August 23, 2010 memorandum, which has a value of 3 ppb (7.86 ug/m³). This interim SIL is based on an impact equal to 4% of the 1-hour SO₂ NAAQS. 1-hr SO₂ modeling was conducted with the same meteorological data used with the modeling of the rest of the pollutants and averaging periods. This correspond to surface data collected from station 03813 in Macon, GA, and upper air data collected from station 3881 in Centreville, AL, both for the 5-year period from 1987 – 1991. The emission rate used for the 1-hr SO₂ analysis was the same previously used for the other SO₂ averaging periods and it was subject to GA EPD's Stationary Source Permitting Program approval prior to assessing the modeling analysis. PM_{2.5} emissions were assumed to be equal to PM₁₀ emissions. Location and stack parameters of the proposed equipment were the same previously used for the other pollutants and averaging periods.

Because the emissions increases from the proposed project result in ambient impacts less than the SIL, no further PSD analyses were conducted for these pollutants.

Table 6-5: Class II Significance Analysis Results – Comparison to SILs

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (ug/m ³)	SIL (ug/m ³)	Significant?
NO ₂	1-hour	88021619	270.5000	3442.3000	8.99	9.4	No
	Annual	1989	270.5000	3442.3000	0.35	1	No
PM ₁₀	24-hour	88121924	269.5490	3442.6510	3.21227	5	No
	Annual	1988	269.6480	3442.6420	0.34922	1	No
SO ₂	3-hour	90100312	269.7000	3442.8000	2.52011	25	No
	24-hour	90042724	269.6000	3442.8000	0.83732	5	No
	Annual	1989	270.5000	3442.4000	0.12525	1	No
	1-Hour	87061519	270.4000	3443.0000	3.31579	7.86	No
		88060914	270.3000	3442.7000	3.31388		
		89050517	270.3000	3442.7000	4.53715		
		90021007	270.5000	3442.4000	4.66016		
		91030306	269.5006	3442.3967	4.14663		
		87061519	270.4000	3443.0000	3.31579		
CO	1-hour	90021007	270.5000	3442.4000	48.024810	2000	No
	8-hour	87090416	269.6000	3442.1000	22.25	500	No

As indicated in the tables above, maximum modeled impacts were below the corresponding SILs for NO₂, PM₁₀, SO₂ and CO.

Ambient Monitoring Requirements

Table 6-6: Significance Analysis Results – Comparison to Monitoring *De Minimis* Levels

Pollutant	Averaging Period	Year*	UTM East (km)	UTM North (km)	Monitoring De Minimis Level (ug/m³)	Modeled Maximum Impact (ug/m³)	Significant?
NO ₂	Annual	1989	270.50000	3442.30000	14	0.35	No
PM ₁₀	24-hour	88121924	269.54900	3442.65100	10	3.21227	No
SO ₂	24-hour	90042724	269.60000	3442.80000	13	0.83732	No
CO	8-hour	87090416	269.60000	3442.10000	575	22.25	No

The impacts for NO_x, CO, SO₂, and PM₁₀ quantified in Table 6-4 of the Class I Significance Analysis are compared to the Monitoring *de minimis* concentrations, shown in Table 6-1, to determine if ambient monitoring requirements need to be considered as part of this permit action. Because all maximum modeled impacts are below the corresponding de minimis concentrations, no pre-construction monitoring is required for NO₂, PM₁₀, SO₂, or CO.

As noted previously, the VOC *de minimis* concentration is mass-based (100 tpy) rather than ambient concentration-based (ppm or µg/m³). Projected VOC emissions increases resulting from the proposed modification exceed 100 tpy; however, the current Georgia EPD ozone monitoring network (which includes monitors in Brunswick, Georgia [approximately 180 km to the west of the site] and Leslie, Georgia [approximately 115 km north northwest of the site]). The Leslie, Georgia monitor is closer to the site, however, this monitor is located downwind of the Columbus, Georgia area and is therefore more representative of the Columbus, Georgia area's ground level ozone than Adel, Georgia's ground level ozone. The Brunswick monitor is to the west of the Adel site and is therefore thought to be more representative of the background concentrations at the Adel site because it is downwind of Adel. The aforementioned monitors will provide sufficient ozone data such that no pre-construction or post-construction ozone monitoring is necessary.

Class I Area Analysis

Federal Class I areas are regions of special national or regional value from a natural, scenic, recreational, or historic perspective. Class I areas are afforded the highest degree of protection among the types of areas classified under the PSD regulations. U.S. EPA has established policies and procedures that generally restrict consideration of impacts of a PSD source on Class I Increments to facilities that are located near a federal Class I area. Historically, a distance of 100 km has been used to define "near", but more recently, a distance of 200 kilometers has been used for all facilities that do not combust coal.

Class I Air Quality Related Values (AQRV)

To determine whether this application is subject to a Class I modeling analysis, the Q/d factor was used, where "Q" is the sum of all SO₂, NO_x, and PM₁₀ emissions in tons per year caused by the project, and "d" is the distance between the proposed source and the nearest Class I area boundary.

The total emissions of these pollutants for the permitted facility are of 192 TPY. Using the different distances to each Class I Area as described previously in this document, the Q/d factors are the following:

- For Okefenokee, Q/d = 2.2
- For St. Marks, Q/d = 1.6
- For Bradwell Bay, Q/d = 1.28

The three (3) Class I areas within approximately 200 kilometers of the Osceola Steel Company are the Okefenokee Swamp National Wildlife Refuge in Georgia, located approximately 87 kilometers southeast of the facility; the St. Marks National Wildlife Refuge in Florida, located approximately 120 kilometers southwest of the facility and the Bradwell Bay National Wilderness Area in Florida, located approximately 150 kilometers southwest of the facility. The U.S. Fish and Wildlife Service (FWS) is the designated Federal Land Manager (FLM) responsible for oversight of Okefenokee Swamp National Wildlife Refuge and the St. Marks National Wildlife Refuge and The Forest Service (FS) is the designated Federal Land Manager (FLM) for the Bradwell Bay National Wilderness Area. Therefore, a brief description of the process and its emissions were submitted to both agencies inquiring if an Air Quality Related Values (AQRV) assessment was required. In addition, an assessment of the Significant Impact Levels at those Class I Areas was submitted to Georgia EPD.

The screening threshold established by the FLMs to determine if a project is required to submit a Class I modeling analysis is $Q/d = 10$. Most results below this value are considered not to have a significant impact on the Class I Air Quality Related Values (AQRVs).

The FWS and the FS were notified of the conditions of this project and a response was received only from the FWS indicating that further analysis was not required. The FS on the other hand, had previously reached an agreement with GA EPD by which PSD applications with Q/d values less than 4 would not be required to be reviewed by them for AQRV compliance.

Class I Significant Impact Analysis

The Class I significant impact analysis was conducted using AERMOD v. 09292 as a screening tool, modeling emissions of PM_{10} , NO_x , and SO_2 from the permitted facility with receptors located at 50 km downwind in direction to each of the Class I areas, forming four arches of approximately 7, 35, 10, and 35 kilometers, which is the width of the extension of Okefenokee and the clustered Saint Marks – Bradwell Bay areas at this distance and with respect to their corresponding azimuths with the proposed facility (See Figure 1 in the Appendix). Such receptor grids were 1km - spaced between adjacent points, and the maximum predicted concentrations are shown in Tables I through V for each of the previously mentioned Class I areas.

TABLE I. PROJECT IMPACTS VS. SIGNIFICANCE LEVELS (OKEFENOCKEE CLASS I AREA)

Criteria Pollutant	Averaging Period	Significance Level	Maximum Predicted Concentration*	Receptor Location UTM ZONE 17		Model Met Data Period
		($\mu g/m^3$)	($\mu g/m^3$)	X	Y	[mmddyyyy]
PM_{10}	Annual	0.2	0.003460	319290.00	3435465.92	1989
	24-Hour	0.3	0.042750	318073.00	3429483.63	89122824
NO_2	Annual	0.1	0.009750	319290.00	3435465.92	1989
SO_2	Annual	0.1	0.003790	319290.00	3435465.92	1989
	24-Hour	0.2	0.049130	313078.00	3417424.58	91110224
	3-Hour	1.0	0.221690	319769.00	3441551.96	89080703

* Highest value.

TABLE II. PROJECT IMPACTS VS. SIGNIFICANCE LEVELS (ST. MARKS CLASS I AREA)

Criteria Pollutant	Averaging Period	Significance Level	Maximum Predicted Concentration*	Receptor Location UTM ZONE 17		Model Met Data Period
		($\mu\text{g}/\text{m}^3$)	($\mu\text{g}/\text{m}^3$)	X	Y	[mmddyyyy]
PM ₁₀	Annual	0.2	0.002930	231474.48	3410285.20	1991
	24-Hour	0.3	0.032570	245536.22,	3398693.59	89030824
NO _x	Annual	0.1	0.008810	232041.22	3409621.63	1991
SO ₂	Annual	0.1	0.003520	232041.22	3409621.63	1991
	24-Hour	0.2	0.039750	246303.12	3398277.20	89030824
	3-Hour	1.0	0.188620	239685.95	3402492.80	89052921

* Highest value.

TABLE III. PROJECT IMPACTS VS. SIGNIFICANCE LEVELS (BRADWELL BAY CLASS I AREA)

Criteria Pollutant	Averaging Period	Significance Level	Maximum Predicted Concentration*	Receptor Location UTM ZONE 17		Model Met Data Period
		($\mu\text{g}/\text{m}^3$)	($\mu\text{g}/\text{m}^3$)	X	Y	[mmddyyyy]
PM ₁₀	Annual	0.2	0.002930	231474.48	3410285.20	1991
	24-Hour	0.3	0.032570	245536.22,	3398693.59	89030824
NO _x	Annual	0.1	0.008810	232041.22	3409621.63	1991
SO ₂	Annual	0.1	0.003520	232041.22	3409621.63	1991
	24-Hour	0.2	0.039750	246303.12	3398277.20	89030824
	3-Hour	1.0	0.188620	239685.95	3402492.80	89052921

* Highest value.

Results show that maximum predicted concentrations of all pollutants in the three Class I areas less than 200 km from the Osceola Steel Company site were below the SILs and therefore no further Class I PSD increment analysis is required. In addition, the air quality analyses reviewed and described in all sections above show conformance of the project's PM_{2.5} and 1-hour SO₂ impacts with the NAAQS. No Class I and Class II PSD Increment limits exist for these pollutants and therefore no such analyses were required.

7.0 ADDITIONAL IMPACT ANALYSES

PSD requires an analysis of impairment to visibility, soils, and vegetation that will occur as a result of a modification to the facility and an analysis of the air quality impact projected for the area as a result of the general commercial, residential, and other growth associated with the proposed project.

PSD regulations require an assessment of other possible impacts, including any secondary impacts on soils and vegetation. An analysis was completed to assess the potential impact of vegetative stress in the area of the proposed plant as outlined in the USEPA document “*A Screening Procedure for the Impact of Air Pollution sources on Plants, Soils, and Animals*”. This document provides ambient concentration levels of SO₂, NO_x, CO, Fluorine, Beryllium and Lead, which can be used for screening levels to determine if there is a potential for vegetative stress.

The area around the plant is in attainment with all air quality standards and the proposed plant is not expected to change the attainment status of the area. An evaluation was completed using the modeled emissions calculated in the previous sections to confirm that the vegetation present in the area would not be stressed by the project. Table 9-1 of the application summarizes the modeled concentrations for each pollutant and compares them to the screening level as taken from Table 3.1 of the USEPA screening procedure document.

As indicated in Table 9-1 of the application, the maximum ground level concentrations for all pollutants for all averaging periods are well below the screening levels. With this demonstration it is apparent that not only is existing vegetation safe from potential vegetative stress but also any potential new crops that may be planted in the area will be as well. The USEPA Screening documents also outlines an evaluation for metals impacts. All these metals along with all other known toxics being emitted from the mill were evaluated as part of the Georgia Air Toxics program in Section 7 of the permit application. The conclusion of that evaluation was that the plant demonstrates compliance with the Georgia toxics program; therefore, no further evaluation is being conducted.

Growth

The proposed plant is expected to employ approximately 140 people during operation. This work force is expected to come from local communities; therefore, growth impacts are expected to be minimal and should not adversely affect the ambient air quality in the surrounding area. No additional automobile roadways are planned for the project.

Construction Impacts

During the construction phase of the proposed plant, there will be two primary sources of air emissions:

- 1) Pollutants emitted from construction equipment and;
- 2) Fugitive dust emissions associated with the construction activities. Because of the small amount of area and involved and because the site is already relatively cleared this impacts are expected to be very limited.

Typically, gasoline and diesel powered construction equipment emit small amounts of VOCs, CO, SO₂, NO_x, and PM. Emissions due to the operation of this equipment are expected to cause only localized increases in pollutant levels. These increases will be only temporary and are not expected to cause any long-term adverse impacts on the construction area or the surrounding communities.

The fugitive dust emissions created from the construction activities will be more visible than the other pollutant emissions from the equipment. Site grading and preparation activities will create dust emissions.

The greatest impact of the fugitive dust emissions will be confined to the construction site, and the effects on the surrounding properties are expected to be minimal. The extent of fugitive emissions will vary day to day, depending on the amount of construction activity and the weather. Standard engineering and construction practices will be implemented in order to minimize fugitive dust emissions (such as watering haul roads).

All pollutants modeled for significance also have to be evaluated to determine if the facility should be required to conduct preconstruction monitoring. For SO₂ this analysis was conducted as previously described in the May 24, 2010 modeling memorandum and it was found that no preconstruction monitoring is required. For PM_{2.5} no Monitoring de Minimis level exist and therefore this assessment is not required.

Visibility

Visibility impairment is any perceptible change in visibility (visual range, contrast, atmospheric color, etc.) from that which would have existed under natural conditions. Poor visibility is caused when fine solid or liquid particles, usually in the form of volatile organics, nitrogen oxides, or sulfur oxides, absorb or scatter light. This light scattering or absorption actually reduces the amount of light received from viewed objects and scatters ambient light in the line of sight. This scattered ambient light appears as haze.

Another form of visibility impairment in the form of plume blight occurs when particles and light-absorbing gases are confined to a single elevated haze layer or coherent plume. Plume blight, a white, gray, or brown plume clearly visible against a background sky or other dark object, usually can be traced to a single source such as a smoke stack.

Georgia's SIP and Georgia *Rules for Air Quality Control* provide no specific prohibitions against visibility impairment other than regulations limiting source opacity and protecting visibility at federally protected Class I areas. To otherwise demonstrate that visibility impairment will not result from continued operation of the mill, the VISCREEN model was used to assess potential impacts on ambient visibility at so-called "sensitive receptors" within the SIA of the Osceola Steel Company. A Class II visibility analysis is conducted at sensitive receptors located within the significant impact area (SIA) of the project. In this case, since the significance levels were not exceeded, no SIA can be defined, and therefore no further analysis would be required. Since there is no ambient visibility protection standard for Class II areas, this analysis is presented for informational purposes only and predicted impacts in excess of screening criteria are not considered "adverse impacts" or cause further refined analyses to be conducted.

Georgia Toxic Air Pollutant Modeling Analysis

Georgia EPD regulates the emissions of toxic air pollutant (TAP) emissions through a program covered by the provisions of *Georgia Rules for Air Quality Control*, 391-3-1-.02(2)(a)3.(ii). A TAP is defined as any substance that may have an adverse effect on public health, excluding any specific substance that is covered by a State or Federal ambient air quality standard. Procedures governing the Georgia EPD's review of TAP emissions as part of air permit reviews are contained in the agency's "*Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions (Revised)*."

Selection of Toxic Air Pollutants for Modeling

The proposed project was evaluated for compliance with the Georgia Air Toxics program using the "Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions" dated June 21, 1998. The first step was to calculate the potential emissions of all toxic pollutants from the Osceola mill. The calculations are based on USEPA AP-42 emission factors for steel mills and natural gas combustion and

metals analysis of EAF dust as outlined in Section 3 of the permit application. Table A-1 in Exhibit A of the permit application provides the toxic emission calculations for the project.

For each toxic pollutant identified, an AAC was developed by following the Georgia guidelines. The Georgia guidelines prioritize the available resources for toxicity data. First priority is given to inhalation reference concentrations (RfC) and Risk Based Air Concentrations (RBAC) identified in the USEPA's Integrated Risk Information System (IRIS) database, followed by OSHA PEL standards, ACGIH TLVs, and NIOSH RELs. AACs developed from worker exposure levels are based on 40 hours/week of exposure and must be adjusted to account for the potential exposure of the public (7 days/week, 24 hours/day). This correction along with the application of a safety factor of 300 for known carcinogenic compounds and 100 for all others is utilized in the development of AACs from worker exposure standards. The safety factor is applied to account for persons who may be sensitive to exposure to these pollutants. Toxicity data taken from the IRIS database does not require any adjustments because exposures to persons with respiratory maladies, young children, or the elderly were taken into account in the determination of these values. Short-term exposures are addressed using OSHA, NIOSH, and ACGIH Short Term Exposure Limits (STEL), and ceiling limits. A safety factor of 10 is universally applied to all short-term standards. The derivation of the AAC for each pollutant assessed is shown in Table A-2 in Exhibit A of the permit application.

The next step was a dispersion analysis. Each source of pollutants (the EAF baghouse and the rehear furnace) was modeled using the USEPA SCREEN3 model assuming an emission rate of 1 g/s. Table 7-1 shows the results of SCREEN3 modeling performed by Osceola Steel Company for each of the sources.

Table 7-1: SCREEN3 Modeling Results Summary

Source ID	Source	Stack Height (m)	Stack Dia. (m)	Stack Velocity (m/s)	Stack Temperature (K)	1-Hour MGLC from SCREEN3 Analysis (ug/m ³)
BH1	EAF Baghouse	36.57	5.00	12.02	373.15	1.754
RHF	Reheat Furnace	36.57	1.346	14.22	616.48	5.883

For each TAP identified for further analysis, both the short-term and long-term AAC were calculated following the procedures given in Georgia EPD's *Guideline*. Figure 8-3 of Georgia EPD's *Guideline* contains a flow chart of the process for determining long-term and short-term ambient thresholds. Osceola Steel Company referenced the resources previously detailed to determine the long-term (i.e., annual average) and short-term AAC (i.e., 24-hour or 15-minute). The AACs were verified by the EPD.

Determination of Toxic Air Pollutant Impact

The Georgia EPD *Guideline* recommends a tiered approach to model TAP impacts, beginning with screening analyses using SCREEN3, followed by refined modeling, if necessary, with ISCST3 or ISCLT3. For the refined modeling completed, the infrastructure setup for the SIA analyses was relied upon with appropriate sources added for the TAP modeling. Note that per the Georgia EPD's *Guideline*, downwash was not considered in the TAP assessment.

Initial Screening Analysis Technique

Generally, an initial screening analysis is performed in which the total TAP emission rate is modeled from the stack with the lowest effective release height to obtain the maximum ground level concentration (MGLC). Note the MGLC could occur within the facility boundary for this evaluation method. The individual MGLC is obtained and compared to the smallest AAC. Due to the likelihood that this

screening would result in the need for further analysis for most TAP, the analyses were initiated with the secondary screening technique.

The permitted facility discharges to the atmosphere 37 hazardous air pollutants (HAPs) shown in Table VII and emitted from the electric arc furnace and the reheat furnace through the stacks. Emission rates were estimated using AP-42 emission factors.

Modeling was conducted using a generic emission rate of 1 g/sec for which a hypothetical predicted concentration was found. The modeled ground level concentration (MGLC) for each pollutant was then calculated multiplying the hypothetical predicted concentration by the ratio of the different emission rates. SCREEN3 V96043 dispersion model was used for such analysis and it was assumed that the total emissions for each pollutant from both sources were discharged from the reheat furnace only, being the source that produced the highest concentration with the generic emission rate.

MGLCs calculated by SCREEN3 are 1-hour concentrations and therefore results were converted to annual 24 hour and 15 minutes averages in order to compare them to the corresponding Acceptable Ambient Concentration (AAC), which was calculated for each one of those substances and their applicable time-averaging periods according to EPD's Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions. It should be noted that several of the AACs had been incorrectly calculated by the consultants and were therefore corrected during the review process. Comparison shows that all MGLCs assessed were found to be less than their respective AACs, as presented in Table VIII in the EPD modeling memo dated May 24, 2010 included in Appendix C.

8.0 EXPLANATION OF DRAFT PERMIT CONDITIONS

The permit requirements for this proposed facility are included in draft Permit No. 3312-075-0024-P-01-0 located within Appendix A.

Facility Description

Osceola Steel Company proposes to construct and operate a micro steel mill with the capability of producing approximately 430,000 tons of steel per year. The proposed project consists of a melt shop containing a 24 million British Thermal Units per hour (10^6 Btu/hr) electric arc furnace; a reheat furnace with a heat input of 75×10^6 Btu/hr, horizontal ladle preheaters, a vertical ladle heating stack, Tundish preheaters, casting machine torches, cooling towers, continuous casting, a lime silo and a carbon silo. All fuel burning equipment associated with the proposed project will fire natural gas.

Section 1.0: Requirements Pertaining to the Entire Facility

Condition 1.6 – General applicability of 40 CFR Part 63, Subpart A and YYYYYY for the entire facility.

Condition 1.7 General applicability of 40 CFR Part 60, Subpart A and AAa for the operation of the electric arc furnace (Source Code: EAF).

Section 2.0: Requirements for Emission Units

Condition 2.1 defines the requirements to construct and operate the facility in accordance with Georgia Rule 391-3-1-.02(7).

Condition 2.2 requires the commencement of construction of the Osceola Steel Company facility within 18 months of the issuance of the permit.

Condition 2.3 requires the submittal of a Title V Permit application within 12 months of commencing operation as well as the review of potential applicability of 40 CFR Part 64 to applicable Osceola Steel Company equipment.

Condition 2.4 defines the Stack BH1.

Condition 2.5 prohibits the Permittee to produce leaded steel.

Condition 2.6 requires the Permittee to submit a pollution prevention plan for scrap selection and inspection in accordance with 40 CFR 63 YYYYYY.

Condition 2.7 defines the specifications of scrap material and requires the Permittee to demonstrate compliance with the specifications.

Condition 2.8 requires the Permittee to fire pipeline quality natural gas exclusively in all fuel burning equipment located within the facility.

Condition 2.9 defines the annual and hourly production limit for Osceola Steel Company

Condition 2.10 defines BACT for CO for Source EAF.

Condition 2.11 defines BACT for NOx for Source EAF.

Condition 2.12 defines BACT for PM for Source EAF.

Condition 2.13 defines BACT for SO₂ for Source EAF.

Condition 2.14 defines BACT for CO for Source RHF.

Condition 2.15 defines BACT for NO_x for Source RHF.

Condition 2.16 defines BACT for PM for Source RHF.

Condition 2.17 defines BACT for SO₂ for Source RHF.

Condition 2.18 defines BACT for CO on the Small Combustion Sources.

Condition 2.19 defines BACT for NO_x on the Small Combustion Sources.

Condition 2.20 defines BACT for PM on the Small Combustion Sources.

Condition 2.21 defines BACT for SO₂ on the Small Combustion Sources

Condition 2.22 requires the Permittee to operate dust suppression techniques to control particulate matter emissions from the roadways.

Condition 2.23 requires the Permittee to operate dust suppression techniques to control particulate matter emissions from the slag piles.

Condition 2.24 defines BACT for the Cooling Towers.

Condition 2.25 defines the emission limits for CO, NO, PM/PM₁₀/PM_{2.5}, SO₂ and opacity emissions limits for the Electric Arc Furnace.

Condition 2.26 defines the emission limits for CO, NO, PM/PM₁₀/PM_{2.5}, SO₂ emissions limits for the Reheat Furnace.

Condition 2.27 defines the mass flow rate limit for the Cooling Towers.

Condition 2.28 defines the total dissolved solids (TDS) limit for the Cooling Towers.

Condition 2.29 defines a 12-consecutive month period.

Condition 2.30 defines the opacity limit from the slag handling and emissions from road travel on the site.

Condition 2.31 requires installation of a physical barrier around the site.

Condition 2.32 defines the Particulate Matter limit for the storage silos

Condition 2.33 requires the Permittee to limit Greenhouse Gas (GHG) Emissions to less than 74,900 tons per year CO₂e.

Section 3.0: Fugitive Emissions

Condition 3.2 establishes dust suppression techniques and practices to reduce fugitive emissions from slag pile and road travel on the site.

Condition 3.3 limits opacity from the slag handling process and roadways to 10 percent opacity.

Condition 3.4 limits the drop height of the slag pile and the slag pile area.

Section 4.0: Process & Control Equipment

Conditions 4.1 through Condition 4.3 requires the Permittee to install a negative or positive pressure fabric filter (baghouse) on stack BH1, CSF and LSF

Section 5.0: Requirements for Monitoring

Condition 5.1 explains general requirements for the operation of a continuous monitoring system.

Condition 5.2 requires the installation of a bag leak detect system on BH1 to comply with the requirements of NSPS Subpart AAa.

Condition 5.3 requires performance of melt shop opacity once per day during meltdown and refining period and to record daily visible emissions in accordance with Method 9 procedures.

Condition 5.4 requires the monitoring and recording of the EAF control system fan motors amperes and damper position in accordance with 40 CFR 60 Subpart Aaa.

Condition 5.5 requires daily visible emissions observations of the each baghouse and retain the records in a daily visible emissions log in accordance with Method 9 procedures.

Condition 5.6 requires the Permittee to perform monthly operational status checks on equipment that is important to the performance of the total capture system.

Condition 5.7 requires the Permittee to initiate procedures to determine the cause of all alarms within 1 hour of the alarm sounding on the bag leak detection system.

Condition 5.8 defines good combustion controls for all combustion sources located within Osceola Steel Company.

Condition 5.9 requires the Permittee to install, calibrate, and maintain a monitoring device that allows the pressure in the free space inside the EAF to be monitored.

Condition 5.10 requires the Permittee to demonstrate compliance with the applicable shop standard during the melting and refining period on the EAF. The pressure determined during the most recent demonstration of compliance shall be maintained at all times when the EAF is operating in a meltdown and refining period.

Condition 5.11 defines the parameters to be monitored during the charging of Source EAF.

Condition 5.12 requires the Permittee to verify sulfur content of all charging and tap materials received by the EAF.

Condition 5.13 defines the monitoring applicable to controlling fugitive emissions associated with road travel and slag handling within Osceola Steel Company.

Conditions 5.14 requires the facility to monitor the quantity of steel produced on an hourly basis.

Section 6.0: Requirements for Performance Testing

Condition 6.2 lists the applicable testing method for applicable equipment.

Condition 6.3 requires performance testing within 180 days after achieving the maximum production rate on the EAF.

Condition 6.4 requires the Permittee to comply with applicable rules of NSPS Subpart AAa for Baghouse 1.

Condition 6.5 outlines the performance test procedures for baghouses that control materials that aren't subject to NSPS Subpart AAa, but share a common control device.

Condition 6.6 prohibits the Permittee from adding gaseous diluents to the effluent gas stream in any pressurized fabric filter collector unless the amount has already been determined.

Section 7.0: Notification, Reporting and Record Keeping

Condition 7.1 defines the records maintenance schedule.

Condition 7.2 requires Osceola Steel Company to record of the amount of steel produced on a monthly basis and for the amount produced in the previous 11 consecutive months to generate a 12-consecutive month total.

Condition 7.3 requires Osceola Steel Company to submit quarterly records of the amount of steel cast on a monthly basis and for the amount produced in the previous 11 consecutive months to generate a 12-consecutive month total

Condition 7.5 requires the Permittee to submit to the Division for approval, a SSMP (site-specific monitoring plan) to demonstrate how the Permittee intends to operate the bag-leak detection system in accordance with NSPS Subpart AAa.

Condition 7.6 prohibits the Permittee from adjusting the averaging period, alarm set point or alarm delay time without prior Division approval with the exception of adjusting for seasonal impacts or if opacities greater than zero are observed over 4 consecutive 15 second readings and the alarm does not react.

Condition 7.7 defines the locations of negative pressure and positive pressure baghouses.

Condition 7.8 discusses record keeping for shop opacity and the bag leak detection system for Sources EAF and RHF.

Condition 7.9 discusses record keeping for shop opacity and the bag leak detection system for the EAF.

Condition 7.10 requires the Permittee to maintain records of all data obtained through compliance with requirements outlined in Condition 5.4 and Condition 5.6.

Condition 7.11 discusses record keeping requirements for the drift eliminators on the cooling towers.

Condition 7.12 requires the Permittee to keep a file containing the specifications for the maximum sulfur content (percent by weight), of each charge carbon product used in the Electric Arc Furnace with supporting documentation demonstrating compliance with the sulfur dioxide limit in Condition 2.13.

Condition 7.13 requires the Permittee to implement a dust suppression plan, record and report the frequency and nature in which fugitive emissions is suppressed from on-site road activities and slag handling.

Condition 7.14 defines the timeline for which the Division shall be notified in the event of malfunction or breakdown of fuel burning, process or emission control equipment.

Condition 7.15 requires reporting of excess emissions, exceedances and excursions associated with this permit.

Condition 7.16 defines excess emissions, exceedances and excursions associated with this permit.

Condition 7.17 requires the Permittee to conduct the performance test 90 days after initial startup of the Electric Arc Furnace, to demonstrate compliance with 40 CFR 60.272a(a) and submit a written report of the results to the Division.

Condition 7.18 requires the Permittee to track and record natural gas consumption for all combustion sources in order to calculate GHG Emissions during the reporting period.

Condition 7.19 requires the Permittee to calculate Greenhouse Gas (GHG) Emissions in tons per year.

Section 8.0: Special Conditions

Condition 8.2 requires facility to pay an annual permit fee once the plant becomes operational.

APPENDIX A

Draft Prevention of Significant Deterioration (PSD) Construction Permit
Osceola Steel Company
Adel (Cook County), Georgia

APPENDIX B

Osceola Steel Company PSD Permit Application and Supporting Data

Contents Include:

1. PSD Permit Application No. 19537, dated March 15, 2010
2. Additional Information Package Dated:
 - a. Information Request dated April 12, 2010
 - b. Information Request dated May 20, 2010
 - c. Information Request dated August 17, 2010
3. EPA Comments on PSD Permit Application No. 19537, dated August 24, 2010

APPENDIX C

EPD'S PSD Dispersion Modeling and Air Toxics Assessment Review