Appendix A

RBLC Search Summary for Pertinent Emission Units at Similar Sources

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emissions Control
Appendix A: EPA RACT BACT LAER Clearinghouse Data
Coke Battery

Nitrogen Oxides (NOx)

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	COK-111-Coke Battery 1 Flue Gas Desulfurization	Coal	197	T/H	Nitrogen Oxides (NOx)	Staged Combustion in coke oven	153.7	LB/H		BACT-PSD	612.03	T/H		0.71	LB/T	WET COAL
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	COK-211-Coke Battery 2 Flue Gas Desulfurization	coal	197	T/H	Nitrogen Oxides (NOx)	Staged combustion in the coke oven	153.7	LB/H		BACT-PSD	612.03	T/H		0.71	LB/T	WET COAL
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	COK-202 - Coke Battery 2 Coke Pushing		126	T/H	Nitrogen Oxides (NOx)		4.11	LB/H		BACT-PSD	16.38	T/YR		0.019	LB/T	DRY COKE
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	COK-102 - Coke Battery 1 Coke Pushing		126	T/H	Nitrogen Oxides (NOx)		4.11	LB/H		BACT-PSD	16.38	T/YR		0.019	LB/T	DRY COKE
OH-0332	MIDDLETOWN COKE COMPANY	SUN COKE ENERGY, INC.	OH	P0104768	324199	2/9/2010	Heat Recovery Coke Battery: 100 heat recovery coke ovens in 3 batteries: 1 w/ 20 ovens, 2 w/ 40 ovens each. Process includes coal handling, charging, heat recovery coking, pushing, quenching, coke handling and storage. Heat recovery steam generators will recover	Coke Oven Batteries (3) without heat recovery	coal	2300	T/D	Nitrogen Oxides (NOx)	Bypass one HRSG at a time, one stack	20.8	LB/H		LAER	10	T/YR	PER ROLLING 12-MO.PERIOD FOR HRSG BYPASS	0		
OH-0332	MIDDLETOWN COKE COMPANY	SUN COKE ENERGY, INC.	OH	P0104768	324199	2/9/2010	Heat Recovery Coke Battery: 100 heat recovery coke ovens in 3 batteries: 1 w/ 20 ovens, 2 w/ 40 ovens each. Process includes coal handling, charging, heat recovery coking, pushing, quenching, coke handling and storage. Heat recovery steam generators will recover	Coke Oven Batteries (3), bypass lime spray	coal	0		Nitrogen Oxides (NOx)	Bypass control	1	LB/T	PER TON COAL W/SPRAYDRYER/FILTER BYPASS	LAER	6.25	T/YR	AS A ROLLING 12-MONTH SUMMATION	0		
OH-0332	MIDDLETOWN COKE COMPANY	SUN COKE ENERGY, INC.	OH	P0104768	324199	2/9/2010	Heat Recovery Coke Battery: 100 heat recovery coke ovens in 3 batteries: 1 w/ 20 ovens, 2 w/ 40 ovens each. Process includes coal handling, charging, heat recovery coking, pushing, quenching, coke handling and storage. Heat recovery steam generators will recover	Coke Oven Batteries (3) with heat recovery	coal	912500	T/YR	Nitrogen Oxides (NOx)	Staged combustion	104.2	LB/H		LAER	456.25	T/YR	AS A ROLLING 12-MONTH SUMMATION	1	LB/T	PER WET TON OF COAL AS LAER
OH-0332	MIDDLETOWN COKE COMPANY	SUN COKE ENERGY, INC.	OH	P0104768	324199	2/9/2010	Heat Recovery Coke Battery: 100 heat recovery coke ovens in 3 batteries: 1 w/ 20 ovens, 2 w/ 40 ovens each. Process includes coal handling, charging, heat recovery coking, pushing, quenching, coke handling and storage. Heat recovery steam generators will recover	Pushing, Coke Battery with heat recovery-3	coal	912500	T/YR	Nitrogen Oxides (NOx)	work practices	9.5	LB/H		LAER	8.67	T/YR	PER A ROLLING 12 MONTH SUMMATION	0.019	LB/T	PER TON OF COAL CHARGED
MI-0415	EES COKE BATTERY, LLC	EES COKE BATTERY, LLC	MI	51-08C	331111	11/21/2014 ACT	Existing coke oven battery.	EUCOKE-BATTERY	COKE OVEN GAS	1.42	M tons of dry coal charged	Nitrogen Oxides (NOx)	Staged combustion for the battery underfire combustion system, and good combustion practices for bypass bleeder flares and COG flare. Proper operation of the battery for the	1411	T/YR	12-MO ROLLING TIME PERIOD END OF EACH MO	BACT-PSD	563.5	LB/H	HOURLY	0		

Sulfur Dioxide (SO_2)

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	COK-111-Coke Battery 1 Flue Gas Desulfurization	Coal	197	T/H	Sulfur Dioxide (SO2)	Maximum content of 1.25% sulfur in the coal. Purchase natural gas containing no more than 2000 grains of sulfur per MM scf	251.62	LB/H		BACT-PSD	1102.1	T/H		0		
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	COK-211-Coke Battery 2 Flue Gas Desulfurization	coal	197	T/H	Sulfur Dioxide (SO2)	Maximum content of 1.25% sulfur in the coal. Purchase natural gas containing no more than 2000 grains of sulfur per MM scf	251.62	LB/H		BACT-PSD	1102.1	T/H		0		
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	COK-202 - Coke Battery 2 Coke Pushing		126	T/H	Sulfur Dioxide (SO2)		21.22	LB/H		BACT-PSD	84.48	T/YR		0.098	LB/T	DRY COKE
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	COK-102 - Coke Battery 1 Coke Pushing		126	T/H	Sulfur Dioxide (SO2)		21.22	LB/H		BACT-PSD	84.48	T/YR		0.098	LB/T DRY COKE	
OH-0332	MIDDLETOWN COKE COMPANY	SUN COKE ENERGY, INC.	OH	P0104768	324199	2/9/2010	Heat Recovery Coke Battery: 100 heat recovery coke ovens in 3 batteries: 1 w/ 20 ovens, 2 w/ 40 ovens each. Process includes coal handling, charging, heat recovery coking, pushing, quenching, coke handling and storage. Heat recovery steam generators will recover	Charging, Coke Oven Batteries (3) with heat recovery	coal	912500	T/YR	Sulfur Dioxide (SO2)		0.15	LB/H		LAER	0.14	T/YR	AS A ROLLING 12-MONTH SUMMATION	0.0003	LB/T	PER TON OF COAL CHARGED* LAER
OH-0332	MIDDLETOWN COKE COMPANY	SUN COKE ENERGY, INC.	OH	P0104768	324199	2/9/2010	Heat Recovery Coke Battery: 100 heat recovery coke ovens in 3 batteries: 1 w/ 20 ovens, 2 w/ 40 ovens each. Process includes coal handling, charging, heat recovery coking, pushing, quenching, coke handling and storage. Heat recovery steam generators will recover	Coke Oven Batteries (3) without heat recovery	coal	2300	T/D	Sulfur Dioxide (SO2)	Bypass one HRSG at a time, one stack	498.33	LB/H		LAER	239.2	T/YR	PER ROLLING 12-MONTHS FOR HRSG BYPASS	0		
OH-0332	MIDDLETOWN COKE COMPANY	SUN COKE ENERGY, INC.	OH	P0104768	324199	2/9/2010	Heat Recovery Coke Battery: 100 heat recovery coke ovens in 3 batteries: 1 w/ 20 ovens, 2 w/ 40 ovens each. Process includes coal handling, charging, heat recovery coking, pushing, quenching, coke handling and storage. Heat recovery steam generators will recover	Coke Oven Batteries (3), bypass lime spray	coal	0		Sulfur Dioxide (SO2)	During the bypass of the spray dryer the charge size shall be reduced by 28% or the sulfur in coal reduced by 28%	1794	LB/H	FROM BYPASS TO SPRAY DRYER/BAGHOUSE	LAER	107.64	T/YR	AS A ROLLING 12-MONTH SUMMATION	0		
OH-0332	MIDDLETOWN COKE COMPANY	SUN COKE ENERGY, INC.	OH	P0104768	324199	2/9/2010	Heat Recovery Coke Battery: 100 heat recovery coke ovens in 3 batteries: 1 w/ 20 ovens, 2 w/ 40 ovens each. Process includes coal handling, charging, heat recovery coking, pushing, quenching, coke handling and storage. Heat recovery steam generators will recover	Coke Oven Batteries (3) with heat recovery	coal	912500	T/YR	Sulfur Dioxide (SO2)	Fabric filter, common tunnel afterburner maintained at 1400 degrees F, lime spray dryer.	300	LB/H	BASED ON 3-HR BLOCK AVERAGE	LAER	700.8	T/YR	AS A ROLLING 12-MONTH SUMMATION	1.54	LB/T	PER WET TON OF COAL
OH-0332	MIDDLETOWN COKE COMPANY	SUN COKE ENERGY, INC.	OH	P0104768	324199	2/9/2010	Heat Recovery Coke Battery: 100 heat recovery coke ovens in 3 batteries: 1 w/ 20 ovens, 2 w/ 40 ovens each. Process includes coal handling, charging, heat recovery coking, pushing, quenching, coke handling and storage. Heat recovery steam generators will recover	Pushing, Coke Battery with heat recovery-3	coal	912500	T/YR	Sulfur Dioxide (SO2)	work practices	49	LB/H		LAER	44.71	T/YR	PER A ROLLING 12 MONTH SUMMATION	0.098	LB/T	PER TON OF COAL CHARGED

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emissions Control
Appendix A: EPA RACT BACT LAER Clearinghouse Data
Flares in the Ferrous Metals Industry

Nitrogen Oxides (NOx)

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
AL-0275	NUCOR STEEL TUSCALOOSA, INC.	NUCOR STEEL TUSCALOOSA, INC.	AL	413-0033	331111	07/22/2014 ACT	Nucor Steel Tuscaloosa, Inc. owns and operates a scrap steel mill. The mill pruduces steel coils.	Vacuum Degasser with flare and cooling towers		0		Nitrogen Oxides (NOx)	Flare	0.005	LB/T		BACT-PSD	0			0		
AR-0150	NUCOR YAMATO STEEL COMPANY (LIMITED PARTNERSHIP)	NUCOR YAMATO STEEL COMPANY (LIMITED PARTNERSHIP)	AR	0883-AOP-R15	331111	06/01/2018 ACT	Nucor-Yamato Steel Company (NYS) owns and operates a steel mill located in Blytheville, AR.	Vacuum tank Degasser and Flare	Natural gas	150	tons per hour	Nitrogen Oxides (NOx)	Proper equipment design and operation	0.098	LB/MMBTU		BACT-PSD	0			0		

Sulfur Dioxide (SO_2)

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
AR-0150	NUCOR YAMATO STEEL COMPANY (LIMITED PARTNERSHIP)	NUCOR YAMATO STEEL COMPANY (LIMITED PARTNERSHIP)	AR	0883-AOP-R15	331111	06/01/2018 ACT	Nucor-Yamato Steel Company (NYS) owns and operates a steel mill located in Blytheville, AR.	Vacuum tank Degasser and Flare	Natural gas	150	tons per hour	Sulfur Dioxide (SO2)	Proper equipment design and operation	0.0006	LB/MMBTU		BACT-PSD	0			0		

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emissions Control
Appendix A: EPA RACT BACT LAER Clearinghouse Data
Gas Fired Boilers

Nitrogen Oxides (NOx)

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RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
*LA-0346	GULF COAST METHANOL COMPLEX	IGP METHANOL LLC	LA	PSD-LA-820	325199	01/04/2018 ACT	proposed facility to produce 20,000 metric tons of methanol per day	Auxiliary Boiler	natural gas	773	mm btu/hr	Nitrogen Oxides (NOx)	LNB + FGR	0			BACT-PSD	0			0		
MD-0044	COVE POINT LNG TERMINAL	DOMINION COVE POINT LNG, LP	MD	PSC CASE NO. 9318	221119	06/09/2014 ACT	LIQUIFIED NATURAL GAS PROCESSING FACILITY AND 130 MEGAWATT GENERATING STATIONFACILITY-WIDE PM10 EMISSION LIMIT = 124.2 TONS/YR FACILITY-WIDE PM2.5 EMISSION LIMIT= 124/2 TONS/YR	2 AUXILLARY BOILERS	PROCESS GAS	435	MMBTU/H	Nitrogen Oxides (NOx)	EXCLUSIVE USE OF FACILITY PROCESS FUEL GAS DURING NORMAL OPERATION AND USE OF A POST-COMBUSTION SCR SYSTEM AND LOW-NOX BURNERS	0.0099	LB/MMBTU	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD	LAER	2946.2	LB/EVENT	FOR ALL STARTUPS	0		
AK-0083	KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	AQ0083CPT06	325311	01/06/2015 ACT	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Nitrogen Oxides (NOx)	Ultra Low NOx Burners	0.01	LB/MMBTU	30-DAY AVERAGE	BACT-PSD	0			0		
TX-0656	GAS TO GASOLINE PLANT	NATGASOLINE	TX	PSDTX1340 AND 107764	325199	05/16/2014 ACT	Chemical Plant	Boiler	natural gas and fuel gas	950	MMBTU/H	Nitrogen Oxides (NOx)	SCR	0.01	LB/MMBTU		BACT-PSD	0			0		
TX-0659	DEER PARK PLANT	ROHM AND HAAS TEXAS INC	TX	PSDTX1320, 2165	325188	12/20/2013 ACT		Boiler	Natural gas	515	MMBTU/H	Nitrogen Oxides (NOx)	Selective catalytic reduction	0.01	LB/MMBTU	1-HR	BACT-PSD	0			0		
TX-0698	BAYPORT COMPLEX	AIR LIQUIDE LARGE INDUSTRIES U.S., L.P.	TX	9346 PSDTX612M2	325120	09/05/2013 ACT	Air Liquid currently operates a cogeneration facility in Pasadena, Texas (Bayou Cogeneration Plant). The permit amendment submitted by Air Liquide will authorize a redevelopment project of its cogeneration plant. The proposed project will involve the	(3) gas-fired boilers	natural gas	550	MMBTU/H	Nitrogen Oxides (NOx)	Selective Catalytic Reduction (SCR)	0.01	LB/MMBTU	3 HOUR ROLLING AVERAGE	BACT-PSD	0			0		
TX-0704	UTILITY PLANT	M & G RESINS USA LLC	TX	108819 PSDTX1354	221112	12/02/2014 ACT	In support of the new PET (polyethylene terephthalate) unit and new PTA (terephthalic acid) plant proposed by M&G Resins USA LLC, the company also proposes a Utility Plant that will consist of either one of two options. All steam generated from the Utility Plant	(2) boilers	natural gas	450	MMBTU/H	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	0.01	LB/MMBTU	3-HR ROLLING AVERAGE	BACT-PSD	0			0		
TX-0704	UTILITY PLANT	M & G RESINS USA LLC	TX	108819 PSDTX1354	221112	12/02/2014 ACT	In support of the new PET (polyethylene terephthalate) unit and new PTA (terephthalic acid) plant proposed by M&G Resins USA LLC, the company also proposes a Utility Plant that will consist of either one of two options. All steam generated from the Utility Plant	boiler	natural gas	250	MMBTU/H	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	0.01	LB/MMBTU	3-HR ROLLING AVERAGE	BACT-PSD	0			0		
TX-0707	CHEMICAL MANUFACTURING FACILITY	ROHM AND HAAS TEXAS INCORPORATED	TX	2165 PSDTX1320	325110	12/20/2013 ACT	RH is proposing to install two 515 million British thermal unit per hour (MMBtu/hr) gas-fired boilers to produce additional steam for the RH Texas Deer Park Plant manufacturing facilities and give the plant the ability to perform planned maintenance on other steam	(2) boilers	natural gas	515	MMBTU/H	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	0.01	LB/MMBTU	1 HOUR	BACT-PSD	0			0		
WY-0074	GREEN RIVER SODA ASH PLANT	SOLVAY CHEMICALS	WY	MD-13083	212391	11/18/2013 ACT	Trona Mine and Refinery	Natural Gas Package Boiler	Natural Gas	254	MMBTU/H	Nitrogen Oxides (NOx)	low NOx burners and flue gas recirculation	0.011	LB/MMBTU	30-DAY ROLLING	BACT-PSD	2.8	LB/H	30-DAY ROLLING	0		
*FL-0330	PORT DOLPHIN ENERGY LLC		FL	DPA-EPA-R4001	213112	12/01/2011 ACT	Port Dolphin is a deepwater port designed to moor liquefied natural gas shuttle and regasification vessels 28 miles off the cost of Florida.	Boilers (4 - 278 mmbtu/hr each)	natural gas	0		Nitrogen Oxides (NOx)	Selective Catalytic Reduction (SCR)	0.012	LB/MMBTU	3-HOUR ROLLING AVERAGE	BACT-PSD	0			0		
IL-0114	CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	13060007	325311	09/05/2014 ACT	Plant will produce urea and ammonia, but ammonia production will be limited to a maximum of 3 months of the year (4,880 tpd urea and 2,789 tpd ammonia).	Boiler	natural gas	864	MMBTU/H	Nitrogen Oxides (NOx)	low-nox burners, scr (or equivalent)	0.012	LB/MMBTU	30-DAY AVERAGE ROLLED DAILY	BACT-PSD	0			0		
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	IA	12-219	325311	10/26/2012 ACT	NITROGENEOUS FERTILIZER MANUFACTURING	Auxiliary Boiler	natural gas	472.4	MMBTU/H	Nitrogen Oxides (NOx)	Low NOx Burners (LNB) and Flue Gas Recirculation (FGR)	0.0125	LB/MMBTU	ROLLING 30 DAY AVERAGE	BACT-PSD	5.52	TONS/YR	ROLLING 12 MONTH TOTAL	0		
IN-0166	INDIANA GASIFICATION, LLC	INDIANA GASIFICATION, LLC	IN	T147-30464-00060	221210	06/27/2012 ACT	THE PERMITTEE OWNS AND OPERATES A STATIONARY SUBSTITUTE NATURAL GAS (SNG) AND LIQUEFIED CARBON DIOXIDE (CO2) PRODUCTION PLANT	TWO (2) AUXILIARY BOILERS	NATURAL GAS	408	MMBTU/H, EACH	Nitrogen Oxides (NOx)	ULTRA LOW NOX BURNER WITH FGR	0.0125	LB/MMBTU	24 HR	BACT-PSD	0			0		
LA-0305	LAKE CHARLES METHANOL FACILITY	LAKE CHARLES METHANOL, LLC	LA	PSD-LA-803(M1)	325199	06/30/2016 ACT	Proposed facility to produce methanol, H2, H2SO4, CO2, Argon and electricity from Pet Coke	Auxiliary Boilers and Superheaters	Natural Gas	0		Nitrogen Oxides (NOx)	SCR	0.015	LBS/MM BTU	30 ROLLING AVG., EXCEPT SCR SU OR MAINT.	BACT-PSD	0			0		
*TX-0888	ORANGE POLYETHYLENE PLANT	CHEVRON PHILLIPS CHEMICAL COMPANY LP	TX	155952 PSDTX1556 GHGPSDTX192	325211	04/23/2020 ACT	An initial NSR, PSD, and GHG project to construct and operate an Olefins Unit, two Polyethylene (PE) Units, and auxiliary support facilities. This permit will consist of furnaces, boilers, heaters, storage tanks, emergency engines, fugitive piping, thermal oxidizers,	BOILERS	Natural gas, ethane, fuel, or vent gas	250	MMBTU	Nitrogen Oxides (NOx)	SCR	0.015	LB/MMBTU	HOURLY	BACT-PSD	0.01	LB/MMBTU	ANNUAL	0		
DE-0020	VALERO DELAWARE CITY REFINERY	VALERO ENERGY CORP	DE	AQM-003/00016	324110	02/26/2010 ACT	191,100 BARREL PER DAY REFINERY AKA THE PREMCOR REFINING GROUP INC.	PACKAGE BOILERS (2009)	REFINERY FUEL GAS	99.9	MMBtu per hour	Nitrogen Oxides (NOx)	SCR AND LOW NOX BURNERS	0.015	LB/MMBTU		RACT	0			0		
DE-0020	VALERO DELAWARE CITY REFINERY	VALERO ENERGY CORP	DE	AQM-003/00016	324110	02/26/2010 ACT	191,100 BARREL PER DAY REFINERY AKA THE PREMCOR REFINING GROUP INC.	DCPP BOILER 1	REFINERY FUEL GAS	618	MMBTU/H	Nitrogen Oxides (NOx)	SCR WITH MODIFICATIONS TO EXISTING BURNERS AND AIR DISTRIBUTION TO BURNERS, OPTIMIZATION TO OVER-FIRE AIR SYSTEMS, INSTALLATION OF INDUCED FLUE	0.015	LB/MMBTU	24-HOUR ROLLING AVERAGE	BACT-PSD	40.6		12-MONTHS	0		
DE-0020	VALERO DELAWARE CITY REFINERY	VALERO ENERGY CORP	DE	AQM-003/00016	324110	02/26/2010 ACT	191,100 BARREL PER DAY REFINERY AKA THE PREMCOR REFINING GROUP INC.	DCPP BOILER 3	REFINERY FUEL GAS	618	MMBTU/H	Nitrogen Oxides (NOx)	SCR WITH MODIFICATIONS TO EXISTING BURNERS AND AIR DISTRIBUTION TO BURNERS, OPTIMIZATION TO OVER-FIRE AIR SYSTEMS, INSTALLATION OF INDUCED FLUE	0.015	LB/MMBTU	24-HOUR ROLLING AVERAGE	BACT-PSD	40.6	T	12-MONTHS	0		
TX-0763	BORGER REFINERY	PHILLIPS 66 COMPANY	TX	85872, PSDTX1158M1, GHGPSDTX13	324110	09/04/2015 ACT	The refinery processes crude oil and other feedstocks into products including gasoline, furnace oil, jet fuels, kerosene, petrochemicals, and blendstocks for liquid fuels.	Utility and Industrial Boiler greater than 250 million British	refinery fuel	560	MMBTU/H	Nitrogen Oxides (NOx)	SCR	0.015	LB/MMBTU		BACT-PSD	0			0		
TX-0763	BORGER REFINERY	PHILLIPS 66 COMPANY	TX	85872, PSDTX1158M1, GHGPSDTX13	324110	09/04/2015 ACT	The refinery processes crude oil and other feedstocks into products including gasoline, furnace oil, jet fuels, kerosene, petrochemicals, and blendstocks for liquid fuels.	Utility and Industrial Boiler greater than 250 million British	refinery fuel	364.6	MMBTU/H	Nitrogen Oxides (NOx)	selective catalytic reduction (SCR)	0.015	LB/MMBTU		BACT-PSD	0			0		
ND-0032	SPIRITWOOD NITROGEN PLANT	CHS, INC.	ND	PTC14027	325311	06/20/2014 ACT	Fertilizer manufacturing plant to manufacture nitrogen-based products ammonia, urea, urea ammonium nitrate (UAN) and diesel exhaust fluid. The facility will produce both feedstock and saleable products in the following capacities: 2,425 tpd ammonia; 3,000 tpd	Package boiler	Natural gas	280	MMBTU/H	Nitrogen Oxides (NOx)	ultra low NOx burners and flue gas recirculation	0.018	LB/MMBTU	30 DAY ROLLING AVERAGE	BACT-PSD	0			0		
*ND-0033	GRAND FORKS FERTILIZER PLANT	NORTHERN PLAINS NITROGEN	ND	PTC15052	325311	08/10/2015 ACT	Fertilizer manufacturing plant designed to produce both feedstock and saleable products in the following nominal capacities: 2425 tpd ammonia, 2540 tpd ammonium nitrate solution, 300 tpd DEF, 3000 tpd urea solution, 3000 tpd granular urea, 2000 tpd nitric acid, 5620	Boilers	Natural gas	187.5	MMBTU/H	Nitrogen Oxides (NOx)	Ultra Low NOx Burners and Flue Gas Recirculation	0.018	LB/MM BTU	30 DAY ROLLING AVERAGE	BACT-PSD	0			0		
AL-0271	GEORGIA PACIFIC BRETON LLC	GEORGIA PACIFIC LLC	AL	502-0001-X049	322130	06/11/2014 ACT	Kraft Pulp & Paper mdu	No.4 Power Boiler	Natural Gas	425	MMBTU/H	Nitrogen Oxides (NOx)	Low NOx Burner with FGR	0.02	LB/MMBTU		BACT-PSD	8.5	LB/H		0		
DE-0020	VALERO DELAWARE CITY REFINERY	VALERO ENERGY CORP	DE	AQM-003/00016	324110	02/26/2010 ACT	191,100 BARREL PER DAY REFINERY AKA THE PREMCOR REFINING GROUP INC.	PACKAGE BOILERS (2004)	REFINERY FUEL GAS	216	MMBtu per hour	Nitrogen Oxides (NOx)		0.02	LB/MMBTU	3-HR AVERAGE	RACT	24.9	T	12 MONTHS	0		
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	OH	P0124972	325110	12/21/2018 ACT	Petrochemical Complex	Natural Gas and Ethane-Fired Steam Boilers (B007 - B009)	Natural gas and ethane	400	MMBTU/H	Nitrogen Oxides (NOx)	ultra-low NOx burners (ULNB) and flue gas recirculation (FGR)	0.02	LB/MMBTU	DURING STARTUP AND SHUTDOWN. SEE NOTES.	BACT-PSD	4	LB/H	AS ROLLING 30-DAY AVG. SEE NOTES.	0.01	LB/MMBTU	AS ROLLING 30-DAY AVG. SEE NOTES.
TX-0776	BISHOP FACILITY	TICONA POLYMERS, INC.	TX	123077, PSDTX1436, AND GHGPSDT	324199	11/12/2015 ACT	The three new boilers will provide steam to existing steam users at the Bishop Site and to a new Methanol Unit Project proposed in a concurrent air permit application (Permit No. 123216 and PSDTX1438). The new Boiler Project will authorize construction and	Boiler	natural gas	452	MMBTU/H	Nitrogen Oxides (NOx)	Selective Catalytic Reduction, Low NOx Burners, Flue Gas Recirculation	0.02	PPM	1-HR AVG	BACT-PSD	0.01	PPM	ROLLING MONTHLY AVERAGE	0		

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emissions Control
Appendix A: EPA RACT BACT LAER Clearinghouse Data
Gas Fired Boilers

Nitrogen Oxides (NOx)

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
FL-0344	OKEELANTA COGENERATION PLANT	NEW HOPE POWER COMPANY	FL	0990332-021-AC	221119	08/27/2013 ACT	Cogeneration facility, fired with bagasse, wood, and natural gas. Four boilers, total electrical generating capacity of 140 MW. Also generates steam for co-located sugar refinery and sugar mill.	Natural Gas Boiler	Natural gas	589	MMBTU/H	Nitrogen Oxides (NOx)	Ultra-low NOx burners with over-fire air	0.035	LB/MMBTU	30-DAY ROLLING AVERAGE BY CEMS	BACT-PSD	18.8	LB/H	30-DAY ROLLING AVERAGE BY CEMS	0		
LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	LA	PSD-LA-890	325320	01/09/2017 ACT	Chemical Manufacture	No. 9 Boiler - Natural Gas Fired	Natural Gas	325	MMBTU/h	Nitrogen Oxides (NOx)	Ultra Low NOx Burners	0.035	LB/MMBTU	ANNUAL AVERAGE	BACT-PSD	0			0		
LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	LA	PSD-LA-890	325320	01/09/2017 ACT	Chemical Manufacture	No. 10 Boiler - Natural Gas Fired	Natural Gas	325	MMBTU/h	Nitrogen Oxides (NOx)	Ultra Low NOx Burners	0.035	LB/MMBTU	ANNUAL AVERAGE	BACT-PSD	0			0		
*MI-0440	MICHIGAN STATE UNIVERSITY	MICHIGAN STATE UNIVERSITY	MI	139-18	611310	05/22/2019 ACT	New natural gas electric and steam generation.	EUSTMBOILER	natural gas	300	MMBTU/H	Nitrogen Oxides (NOx)	Low-NOx burners and internal flue gas recirculation (FGR)	0.04	LB/MMBTU	30 DAY ROLL AVG WHEN FIRING NAT. GAS	BACT-PSD	0.07	LB/MMBTU	30 DAY ROLL AVG WHEN FIRING NO2 FUEL OIL	0		
NE-0054	CARGILL, INCORPORATED	CARGILL, INCORPORATED	NE	12-042	311221	09/12/2013 ACT		Boiler K	natural gas	300	mmbtu/h	Nitrogen Oxides (NOx)	LOW NOX BURNERS AND INDUCED FLUE GAS RECIRCULATION	0.04	LB/MMBTU	30-DAY ROLLING AVERAGE	BACT-PSD	12	LB/H	3-HOUR ROLLING AVERAGE	0		
TX-0763	BORGER REFINERY	PHILLIPS 66 COMPANY	TX	85872, PSDTX1158M1, GHGPSDTX13	324110	09/04/2015 ACT	The refinery processes crude oil and other feedstocks into products including gasoline, furnace oil, jet fuels, kerosene, petrochemicals, and blendstocks for liquid fuels.	Utility and Industrial Boiler greater than 250 million British	refinery fuel	462.3	MMBTU/H	Nitrogen Oxides (NOx)		0.04	LB/MMBTU		BACT-PSD	0			0		
IN-0234	GRAIN PROCESSING CORPORATION	GRAIN PROCESSING CORPORATION	IN	027-35177-00046	311221	12/08/2015 ACT	THIS FACILITY IS A STATIONARY CORN WET MILLING PLANT.	BOILER 1	NATURAL GAS	271	MMBTU/H	Nitrogen Oxides (NOx)	LOW-NOX BURNER AND FLUE GAS RECIRCULATION SYSTEM	0.05	LB/MMBTU	NORMAL OPERATION	BACT-PSD	0.2	LB/MMBTU	DURING SSM	0		
IN-0234	GRAIN PROCESSING CORPORATION	GRAIN PROCESSING CORPORATION	IN	027-35177-00046	311221	12/08/2015 ACT	THIS FACILITY IS A STATIONARY CORN WET MILLING PLANT.	BOILER 2	NATURAL GAS	271	MMBTU/H	Nitrogen Oxides (NOx)	LOW-NOX BURNERS AND FLUE GAS RECIRCULATION	0.05	LB/MMBTU	NORMAL OPERATION	BACT-PSD	0.2	LB/MMBTU	DURING SSM	0		
OH-0368	PALLAS NITROGEN LLC	PALLAS NITROGEN LLC	OH	P0118959	325311	04/19/2017 ACT	Natural gas-based facility for the manufacture of nitrogenous products.	Package Boilers (2 identical, B003 and B004)	Natural gas	265	MMBTU/H	Nitrogen Oxides (NOx)	Low NOx burners and flu gas recirculation (FGR)	3.3	LB/H		BACT-PSD	14.5	T/YR	PER ROLLING 12 MONTH PERIOD	0.0125	LB/MMBTU	
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	LA	PSD-LA-780(M-1)	325998	06/30/2017 ACT	New MeOH plant designed to produce 5,275 metric tons per day of refined methanol from natural gas and carbon dioxide (CO2) feedstock	B1-13 - Boiler 1 (EQT0003)	Natural Gas	350	MM BTU/hr	Nitrogen Oxides (NOx)	Selective Catalytic Reduction, Low NOx Burners, & Good Combustion Practices	3.5	LB/HR		BACT-PSD	0.01	LB/MMMTU	12 MONTH AVERAGE	0		
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	LA	PSD-LA-780(M-1)	325998	06/30/2017 ACT	New MeOH plant designed to produce 5,275 metric tons per day of refined methanol from natural gas and carbon dioxide (CO2) feedstock	B2-13 - Boiler 2 (EQT0004)	Natural Gas	350	MM BTU/hr	Nitrogen Oxides (NOx)	Selective Catalytic Reduction, Low NOx Burners, & Good Combustion Practices	3.5	LB/HR		BACT-PSD	0.01	LB/MMBTU	12-MONTH AVERAGE	0		
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	PSD-LA-781	325110	05/23/2014 ACT	The G2G Plant will be a natural gas to gasoline production facility which will use natural gas to produce methanol that will be subsequently converted into gasoline.	Utility Boiler 1	Natural Gas	656	MMBTU/HR	Nitrogen Oxides (NOx)	Selective Catalytic Reduction (SCR)	3.94	LB/H	HOURLY MAXIMUM	BACT-PSD	17.25	T/YR	ANNUAL MAXIMUM	0.2	LB/MMBTU	30-DAY ROLLING AVERAGE
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	PSD-LA-781	325110	05/23/2014 ACT	The G2G Plant will be a natural gas to gasoline production facility which will use natural gas to produce methanol that will be subsequently converted into gasoline.	Utility Boiler 2	Natural Gas	656	MMBTU/HR	Nitrogen Oxides (NOx)	Selective Catalytic Reduction (SCR)	3.94	LB/H	HOURLY MAXIMUM	BACT-PSD	17.25	T/YR	ANNUAL MAXIMUM	0.2	LB/MMBTU	30-DAY ROLLING AVERAGE
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	PSD-LA-781	325110	05/23/2014 ACT	The G2G Plant will be a natural gas to gasoline production facility which will use natural gas to produce methanol that will be subsequently converted into gasoline.	Utility Boiler 3	Natural Gas	656	MMBTU/HR	Nitrogen Oxides (NOx)	Selective Catalytic Reduction (SCR)	3.94	LB/H	HOURLY MAXIMUM	BACT-PSD	17.25	T/YR	ANNUAL MAXIMUM	0.2	LB/MMBTU	30-DAY ROLLING AVERAGE
TX-0803	PL PROPYLENE HOUSTON OLEFINS PLANT	FLINT HILLS RESOURCES HOUSTON CHEMICAL LLC	TX	18999, PSDTX755M1, N216	325110	07/12/2016 ACT	catalytic process to produce propylene from propane and mixed propane/propylene feed	Waste Heat Boiler	natural gas	1690	MMBTU/H	Nitrogen Oxides (NOx)	selective catalytic reduction	5	PPMVD @ 15% O2	12-MONTH AVG	LAER	9	PPMVD @ 15% O2	3-HR AVERAGE	0		
AK-0083	KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	AQ0083CPT06	325311	01/06/2015 ACT	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	7	PPMV	3-HR AVG @ 15 % O2	BACT-PSD	0			0		
CA-1214	GROSSMONT HOSPITAL	GROSSMONT HOSPITAL	CA	2012-APP-002050	622110	11/06/2012 ACT		Two 29.4 MMBtu/hr Boilers with low NOx burners	natural gas	0		Nitrogen Oxides (NOx)	Low NOx burners	9	PPMVD@3% O2	1 HOUR	OTHER CASE-BY-CASE	0			0		
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	THREE (3) AUXILARY BOILERS	NATURAL GAS	218.6	MMBTU/H, EACH	Nitrogen Oxides (NOx)	LOW NOX BURNERS, FLUE GAS RECIRCULATION	20.4	LB/MMCF	3-HR AVERAGE	BACT-PSD	0			0		
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	THREE (3) AUXILARY BOILERS	NATURAL GAS	218.6	MMBTU/H, EACH	Nitrogen Oxides (NOx)	LOW NOX BURNERS, FLUE GAS RECIRCULATION	20.4	LB/MMCF	3-HR AVERAGE	BACT-PSD	0			0		
LA-0288	LAKE CHARLES CHEMICAL COMPLEX	SASOL CHEMICALS (USA) LLC	LA	PSD-LA-778	325110	05/23/2014 ACT		HP SH Steam Boilers (EQT 631, 632, & 633)	PROCESS GAS	408.4	MM BTU/HR	Nitrogen Oxides (NOx)	Ultra low NOx burners (ULNBs) and selective catalytic reduction (SCR)	20.59	LB/HR	HOURLY MAXIMUM	BACT-PSD	11.33	TPY	ANNUAL MAXIMUM	0.01	LB/MMBTU	30-DAY ROLLING AVERAGE
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	SASOL CHEMICALS (USA) LLC	LA	PSD-LA-779	325110	05/23/2014 ACT		Utility Steam Boiler Nos. 1-3 (EQTs 967, 968, & 969)	Process Gas	662	MM BTU/HR	Nitrogen Oxides (NOx)	Selective catalytic reduction (SCR) and ultra low NOx burners (ULNB)	33.7	LB/HR	HOURLY MAXIMUM	BACT-PSD	70.96	TPY*	ANNUAL MAXIMUM	0.01	LB/MMBTU	30-DAY ROLLING AVERAGE

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emissions Control
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Gas Fired Boilers

Sulfur Dioxide (SO_2)

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RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
LA-0288	LAKE CHARLES CHEMICAL COMPLEX	SASOL CHEMICALS (USA) LLC	LA	PSD-LA-778	325110	05/23/2014 ACT		HP SH Steam Boilers (EQT 631, 632, & 633)	PROCESS GAS	408.4	MM BTU/HR	Sulfur Dioxide (SO2)	Use of gaseous fuels with a sulfur content no more than 0.005 gr/scf	24.22	LB/HR	HOURLY MAXIMUM	BACT-PSD	1.67	TPY	ANNUAL MAXIMUM	0		
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	SASOL CHEMICALS (USA) LLC	LA	PSD-LA-779	325110	05/23/2014 ACT		Utility Steam Boiler Nos. 1-3 (EQTs 967, 968, & 969)	Process Gas	662	MM BTU/HR	Sulfur Dioxide (SO2)	Use of gaseous fuels with a sulfur content of no more than 0.005 grains per standard cubic foot (annual average)	1.98	LB/HR	HOURLY MAXIMUM	BACT-PSD	10.43	TPY*	ANNUAL MAXIMUM	0		
*FL-0330	PORT DOLPHIN ENERGY LLC		FL	DPA-EPA-R4001	213112	12/01/2011 ACT	Port Dolphin is a deepwater port designed to moor liquefied natural gas shuttle and regasification vessels 28 miles off the cost of Florida.	Boilers (4 - 278 mmbtu/hr each)	natural gas	0		Sulfur Dioxide (SO2)	use of natural gas	0.0006	LB/MMBTU	3-HOUR ROLLING AVERAGE	BACT-PSD	0			0		
IN-0166	INDIANA GASIFICATION, LLC	INDIANA GASIFICATION, LLC	IN	T147-30464-00060	221210	06/27/2012 ACT	THE PERMITTEE OWNS AND OPERATES A STATIONARY SUBSTITUTE NATURAL GAS (SNG) AND LIQUEFIED CARBON DIOXIDE (CO2) PRODUCTION PLANT	TWO (2) AUXILIARY BOILERS	NATURAL GAS	408	MMBTU/H, EACH	Sulfur Dioxide (SO2)	USE OF NATURAL GAS OR SNG	0.0006	MMBTU/H	3 HR	BACT-PSD	0			0		
IN-0234	GRAIN PROCESSING CORPORATION	GRAIN PROCESSING CORPORATION	IN	027-35177-00046	311221	12/08/2015 ACT	THIS FACILITY IS A STATIONARY CORN WET MILLING PLANT.	BOILER 1	NATURAL GAS	271	MMBTU/H	Sulfur Dioxide (SO2)	SULFUR CONTENT OF ALCOHOL AND BY-PRODUCT WASTE OIL	0.0006	LB/MMBTU	NATURAL GAS ALONE	BACT-PSD	0.0008	LB/MMBTU	NATURAL GAS AND ALCOHOL	0		
LA-0305	LAKE CHARLES METHANOL FACILITY	LAKE CHARLES METHANOL, LLC	LA	PSD-LA-803(M1)	325199	06/30/2016 ACT	Proposed facility to produce methanol, H2, H2SO4, CO2, Argon and electricity from Pet Coke	Auxiliary Boilers and Superheaters	Natural Gas	0		Sulfur Dioxide (SO2)	fuel gases and/or pipeline quality natural gas	0			BACT-PSD	0			0		
*TX-0888	ORANGE POLYETHYLENE PLANT	CHEVRON PHILLIPS CHEMICAL COMPANY LP	TX	155952 PSDTX1556 GHGPSDTX192	325211	04/23/2020 ACT	An initial NSR, PSD, and GHG project to construct and operate an Olefins Unit, two Polyethylene (PE) Units, and auxiliary support facilities. This permit will consist of furnaces, boilers, heaters, storage tanks, emergency engines, fugitive piping, thermal oxidizers,	BOILERS	Natural gas, ethane, fuel, or vent gas	250	MMBTU	Sulfur Dioxide (SO2)	Good combustion practice and clean fuel	2	GR/100 SCF		BACT-PSD	0			0		

Nitrogen Oxides (NOx)

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RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	SLG-104 - Blast Furnace 1 Slag Pit 1		28.66	T/H	Nitrogen Oxides (NOx)		0.71	LB/H		BACT-PSD	0.47	T/YR		0.0248	LB/T OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	SLG-105 - Blast Furnace 1 Slag Pit 2		28.66	T/H	Nitrogen Oxides (NOx)		0.71	LB/H		BACT-PSD	0.47	T/YR		0.0248	LB/T OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	SLG-106 - Blast Furnace 1 Slag Pit 3		28.66	T/H	Nitrogen Oxides (NOx)		0.71	LB/H		BACT-PSD	0.47	T/YR		0.0248	LB/T OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	SLG-204 - Blast Furnace 2 Slag Pit 1		28.66	T/h	Nitrogen Oxides (NOx)		0.71	LB/H		BACT-PSD	0.47	T/YR		0.0248	LB/T OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	SLG-205 - Blast Furnace 2 Slag Pit 2		28.66	t/h	Nitrogen Oxides (NOx)		0.71	LB/H		BACT-PSD	0.47	T/YR		0.0248	LB/TON OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	SLG-206 - Blast Furnace 2 Slag Pit 3		28.66	t/h	Nitrogen Oxides (NOx)		0.71	LB/H		BACT-PSD	0.47	T/YR		0.0248	LB/TON OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	05/24/2010 ACT	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	STV-101-Blast Furnace 1 Hot Blast Stoves Common Stack	Blast Furnace Gas	627.04	MMBTU/H	Nitrogen Oxides (NOx)	Low-NOx fuel combustion	66.29	LB/H		BACT-PSD	161.23	T/YR		0.06	LB/MMBTU	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	05/24/2010 ACT	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	STV-201-Blast Furnace 2 Hot Blast Stoves Common Stack	Blast Furnace Gas	627.04	MMBTU/H	Nitrogen Oxides (NOx)	Low-NOx fuel combustion	66.29	LB/H		BACT-PSD	161.23	T/YR		0.06	LB/MMBTU	

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Blast Furnace

Sulfur Dioxide (SO_2)

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	SLG-104 - Blast Furnace 1 Slag Pit 1		28.66	T/H	Sulfur Dioxide (SO2)		3.28	LB/H		BACT-PSD	2.16	T/YR		0.115	LB/ OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	SLG-105 - Blast Furnace 1 Slag Pit 2		28.66	T/H	Sulfur Dioxide (SO2)		3.28	LB/H		BACT-PSD	2.16	T/YR		0.115	LB/T OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	SLG-106 - Blast Furnace 1 Slag Pit 3		28.66	T/H	Sulfur Dioxide (SO2)		3.28	LB/H		BACT-PSD	2.16	T/YR		0.115	LB/T OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	SLG-204 - Blast Furnace 2 Slag Pit 1		28.66	T/h	Sulfur Dioxide (SO2)		3.28	LB/H		BACT-PSD	2.16	T/YR		0.115	LB/TON OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	SLG-205 - Blast Furnace 2 Slag Pit 2		28.66	t/h	Sulfur Dioxide (SO2)		3.28	LB/H		BACT-PSD	2.16	T/YR		0.115	LB/TON OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	SLG-206 - Blast Furnace 2 Slag Pit 3		28.66	t/h	Sulfur Dioxide (SO2)		3.28	LB/H		BACT-PSD	2.16	T/YR		0.115	LB/T OF SLAG	
MI-0377	SEVERSTAL NORTH AMERICA, INC.	SEVERSTAL NORTH AMERICA, INC.	MI	182-05	331111	1/31/2006	INTEGRATED IRON AND STEEL PLANT	BLAST FURNACE STOVES	BLAST FURNACE GAS	24003	MMSCF/YR	Sulfur Dioxide (SO2)	NO CONTROLS FEASIBLE. COMPLIANCE VERIFICATION VIA CEMS.	14.37	LB/MMMSCF	WHEN B FURNACE OPERATING	BACT-PSD	16.62	LB/MMSCF	WHEN B FURNACE NOT OPERATING	0		
MI-0413	AK STEEL	AK STEEL CORPORATION	MI	182-05C	331111	5/12/2014	Iron and steel manufacturing facility	EUCFURNACE - C Blast Furnace which includes the blast furnace	Nat. gas, BFG, pulv coal, coke	37841	MMCF/YR	Sulfur Dioxide (SO2)		179.65	LB/H	CALENDAR DAY AVG; BAGHOUSE STACK	BACT-PSD	193.6	LB/H	CALENDAR DAY AVG; STOVE STACK	0		
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	05/24/2010 ACT	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	STV-101-Blast Furnace 1 Hot Blast Stoves Common Stack	Blast Furnace Gas	627.04	MMBTU/H	Sulfur Dioxide (SO2)	No feasible control technology for Blast Furnace Gas. (BFG) Limit Natural Gas sulfur content	19.54	LB/H		BACT-PSD	28.19	T/YR		0		
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	05/24/2010 ACT	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	STV-201-Blast Furnace 2 Hot Blast Stoves Common Stack	Blast Furnace Gas	627.04	MMBTU/H	Sulfur Dioxide (SO2)	No feasible control technology for Blast Furnace Gas. (BFG) Limit Natural Gas sulfur content	19.54	LB/H		BACT-PSD	28.19	T/H		0		
MI-0377	SEVERSTAL NORTH AMERICA, INC.	SEVERSTAL NORTH AMERICA, INC.	MI	182-05	331111	01/31/2006 ACT	INTEGRATED IRON AND STEEL PLANT	C FURNACE CASTHOUSE	PULVERIZED COAL, COKE	6700	T/D	Sulfur Dioxide (SO2)	NO FEASIBLE CONTROLS	14.65	LB/H	AVERAGING TIME PER TEST PROTOCOL	BACT-PSD	0			0		

Appendix B

Air Permit Summary for II&S Mills

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	Boiler			
	Emission Unit Description	**Controls**	**NOx Limit**	**Comments**
AM Burns Harbor	1976 No. 7 Boiler 650 MMBtu/hr max HI (ea.) natural gas, coke oven gas, blast furnace gas, and fuel oil	None	0.17 lb/MMBtu & 50% Heat Input from BFG	Pursuant to 326 IAC 10-3-3: Applies to all 6 boilers, limit for each individual boiler; only applicable during ozone control periods
AM Burns Harbor	1970 No. 8 Boiler 650 MMBtu/hr max HI (ea.) natural gas, coke oven gas, blast furnace gas, No. 2 fuel oil, No. 6 fuel oil	None		
AM Burns Harbor	1970 No. 9 Boiler 650 MMBtu/hr max HI (ea.) natural gas, coke oven gas, blast furnace gas, No. 2 fuel oil, No. 6 fuel oil	None		
AM Burns Harbor	1969 No. 10 Boiler 650 MMBtu/hr max HI (ea.) natural gas, coke oven gas, blast furnace gas, No. 2 fuel oil, No. 6 fuel oil	None		
AM Burns Harbor	1968 No. 11 Boiler 650 MMBtu/hr max HI (ea.) natural gas, coke oven gas, blast furnace gas, No. 2 fuel oil, No. 6 fuel oil	None		
AM Burns Harbor	1968 No. 12 Boiler 650 MMBtu/hr max HI (ea.) natural gas, coke oven gas, blast furnace gas, No. 2 fuel oil, No. 6 fuel oil	None		
AM Indiana Harbor East	1976 No. 501 Boiler 520 MMBtu/hr max HI (ea.) Natural Gas, Blast Furnace Gas	None	0.17 lb/MMBtu & 50% Heat Input from BFG	Pursuant to 326 IAC 10-3-3(c): Applies to all 4 boilers, limit for each individual boiler; only applicable during ozone control periods
AM Indiana Harbor East	1976 No. 502 Boiler 520 MMBtu/hr max HI (ea.) Natural Gas, Blast Furnace Gas	None		
AM Indiana Harbor East	1976 No. 503 Boiler 520 MMBtu/hr max HI (ea.) Natural Gas, Blast Furnace Gas	None		
AM Indiana Harbor East	Approved in 2010 - No. 504 Boiler 561.6 MMBtu/hr max HI (ea.) Natural Gas, Blast Furnace Gas	None	240.6 tpy (12-mo. Rolling Sum)	PM10, PM2.5, SO2, NOx and CO PSD and Emission Offset Credit Limits [326 IAC 2-2] [326 IAC 2-3]: Limit is only for Boiler 504
AM Indiana Harbor West	1952 No. 5 Boiler 454 MMBtu/hr max HI (ea.) Natural Gas, blast furnace gas	None	0.17 lb/MMBtu & 50% Heat Input from BFG	Pursuant to 326 IAC 10-3-3: Applies to all 4 boilers, limit for each individual boiler; only applicable during ozone control periods
AM Indiana Harbor West	1956 No. 6 Boiler 454 MMBtu/hr max HI (ea.) Natural Gas, blast furnace gas	None		
AM Indiana Harbor West	1056 No. 7 Boiler 454 MMBtu/hr max HI (ea.) Natural Gas, blast furnace gas	None		
AM Indiana Harbor West	1967 No. 8 Boiler 1,090 MMBtu/hr max HI (ea.) Natural Gas, blast furnace gas	None		
Nucor St. James	Not Constructed - Topgas Boiler No. 1 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low NOx fuels	1. 0.2 lb/MMBtu 2. 0.092 lb/MMBtu 3. 0.137 lb/MMBtu	1. 40 CFR60.44(a)(l) (NSPS D): For all boilers individually. 2. LAC 33:III.509, BACT: For all boilers individually. Specific to BFG. This limit for Normal operation consists of a fuel mixture of Blast Furnace Top Gas and Natural gas with less than or equal to 41 % natural gas on a MMBTU / hr heat input. 3. LAC 33:III.509, BACT: For all boilers individually. Total for all fuels. This emission rate is based upon any operation with natural gas greater than 41 % heat input of the fuel up to and including 100%. Operating under this alternate operating scenario shall be minimized to the maximum extent possible.
Nucor St. James	Not Constructed - Topgas Boiler No. 2 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low NOx fuels		
Nucor St. James	Not Constructed - Topgas Boiler No. 3 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low NOx fuels		
Nucor St. James	Not Constructed - Topgas Boiler No. 4 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low NOx fuels		
Nucor St. James	Not Constructed - Topgas Boiler No. 5 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low NOx fuels		
Nucor St. James	Not Constructed - Topgas Boiler No. 6 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low NOx fuels		
Nucor St. James	Not Constructed - Topgas Boiler No. 7 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low NOx fuels		
Nucor St. James	Not Constructed - Topgas Boiler No. 8 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low NOx fuels		
USS Clairton	B001 - Boiler No. 1 760 mmbtu/hr heat input Desulfurized Coke Oven Gas and Natural Gas	None	410.40 lb/hr 1,740 tpy 0.54 lb/MMBtu	 RACT Plan (shall not exceed at any time)
USS Clairton	B002 - Boiler No. 2 481 mmbtu/hr heat input Desulfurized Coke Oven Gas and Natural Gas	None	259.74 lb/hr 1,285 tpy 0.54 lb/MMBtu	 RACT Plan (shall not exceed at any time)
USS Clairton	B005 - R1 Boiler 229 mmbtu/hr heat input Desulfurized Coke Oven Gas and Natural Gas	None	123.66 lb/hr 525 tpy 0.54 lb/MMBtu	 RACT Plan (shall not exceed at any time)
USS Clairton	B006 - R2 Boiler 229 mmbtu/hr heat input Desulfurized Coke Oven Gas and Natural Gas	None	123.66 lb/hr 525 tpy 0.54 lb/MMBtu	 RACT Plan (shall not exceed at any time)
USS Clairton	B007 - T1 Boiler 156 mmbtu/hr heat input Desulfurized Coke Oven Gas and Natural Gas	None	84.24 lb/hr 358 tpy 0.54 lb/MMBtu	 RACT Plan (shall not exceed at any time)
USS Clairton	B008 - T2 Boiler 156 mmbtu/hr heat input Desulfurized Coke Oven Gas and Natural Gas	None	84.24 lb/hr 358 tpy 0.54 lb/MMBtu	 RACT Plan (shall not exceed at any time)

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	Boiler			
	Emission Unit Description	**Controls**	**NOx Limit**	**Comments**
AK Dearborn	Facility does not have a boiler			
AK Middleton	P009 No. 3 Slab Reheat Furnace/Waste Heat Boiler 598 MMBtu/hr Slab Furnace 305 MMBtu/hr Waste Heat Boiler Natural gas, fuel oil, coke oven gas	None	None	
	P010 No. 2 Slab Reheat Furnace/Waste Heat Boiler 598 MMBtu/hr Slab Furnace 305 MMBtu/hr Waste Heat Boiler Natural gas, fuel oil, coke oven gas	None	None	
	P011 No. 1 Slab Reheat Furnace/Waste Heat Boiler 598 MMBtu/hr Slab Furnace 305 MMBtu/hr Waste Heat Boiler Natural gas, fuel oil, coke oven gas	None	None	
	P012 No. 4 Slab Reheat Furnace/Waste Heat Boiler 598 MMBtu/hr Slab Furnace 305 MMBtu/hr Waste Heat Boiler Natural gas, fuel oil, coke oven gas	None	None	
AM Cleveland	Facility does not have a boiler			
USS Edgar Thompson	Facility does not have a boiler			
USS East Chicago	B-1 Steam Generation Boiler 181.1 MMBtu/hr max HI (ea.) Natural gas	Low-NOx burners, Flue gas recirculation	40 tpy (12-mo. Rolling Sum)	NOx PSD and Emission Offset Minor Limit [326 IAC 2-2] [326 IAC 2-3]

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	Coke Battery			
	Emission Unit Description	**Controls**	**NOx Limit**	**Comments**
AM Burns Harbor	1983 Coke Oven Battery #1 and #2 300 tons/hr coal Coke oven gas	Baghouse Flares	650 tpy (12-mo. Rolling Sum)	Prevention of Significant Deterioration (PSD) Minor Limit [326 IAC 2-2] and Emission Offset (EO) Minor Limit [326 IAC 2-3]
AM Indiana Harbor East	Facility does not have a coke battery			
AM Indiana Harbor West	Facility does not have a coke battery			
AK Dearborn	Facility does not have a sinter plant			
AK Middleton	B198 No. 2 Coke Plant, Wilputte Underjet 76-oven Coke Battery Coke Oven Gas	Flare	None	
AM Cleveland	Facility does not have a sinter plant			
AM Monassen Coke	801 COKE BATTERIES - CHARGING	None	1 tpy (12-mo. Rolling Sum)	25 Pa. Code §127.441
	802 COKE BATTERIES - PUSHING	PECS baghouse, Desulfurization/Recovery Plant	5 tpy (12-mo. Rolling Sum)	25 Pa. Code §127.441
	803 COKE BATTERIES - PUSHING	Quench tower, Desulfurization/Recovery Plant	None	
	805 COKE BATTERIES - UNDERFIRING	None	None	
	806 COKE BATTERIES - DOOR LEAKS	None	None	
	807 COKE BATTERIES - TOPSIDE	None	None	
	808 COKE BATTERIES -SOAKING	None	None	
	809 EXCESS COG FLARES (2 NON-EMERGENCY)	Flare	None	
	810 COAL AND COKE MATERIAL HANDLING	None	None	
	811 COAL AND COKE MATERIAL HANDLING	Flare	None	
AM Warren Coke Plant	B901/P002 No. 4 Coke Oven Battery and Tail Gas Desulfurization	None listed, likely not listed	None	
EES Coke Battery	1992, 1997, and 2014 Coke Batteries	Flares Baghouses	1411 tpy (12-mo rolling sum)	R336.2803, R336.2804
			563.5 pph (hourly average)	R336.2803, R336.2804
			0.75 lb/MMBtu (12-mo. Rolling avg)	R336.2810
			1.25 lb/MMBtu (24-hr Rolling avg)	R336.2810
			2.61 pph	For PECS baghouse stack. R336.2803, R336.2804, R336.2810

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	Coke Battery			
	Emission Unit Description	**Controls**	**NOx Limit**	**Comments**
Haverhill Coke Company	P901 AB Battery	Lime Spray Dryer Baghouse Staged Combustion	120 lb/hr	For waste gas stack. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			438 tpy (12-mo rolling sum)	For waste gas stack. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			24 lb/hr	For any HRSG stack. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			19.2 tpy	Total for all HRSG stacks on P901 and P902. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			1 lb/ton coal	For waste gas stack. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			7.68 lb/hr	From flat push car multicyclone dust collector OAC rules 3745-31-10 through 20
			7.01 tpy (12-mo rolling sum)	From flat push car multicyclone dust collector OAC rules 3745-31-10 through 20
			0.016 lb/ton coal	From flat push car multicyclone dust collector OAC rules 3745-31-10 through 20
	P902 CD Battery	Lime Spray Dryer Baghouse Staged Combustion	120 lb/hr	For waste gas stack. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			438 tpy (12-mo rolling sum)	For waste gas stack. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			24 lb/hr	For any HRSG stack. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			19.2 tpy	Total for all HRSG stacks on P901 and P902. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			1 lb/ton coal	For waste gas stack. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			7.68 lb/hr	From flat push car multicyclone dust collector OAC rules 3745-31-10 through 20
			7.01 tpy (12-mo rolling sum)	From flat push car multicyclone dust collector OAC rules 3745-31-10 through 20
			0.016 lb/ton coal	From flat push car multicyclone dust collector OAC rules 3745-31-10 through 20
Indiana Harbor Coke	Coke oven charging, pushing, and oven units 5,589 ton/day coke	Baghouse Lime Spray Dryer	40 tpy	Prevention of Significant Deterioration (PSD) Minor Limits [326 IAC 2-2]
Jewel Coke Company	143 Thompson Sole Flue Non-Recovery Coke Ovens	Afterburner Baghouses	29.07 lb/hr	9 VAC 5-80-110, 9 VAC 5-50-180, 9 VAC 5-50-260 and Condition 8 of NSR permit dated 6/12/02
	Heyl & Patterson Model 135 Thermal Dryer	Venturi Scubber	None	
Nucor St. James	COK-102 Coke Battery 1 Coke Pushing 1,102,311 tons/yr coal	None	0.02 lb/ton coke	LAC 33:III.509, BACT
	COK-202 Coke Battery 2 Coke Pushing 1,102,311 tons/yr coal	None	0.02 lb/ton coke	LAC 33:III.509, BACT
	COK-111 Coke Battery 1 FGD Stack 1,725,720 tons/yr coal	Staged Combustion	0.71 lb/ton coke	LAC 33:III.509, BACT
	COK-211 Coke Battery 2 FGD Stack 1,725,720 tons/yr coal	Staged Combustion	0.71 lb/ton coke	LAC 33:III.509, BACT
	PCS 0002 Coke Battery Area	None	None	
SunCoke Energy Midtown	P901 Coke Battery	None listed, likely not listed	None	

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	Coke Battery			
	Emission Unit Description	**Controls**	**NOx Limit**	**Comments**
USS Clairton	P001 Coke Battery No. 1 517,935 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	None	
USS Clairton	P002 Coke Battery No. 2 517,935 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	None	
USS Clairton	P003 Coke Battery No. 3 517,935 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	None	
USS Clairton	P007 Coke Battery No. 13 545,675 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	None	
USS Clairton	P008 Coke Battery No. 14 545,675 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	None	
USS Clairton	P009 Coke Battery No. 15 545,675 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	None	
USS Clairton	P010 Coke Battery No. 19 1,002,290 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	None	
USS Clairton	P011 Coke Battery No. 20 1,002,290 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	None	
USS Clairton	P012 Coke Battery B 1,491,025 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	None	
USS Clairton	P001 Coke Battery No. 1 517,935 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	None	
USS Clairton	P019 Desulfurization Plant 6,394,800 tons/yr coke Coke Oven Tail Gas	Afterburner SRU-SCOT Plant and Incinerator	500 ppmd 0.4 gr H2S/dscf coke oven gas	§2104.03.c §2105.21.h
USS Gary Works	Facility does not have a coke battery			
USS East Chicago	Facility does not have a sinter plan			
USS Edgar Thompson	Facility does not have a sinter plant			

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	Blast Furnace Stoves, Casthouses, and Slag Pits			
	Emission Unit Description	**Controls**	**NOx Limit**	**Comments**
AM Burns Harbor	1971 C Blast Furnace Consisting of C Blast Furnace Stoves 623 tons/hr iron (total with D Blast Furnace) 660 MMBtu/hr max HI total	integral gas cleaning system consisting of various components including a dust catcher, separator, and 2 scrubbers (primary and secondary), which provides clean fuel to the plant fuel distribution system with excess gas flared	None	Listed controls are for CO only.
		Stoves, exhausting to combustion stack (EP520-3547) with an estimated heat input rate of 660 MMBtu/hr		Primarily combust BFG which is a low NOx fuel
		East and West casthouses with iron and slag runner fugitive emissions reporting to roof monitors EP520-3543 and 3545 respectively and tap hole and tilting runner emissions controlled by MACT baghouse installed in 2007		Listed controls are for PM only.
	1968 D Blast Furnace Consisting of D Blast Furnace Stoves 623 tons/hr iron (total with C Blast Furnace) 660 MMBtu/hr max HI total	integral gas cleaning system consisting of various components including a dust catcher, separator, and 2 scrubbers (primary and secondary), which provides clean fuel to the plant fuel distribution system with excess gas flared	None	Listed controls are for CO only.
		Stoves, exhausting to combustion stack (EP520-3560) with an estimated heat input rate of 660 MMBtu/hr		Primarily combust BFG which is a low NOx fuel
		East and West casthouses with iron and slag runner fugitive emissions reporting to roof monitors EP520-3556 and 3558 respectively and respectively and tap hole and tilting runner emissions controlled by MACT baghouse installed in 2007		Listed controls are for PM only.
AM Indiana Harbor East	1980 No. 7 Blast Furnace Comprised of four No. 7 Blast Furnace Stoves 4.417 Mmtons/yr metal production 953 MMBtu/hr max HI total Pulverized coal (132 tons/hr) / Natural Gas / Blast Furnace Gas	Integral gas cleaning system with excess gas exhausting through Three (3) flares, each with a 1.15 MMBtu per hour igniter capacity of flaring one-third of the maximum generated blast furnace gas through stack 195	None	Listed controls are for CO only.
		Four Stoves have no controls for NOx		Primarily combust BFG which is a low NOx fuel
		Casthouse emissions controlled by two baghouses rated at 500,000 acfm (stack 166) and 300,000 acfm (stack 167) respectively.		Listed controls are for PM only.
		PCI system has two pulverizers each with cyclone and baghouse (stack 187).		Listed controls are for PM only.
AM Indiana Harbor West	1953 No. 3 Blast Furnace Including three No. 3 Blast Furnace Stoves 4.5552 Mmtons/yr input 441 MMBtu/hr max HI total	integral gas cleaning system consisting of a dust catcher, separator, two scrubbers (primary and secondary) and one cooling tower, with excess gas exhausting through a flare at stack (S1E)	None	Listed controls are for CO only.
		Three Stoves have no controls for NOx		Primarily combust BFG which is a low NOx fuel
		Passive Emission Control (PEC) to suppress fumes in the casthouse, consisting of slag and iron runner covers along with natural gas flame suppression exhausting to the No. 3 Blast		Listed controls are for PM only.
	1967 No. 4 Blast Furnace Including three No. 4 Blast Furnace Stoves 5.490836 Mmtons/yr input 486 MMBtu/hr max HI total	integral gas cleaning system consisting of a dust catcher, separator, two scrubbers (primary and secondary) and one cooling tower with excess gas exhausting through a flare at stack (S1D)	None	Listed controls are for CO only.
		Three Stoves have no controls for NOx		Primarily combust BFG which is a low NOx fuel
		Passive Emission Control (PEC) to suppress fumes in the casthouse, consisting of slag and iron runner covers along with natural gas flame suppression exhausting to the No. 4 Blast Furnace Casthouse Roof Monitor (V1B). No. 4 Blast Furnace Casthouse Baghouse used to control emissions from the casthouse with an airflow rate of 147,000 acfm exhausting at stack (S1B) when operating one (1) fan. No. 4 Blast Furnace Casthouse Baghouse has an air flow rate of 240,000 acfm when operating two (2) fans.		Listed controls are for PM only.
	2 Ladle Burners	None	None	
	Railcar Thaw Shed Heater 50.4 MMBtu/hr max HI total	None	None	
USS Gary Works	IDBF0369 No. 14 Blast Furnace Comprised of three No. 14 Blast Furnace Stoves (IDST0359) 450 tons metal production/hr 700 MMBtu/hr max HI total Natural gas / Pulverized coal (80 tons/hr) / Oil (150	Stockhouse Baghouse	None	
Nucor St. James	Not Constructed Blast Furnace 1 1,088 MMBtu/hr Natural gas, Blast furnace gas	Low NOx fuels	0.06 lb/MMBtu	LAC 33:III.509, BACT
	Not Constructed Casthouse No. 1	None	None	
	Not Constructed Blast Furnace 2 1,088 MMBtu/hr Natural gas, Blast furnace gas	Low NOx fuels	0.06 lb/MMBtu	LAC 33:III.509, BACT
	Not Constructed Casthouse No. 2	None	None	
USS Clairton	Facility does not have a blast furnace			
AK Dearborn	1/1/1922 EUBFURNACE (part of FGB&CFURNACES), group of 4 stoves with a common stack, cast house emission control system (collection hoods, baghouse, stack), a blast furnace gas scrubber and dust collector, semi-clean bleeder, and dirty gas bleeder. 3,321,500 tons iron/yr (material limit on FGB&CFURNACES) Natural gas, Blast furnace gas	Stoves: Low-Nox Technology Casthouse: Baghouse Venturi scrubber and mechanical collector for blast furnace pre-cleaning	25.74 tons/yr (12mo rolling)	Limit on: FGB&CFURNACES baghouse stacks R336.2801 - R336.2804 -- PSD
	1/1/1948, 10/1/2007 EUCFURNACE (part of FGB&CFURNACES), group of 4 stoves with a common		439.2 tons/yr (12mo rolling)	Limit on: FGB&CFURNACES stove stacks R336.2801 - R336.2804 -- PSD
AK Middleton	P925 No. 3 Blast Furnace 740 tons metal production/hr	For PM control: equipped with a casthouse baghouse, a settling chamber/dustcatcher (cyclone), a wet venturi scrubber system (Bischoff), stoves, and a blast furnace gas flare	None	

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Regional Haze Four-Factor Analyses for NO_X and SO_2 Emissions Control

Appendix B: Air Permit Summary for II&S Mills

	Blast Furnace Stoves, Casthouses, and Slag Pits			
	Emission Unit Description	**Controls**	**NOx Limit**	**Comments**
AM Cleveland	P903 Blast Furnace C5	equipped with a venturi scrubber for cleaning reusable blast furnace gas, natural gas suppression, oxygen enrichment, dirty and clean gas bleeders, and flue dust handling with passive emission control (PEC) system, and flare	0.06 lbs/MMBtu	for furnace stoves
AM Cleveland	P904 Blast Furnace C6	equipped with a venturi scrubber for cleaning reusable blast furnace gas, natural gas suppression, oxygen enrichment, dirty and clean gas bleeders, and flue dust handling with passive emission control (PEC) system and a flare	0.06 lbs/MMBtu	for furnace stoves
USS Edgar Thompson	P001a Blast Furnace No. 1 Casthouse 1,752,000 tpy (production capacity) Coke, Iron-bearing materials, fluxes	Stack S002, Casthouse Baghouse (shared between P001a and P002a)	None	
USS Edgar Thompson	P001b Blast Furnace No. 1 Stoves 495 MMBtu/hr BFG, COG, Natural Gas	Stack S001, Dust Catch/Venturi scrubber for BFG cleaning	None	
USS Edgar Thompson	P001c BFG Flare 3 MMcfh BFG	Stack S003	None	
USS Edgar Thompson	P002a Blast Furnace No. 3 Casthouse 1,752,000 tpy (production capacity) Coke, Iron-bearing materials, fluxes	Stack S002, Casthouse Baghouse (shared between P001a and P002a)	None	
USS Edgar Thompson	P002b Base Furnace No. 3 Stoves 495 MMBtu/hr BFG, COG, Natural Gas	Stack S004, Dust Catch/Venturi scrubber for BFG cleaning	None	
USS East Chicago	Facility does not have a blast furnace			

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Appendix B: Air Permit Summary for II&S Mills

	Boilers			
	Emission Unit Description	**Controls**	**SO2 Limit**	**Comments**
AM Burns Harbor	1976 No. 7 Boiler 650 MMBtu/hr max HI (ea.) natural gas, coke oven gas, blast furnace gas, and fuel oil	None	None	
	1970 No. 8 Boiler 650 MMBtu/hr max HI (ea.) natural gas, coke oven gas, blast furnace gas, No. 2 fuel oil, No. 6 fuel oil	None		
	1970 No. 9 Boiler 650 MMBtu/hr max HI (ea.) natural gas, coke oven gas, blast furnace gas, No. 2 fuel oil, No. 6 fuel oil	None		
	1969 No. 10 Boiler 650 MMBtu/hr max HI (ea.) natural gas, coke oven gas, blast furnace gas, No. 2 fuel oil, No. 6 fuel oil	None		
	1968 No. 11 Boiler 650 MMBtu/hr max HI (ea.) natural gas, coke oven gas, blast furnace gas, No. 2 fuel oil, No. 6 fuel oil	None		
	1968 No. 12 Boiler 650 MMBtu/hr max HI (ea.) natural gas, coke oven gas, blast furnace gas, No. 2 fuel oil, No. 6 fuel oil	None		
AM Indiana Harbor East	1976 No. 501 Boiler 520 MMBtu/hr max HI (ea.) Natural Gas, Blast Furnace Gas	None	0.198 lb/MMBtu 265.2 lb/hr	Pursuant to 326 IAC 7-4.1-11(a): Limits are for all 4 boilers in total
	1976 No. 502 Boiler 520 MMBtu/hr max HI (ea.) Natural Gas, Blast Furnace Gas	None		
	1976 No. 503 Boiler 520 MMBtu/hr max HI (ea.) Natural Gas, Blast Furnace Gas	None		
	Approved in 2010 - No. 504 Boiler 561.6 MMBtu/hr max HI (ea.)	None		
AM Indiana Harbor West	1952 No. 5 Boiler 454 MMBtu/hr max HI (ea.) Natural Gas, blast furnace gas	None	1. 0.594 lb/MMBtu 2. 1,456.5 lbs/hr 3. 5,871.61 tpy	1. Pursuant to 326 IAC 7-4.1-10(a)(1): Limit applies to all 4 boilers, for each individual stack 2. Pursuant to 326 IAC 7-4.1-10(a)(1): Limit applies to all 4 boilers in total 3. Pursuant to 326 IAC 7-4.1-10(a)(1): Limit applies to all 4 boilers in total, also with Ironside Energy, LLC Utility Boiler No. 9
	1956 No. 6 Boiler 454 MMBtu/hr max HI (ea.) Natural Gas, blast furnace gas	None		
	1056 No. 7 Boiler 454 MMBtu/hr max HI (ea.) Natural Gas, blast furnace gas	None		
	1967 No. 8 Boiler 1,090 MMBtu/hr max HI (ea.) Natural Gas, blast furnace gas	None		
Nucor St. James	Not Constructed - Topgas Boiler No. 1 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low sulfur fuels	1. 1.2 lb/MMBtu 2. 0.008 lb/MMBtu 3. 0.002 gr/dscf 4. 0.022 lb/MMBtu	1. 40 CFR60.43(a)(2) (NSPS D): For all boilers individually 2. LAC 33:III.509, BACT: For all boilers individually. Specific to BFG. This limit for Normal operation consists of a fuel mixture of Blast Furnace Top Gas and Natural gas with less than or equal to 41 % natural gas on a MMBTU / hr heat input. 3. LAC 33:III.509, BACT: Sulfur content in natural gas 4. LAC 33:III.509, BACT: For all boilers individually. Total for all fuels. This emission rate is based upon any operation with natural gas greater than 41 % heat input of the fuel up to and including 100%. Operating under this alternate operating scenario shall be minimized to the maximum extent possible.
	Not Constructed - Topgas Boiler No. 2 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low sulfur fuels		
	Not Constructed - Topgas Boiler No. 3 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low sulfur fuels		
	Not Constructed - Topgas Boiler No. 4 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low sulfur fuels		
	Not Constructed - Topgas Boiler No. 5 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low sulfur fuels		
	Not Constructed - Topgas Boiler No. 6 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low sulfur fuels		
	Not Constructed - Topgas Boiler No. 7 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low sulfur fuels		
	Not Constructed - Topgas Boiler No. 8 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low sulfur fuels		
USS Clairton	B001 - Boiler No. 1 760 mmbtu/hr heat input Desulfurized Coke Oven Gas and Natural Gas	None	163.50 lb/hr 716.11 tpy	County-only enforceable, per permit County-only enforceable, per permit
	B002 - Boiler No. 2 481 mmbtu/hr heat input Desulfurized Coke Oven Gas and Natural Gas	None	103.48 lb/hr 453.22 tpy	County-only enforceable, per permit County-only enforceable, per permit
	B005 - R1 Boiler 229 mmbtu/hr heat input Desulfurized Coke Oven Gas and Natural Gas	None	49.26 lb/hr 215.78 tpy	County-only enforceable, per permit County-only enforceable, per permit
	B006 - R2 Boiler 229 mmbtu/hr heat input Desulfurized Coke Oven Gas and Natural Gas	None	49.26 lb/hr 215.78 tpy	County-only enforceable, per permit County-only enforceable, per permit
	B007 - T1 Boiler 156 mmbtu/hr heat input Desulfurized Coke Oven Gas and Natural Gas	None	33.56 lb/hr 146.99 tpy	
	B008 - T2 Boiler 156 mmbtu/hr heat input Desulfurized Coke Oven Gas and Natural Gas	None	33.56 lb/hr 146.99 tpy	

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Appendix B: Air Permit Summary for II&S Mills

	Boilers			
	Emission Unit Description	**Controls**	**SO2 Limit**	**Comments**
AK Dearborn	Facility does not have a boiler			
AK Middleton	P009 No. 3 Slab Reheat Furnace/Waste Heat Boiler 598 MMBtu/hr Slab Furnace 305 MMBtu/hr Waste Heat Boiler Natural gas, fuel oil, coke oven gas	None	1.10 lbs/MMBtu	OAC rule citation(s)
	P010 No. 2 Slab Reheat Furnace/Waste Heat Boiler 598 MMBtu/hr Slab Furnace 305 MMBtu/hr Waste Heat Boiler Natural gas, fuel oil, coke oven gas	None	1.10 lbs/MMBtu	OAC rule citation(s)
	P011 No. 1 Slab Reheat Furnace/Waste Heat Boiler 598 MMBtu/hr Slab Furnace 305 MMBtu/hr Waste Heat Boiler Natural gas, fuel oil, coke oven gas	None	1.10 lbs/MMBtu	OAC rule citation(s)
	P012 No. 4 Slab Reheat Furnace/Waste Heat Boiler 598 MMBtu/hr Slab Furnace 305 MMBtu/hr Waste Heat Boiler Natural gas, fuel oil, coke oven gas	None	1.10 lbs/MMBtu	OAC rule citation(s)
AM Cleveland	Facility does not have a boiler			
USS Edgar Thompson	Facility does not have a boiler			
USS East Chicago	B-1 Steam Generation Boiler 181.1 MMBtu/hr max HI (ea.) Natural gas	Flue gas recirculation	None	

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	Coke Battery			
	Emission Unit Description	Controls	SO2 Limit	Comments
AM Burns Harbor	1983 Coke Oven Battery #1 and #2 300 tons/hr coal Coke oven gas	Baghouse Flares	None	
AM Indiana	Facility does not have a coke battery			
AM Indiana Harbor West	Facility does not have a coke battery			
AK Dearborn	Facility does not have a sinter plant			
AK Middleton	B198 No. 2 Coke Plant, Wilputte Underjet 76-oven Coke Battery Coke Oven Gas	Flare	2.8 gr H2S/dscf (30-day Rolling Average)	Limit on coke oven gas. OAC rule 3745-18-15(C)(3)(a)
AM Cleveland	Facility does not have a sinter plant			
AM Monassen Coke	801 COKE BATTERIES - CHARGING	None	None	
AM Monassen Coke	802 COKE BATTERIES - PUSHING	PECS baghouse, Desulfurization/Recovery Plant	None	
AM Monassen Coke	803 COKE BATTERIES - PUSHING	Quench tower, Desulfurization/Recovery Plant	None	
AM Monassen Coke	805 COKE BATTERIES - UNDERFIRING	None	None	
AM Monassen Coke	806 COKE BATTERIES - DOOR LEAKS	None	None	
AM Monassen Coke	807 COKE BATTERIES - TOPSIDE	None	None	
AM Monassen Coke	808 COKE BATTERIES -SOAKING	None	None	
AM Monassen Coke	809 EXCESS COG FLARES (2 NON-EMERGENCY)	Flare	None	
AM Monassen Coke	810 COAL AND COKE MATERIAL HANDLING	None	None	
AM Monassen Coke	811 COAL AND COKE MATERIAL HANDLING	Flare	None	
AM Warren Coke Plant	B901/P002 No. 4 Coke Oven Battery and Tail Gas Desulfurization	None listed, likely not listed	0.35 gr H2S/dscf	Limit for coke oven gas combusted. OAC rule 3745-31-05 (PTI No. 02-171)
EES Coke Battery	1992, 1997, and 2014 Coke Batteries	Flares Baghouses	2071 tpy (12-mo rolling sum) 544.6 pph (3-hr block avg) 0.702 lb/Mscf coke oven gas	R336.1205(1)(a) and (1)(b), 40 CFR 52.21(c) and (d) 40 CFR 52.21(c) and (d) R336.1205(1)(a) and (1)(b), Section 110 of CAA

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	Coke Battery			
	Emission Unit Description	**Controls**	**SO2 Limit**	**Comments**
Haverhill Coke Company	P901 AB Battery	Lime Spray Dryer Baghouse Staged Combustion	192 lb/hr (3-hr block average)	40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			700.8 tpy (12-mo rolling sum)	40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			420 lb/hr (3-hr block average)	For any HRSG stack. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			323 lb/hr (48-hr rolling average)	For any HRSG stack during bypass venting longer than 48 hours. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			384 tpy	Total for all HRSG stacks on P901 and P902. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			520.8 tons/24-mo. (Rolling sum)	Total for all HRSG stacks on P901 and P902. Not enforcable until 2021. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			1.6 lb/ton coal	For waste gas stack. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			0.14 lb/hr	For charging baghouse. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			0.13 tpy (12-mo rolling sum)	For charging baghouse. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			0.0003 lb/ton coal	For charging baghouse. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			24 lb/hr	From flat push car multicyclone dust collector OAC rules 3745-31-10 through 20
			21.9 tpy (12-mo rolling sum)	From flat push car multicyclone dust collector OAC rules 3745-31-10 through 20
			0.05 lb/ton coal	From flat push car multicyclone dust collector OAC rules 3745-31-10 through 20
	P902 CD Battery	Lime Spray Dryer Baghouse Staged Combustion	192 lb/hr (3-hr block average)	40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			700.8 tpy (12-mo rolling sum)	40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			420 lb/hr (3-hr block average)	For any HRSG stack. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			323 lb/hr (48-hr rolling average)	For any HRSG stack during bypass venting longer than 48 hours. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			384 tpy	Total for all HRSG stacks on P901 and P902. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			520.8 tons/24-mo. (Rolling sum)	Total for all HRSG stacks on P901 and P902. Not enforcable until 2021. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			1.6 lb/ton coal	For waste gas stack. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			0.14 lb/hr	For charging baghouse. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			0.13 tpy (12-mo rolling sum)	For charging baghouse. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			0.0003 lb/ton coal	For charging baghouse. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			24 lb/hr	From flat push car multicyclone dust collector OAC rules 3745-31-10 through 20
			21.9 tpy (12-mo rolling sum)	From flat push car multicyclone dust collector OAC rules 3745-31-10 through 20
			0.05 lb/ton coal	From flat push car multicyclone dust collector OAC rules 3745-31-10 through 20
Indianca Harbor Coke	Coke oven charging, pushing, and oven units 5,589 ton/day coke	Baghouse Lime Spray Dryer	0.0068 lb/ton coal	For charging. 326 IAC 7-4.1-8
			1.57 lb/hr	For charging. 326 IAC 7-4.1-8
			0.0084 lb/ton coal	For pushing. 326 IAC 7-4.1-8
			1.96 lb/hr	For pushing. 326 IAC 7-4.1-8
			0.0053 lb/ton coal	For quenching. 326 IAC 7-4.1-8
			1.232 lb/hr	For quenching. 326 IAC 7-4.1-8
			1656 lb/hr	For waste gas stack. 326 IAC 7-4.1-8
Jewel Coke Company	143 Thompson Sole Flue Non-Recovery Coke Ovens	Afterburner Baghouses	310 lb/hr	9 VAC 5-80-110, 9 VAC 5-50-180, 9 VAC 5-50-260 and Condition 8 of NSR permit dated 6/12/02
	Heyl & Patterson Model 135 Thermal Dryer	Venturi Scrubber	1.4 lb/hr	VAC 5-50-260, 9 VAC 5-80-110 and Condition 10 of NSR permit dated 6/12/02
			3.9 tpy (12-mo rolling sum)	VAC 5-50-260, 9 VAC 5-80-110 and Condition 10 of NSR permit dated 6/12/02
Nucor St. James	COK-102 Coke Battery 1 Coke Pushing 1,102,311 tons/yr coal	None	0.10 lb/ton coke	LAC 33:III.509, BACT
	COK-202 Coke Battery 2 Coke Pushing 1,102,311 tons/yr coal	None	0.10 lb/ton coke	LAC 33:III.509, BACT
	COK-111 Coke Battery 1 FGD Stack 1,725,720 tons/yr coal	None listed, likely not listed	2000 ppmv	LAC 33:III.1503.C
	COK-211 Coke Battery 2 FGD Stack 1,725,720 tons/yr coal	None listed, likely not listed	2000 ppmv	LAC 33:III.1503.C
	PCS 0002 Coke Battery Area	None	1.25% Sulfur in Charge 37% Redyction by Weight of Retained Sulfur	LAC 33:III.509, BACT

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	Coke Battery			
	Emission Unit Description	**Controls**	**SO2 Limit**	**Comments**
SunCoke Energy Midtown	P901 Coke Battery	None listed, likely not listed	None	
USS Clairton	P001 Coke Battery No. 1 517,935 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	139.46 tpy 31.8 lb/hr 10.41 lb/hr (30-day Rolling Average) 13.27 lb/hr (24-hr Average) 0.4 gr H2S/dscf	Limit for a consecutive 12-mo period. Same limit used on lb/hr basis (8760 hr/yr). §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2102.04.b.6, §2105.21.h §2102.04.b.6, §2105.21.h §2105.21.h; §2105.21.h.4
USS Clairton	P002 Coke Battery No. 2 517,935 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	139.46 tpy 31.8 lb/hr 9.15 lb/hr (30-day Rolling Average) 11.66 lb/hr (24-hr Average) 0.4 gr H2S/dscf	Limit for a consecutive 12-mo period. Same limit used on lb/hr basis (8760 hr/yr). §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2102.04.b.6, §2105.21.h §2102.04.b.6, §2105.21.h §2105.21.h; §2105.21.h.4
USS Clairton	P003 Coke Battery No. 3 517,935 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	139.46 tpy 31.8 lb/hr 10.57 lb/hr (30-day Rolling Average) 13.47 lb/hr (24-hr Average) 0.4 gr H2S/dscf	Limit for a consecutive 12-mo period. Same limit used on lb/hr basis (8760 hr/yr). §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2102.04.b.6, §2105.21.h §2102.04.b.6, §2105.21.h §2105.21.h; §2105.21.h.4
USS Clairton	P007 Coke Battery No. 13 545,675 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	146.5 tpy 33.5 lb/hr 13.93 lb/hr (30-day Rolling Average) 15.7 lb/hr (24-hr Average) 0.4 gr H2S/dscf	Limit for a consecutive 12-mo period. Same limit used on lb/hr basis (8760 hr/yr). §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2102.04.b.6, §2105.21.h §2102.04.b.6, §2105.21.h §2105.21.h; §2105.21.h.4
USS Clairton	P008 Coke Battery No. 14 545,675 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	146.5 tpy 33.5 lb/hr 14.03 lb/hr (30-day Rolling Average) 15.8 lb/hr (24-hr Average) 0.4 gr H2S/dscf	Limit for a consecutive 12-mo period. Same limit used on lb/hr basis (8760 hr/yr). §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2102.04.b.6, §2105.21.h §2102.04.b.6, §2105.21.h §2105.21.h; §2105.21.h.4
USS Clairton	P009 Coke Battery No. 15 545,675 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	146.5 tpy 33.5 lb/hr 18.67 lb/hr (30-day Rolling Average) 21.04 lb/hr (24-hr Average) 0.4 gr H2S/dscf	Limit for a consecutive 12-mo period. Same limit used on lb/hr basis (8760 hr/yr). §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2102.04.b.6, §2105.21.h §2102.04.b.6, §2105.21.h §2105.21.h; §2105.21.h.4
USS Clairton	P010 Coke Battery No. 19 1,002,290 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	269.48 tpy 61.53lb/hr 29.37 lb/hr (30-day Rolling Average) 33.09 lb/hr (24-hr Average) 0.4 gr H2S/dscf	Limit for a consecutive 12-mo period. Same limit used on lb/hr basis (8760 hr/yr). §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2102.04.b.6, §2105.21.h §2102.04.b.6, §2105.21.h §2105.21.h; §2105.21.h.4
USS Clairton	P011 Coke Battery No. 20 1,002,290 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	269.48 tpy 61.53lb/hr 27 lb/hr (30-day Rolling Average) 30.42 lb/hr (24-hr Average) 0.4 gr H2S/dscf	Limit for a consecutive 12-mo period. Same limit used on lb/hr basis (8760 hr/yr). §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2102.04.b.6, §2105.21.h §2102.04.b.6, §2105.21.h §2105.21.h; §2105.21.h.4
USS Clairton	P012 Coke Battery B 1,491,025 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	400.95 tpy 91.5 lb/hr 21.38 lb/hr (30-day Rolling Average) 27.26 lb/hr (24-hr Average) 0.4 gr H2S/dscf	Limit for a consecutive 12-mo period. Same limit used on lb/hr basis (8760 hr/yr). §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2102.04.b.6, §2105.21.h §2102.04.b.6, §2105.21.h §2105.21.h; §2105.21.h.4
USS Clairton	P046 Coke Battery C 1,379,059 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	27 lb/hr (30-day Rolling Average) 30.42 lb/hr (24-hr Average)	§2102.04.b.6, §2105.21.h §2105.21.h; §2105.21.h.4
USS Clairton	P019 Desulfurization Plant 6,394,800 tons/yr coke Coke Oven Tail Gas	Afterburner SRU-SCOT Plant and Incinerator	None	

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Appendix B: Air Permit Summary for II&S Mills

	Coke Battery			
	Emission Unit Description	Controls	SO2 Limit	Comments
USS Gary Works	Facility does not have a coke battery			
USS East Chicago	Facility does not have a sinter plan			
USS Edgar Thompson	Facility does not have a sinter plant			

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Appendix B: Air Permit Summary for II&S Mills

	Blast Furnace Stoves, Casthouses, and Slag Pits			
	Emission Unit Description	**Controls**	**SO2 Limit**	**Comments**
AM Burns Harbor	1971 C Blast Furnace Consisting of C Blast Furnace Stoves 623 tons/hr iron (total with D Blast Furnace) 660 MMBtu/hr max HI total	Integral gas cleaning system consisting of various components including a dust catcher, separator, and 2 scrubbers (primary and secondary), which provides clean fuel to the plant fuel distribution system with excess gas flared	None	Listed controls are for CO only.
		Stoves, exhausting to combustion stack (EP520-3547) with an estimated heat input rate of 660 MMBtu/hr		Primarily combust BFG which is a low NOx fuel
		East and West casthouses with iron and slag runner fugitive emissions reporting to roof monitors EP520-3543 and 3545 respectively and tap hole and tilting runner emissions controlled by MACT baghouse installed in 2007		Listed controls are for PM only.
	1968 D Blast Furnace Consisting of D Blast Furnace Stoves 623 tons/hr iron (total with C Blast Furnace) 660 MMBtu/hr max HI total	Integral gas cleaning system consisting of various components including a dust catcher, separator, and 2 scrubbers (primary and secondary), which provides clean fuel to the plant fuel distribution system with excess gas flared	None	Listed controls are for CO only.
		Stoves, exhausting to combustion stack (EP520-3560) with an estimated heat input rate of 660 MMBtu/hr		Primarily combust BFG which is a low NOx fuel
		East and West casthouses with iron and slag runner fugitive emissions reporting to roof monitors EP520-3556 and 3558 respectively and respectively and tap hole and tilting runner emissions controlled by MACT baghouse installed in 2007		Listed controls are for PM only.
AM Indiana Harbor East	1980 No. 7 Blast Furnace Comprised of four No. 7 Blast Furnace Stoves 4.417 Mmtons/yr metal production 953 MMBtu/hr max HI total Pulverized coal (132 tons/hr) / Natural Gas / Blast Furnace Gas	Integral gas cleaning system with excess gas exhausting through Three (3) flares, each with a 1.15 MMBtu per hour igniter capacity of flaring one-third of the maximum generated blast furnace gas through stack 195	None	Listed controls are for CO only.
		Four Stoves have no controls for SO2	0.195 lb/MMBtu 162 lb/hr	Pursuant to 326 IAC 7-4.1-11(a) Limit on: Blast Furnace No. 7 Stove Stack
		Casthouse emissions controlled by two baghouses rated at 500,000 acfm (stack 166) and 300,000 acfm (stack 167) respectively.	0.22 lb/ton 50.4 lb/hr per BH	Pursuant to 326 IAC 7-4.1-11(a) Limit on: Blast Furnace No. 7 Casthouse Listed controls are for PM only.
		PCI system has two pulverizers each with cyclone and baghouse (stack 187).	None	Listed controls are for PM only.
AM Indiana Harbor West	1953 No. 3 Blast Furnace Comprised of three No. 3 Blast Furnace Stoves 4.5552 Mmtons/yr input 441 MMBtu/hr max HI total	Integral gas cleaning system consisting of a dust catcher, separator, two scrubbers (primary and secondary) and one cooling tower, with excess gas exhausting through a flare at stack (S1E)	None	Listed controls are for CO only.
		Three Stoves have no controls for SO2	0.29 lb/MMBtu 127.89 lb/hr	Pursuant to 326 IAC 7-4.1-10(a)(4)(A) Limit on: Blast Furnace No. 3 Stove Stack
		Passive Emission Control (PEC) to suppress fumes in the casthouse, consisting of slag and iron runner covers along with natural gas flame suppression exhausting to the No. 3 Blast Furnace Casthouse Roof Monitor (V1A).	None	Listed controls are for PM only.
	1967 No. 4 Blast Furnace Comprised of three No. 4 Blast Furnace Stoves 5.490836 Mmtons/yr input 486 MMBtu/hr max HI total	Integral gas cleaning system consisting of a dust catcher, separator, two scrubbers (primary and secondary) and one cooling tower with excess gas exhausting through a flare at stack (S1D)	None	Listed controls are for CO only.
		Three Stoves have no controls for SO2	0.29 lb/MMBtu 140.94 lb/hr	Pursuant to 326 IAC 7-4.1-10(a)(4)(B) Limit on: Blast Furnace No. 4 Stove Stack
		Passive Emission Control (PEC) to suppress fumes in the casthouse, consisting of slag and iron runner covers along with natural gas flame suppression exhausting to the No. 4 Blast Furnace Casthouse Roof Monitor (V1B). No. 4 Blast Furnace Casthouse Baghouse used to control emissions from the casthouse with an airflow rate of 147,000 acfm exhausting at stack (S1B) when operating one (1) fan. No. 4 Blast Furnace Casthouse Baghouse has an air flow rate of 240,000 acfm when operating two (2) fans.	0.18 lb/ton 69.9 lb/hr	Pursuant to 326 IAC 7-4.1-10(a)(6) Limit on : Blast Furnace No. 4 Casting Listed controls are for PM only.
	2 Ladle Burners 36 MMBtu/hr max HI total	None	None	
	Railcar Thaw Shed Heater 50.4 MMBtu/hr max HI total	None	None	
USS Gary Works	IDBF0369 No. 14 Blast Furnace Comprised of three No. 14 Blast Furnace Stoves (IDST0359) 450 tons metal production/hr 700 MMBtu/hr max HI total Natural gas / Pulverized coal (80 tons/hr) / Oil (150 gal/min) and/or coal tar (150 gal/min)	Stockhouse Baghouse	0.134 lb/MMBtu	Limit on: Blast Furnace No. 14 Stove Stack
			93.5 lb/hr total	Limit on: Blast Furnace No. 14 Stove Stack
			115 lb/hr	Limit on: Blast Furnace No. 14 Casthouse Baghouse Stack
Nucor St. James	Not Constructed Blast Furnace 1 1,088 MMBtu/hr Natural gas, Blast furnace gas	Low sulfur fuels	0.002 gr/dscf Natural Gas (SO2 as H2S) 0.00874 gr/dscf BFG	LAC 33:III.509, BACT: Sulfur content in natural gas
	Not Constructed Casthouse No. 1	None	0.040 lb/ton hot metal	LAC 33:III.509, BACT
	Not Constructed Blast Furnace 2 1,088 MMBtu/hr Natural gas, Blast furnace gas	Low sulfur fuels	0.002 gr/dscf Natural Gas (SO2 as H2S) 0.00874 gr/dscf BFG	LAC 33:III.509, BACT: Sulfur content in natural gas
	Not Constructed Casthouse No. 2	None	0.040 lb/ton hot metal	LAC 33:III.509, BACT
USS Clairton	Facility does not have a blast furnace			

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emissions Control
Appendix B: Air Permit Summary for II&S Mills

	Blast Furnace Stoves, Casthouses, and Slag Pits			
	Emission Unit Description	**Controls**	**SO2 Limit**	**Comments**
AK Dearborn	1/1/1922 EUBFURNACE (part of FGB&CFURNACES), group of 4 stoves with a common stack, cast house emission control system (collection hoods, baghouse, stack), a blast furnace gas scrubber and dust collector, semi-clean bleeder, and dirty gas bleeder. 3,321,500 tons iron/yr (material limit on FGB&CFURNACES) Natural gas, Blast furnace gas	Stoves: No SO2 controls Casthouse: Baghouse Venturi scrubber and mechanical collector for blast furnace pre-cleaning	1,188 tpy (12mo rolling)	Limit on: FGB&CFURNACES baghouse and stove stacks R336.2803, R336.2804 -- PSD
AK Dearborn	1/1/1948, 10/1/2007 EUCFURNACE (part of FGB&CFURNACES), group of 4 stoves with a common			
AK Middleton	P925 No. 3 Blast Furnace 740 tons metal production/hr	For PM control: equipped with a casthouse baghouse, a settling chamber/dustcatcher (cyclone), a wet venturi scrubber system (Bischoff), stoves, and a blast furnace gas flare	None	
AM Cleveland	P903 Blast Furnace C5	equipped with a venturi scrubber for cleaning reusable blast furnace gas, natural gas suppression, oxygen enrichment, dirty and clean gas bleeders, and flue dust handling with passive emission control (PEC) system, and flare	33 lb/hr	from the blast furnace casthouse when combusting coke oven gas d. These emission limitations are not applicable because coke oven gas is no longer capable of being burned in this emissions unit.
			53 lb/hr	from the blast furnace stoves when combusting coke oven gas d. These emission limitations are not applicable because coke oven gas is no longer capable of being burned in this emissions unit.
AM Cleveland	P904 Blast Furnace C6	equipped with a venturi scrubber for cleaning reusable blast furnace gas, natural gas suppression, oxygen enrichment, dirty and clean gas bleeders, and flue dust handling with passive emission control (PEC) system and a flare	33 lb/hr	A maximum of 390 grains of hydrogen sulfide per 100 dry standard cubic feet of coke oven gas, and the daily average not to exceed 33 lbs of SO2 per hour from the blast furnace casthouse when combusting coke oven gas.
			53 lb/hr	Maximum of 390 grains of hydrogen sulfide per 100 dscf of coke oven gas and the daily average not to exceed 53 lbs SO2/hr from the blast furnace stoves when combusting coke oven gas.
USS Edgar Thompson	P001a Blast Furnace No. 1 Casthouse 1,752,000 tpy (production capacity) Coke, Iron-bearing materials, fluxes	Stack S002, Casthouse Baghouse (shared between P001a and P002a)	None	
USS Edgar Thompson	P002a Blast Furnace No. 3 Casthouse 1,752,000 tpy (production capacity) Coke, Iron-bearing materials, fluxes	Stack S002, Casthouse Baghouse (shared between P001a and P002a)	None	
USS Edgar Thompson	P001b Blast Furnace No. 1 Stoves 495 MMBtu/hr BFG, COG, Natural Gas	Stack S001, Dust Catch/Venturi scrubber for BFG cleaning	1. 353.03 lb/hr 2. 108.41 tpy 3. A = 1.7 E^(-0.14)	1. Applies to each set of stoves (No. 1 Blast furnace stoves & No. 3 Blast furnace stoves) Permit References: (§2104.03.a.2.B, §2104.02.b, §2103.12.a.2.B)
USS Edgar Thompson	P002b Base Furnace No. 3 Stoves 495 MMBtu/hr BFG, COG, Natural Gas	Stack S004, Dust Catch/Venturi scrubber for BFG cleaning		
USS Edgar Thompson	P001c BFG Flare 3 MMcfh BFG	Stack S003	None	
USS East Chicago	Facility does not have a blast furnace			

Appendix C

Unit-specific Screening Level Cost Summary for SO_2 Emission Control Measures

Appendix C.1

Battery No. 1 Underfire

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.1 – Table C.1-1: Cost Summary

Battery No. 1 Underfire

SO_2 Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Total Annualized Cost $/yr	Pollution Control Cost $/ton
Spray Dry Absorber (SDA)	90%	167.5	1507.4	$64,478,506	$9,527,094	$6,320

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Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.1 – Table C.1-2: Summary of Utility, Chemical and Supply Costs

Battery No. 1 Underfire

Operating Unit:	Battery No. 1 Underfire	**Study Year**	2020
Emission Unit Number			
Stack/Vent Number			

Item	2020 Unit Cost	Units	Cost	Year	Data Source	Notes
Operating Labor	68	$/hr	60	2016	EPA SCR Control Cost Manual Spreadsheet	
Maintenance Labor	68	$/hr				Assumed to be equivalent to operating labor
Installation Labor	68	$/hr				Assumed to be equivalent to operating labor
Electricity	0.07	$/kwh			2016-2019 EIA Average prices for the industrial sector in Indiana	
Natural Gas	6.15	$/kscf			2014-2018 EIA Average prices for the Industrial sector in Indiana (latest available 8/20/2020)	
Compressed Air	0.48	$/kscf	0.38	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Chemicals & Supplies						
Lime	183.68	$/ton	145.00	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Trona	285.00	$/ton		2020	Reagent cost for trona from another Barr Engineering Co. Project.	
Fabric Filter Bags	228.02	$/bag	180	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Other						
Sales Tax	7%			2020	Indiana sales tax rate	
Interest Rate	5.50%			2016	EPA SCR Control Cost Manual Spreadsheet	
Solid Waste Disposal	63.34	$/ton	50	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Contingencies	10%	of purchased equip cost (B)			EPA Cost Control Cost Manual Chapter 2	Suggested contingency range of 5% to 15% of total capital investment
Markup on capital investment (retrofit factor)	0%				EPA Cost Control Cost Manual Chapter 2	
Operating Information						
Annual Op. Hrs	8,760	Hours			Emission Inventory Data	
Utilization Rate	100%				Assumed	
Design Capacity	465.0	MMBTU/hr			Boiler Design Capacity	
Equipment Life	20	yrs			Assumed	
Temperature	385	Deg F			Performance test data	
Moisture Content	14.4%				Performance test data	
Actual Flow Rate	177,000	acfm			Performance test data	
Standardized Flow Rate	110,599	scfm @ 68º F	103,058	scfm @ 32º F	Calculated Value	
Dry Std Flow Rate	93,000	dscfm @ 68º F			Performance test data	
Plant Elevation	610	Feet above sea level				Plant elevation
	Baseline Emissions		**lb/hr**	**ton/year**		
Pollutant	**Lb/Hr**	**Ton/Year**	**ppmv**	**ppmv**	**lb/mmbtu**	
Nitrous Oxides (NOx)	811.0	3,552.0	1216	1216.1		Emission inventory data
Sulfur Dioxides (SO2)	382.4	1,674.9	412	411.9		Emission inventory data
SDA - SO_2 Control Efficiency	90%				EPA fact sheet for flue gas desulfurization (new installations) https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf	

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.1 – Table C.1-3: SO_2 Control Spray Dry Absorber (SDA)

Battery No. 1 Underfire

Operating Unit: **Battery No. 1 Underfire**

Emission Unit Number	0		Stack/Vent Number	0	
Design Capacity	465	MMBtu/hr	Standardized Flow Rate	103,058	scfm @ 32º F
Utilization Rate	100%		Temperature	385	Deg F
Annual Operating Hours	8,760	Hours	Moisture Content	14.4%	
Annual Interest Rate	5.5%		Actual Flow Rate	177,000	acfm
Equipment Life	20	yrs	Standardized Flow Rate	110,599	scfm @ 68º F
			Dry Std Flow Rate	93,000	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**23,385,502**
Purchased Equipment Total (B)	22%	of control device cost (A)	**28,530,312**
Installation - Standard Costs	74%	of purchased equip cost (B)	21,112,431
Installation - Site Specific Costs			NA
Installation Total			21,112,431
Total Direct Capital Cost, DC			49,642,744
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	14,835,762
Total Capital Investment (TCI) = DC + IC			**64,478,506**
Adjusted TCI for Replacment Parts			**64,282,882**
TCI with Retrofit Factor			**64,282,882**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	1,313,341
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	8,213,753
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**9,527,094**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc.**	**Conc. Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10						0.0	-	NA
PM2.5						0.0	-	NA
Total Particulates						0.0	-	NA
Nitrous Oxides (NOx)						0.0	-	NA
Sulfur Dioxide (SO_2)		1,674.9	90%			167.5	1,507.4	6,320
Sulfuric Acid Mist						0.00	-	NA
Fluorides						0.0	-	NA
Volatile Organic Compounds (VOC)						0.0	-	NA
Carbon Monoxide (CO)						0.0	-	NA
Lead (Pb)						0.00	-	NA

Notes & Assumptions

1. Capital cost estimate based on mid-range of EPA spray dry fact sheet $/(MMBtu/hr): https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf
2. Costs scaled up to design airflow using the 6/10 power law
3. Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NOX and SO2 Emission Controls
Appendix C.1 – Table C.1-3: SO_2 Control Spray Dry Absorber (SDA)
Battery No. 1 Underfire

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (A) [1]		**23,385,502**
Purchased Equipment Costs (A) - Absorber + packing + auxiliary equipment, EC		
Instrumentation	10% of control device cost (A)	2,338,550
State Sales Taxes	7.0% of control device cost (A)	1,636,985
Freight	5% of control device cost (A)	1,169,275
Purchased Equipment Total (B)	22%	**28,530,312**
Installation		
Foundations & supports	4% of purchased equip cost (B)	1,141,212
Handling & erection	50% of purchased equip cost (B)	14,265,156
Electrical	8% of purchased equip cost (B)	2,282,425
Piping	1% of purchased equip cost (B)	285,303
Insulation	7% of purchased equip cost (B)	1,997,122
Painting	4% of purchased equip cost (B)	1,141,212
Installation Subtotal Standard Expenses	74%	**21,112,431**
Other Specific Costs (see summary)		
Site Preparation, as required	N/A Site Specific	-
Buildings, as required	N/A Site Specific	-
Site Specific - Other	N/A Site Specific	-
Total Site Specific Costs		NA
Installation Total		**21,112,431**
Total Direct Capital Cost, DC		**49,642,744**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	2,853,031
Construction & field expenses	20% of purchased equip cost (B)	5,706,062
Contractor fees	10% of purchased equip cost (B)	2,853,031
Start-up	1% of purchased equip cost (B)	285,303
Performance test	1% of purchased equip cost (B)	285,303
Model Studies	N/A of purchased equip cost (B)	-
Contingencies	10% of purchased equip cost (B)	2,853,031
Total Indirect Capital Costs, IC	52% of purchased equip cost (B)	**14,835,762**
Total Capital Investment (TCI) = DC + IC		**64,478,506**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		**64,282,882**
Total Capital Investment (TCI) with Retrofit Factor	0%	**64,282,882**
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	67.53 $/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	147,892
Supervisor	15% of Op., 0.0 , 8760 hr/yr, 100% utilization	22,184
Maintenance		
Maintenance Labor	67.53 $/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	73,946
Maintenance Materials	100% of maintenance labor costs	73,946
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.07 $/kwh, 320.4 kW-hr, 8760 hr/yr, 100% utilization	204,800
Compressed Air	0.48 $/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization	89,565
N/A		-
SW Disposal	63.34 $/ton, 0.4 ton/hr, 8760 hr/yr, 100% utilization	212,215
Lime	183.68 $/ton, 517.4 lb/hr, 8760 hr/yr, 100% utilization	416,284
Filter Bags	228.02 $/bag, 704 bags, 8760 hr/yr, 100% utilization	72,509
N/A		
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
Total Annual Direct Operating Costs		**1,313,341**
Indirect Operating Costs		
Overhead	60% of total labor and material costs	190,780
Administration (2% total capital costs)	2% of total capital costs (TCI)	1,285,658
Property tax (1% total capital costs)	1% of total capital costs (TCI)	642,829
Insurance (1% total capital costs)	1% of total capital costs (TCI)	642,829
Capital Recovery	0.0837 for a 20- year equipment life and a 5.5% interest rate	5,451,657
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**8,213,753**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**9,527,094**

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NOX and SO2 Emission Controls

Appendix C.1 – Table C.1-3: SO_2 Control Spray Dry Absorber (SDA)

Battery No. 1 Underfire

Capital Recovery Factors

Primary Installation	
Interest Rate	5.50%
Equipment Life	20 years
CRF	0.0837

Replacement Parts & Equipment:	**Filter Bags**	
Equipment Life	3 years	
CRF	0.3707	
Rep part cost per unit	228.02 $/bag	
Amount Required	704	
Total Rep Parts Cost	179,778 Cost adjusted for freight & sales tax	
Installation Labor	15,846 10 min per bag	EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**195,624**	
Annualized Cost	**72,509**	

Electrical Use

	Flow acfm	D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	177,000	10.00			2,806,441	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total					2,806,441	

Reagents and Other Operating Costs

Lime Use Rate	1.30 lb-mole CaO/lb-mole SO2	517.43 lb/hr Lime
Solid Waste Disposal	3,350 ton/yr GSA unreacted sorbent and reaction byproducts	

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours		8,760			
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	2,190	$ 147,892	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Supervisor	15%	of Op.			NA	$ 22,184	of Op., 0.0 , 8760 hr/yr, 100% utilization
Maintenance							
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	1,095	$ 73,946	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Maint Mtls	100	% of Maintenance Labor			NA	$ 73,946	% of Maintenance Labor, 0.0 , 8760 hr/yr, 100% utilization
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	320.4	kW-hr	2,806,441	$ 204,800	$/kwh, 320.4 kW-hr, 8760 hr/yr, 100% utilization
Compressed Air	0.481	$/kscf	2	scfm/kacfm	186,062	$ 89,565	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization
Water	5.129	$/mgal		gpm			$/mgal, 0 gpm, 8760 hr/yr, 100% utilization
SW Disposal	63.34	$/ton	0.38	ton/hr	3,350	$ 212,215	$/ton, 0.4 ton/hr, 8760 hr/yr, 100% utilization
Lime	183.68	$/ton	517.4	lb/hr	2,266	$ 416,284	$/ton, 517.4 lb/hr, 8760 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	704	bags	N/A	$ 72,509	$/bag, 704 bags, 8760 hr/yr, 100% utilization

Appendix C.2

Battery No. 2 Underfire

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.2 – Table C.2-1: Cost Summary
Battery No. 2 Underfire
SO_2 Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Total Annualized Cost $/yr	Pollution Control Cost $/ton
Spray Dry Absorber (SDA)	90%	185.4	1668.4	$58,238,651	$8,782,589	$5,264

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.2 – Table C.2-2: Summary of Utility, Chemical and Supply Costs
Battery No. 2 Underfire

Operating Unit:	Battery No. 2 Underfire		**Study Year**	2020
Emission Unit Number				
Stack/Vent Number				

Item	2020 Unit Cost	Units	Cost	Year	Data Source	Notes
Operating Labor	68	$/hr	60	2016	EPA SCR Control Cost Manual Spreadsheet	
Maintenance Labor	68	$/hr				Assumed to be equivalent to operating labor
Installation Labor	68	$/hr				Assumed to be equivalent to operating labor
Electricity	0.07	$/kwh			2016-2019 EIA Average prices for the industrial sector in Indiana	
Natural Gas	6.15	$/kscf			2014-2018 EIA Average prices for the Industrial sector in Indiana (latest available 8/20/2020)	
Compressed Air	0.48	$/kscf	0.38	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Chemicals & Supplies						
Lime	183.68	$/ton	145.00	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Trona	285.00	$/ton		2020	Reagent cost for trona from another Barr Engineering Co. Project.	
Fabric Filter Bags	228.02	$/bag	180	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Other						
Sales Tax	7%			2020	Indiana sales tax rate	
Interest Rate	5.50%			2016	EPA SCR Control Cost Manual Spreadsheet	
Solid Waste Disposal	63.34	$/ton	50	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Contingencies	10%	of purchased equip cost (B)			EPA Cost Control Cost Manual Chapter 2	Suggested contingency range of 5% to 15% of total capital investment
Markup on capital investment (retrofit factor)	0%				EPA Cost Control Cost Manual Chapter 2	
Operating Information						
Annual Op. Hrs	8,760	Hours			Emission Inventory Data	
Utilization Rate	100%				Assumed	
Design Capacity	420.0	MMBTU/hr			Boiler Design Capacity	
Equipment Life	20	yrs			Assumed	
Temperature	385	Deg F			Performance test data	
Moisture Content	14.4%				Performance test data	
Actual Flow Rate	160,000	acfm			Performance test data	
Standardized Flow Rate	99,976	scfm @ 68º F	93,160	scfm @ 32º F	Calculated Value	
Dry Std Flow Rate	94,000	dscfm @ 68º F			Performance test data	
Plant Elevation	610	Feet above sea level				Plant elevation
	Baseline Emissions		**lb/hr**	**ton/year**		
Pollutant	**Lb/Hr**	**Ton/Year**	**ppmv**	**ppmv**	**lb/mmbtu**	
Nitrous Oxides (NOx)	42.5	186.0	63	63.0		Emission inventory data
Sulfur Dioxides (SO2)	423.2	1,853.8	451	451.0		Emission inventory data
SDA - SO_2 Control Efficiency	90%				EPA fact sheet for flue gas desulfurization (new installations) https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf	

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.2 – Table C.2-3: SO_2 Control Spray Dry Absorber (SDA)

Battery No. 2 Underfire

Operating Unit: **Battery No. 2 Underfire**

Emission Unit Number	0		Stack/Vent Number	0	
Design Capacity	420	MMBtu/hr	Standardized Flow Rate	93,160	scfm @ 32º F
Utilization Rate	100%		Temperature	385	Deg F
Annual Operating Hours	8,760	Hours	Moisture Content	14.4%	
Annual Interest Rate	5.5%		Actual Flow Rate	160,000	acfm
Equipment Life	20	yrs	Standardized Flow Rate	99,976	scfm @ 68º F
			Dry Std Flow Rate	94,000	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**21,122,389**
Purchased Equipment Total (B)	22%	of control device cost (A)	**25,769,315**
Installation - Standard Costs	74%	of purchased equip cost (B)	19,069,293
Installation - Site Specific Costs			NA
Installation Total			19,069,293
Total Direct Capital Cost, DC			44,838,607
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	13,400,044
Total Capital Investment (TCI) = DC + IC			**58,238,651**
Adjusted TCI for Replacment Parts			**58,061,815**
TCI with Retrofit Factor			**58,061,815**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	1,345,217
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	7,437,372
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**8,782,589**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual T/Yr	Cont Eff %	Exit Conc.	Conc. Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
PM10						0.0	-	NA
PM2.5						0.0	-	NA
Total Particulates						0.0	-	NA
Nitrous Oxides (NOx)						0.0	-	NA
Sulfur Dioxide (SO_2)		1,853.8	90%			185.4	1,668.4	5,264
Sulfuric Acid Mist						0.00	-	NA
Fluorides						0.0	-	NA
Volatile Organic Compounds (VOC)						0.0	-	NA
Carbon Monoxide (CO)						0.0	-	NA
Lead (Pb)						0.00	-	NA

Notes & Assumptions

1 Capital cost estimate based on mid-range of EPA spray dry fact sheet $/(MMBtu/hr): https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf
2 Costs scaled up to design airflow using the 6/10 power law
3 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NOX and SO2 Emission Controls
Appendix C.2 – Table C.2-3: SO_2 Control Spray Dry Absorber (SDA)
Battery No. 2 Underfire

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (A) (1)		**21,122,389**
Purchased Equipment Costs (A) - Absorber + packing + auxiliary equipment, EC		
Instrumentation	10% of control device cost (A)	2,112,239
State Sales Taxes	7.0% of control device cost (A)	1,478,567
Freight	5% of control device cost (A)	1,056,119
Purchased Equipment Total (B)	22%	**25,769,315**
Installation		
Foundations & supports	4% of purchased equip cost (B)	1,030,773
Handling & erection	50% of purchased equip cost (B)	12,884,657
Electrical	8% of purchased equip cost (B)	2,061,545
Piping	1% of purchased equip cost (B)	257,693
Insulation	7% of purchased equip cost (B)	1,803,852
Painting	4% of purchased equip cost (B)	1,030,773
Installation Subtotal Standard Expenses	74%	**19,069,293**
Other Specific Costs (see summary)		
Site Preparation, as required	N/A Site Specific	-
Buildings, as required	N/A Site Specific	-
Site Specific - Other	N/A Site Specific	-
Total Site Specific Costs		NA
Installation Total		**19,069,293**
Total Direct Capital Cost, DC		**44,838,607**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	2,576,931
Construction & field expenses	20% of purchased equip cost (B)	5,153,863
Contractor fees	10% of purchased equip cost (B)	2,576,931
Start-up	1% of purchased equip cost (B)	257,693
Performance test	1% of purchased equip cost (B)	257,693
Model Studies	N/A of purchased equip cost (B)	-
Contingencies	10% of purchased equip cost (B)	2,576,931
Total Indirect Capital Costs, IC	52% of purchased equip cost (B)	**13,400,044**
Total Capital Investment (TCI) = DC + IC		**58,238,651**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		**58,061,815**
Total Capital Investment (TCI) with Retrofit Factor	0%	**58,061,815**
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	67.53 $/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	147,892
Supervisor	15% of Op., 0.0 , 8760 hr/yr, 100% utilization	22,184
Maintenance		
Maintenance Labor	67.53 $/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	73,946
Maintenance Materials	100% of maintenance labor costs	73,946
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.07 $/kwh, 289.6 kW-hr, 8760 hr/yr, 100% utilization	185,130
Compressed Air	0.48 $/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization	80,963
N/A		-
SW Disposal	63.34 $/ton, 0.4 ton/hr, 8760 hr/yr, 100% utilization	234,875
Lime	183.68 $/ton, 572.7 lb/hr, 8760 hr/yr, 100% utilization	460,736
Filter Bags	228.02 $/bag, 636 bags, 8760 hr/yr, 100% utilization	65,545
N/A		
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
Total Annual Direct Operating Costs		**1,345,217**
Indirect Operating Costs		
Overhead	60% of total labor and material costs	190,780
Administration (2% total capital costs)	2% of total capital costs (TCI)	1,161,236
Property tax (1% total capital costs)	1% of total capital costs (TCI)	580,618
Insurance (1% total capital costs)	1% of total capital costs (TCI)	580,618
Capital Recovery	0.0837 for a 20- year equipment life and a 5.5% interest rate	4,924,119
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**7,437,372**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**8,782,589**

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NOX and SO2 Emission Controls
Appendix C.2 – Table C.2-3: SO_2 Control Spray Dry Absorber (SDA)
Battery No. 2 Underfire

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:	**Filter Bags**		
Equipment Life	3	years	
CRF	0.3707		
Rep part cost per unit	228.02	$/bag	
Amount Required	636		
Total Rep Parts Cost	162,511	Cost adjusted for freight & sales tax	
Installation Labor	14,324	10 min per bag	EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**176,836**		
Annualized Cost	**65,545**		

Electrical Use

	Flow acfm	D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	160,000	10.00			2,536,896	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total					2,536,896	

Reagents and Other Operating Costs

Lime Use Rate	1.30	lb-mole CaO/lb-mole SO2	572.68 lb/hr Lime
Solid Waste Disposal	3,708	ton/yr GSA unreacted sorbent and reaction byproducts	

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours		8,760			
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	2,190	$ 147,892	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Supervisor	15%	of Op.			NA	$ 22,184	of Op., 0.0 , 8760 hr/yr, 100% utilization
Maintenance							
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	1,095	$ 73,946	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Maint Mtls	100	% of Maintenance Labor			NA	$ 73,946	% of Maintenance Labor, 0.0 , 8760 hr/yr, 100% utilization
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	289.6	kW-hr	2,536,896	$ 185,130	$/kwh, 289.6 kW-hr, 8760 hr/yr, 100% utilization
Compressed Air	0.481	$/kscf	2	scfm/kacfm	168,192	$ 80,963	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization
Water	5.129	$/mgal		gpm			$/mgal, 0 gpm, 8760 hr/yr, 100% utilization
SW Disposal	63.34	$/ton	0.42	ton/hr	3,708	$ 234,875	$/ton, 0.4 ton/hr, 8760 hr/yr, 100% utilization
Lime	183.68	$/ton	572.7	lb/hr	2,508	$ 460,736	$/ton, 572.7 lb/hr, 8760 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	636	bags	N/A	$ 65,545	$/bag, 636 bags, 8760 hr/yr, 100% utilization

Appendix C.3

Coke Oven Gas Desulfurization

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.3 – Table C.3-1: Cost Summary
Coke Oven Gas Desulfurization
SO_2 Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Total Annualized Cost $/yr	Pollution Control Cost $/ton
Coke Oven Gas Desulfurization	86.4%	1098.9	6997.1	$123,673,000	$27,854,000	$4,000

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.3 – Table C.3-2: Summary of Utility, Chemical and Supply Costs
Coke Oven Gas Desulfurization

Operating Unit:	Coke Oven Gas Desulfurization	**Study Year**	2020
Emission Unit Number	NA		
Stack/Vent Number	NA		

Item	2020 Unit Cost	Units	Cost	Year	Data Source	Notes
Operating Labor	68	$/hr	60	2016	EPA SCR Control Cost Manual Spreadsheet	
Maintenance Labor	68	$/hr				Assumed to be equivalent to operating labor
Installation Labor	68	$/hr				Assumed to be equivalent to operating labor
Electricity	0.07	$/kwh			2016-2019 EIA Average prices for the industrial sector in Indiana	
Steam	5.54	$/klb	4.00	2009	2014-2018 EIA Average prices for the Industrial sector in Indiana (latest available 8/20/2020)	
Amine	10.55	$/gallon	7.62	2009	Engineering cost estimate for desulfurization process	
Caustic	27.68	$/gallon	20.00	2009	Engineering cost estimate for desulfurization process	
Glycol	1.38	$/gallon	1.00	2009	Engineering cost estimate for desulfurization process	
Anti-Foam - Annual Cost	14,534	$/yr	10,500	2009	Engineering cost estimate for desulfurization process	
Corrosion Inhibitor - Annual Cost	41,527	$/yr	30,000	2009	Engineering cost estimate for desulfurization process	
Cooling Tower Chemicals - Annual Cost	17,303	$/yr	12,500	2009	Engineering cost estimate for desulfurization process	
Hot Feed Water Chemicals - Annual Cost	12,458	$/yr	9,000	2009	Engineering cost estimate for desulfurization process	
Reclaimer waste	1.25	$/gallon	0.9	2009	Engineering cost estimate for desulfurization process	
Maintenance Labor - Annual Cost	415,270	$/yr	300,000.0	2009	Engineering cost estimate for desulfurization process	
Water	5.13	$/mgal	4.17	2013	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Wastewater Disposal, Biological Treatment	6.47	$/mgal	3.80	2002	EPA Cost Control Cost Manual	
Compressed Air	0.48	$/kscf	0.38	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Chemicals & Supplies						
Lime	183.68	$/ton	145.00	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Trona	285.00	$/ton		2020	Reagent cost for trona from another Barr Engineering Co. Project.	
Fabric Filter Bags	228.02	$/bag	180	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Other						
Sales Tax	7%			2020	Indiana sales tax rate	
Interest Rate	5.50%			2016	EPA SCR Control Cost Manual Spreadsheet	
Solid Waste Disposal	63.34	$/ton	50	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Contingencies	25%	of purchased equip cost (B)			Site-specific estimate given several project unknowns and complexities	
Markup on capital investment (retrofit factor)	0%				EPA Cost Control Cost Manual Chapter 2	
Operating Information						
Annual Op. Hrs	8,760	Hours			Emission Inventory Data	
Utilization Rate	100%				Estimate from Engineering	
Equipment Life	20	yrs			Assumed	
	Baseline Emissions					
Pollutant	**Ton/Year**					
Sulfur Dioxides (SO_2)	8,096.0				Emission inventory data	
SO_2 Reduction	86.4%				Design basis for COG desulfurization plant 90% Control Efficiency 97% Reliability 99% control from sulfur plant	

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.3 – Table C.3-3: COG Desulfurization Plant (SO_2 Control)

Coke Oven Gas Desulfurization

Operating Unit: **Coke Oven Gas Desulfurization**

Expected Utilization Rate	100%	
Expected Annual Hours of Operation	8,760	Hours

CONTROL EQUIPMENT COSTS

Capital Costs		
Purchased Equipment		53,247,000
Site Preparation and Engineering		11,704,000
Construction		30,501,000
Startup Costs		3,486,000
Contingency		24,735,000
Total Capital Investment (TCI)		**123,673,000**
Operating Costs		
Total Annual Direct Operating Costs	Labor, supervision, materials, replacement parts, utilities, etc.	10,835,000
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	17,019,000
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**27,854,000**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Cont. Emis. lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10		-			-	NA
Total Particulates		-			-	NA
Nitrous Oxides (NOx)		-			-	NA
Sulfur Dioxide (SO_2)	8,096			1,099	6,997	4,000

Notes & Assumptions

1 COG Desulfurization costs are based on a previous engineering study specific to this facility and have been scaled for inflation

2 COG Desulfurization would require several process units and upgrades, including:

Absorber-Desorber Unit	Piping
Reflux Unit	Electrical including upgrades as needed
Aromatic Removal Unit	Utilities including upgrades as needed
HCN Destruct Unit	Control building
Sulfur Recovery Unit	

3 COG Desulfurization operating costs were evaluated as part of the engineering study and are based on benchmarking and comparison to similar sources

4 COG Desulfurization controlled emissions assumes 90% SO_2 reduction in COG for downstream combustion sources, 97% reliability, and 99% control of sulfur plant.

5 Investment risk associated with the contingency is presented in Table C.3-4

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NOX and SO2 Emission Controls

Appendix C.3 – Table C.3-3: COG Desulfurization Plant (SO_2 Control)

Coke Oven Gas Desulfurization

CAPITAL COSTS

(all values rounded to 1,000s)

Purchased Equipment		
Purchased Equipment Cost (A)		53,247,000
Sales Taxes	included	0
Freight	included	0
Purchased Equipment Total		**53,247,000**
Site Preparation and Engineering		
Site Preparation		2,484,000
Engineering		9,220,000
Site Preparation and Engineering Total		**11,704,000**
Construction		
Construction		29,896,000
Project assistance		222,000
Construction Coordination		383,000
Construction Total		**30,501,000**
Startup Costs		
Startup and commissioning		1,520,000
Spares		1,769,000
Training		197,000
Startup Total		**3,486,000**
Total		**98,938,000**
Total Capital Investment (TCI) with Contingency	25%	**123,673,000**

OPERATING COSTS

(all values rounded to 1,000s)

Direct Annual Operating Costs, DC

Operating Labor			
Operator	67.53	\$/Hr, 24.0 hr/8 hr shift, 8760 hr/yr	1,775,000
Supervisor	15%	15% of Operator Costs	266,000
Maintenance (2)			
Maintenance Labor		Engineering estimate	415,000
Maintenance Materials	100%	of maintenance labor costs	415,000
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.07	\$/kwh, 708 kW-hr, 8760 hr/yr, 100% utilization	452,000
Steam	5.54	\$/klb, 76,205 lb/hr, 8760 hr/yr, 100% utilization	3,696,000
Cooling Water	5.13	\$/kgal, 294 gpm, 8760 hr/yr, 100% utilization	793,000
WWTP Biological Treatment	6.47	\$/kgal, 50 gpm, 8760 hr/yr, 100% utilization	170,000
Amine	10.55	\$/gallon, 600 gpd, 8760 hr/yr, 100% utilization	2,310,000
Caustic	27.68	\$/gallon, 12 gpd, 8760 hr/yr, 100% utilization	121,000
Glycol	1.38	\$/gallon, 73 gpd, 8760 hr/yr, 100% utilization	37,000
Anti-Foam - Annual Cost		Engineering estimate	15,000
Corrosion Inhibitor - Annual Cost		Engineering estimate	42,000
Cooling Tower Chemicals - Annual Cost		Engineering estimate	17,000
Hot Feed Water Chemicals - Annual Cost		Engineering estimate	12,000
Reclaimer waste	1.25	Engineering estimate	299,000
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**10,835,000**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	1,723,000
Administration (2% total capital costs)	2%	of total capital costs (TCI)	2,473,000
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	1,237,000
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	1,237,000
Capital Recovery	8%	for a 20- year equipment life and a 5.5% interest rate	10,349,000
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**17,019,000**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**27,854,000**

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NOX and SO2 Emission Controls

Appendix C.3 – Table C.3-3: COG Desulfurization Plant (SO_2 Control)

Coke Oven Gas Desulfurization

Capital Recovery Factors	
Primary Installation	
Interest Rate	5.50%
Equipment Life	20 years
CRF	0.0837

Replacement Parts & Equipment:
N/A

Replacement Parts & Equipment:
N/A

Electrical Use
N/A

Reagent Use & Other Operating Costs

Operating Cost Calculations **Annual hours of operation:** **8,760**

Utilization Rate: **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	67.53	$/Hr	24.0	hr/8 hr shift	26,280	1,775,000	$/Hr, 24.0 hr/8 hr shift, 8760 hr/yr
Supervisor	15%	of Op.			NA	266,000	15% of Operator Costs
Maintenance							
Maint Labor						415,000	Engineering estimate
Maint Mtls	100	% of Maintenance Labor			NA	415,000	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	707.8	kW-hr	6,199,890	452,000	$/kwh, 708 kW-hr, 8760 hr/yr, 100% utilization
Steam	5.54	$/klb	76205	lb/hr	667,556	3,696,000	$/klb, 76,205 lb/hr, 8760 hr/yr, 100% utilization
Cooling Water	5.13	$/kgal	294.0	gpm	154,526	793,000	$/kgal, 294 gpm, 8760 hr/yr, 100% utilization
WWTP Biological Treatı	6.47	$/kgal	50.0	gpm	26,280	170,000	$/kgal, 50 gpm, 8760 hr/yr, 100% utilization
Amine	10.55	$/gallon	600	gpd	219,000	2,310,000	$/gallon, 600 gpd, 8760 hr/yr, 100% utilization
Caustic	27.68	$/gallon	12.0	gpd	4,380	121,000	$/gallon, 12 gpd, 8760 hr/yr, 100% utilization
Glycol	1.38	$/gallon	73.4	gpd	26,806	37,000	$/gallon, 73 gpd, 8760 hr/yr, 100% utilization
Anti-Foam - Annual Cost						15,000	Engineering estimate
Corrosion Inhibitor - Annual Cost						42,000	Engineering estimate
Cooling Tower Chemicals - Annual Cost						17,000	Engineering estimate
Hot Feed Water Chemicals - Annual Cost						12,000	Engineering estimate
Reclaimer waste	1.2	$/gallon	20000	gallon/month	240,000	299,000	Engineering estimate

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NOX and SO2 Emission Controls
Appendix C.3 – Table C.3-4: COG Desulfurization Plant (SO_2 Control)
Coke Oven Gas Desulfurization

Contingency Assessment

The following risks were considered for the ArcelorMittal Burns Harbor Coke Plant Desulfurization Plant project and comprise the level of contingency build to apply overall to the project.

1	Cold weather conditions along the Lake Michigan lake front - high winds and 10 degrees cooler than inland - for winter months. Reduced construction efficiency as a result.
2	Union cost premium - Expertise and talent are a premium with the AFL-CIO trades. There are also limitations to worker utilization, which can impede on overall efficiency.
3	Construction worker rates - This area is being impacted by high construction worker labor fees. While the base estimate includes these rates, where extra work is involved, the extra construction work is disproportionately higher in cost.
4	Precious metals - The system would require ample amounts of titanium and other precious metals. With this market being controlled by foreign markets which are impacted by trade issues, the equipment cost could be disproportionately inflated as a result of precious metals costs.
5	Technology - Incremental technology advances since the engineering study was completed may be available that provide incremental benefits, but also incremental costs.
6	Development Detail - The level of development effort for the engineering study was identified as "Step 0", with less than 0.5% of total project value exhausted as development effort. This is a very low level for such a large project. While the project has been performed elsewhere previously, and many repeat costs are available, the development detail is substituted with a larger proportion of contingency to offset further spending on development.
7	Sub-surface - The site is brownfield, therefore, unexpected costs could be incurred when preparing the site for construction. This cost was not included and is typically the largest additional-cost category for a brownfield site (up to 15% of all extras are sub-surface).
8	Inflation - Pricing for equipment and installation could be upwards of 40% higher than norm if the project proceeds during a significant upcycle in business and/or if certain components/materials are in high global demand. This is above and beyond the normalized inflation rate that was considered.

Appendix C.4

Power Station Boiler No. 7

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.4 – Table C.4-1: Cost Summary
Power Station Boiler No. 7

SO_2 Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Total Annualized Cost $/yr	Pollution Control Cost $/ton
Spray Dry Absorber (SDA)	90%	90.1	810.7	$90,131,245	$13,025,113	$16,066
Dry Sorbent Injection (DSI)	70%	270.2	630.5	$20,036,476	$5,555,483	$8,800

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.4 – Table C.4-2: Summary of Utility, Chemical and Supply Costs
Power Station Boiler No. 7

Operating Unit:	Power Station Boiler No. 7	**Study Year**	2020
Emission Unit Number			
Stack/Vent Number			

Item	2020 Unit Cost	Units	Cost	Year	Data Source	Notes
Operating Labor	68	$/hr	60	2016	EPA SCR Control Cost Manual Spreadsheet	
Maintenance Labor	68	$/hr				Assumed to be equivalent to operating labor
Installation Labor	68	$/hr				Assumed to be equivalent to operating labor
Electricity	0.07	$/kwh			2016-2019 EIA Average prices for the industrial sector in Indiana	
Natural Gas	6.15	$/kscf			2014-2018 EIA Average prices for the Industrial sector in Indiana (latest available 8/20/2020)	
Compressed Air	0.48	$/kscf	0.38	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Chemicals & Supplies						
Lime	183.68	$/ton	145.00	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Trona	285.00	$/ton		2020	Reagent cost for trona from another Barr Engineering Co. Project.	
Fabric Filter Bags	228.02	$/bag	180	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Other						
Sales Tax	7%			2020	Indiana sales tax rate	
Interest Rate	5.50%			2016	EPA SCR Control Cost Manual Spreadsheet	
Solid Waste Disposal	63.34	$/ton	50	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Contingencies	10%	of purchased equip cost (B)			EPA Cost Control Cost Manual Chapter 2	Suggested contingency range of 5% to 15% of total capital investment
Markup on capital investment (retrofit factor)	0%				EPA Cost Control Cost Manual Chapter 2	
Operating Information						
Annual Op. Hrs	8,760	Hours			Emission Inventory Data	
Utilization Rate	100%				Assumed	
Design Capacity	650.0	MMBTU/hr			Boiler Design Capacity	
Equipment Life	20	yrs			Assumed	
Temperature	462	Deg F			Performance test data	
Moisture Content	10.9%				Performance test data	
Actual Flow Rate	439,519	acfm			Performance test data	
Standardized Flow Rate	251,699	scfm @ 68º F	234,537	scfm @ 32º F	Calculated Value	
Dry Std Flow Rate	221,045	dscfm @ 68º F			Performance test data	
Plant Elevation	610	Feet above sea level				Plant elevation
	Baseline Emissions		**lb/hr**	**ton/year**		
Pollutant	**Lb/Hr**	**Ton/Year**	**ppmv**	**ppmv**	**lb/mmbtu**	
Nitrous Oxides (NOx)	33.3	146.0	21	21.0		Emission inventory data
Sulfur Dioxides (SO2)	205.7	900.8	93	93.2		Emission inventory data
SDA - SO_2 Control Efficiency	90%				EPA fact sheet for flue gas desulfurization (new installations) https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf	
DSI - SO_2 Control Efficiency	70%				Control efficiency is based on trona as injected reagent.	

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.4 – Table C.4-3: SO_2 Control Spray Dry Absorber (SDA)

Power Station Boiler No. 7

Operating Unit: **Power Station Boiler No. 7**

Emission Unit Number	0		Stack/Vent Number	0	
Design Capacity	650	MMBtu/hr	Standardized Flow Rate	234,537	scfm @ 32º F
Utilization Rate	100%		Temperature	462	Deg F
Annual Operating Hours	8,760	Hours	Moisture Content	10.9%	
Annual Interest Rate	5.5%		Actual Flow Rate	439,519	acfm
Equipment Life	20	yrs	Standardized Flow Rate	251,699	scfm @ 68º F
			Dry Std Flow Rate	221,045	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**32,689,411**
Purchased Equipment Total (B)	22%	of control device cost (A)	**39,881,082**
Installation - Standard Costs	74%	of purchased equip cost (B)	29,512,001
Installation - Site Specific Costs			NA
Installation Total			29,512,001
Total Direct Capital Cost, DC			69,393,083
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	20,738,163
Total Capital Investment (TCI) = DC + IC			**90,131,245**
Adjusted TCI for Replacment Parts			**89,645,479**
TCI with Retrofit Factor			**89,645,479**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	1,566,988
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	11,458,125
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**13,025,113**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc.**	**Conc. Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10						0.0	-	NA
PM2.5						0.0	-	NA
Total Particulates						0.0	-	NA
Nitrous Oxides (NOx)						0.0	-	NA
Sulfur Dioxide (SO_2)		900.8	90%			90.1	810.7	16,066
Sulfuric Acid Mist						0.00	-	NA
Fluorides						0.0	-	NA
Volatile Organic Compounds (VOC)						0.0	-	NA
Carbon Monoxide (CO)						0.0	-	NA
Lead (Pb)						0.00	-	NA

Notes & Assumptions

1 Capital cost estimate based on mid-range of EPA spray dry fact sheet $/(MMBtu/hr): https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf
2 Costs scaled up to design airflow using the 6/10 power law
3 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.4 – Table C.4-3: SO_2 Control Spray Dry Absorber (SDA)
Power Station Boiler No. 7

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (A) [1]		**32,689,411**
Purchased Equipment Costs (A) - Absorber + packing + auxiliary equipment, EC		
Instrumentation	10% of control device cost (A)	3,268,941
State Sales Taxes	7.0% of control device cost (A)	2,288,259
Freight	5% of control device cost (A)	1,634,471
Purchased Equipment Total (B)	22%	**39,881,082**
Installation		
Foundations & supports	4% of purchased equip cost (B)	1,595,243
Handling & erection	50% of purchased equip cost (B)	19,940,541
Electrical	8% of purchased equip cost (B)	3,190,487
Piping	1% of purchased equip cost (B)	398,811
Insulation	7% of purchased equip cost (B)	2,791,676
Painting	4% of purchased equip cost (B)	1,595,243
Installation Subtotal Standard Expenses	74%	**29,512,001**
Other Specific Costs (see summary)		
Site Preparation, as required	N/A Site Specific	-
Buildings, as required	N/A Site Specific	-
Site Specific - Other	N/A Site Specific	-
Total Site Specific Costs		NA
Installation Total		**29,512,001**
Total Direct Capital Cost, DC		**69,393,083**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	3,988,108
Construction & field expenses	20% of purchased equip cost (B)	7,976,216
Contractor fees	10% of purchased equip cost (B)	3,988,108
Start-up	1% of purchased equip cost (B)	398,811
Performance test	1% of purchased equip cost (B)	398,811
Model Studies	N/A of purchased equip cost (B)	-
Contingencies	10% of purchased equip cost (B)	3,988,108
Total Indirect Capital Costs, IC	52% of purchased equip cost (B)	**20,738,163**
Total Capital Investment (TCI) = DC + IC		**90,131,245**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		**89,645,479**
Total Capital Investment (TCI) with Retrofit Factor	0%	**89,645,479**
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	67.53 $/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	147,892
Supervisor	15% of Op., 0.0 , 8760 hr/yr, 100% utilization	22,184
Maintenance		
Maintenance Labor	67.53 $/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	73,946
Maintenance Materials	100% of maintenance labor costs	73,946
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.07 $/kwh, 795.5 kW-hr, 8760 hr/yr, 100% utilization	508,551
Compressed Air	0.48 $/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization	222,405
N/A		-
SW Disposal	63.34 $/ton, 0.2 ton/hr, 8760 hr/yr, 100% utilization	114,131
Lime	183.68 $/ton, 278.3 lb/hr, 8760 hr/yr, 100% utilization	223,882
Filter Bags	228.02 $/bag, 1,748 bags, 8760 hr/yr, 100% utilization	180,051
N/A		
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
Total Annual Direct Operating Costs		**1,566,988**
Indirect Operating Costs		
Overhead	60% of total labor and material costs	190,780
Administration (2% total capital costs)	2% of total capital costs (TCI)	1,792,910
Property tax (1% total capital costs)	1% of total capital costs (TCI)	896,455
Insurance (1% total capital costs)	1% of total capital costs (TCI)	896,455
Capital Recovery	0.0837 for a 20- year equipment life and a 5.5% interest rate	7,681,525
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**11,458,125**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**13,025,113**

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.4 – Table C.4-3: SO_2 Control Spray Dry Absorber (SDA)

Power Station Boiler No. 7

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:	**Filter Bags**		
Equipment Life	3	years	
CRF	0.3707		
Rep part cost per unit	228.02	$/bag	
Amount Required	1748		
Total Rep Parts Cost	446,417	Cost adjusted for freight & sales tax	
Installation Labor	39,349	10 min per bag	EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**485,766**		
Annualized Cost	**180,051**		

Electrical Use

	Flow acfm	D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	439,519	10.00			6,968,837	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total					6,968,837	

Reagents and Other Operating Costs

Lime Use Rate	1.30	lb-mole CaO/lb-mole SO2	278.28 lb/hr Lime
Solid Waste Disposal	1,802	ton/yr GSA unreacted sorbent and reaction byproducts	

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours		8,760			
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	2,190	$ 147,892	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Supervisor	15%	of Op.			NA	$ 22,184	of Op., 0.0 , 8760 hr/yr, 100% utilization
Maintenance							
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	1,095	$ 73,946	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Maint Mtls	100	% of Maintenance Labor			NA	$ 73,946	% of Maintenance Labor, 0.0 , 8760 hr/yr, 100% utilization
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	795.5	kW-hr	6,968,837	$ 508,551	$/kwh, 795.5 kW-hr, 8760 hr/yr, 100% utilization
Compressed Air	0.481	$/kscf	2	scfm/kacfm	462,022	$ 222,405	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization
Water	5.129	$/mgal		gpm			$/mgal, 0 gpm, 8760 hr/yr, 100% utilization
SW Disposal	63.34	$/ton	0.21	ton/hr	1,802	$ 114,131	$/ton, 0.2 ton/hr, 8760 hr/yr, 100% utilization
Lime	183.68	$/ton	278.3	lb/hr	1,219	$ 223,882	$/ton, 278.3 lb/hr, 8760 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	1,748	bags	N/A	$ 180,051	$/bag, 1,748 bags, 8760 hr/yr, 100% utilization

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.4 – Table C.4-4: SO_2 Control Dry Sorbent Injection (DSI) with Baghouse

Power Station Boiler No. 7

Operating Unit: **Power Station Boiler No. 7**

Emission Unit Number			Stack/Vent Number		
Design Capacity	650	MMBtu/hr	Standardized Flow Rate	234,537	scfm @ 32º F
Utilization Rate	100%		Exhaust Temperature	462	Deg F
Annual Operating Hours	8,760	hr/yr	Exhaust Moisture Content	10.9%	
Annual Interest Rate	5.50%		Actual Flow Rate	439,519	acfm
Control Equipment Life	20	yrs	Standardized Flow Rate	251,699	scfm @ 68º F
Plant Elevation	610	ft	Dry Std Flow Rate	221,045	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs						
Direct Capital Costs						
Purchased Equipment (A)						**7,443,146**
Purchased Equipment Total (B)	22%	of control device cost (A)				**9,080,638**
Installation - Standard Costs	74%	of purchased equip cost (B)				6,719,672
Installation - Site Specific Costs						N/A
Installation Total						6,719,672
Total Direct Capital Cost, DC						15,800,310
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)				4,721,932
Total Capital Investment (TCI) = DC + IC						**20,036,476**
Adjusted TCI for Replacement Parts						20,036,476
Total Capital Investment (TCI) with Retrofit Factor						**20,036,476**
Operating Costs						
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.				2,706,554
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost				2,848,930
Total Annual Cost (Annualized Capital Cost + Operating Cost)						**5,555,483**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual Ton/Yr**	**Cont Eff %**	**Cont Emis Ton/Yr**	**Reduction Ton/Yr**	**Cont Cost $/Ton Rem**
PM10						
PM2.5						
Total Particulates						
Nitrous Oxides (NOx)						
Sulfur Dioxide (SO2)	205.66	900.78	70%	270.23	630.55	$8,800
Sulfuric Acid Mist (H2SO4)						
Fluorides						
Volatile Organic Compounds (VOC)						
Carbon Monoxide (CO)						
Lead (Pb)						

Notes & Assumptions

1 Baghouse capital cost estimate based on EPA-R05-OAR-2010-0954-0079, ancillary equipment from other Barr Engineering projects
2 Costs scaled up to design airflow using the 6/10 power law
3 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.4 – Table C.4-4: SO_2 Control Dry Sorbent Injection (DSI) with Baghouse
Power Station Boiler No. 7

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [(1)]			**7,443,146**
Purchased Equipment Costs (A) - Injection System + auxiliary equipment, EC			
Instrumentation	10%	Included in vendor estimate	744,315
State Sales Taxes	7.0%	of control device cost (A)	521,020
Freight	5%	of control device cost (A)	372,157
Purchased Equipment Total (B)	22%		**9,080,638**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	363,226
Handling & erection	50%	of purchased equip cost (B)	4,540,319
Electrical	8%	of purchased equip cost (B)	726,451
Piping	1%	of purchased equip cost (B)	90,806
Insulation	7%	of purchased equip cost (B)	635,645
Painting	4%	Included in vendor estimate	363,226
Installation Subtotal Standard Expenses	74%		**6,719,672**
Other Specific Costs (see summary)			
Site Preparation, as required	N/A	Site Specific	
Buildings, as required	N/A	Site Specific	
Lost Production for Tie-In	N/A	Site Specific	
Total Site Specific Costs			N/A
Installation Total			**6,719,672**
Total Direct Capital Cost, DC			**15,800,310**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	908,064
Construction & field expenses	20%	of purchased equip cost (B)	1,816,128
Contractor fees	10%	of purchased equip cost (B)	908,064
Start-up	1%	of purchased equip cost (B)	90,806
Performance test	1%	of purchased equip cost (B)	90,806
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	908,064
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**4,721,932**
Total Capital Investment (TCI) = DC + IC			**20,522,242**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**20,036,476**
Total Capital Investment (TCI) with Retrofit Factor	0%		**20,036,476**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	67.53	$/Hr	147,892
Supervisor	0.15	of Op Labor	22,184
Maintenance			
Maintenance Labor	67.53	$/Hr	73,946
Maintenance Materials	100	% of Maintenance Labor	73,946
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.07	$/kwh, 477.3 kW-hr, 8760 hr/yr, 100% utilization	305,131
N/A			-
Compressed Air	0.48	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization	222,405
N/A			-
Solid Waste Disposal	63.34	$/ton, 0.5 ton/hr, 8760 hr/yr, 100% utilization	254,653
Trona	285.00	$/ton, 1,142.6 lb/hr, 8760 hr/yr, 100% utilization	1,426,346
Filter Bags	228.02	$/bag, 1,748 bags, 8760 hr/yr, 100% utilization	180,051
N/A			-
N/A			-
N/A			-
N/A			-
Total Annual Direct Operating Costs			**2,706,554**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	190,780
Administration (2% total capital costs)	2%	of total capital costs (TCI)	400,730
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	200,365
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	200,365
Capital Recovery	0.0837	for a 20-year equipment life and a 5.5% interest rate	1,676,639
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery costs	**2,848,930**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**5,555,483**

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.4 – Table C.4-4: SO_2 Control Dry Sorbent Injection (DSI) with Baghouse

Power Station Boiler No. 7

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:	**Filter Bags**	
Equipment Life	3	years
CRF	0.3707	
Rep part cost per unit	228.02	$/bag
Amount Required	1748	Bags
Total Rep Parts Cost	446,417	Cost adjusted for freight, sales tax, and bag disposal
Installation Labor	39,349	20 min per bag
Total Installed Cost	**485,766**	
Annualized Cost	**180,051**	

Electrical Use

	Flow acfm	D P in H2O	kWhr/yr	
Blower	439,519	6.00	4,181,302	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total			4,181,302	

Reagent Use & Other Operating Costs

Trona use - 1.5 NSR	205.66 lb/hr SO2	1142.63 lb/hr Trona
Solid Waste Disposal	4,021	ton/yr DSI unreacted sorbent and reaction byproducts

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours		8,760			
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	2,190	$ 147,892	$/Hr, 2.0 hr/8 hr shift, 2,190 hr/yr
Supervisor	15%	of Op Labor			NA	$ 22,184	% of Operator Costs
Maintenance							
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	1,095	$ 73,946	$/Hr, 1.0 hr/8 hr shift, 1,095 hr/yr
Maint Mtls	100%	of Maintenance Labor			NA	$ 73,946	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	477.3	kW-hr	4,181,302	$ 305,131	$/kwh, 477.3 kW-hr, 8760 hr/yr, 100% utilization
Water			N/A	gpm			
Compressed Air	0.481	$/kscf	2.0	scfm/kacfm	462,022	$ 222,405	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization
Cooling Water			N/A	gpm			
Solid Waste Disposal	63.34	$/ton	0.5	ton/hr	4,021	$ 254,653	$/ton, 0.5 ton/hr, 8760 hr/yr, 100% utilization
Trona	285.00	$/ton	1,142.6	lb/hr	5,005	$ 1,426,346	$/ton, 1,142.6 lb/hr, 8760 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	1,748	bags	N/A	$ 180,051	$/bag, 1,748 bags, 8760 hr/yr, 100% utilization

Appendix C.5

Power Station Boiler No. 8

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.5 – Table C.5-1: Cost Summary
Power Station Boiler No. 8

SO_2 Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Total Annualized Cost $/yr	Pollution Control Cost $/ton
Spray Dry Absorber (SDA)	90%	65.1	585.9	$90,131,245	$12,700,296	$21,676
Dry Sorbent Injection (DSI)	70%	195.3	455.7	$17,155,347	$4,534,089	$9,900

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.5 – Table C.5-2: Summary of Utility, Chemical and Supply Costs
Power Station Boiler No. 8

Operating Unit:	Power Station Boiler No. 8	**Study Year**	2020
Emission Unit Number			
Stack/Vent Number			

Item	2020 Unit Cost	Units	Cost	Year	Data Source	Notes
Operating Labor	68	$/hr	60	2016	EPA SCR Control Cost Manual Spreadsheet	
Maintenance Labor	68	$/hr				Assumed to be equivalent to operating labor
Installation Labor	68	$/hr				Assumed to be equivalent to operating labor
Electricity	0.07	$/kwh			2016-2019 EIA Average prices for the industrial sector in Indiana	
Natural Gas	6.15	$/kscf			2014-2018 EIA Average prices for the Industrial sector in Indiana (latest available 8/20/2020)	
Compressed Air	0.48	$/kscf	0.38	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Chemicals & Supplies						
Lime	183.68	$/ton	145.00	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Trona	285.00	$/ton		2020	Reagent cost for trona from another Barr Engineering Co. Project.	
Fabric Filter Bags	228.02	$/bag	180	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Other						
Sales Tax	7%			2020	Indiana sales tax rate	
Interest Rate	5.50%			2016	EPA SCR Control Cost Manual Spreadsheet	
Solid Waste Disposal	63.34	$/ton	50	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Contingencies	10%	of purchased equip cost (B)			EPA Cost Control Cost Manual Chapter 2	Suggested contingency range of 5% to 15% of total capital investment
Markup on capital investment (retrofit factor)	0%				EPA Cost Control Cost Manual Chapter 2	
Operating Information						
Annual Op. Hrs	8,760	Hours			Emission Inventory Data	
Utilization Rate	100%				Assumed	
Design Capacity	650.0	MMBTU/hr			Boiler Design Capacity	
Equipment Life	20	yrs			Assumed	
Temperature	415	Deg F			Performance test data	
Moisture Content	12.8%				Performance test data	
Actual Flow Rate	341,000	acfm			Performance test data	
Standardized Flow Rate	205,769	scfm @ 68º F	191,739	scfm @ 32º F	Calculated Value	
Dry Std Flow Rate	175,000	dscfm @ 68º F			Performance test data	
Plant Elevation	610	Feet above sea level				Plant elevation
	Baseline Emissions		**lb/hr**	**ton/year**		
Pollutant	**Lb/Hr**	**Ton/Year**	**ppmv**	**ppmv**	**lb/mmbtu**	
Nitrous Oxides (NOx)	63.0	276.0	50	50.2		Emission inventory data
Sulfur Dioxides (SO2)	148.6	651.0	85	85.1		Emission inventory data
SDA - SO_2 Control Efficiency	90%				EPA fact sheet for flue gas desulfurization (new installations) https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf	
DSI - SO_2 Control Efficiency	70%				Control efficiency is based on trona as injected reagent.	

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.5 – Table C.5-3: SO_2 Control Spray Dry Absorber (SDA)

Power Station Boiler No. 8

Operating Unit: **Power Station Boiler No. 8**

Emission Unit Number	0		Stack/Vent Number	0	
Design Capacity	650	MMBtu/hr	Standardized Flow Rate	191,739	scfm @ 32º F
Utilization Rate	100%		Temperature	415	Deg F
Annual Operating Hours	8,760	Hours	Moisture Content	12.8%	
Annual Interest Rate	5.5%		Actual Flow Rate	341,000	acfm
Equipment Life	20	yrs	Standardized Flow Rate	205,769	scfm @ 68º F
			Dry Std Flow Rate	175,000	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs									
Direct Capital Costs									
Purchased Equipment (A)									**32,689,411**
Purchased Equipment Total (B)	22%	of control device cost (A)							**39,881,082**
Installation - Standard Costs	74%	of purchased equip cost (B)							29,512,001
Installation - Site Specific Costs									NA
Installation Total									29,512,001
Total Direct Capital Cost, DC									69,393,083
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)							20,738,163
Total Capital Investment (TCI) = DC + IC									**90,131,245**
Adjusted TCI for Replacment Parts									**89,754,364**
TCI with Retrofit Factor									**89,754,364**
Operating Costs									
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.							1,269,063
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost							11,431,233
Total Annual Cost (Annualized Capital Cost + Operating Cost)									**12,700,296**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc.**	**Conc. Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10						0.0	-	NA
PM2.5						0.0	-	NA
Total Particulates						0.0	-	NA
Nitrous Oxides (NOx)						0.0	-	NA
Sulfur Dioxide (SO_2)		651.0	90%			65.1	585.9	21,676
Sulfuric Acid Mist						0.00	-	NA
Fluorides						0.0	-	NA
Volatile Organic Compounds (VOC)						0.0	-	NA
Carbon Monoxide (CO)						0.0	-	NA
Lead (Pb)						0.00	-	NA

Notes & Assumptions

1 Capital cost estimate based on mid-range of EPA spray dry fact sheet $/(MMBtu/hr): https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf
2 Costs scaled up to design airflow using the 6/10 power law
3 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.5 – Table C.5-3: SO_2 Control Spray Dry Absorber (SDA)

Power Station Boiler No. 8

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (A) [1]		**32,689,411**
Purchased Equipment Costs (A) - Absorber + packing + auxiliary equipment, EC		
Instrumentation	10% of control device cost (A)	3,268,941
State Sales Taxes	7.0% of control device cost (A)	2,288,259
Freight	5% of control device cost (A)	1,634,471
Purchased Equipment Total (B)	22%	**39,881,082**
Installation		
Foundations & supports	4% of purchased equip cost (B)	1,595,243
Handling & erection	50% of purchased equip cost (B)	19,940,541
Electrical	8% of purchased equip cost (B)	3,190,487
Piping	1% of purchased equip cost (B)	398,811
Insulation	7% of purchased equip cost (B)	2,791,676
Painting	4% of purchased equip cost (B)	1,595,243
Installation Subtotal Standard Expenses	74%	**29,512,001**
Other Specific Costs (see summary)		
Site Preparation, as required	N/A Site Specific	-
Buildings, as required	N/A Site Specific	-
Site Specific - Other	N/A Site Specific	-
Total Site Specific Costs		NA
Installation Total		**29,512,001**
Total Direct Capital Cost, DC		**69,393,083**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	3,988,108
Construction & field expenses	20% of purchased equip cost (B)	7,976,216
Contractor fees	10% of purchased equip cost (B)	3,988,108
Start-up	1% of purchased equip cost (B)	398,811
Performance test	1% of purchased equip cost (B)	398,811
Model Studies	N/A of purchased equip cost (B)	-
Contingencies	10% of purchased equip cost (B)	3,988,108
Total Indirect Capital Costs, IC	52% of purchased equip cost (B)	**20,738,163**
Total Capital Investment (TCI) = DC + IC		**90,131,245**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		**89,754,364**
Total Capital Investment (TCI) with Retrofit Factor	0%	**89,754,364**
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	67.53 $/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	147,892
Supervisor	15% of Op., 0.0 , 8760 hr/yr, 100% utilization	22,184
Maintenance		
Maintenance Labor	67.53 $/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	73,946
Maintenance Materials	100% of maintenance labor costs	73,946
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.07 $/kwh, 617.2 kW-hr, 8760 hr/yr, 100% utilization	394,558
Compressed Air	0.48 $/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization	172,552
N/A		-
SW Disposal	63.34 $/ton, 0.1 ton/hr, 8760 hr/yr, 100% utilization	82,486
Lime	183.68 $/ton, 201.1 lb/hr, 8760 hr/yr, 100% utilization	161,806
Filter Bags	228.02 $/bag, 1,356 bags, 8760 hr/yr, 100% utilization	139,692
N/A		
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
Total Annual Direct Operating Costs		**1,269,063**
Indirect Operating Costs		
Overhead	60% of total labor and material costs	190,780
Administration (2% total capital costs)	2% of total capital costs (TCI)	1,795,087
Property tax (1% total capital costs)	1% of total capital costs (TCI)	897,544
Insurance (1% total capital costs)	1% of total capital costs (TCI)	897,544
Capital Recovery	0.0837 for a 20- year equipment life and a 5.5% interest rate	7,650,277
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**11,431,233**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**12,700,296**

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.5 – Table C.5-3: SO_2 Control Spray Dry Absorber (SDA)

Power Station Boiler No. 8

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:	**Filter Bags**		
Equipment Life	3	years	
CRF	0.3707		
Rep part cost per unit	228.02	$/bag	
Amount Required	1356		
Total Rep Parts Cost	346,352	Cost adjusted for freight & sales tax	
Installation Labor	30,529	10 min per bag	EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**376,881**		
Annualized Cost	**139,692**		

Electrical Use

	Flow acfm	D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	341,000	10.00			5,406,760	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total					5,406,760	

Reagents and Other Operating Costs

Lime Use Rate	1.30	lb-mole CaO/lb-mole SO2	201.12 lb/hr Lime
Solid Waste Disposal	1,302	ton/yr GSA unreacted sorbent and reaction byproducts	

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours		8,760			
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	2,190	$ 147,892	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Supervisor	15%	of Op.			NA	$ 22,184	of Op., 0.0 , 8760 hr/yr, 100% utilization
Maintenance							
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	1,095	$ 73,946	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Maint Mtls	100	% of Maintenance Labor			NA	$ 73,946	% of Maintenance Labor, 0.0 , 8760 hr/yr, 100% utilization
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	617.2	kW-hr	5,406,760	$ 394,558	$/kwh, 617.2 kW-hr, 8760 hr/yr, 100% utilization
Compressed Air	0.481	$/kscf	2	scfm/kacfm	358,459	$ 172,552	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization
Water	5.129	$/mgal		gpm			$/mgal, 0 gpm, 8760 hr/yr, 100% utilization
SW Disposal	63.34	$/ton	0.15	ton/hr	1,302	$ 82,486	$/ton, 0.1 ton/hr, 8760 hr/yr, 100% utilization
Lime	183.68	$/ton	201.1	lb/hr	881	$ 161,806	$/ton, 201.1 lb/hr, 8760 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	1,356	bags	N/A	$ 139,692	$/bag, 1,356 bags, 8760 hr/yr, 100% utilization

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.5 – Table C.5-4: SO_2 Control Dry Sorbent Injection (DSI)

Power Station Boiler No. 8

Operating Unit: **Power Station Boiler No. 8**

Emission Unit Number			Stack/Vent Number		
Design Capacity	650	MMBtu/hr	Standardized Flow Rate	191,739	scfm @ 32º F
Utilization Rate	100%		Exhaust Temperature	415	Deg F
Annual Operating Hours	8,760	hr/yr	Exhaust Moisture Content	12.8%	
Annual Interest Rate	5.50%		Actual Flow Rate	341,000	acfm
Control Equipment Life	20	yrs	Standardized Flow Rate	205,769	scfm @ 68º F
Plant Elevation	610	ft	Dry Std Flow Rate	175,000	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**6,358,707**
Purchased Equipment Total (B)	22%	of control device cost (A)	**7,757,623**
Installation - Standard Costs	74%	of purchased equip cost (B)	5,740,641
Installation - Site Specific Costs			N/A
Installation Total			5,740,641
Total Direct Capital Cost, DC			13,498,264
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	4,033,964
Total Capital Investment (TCI) = DC + IC			**17,155,347**
Adjusted TCI for Replacement Parts			17,155,347
Total Capital Investment (TCI) with Retrofit Factor			**17,155,347**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	2,081,855
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	2,452,235
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,534,089**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual Ton/Yr	Cont Eff %	Cont Emis Ton/Yr	Reduction Ton/Yr	Cont Cost $/Ton Rem
PM10						
PM2.5						
Total Particulates						
Nitrous Oxides (NOx)						
Sulfur Dioxide (SO2)	148.63	651.02	70%	195.31	455.71	$9,900
Sulfuric Acid Mist (H2SO4)						
Fluorides						
Volatile Organic Compounds (VOC)						
Carbon Monoxide (CO)						
Lead (Pb)						

Notes & Assumptions

1 Baghouse capital cost estimate based on EPA-R05-OAR-2010-0954-0079, ancillary equipment from other Barr Engineering projects
2 Costs scaled up to design airflow using the 6/10 power law
3 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.5 – Table C.5-4: SO_2 Control Dry Sorbent Injection (DSI)

Power Station Boiler No. 8

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [1]			**6,358,707**
Purchased Equipment Costs (A) - Injection System + auxiliary equipment, EC			
Instrumentation	10%	Included in vendor estimate	635,871
State Sales Taxes	7.0%	of control device cost (A)	445,110
Freight	5%	of control device cost (A)	317,935
Purchased Equipment Total (B)	22%		**7,757,623**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	310,305
Handling & erection	50%	of purchased equip cost (B)	3,878,811
Electrical	8%	of purchased equip cost (B)	620,610
Piping	1%	of purchased equip cost (B)	77,576
Insulation	7%	of purchased equip cost (B)	543,034
Painting	4%	Included in vendor estimate	310,305
Installation Subtotal Standard Expenses	74%		**5,740,641**
Other Specific Costs (see summary)			
Site Preparation, as required	N/A	Site Specific	
Buildings, as required	N/A	Site Specific	
Lost Production for Tie-In	N/A	Site Specific	
Total Site Specific Costs			N/A
Installation Total			**5,740,641**
Total Direct Capital Cost, DC			**13,498,264**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	775,762
Construction & field expenses	20%	of purchased equip cost (B)	1,551,525
Contractor fees	10%	of purchased equip cost (B)	775,762
Start-up	1%	of purchased equip cost (B)	77,576
Performance test	1%	of purchased equip cost (B)	77,576
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	775,762
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**4,033,964**
Total Capital Investment (TCI) = DC + IC			**17,532,228**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**17,155,347**
Total Capital Investment (TCI) with Retrofit Factor	0%		**17,155,347**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	67.53	$/Hr	147,892
Supervisor	0.15	of Op Labor	22,184
Maintenance			
Maintenance Labor	67.53	$/Hr	73,946
Maintenance Materials	100	% of Maintenance Labor	73,946
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.07	$/kwh, 370.3 kW-hr, 8760 hr/yr, 100% utilization	236,735
N/A			-
Compressed Air	0.48	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization	172,552
N/A			-
Solid Waste Disposal	63.34	$/ton, 0.3 ton/hr, 8760 hr/yr, 100% utilization	184,045
Trona	285.00	$/ton, 825.8 lb/hr, 8760 hr/yr, 100% utilization	1,030,862
Filter Bags	228.02	$/bag, 1,356 bags, 8760 hr/yr, 100% utilization	139,692
N/A			-
N/A			-
N/A			-
N/A			-
Total Annual Direct Operating Costs			**2,081,855**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	190,780
Administration (2% total capital costs)	2%	of total capital costs (TCI)	343,107
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	171,553
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	171,553
Capital Recovery	0.0837	for a 20-year equipment life and a 5.5% interest rate	1,435,548
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery costs	**2,452,235**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,534,089**

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.5 – Table C.5-4: SO_2 Control Dry Sorbent Injection (DSI)

Power Station Boiler No. 8

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:	**Filter Bags**	
Equipment Life	3	years
CRF	0.3707	
Rep part cost per unit	228.02	$/bag
Amount Required	1356	Bags
Total Rep Parts Cost	346,352	Cost adjusted for freight, sales tax, and bag disposal
Installation Labor	30,529	20 min per bag
Total Installed Cost	**376,881**	
Annualized Cost	**139,692**	

Electrical Use

	Flow acfm	D P in H2O	kWhr/yr	
Blower	341,000	6.00	3,244,056	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total			3,244,056	

Reagent Use & Other Operating Costs

Trona use - 1.5 NSR	148.63 lb/hr SO2	825.81 lb/hr Trona
Solid Waste Disposal	2,906 ton/yr DSI unreacted sorbent and reaction byproducts	

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours		8,760			
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	2,190	$ 147,892	$/Hr, 2.0 hr/8 hr shift, 2,190 hr/yr
Supervisor	15%	of Op Labor			NA	$ 22,184	% of Operator Costs
Maintenance							
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	1,095	$ 73,946	$/Hr, 1.0 hr/8 hr shift, 1,095 hr/yr
Maint Mtls	100%	of Maintenance Labor			NA	$ 73,946	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	370.3	kW-hr	3,244,056	$ 236,735	$/kwh, 370.3 kW-hr, 8760 hr/yr, 100% utilization
Water			N/A	gpm			
Compressed Air	0.481	$/kscf	2.0	scfm/kacfm	358,459	$ 172,552	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization
Cooling Water			N/A	gpm			
Solid Waste Disposal	63.34	$/ton	0.3	ton/hr	2,906	$ 184,045	$/ton, 0.3 ton/hr, 8760 hr/yr, 100% utilization
Trona	285.00	$/ton	825.8	lb/hr	3,617	$ 1,030,862	$/ton, 825.8 lb/hr, 8760 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	1,356	bags	N/A	$ 139,692	$/bag, 1,356 bags, 8760 hr/yr, 100% utilization

Appendix C.6

Power Station Boiler No. 9

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.6 – Table C.6-1: Cost Summary
Power Station Boiler No. 9

SO_2 Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Total Annualized Cost $/yr	Pollution Control Cost $/ton
Spray Dry Absorber (SDA)	90%	52.4	471.8	$90,131,245	$12,633,930	$26,781
Dry Sorbent Injection (DSI)	70%	157.3	366.9	$16,690,046	$4,223,662	$11,500

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.6 – Table C.6-2: Summary of Utility, Chemical and Supply Costs

Power Station Boiler No. 9

Operating Unit:	Power Station Boiler No. 9	**Study Year**	2020
Emission Unit Number			
Stack/Vent Number			

Item	2020 Unit Cost	Units	Cost	Year	Data Source	Notes
Operating Labor	68	$/hr	60	2016	EPA SCR Control Cost Manual Spreadsheet	
Maintenance Labor	68	$/hr				Assumed to be equivalent to operating labor
Installation Labor	68	$/hr				Assumed to be equivalent to operating labor
Electricity	0.07	$/kwh			2016-2019 EIA Average prices for the industrial sector in Indiana	
Natural Gas	6.15	$/kscf			2014-2018 EIA Average prices for the Industrial sector in Indiana (latest available 8/20/2020)	
Compressed Air	0.48	$/kscf	0.38	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Chemicals & Supplies						
Lime	183.68	$/ton	145.00	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Trona	285.00	$/ton		2020	Reagent cost for trona from another Barr Engineering Co. Project.	
Fabric Filter Bags	228.02	$/bag	180	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Other						
Sales Tax	7%			2020	Indiana sales tax rate	
Interest Rate	5.50%			2016	EPA SCR Control Cost Manual Spreadsheet	
Solid Waste Disposal	63.34	$/ton	50	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Contingencies	10%	of purchased equip cost (B)			EPA Cost Control Cost Manual Chapter 2	Suggested contingency range of 5% to 15% of total capital investment
Markup on capital investment (retrofit factor)	0%				EPA Cost Control Cost Manual Chapter 2	
Operating Information						
Annual Op. Hrs	8,760	Hours			Emission Inventory Data	
Utilization Rate	100%				Assumed	
Design Capacity	650.0	MMBTU/hr			Boiler Design Capacity	
Equipment Life	20	yrs			Assumed	
Temperature	451	Deg F			Performance test data	
Moisture Content	17.0%				Performance test data	
Actual Flow Rate	333,000	acfm			Performance test data	
Standardized Flow Rate	193,001	scfm @ 68º F	179,842	scfm @ 32º F	Calculated Value	
Dry Std Flow Rate	157,000	dscfm @ 68º F			Performance test data	
Plant Elevation	610	Feet above sea level				Plant elevation
	Baseline Emissions		**lb/hr**	**ton/year**		
Pollutant	**Lb/Hr**	**Ton/Year**	**ppmv**	**ppmv**	**lb/mmbtu**	
Nitrous Oxides (NOx)	42.0	184.0	37	37.3		Emission inventory data
Sulfur Dioxides (SO2)	119.7	524.2	76	76.4		Emission inventory data
SDA - SO_2 Control Efficiency	90%				EPA fact sheet for flue gas desulfurization (new installations) https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf	
DSI - SO_2 Control Efficiency	70%				Control efficiency is based on trona as injected reagent.	

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.6 – Table C.6-3: SO_2 Control Spray Dry Absorber (SDA)

Power Station Boiler No. 9

Operating Unit: **Power Station Boiler No. 9**

Emission Unit Number	0		Stack/Vent Number	0	
Design Capacity	650	MMBtu/hr	Standardized Flow Rate	179,842	scfm @ 32º F
Utilization Rate	100%		Temperature	451	Deg F
Annual Operating Hours	8,760	Hours	Moisture Content	17.0%	
Annual Interest Rate	5.5%		Actual Flow Rate	333,000	acfm
Equipment Life	20	yrs	Standardized Flow Rate	193,001	scfm @ 68º F
			Dry Std Flow Rate	157,000	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**32,689,411**
Purchased Equipment Total (B)	22%	of control device cost (A)	**39,881,082**
Installation - Standard Costs	74%	of purchased equip cost (B)	29,512,001
Installation - Site Specific Costs			NA
Installation Total			29,512,001
Total Direct Capital Cost, DC			69,393,083
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	20,738,163
Total Capital Investment (TCI) = DC + IC			**90,131,245**
Adjusted TCI for Replacment Parts			**89,763,206**
TCI with Retrofit Factor			**89,763,206**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	1,204,881
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	11,429,049
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**12,633,930**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual T/Yr	Cont Eff %	Exit Conc.	Conc. Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
PM10						0.0	-	NA
PM2.5						0.0	-	NA
Total Particulates						0.0	-	NA
Nitrous Oxides (NOx)						0.0	-	NA
Sulfur Dioxide (SO_2)		524.2	90%			52.4	471.8	26,781
Sulfuric Acid Mist						0.00	-	NA
Fluorides						0.0	-	NA
Volatile Organic Compounds (VOC)						0.0	-	NA
Carbon Monoxide (CO)						0.0	-	NA
Lead (Pb)						0.00	-	NA

Notes & Assumptions

1 Capital cost estimate based on mid-range of EPA spray dry fact sheet $/(MMBtu/hr): https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf
2 Costs scaled up to design airflow using the 6/10 power law
3 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.6 – Table C.6-3: SO_2 Control Spray Dry Absorber (SDA)

Power Station Boiler No. 9

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (A) [1]		**32,689,411**
Purchased Equipment Costs (A) - Absorber + packing + auxiliary equipment, EC		
Instrumentation	10% of control device cost (A)	3,268,941
State Sales Taxes	7.0% of control device cost (A)	2,288,259
Freight	5% of control device cost (A)	1,634,471
Purchased Equipment Total (B)	22%	**39,881,082**
Installation		
Foundations & supports	4% of purchased equip cost (B)	1,595,243
Handling & erection	50% of purchased equip cost (B)	19,940,541
Electrical	8% of purchased equip cost (B)	3,190,487
Piping	1% of purchased equip cost (B)	398,811
Insulation	7% of purchased equip cost (B)	2,791,676
Painting	4% of purchased equip cost (B)	1,595,243
Installation Subtotal Standard Expenses	74%	**29,512,001**
Other Specific Costs (see summary)		
Site Preparation, as required	N/A Site Specific	-
Buildings, as required	N/A Site Specific	-
Site Specific - Other	N/A Site Specific	-
Total Site Specific Costs		NA
Installation Total		**29,512,001**
Total Direct Capital Cost, DC		**69,393,083**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	3,988,108
Construction & field expenses	20% of purchased equip cost (B)	7,976,216
Contractor fees	10% of purchased equip cost (B)	3,988,108
Start-up	1% of purchased equip cost (B)	398,811
Performance test	1% of purchased equip cost (B)	398,811
Model Studies	N/A of purchased equip cost (B)	-
Contingencies	10% of purchased equip cost (B)	3,988,108
Total Indirect Capital Costs, IC	52% of purchased equip cost (B)	**20,738,163**
Total Capital Investment (TCI) = DC + IC		**90,131,245**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		**89,763,206**
Total Capital Investment (TCI) with Retrofit Factor	0%	**89,763,206**
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	67.53 $/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	147,892
Supervisor	15% of Op., 0.0 , 8760 hr/yr, 100% utilization	22,184
Maintenance		
Maintenance Labor	67.53 $/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	73,946
Maintenance Materials	100% of maintenance labor costs	73,946
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.07 $/kwh, 602.7 kW-hr, 8760 hr/yr, 100% utilization	385,302
Compressed Air	0.48 $/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization	168,504
N/A		-
SW Disposal	63.34 $/ton, 0.1 ton/hr, 8760 hr/yr, 100% utilization	66,414
Lime	183.68 $/ton, 161.9 lb/hr, 8760 hr/yr, 100% utilization	130,279
Filter Bags	228.02 $/bag, 1,324 bags, 8760 hr/yr, 100% utilization	136,415
N/A		
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
Total Annual Direct Operating Costs		**1,204,881**
Indirect Operating Costs		
Overhead	60% of total labor and material costs	190,780
Administration (2% total capital costs)	2% of total capital costs (TCI)	1,795,264
Property tax (1% total capital costs)	1% of total capital costs (TCI)	897,632
Insurance (1% total capital costs)	1% of total capital costs (TCI)	897,632
Capital Recovery	0.0837 for a 20- year equipment life and a 5.5% interest rate	7,647,740
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**11,429,049**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**12,633,930**

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.6 – Table C.6-3: SO_2 Control Spray Dry Absorber (SDA)

Power Station Boiler No. 9

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:	**Filter Bags**		
Equipment Life	3	years	
CRF	0.3707		
Rep part cost per unit	228.02	$/bag	
Amount Required	1324		
Total Rep Parts Cost	338,227	Cost adjusted for freight & sales tax	
Installation Labor	29,812	10 min per bag	EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**368,039**		
Annualized Cost	**136,415**		

Electrical Use

	Flow acfm	D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	333,000	10.00			5,279,915	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total					5,279,915	

Reagents and Other Operating Costs

Lime Use Rate	1.30	lb-mole CaO/lb-mole SO2	161.93 lb/hr Lime
Solid Waste Disposal	1,049	ton/yr GSA unreacted sorbent and reaction byproducts	

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours		8,760			
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	2,190	$ 147,892	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Supervisor	15%	of Op.			NA	$ 22,184	of Op., 0.0 , 8760 hr/yr, 100% utilization
Maintenance							
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	1,095	$ 73,946	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Maint Mtls	100	% of Maintenance Labor			NA	$ 73,946	% of Maintenance Labor, 0.0 , 8760 hr/yr, 100% utilization
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	602.7	kW-hr	5,279,915	$ 385,302	$/kwh, 602.7 kW-hr, 8760 hr/yr, 100% utilization
Compressed Air	0.481	$/kscf	2	scfm/kacfm	350,050	$ 168,504	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization
Water	5.129	$/mgal		gpm			$/mgal, 0 gpm, 8760 hr/yr, 100% utilization
SW Disposal	63.34	$/ton	0.12	ton/hr	1,049	$ 66,414	$/ton, 0.1 ton/hr, 8760 hr/yr, 100% utilization
Lime	183.68	$/ton	161.9	lb/hr	709	$ 130,279	$/ton, 161.9 lb/hr, 8760 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	1,324	bags	N/A	$ 136,415	$/bag, 1,324 bags, 8760 hr/yr, 100% utilization

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.6 – Table C.6-4: SO_2 Control Dry Sorbent Injection (DSI)

Power Station Boiler No. 9

Operating Unit: **Power Station Boiler No. 9**

Emission Unit Number			Stack/Vent Number		
Design Capacity	650	MMBtu/hr	Standardized Flow Rate	179,842	scfm @ 32º F
Utilization Rate	100%		Exhaust Temperature	451	Deg F
Annual Operating Hours	8,760	hr/yr	Exhaust Moisture Content	17.0%	
Annual Interest Rate	5.50%		Actual Flow Rate	333,000	acfm
Control Equipment Life	20	yrs	Standardized Flow Rate	193,001	scfm @ 68º F
Plant Elevation	610	ft	Dry Std Flow Rate	157,000	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**6,186,742**
Purchased Equipment Total (B)	22%	of control device cost (A)	**7,547,825**
Installation - Standard Costs	74%	of purchased equip cost (B)	5,585,391
Installation - Site Specific Costs			N/A
Installation Total			5,585,391
Total Direct Capital Cost, DC			13,133,216
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	3,924,869
Total Capital Investment (TCI) = DC + IC			**16,690,046**
Adjusted TCI for Replacement Parts			16,690,046
Total Capital Investment (TCI) with Retrofit Factor			**16,690,046**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	1,832,253
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	2,391,409
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,223,662**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual Ton/Yr	Cont Eff %	Cont Emis Ton/Yr	Reduction Ton/Yr	Cont Cost $/Ton Rem
PM10						
PM2.5						
Total Particulates						
Nitrous Oxides (NOx)						
Sulfur Dioxide (SO2)	119.67	524.17	70%	157.25	366.92	$11,500
Sulfuric Acid Mist (H2SO4)						
Fluorides						
Volatile Organic Compounds (VOC)						
Carbon Monoxide (CO)						
Lead (Pb)						

Notes & Assumptions

1 Baghouse capital cost estimate based on EPA-R05-OAR-2010-0954-0079, ancillary equipment from other Barr Engineering projects
2 Costs scaled up to design airflow using the 6/10 power law
3 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.6 – Table C.6-4: SO_2 Control Dry Sorbent Injection (DSI)
Power Station Boiler No. 9

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [1]			**6,186,742**
Purchased Equipment Costs (A) - Injection System + auxiliary equipment, EC			
Instrumentation	10%	Included in vendor estimate	618,674
State Sales Taxes	7.0%	of control device cost (A)	433,072
Freight	5%	of control device cost (A)	309,337
Purchased Equipment Total (B)	22%		**7,547,825**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	301,913
Handling & erection	50%	of purchased equip cost (B)	3,773,913
Electrical	8%	of purchased equip cost (B)	603,826
Piping	1%	of purchased equip cost (B)	75,478
Insulation	7%	of purchased equip cost (B)	528,348
Painting	4%	Included in vendor estimate	301,913
Installation Subtotal Standard Expenses	74%		**5,585,391**
Other Specific Costs (see summary)			
Site Preparation, as required	N/A	Site Specific	
Buildings, as required	N/A	Site Specific	
Lost Production for Tie-In	N/A	Site Specific	
Total Site Specific Costs			N/A
Installation Total			**5,585,391**
Total Direct Capital Cost, DC			**13,133,216**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	754,783
Construction & field expenses	20%	of purchased equip cost (B)	1,509,565
Contractor fees	10%	of purchased equip cost (B)	754,783
Start-up	1%	of purchased equip cost (B)	75,478
Performance test	1%	of purchased equip cost (B)	75,478
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	754,783
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**3,924,869**
Total Capital Investment (TCI) = DC + IC			**17,058,085**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**16,690,046**
Total Capital Investment (TCI) with Retrofit Factor	0%		**16,690,046**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	67.53	$/Hr	147,892
Supervisor	0.15	of Op Labor	22,184
Maintenance			
Maintenance Labor	67.53	$/Hr	73,946
Maintenance Materials	100	% of Maintenance Labor	73,946
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.07	$/kwh, 361.6 kW-hr, 8760 hr/yr, 100% utilization	231,181
N/A			-
Compressed Air	0.48	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization	168,504
N/A			-
Solid Waste Disposal	63.34	$/ton, 0.3 ton/hr, 8760 hr/yr, 100% utilization	148,184
Trona	285.00	$/ton, 664.9 lb/hr, 8760 hr/yr, 100% utilization	830,001
Filter Bags	228.02	$/bag, 1,324 bags, 8760 hr/yr, 100% utilization	136,415
N/A			-
N/A			-
N/A			-
N/A			-
Total Annual Direct Operating Costs			**1,832,253**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	190,780
Administration (2% total capital costs)	2%	of total capital costs (TCI)	333,801
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	166,900
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	166,900
Capital Recovery	0.0837	for a 20-year equipment life and a 5.5% interest rate	1,396,612
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery costs	**2,391,409**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,223,662**

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.6 – Table C.6-4: SO_2 Control Dry Sorbent Injection (DSI)

Power Station Boiler No. 9

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment: **Filter Bags**

Equipment Life	3	years
CRF	0.3707	
Rep part cost per unit	228.02	$/bag
Amount Required	1324	Bags
Total Rep Parts Cost	338,227	Cost adjusted for freight, sales tax, and bag disposal
Installation Labor	29,812	20 min per bag
Total Installed Cost	**368,039**	
Annualized Cost	**136,415**	

Electrical Use

	Flow acfm	D P in H2O	kWhr/yr	
Blower	333,000	6.00	3,167,949	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total			3,167,949	

Reagent Use & Other Operating Costs

Trona use - 1.5 NSR	119.67	lb/hr SO2	664.90	lb/hr Trona
Solid Waste Disposal	2,340	ton/yr DSI unreacted sorbent and reaction byproducts		

Operating Cost Calculations

Utilization Rate 100% | Annual Operating Hours 8,760

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*		Annual Cost	Comments
Operating Labor								
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	2,190	$	147,892	$/Hr, 2.0 hr/8 hr shift, 2,190 hr/yr
Supervisor	15%	of Op Labor			NA	$	22,184	% of Operator Costs
Maintenance								
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	1,095	$	73,946	$/Hr, 1.0 hr/8 hr shift, 1,095 hr/yr
Maint Mtls	100%	of Maintenance Labor			NA	$	73,946	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management								
Electricity	0.073	$/kwh	361.6	kW-hr	3,167,949	$	231,181	$/kwh, 361.6 kW-hr, 8760 hr/yr, 100% utilization
Water			N/A	gpm				
Compressed Air	0.481	$/kscf	2.0	scfm/kacfm	350,050	$	168,504	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization
Cooling Water			N/A	gpm				
Solid Waste Disposal	63.34	$/ton	0.3	ton/hr	2,340	$	148,184	$/ton, 0.3 ton/hr, 8760 hr/yr, 100% utilization
Trona	285.00	$/ton	664.9	lb/hr	2,912	$	830,001	$/ton, 664.9 lb/hr, 8760 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	1,324	bags	N/A	$	136,415	$/bag, 1,324 bags, 8760 hr/yr, 100% utilization

Appendix C.7

Power Station Boiler No. 10

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.7 – Table C.7-1: Cost Summary
Power Station Boiler No. 10

SO_2 Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Total Annualized Cost $/yr	Pollution Control Cost $/ton
Spray Dry Absorber (SDA)	90%	33.4	300.2	$90,131,245	$12,599,932	$41,972
Dry Sorbent Injection (DSI)	70%	100.1	233.5	$16,669,213	$3,897,671	$16,700

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.7 – Table C.7-2: Summary of Utility, Chemical and Supply Costs

Power Station Boiler No. 10

Operating Unit:	Power Station Boiler No. 10	**Study Year**	2020
Emission Unit Number			
Stack/Vent Number			

Item	2020 Unit Cost	Units	Cost	Year	Data Source	Notes
Operating Labor	68	$/hr	60	2016	EPA SCR Control Cost Manual Spreadsheet	
Maintenance Labor	68	$/hr				Assumed to be equivalent to operating labor
Installation Labor	68	$/hr				Assumed to be equivalent to operating labor
Electricity	0.07	$/kwh			2016-2019 EIA Average prices for the industrial sector in Indiana	
Natural Gas	6.15	$/kscf			2014-2018 EIA Average prices for the Industrial sector in Indiana (latest available 8/20/2020)	
Compressed Air	0.48	$/kscf	0.38	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Chemicals & Supplies						
Lime	183.68	$/ton	145.00	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Trona	285.00	$/ton		2020	Reagent cost for trona from another Barr Engineering Co. Project.	
Fabric Filter Bags	228.02	$/bag	180	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Other						
Sales Tax	7%			2020	Indiana sales tax rate	
Interest Rate	5.50%			2016	EPA SCR Control Cost Manual Spreadsheet	
Solid Waste Disposal	63.34	$/ton	50	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Contingencies	10%	of purchased equip cost (B)			EPA Cost Control Cost Manual Chapter 2	Suggested contingency range of 5% to 15% of total capital investment
Markup on capital investment (retrofit factor)	0%				EPA Cost Control Cost Manual Chapter 2	
Operating Information						
Annual Op. Hrs	8,760	Hours			Emission Inventory Data	
Utilization Rate	100%				Assumed	
Design Capacity	650.0	MMBTU/hr			Boiler Design Capacity	
Equipment Life	20	yrs			Assumed	
Temperature	432	Deg F			Performance test data	
Moisture Content	13.7%				Performance test data	
Actual Flow Rate	349,000	acfm			Performance test data	
Standardized Flow Rate	206,583	scfm @ 68º F	192,498	scfm @ 32º F	Calculated Value	
Dry Std Flow Rate	174,000	dscfm @ 68º F			Performance test data	
Plant Elevation	610	Feet above sea level				Plant elevation
	Baseline Emissions		**lb/hr**	**ton/year**		
Pollutant	**Lb/Hr**	**Ton/Year**	**ppmv**	**ppmv**	**lb/mmbtu**	
Nitrous Oxides (NOx)	38.8	170.0	31	31.1		Emission inventory data
Sulfur Dioxides (SO2)	76.2	333.6	44	43.8		Emission inventory data
SDA - SO_2 Control Efficiency	90%				EPA fact sheet for flue gas desulfurization (new installations) https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf	
DSI - SO_2 Control Efficiency	70%				Control efficiency is based on trona as injected reagent.	

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.7 – Table C.7-3: SO_2 Control Spray Dry Absorber (SDA)

Power Station Boiler No. 10

Operating Unit: **Power Station Boiler No. 10**

Emission Unit Number	0		Stack/Vent Number	0	
Design Capacity	650	MMBtu/hr	Standardized Flow Rate	192,498	scfm @ 32º F
Utilization Rate	100%		Temperature	432	Deg F
Annual Operating Hours	8,760	Hours	Moisture Content	13.7%	
Annual Interest Rate	5.5%		Actual Flow Rate	349,000	acfm
Equipment Life	20	yrs	Standardized Flow Rate	206,583	scfm @ 68º F
			Dry Std Flow Rate	174,000	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs									
Direct Capital Costs									
Purchased Equipment (A)									**32,689,411**
Purchased Equipment Total (B)	22%	of control device cost (A)							**39,881,082**
Installation - Standard Costs	74%	of purchased equip cost (B)							29,512,001
Installation - Site Specific Costs									NA
Installation Total									29,512,001
Total Direct Capital Cost, DC									69,393,083
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)							20,738,163
Total Capital Investment (TCI) = DC + IC									**90,131,245**
Adjusted TCI for Replacment Parts									**89,745,523**
TCI with Retrofit Factor									**89,745,523**
Operating Costs									
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.							1,166,516
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost							11,433,416
Total Annual Cost (Annualized Capital Cost + Operating Cost)									**12,599,932**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc.**	**Conc. Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10						0.0	-	NA
PM2.5						0.0	-	NA
Total Particulates						0.0	-	NA
Nitrous Oxides (NOx)						0.0	-	NA
Sulfur Dioxide (SO_2)		333.6	90%			33.4	300.2	41,972
Sulfuric Acid Mist						0.00	-	NA
Fluorides						0.0	-	NA
Volatile Organic Compounds (VOC)						0.0	-	NA
Carbon Monoxide (CO)						0.0	-	NA
Lead (Pb)						0.00	-	NA

Notes & Assumptions

1. Capital cost estimate based on mid-range of EPA spray dry fact sheet $/(MMBtu/hr): https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf
2. Costs scaled up to design airflow using the 6/10 power law
3. Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.7 – Table C.7-3: SO_2 Control Spray Dry Absorber (SDA)

Power Station Boiler No. 10

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (A) [1]		**32,689,411**
Purchased Equipment Costs (A) - Absorber + packing + auxiliary equipment, EC		
Instrumentation	10% of control device cost (A)	3,268,941
State Sales Taxes	7.0% of control device cost (A)	2,288,259
Freight	5% of control device cost (A)	1,634,471
Purchased Equipment Total (B)	22%	**39,881,082**
Installation		
Foundations & supports	4% of purchased equip cost (B)	1,595,243
Handling & erection	50% of purchased equip cost (B)	19,940,541
Electrical	8% of purchased equip cost (B)	3,190,487
Piping	1% of purchased equip cost (B)	398,811
Insulation	7% of purchased equip cost (B)	2,791,676
Painting	4% of purchased equip cost (B)	1,595,243
Installation Subtotal Standard Expenses	74%	**29,512,001**
Other Specific Costs (see summary)		
Site Preparation, as required	N/A Site Specific	-
Buildings, as required	N/A Site Specific	-
Site Specific - Other	N/A Site Specific	-
Total Site Specific Costs		NA
Installation Total		**29,512,001**
Total Direct Capital Cost, DC		**69,393,083**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	3,988,108
Construction & field expenses	20% of purchased equip cost (B)	7,976,216
Contractor fees	10% of purchased equip cost (B)	3,988,108
Start-up	1% of purchased equip cost (B)	398,811
Performance test	1% of purchased equip cost (B)	398,811
Model Studies	N/A of purchased equip cost (B)	-
Contingencies	10% of purchased equip cost (B)	3,988,108
Total Indirect Capital Costs, IC	52% of purchased equip cost (B)	**20,738,163**
Total Capital Investment (TCI) = DC + IC		**90,131,245**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		**89,745,523**
Total Capital Investment (TCI) with Retrofit Factor	0%	**89,745,523**
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	67.53 $/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	147,892
Supervisor	15% of Op., 0.0 , 8760 hr/yr, 100% utilization	22,184
Maintenance		
Maintenance Labor	67.53 $/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	73,946
Maintenance Materials	100% of maintenance labor costs	73,946
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.07 $/kwh, 631.7 kW-hr, 8760 hr/yr, 100% utilization	403,815
Compressed Air	0.48 $/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization	176,601
N/A		-
SW Disposal	63.34 $/ton, 0.1 ton/hr, 8760 hr/yr, 100% utilization	42,262
Lime	183.68 $/ton, 103.0 lb/hr, 8760 hr/yr, 100% utilization	82,901
Filter Bags	228.02 $/bag, 1,388 bags, 8760 hr/yr, 100% utilization	142,970
N/A		
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
Total Annual Direct Operating Costs		**1,166,516**
Indirect Operating Costs		
Overhead	60% of total labor and material costs	190,780
Administration (2% total capital costs)	2% of total capital costs (TCI)	1,794,910
Property tax (1% total capital costs)	1% of total capital costs (TCI)	897,455
Insurance (1% total capital costs)	1% of total capital costs (TCI)	897,455
Capital Recovery	0.0837 for a 20- year equipment life and a 5.5% interest rate	7,652,815
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**11,433,416**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**12,599,932**

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.7 – Table C.7-3: SO_2 Control Spray Dry Absorber (SDA)

Power Station Boiler No. 10

Capital Recovery Factors

Primary Installation	
Interest Rate	5.50%
Equipment Life	20 years
CRF	0.0837

Replacement Parts & Equipment:	**Filter Bags**	
Equipment Life	3 years	
CRF	0.3707	
Rep part cost per unit	228.02 $/bag	
Amount Required	1388	
Total Rep Parts Cost	354,478 Cost adjusted for freight & sales tax	
Installation Labor	31,245 10 min per bag	EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**385,723**	
Annualized Cost	**142,970**	

Electrical Use

	Flow acfm	D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	349,000	10.00			5,533,604	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total					5,533,604	

Reagents and Other Operating Costs

Lime Use Rate	1.30 lb-mole CaO/lb-mole SO2	103.04 lb/hr Lime
Solid Waste Disposal	667 ton/yr GSA unreacted sorbent and reaction byproducts	

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours		8,760			
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	2,190	$ 147,892	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Supervisor	15%	of Op.			NA	$ 22,184	of Op., 0.0 , 8760 hr/yr, 100% utilization
Maintenance							
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	1,095	$ 73,946	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Maint Mtls	100	% of Maintenance Labor			NA	$ 73,946	% of Maintenance Labor, 0.0 , 8760 hr/yr, 100% utilization
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	631.7	kW-hr	5,533,604	$ 403,815	$/kwh, 631.7 kW-hr, 8760 hr/yr, 100% utilization
Compressed Air	0.481	$/kscf	2	scfm/kacfm	366,869	$ 176,601	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization
Water	5.129	$/mgal		gpm			$/mgal, 0 gpm, 8760 hr/yr, 100% utilization
SW Disposal	63.34	$/ton	0.08	ton/hr	667	$ 42,262	$/ton, 0.1 ton/hr, 8760 hr/yr, 100% utilization
Lime	183.68	$/ton	103.0	lb/hr	451	$ 82,901	$/ton, 103.0 lb/hr, 8760 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	1,388	bags	N/A	$ 142,970	$/bag, 1,388 bags, 8760 hr/yr, 100% utilization

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.7 – Table C.7-4: SO_2 Control Dry Sorbent Injection (DSI)

Power Station Boiler No. 10

Operating Unit: **Power Station Boiler No. 10**

Emission Unit Number			Stack/Vent Number		
Design Capacity	650	MMBtu/hr	Standardized Flow Rate	192,498	scfm @ 32º F
Utilization Rate	100%		Exhaust Temperature	432	Deg F
Annual Operating Hours	8,760	hr/yr	Exhaust Moisture Content	13.7%	
Annual Interest Rate	5.50%		Actual Flow Rate	349,000	acfm
Control Equipment Life	20	yrs	Standardized Flow Rate	206,583	scfm @ 68º F
Plant Elevation	610	ft	Dry Std Flow Rate	174,000	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**6,185,600**
Purchased Equipment Total (B)	22%	of control device cost (A)	**7,546,432**
Installation - Standard Costs	74%	of purchased equip cost (B)	5,584,359
Installation - Site Specific Costs			N/A
Installation Total			5,584,359
Total Direct Capital Cost, DC			13,130,791
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	3,924,144
Total Capital Investment (TCI) = DC + IC			**16,669,213**
Adjusted TCI for Replacement Parts			16,669,213
Total Capital Investment (TCI) with Retrofit Factor			**16,669,213**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	1,502,284
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	2,395,387
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**3,897,671**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual Ton/Yr**	**Cont Eff %**	**Cont Emis Ton/Yr**	**Reduction Ton/Yr**	**Cont Cost $/Ton Rem**
PM10						
PM2.5						
Total Particulates						
Nitrous Oxides (NOx)						
Sulfur Dioxide (SO2)	76.15	333.55	70%	100.07	233.49	$16,700
Sulfuric Acid Mist (H2SO4)						
Fluorides						
Volatile Organic Compounds (VOC)						
Carbon Monoxide (CO)						
Lead (Pb)						

Notes & Assumptions

1. Baghouse capital cost estimate based on EPA-R05-OAR-2010-0954-0079, ancillary equipment from other Barr Engineering projects
2. Costs scaled up to design airflow using the 6/10 power law
3. Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.7 – Table C.7-4: SO_2 Control Dry Sorbent Injection (DSI)
Power Station Boiler No. 10

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [1]			**6,185,600**
Purchased Equipment Costs (A) - Injection System + auxiliary equipment, EC			
Instrumentation	10%	Included in vendor estimate	618,560
State Sales Taxes	7.0%	of control device cost (A)	432,992
Freight	5%	of control device cost (A)	309,280
Purchased Equipment Total (B)	22%		**7,546,432**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	301,857
Handling & erection	50%	of purchased equip cost (B)	3,773,216
Electrical	8%	of purchased equip cost (B)	603,715
Piping	1%	of purchased equip cost (B)	75,464
Insulation	7%	of purchased equip cost (B)	528,250
Painting	4%	Included in vendor estimate	301,857
Installation Subtotal Standard Expenses	74%		**5,584,359**
Other Specific Costs (see summary)			
Site Preparation, as required	N/A	Site Specific	
Buildings, as required	N/A	Site Specific	
Lost Production for Tie-In	N/A	Site Specific	
Total Site Specific Costs			N/A
Installation Total			**5,584,359**
Total Direct Capital Cost, DC			**13,130,791**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	754,643
Construction & field expenses	20%	of purchased equip cost (B)	1,509,286
Contractor fees	10%	of purchased equip cost (B)	754,643
Start-up	1%	of purchased equip cost (B)	75,464
Performance test	1%	of purchased equip cost (B)	75,464
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	754,643
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**3,924,144**
Total Capital Investment (TCI) = DC + IC			**17,054,936**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**16,669,213**
Total Capital Investment (TCI) with Retrofit Factor	0%		**16,669,213**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	67.53	$/Hr	147,892
Supervisor	0.15	of Op Labor	22,184
Maintenance			
Maintenance Labor	67.53	$/Hr	73,946
Maintenance Materials	100	% of Maintenance Labor	73,946
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.07	$/kwh, 379.0 kW-hr, 8760 hr/yr, 100% utilization	242,289
N/A			-
Compressed Air	0.48	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization	176,601
N/A			-
Solid Waste Disposal	63.34	$/ton, 0.2 ton/hr, 8760 hr/yr, 100% utilization	94,296
Trona	285.00	$/ton, 423.1 lb/hr, 8760 hr/yr, 100% utilization	528,162
Filter Bags	228.02	$/bag, 1,388 bags, 8760 hr/yr, 100% utilization	142,970
N/A			-
N/A			-
N/A			-
N/A			-
Total Annual Direct Operating Costs			**1,502,284**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	190,780
Administration (2% total capital costs)	2%	of total capital costs (TCI)	333,384
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	166,692
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	166,692
Capital Recovery	0.0837	for a 20-year equipment life and a 5.5% interest rate	1,394,869
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery costs	**2,395,387**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**3,897,671**

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Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.7 – Table C.7-4: SO_2 Control Dry Sorbent Injection (DSI)

Power Station Boiler No. 10

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:	**Filter Bags**	
Equipment Life	3	years
CRF	0.3707	
Rep part cost per unit	228.02	$/bag
Amount Required	1388	Bags
Total Rep Parts Cost	354,478	Cost adjusted for freight, sales tax, and bag disposal
Installation Labor	31,245	20 min per bag
Total Installed Cost	**385,723**	
Annualized Cost	**142,970**	

Electrical Use

	Flow acfm	D P in H2O	kWhr/yr	
Blower	349,000	6.00	3,320,163	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total			3,320,163	

Reagent Use & Other Operating Costs

Trona use - 1.5 NSR	76.15	lb/hr SO2	423.11	lb/hr Trona
Solid Waste Disposal	1,489	ton/yr DSI unreacted sorbent and reaction byproducts		

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours		8,760			
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	2,190	$ 147,892	$/Hr, 2.0 hr/8 hr shift, 2,190 hr/yr
Supervisor	15%	of Op Labor			NA	$ 22,184	% of Operator Costs
Maintenance							
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	1,095	$ 73,946	$/Hr, 1.0 hr/8 hr shift, 1,095 hr/yr
Maint Mtls	100%	of Maintenance Labor			NA	$ 73,946	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	379.0	kW-hr	3,320,163	$ 242,289	$/kwh, 379.0 kW-hr, 8760 hr/yr, 100% utilization
Water			N/A	gpm			
Compressed Air	0.481	$/kscf	2.0	scfm/kacfm	366,869	$ 176,601	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization
Cooling Water			N/A	gpm			
Solid Waste Disposal	63.34	$/ton	0.2	ton/hr	1,489	$ 94,296	$/ton, 0.2 ton/hr, 8760 hr/yr, 100% utilization
Trona	285.00	$/ton	423.1	lb/hr	1,853	$ 528,162	$/ton, 423.1 lb/hr, 8760 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	1,388	bags	N/A	$ 142,970	$/bag, 1,388 bags, 8760 hr/yr, 100% utilization

Appendix C.8

Power Station Boiler No. 11

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.8 – Table C.8-1: Cost Summary
Power Station Boiler No. 11

SO_2 Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Total Annualized Cost $/yr	Pollution Control Cost $/ton
Spray Dry Absorber (SDA)	90%	55.4	498.9	$90,131,245	$12,621,798	$25,298
Dry Sorbent Injection (DSI)	70%	166.3	388.0	$16,488,210	$4,234,824	$10,900

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.8 – Table C.8-2: Summary of Utility, Chemical and Supply Costs

Power Station Boiler No. 11

Operating Unit:	Power Station Boiler No. 11	**Study Year**	2020
Emission Unit Number			
Stack/Vent Number			

Item	2020 Unit Cost	Units	Cost	Year	Data Source	Notes
Operating Labor	68	$/hr	60	2016	EPA SCR Control Cost Manual Spreadsheet	
Maintenance Labor	68	$/hr				Assumed to be equivalent to operating labor
Installation Labor	68	$/hr				Assumed to be equivalent to operating labor
Electricity	0.07	$/kwh			2016-2019 EIA Average prices for the industrial sector in Indiana	
Natural Gas	6.15	$/kscf			2014-2018 EIA Average prices for the Industrial sector in Indiana (latest available 8/20/2020)	
Compressed Air	0.48	$/kscf	0.38	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Chemicals & Supplies						
Lime	183.68	$/ton	145.00	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Trona	285.00	$/ton		2020	Reagent cost for trona from another Barr Engineering Co. Project.	
Fabric Filter Bags	228.02	$/bag	180	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Other						
Sales Tax	7%			2020	Indiana sales tax rate	
Interest Rate	5.50%			2016	EPA SCR Control Cost Manual Spreadsheet	
Solid Waste Disposal	63.34	$/ton	50	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Contingencies	10%	of purchased equip cost (B)			EPA Cost Control Cost Manual Chapter 2	Suggested contingency range of 5% to 15% of total capital investment
Markup on capital investment (retrofit factor)	0%				EPA Cost Control Cost Manual Chapter 2	
Operating Information						
Annual Op. Hrs	8,760	Hours			Emission Inventory Data	
Utilization Rate	100%				Assumed	
Design Capacity	650.0	MMBTU/hr			Boiler Design Capacity	
Equipment Life	20	yrs			Assumed	
Temperature	441	Deg F			Performance test data	
Moisture Content	13.6%				Performance test data	
Actual Flow Rate	323,000	acfm			Performance test data	
Standardized Flow Rate	189,283	scfm @ 68º F	176,377	scfm @ 32º F	Calculated Value	
Dry Std Flow Rate	161,000	dscfm @ 68º F			Performance test data	
Plant Elevation	610	Feet above sea level				Plant elevation
	Baseline Emissions		**lb/hr**	**ton/year**		
Pollutant	**Lb/Hr**	**Ton/Year**	**ppmv**	**ppmv**	**lb/mmbtu**	
Nitrous Oxides (NOx)	43.2	189.0	37	37.4		Emission inventory data
Sulfur Dioxides (SO2)	126.6	554.4	79	78.7		Emission inventory data
SDA - SO_2 Control Efficiency	90%				EPA fact sheet for flue gas desulfurization (new installations) https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf	
DSI - SO_2 Control Efficiency	70%				Control efficiency is based on trona as injected reagent.	

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.8 – Table C.8-3: SO_2 Control Spray Dry Absorber (SDA)

Power Station Boiler No. 11

Operating Unit: **Power Station Boiler No. 11**

Emission Unit Number	0		Stack/Vent Number	0	
Design Capacity	650	MMBtu/hr	Standardized Flow Rate	176,377	scfm @ 32º F
Utilization Rate	100%		Temperature	441	Deg F
Annual Operating Hours	8,760	Hours	Moisture Content	13.6%	
Annual Interest Rate	5.5%		Actual Flow Rate	323,000	acfm
Equipment Life	20	yrs	Standardized Flow Rate	189,283	scfm @ 68º F
			Dry Std Flow Rate	161,000	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**32,689,411**
Purchased Equipment Total (B)	22%	of control device cost (A)	**39,881,082**
Installation - Standard Costs	74%	of purchased equip cost (B)	29,512,001
Installation - Site Specific Costs			NA
Installation Total			29,512,001
Total Direct Capital Cost, DC			69,393,083
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	20,738,163
Total Capital Investment (TCI) = DC + IC			**90,131,245**
Adjusted TCI for Replacment Parts			**89,774,258**
TCI with Retrofit Factor			**89,774,258**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	1,195,479
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	11,426,319
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**12,621,798**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc.**	**Conc. Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10						0.0	-	NA
PM2.5						0.0	-	NA
Total Particulates						0.0	-	NA
Nitrous Oxides (NOx)						0.0	-	NA
Sulfur Dioxide (SO_2)		554.4	90%			55.4	498.9	25,298
Sulfuric Acid Mist						0.00	-	NA
Fluorides						0.0	-	NA
Volatile Organic Compounds (VOC)						0.0	-	NA
Carbon Monoxide (CO)						0.0	-	NA
Lead (Pb)						0.00	-	NA

Notes & Assumptions

1 Capital cost estimate based on mid-range of EPA spray dry fact sheet $/(MMBtu/hr): https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf
2 Costs scaled up to design airflow using the 6/10 power law
3 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.8 – Table C.8-3: SO_2 Control Spray Dry Absorber (SDA)

Power Station Boiler No. 11

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (A) [1]		**32,689,411**
Purchased Equipment Costs (A) - Absorber + packing + auxiliary equipment, EC		
Instrumentation	10% of control device cost (A)	3,268,941
State Sales Taxes	7.0% of control device cost (A)	2,288,259
Freight	5% of control device cost (A)	1,634,471
Purchased Equipment Total (B)	22%	**39,881,082**
Installation		
Foundations & supports	4% of purchased equip cost (B)	1,595,243
Handling & erection	50% of purchased equip cost (B)	19,940,541
Electrical	8% of purchased equip cost (B)	3,190,487
Piping	1% of purchased equip cost (B)	398,811
Insulation	7% of purchased equip cost (B)	2,791,676
Painting	4% of purchased equip cost (B)	1,595,243
Installation Subtotal Standard Expenses	74%	**29,512,001**
Other Specific Costs (see summary)		
Site Preparation, as required	N/A Site Specific	-
Buildings, as required	N/A Site Specific	-
Site Specific - Other	N/A Site Specific	-
Total Site Specific Costs		NA
Installation Total		**29,512,001**
Total Direct Capital Cost, DC		**69,393,083**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	3,988,108
Construction & field expenses	20% of purchased equip cost (B)	7,976,216
Contractor fees	10% of purchased equip cost (B)	3,988,108
Start-up	1% of purchased equip cost (B)	398,811
Performance test	1% of purchased equip cost (B)	398,811
Model Studies	N/A of purchased equip cost (B)	-
Contingencies	10% of purchased equip cost (B)	3,988,108
Total Indirect Capital Costs, IC	52% of purchased equip cost (B)	**20,738,163**
Total Capital Investment (TCI) = DC + IC		**90,131,245**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		**89,774,258**
Total Capital Investment (TCI) with Retrofit Factor	0%	**89,774,258**
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	67.53 $/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	147,892
Supervisor	15% of Op., 0.0 , 8760 hr/yr, 100% utilization	22,184
Maintenance		
Maintenance Labor	67.53 $/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	73,946
Maintenance Materials	100% of maintenance labor costs	73,946
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.07 $/kwh, 584.6 kW-hr, 8760 hr/yr, 100% utilization	373,731
Compressed Air	0.48 $/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization	163,444
N/A		-
SW Disposal	63.34 $/ton, 0.1 ton/hr, 8760 hr/yr, 100% utilization	70,238
Lime	183.68 $/ton, 171.3 lb/hr, 8760 hr/yr, 100% utilization	137,780
Filter Bags	228.02 $/bag, 1,285 bags, 8760 hr/yr, 100% utilization	132,319
N/A		
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
Total Annual Direct Operating Costs		**1,195,479**
Indirect Operating Costs		
Overhead	60% of total labor and material costs	190,780
Administration (2% total capital costs)	2% of total capital costs (TCI)	1,795,485
Property tax (1% total capital costs)	1% of total capital costs (TCI)	897,743
Insurance (1% total capital costs)	1% of total capital costs (TCI)	897,743
Capital Recovery	0.0837 for a 20- year equipment life and a 5.5% interest rate	7,644,568
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**11,426,319**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**12,621,798**

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.8 – Table C.8-3: SO_2 Control Spray Dry Absorber (SDA)

Power Station Boiler No. 11

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:	**Filter Bags**		
Equipment Life	3	years	
CRF	0.3707		
Rep part cost per unit	228.02	$/bag	
Amount Required	1285		
Total Rep Parts Cost	328,070	Cost adjusted for freight & sales tax	
Installation Labor	28,917	10 min per bag	EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**356,987**		
Annualized Cost	**132,319**		

Electrical Use

	Flow acfm	D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	323,000	10.00			5,121,359	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total					5,121,359	

Reagents and Other Operating Costs

Lime Use Rate	1.30 lb-mole CaO/lb-mole SO2	171.26 lb/hr Lime
Solid Waste Disposal	1,109 ton/yr GSA unreacted sorbent and reaction byproducts	

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours		8,760			
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	2,190	$ 147,892	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Supervisor	15%	of Op.			NA	$ 22,184	of Op., 0.0 , 8760 hr/yr, 100% utilization
Maintenance							
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	1,095	$ 73,946	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Maint Mtls	100	% of Maintenance Labor			NA	$ 73,946	% of Maintenance Labor, 0.0 , 8760 hr/yr, 100% utilization
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	584.6	kW-hr	5,121,359	$ 373,731	$/kwh, 584.6 kW-hr, 8760 hr/yr, 100% utilization
Compressed Air	0.481	$/kscf	2	scfm/kacfm	339,538	$ 163,444	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization
Water	5.129	$/mgal		gpm			$/mgal, 0 gpm, 8760 hr/yr, 100% utilization
SW Disposal	63.34	$/ton	0.13	ton/hr	1,109	$ 70,238	$/ton, 0.1 ton/hr, 8760 hr/yr, 100% utilization
Lime	183.68	$/ton	171.3	lb/hr	750	$ 137,780	$/ton, 171.3 lb/hr, 8760 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	1,285	bags	N/A	$ 132,319	$/bag, 1,285 bags, 8760 hr/yr, 100% utilization

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Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.8 – Table C.8-4: SO_2 Control Dry Sorbent Injection (DSI)

Power Station Boiler No. 11

Operating Unit: **Power Station Boiler No. 11**

Emission Unit Number			Stack/Vent Number		
Design Capacity	650	MMBtu/hr	Standardized Flow Rate	176,377	scfm @ 32º F
Utilization Rate	100%		Exhaust Temperature	441	Deg F
Annual Operating Hours	8,760	hr/yr	Exhaust Moisture Content	13.6%	
Annual Interest Rate	5.50%		Actual Flow Rate	323,000	acfm
Control Equipment Life	20	yrs	Standardized Flow Rate	189,283	scfm @ 68º F
Plant Elevation	610	ft	Dry Std Flow Rate	161,000	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**6,109,530**
Purchased Equipment Total (B)	22%	of control device cost (A)	**7,453,627**
Installation - Standard Costs	74%	of purchased equip cost (B)	5,515,684
Installation - Site Specific Costs			N/A
Installation Total			5,515,684
Total Direct Capital Cost, DC			12,969,311
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	3,875,886
Total Capital Investment (TCI) = DC + IC			**16,488,210**
Adjusted TCI for Replacement Parts			16,488,210
Total Capital Investment (TCI) with Retrofit Factor			**16,488,210**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	1,872,475
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	2,362,350
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,234,824**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual Ton/Yr**	**Cont Eff %**	**Cont Emis Ton/Yr**	**Reduction Ton/Yr**	**Cont Cost $/Ton Rem**
PM10						
PM2.5						
Total Particulates						
Nitrous Oxides (NOx)						
Sulfur Dioxide (SO2)	126.56	554.35	70%	166.31	388.05	$10,900
Sulfuric Acid Mist (H2SO4)						
Fluorides						
Volatile Organic Compounds (VOC)						
Carbon Monoxide (CO)						
Lead (Pb)						

Notes & Assumptions

1. Baghouse capital cost estimate based on EPA-R05-OAR-2010-0954-0079, ancillary equipment from other Barr Engineering projects
2. Costs scaled up to design airflow using the 6/10 power law
3. Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.8 – Table C.8-4: SO_2 Control Dry Sorbent Injection (DSI)

Power Station Boiler No. 11

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [1]			**6,109,530**
Purchased Equipment Costs (A) - Injection System + auxiliary equipment, EC			
Instrumentation	10%	Included in vendor estimate	610,953
State Sales Taxes	7.0%	of control device cost (A)	427,667
Freight	5%	of control device cost (A)	305,477
Purchased Equipment Total (B)	22%		**7,453,627**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	298,145
Handling & erection	50%	of purchased equip cost (B)	3,726,813
Electrical	8%	of purchased equip cost (B)	596,290
Piping	1%	of purchased equip cost (B)	74,536
Insulation	7%	of purchased equip cost (B)	521,754
Painting	4%	Included in vendor estimate	298,145
Installation Subtotal Standard Expenses	74%		**5,515,684**
Other Specific Costs (see summary)			
Site Preparation, as required	N/A	Site Specific	
Buildings, as required	N/A	Site Specific	
Lost Production for Tie-In	N/A	Site Specific	
Total Site Specific Costs			N/A
Installation Total			**5,515,684**
Total Direct Capital Cost, DC			**12,969,311**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	745,363
Construction & field expenses	20%	of purchased equip cost (B)	1,490,725
Contractor fees	10%	of purchased equip cost (B)	745,363
Start-up	1%	of purchased equip cost (B)	74,536
Performance test	1%	of purchased equip cost (B)	74,536
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	745,363
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**3,875,886**
Total Capital Investment (TCI) = DC + IC			**16,845,196**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**16,488,210**
Total Capital Investment (TCI) with Retrofit Factor	0%		**16,488,210**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	67.53	$/Hr	147,892
Supervisor	0.15	of Op Labor	22,184
Maintenance			
Maintenance Labor	67.53	$/Hr	73,946
Maintenance Materials	100	% of Maintenance Labor	73,946
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.07	$/kwh, 350.8 kW-hr, 8760 hr/yr, 100% utilization	224,239
N/A			-
Compressed Air	0.48	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization	163,444
N/A			-
Solid Waste Disposal	63.34	$/ton, 0.3 ton/hr, 8760 hr/yr, 100% utilization	156,716
Trona	285.00	$/ton, 703.2 lb/hr, 8760 hr/yr, 100% utilization	877,789
Filter Bags	228.02	$/bag, 1,285 bags, 8760 hr/yr, 100% utilization	132,319
N/A			-
N/A			-
N/A			-
N/A			-
Total Annual Direct Operating Costs			**1,872,475**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	190,780
Administration (2% total capital costs)	2%	of total capital costs (TCI)	329,764
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	164,882
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	164,882
Capital Recovery	0.0837	for a 20-year equipment life and a 5.5% interest rate	1,379,722
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery costs	**2,362,350**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,234,824**

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Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.8 – Table C.8-4: SO_2 Control Dry Sorbent Injection (DSI)

Power Station Boiler No. 11

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment: Filter Bags

Equipment Life	3	years
CRF	0.3707	
Rep part cost per unit	228.02	$/bag
Amount Required	1285	Bags
Total Rep Parts Cost	328,070	Cost adjusted for freight, sales tax, and bag disposal
Installation Labor	28,917	20 min per bag
Total Installed Cost	**356,987**	
Annualized Cost	**132,319**	

Electrical Use

	Flow acfm	D P in H2O	kWhr/yr	
Blower	323,000	6.00	3,072,815	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total			3,072,815	

Reagent Use & Other Operating Costs

Trona use - 1.5 NSR	126.56 lb/hr SO2	703.19 lb/hr Trona
Solid Waste Disposal	2,474 ton/yr DSI unreacted sorbent and reaction byproducts	

Operating Cost Calculations

Utilization Rate: 100% | Annual Operating Hours: 8,760

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	2,190	$ 147,892	$/Hr, 2.0 hr/8 hr shift, 2,190 hr/yr
Supervisor	15%	of Op Labor			NA	$ 22,184	% of Operator Costs
Maintenance							
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	1,095	$ 73,946	$/Hr, 1.0 hr/8 hr shift, 1,095 hr/yr
Maint Mtls	100%	of Maintenance Labor			NA	$ 73,946	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	350.8	kW-hr	3,072,815	$ 224,239	$/kwh, 350.8 kW-hr, 8760 hr/yr, 100% utilization
Water			N/A	gpm			
Compressed Air	0.481	$/kscf	2.0	scfm/kacfm	339,538	$ 163,444	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization
Cooling Water			N/A	gpm			
Solid Waste Disposal	63.34	$/ton	0.3	ton/hr	2,474	$ 156,716	$/ton, 0.3 ton/hr, 8760 hr/yr, 100% utilization
Trona	285.00	$/ton	703.2	lb/hr	3,080	$ 877,789	$/ton, 703.2 lb/hr, 8760 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	1,285	bags	N/A	$ 132,319	$/bag, 1,285 bags, 8760 hr/yr, 100% utilization

Appendix C.9

Power Station Boiler No. 12

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Control
Appendix C.9 – Table C.9-1: Cost Summary
Power Station Boiler No. 12

SO_2 Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Total Annualized Cost $/yr	Pollution Control Cost $/ton
Spray Dry Absorber (SDA)	90%	70.3	632.5	$90,131,245	$12,855,776	$20,325
Dry Sorbent Injection (DSI)	70%	210.8	492.0	$18,715,200	$4,940,776	$10,000

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Control
Appendix C.9 – Table C.9-2: Summary of Utility, Chemical and Supply Costs
Power Station Boiler No. 12

Operating Unit:	Power Station Boiler No. 12	**Study Year**	2020
Emission Unit Number			
Stack/Vent Number			

Item	2020 Unit Cost	Units	Cost	Year	Data Source	Notes
Operating Labor	68	$/hr	60	2016	EPA SCR Control Cost Manual Spreadsheet	
Maintenance Labor	68	$/hr				Assumed to be equivalent to operating labor
Installation Labor	68	$/hr				Assumed to be equivalent to operating labor
Electricity	0.07	$/kwh			2016-2019 EIA Average prices for the industrial sector in Indiana	
Natural Gas	6.15	$/kscf			2014-2018 EIA Average prices for the Industrial sector in Indiana (latest available 8/20/2020)	
Compressed Air	0.48	$/kscf	0.38	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Chemicals & Supplies						
Lime	183.68	$/ton	145.00	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Trona	285.00	$/ton		2020	Reagent cost for trona from another Barr Engineering Co. Project.	
Fabric Filter Bags	228.02	$/bag	180	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Other						
Sales Tax	7%			2020	Indiana sales tax rate	
Interest Rate	5.50%			2016	EPA SCR Control Cost Manual Spreadsheet	
Solid Waste Disposal	63.34	$/ton	50	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Contingencies	10%	of purchased equip cost (B)			EPA Cost Control Cost Manual Chapter 2	Suggested contingency range of 5% to 15% of total capital investment
Markup on capital investment (retrofit factor)	0%				EPA Cost Control Cost Manual Chapter 2	
Operating Information						
Annual Op. Hrs	8,760	Hours			Emission Inventory Data	
Utilization Rate	100%				Assumed	
Design Capacity	650.0	MMBTU/hr			Boiler Design Capacity	
Equipment Life	20	yrs			Assumed	
Temperature	421	Deg F			Performance test data	
Moisture Content	11.3%				Performance test data	
Actual Flow Rate	399,000	acfm			Performance test data	
Standardized Flow Rate	239,128	scfm @ 68º F	222,824	scfm @ 32º F	Calculated Value	
Dry Std Flow Rate	202,000	dscfm @ 68º F			Performance test data	
Plant Elevation	610	Feet above sea level				Plant elevation
	Baseline Emissions		**lb/hr**	**ton/year**		
Pollutant	**Lb/Hr**	**Ton/Year**	**ppmv**	**ppmv**	**lb/mmbtu**	
Nitrous Oxides (NOx)	46.6	204.0	32	32.2		Emission inventory data
Sulfur Dioxides (SO2)	160.5	702.8	80	79.6		Emission inventory data
SDA - SO_2 Control Efficiency	90%				EPA fact sheet for flue gas desulfurization (new installations) https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf	
DSI - SO_2 Control Efficiency	70%				Control efficiency is based on trona as injected reagent.	

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Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Control

Appendix C.9 – Table C.9-3: SO_2 Control Spray Dry Absorber (SDA)

Power Station Boiler No. 12

Operating Unit: **Power Station Boiler No. 12**

Emission Unit Number	0		Stack/Vent Number	0	
Design Capacity	650	MMBtu/hr	Standardized Flow Rate	222,824	scfm @ 32º F
Utilization Rate	100%		Temperature	421	Deg F
Annual Operating Hours	8,760	Hours	Moisture Content	11.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	399,000	acfm
Equipment Life	20	yrs	Standardized Flow Rate	239,128	scfm @ 68º F
			Dry Std Flow Rate	202,000	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**32,689,411**
Purchased Equipment Total (B)	22%	of control device cost (A)	**39,881,082**
Installation - Standard Costs	74%	of purchased equip cost (B)	29,512,001
Installation - Site Specific Costs			NA
Installation Total			29,512,001
Total Direct Capital Cost, DC			69,393,083
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	20,738,163
Total Capital Investment (TCI) = DC + IC			**90,131,245**
Adjusted TCI for Replacment Parts			**89,690,262**
TCI with Retrofit Factor			**89,690,262**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	1,408,712
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	11,447,064
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**12,855,776**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc.**	**Conc. Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10						0.0	-	NA
PM2.5						0.0	-	NA
Total Particulates						0.0	-	NA
Nitrous Oxides (NOx)						0.0	-	NA
Sulfur Dioxide (SO_2)		702.8	90%			70.3	632.5	20,325
Sulfuric Acid Mist						0.00	-	NA
Fluorides						0.0	-	NA
Volatile Organic Compounds (VOC)						0.0	-	NA
Carbon Monoxide (CO)						0.0	-	NA
Lead (Pb)						0.00	-	NA

Notes & Assumptions

1 Capital cost estimate based on mid-range of EPA spray dry fact sheet $/(MMBtu/hr): https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf
2 Costs scaled up to design airflow using the 6/10 power law
3 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Control
Appendix C.9 – Table C.9-3: SO_2 Control Spray Dry Absorber (SDA)
Power Station Boiler No. 12

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (A) [1]		**32,689,411**
Purchased Equipment Costs (A) - Absorber + packing + auxiliary equipment, EC		
Instrumentation	10% of control device cost (A)	3,268,941
State Sales Taxes	7.0% of control device cost (A)	2,288,259
Freight	5% of control device cost (A)	1,634,471
Purchased Equipment Total (B)	22%	**39,881,082**
Installation		
Foundations & supports	4% of purchased equip cost (B)	1,595,243
Handling & erection	50% of purchased equip cost (B)	19,940,541
Electrical	8% of purchased equip cost (B)	3,190,487
Piping	1% of purchased equip cost (B)	398,811
Insulation	7% of purchased equip cost (B)	2,791,676
Painting	4% of purchased equip cost (B)	1,595,243
Installation Subtotal Standard Expenses	74%	**29,512,001**
Other Specific Costs (see summary)		
Site Preparation, as required	N/A Site Specific	-
Buildings, as required	N/A Site Specific	-
Site Specific - Other	N/A Site Specific	-
Total Site Specific Costs		NA
Installation Total		**29,512,001**
Total Direct Capital Cost, DC		**69,393,083**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	3,988,108
Construction & field expenses	20% of purchased equip cost (B)	7,976,216
Contractor fees	10% of purchased equip cost (B)	3,988,108
Start-up	1% of purchased equip cost (B)	398,811
Performance test	1% of purchased equip cost (B)	398,811
Model Studies	N/A of purchased equip cost (B)	-
Contingencies	10% of purchased equip cost (B)	3,988,108
Total Indirect Capital Costs, IC	52% of purchased equip cost (B)	**20,738,163**
Total Capital Investment (TCI) = DC + IC		**90,131,245**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		**89,690,262**
Total Capital Investment (TCI) with Retrofit Factor	0%	**89,690,262**
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	67.53 $/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	147,892
Supervisor	15% of Op., 0.0 , 8760 hr/yr, 100% utilization	22,184
Maintenance		
Maintenance Labor	67.53 $/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	73,946
Maintenance Materials	100% of maintenance labor costs	73,946
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.07 $/kwh, 722.2 kW-hr, 8760 hr/yr, 100% utilization	461,668
Compressed Air	0.48 $/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization	201,902
N/A		-
SW Disposal	63.34 $/ton, 0.2 ton/hr, 8760 hr/yr, 100% utilization	89,047
Lime	183.68 $/ton, 217.1 lb/hr, 8760 hr/yr, 100% utilization	174,676
Filter Bags	228.02 $/bag, 1,587 bags, 8760 hr/yr, 100% utilization	163,452
N/A		
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
Total Annual Direct Operating Costs		**1,408,712**
Indirect Operating Costs		
Overhead	60% of total labor and material costs	190,780
Administration (2% total capital costs)	2% of total capital costs (TCI)	1,793,805
Property tax (1% total capital costs)	1% of total capital costs (TCI)	896,903
Insurance (1% total capital costs)	1% of total capital costs (TCI)	896,903
Capital Recovery	0.0837 for a 20- year equipment life and a 5.5% interest rate	7,668,673
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**11,447,064**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**12,855,776**

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Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Control

Appendix C.9 – Table C.9-3: SO_2 Control Spray Dry Absorber (SDA)

Power Station Boiler No. 12

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:	**Filter Bags**		
Equipment Life	3	years	
CRF	0.3707		
Rep part cost per unit	228.02	$/bag	
Amount Required	1587		
Total Rep Parts Cost	405,262	Cost adjusted for freight & sales tax	
Installation Labor	35,721	10 min per bag	EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**440,984**		
Annualized Cost	**163,452**		

Electrical Use

	Flow acfm	D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	399,000	10.00			6,326,384	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total					6,326,384	

Reagents and Other Operating Costs

Lime Use Rate	1.30	lb-mole CaO/lb-mole SO2	217.12 lb/hr Lime
Solid Waste Disposal	1,406	ton/yr GSA unreacted sorbent and reaction byproducts	

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours		8,760			
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	2,190	$ 147,892	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Supervisor	15%	of Op.			NA	$ 22,184	of Op., 0.0 , 8760 hr/yr, 100% utilization
Maintenance							
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	1,095	$ 73,946	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Maint Mtls	100	% of Maintenance Labor			NA	$ 73,946	% of Maintenance Labor, 0.0 , 8760 hr/yr, 100% utilization
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	722.2	kW-hr	6,326,384	$ 461,668	$/kwh, 722.2 kW-hr, 8760 hr/yr, 100% utilization
Compressed Air	0.481	$/kscf	2	scfm/kacfm	419,429	$ 201,902	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization
Water	5.129	$/mgal		gpm			$/mgal, 0 gpm, 8760 hr/yr, 100% utilization
SW Disposal	63.34	$/ton	0.16	ton/hr	1,406	$ 89,047	$/ton, 0.2 ton/hr, 8760 hr/yr, 100% utilization
Lime	183.68	$/ton	217.1	lb/hr	951	$ 174,676	$/ton, 217.1 lb/hr, 8760 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	1,587	bags	N/A	$ 163,452	$/bag, 1,587 bags, 8760 hr/yr, 100% utilization

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Control

Appendix C.9 – Table C.9-4: SO_2 Control Dry Sorbent Injection (DSI)

Power Station Boiler No. 12

Operating Unit: **Power Station Boiler No. 12**

Emission Unit Number			Stack/Vent Number		
Design Capacity	650	MMBtu/hr	Standardized Flow Rate	222,824	scfm @ 32º F
Utilization Rate	100%		Exhaust Temperature	421	Deg F
Annual Operating Hours	8,760	hr/yr	Exhaust Moisture Content	11.3%	
Annual Interest Rate	5.50%		Actual Flow Rate	399,000	acfm
Control Equipment Life	20	yrs	Standardized Flow Rate	239,128	scfm @ 68º F
Plant Elevation	610	ft	Dry Std Flow Rate	202,000	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**6,947,695**
Purchased Equipment Total (B)	22%	of control device cost (A)	**8,476,187**
Installation - Standard Costs	74%	of purchased equip cost (B)	6,272,379
Installation - Site Specific Costs			N/A
Installation Total			6,272,379
Total Direct Capital Cost, DC			14,748,566
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	4,407,617
Total Capital Investment (TCI) = DC + IC			**18,715,200**
Adjusted TCI for Replacement Parts			18,715,200
Total Capital Investment (TCI) with Retrofit Factor			**18,715,200**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	2,271,859
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	2,668,916
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,940,776**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual Ton/Yr**	**Cont Eff %**	**Cont Emis Ton/Yr**	**Reduction Ton/Yr**	**Cont Cost $/Ton Rem**
PM10						
PM2.5						
Total Particulates						
Nitrous Oxides (NOx)						
Sulfur Dioxide (SO2)	160.46	702.80	70%	210.84	491.96	$10,000
Sulfuric Acid Mist (H2SO4)						
Fluorides						
Volatile Organic Compounds (VOC)						
Carbon Monoxide (CO)						
Lead (Pb)						

Notes & Assumptions

1 Baghouse capital cost estimate based on EPA-R05-OAR-2010-0954-0079, ancillary equipment from other Barr Engineering projects
2 Costs scaled up to design airflow using the 6/10 power law
3 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Control
Appendix C.9 – Table C.9-4: SO_2 Control Dry Sorbent Injection (DSI)
Power Station Boiler No. 12

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [(1)]			**6,947,695**
Purchased Equipment Costs (A) - Injection System + auxiliary equipment, EC			
Instrumentation	10%	Included in vendor estimate	694,769
State Sales Taxes	7.0%	of control device cost (A)	486,339
Freight	5%	of control device cost (A)	347,385
Purchased Equipment Total (B)	22%		**8,476,187**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	339,047
Handling & erection	50%	of purchased equip cost (B)	4,238,094
Electrical	8%	of purchased equip cost (B)	678,095
Piping	1%	of purchased equip cost (B)	84,762
Insulation	7%	of purchased equip cost (B)	593,333
Painting	4%	Included in vendor estimate	339,047
Installation Subtotal Standard Expenses	74%		**6,272,379**
Other Specific Costs (see summary)			
Site Preparation, as required	N/A	Site Specific	
Buildings, as required	N/A	Site Specific	
Lost Production for Tie-In	N/A	Site Specific	
Total Site Specific Costs			N/A
Installation Total			**6,272,379**
Total Direct Capital Cost, DC			**14,748,566**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	847,619
Construction & field expenses	20%	of purchased equip cost (B)	1,695,237
Contractor fees	10%	of purchased equip cost (B)	847,619
Start-up	1%	of purchased equip cost (B)	84,762
Performance test	1%	of purchased equip cost (B)	84,762
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	847,619
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**4,407,617**
Total Capital Investment (TCI) = DC + IC			**19,156,183**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**18,715,200**
Total Capital Investment (TCI) with Retrofit Factor	0%		**18,715,200**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	67.53	$/Hr	147,892
Supervisor	0.15	of Op Labor	22,184
Maintenance			
Maintenance Labor	67.53	$/Hr	73,946
Maintenance Materials	100	% of Maintenance Labor	73,946
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.07	$/kwh, 433.3 kW-hr, 8760 hr/yr, 100% utilization	277,001
N/A			-
Compressed Air	0.48	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization	201,902
N/A			-
Solid Waste Disposal	63.34	$/ton, 0.4 ton/hr, 8760 hr/yr, 100% utilization	198,684
Trona	285.00	$/ton, 891.5 lb/hr, 8760 hr/yr, 100% utilization	1,112,854
Filter Bags	228.02	$/bag, 1,587 bags, 8760 hr/yr, 100% utilization	163,452
N/A			-
N/A			-
N/A			-
N/A			-
Total Annual Direct Operating Costs			**2,271,859**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	190,780
Administration (2% total capital costs)	2%	of total capital costs (TCI)	374,304
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	187,152
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	187,152
Capital Recovery	0.0837	for a 20-year equipment life and a 5.5% interest rate	1,566,075
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery costs	**2,668,916**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,940,776**

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Control

Appendix C.9 – Table C.9-4: SO_2 Control Dry Sorbent Injection (DSI)

Power Station Boiler No. 12

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment: Filter Bags

Equipment Life	3	years
CRF	0.3707	
Rep part cost per unit	228.02	$/bag
Amount Required	1587	Bags
Total Rep Parts Cost	405,262	Cost adjusted for freight, sales tax, and bag disposal
Installation Labor	35,721	20 min per bag
Total Installed Cost	**440,984**	
Annualized Cost	**163,452**	

Electrical Use

	Flow acfm	D P in H2O	kWhr/yr	
Blower	399,000	6.00	3,795,831	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total			3,795,831	

Reagent Use & Other Operating Costs

Trona use - 1.5 NSR	160.46	lb/hr SO2	891.50	lb/hr Trona
Solid Waste Disposal	3,137	ton/yr DSI unreacted sorbent and reaction byproducts		

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours		8,760			
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	2,190	$ 147,892	$/Hr, 2.0 hr/8 hr shift, 2,190 hr/yr
Supervisor	15%	of Op Labor			NA	$ 22,184	% of Operator Costs
Maintenance							
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	1,095	$ 73,946	$/Hr, 1.0 hr/8 hr shift, 1,095 hr/yr
Maint Mtls	100%	of Maintenance Labor			NA	$ 73,946	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	433.3	kW-hr	3,795,831	$ 277,001	$/kwh, 433.3 kW-hr, 8760 hr/yr, 100% utilization
Water			N/A	gpm			
Compressed Air	0.481	$/kscf	2.0	scfm/kacfm	419,429	$ 201,902	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization
Cooling Water			N/A	gpm			
Solid Waste Disposal	63.34	$/ton	0.4	ton/hr	3,137	$ 198,684	$/ton, 0.4 ton/hr, 8760 hr/yr, 100% utilization
Trona	285.00	$/ton	891.5	lb/hr	3,905	$ 1,112,854	$/ton, 891.5 lb/hr, 8760 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	1,587	bags	N/A	$ 163,452	$/bag, 1,587 bags, 8760 hr/yr, 100% utilization

Appendix D

2008 ArcelorMittal Burns Harbor BART Modeling Report

Prepared for: ArcelorMittal Burns Harbor LLC
Burns Harbor, Indiana

Source-Specific BART Modeling Report: ArcelorMittal Burns Harbor LLC

ENSR Corporation
August 2008
Document No.: 12591-001-0600

ENSR | AECOM

Prepared for: Mittal Steel USA
Burns Harbor, Indiana

Source-Specific BART Modeling Report: ArcelorMittal Burns Harbor LLC

Prepared By: Jeffrey Connors

Reviewed By: Olga Kostrova

ENSR Corporation
August 2008
Document No.: 12591-001-0600

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1.0 Introduction

1.1 Objectives

The Regional Haze Rule regulations require Best Available Retrofit Technology (BART) for any BART-eligible source that "emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility" in any mandatory Class I federal area. Pursuant to federal regulations, states and/or local regulatory agencies have the option of exempting a BART-eligible source from the BART requirements based on dispersion modeling demonstrating that the source cannot reasonably be anticipated to cause or contribute to visibility impairment in a Class I area. Indiana's BART rule at 326 IAC 26-1-6 allows Burns Harbor to submit an analysis sufficient to demonstrate that it is not subject to BART. That analysis was timely submitted in May 2008 within ninety (90) days after receiving IDEM's BART notice. IDEM identified some outdated emission factors that were inadvertently included in the May 2008 Report. This revised Source-Specific BART Modeling Report updates the May 2008 Report with improved model inputs based on the most recent and accurate emission information available for each emissions unit.

ArcelorMittal Burns Harbor LLC (Burns Harbor) is a facility located on Lake Michigan in northwestern Indiana, approximately 50 miles southeast of Chicago. The Burns Harbor facility is a steelmaking facility that has been identified by Indiana Department of Environmental Management (IDEM) as being a BART-eligible source. The purpose of this Report is to summarize the procedures by which a refined air dispersion modeling analysis was conducted for the Burns Harbor facility and to transmit an analysis of the modeling results in accordance with 326 IAC 26-1-6 in support of a refined assessment of Burns Harbor's contribution to visibility impairment in Class I areas.

The first step in the BART process is to model the visibility impact of baseline emissions to determine whether the BART-eligible sources at a facility are subject to BART. According to the BART rule (326 IAC 26-1-4), a facility will be exempt from BART if its 98th percentile visibility impacts for baseline emissions are less than 0.5 delta-deciviews (delta-dv) in each Class I area for each modeled year. The refined modeling provided in this Report demonstrates that Burns Harbor's impact on all relevant Class I Areas is comfortably below 0.5 deciviews and cannot reasonably be anticipated to cause or contribute to visibility impairment in a Class I Area.

1.2 Location of Source vs. Relevant Class I Areas

Figure 1-1 shows a plot of the Burns Harbor facility relative to nearby Class I areas. There are no PSD Class I areas within 300 km of the facility, which is the outer extent of the reliability range for predicting impacts with CALPUFF air dispersion modeling. Nonetheless, the four closest Class I areas were included in the modeling to capture possible impacts from the Burns Harbor facility. These Class I areas are listed below:

- Isle Royale National Park (674 km)
- Mammoth Cave National Park (485 km)
- Mingo Wilderness (580 km)
- Seney Wilderness (539 km)

IDEM's CALPUFF modeling screened for potential contributions to visibility impairment from the Burns Harbor facility at these four Class I areas. The refined modeling summarized in this Report offers a more accurate assessment of the potential contribution of Burns Harbor to visibility impairments at any of these far-off Class I areas. This Report describes in detail the procedures used for this refined CALPUFF modeling.

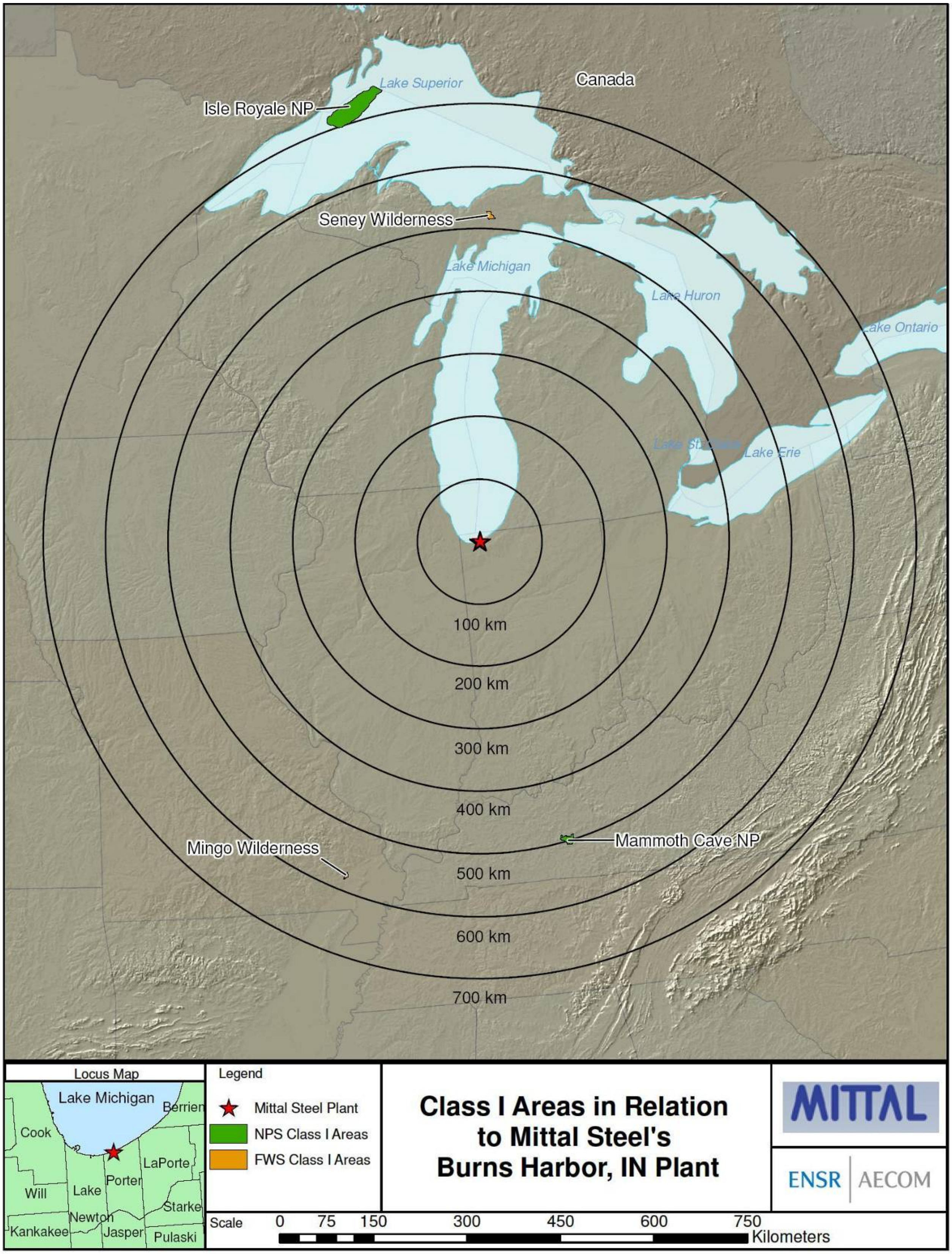
CALPUFF is the only EPA-approved model for predicting impacts for long-range emission transport beyond 50 km. The Guideline on Air Quality Models (GAQM) (Appendix W to 40 CFR Part 51) suggests that CALPUFF "had performed in a reasonable manner, and had no apparent bias toward over or under prediction, so long as the transport distance was limited to less than 300 km". Beyond 300 km, CALPUFF's modeled impacts are less reliable with a tendency toward over predicting impacts.

The closest Class I area is Mammoth Cave NP, located approximately 485 km to the south-southeast well beyond the suggested use of CALPUFF. The modeling analysis in this Report uses CALPUFF as directed by the Midwest Regional Planning Organization (MWRPO) and IDEM with the stipulation that the model's performance has tended toward over prediction of modeled impacts beyond 300 km and the fact that the federal Guidance suggests that its use beyond 300 km may not be reliable or appropriate.

1.3 Organization of Report

Section 2 of this report describes the method for determining the peak 24-hour source emissions that were used as input to the BART modeling. Section 3 describes refinements to the meteorological database and the CALMET processing that provide essential data for predicting the transport of emissions. Section 4 discusses CALPUFF technical options and modeling procedures. Section 5 presents the modeling results. References are provided in Section 6. Appendix A lists meteorological stations that were used for CALMET processing and Appendix B provides documentation of the implementation of the new IMPROVE equation. Appendix C provides a detailed description of the method used to derive the oxides of nitrogen and sulfur dioxide inputs to the model.

Figure 1-1 Location of Class I Areas in Relation the Burns Harbor Facility



2.0 Emissions and Source Parameters

The Lake Michigan Air Directors Consortium (LADCO) developed a protocol to be used in the BART CALPUFF modeling for Indiana. The LADCO protocol specifies that "States will use the 24-hour maximum emissions rate between 2002 and 2004. If this data is not available, then a short term "allowable" or "potential emission rate of emissions between the years 2002-2004 will be used. If neither of these types of emission rates is available, then the highest actual annual emissions divided by hours of operation will be applied in CALPUFF." For this Report, we calculate the 24-hour maximum emission rate for the years 2002-2004.

Emission units included in the modeling are of two main types, combustion units and process units. Combustion unit emissions are calculated using actual daily fuel use records from Burns Harbor's computerized database for 2002, 2003, and 2004 and relevant emission factors. The emission factors for combustions units are based on fuel sampling, stack testing, or U.S. EPA's AP-42 (see Table 2-4). The 24-hour emission rate was determined by multiplying the daily fuel use day for each fuel used that day by the appropriate emission factor for each combustion unit for 2002, 2003 and 2004. Emission for each fuel used was summed to determine the total emissions for each unit by day. The 24-hour maximum emission rate was determined by selecting the highest total emissions day for each unit and were used as the maximum 24-hour emissions inputs to the CALPUFF model.

Burns Harbor's Power Station contains multi-fuel Boiler Nos. 7 through 12. The Power Station is operated as one unit with switching between boilers as necessary to provide the needed steam and to maintain backup capabilities. Consequently, fuel use and emissions calculations were determined for the entire Power Station rather than for individual boilers to more accurately reflect 24-hour maximum emissions.

Process unit emissions are calculated using the maximum 24-hour production rate for each process unit during 2002, 2003 and 2004 and appropriate emission factors per unit of production. The process emission factors were derived from stack tests on the same or similar units and from AP-42 emission factors (see Table 2-5). For smaller incidental units (e.g., FM Boiler, Hot Metal Desulfurization, etc.) where only monthly production data were available, the average daily production was calculated by dividing the monthly production by the number of days in the period. The day with the highest calculated sulfur dioxide emission rate and the day with the highest oxides of nitrogen emissions rate from 2002, 2003 or 2004 were selected for each process unit as the maximum 24-hour emission inputs to the CALPUFF model.

Emissions from slag pits and steelmaking fugitives that do not vent through stacks are "volume" sources (see Table 2-1). Without stacks, volume sources have limited velocity at the point of emission and are, thus, not expected to be transported very far away from the emission source. As such, we do not expect these volume sources to contribute to visibility impacts that require the transport of emissions to Class I areas over 480 km away. Nonetheless, we conservatively included the emissions from volume sources in the modeling by adding their emissions to the combustion emissions from the Power Station.

This method combines the highest daily emission rates for each of 26 emission units (+3 volume sources) into a fictitious worst case day. A complex steel manufacturer cannot simultaneously achieve the 24-hour maximum emission rate at all 26+ emission units listed in Table 2-1. While the modeling demonstrates that Burns Harbor's visibility impact is acceptable even using this highly conservative approach (see Table 5-1), This scenario conservatively overestimates the impact on Class I areas. In order to estimate plant emissions on a more realistic basis, we calculated the maximum individual day of plant-wide sulfur dioxide and oxides of nitrogen emissions during the period of 2002 through 2004. Daily sulfur dioxide and oxides of nitrogen emissions from all emission units were summed for each day to obtain the total plant daily emissions. The plant-wide daily sulfur dioxide and oxides of nitrogen emissions for 2002, 2003 and 2004 were scanned to determine the highest daily plant-wide emissions for each of the two pollutants. These maximum 24-hour plant-wide emission rates for sulfur dioxide emissions and for oxides of nitrogen were used as inputs in a separate modeling run summarized in Table 5-2. The modeling results confirm that Burns Harbor is comfortably below the threshold that triggers BART regulation when using this more realistic assessment of the 24-hour maximum emission rate as input to the CALPUFF model.

Table 2-1 provides a summary of the baseline emissions used in the BART CALPUFF model to model the maximum day on an emission unit basis. Table 2-2 provides the modeling parameters that were used in the BART CALPUFF modeling. Table 2-3 provides a summary of the baseline emissions used in the plant-wide maximum emission day modeling. The same modeling parameters in Table 2-2 were used for the plant-wide maximum modeling. Table 2-4 contains the emission factors used to calculate emissions for combustion units. Table 2-5 provides the emission factors used to calculate emissions from process units.

Table 2-1 Burns Harbor Facility Baseline Emission Rates - Maximum by Emission Unit

Stack Description	Peak 24-Hour Emissions (g/s)		Fuel & Production Data Record Frequency
	SO_2	NO_X	
POWER STATION Boiler Nos 7-12	218.31	162.49	Daily
#1 COKE BATTERY PUSHING	1.38	0.27	Monthly
#1 COKE BATTERY UNDERFIRE	64.13	94.53	Daily
#2 COKE BATTERY PUSHING	1.39	0.27	Monthly
#2 COKE BATTERY UNDERFIRE	69.29	5.45	Daily
SINTER WINDBOX STACK	25.20	43.59	Daily
BLAST FCE D CASTHOUSE/FUG	0.00	1.02	Monthly
BLAST FURNACE C STOVES	42.03	4.27	Daily
BLAST FURNACE D STOVES	41.88	4.33	Daily
BLAST FCE C CASTHOUSE/FUG	0.00	0.99	Monthly
STEELMAKING HMD STATION #1	0.30	0.02	Monthly
STEELMAKING HMD STATION #2	0.30	0.02	Monthly
STEELMAKING VESSELS #1 & #2	0.09	2.76	Monthly
STEELMAKING VESSEL #3	0.09	1.53	Monthly
STEELMAKING FM BOILER	0.002	0.47	Monthly
HOT STRIP FURNACE #1	7.74	7.36	Daily
HOT STRIP FURNACE #3	7.93	8.16	Daily
HOT STRIP FURNACE #2	7.95	7.17	Daily
160" PLATE MILL FURNACE #1	18.17	4.09	Daily
160" PLATE MILL FURNACE #2	25.28	4.39	Daily
160" PLATE MILL FURNACE #5	0.00	0.00	Daily
160" PLATE MILL FURNACES 6 & 7	0.01	1.27	Daily
160" PLATE MILL FURNACE #8	0.00	0.00	Daily
110 PLATE MILL FURNACES 1 &2	0.00	0.00	Daily
STEELMAKING HMD STATION #3	0.26	0.02	Monthly
110" Plate Mill Normalizing Fce	0.00	0.00	Daily

Volume Source Description(1)	Model Inputs (g/s)	
	SO_2	NO_x
Blast Furnace C Slag Pit	4.04	0.00
Blast Furnace D Slag Pit	3.36	0.00
Steelmaking Fugitives	0.37	0.99

(1) Total emission from the volume sources were added to the Power Station Source when modeled. Production data frequency is monthly for all volume sources

Table 2-2 Burns Harbor Facility Modeling Stack Parameters

Stack Description	Base Elevation(m)	Stack Height (m)	Diameter (m)	Flow (m^3/s)	Temperature (K)	Exit velocity (m/sec)	UTM Easting (m)	UTM Northing (m)
POWER STATION Boiler Nos 7-12	187.14	67.06	3.43	123.2	505	13.34	488375	4609318
#1 COKE BATTERY PUSHING	187.54	20.12	0.76	4.3	323	9.44	488045	4608362
#1 COKE BATTERY UNDERFIRE	187.15	76.81	3.78	80.2	547	7.15	487968	4608346
#2 COKE BATTERY PUSHING	187.15	26.82	2.44	94.4	335	20.20	488059	4608115
#2 COKE BATTERY UNDERFIRE	187.14	75.90	4.18	63.4	505	4.48	487959	4608191
SINTER WINDBOX STACK*	187.15	24.08	2.39	247.2	319	55.12	488038	4609329
BLAST FCE D CASTHOUSE/FUG	187.14	18.90	1.56	47.2	533	24.70	488203	4609371
BLAST FURNACE C STOVES	187.15	61.26	3.48	151.1	519	15.89	488244	4609339
BLAST FURNACE D STOVES	187.14	61.26	3.59	151.1	519	14.93	488229	4609496
BLAST FCE C CASTHOUSE/FUG	187.14	18.90	1.56	47.2	533	24.70	488203	4609371
STEELMAKING HMD STATION #1	187.14	25.91	2.05	42.7	305	12.95	488512	4609936
STEELMAKING HMD STATION #2	187.14	25.91	3.04	42.7	305	5.89	488542	4609936
STEELMAKING VESSELS #1 & #2	187.15	24.99	6.02	160.7	325	5.65	488544	4609957
STEELMAKING VESSEL #3	187.15	11.58	6.71	93.4	332	2.64	488555	4610037
STEELMAKING FM BOILER	187.15	67.66	1.99	5.6	478	1.79	488690	4609918
HOT STRIP FURNACE #1	187.14	41.45	4.30	402.5	811	7.06	489030	4609212
HOT STRIP FURNACE #3	187.14	41.45	3.97	109.0	811	8.81	489063	4609212
HOT STRIP FURNACE #2	187.14	41.45	4.30	102.0	811	7.02	489046	4609212
160" PLATE MILL FURNACE #1	187.14	54.25	3.10	33.0	673	4.37	489014	4609043
160" PLATE MILL FURNACE #2	187.14	54.25	3.10	33.0	693	4.09	489035	4609043
160" PLATE MILL FURNACE #5	187.14	39.92	1.95	37.3	783	12.48	489054	4609039
160" PLATE MILL FURNACES 6 & 7	187.14	32.92	2.24	39.3	783	9.99	489042	4608914
160" PLATE MILL FURNACE #8	187.14	50.90	1.74	7.1	673	2.99	489042	4608894
110 PLATE MILL FURNACES 1 & 2	187.14	54.56	4.44	33.0	838	2.13	489030	4608811
STEELMAKING HMD STATION #3	187.14	25.91	2.05	42.7	305	12.95	488601	4609962
110" Plate Mill Normalizing Fce	187.14	45.72	1.92	12.4	505	4.27	489801	4608431

Table 2-3 Burns Harbor Facility Baseline Emission Rates - Plant-wide Maximum Emission Day

Stack Description[(2)]	Peak 24-Hour Emissions (g/s)	
	SO_2	NO_X
POWER STATION Boiler Nos 7-12	218.31	162.49
#1 COKE BATTERY PUSHING	1.38	0.25
#1 COKE BATTERY UNDERFIRE	61.34	81.30
#2 COKE BATTERY PUSHING	1.39	0.25
#2 COKE BATTERY UNDERFIRE	64.26	4.65
SINTER WINDBOX STACK*	25.20	37.31
BLAST FCE D CASTHOUSE/FUG	0.00	1.02
BLAST FURNACE C STOVES	29.20	3.44
BLAST FURNACE D STOVES	32.28	3.28
BLAST FCE C CASTHOUSE/FUG	0.00	0.99
STEELMAKING HMD STATION #1	0.30	0.02
STEELMAKING HMD STATION #2	0.30	0.02
STEELMAKING VESSELS #1 & #2	0.15	2.54
STEELMAKING VESSEL #3	0.08	1.53
STEELMAKING FM BOILER	0.00	0.43
HOT STRIP FURNACE #1	4.23	5.97
HOT STRIP FURNACE #3	0.00	6.09
HOT STRIP FURNACE #2	4.29	6.14
160" PLATE MILL FURNACE #1	3.23	1.89
160" PLATE MILL FURNACE #2	3.31	1.83
160" PLATE MILL FURNACE #5	0.00	0.00
160" PLATE MILL FURNACES 6 & 7	0.00	0.00
160" PLATE MILL FURNACE #8	0.00	0.00
110 PLATE MILL FURNACES 1 &2	0.00	0.00
STEELMAKING HMD STATION #3	0.26	0.02
110" Plate Mill Normalizing Fce	0.00	0.00

Volume Source Description[(1)]	Model Inputs (g/s)	
	SO_2	NO_x
Blast Furnace C Slag Pit	3.28	0.00
Blast Furnace D Slag Pit	2.85	0.00
Steelmaking Fugitives	0.37	0.99

(1) Total emission from the volume sources were added to the Power Station Source when modeled. Production data frequency is monthly for all volume sources

(2) Fuel use and production data record frequency is same as that shown in Table 2-1.

Table 2-4 Combustion Unit Emission Factors Used In Emissions Calculations

Sulfur Dioxide

Fuel	Emission Units	SO_2 Emission Factor (lb/MMBTU)	Source of Emission Factor
Blast Furnace Gas	All Units	0.13	Based on stack test used as basis for annual emission fees reporting
Coke Oven Gas		Varies from 1.088 to 1.395	Semi-annual testing of No. 2 Coke Battery Underfiring Stack when combusting coke oven gas
Natural Gas		0.0006	AP-42, External Combustion

Oxides of Nitrogen

Fuel	Emission Units	NOx Emission Factor (lb/MMBTU)	Source of Emission Factor
Blast Furnace Gas	All Units Except Coke Battery Underfiring and Hot Strip Mill Reheat Furnaces	0.0100	ISG Indiana Harbor test of No. 7 Boiler Stack on 5/11/04
Coke Oven Gas		0.1367	FIRE database [SCC 10200707]
Natural Gas		0.1373	AP-42, External Combustion, Table 1.4-1, Low-NOx Burners. Converted from lb/MMscf using 1020 BTU/scf.
Fuel	**Emission Units**	**NOx Emission Factor (lb/MMcf)**	**Source of Emission Factor**
Blast Furnace Gas	No. 1 Coke Battery Underfiring	168.50	Average of 1995 & 2000 Burns Harbor Stack Tests
Coke Oven Gas		987	Average of 1995 & 2000 Burns Harbor Stack Tests
Natural Gas		NA	NA
Blast Furnace Gas	No. 2 Coke Battery Underfiring	NA	NA
Coke Oven Gas		60.57	2000 Burns Harbor Stack Test
Natural Gas		NA	NA
Coke Oven Gas	Hot Strip Mill Reheat Fce. Nos. 1 ,2 & 3	82.07	2/14/06 Burns Harbor Stack Test
Natural Gas		143.14	

Table 2-5 Process Unit Emission Factors Used In Emissions Calculations

Source	Pollutant	Emission Factor Uncontrolled	Units	Capture Efficiency (Control Device)	Control Efficiency (Control Device)	Controlled Emission Factor (lb/unit)	Source of Emission Factor
HMD Station Nos. 1, 2 & 3 Baghouse Stack Emissions	NOx	0.00100	lbs/ton HM	98.00%	0.00%	0.00098	BH Test Data (HMD/transfer/skimming) 8/13/02 Stack Test @ #2 HMD
	SO2	0.01400	lbs/ton HM	98.00%	0.00%	0.01372	BH Test Data (HMD/transfer/skimming) 8/13/02 Stack Test @ #2 HMD
BOF Nos. 1 & 2 (refining/blow) Stack Primary Emissions	NOx	0.05400	lbs/ton steel	99.80%	0.00%	0.05389	BH Test 9/29/93-10/14/93
	SO2	0.00604	lbs/ton steel	99.80%	50.00%	0.00302	BH 4/7/05 Test
BOF No. 3 (refining/blow) Stack Primary Emissions	NOx	0.05400	lbs/ton steel	99.99%	0.00%	0.05399	BH Test 9/29/93-10/14/93
	SO2	0.00604	lbs/ton steel	99.99%	50.00%	0.00302	BH 4/7/05 Test
Ladle Treatment Station (LTS) Nos. 4 & 5 BH Stack Emissions	NOx	0.00300	lbs/ton steel	99.99%	0.00%	0.00300	ArcelorMittal Indiana Harbor f/k/a Inland 2001 Emission Inv 2BOF Ladle Metallurgy
	SO2	0.02500	lbs/ton steel	99.99%	0.00%	0.02500	ArcelorMittal Indiana Harbor f/k/a Inland 2001 Emission Inv 2BOF Ladle Metallurgy
Steel Ladle Desulf Station Nos. 2 & 3 BH Stack Emissions	SO2	0.00245	lbs/ton steel	90.00%	0.00%	0.00221	Same SO2 emitted/steel sulfur conc. as HMD
Vacuum Degasser Process Flare Stack Emissions	NOx	0.00015	lbs/ton steel	100.00%	0.00%	0.00015	USS Gary Works 1998 Application for RH Vacuum Degasser
Coke Battery No. 1 Pushing	NOx	N/A	lbs/ton coal	N/A	N/A	0.01900	AP-42 Table 12.2-9
	SO2	N/A	lbs/ton coal	N/A	N/A	0.09800	AP-42 Table 12.2-9
Coke Battery No. 2 Pushing	NOx	N/A	lbs/ton coal	N/A	N/A	0.01900	AP-42 Table 12.2-9
	SO2	N/A	lbs/ton coal	N/A	N/A	0.09800	AP-42 Table 12.2-9
BF C Slag Pit	SO2	0.08500	lbs/ton HM	100.00%	0.00%	0.08500	USS Gary Works and Mittal Indiana Harbor West SIP Model
BF D Slag Pit	SO2	0.08500	lbs/ton HM	100.00%	0.00%	0.08500	USS Gary Works and Mittal Indiana Harbor West SIP Model
Sinter Plant Windbox	NOx	N/A	lbs/ton sinter	N/A	N/A	0.66700	BH 1/8/97 Test
	SO2	N/A	lbs/hr	N/A	N/A	200	Engineering Estimate based on stack sampling in 2008*

* Engineering evaluation in 2008 confirmed that Sinter Plant Windbox Scrubber properly operated sustained SO2 emissions below 200 lb./ ton.

3.0 Meteorological Data

This section discusses refinements to Lake Michigan Air Directors Consortium (LADCO) and Midwest Regional Planning Organization (MWRPO) meteorological database that were used for the Burns Harbor facility BART modeling.

3.1 Elements of the Refined Analysis

ENSR refined the CALMET meteorological data produced by LADCO/MWRPO for BART CALPUFF analyses for Midwestern States. The CALMET database derived by LADCO/MWRPO has a domain that covers approximately a 3,492 km (east-west) by 3,240 km (north-south) area with a 36-km grid resolution. This area covers the entire continental United States east of the Rocky Mountains, but its large size limits the horizontal resolution of each grid element to 36 km. This coarse grid resolution can be deemed appropriate for a screening-level analysis, but it would not be considered appropriate for a more refined analysis.

ENSR developed a refined meteorological database that would include a modeling domain encompassing the four Class I areas (Seney, Mingo, Mammoth, and Isle Royale), the Burns Harbor facility, and the appropriate buffers around the source and Class I areas for puffs recirculation. This domain covers approximately a 1,002 km (east-west) by 1,374 km (north-south) area, has a grid resolution of 6 km (6 times more resolved than the LADCO/MWRPO database in both east-west and north-south directions), and contains 10 vertical levels. The refined database utilizes the same MM5 databases that were used to develop the LADCO/MWRPO 36-km CALMET database.

In addition to the use of consistent MM5 databases with the LADCO-developed meteorological data, ENSR utilized similar model switches/settings, when appropriate, that were used to develop the LADCO/MWRPO CALMET database. To improve the database even further, ENSR introduced actual surface, precipitation, and twice-daily upper air sounding observations into the refined meteorological database. These improvements in the CALMET database provide more accurate plume trajectories from the Burns Harbor facility to the distant Class I areas.

In addition, ENSR used the latest EPA-approved versions of CALMET (Version 5.8) and CALPUFF (Version 5.8), rather than the "old" EPA-approved versions suggested in the MWRPO BART common protocol (available at http://www.state.in.us/idem/programs/air/workgroups/regionalhaze/docs/BART_protocol.pdf).

3.2 CALMET Processing

ENSR used refined 6-km grid spacing for the CALMET and CALPUFF models. The modeling domain was based on a 100 km buffer around the source and a 50 km buffer around each of the four Class I areas plus an additional buffer to the east and to the west to account for puffs recirculation. The modeling domain is shown in Figure 3-1. This design allows for a 1,002 km (east-west) x 1,374 km (north-south) domain extent and, at a 6-km resolution, there are 167 x 229 horizontal grid cells.

Due to the size of the modeling domain, a Lambert Conformal Conic (LCC) coordinate system was used to account for the curvature of the Earth's surface. The LCC projection for this analysis was based on the NAS-C datum and standard parallels of 33 and 45 degrees North, with an origin of 40 degrees North and 97 degrees West.

ENSR used the latest EPA-approved version of CALMET (Version 5.8, Level 070623) to produce three-dimensional wind fields for three years (2002-2004). Advanced meteorological data in the form of prognostic mesoscale meteorological data, such as the Fifth Generation Mesoscale Model (MM5), were used to provide a superior estimate of the initial wind fields. This application considered 3 years (2002-2004) of prognostic MM5 meteorological data at a 36-km resolution.

- 2002 MM5 data set at 36 km resolution provided by CENRAP;
- 2003 MM5 data set at 36 km resolution provided by Midwest RPO;
- 2004 MM5 data set at 36 km resolution provided by Midwest RPO.

These databases are consistent with those used by LADCO/MWRPO for their BART assessments.

These prognostic meteorological data sets were combined with the 6-km grid resolution terrain and land use data to more accurately characterize the wind flow throughout the modeling domain. The gridded terrain data was derived using several data sources because the modeling domain extends into Canadian territory. The U.S. Geological Survey (USGS) 90-meter grid spacing Digital Elevation Model (DEM) files were combined with the 100-meter grid spacing Canadian DEM files and the 90-meter spacing Shuttle RADAR Topo Mission files. These files were processed in the TERREL pre-processor program. The gridded land use data was derived from USGS 1:250,000 Composite Theme Grid land use files.

The Step 2 wind fields were produced using the input of all available National Weather Service (NWS) hourly surface and twice-daily upper air balloon sounding data within and just outside the modeling domain. Hourly surface data from both first-order and second-order stations also were considered in this analysis. Other sources of meteorological data such as CASTNET data and buoy stations were used to supplement areas lacking NWS or second-order data. Hourly precipitation data from stations within and just outside of the modeling domain were taken from a National Climatic Data Center data set. Figure 3-2 shows the meteorological stations that were used in the CALMET modeling and Appendix A provides their names and locations.

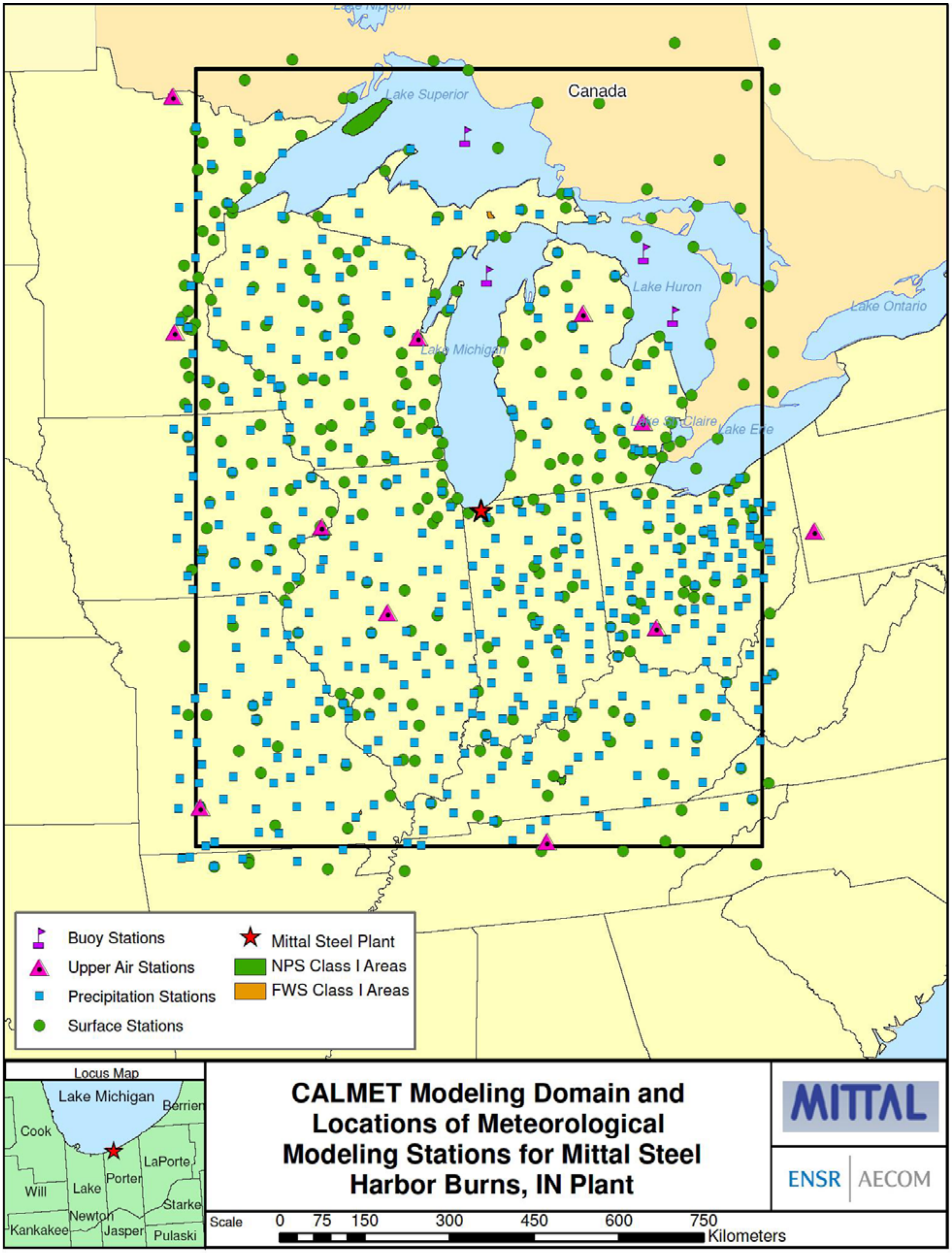
The non-default user-defined settings proposed for the CALMET processing are provided in Table 3-1.

Table 3-1 CALMET User-Defined Fields Not Specified in IWAQM Appendix A

Variable	Description	Value
NX	Number of east-west grid cells	167
NY	Number of north-south grid cells	229
DGRIDKM	Meteorology grid spacing (km)	6.0
NZ	Number of Vertical layers of input meteorology	10
ZFACE	Vertical cell face heights (m)	0.,20.,40.,80.,160.,300.,600.,1000.,1500.,2000.,3500.
RMAX1	Max surface over-land extrapolation radius (km)	40
RMAX2	Max aloft over-land extrapolation radius (km)	40
RMAX3	Maximum over-water extrapolation radius (km)	100
TERRAD	Radius of influence of terrain features (km)	15
R1	Relative weight at surface of Step 1 field and obs	5
R2	Relative weight aloft of Step 1 field and obs	5
IUPT	Station for lapse rates	International Falls, MN
IPROG	Gridded initial prognostic wind field – MM4/MM5 data	14

Figure 3-1 Burns Harbor CALMET and CALPUFF Modeling Domain

Figure 3-2 Location of Meteorological Stations used in CALMET Processing



4.0 CALPUFF Modeling

This section provides a summary of the modeling procedures that were used for the refined CALPUFF analysis conducted for the Burns Harbor facility.

4.1 CALPUFF Modeling Domain and Receptors

ENSR used the latest EPA-approved version of CALPUFF (Version 5.8, Level 070623) that has been posted at http://www.src.com/calpuff/download/download.htm#EPA_VERSION.

The extent of the CALMET/CALPUFF modeling domain are shown in Figure 3-1. The modeling domain included a 100 km buffer around the source and a 50 km buffer around each of the four Class I areas plus an additional buffer to the east and to the west to account for puffs recirculation. This design allows the modeling domain to extend 1,002 km east-west and 1,374 km north-south and have a 6-km grid element size.

The receptors for each of the Class I areas were based on the National Park Service database of Class I receptors.

4.2 Technical Options Used in the Modeling

For CALPUFF model technical options, inputs and processing steps, Burns Harbor followed the MWRPO common BART protocol.

For CALPUFF modeling, ENSR used seasonal ozone and ammonia ambient background concentrations that are consistent with the MWRPO common BART modeling protocol. For convenience, there values are listed in Table 4-1.

Table 4-1 MWRPO Ozone and Ammonia Seasonal Concentrations

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
O_3 (ppb)	31	31	31	37	37	37	33	33	33	27	27	27
NH_3 (ppb)	.3	.3	.3	.5	.5	.5	.5	.5	.5	.5	.5	.5

Due to the large distance to the nearest Class I area, building downwash effects were not included in the CALPUFF modeling.

4.3 Natural Conditions and Monthly f(RH) at Class I Areas

There are four Class I areas to be modeled for the Burns Harbor facility. For these Class I areas, natural background conditions must be established in order to determine a change in natural conditions related to a source's emissions.

For BART analyses, EPA has chosen to accept either the annual average or 20% best day's natural background for BART exemption and determination modeling analyses. Regional Planning Organization(s) (RPOs) have provided guidance to states within their RPOs on what values to accept, which typically has varied based on the degree of the meteorological database refinement. Since MWRPO uses the 36-km database with no observations, as a measure of conservatism, MWRPO/LADCO recommended to states that the 20% best day's background be incorporated into the analysis as opposed to the annual average. This conservative approach compensated for the inaccuracy of the 36-km meteorological data in no-obs mode.

Model refinements to improve accuracy reduce the need for conservative background assumptions. For instance, Wisconsin, a MWRPO state, has stated that they would allow sources to use the annual average background with the 98th percentile day as opposed to the 20% best days if a site-specific meteorological database is developed.

In addition, states within the VISTAS RPO* have uniformly decided to allow sources to use the annual average background coupled with the 98th percentile day when refined meteorological data (that incorporates observations) is used as input to the BART CALPUFF runs. This procedure was approved by EPA Region 4. To conduct the BART modeling, VISTAS, like the MWRPO, developed its own coarse no-obs 12-km resolution CALMET meteorological database covering all VISTAS states and Class I areas within 300 km. The 12-km CALMET meteorological data was used in the modeling analyses as a screening step to exempt BART eligible sources that, based on modeling, did not cause or contribute to visibility impairment (i.e. according to the BART rule did not have impacts greater than 0.5 dv).VISTAS also developed a more refined 4-km resolution CALMET databases that covered a sub-set of the large 12-km grid. These databases were able to be used in refined BART modeling analyses along with the annual average background. To ENSR's knowledge, all VISTAS states have accepted the use of the annual average background.

Burns Harbor used refined meteorological database with a finer grid resolution (6-km) and introduced surface observations. In addition, ENSR used the annual average background while evaluating BART exemption based on the source's impacts at the 98th percentile day. This procedure is consistent with the modeling approach taken by other eastern states and consistent with Wisconsin's approach within the MWRPO.

For the modeling described in this document, ENSR used the annual average natural background concentrations shown in Table 4-2, modified as noted below with site-specific considerations (as shown in Table 4-3), and corresponding to the annual average natural background concentrations (EPA 2003, Appendix B).

To determine the input to CALPOST, it is first necessary to convert the deciviews to extinction using the equation:

Extinction (Mm^{-1}) = 10 exp(deciviews/10).

For example, for Mingo, 7.43 deciviews is equivalent to an extinction of 21.02 inverse megameters (Mm^{-1}); this extinction includes the default 10 Mm-1 for Rayleigh scattering. This remaining extinction is due to naturally occurring particles, and is held constant for the entire year's simulation. Therefore, the data provided to CALPOST for Mingo would be the total natural background extinction minus 10 (expressed in Mm^{-1}), or 11.02. This is most easily input as a fine soil concentration of 11.02 $\mu g/m^3$ in CALPOST, since the extinction efficiency of soil (PM-fine) is 1.0 and there is no f(RH) component. The concentration entries for all other particle constituents would be set to zero, and the fine soil concentration would be kept the same for each month of the year. The monthly values for f(RH) that CALPOST needs were taken from "Guidance for Tracking Progress Under the Regional Haze Rule" (EPA, 2003) Appendix A, Table A-3.

* The VISTAS states include: Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee, Virginia, and West Virginia.

Table 4-2 Annual Average Natural Background Concentrations

Component Represented	Isle Royale	Mammoth Cave	Mingo	Seney
Soil (PM fine) (deciview)	7.38	7.69	7.43	7.53
Soil (PM fine) (Mm^{-1} or $\mu g/m^3$)	20.92	21.58	21.02	21.23

* Extinction values include Rayleigh scattering.

Table 4-3 New IMPROVE Equation Background Sea Salt Concentration and Site-specific Rayleigh Scattering Coefficient

Parameter	Isle Royale	Mammoth Cave	Mingo	Seney
Sea Salt Concentration ($\mu g/m^3$)	0.03	0.02	0.01	0.02
Rayleigh Scattering Coefficient (Mm-1)	12	11	12	12

Note: Data taken from VIEWS website (http://vista.cira.colostate.edu/views/)

4.4 Light Extinction and Haze Impact Calculations

The CALPOST postprocessor was used for the calculation of the impact from the modeled source's primary and secondary particulate matter concentrations on light extinction. The formula that is used is the existing IMPROVE/EPA formula, which is applied to determine a change in light extinction due to increases in the particulate matter component concentrations. Using the notation of CALPOST, the formula is the following:

$$b_{ext} = 3\ f(RH)\ [(NH_4)_2SO_4] + 3\ f(RH)\ [NH_4NO_3] + 4[OC] + 1[Soil] + 0.6[Coarse\ Mass] + 10[EC] + b_{Ray}$$

The concentrations, in square brackets, are in $\mu g/m^3$ and b_{ext} is in units of Mm^{-1}. The Rayleigh scattering term (b_{Ray}) has a default value of 10 Mm^{-1}, as recommended in EPA guidance for tracking reasonable progress (EPA, 2003a).

Dr. Ivar Tombach, consultant to VISTAS, has provided a spreadsheet calculation system (see Appendix B) that incorporates the revised IMPROVE equation (also documented in Appendix B) for determining light extinction from particulate concentration estimates. We used this approach instead of the old/current IMPROVE equation in the presentation of the BART modeling. The Fish & Wildlife Service, who administer the Seney and Mingo Wilderness Areas, have previously communicated to ENSR (2006) that they approve of Dr. Tombach's procedure for implementing the new IMPROVE equation, and that this equation may be used for regional haze assessments with this approach. Notably, the Federal Land Managers associated with the US Fish and Wildlife Service recently approved the use of the new IMPROVE equation at Seney Wilderness (as implemented here using Dr. Tombach's procedures) for a PSD permit application in Michigan.

The new IMPROVE equation is fundamentally different in 3 major areas (taken from Ivar Tombach's *"Instructions: A Postprocessor for Recalculating CALPOST Visibility Outputs with the New IMPROVE Algorithm"*):

(1) The extinction efficiencies of sulfates, nitrates, and organics have been changed and are now functions of their concentrations. The extinction efficiencies of sulfate and nitrate are no longer identical, although the new hygroscopic scattering enhancement factors applied to them are the same.

(2) The contribution of fine sea salt to light extinction has been added, and is accompanied by its own hygroscopic scattering enhancement factor, fss(RH).

(3) The light scattering by air itself (Rayleigh scattering) now varies with site elevation and mean temperature. It is to be rounded off to the nearest one Mm-1 when used with the new algorithm.

States and other RPOs have allowed sources to use the new IMPROVE equation as opposed to the IMPROVE equation algorithms that are currently coded into CALPOST because these differences (noted above) represent a real improvement over how the old/current IMPROVE equation calculates light extinction. ENSR used the new IMPROVE equation for the light extinction calculations in this refined BART analysis using the guidance provided by Dr. Ivar Tombach. Table 4-3 lists sea salt concentrations and Rayleigh coefficients that were used as input to the new IMPROVE equation.

In addition to using the new IMPROVE equation, the assessment of visibility impacts at the Class I areas used CALPOST Method 6 (as standard with all BART applications). Each hour's source-caused extinction is calculated by first using the hygroscopic components of the source-caused concentrations, due to ammonium sulfate and nitrate, and monthly Class I area-specific f(RH) values. The contribution to the total source-caused extinction from ammonium sulfate and nitrate is then added to the other, non-hygroscopic components of the particulate concentration (from coarse and fine soil, secondary organic aerosols, and from elemental carbon) to yield the total hourly source-caused extinction.

5.0 Modeling Results

The BART exemption modeling results at the four Class I areas using the maximum emissions by emission unit are provided in Table 5-1. Table 5-2 provides the results of the more realistic modeling using the maximum plant-wide emission days. Both tables indicate that the 8th highest day's impacts for each year are below the 0.5 delta-deciviews threshold. These results demonstrate that the ArcelorMittal Burns Harbor emissions do not cause or contribute to regional haze in any of these four Class I area. Therefore, Burns Harbor facility is not subject to BART and no further BART analysis is required.

Table 5-1 BART Exemption Modeling Results - Maximum by Emission Unit

Class I Area	2002				2003				2004			
	Days > than		MAX Δ dv	8th Highest Δ dv_t	Days > than		MAX Δ dv	8th Highest Δ dv	Days > than		MAX Δ dv	8th Highest Δ dv_t
	0.5 Δ dv	1.0 Δ dv			0.5 D dv	1.0 D dv			0.5 D dv	1.0 D dv		
MVISBK=6, Annual Average Background, 6-km CALMET, New IMPROVE Equation												
Isle Royale National Park	0	0	0.220	0.083	2	0	0.601	0.117	2	0	0.615	0.163
Mammoth Cave National Park	2	0	0.898	0.351	3	0	0.674	0.333	1	0	0.658	0.218
Mingo Wilderness	3	0	0.705	0.199	1	0	0.559	0.224	0	0	0.414	0.181
Seney Wilderness	4	0	0.750	0.346	4	1	1.165	0.375	7	1	1.030	0.464

Table 5-2 BART Exemption Modeling Results - Plant-wide Maximum Emission Day

Class I Area	2002				2003				2004			
	Days > than		MAX Δ dv	8th Highest Δ dv_t	Days > than		MAX Δ dv	8th Highest Δ dv	Days > than		MAX Δ dv	8th Highest Δ dv_t
	0.5 Δ dv	1.0 Δ dv			0.5 D dv	1.0 D dv			0.5 D dv	1.0 D dv		
MVISBK=6, Annual Average Background, 6-km CALMET, New IMPROVE Equation												
Isle Royale National Park	0	0	0.188	0.069	2	0	0.533	0.099	2	0	0.542	0.143
Mammoth Cave National Park	2	0	0.789	0.300	2	0	0.574	0.287	1	0	0.563	0.185
Mingo Wilderness	2	0	0.629	0.170	0	0	0.474	0.189	0	0	0.352	0.155
Seney Wilderness	2	0	0.675	0.297	2	0	1.027	0.332	6	0	0.914	0.405

6.0 References

ENSR, Personal communication to Mr. Robert Paine from Mr. Tim Allen of the U.S Fish and Wildlife Service

Environmental Protection Agency (EPA), AP 42, Fifth Edition, Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources, January, 1995

Environmental Protection Agency (EPA), Guidance for Tracking Progress Under the Regional Haze Rule, EPA-454/B-03-003, Appendix A, Table A-3, September, 2003a

Environmental Protection Agency (EPA), Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program, EPA 454/B-03-005, September 2003b

Environmental Protection Agency (EPA), Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts, EPA-454/R-98-019, December, 1998

Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule (FR Vol. 70, No. 128 published July 6, 2005)

Regional Haze Regulations; Revisions to Provisions Governing Alternative to Source-Specific Best Available Retrofit Technology (BART) Determinations; Final Rule (FR Vol. 71, NO. 198 published October 13, 2006)

Single Source Modeling to Support Regional Haze BART Modeling Protocol November 17, 2005, Lake Michigan Air Directors Consortium, Des Plaines, IL

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Appendix A

Meteorological Stations used in CALMET Processing

Table A-1 Surface Stations used in CALMET Processing

Country/State	WBAN ID	Source (1)	Name	Latitude	Longitude	Elevation (m)	2002	2003	2004
Canada	712600	NNDC	SAULT STE MARIE	46.48	-84.51	192	x	x	x
Canada	712610	NNDC	GODERICH (AUT08)	43.76	-81.71	214	x	x	x
Canada	712700	NNDC	COLLINGWOOD (AUT8)	44.50	-80.21	180	x	x	x
Canada	712730	NNDC	BELLE RIVER	42.30	-82.70	184	x	x	x
Canada	713680	NNDC	WATERLOO WELL	43.46	-80.38	317	x	x	x
Canada	714330	NCDC	CARIBOU ISL (MAPS)	47.33	-85.83	187	x	x	x
Canada	714350	NCDC	UPSALA (MARS)	49.03	-90.46	489	x	x	x
Canada	714390	NCDC	COVE ISLAND (MAPS)	45.33	-81.73	181	x	x	x
Canada	714600	NCDC	KILLARNEY (MAPS)	45.96	-81.48	196	x	x	x
Canada	714620	NCDC	GREAT DUCK ISLAND	45.63	-82.96	183	x	x	x
Canada	714650	NCDC	ERIEAU (MAPS)	42.25	-81.90	178	x	x	x
Canada	714660	NCDC	S.E. SHOAL (MAPS)	41.83	-82.46	195	x	x	x
Canada	715380	NCDC	WINDSOR AIRPORT	42.26	-82.96	190	x	x	x
Canada	715730	NCDC	DELHI CS	42.83	-80.55	232	x	x	x
Canada	716230	NCDC	LONDON AIRPORT	43.03	-81.15	278	x	x	x
Canada	716310	NCDC	MOUNT FOREST(MARS)	43.98	-80.75	415	x	x	x
Canada	716330	NCDC	WIARTON AIRPORT	44.75	-81.10	222	x	x	x
Canada	716340	NCDC	SARNIA AIRPORT	43.00	-82.31	181	x	x	x
Canada	716420	NCDC	CHAPLEAU A	47.81	-83.35	447	x	x	x
Canada	717300	NCDC	SUDBURY AIRPORT	46.61	-80.80	348	x	x	x
Canada	717320	NCDC	BRITT (MARS)	45.80	-80.53	192	x	x	x
Canada	717330	NCDC	GORE BAY AIRPORT	45.88	-82.56	193	x	x	x
Canada	717334	NCDC	ELLIOT LAKE (SAWR)	46.35	-82.56	329	x	x	x
Canada	717340	NCDC	ROUYN	48.25	-79.03	318	x	x	x
Canada	717350	NCDC	EARLTON AIRPORT	47.70	-79.85	243	x	x	x
Canada	717380	NCDC	WAWA AIRPORT	47.96	-84.78	287	x	x	x
Canada	717390	NCDC	TIMMINS AIRPORT	48.56	-81.36	295	x	x	x
Canada	717470	NCDC	ATIKOKAN	48.76	-91.63	389	x	x	x
Canada	717490	NCDC	THUNDER BAY AIRPORT	48.36	-89.31	199	x	x	x
Canada	717493	NCDC	TERRACE BAY (SAWR)	48.81	-87.10	287	x	x	x
Canada	717500	NCDC	PUKASKWA	48.60	-86.30	206	x	x	x
Canada	717510	NCDC	WELCOME ISLAND	48.36	-89.11	209	x	x	x
Canada	718200	NCDC	BARRAGE ANGLIERS	47.55	-79.23	266	x	x	x
AR	723406	NCDC	WALNUT RIDGE (AWOS)	36.13	-90.91	83	x	x	x
AR	723439	NCDC	BAXTER CO RGNL APT	36.36	-92.46	283	x	x	x
AR	723446	NCDC	HARRISON FAA AP	36.26	-93.15	418	x	x	x
AR	723447	NCDC	FLIPPIN (AWOS)	36.30	-92.46	350	x	x	x
IA	725349	NCDC	DAVENPORT NEXRAD	41.61	-90.58	259	x	x	x
IA	725450	NCDC	CEDAR RAPIDS MUNICI	41.88	-91.71	256	x	x	x
IA	725454	NCDC	WASHINGTON	41.28	-91.66	230	x	x	x
IA	725455	NCDC	BURLINGTON MUNICIPA	40.78	-91.11	210	x	x	x
IA	725456	NCDC	KEOKUK MUNI	40.46	-91.43	205	x	x	x
IA	725461	NCDC	MARSHALL TOWN MUNI	42.10	-92.91	296	x	x	x
IA	725462	NCDC	IOWA CITY MUNI	41.63	-91.55	198	x	x	x
IA	725463	NCDC	CHARLES CITY	43.06	-92.61	343	x	x	x
IA	725464	NCDC	NEWTON MUNI	41.68	-93.01	290	x	x	x
IA	725465	NCDC	OTTUMWA INDUSTRIAL	41.10	-92.45	256	x	x	x
IA	725469	NCDC	CHARITON	41.03	-93.36	320	x	x	x
IA	725470	NCDC	DUBUQUE REGIONAL AP	42.40	-90.70	321	x	x	x
IA	725473	NCDC	CLINTON MUNI (AWOS)	41.83	-90.33	216	x	x	x
IA	725475	NCDC	MONTICELLO MUNI	42.23	-91.16	259	x	x	x
IA	725476	NCDC	DECORAH	43.28	-91.73	353	x	x	x
IA	725480	NCDC	WATERLOO MUNICIPAL	42.55	-92.40	263	x	x	x
IA	725483	NCDC	FORT MADISON	40.66	-91.33	221	x	x	x
IA	725485	NCDC	MASON CITY MUNICIPA	43.15	-93.33	363	x	x	x
IA	725487	NCDC	MUSCATINE	41.36	-91.15	167	x	x	x
IA	725488	NCDC	OELWEN	42.68	-91.96	328	x	x	x
IA	725493	NCDC	KNOXVILLE	41.30	-93.11	283	x	x	x
IA	726498	NCDC	FAIR FIELD	41.05	-91.98	244	x	x	x
IL	724330	NCDC	SALEM-LECKRONE	38.65	-88.96	174	x	x	x
IL	724335	NCDC	MOUNT VERNON (AWOS)	38.31	-88.86	146	x	x	x
IL	724336	NCDC	CARBONDALE/MURPHYSB	37.78	-89.25	125	x	x	x
IL	724338	NCDC	BELLEVILLE SCOTT AF	38.55	-89.85	135	x	x	x
IL	724339	NCDC	MARION REGIONAL	37.75	-89.01	144	x	x	x
IL	724390	NCDC	SPRINGFIELD CAPITAL	39.85	-89.68	178	x	x	x
IL	724395	NCDC	ALTON/ST LOUIS RGNL	38.90	-90.05	166	x	x	x
IL	724396	NCDC	QUINCY MUNI BALDWIN	39.93	-91.20	232	x	x	x
IL	724397	NCDC	BLOOMINGTON/NORMAL	40.48	-88.91	267	x	x	x
IL	725300	NCDC	CHICAGO OHARE INTL	41.98	-87.91	200	x	x	x
IL	725305	NCDC	W. CHICAGO/DU PAGE	41.91	-88.25	231	x	x	x
IL	725314	NCDC	CAHOKIA/ST. LOUIS	38.56	-90.15	126	x	x	x
IL	725315	NCDC	CHAMPAIGN/URBANA	40.03	-88.28	230	x	x	x
IL	725316	NCDC	DECATUR AIRPORT	39.83	-88.86	208	x	x	x
IL	725317	NCDC	MATTOON/CHARLESTON	39.48	-88.28	220	x	x	x
IL	725320	NCDC	PEORIA GREATER PEOR	40.66	-89.68	198	x	x	x
IL	725326	NCDC	STERLING ROCKFALLS	41.75	-89.66	197	x	x	x

Table A-1 Surface Stations used in CALMET Processing

Country/State	WBAN ID	Source [1]	Name	Latitude	Longitude	Elevation (m)	2002	2003	2004
IL	724397	NCDC	BLOOMINGTON/NORMAL	40.48	-88.91	267	x	x	x
IL	725300	NCDC	CHICAGO OHARE INTL	41.98	-87.91	200	x	x	x
IL	725305	NCDC	W. CHICAGO/DU PAGE	41.91	-88.25	231	x	x	x
IL	725314	NCDC	CAHOKIA/ST. LOUIS	38.56	-90.15	126	x	x	x
IL	725315	NCDC	CHAMPAIGN/URBANA	40.03	-88.28	230	x	x	x
IL	725316	NCDC	DECATUR AIRPORT	39.83	-88.86	208	x	x	x
IL	725317	NCDC	MATTOON/CHARLESTON	39.48	-88.28	220	x	x	x
IL	725320	NCDC	PEORIA GREATER PEOR	40.66	-89.68	198	x	x	x
IL	725326	NCDC	STERLING ROCKFALLS	41.75	-89.66	197	x	x	x
IL	725340	NCDC	CHICAGO MIDWAY AP	41.78	-87.75	186	x	x	x
IL	725342	NCDC	LAWRENCEVILLE\VIN.	38.76	-87.60	131	x	x	x
IL	725345	NCDC	JOLIET PARK DISTRIC	41.51	-88.18	177	x	x	x
IL	725346	NCDC	CHICAGO MEIGS FIELD	41.86	-87.61	180	x	x	
IL	725347	NCDC	CHICAGO/WAUKEGAN	42.41	-87.86	222	x	x	x
IL	725348	NCDC	CHICAGO NEXRAD	41.60	-88.08	231	x	x	x
IL	725430	NCDC	ROCKFORD GREATER RO	42.20	-89.10	223	x	x	x
IL	725440	NCDC	MOLINE QUAD CITY IN	41.46	-90.51	180	x	x	x
IL	744655	NCDC	AURORA MUNICIPAL	41.76	-88.46	215	x	x	x
IL	744665	NCDC	CHICAGO/PALWAUKEE	42.11	-87.90	197		x	x
IL	ALH157	CASTNET	Alhambra	38.87	-89.62	164	x	x	x
IL	STK138	CASTNET	Stockton	42.29	-90.00	274	x	x	x
IN	724320	NCDC	EVANSVILLE REGIONAL	38.05	-87.53	116	x	x	x
IN	724356	NCDC	SHELBYVILLE MUNI	39.58	-85.80	245	x	x	x
IN	724363	NCDC	COLUMBUS BAKALAR	39.26	-85.90	199	x	x	x
IN	724365	NCDC	HUNTINGBURG	38.25	-86.95	161		x	x
IN	724373	NCDC	TERRE HAUTE HULMAN	39.45	-87.30	175	x	x	x
IN	724375	NCDC	BLOOMINGTON/MONROE	39.15	-86.61	258	x	x	x
IN	724380	NCDC	INDIANAPOLIS INTL A	39.71	-86.26	241	x	x	x
IN	724384	NCDC	EAGLE CREEK	39.83	-86.30	250	x	x	x
IN	724385	NCDC	ANDERSON MUNICIPAL	40.11	-85.61	280	x	x	x
IN	724386	NCDC	LAFAYETTE PURDUE UN	40.41	-86.93	182	x	x	x
IN	724387	NCDC	KOKOMO(AWOS)	40.53	-86.06	253		x	x
IN	724388	NCDC	GOSHEN	41.53	-85.78	252	x	x	x
IN	725327	NCDC	VALPARAISO	41.45	-87.00	234	x	x	x
IN	725330	NCDC	FORT WAYNE INTL AP	41.00	-85.20	241	x	x	x
IN	725335	NCDC	GRISSOM AFB/PERU	40.65	-86.15	247	x	x	x
IN	725336	NCDC	MUNCIE/JOHNSON FLD	40.25	-85.40	286	x	x	x
IN	725337	NCDC	GARY REGIONAL	41.61	-87.41	180	x	x	x
IN	725350	NCDC	SOUTH BEND MICHIANA	41.70	-86.33	235	x	x	x
IN	725354	NCDC	ELKHART MUNICIPAL	41.71	-86.00	237	x	x	x
IN	SAL133	CASTNET	Salamonie Reservoir	40.82	-85.66	250	x	x	x
KY	724210	NCDC	CINCINNATI NORTHERN	39.05	-84.66	264	x	x	x
KY	724220	NCDC	LEXINGTON BLUEGRASS	38.03	-84.60	294	x	x	x
KY	724230	NCDC	LOUISVILLE STANDIFO	38.18	-85.73	146	x	x	x
KY	724233	NCDC	CAPITAL CITY ARPT	38.18	-84.90	245	x	x	x
KY	724235	NCDC	LOUISVILLE BOWMAN F	38.23	-85.66	164	x	x	x
KY	724236	NCDC	JACKSON JULIAN CARR	37.58	-83.31	416	x	x	x
KY	724237	NCDC	OWENSBORO/DAVIESS	37.73	-87.16	124	x	x	x
KY	724238	NCDC	HENDERSON CITY	37.81	-87.68	117	x	x	x
KY	724240	NCDC	FORT KNOX GODMAN AA	37.90	-85.96	239	x	x	x
KY	724243	NCDC	LONDON-CORBIN AP	37.08	-84.08	362	x	x	x
KY	724350	NCDC	PADUCAH BARKLEY REG	37.05	-88.76	124	x	x	x
KY	724354	NCDC	SOMERSET(AWOS)	38.00	-84.60	283	x	x	x
KY	746710	NCDC	FORT CAMPBELL (AAF)	36.66	-87.50	173	x	x	x
KY	746716	NCDC	BOWLING GREEN WARRE	36.98	-86.43	160	x	x	x
KY	CDZ171	CASTNET	Cadiz	36.78	-87.85	189	x	x	x
KY	CKT136	CASTNET	Crockett	37.92	-83.07	455	x	x	x
KY	MCK131	CASTNET	Mackville	37.70	-85.05	353	x	x	x
KY	MAC426	CASTNET	Mammoth Cave	37.28	-86.26	236	x	x	x
MI	725370	NCDC	DETROIT METROPOLITA	42.21	-83.35	194	x	x	x
MI	725373	NCDC	GROSSE ISLE ARPT	42.10	-83.15	176	x	x	x
MI	725374	NCDC	ANN ARBOR MUNICIPAL	42.21	-83.75	256	x	x	x
MI	725375	NCDC	DETROIT CITY AIRPOR	42.40	-83.00	190	x	x	x
MI	725376	NCDC	DETROIT WILLOW RUN	42.23	-83.53	218	x	x	x
MI	725377	NCDC	MOUNT CLEMENS SELFR	42.61	-82.83	176	x	x	x
MI	725378	NCDC	HOWELL	42.63	-83.98	293	x	x	x
MI	725383	NCDC	STURGIS\KIRSH MUNI	41.81	-85.43	0	x	x	x
MI	725384	NCDC	ST.CLAIR COUNTY INT	42.91	-82.53	198	x	x	x
MI	725386	NCDC	HARBOR BEACH(RAMOS)	44.01	-82.80	183	x	x	x
MI	725387	NCDC	COPPER HARBOR RAMOS	47.45	-87.90	186	x	x	x
MI	725390	NCDC	LANSING CAPITAL CIT	42.78	-84.58	256	x	x	x
MI	725394	NCDC	HOLLAND/TULIP CITY	42.75	-86.10	210	x	x	x
MI	725395	NCDC	JACKSON REYNOLDS FI	42.26	-84.46	304	x	x	x

Table A-1 Surface Stations used in CALMET Processing

Country/State	WBAN ID	Source [1]	Name	Latitude	Longitude	Elevation (m)	2002	2003	2004
MI	725396	NCDC	BATTLE CREEK	42.30	-85.25	282	x	x	x
MI	725404	NCDC	ADRIAN	41.86	-84.08	244	x	x	x
MI	725405	NCDC	ALMA	43.31	-84.68	230	x	x	x
MI	725406	NCDC	BAD AXE	43.78	-82.98	234	x	x	x
MI	725407	NCDC	GAYLORD	45.01	-84.68	404	x	x	x
MI	725408	NCDC	MANISTIQUE	45.96	-86.18	209	x	x	x
MI	725409	NCDC	HILLSDALE	41.91	-84.58	360	x	x	x
MI	725414	NCDC	COLDWATER	41.93	-85.05	292	x	x	x
MI	725415	NCDC	MARSHALL BROOKS	42.25	-84.95	287	x	x	x
MI	725416	NCDC	BIG RAPIDS	43.71	-85.50	302	x	x	x
MI	725417	NCDC	MASON	42.56	-84.41	280	x	x	x
MI	725418	NCDC	MONROE	41.93	-83.43	188	x	x	x
MI	725424	NCDC	MT PLEASANT MUNI	43.61	-84.73	230	x	x	x
MI	726284	NCDC	GWINN SAWYER AIRPO	46.35	-87.38	372	x	x	x
MI	726350	NCDC	GRAND RAPIDS KENT C	42.88	-85.51	241	x	x	x
MI	726355	NCDC	BENTON HARBOR/ROSS	42.13	-86.43	196	x	x	x
MI	726357	NCDC	KALAMAZOO INTL ARPT	42.23	-85.55	266	x	x	x
MI	726360	NCDC	MUSKEGON COUNTY ARP	43.16	-86.23	190	x	x	x
MI	726364	NCDC	LUDINGTON/MASON	43.96	-86.40	197	x	x	x
MI	726370	NCDC	FLINT BISHOP INTL A	42.96	-83.75	233	x	x	x
MI	726375	NCDC	PONTIAC-OAKLAND	42.66	-83.41	299	x	x	x
MI	726379	NCDC	SAGINAW TRI CITY IN	43.53	-84.08	201	x	x	x
MI	726380	NCDC	HOUGHTON LAKE ROSCO	44.36	-84.68	350	x	x	x
MI	726384	NCDC	CADILLAC WEXFORD CO	44.28	-85.41	396	x	x	x
MI	726385	NCDC	MANISTEE (AWOS)	44.26	-86.25	189	x	x	x
MI	726387	NCDC	TRAVERSE CITY CHERR	44.73	-85.58	188	x	x	x
MI	726390	NCDC	ALPENA COUNTY REGIO	45.06	-83.58	210	x	x	x
MI	726394	NCDC	NEWBERRY LUCE CO.	46.31	-85.46	198	x	x	x
MI	726395	NCDC	OSCODA WURTSMITH AF	44.45	-83.40	188	x	x	x
MI	726399	NCDC	SEUL CHOIX PT(AMOS)	45.91	-85.91	180	x	x	x
MI	726480	NCDC	ESCANABA (AWOS)	45.75	-87.03	187	x	x	x
MI	726487	NCDC	MENOMINEE (AWOS)	45.13	-87.63	191	x	x	x
MI	727340	NCDC	SAULT STE MARIE SAN	46.46	-84.35	218	x	x	x
MI	727344	NCDC	CHIPPEWA INTL(AWOS)	46.25	-84.46	244	x	x	x
MI	727347	NCDC	PELLSTON EMMET COUN	45.56	-84.78	217	x	x	x
MI	727435	NCDC	MACKINACK ISLAND	46.35	-87.40	372	x	x	x
MI	727436	NCDC	ANTRIM CO ARPT	44.98	-85.20	190	x	x	x
MI	727437	NCDC	IRON MOUNTAIN/FORD	45.81	-88.11	360	x	x	x
MI	727440	NCDC	HANCOCK HOUGHTON CO	47.16	-88.50	327	x	x	x
MI	727445	NCDC	IRONWOOD (AWOS)	46.53	-90.13	375	x	x	x
MI	727449	NCDC	MOOSE LAKE CO ARPT	46.41	-92.80	184	x	x	x
MI	ANA115	CASTNET	Ann Arbor	42.42	-83.90	267	x	x	x
MI	HOX148	CASTNET	Hoxyville	44.18	-85.74	305	x	x	x
MI	UVL124	CASTNET	Unionville	43.61	-83.36	201	x	x	x
MN	726440	NCDC	ROCHESTER INTERNATI	43.90	-92.50	397	x	x	x
MN	726544	NCDC	ORR	48.01	-92.86	397	x	x	x
MN	726549	NCDC	COOK MUNI ARPT	47.81	-92.70	402	x	x	x
MN	726558	NCDC	CLOQUET (AWOS)	46.70	-92.50	390	x	x	x
MN	726563	NCDC	FARIBAULT MUNI AWOS	44.33	-93.31	322	x	x	x
MN	726564	NCDC	RED WING	44.58	-92.48	239	x	x	x
MN	726568	NCDC	OWATONNA (AWOS)	44.11	-93.25	350	x	x	x
MN	726575	NCDC	MINNEAPOLIS/CRYSTAL	45.06	-93.35	265	x	x	x
MN	726577	NCDC	MINNEAPOLIS/BLAINE	45.15	-93.21	278	x	x	x
MN	726580	NCDC	MINNEAPOLIS-ST PAUL	44.88	-93.23	254	x	x	x
MN	726584	NCDC	SAINT PAUL DOWNTOWN	44.95	-93.06	219	x	x	x
MN	726588	NCDC	WINONA MUNI (AWOS)	44.08	-91.70	200	x	x	x
MN	726589	NCDC	ALBERT LEA (AWOS)	43.68	-93.36	383	x	x	x
MN	726596	NCDC	DODGE CENTER AIRPOR	44.01	-92.81	398	x	x	x
MN	726603	NCDC	SOUTH ST PAUL MUNI	44.85	-93.15	250	x	x	x
MN	726679	NCDC	RUSH CITY RGNL ARPT	45.68	-92.95	281	x	x	x
MN	727444	NCDC	TWO HARBORS	47.05	-91.75	328	x	x	x
MN	727450	NCDC	DULUTH INTERNATIONA	46.83	-92.21	433	x	x	x
MN	727454	NCDC	GRAND MARAIS MUNI	47.83	-90.38	505	x	x	x
MN	727455	NCDC	HIBBING CHISHOLM-HI	47.38	-92.85	410	x	x	x
MN	727456	NCDC	DULUTH HARBOR (CGS)	46.76	-92.08	186	x	x	x
MN	727459	NCDC	ELY MUNI (AWOS)	47.81	-91.83	443	x	x	x
MN	727469	NCDC	GRAND MARIAS	47.83	-90.38	186	x	x	x
MN	727473	NCDC	CRANE LAKE (AWOS)	46.26	-92.56	350	x	x	x
MN	727474	NCDC	EVELETH MUNI (AWOS)	47.40	-92.50	421	x	x	x
MN	727475	NCDC	MORA MUNI (AWOS)	45.88	-93.26	309	x	x	x
MN	727503	NCDC	CAMBRIDGE MUNI	45.56	-93.26	287	x	x	x
MN	727556	NCDC	SILVER BAY	47.20	-91.40	331	x	x	x
MN	727566	NCDC	AUSTIN MUNI	43.66	-92.93	375	x	x	x

Table A-1 Surface Stations used in CALMET Processing

Country/State	WBAN ID	Source [1]	Name	Latitude	Longitude	Elevation (m)	2002	2003	2004
MO	723300	NCDC	POPLAR BLUFF(AMOS)	36.76	-90.46	146	x	x	x
MO	723484	NCDC	WEST PLAINS - ASOS	36.88	-91.90	374	x	x	x
MO	723489	NCDC	CAPE GIRARDEAU MUNI	37.23	-89.56	102	x	x	x
MO	724340	NCDC	ST LOUIS LAMBERT IN	38.75	-90.36	173	x	x	x
MO	724345	NCDC	ST LOUIS SPIRIT OF	38.65	-90.65	140	x	x	x
MO	724347	NCDC	ST CHARLES COUNTY A	38.91	-90.41	133	x	x	x
MO	724400	NCDC	SPRINGFIELD REGIONA	37.23	-93.38	383	x	x	x
MO	724450	NCDC	COLUMBIA REGIONAL A	38.81	-92.21	272	x	x	x
MO	724453	NCDC	SEDALIA MEMORIAL	38.70	-93.18	277	x	x	x
MO	724454	NCDC	FARMINGTON	37.76	-90.40	274	x	x	x
MO	724455	NCDC	KIRKSVILLE REGIONAL	40.10	-92.55	294	x	x	x
MO	724456	NCDC	VICHY ROLLA NATL AR	38.13	-91.76	335	x	x	x
MO	724457	NCDC	FORT LEONARD WOOD	37.73	-92.13	351	x	x	x
MO	724458	NCDC	JEFFERSON CITY MEM	38.58	-92.15	167	x	x	x
MO	724459	NCDC	KAISER MEM (AWOS)	38.10	-92.55	265	x	x	x
MO	724464	NCDC	CHILLICOTHE	39.81	-93.58	234	x	x	x
MO	724467	NCDC	WHITEMAN AFB	38.71	-93.55	255	x	x	x
NC	723150	NCDC	ASHEVILLE REGIONAL	35.43	-82.53	652	x	x	x
OH	724276	NCDC	DAYTON GENERL ARPT	39.60	-84.23	293	x	x	x
OH	724280	NCDC	COLUMBUS PORT COLUM	39.98	-82.88	246	x	x	x
OH	724284	NCDC	COLUMBUS/BOLTON FLD	39.90	-83.13	280	x	x	x
OH	724285	NCDC	COLUMBUS RICKENBACK	39.81	-82.93	230	x	x	x
OH	724286	NCDC	ZANESVILLE MUNICIPA	39.95	-81.90	268	x	x	x
OH	724287	NCDC	METCALF FIELD	41.55	-83.46	189	x	x	x
OH	724288	NCDC	OHIO ST U/COLUMBUS	40.08	-83.06	276	x	x	x
OH	724290	NCDC	DAYTON INTERNATIONA	39.90	-84.21	304	x	x	x
OH	724294	NCDC	LANCASTER\FAIRFIEL	39.75	-82.65	264	x	x	x
OH	724296	NCDC	WILMINGTON AIRBORNE	39.41	-83.81	328	x	x	x
OH	724297	NCDC	CINCINNATI MUNICIPA	39.10	-84.41	149	x	x	x
OH	724298	NCDC	LIMA ALLEN CO ARPT	40.40	-84.01	296	x	x	x
OH	724303	NCDC	AKRON FULTON ASOS	41.03	-81.46	326	x	x	x
OH	725208	NCDC	MARION MUNI ARPT	40.61	-83.06	303	x	x	x
OH	725210	NCDC	AKRON AKRON-CANTON	40.91	-81.43	368	x	x	x
OH	725214	NCDC	ELYRIA/LORAIN CO.	41.35	-82.18	242	x	x	x
OH	725216	NCDC	WOOSTER	40.86	-81.88	346	x	x	x
OH	725217	NCDC	HAMILTON	39.36	-84.51	193	x	x	x
OH	725224	NCDC	NEW PHILADELPHIA	40.46	-81.41	272	x	x	x
OH	725229	NCDC	NEWARK/HEATH AIRPRT	40.01	-82.45	269	x	x	x
OH	725240	NCDC	CLEVELAND HOPKINS I	41.40	-81.85	234	x	x	x
OH	725245	NCDC	CLEVELAND/BURKELAKE	41.51	-81.68	178	x	x	x
OH	725246	NCDC	MANSFIELD LAHM MUNI	40.81	-82.51	394	x	x	x
OH	725247	NCDC	CLEVELAND/CUYAHOGA	41.56	-81.48	268	x	x	x
OH	725254	NCDC	DEFIANCE MEMORIAL	41.33	-84.41	219	x	x	x
OH	725360	NCDC	TOLEDO EXPRESS AIRP	41.58	-83.80	203	x	x	x
OH	725366	NCDC	FINDLAY AIRPORT	41.01	-83.66	243	x	x	x
OH	745700	NCDC	DAYTON WRIGHT PATTE	39.83	-84.05	249	x	x	x
OH	DCP114	CASTNET	Deer Creek	39.64	-83.26	267	x	x	x
OH	LYK123	CASTNET	Lykens	40.92	-83.00	303	x	x	x
OH	OXF122	CASTNET	Oxford	39.53	-84.73	284	x	x	x
SD	726626	NCDC	ANTIGO\LANG(AWOS)	45.15	-87.15	464	x	x	x

Table A-1 Surface Stations used in CALMET Processing

Country/State	WBAN ID	Source (1)	Name	Latitude	Longitude	Elevation (m)	2002	2003	2004
TN	723183	NCDC	BRISTOL TRI CITY AI	36.46	-82.40	457	x	x	x
TN	723246	NCDC	OAK RIDGE	36.01	-84.23	277	x	x	x
TN	723260	NCDC	KNOXVILLE MCGHEE TY	35.81	-83.98	293	x	x	x
TN	723265	NCDC	CROSSVILLE MEMORIAL	35.95	-85.08	569	x	x	x
TN	723270	NCDC	NASHVILLE INTERNATI	36.11	-86.68	176	x	x	x
TN	723347	NCDC	DYERSBURG MUNICIPAL	36.01	-89.40	102	x	x	x
TN	SPD111	CASTNET	Speedwell	36.47	-83.83	361	x	x	x
VA	724058	NCDC	ABINGTON	36.68	-82.03	631	x	x	x
VA	724117	NCDC	WISE/LONESOME PINE	36.98	-82.53	817	x	x	x
WI	726400	NCDC	MILWAUKEE MITCHELL	42.95	-87.90	204	x	x	x
WI	726404	NCDC	MINOCQUA/WOODRUFF	45.93	-89.73	496	x	x	x
WI	726405	NCDC	MILWAUKEE TIMMERMAN	43.11	-88.05	224	x	x	x
WI	726409	NCDC	WAUKESHA	43.03	-88.23	284	x	x	x
WI	726410	NCDC	MADISON DANE CO REG	43.13	-89.35	261	x	x	x
WI	726413	NCDC	WEST BEND MUNI	43.41	-88.11	270	x	x	x
WI	726414	NCDC	MONROE MUNICIPAL AI	42.60	-89.58	331	x	x	x
WI	726415	NCDC	JANESVILLE/ROCK CO.	42.61	-89.03	246	x	x	x
WI	726416	NCDC	LONE ROCK FAA AP	43.20	-90.18	219	x	x	x
WI	726417	NCDC	MEDFORD	45.10	-90.30	448	x	x	x
WI	726418	NCDC	OSCEOLA	45.31	-92.68	275	x	x	x
WI	726419	NCDC	ASHLAND KENNEDY ME	46.55	-90.91	251	x	x	x
WI	726424	NCDC	RACINE	42.76	-87.81	205	x	x	x
WI	726425	NCDC	SHEBOYGAN	43.78	-87.85	228	x	x	x
WI	726426	NCDC	STEVENS POINT	44.55	-89.53	338	x	x	x
WI	726427	NCDC	SUPERIOR	46.68	-92.10	206	x	x	x
WI	726430	NCDC	LA CROSSE MUNICIPAL	43.86	-91.25	198	x	x	x
WI	726435	NCDC	EAU CLAIRE COUNTY A	44.86	-91.48	271	x	x	x
WI	726436	NCDC	VOLK FIELD ANG	43.93	-90.26	280	x	x	x
WI	726437	NCDC	MCCOY (USA-AF)	43.96	-90.73	256	x	x	x
WI	726438	NCDC	BOSCOBEL AIRPORT	43.15	-90.42	205	x	x	x
WI	726444	NCDC	PRAIRIE DU CHIEN	43.01	-91.11	201	x	x	x
WI	726449	NCDC	MERRILL MUNI ARPT	45.18	-89.70	401	x	x	x
WI	726450	NCDC	GREEN BAY AUSTIN ST	44.48	-88.13	209	x	x	x
WI	726452	NCDC	WISCONSIN RAPIDS	44.35	-89.83	308	x	x	x
WI	726455	NCDC	MANITOWAC MUNI AWOS	44.13	-87.68	198	x	x	x
WI	726456	NCDC	OSHKOSH/WITTMAN FLD	43.96	-88.55	246	x	x	x
WI	726457	NCDC	APPLETON/OUTAGAMIE	44.25	-88.51	280	x	x	x
WI	726458	NCDC	STURGEON BAY	44.85	-87.41	221	x	x	x
WI	726463	NCDC	WAUSAU MUNICIPAL AR	44.91	-89.63	365	x	x	x
WI	726464	NCDC	WATERTOWN	43.16	-88.71	254	x	x	x
WI	726465	NCDC	MOSINEE/CENTRAL WI	44.78	-89.66	389	x	x	x
WI	726466	NCDC	APPLETON MUNI ARPT	44.55	-89.53	338	x	x	x
WI	726467	NCDC	RICE LAKE MUNICIPAL	45.48	-91.71	347	x	x	x
WI	726468	NCDC	PHILLIPS/PRICE CO.	45.70	-90.40	449	x	x	x
WI	726502	NCDC	CLINTONVILLE MUNI	44.61	-88.73	0	x	x	x
WI	726503	NCDC	WISCONSIN DELLS	43.51	-89.76	0	x	x	x
WI	726504	NCDC	EAGLE RIVER UNION	45.93	-89.26	500	x	x	x
WI	726505	NCDC	KENOSHA REGIONAL	42.60	-87.93	226	x	x	x
WI	726506	NCDC	FOND DU LAC CO.	43.76	-88.48	246		x	x
WI	726507	NCDC	MINERAL POINT	42.88	-90.23	0	x	x	x
WI	726508	NCDC	HAYWARD MUNI ARPT	46.03	-91.45	370	x	x	x
WI	726509	NCDC	JUNEAU\DODGE CO	43.43	-88.70	285	x	x	x
WI	726574	NCDC	MARSHFIELD MUNI	44.63	-90.18	389	x	x	x
WI	727415	NCDC	RHINELANDER/ONEIDA	45.63	-89.46	495	x	x	x
WI	PRK134	CASTNET	Perkinstown	45.21	-90.60	472	x	x	x
WV	724140	NCDC	CHARLESTON YEAGER A	38.38	-81.58	309	x	x	x
WV	724250	NCDC	HUNTINGTON TRI-STAT	38.38	-82.55	253	x	x	x
WV	724273	NCDC	PARKERSBURG WOOD CO	39.35	-81.43	253	x	x	x

x - Data is used in CALMET

(1) The Clean Air Status and Trends Network (CASTNET): http://www.epa.gov/castnet/site.html

National Climatic Data Center (NCDC): http://www.ncdc.noaa.gov/oa/ncdc.html

NOAA National Data Centers (NNDC): http://ols.nndc.noaa.gov/plolstore/plsql/olstore.main?look=1

Table A-2 Upper Air Stations used in CALMET Processing

State	Station Name	Station ID	Latitude	Longitude	Base Elevation (m)	2002	2003	2004
IA	DAVENPORT MUNICIPAL AP	94982	41.60	-90.57	229	x	x	x
IL	LINCOLN-LOGAN COUNTY AP	04833	40.15	-89.33	178	x	x	x
MI	GAYLORD / ALPENA	04837	44.55	-84.43	448	x	x	x
MI	DETROIT/PONTIAC	04830	42.70	-83.47	329	x	x	x
MN	INTERNATIONAL FALLS	14918	48.57	-93.38	359	x	x	x
MN	MINNEAPOLIS	94983	44.83	-93.55	287	x	x	x
MO	SPRINGFIELD REGIONAL AP	13995	37.23	-93.40	394	x	x	x
OH	WILMINGTON	13841	39.42	-83.82	317	x	x	x
PA	PITTSBURGH/MOON TOWNSHIP	94823	40.53	-80.23	360	x	x	x
TN	NASHVILLE	13897	36.25	-86.57	180	x	x	x
WI	GREEN BAY	14898	44.48	-88.13	210	x	x	x
x - Data is used in CALMET								

Table A-3 Buoy Stations used in CALMET Processing

Buoy Name	Station ID	Latitude	Longitude	Anemometer Height (m)	2002	2003	2004
N Michigan	45002	45.33	-86.42	5	x	x	x
N Huron	45003	45.35	-82.84	5	x	x	x
E Superior	45004	47.57	-86.55	5	x	x	x
S Huron	45008	44.29	-82.42	5	x	x	x
x - Data is used in CALMET							

Table A-4 Precipitation Stations used in CALMET Processing

State	ID	Station Name	Latitude	Longitude	Elevation (m)	2002	2003	2004
AR	030616	BERRYVILLE 5 NW	36.4294	-93.6256	1180	x	x	x
AR	031020	BULL SHOALS DAM	36.3647	-92.5781	480	x	x	x
AR	031632	CORNING	36.4197	-90.5858	300	x	x	x
AR	032356	EUREKA SPRINGS 3 WNW	36.4164	-93.7917	1420	x	x	x
AR	033132	HARDY	36.2747	-91.5056	400	x	x	x
AR	033165	HARRISON BOONE CNTY AP	36.2667	-93.1567	1374	x	x	x
IL	110082	ALEXIS 1 SW	41.0639	-90.5639	680	x	x	x
IL	110281	ASHLEY	38.3306	-89.1814	555	x	x	x
IL	110330	AUGUSTA	40.2378	-90.9456	680	x	x	x
IL	110510	BELLEVILLE SIU RESEARCH	38.5200	-89.8467	450	x	x	x
IL	110583	BELVIDERE	42.2550	-88.8644	738	x	x	x
IL	111166	CAIRO 3 N	37.0425	-89.1856	310	x	x	x
IL	111284	CARLINVILLE 2	39.2881	-89.8700	621	x	x	x
IL	111290	CARLYLE RESERVOIR	38.6308	-89.3658	501	x	x	x
IL	111302	CARMI 3	38.0781	-88.1831	335	x	x	x
IL	111549	CHICAGO OHARE AP	41.9950	-87.9336	658	x	x	x
IL	111577	CHICAGO MIDWAY AP 3SW	41.7372	-87.7775	620	x	x	x
IL	111664	CISNE 2 S	38.5047	-88.4094	454	x	x	x
IL	112011	CRETE	41.4492	-87.6222	664	x	x	x
IL	112140	DANVILLE	40.1389	-87.6483	558	x	x	x
IL	112193	DECATUR	39.8275	-88.9525	620	x	x	x
IL	112353	DIXON SPRINGS AGRIC CNT	37.4367	-88.6672	540	x	x	x
IL	112687	EFFINGHAM	39.1189	-88.6242	625	x	x	x
IL	112923	FAIRBURY WWTP	40.7511	-88.4983	690	x	x	x
IL	113262	FREEPORT WASTE WTR PL	42.2972	-89.6039	750	x	x	x
IL	113666	GREENFIELD	39.3425	-90.2058	548	x	x	x
IL	113683	GREENUP 3SE	39.2283	-88.1261	545	x	x	x
IL	113879	HARRISBURG	37.7408	-88.5244	365	x	x	x
IL	114198	HOOPESTON 1 NE	40.4744	-87.6558	710	x	x	x
IL	114317	HUTSONVILLE POWER PLANT	39.1333	-87.6578	455	x	x	x
IL	114355	ILLINOIS CITY DAM 16	41.4253	-91.0094	550	x	x	x
IL	114442	JACKSONVILLE 2E	39.7353	-90.2153	610	x	x	x
IL	114603	KANKAKEE METRO WASTWTR	41.1381	-87.8856	640	x	x	x
IL	114629	KASKASKIA RIV NAV LOCK	37.9842	-89.9492	380	x	x	x
IL	114710	KEWANEE 1 E	41.2483	-89.8992	780	x	x	x
IL	114805	LACON 1 N	41.0414	-89.4061	460	x	x	x
IL	114879	LANARK	42.0925	-89.8422	830	x	x	x
IL	114957	LAWRENCEVILLE	38.7267	-87.6903	442	x	x	x
IL	115272	MACKINAW 1N	40.5525	-89.3336	710	x	x	x
IL	115334	MARIETTA	40.5019	-90.3892	640	x	x	x
IL	115413	MASON CITY 1 E	40.2003	-89.6775	575	x	x	x
IL	115493	MCHENRY WG STRATTON L&D	42.3103	-88.2525	742	x	x	x
IL	115751	MOLINE WSO AP	41.4653	-90.5233	592	x	x	x
IL	115768	MONMOUTH	40.9247	-90.6392	745	x	x	x
IL	115825	MORRIS 1 NW	41.3708	-88.4336	524	x	x	x
IL	115841	MORRISONVILLE	39.4158	-89.4614	630	x	x	x
IL	115888	MT CARMEL	38.4106	-87.7578	430	x	x	x
IL	115983	MURPHYSBORO 2 SW	37.7608	-89.3656	550	x	x	x
IL	116185	NOKOMIS	39.3053	-89.2828	680	x	x	x
IL	116610	PARIS WATERWORKS	39.6356	-87.6933	680	x	x	x
IL	116711	PEORIA GTR PEORIA RGNL	40.6675	-89.6839	650	x	x	x
IL	116819	PIPER CITY	40.7569	-88.1828	670	x	x	x
IL	116837	PITTSFIELD NO 2	39.6222	-90.8058	670	x	x	x
IL	117014	PROPHETSTOWN	41.6808	-89.9403	605	x	x	x
IL	117072	QUINCY REGIONAL AP	39.9369	-91.1919	769	x	x	x
IL	117077	QUINCY DAM 21	39.9058	-91.4281	483	x	x	x
IL	117150	RANTOUL	40.3131	-88.1594	740	x	x	x
IL	117187	REND LAKE DAM	38.0406	-88.9883	455	x	x	x
IL	117382	ROCKFORD AIRPORT	42.1928	-89.0931	730	x	x	x
IL	117391	ROCK ISLAND L&D 15	41.5194	-90.5644	568	x	x	x
IL	117833	SHABBONA 3S	41.7322	-88.8653	850	x	x	x
IL	117876	SHELBYVILLE DAM	39.4106	-88.7800	655	x	x	x
IL	118020	SMITHLAND LOCK & DAM	37.1644	-88.4311	357	x	x	x
IL	118147	SPARTA 1 W	38.1167	-89.7167	535	x	x	x
IL	118179	SPRINGFIELD CAPITAL AP	39.8447	-89.6839	594	x	x	x
IL	118389	SULLIVAN 3 S	39.5608	-88.6067	659	x	x	x
IL	118740	URBANA	40.0842	-88.2406	721	x	x	x
IL	118781	VANDALIA	38.9703	-89.0922	540	x	x	x
IL	119193	WEST SALEM	38.5306	-88.0219	445	x	x	x
IL	119816	YATES CITY	40.7764	-90.0203	675	x	x	x

Table A-4 Precipitation Stations used in CALMET Processing

State	ID	Station Name	Latitude	Longitude	Elevation (m)	2002	2003	2004
IN	120132	ALPINE 2 NE	39.5736	-85.1583	850	x	x	x
IN	120177	ANDERSON SEWAGE PLANT	40.1122	-85.7175	845	x	x	x
IN	120200	ANGOLA	41.6397	-84.9900	1010	x	x	x
IN	120331	ATTICA 2E	40.2839	-87.1964	727	x	x	x
IN	120482	BATESVILLE WATERWORKS	39.2969	-85.2186	970	x	x	x
IN	120830	BLUFFTON 1 N	40.7478	-85.1733	825	x	x	x
IN	120922	BRAZIL	39.5108	-87.1242	680	x	x	x
IN	121147	BURLINGTON 1 NW	40.4875	-86.4089	724	x	x	x
IN	121256	CANNELTON	37.8994	-86.7072	402	x	x	x
IN	121415	CHALMERS	40.6628	-86.8814	700	x	x	x
IN	121628	CLINTON 2 W	39.6592	-87.4392	605	x	x	x
IN	121739	COLUMBIA CITY	41.1450	-85.4897	850	x	x	x
IN	121752	COLUMBUS UTILITIES	39.2106	-85.8883	632	x	x	x
IN	121814	CORYDON	38.2181	-86.1178	590	x	x	x
IN	121873	CRAWFORDSVILLE 6 SE	39.9664	-86.9289	840	x	x	x
IN	121929	CROTHERSVILLE	38.7908	-85.8483	560	x	x	x
IN	122309	DUBOIS SRN IN FORAGE FA	38.4558	-86.7000	690	x	x	x
IN	122738	EVANSVILLE REGIONAL AP	38.0431	-87.5203	400	x	x	x
IN	122825	FARMLAND 5 NNW	40.2539	-85.1483	965	x	x	x
IN	123037	FORT WAYNE WSO AP	41.0061	-85.2056	791	x	x	x
IN	123082	FRANKFORT DISPOSAL PLT	40.2986	-86.5067	824	x	x	x
IN	123091	FRANKLIN WWTP	39.4689	-86.0408	719	x	x	x
IN	123104	FREELANDVILLE	38.8672	-87.3083	550	x	x	x
IN	123206	GARRETT	41.3411	-85.1292	880	x	x	x
IN	123418	GOSHEN 3W	41.5575	-85.8825	875	x	x	x
IN	123714	HARRISON CRAWFORD S F	38.1975	-86.2686	850	x	x	x
IN	123777	HARTFORD CITY 4 ESE	40.4356	-85.2892	942	x	x	x
IN	124181	HUNTINGTON	40.8556	-85.4981	725	x	x	x
IN	124259	INDIANAPOLIS INTL AP	39.7317	-86.2789	790	x	x	x
IN	124286	INDIANAPOLIS ZOO	39.7681	-86.1806	710	x	x	x
IN	124372	JASPER	38.3861	-86.9408	460	x	x	x
IN	124527	KENTLAND	40.7592	-87.4353	695	x	x	x
IN	124730	LAGRANGE 1 N	41.6739	-85.4250	915	x	x	x
IN	124782	LAKEVILLE	41.5269	-86.2692	841	x	x	x
IN	124837	LA PORTE	41.6117	-86.7297	845	x	x	x
IN	124908	LEBANON WATER WORKS	40.0517	-86.4750	950	x	x	x
IN	124973	LEWISVILLE	39.8061	-85.3483	1065	x	x	x
IN	125337	MARION 2 N	40.5800	-85.6586	790	x	x	x
IN	125407	MARTINSVILLE 2 SW	39.4042	-86.4517	610	x	x	x
IN	125535	MEDARYVILLE 5 N	41.1589	-86.9014	695	x	x	x
IN	126151	NEWBURGH LOCK & DAM	37.9325	-87.3744	380	x	x	x
IN	126580	OOLITIC PURDUE EXP FRM	38.8894	-86.5519	650	x	x	x
IN	126697	PALMYRA	38.4075	-86.1106	770	x	x	x
IN	126864	PERU WASTE WATER PLANT	40.7453	-86.0717	645	x	x	x
IN	127069	PORTLAND 1 SW	40.4356	-85.2889	910	x	x	x
IN	127125	PRINCETON 1 W	38.3567	-87.5906	480	x	x	x
IN	127298	RENSSELAER	40.9356	-87.1564	650	x	x	x
IN	127370	RICHMOND WTR WKS	39.8833	-84.8833	1015	x	x	x
IN	127482	ROCHESTER	41.0658	-86.2094	770	x	x	x
IN	127930	SEYMOUR HIGHWAY GARAGE	38.9617	-85.8608	595	x	x	x
IN	127959	SHAKAMAK STATE PARK	39.1614	-87.2436	530	x	x	x
IN	127999	SHELBYVILLE SEWAGE PL	39.5283	-85.7917	750	x	x	x
IN	128036	SHOALS 8 S	38.5897	-86.7989	506	x	x	x
IN	128187	SOUTH BEND WSO AP	41.7072	-86.3331	773	x	x	x
IN	128442	STENDAL	38.2692	-87.1631	635	x	x	x
IN	128784	TIPTON 5 SW	40.2233	-86.1086	895	x	x	x
IN	128967	J T MYERS LOCKS & DAM	37.7953	-87.9931	340	x	x	x
IN	128999	VALPARAISO WATERWORKS	41.5114	-87.0378	800	x	x	x
IN	129069	VERSAILLES WATERWORKS	39.0717	-85.2453	939	x	x	x
IN	129174	WALDRON 2 W	39.4539	-85.6964	825	x	x	x
IN	129430	WEST LAFAYETTE 6 NW	40.4750	-86.9919	715	x	x	x
IA	130149	ALLERTON	40.7039	-93.3639	1090	x	x	x
IA	130608	BELLEVUE L AND D 12	42.2614	-90.4233	603	x	x	x
IA	131060	BURLINGTON RADIO KBUR	40.8167	-91.1667	703	x	x	x
IA	131257	CASCADE	42.2975	-91.0133	850	x	x	x
IA	131354	CENTERVILLE	40.7364	-92.8692	980	x	x	x
IA	131363	CENTRAL CITY	42.2011	-91.5286	870	x	x	x
IA	131724	COLUMBIA	41.1756	-93.1522	950	x	x	x
IA	132195	DERBY	40.9308	-93.4581	1190	x	x	x
IA	132203	DES MOINES AP	41.5339	-93.6531	957	x	x	x

Table A-4 Precipitation Stations used in CALMET Processing

State	ID	Station Name	Latitude	Longitude	Elevation (m)	2002	2003	2004
IA	132367	DUBUQUE WSO AP	42.3978	-90.7036	1056	x	x	x
IA	132977	FOREST CITY 2 NNE	43.2844	-93.6306	1300	x	x	x
IA	133473	GRINNELL 3 SW	41.7203	-92.7489	905	x	x	x
IA	134101	IOWA CITY	41.6092	-91.5050	640	x	x	x
IA	134142	IOWA FALLS	42.5189	-93.2536	1130	x	x	x
IA	134381	KEOKUK LOCK DAM 19	40.3969	-91.3767	527	x	x	x
IA	134502	KNOXVILLE	41.3336	-93.1117	920	x	x	x
IA	134963	LOWDEN	41.8564	-90.9300	715	x	x	x
IA	135198	MARSHALLTOWN	42.0647	-92.9244	870	x	x	x
IA	135235	MASON CITY MUNI AP	43.1544	-93.3269	1225	x	x	x
IA	135295	MAXWELL	41.8875	-93.3919	875	x	x	x
IA	135315	MCGREGOR	43.0239	-91.1747	627	x	x	x
IA	135796	MOUNT PLEASANT 1 SSW	40.9486	-91.5647	730	x	x	x
IA	136076	NORTH ENGLISH	41.5119	-92.0725	797	x	x	x
IA	136389	OTTUMWA INDUSTRIAL AP	41.1078	-92.4467	842	x	x	x
IA	137326	ST ANSGAR	43.3817	-92.9156	1170	x	x	x
IA	137572	SHEFFIELD 3 NW	42.9217	-93.2828	1045	x	x	x
IA	137602	SHELL ROCK 2W	42.7081	-92.6153	912	x	x	x
IA	137855	SPILLVILLE	43.2053	-91.9536	1080	x	x	x
IA	137985	STORY CITY	42.1792	-93.5817	975	x	x	x
IA	138009	STRAWBERRY POINT	42.6842	-91.5353	1200	x	x	x
IA	138315	TRAER	42.1869	-92.4728	950	x	x	x
IA	138688	WASHINGTON	41.2828	-91.7069	690	x	x	x
IA	138706	WATERLOO MUNICIPAL AP	42.5544	-92.4011	868	x	x	x
KY	150381	BARBOURVILLE	36.8825	-83.8819	990	x	x	x
KY	150450	BAXTER	36.8583	-83.3303	1164	x	x	x
KY	150611	BENTON	36.8581	-88.3364	365	x	x	x
KY	150619	BEREA COLLEGE	37.5733	-84.2908	1070	x	x	x
KY	151080	BUCKHORN LAKE	37.3500	-83.3833	936	x	x	x
KY	151227	CALHOUN LOCK 2	37.5317	-87.2667	402	x	x	x
KY	151631	CLINTON 4 S	36.6267	-88.9608	350	x	x	x
KY	151855	COVINGTON WSO	39.0431	-84.6717	869	x	x	x
KY	152358	DUNDEE 2NE	37.5806	-86.7769	450	x	x	x
KY	152979	FORDSVILLE	37.6372	-86.7206	480	x	x	x
KY	153741	HEIDELBERG	37.5500	-83.7667	665	x	x	x
KY	153798	HERNDON 5 S	36.6703	-87.5589	560	x	x	x
KY	153929	HODGENVILLE-LINCOLN NP	37.5317	-85.7350	788	x	x	x
KY	154202	JACKSON WSO	37.5914	-83.3144	1365	x	x	x
KY	154650	LEBANON 5 S	37.5050	-85.3086	660	x	x	x
KY	154746	LEXINGTON BLUEGRASS AP	38.0408	-84.6058	980	x	x	x
KY	154948	LOUISA 5 W	38.1250	-82.6947	753	x	x	x
KY	154954	LOUISVILLE INTL AP	38.1811	-85.7392	488	x	x	x
KY	154955	LOUISVILLE UPPER GAGE	38.2833	-85.8000	440	x	x	x
KY	155067	MADISONVILLE	37.3467	-87.5244	440	x	x	x
KY	155243	MAYSVILLE SEWAGE PLANT	38.6869	-83.7872	515	x	x	x
KY	155555	MOREHEAD 3 NW	38.2167	-83.4833	830	x	x	x
KY	155684	MUNFORDVILLE 5 NW	37.3347	-85.9503	680	x	x	x
KY	156012	OLIVE HILL 5 NE	38.3422	-83.1036	891	x	x	x
KY	156110	PADUCAH BARKLEY AP	37.0564	-88.7742	413	x	x	x
KY	156170	PARIS	38.2047	-84.2392	810	x	x	x
KY	156580	PRINCETON 1 SE	37.1244	-87.8672	497	x	x	x
KY	157074	SADIEVILLE	38.4078	-84.6836	945	x	x	x
KY	157473	SMITHFIELD 4 S	38.3333	-85.2861	850	x	x	x
KY	157508	SOMERSET 2 NE	37.1167	-84.6000	955	x	x	x
KY	157622	STAFFORDSVILLE 2 NW	37.8500	-82.8667	760	x	x	x
KY	157677	STEARNS 2 S	36.6667	-84.4833	1220	x	x	x
KY	158070	TOMPKINSVILLE 9 NW	36.8136	-85.7081	1060	x	x	x
KY	158719	WILLISBURG	37.8014	-85.1131	870	x	x	x
KY	158824	WOODBURY	37.1842	-86.6353	465	x	x	x
MI	200128	ALLEGAN 5 NE	42.5797	-85.7894	750	x	x	x
MI	200164	ALPENA COUNTY RGNL AP	45.0717	-83.5644	684	x	x	x
MI	200230	ANN ARBOR U OF MICH	42.2947	-83.7108	900	x	x	x
MI	200373	AVOCA 4 N	43.1256	-82.6886	770	x	x	x
MI	200662	BELLAIRE	44.9758	-85.1978	625	x	x	x
MI	200766	BIG BAY 8 NW	46.8867	-87.8642	612	x	x	x
MI	201088	BRUCE CROSSING	46.5333	-89.1833	1135	x	x	x
MI	201361	CASS CITY 1 SSW	43.5861	-83.1806	698	x	x	x
MI	201486	CHATHAM EXP FARM 2	46.3467	-86.9289	870	x	x	x
MI	201680	COLDWTR WASTEWTR PLT	41.9397	-85.0183	950	x	x	x
MI	201780	COPPER HARBOR FT WILKIN	47.4675	-87.8669	625	x	x	x

Table A-4 Precipitation Stations used in CALMET Processing

State	ID	Station Name	Latitude	Longitude	Elevation (m)	2002	2003	2004
MI	202094	DETOUR VILLAGE	45.9983	-83.9014	595	x	x	x
MI	202103	DETROIT METRO AP	42.2314	-83.3308	631	x	x	x
MI	202395	EAST LANSING 4 S	42.6742	-84.4850	880	x	x	x
MI	202626	ESCANABA	45.7500	-87.0333	591	x	x	x
MI	202788	FIFE LAKE 3WSW	44.5650	-85.4133	1112	x	x	x
MI	202846	FLINT BISHOP INTL AP	42.9667	-83.7494	770	x	x	x
MI	203170	GLADWIN	43.9758	-84.4908	775	x	x	x
MI	203199	GLENNIE ALCONA DAM	44.5617	-83.8031	805	x	x	x
MI	203295	GRAND HAVEN WASTEWTR PL	43.0608	-86.2047	605	x	x	x
MI	203333	GRAND RAPIDS INTL AP	42.8825	-85.5239	803	x	x	x
MI	203391	GRAYLING	44.6542	-84.6994	1136	x	x	x
MI	203516	GWINN 1 W	46.2864	-87.4511	1162	x	x	x
MI	203585	HARBOR BEACH 1 SSE	43.8322	-82.6428	595	x	x	x
MI	203936	HOUGHTON LAKE ROSCOMMON	44.3592	-84.6739	1151	x	x	x
MI	203947	HOWELL WWTP	42.5936	-83.9322	917	x	x	x
MI	204090	IRON MTN-KINGSFORD WWTP	45.7858	-88.0842	1071	x	x	x
MI	204155	JACKSON 3 N	42.2833	-84.4167	950	x	x	x
MI	204320	KENT CITY 2 SW	43.1994	-85.7717	840	x	x	x
MI	204641	LANSING CAPITAL CITY A	42.7803	-84.5789	841	x	x	x
MI	205073	MANISTIQUE WWTP	45.9511	-86.2511	620	x	x	x
MI	205567	MONTAGUE 4 NW	43.4614	-86.4175	650	x	x	x
MI	205712	MUSKEGON COUNTY AP	43.1711	-86.2367	625	x	x	x
MI	205816	NEWBERRY 3 S	46.3133	-85.5106	850	x	x	x
MI	206215	ONTONAGON	46.8561	-89.3119	673	x	x	x
MI	206300	OWOSSO WWTP	43.0161	-84.1800	730	x	x	x
MI	206438	PELLSTON REGIONAL AP	45.5644	-84.7928	705	x	x	x
MI	207366	SAULT STE MARIE SNDRSN	46.4794	-84.3572	722	x	x	x
MI	207812	STAMBAUGH 2 SSE	46.0556	-88.6278	1450	x	x	x
MI	207828	STANTON	43.2908	-85.0922	930	x	x	x
MI	208246	TRAVERSE CITY	44.7683	-85.5761	604	x	x	x
MI	208293	TROUT LAKE 2WNW	46.1989	-85.0728	871	x	x	x
MI	208417	VANDERBILT 11ENE	45.1703	-84.4397	905	x	x	x
MI	208443	VASSAR	43.3656	-83.5828	630	x	x	x
MI	208559	WAKEFIELD	46.4792	-89.9322	1600	x	x	x
MI	209218	YPSILANTI E MICH U	42.2475	-83.6253	780	x	x	x
MN	210075	ALBERT LEA 3 SE	43.6064	-93.3019	1230	x	x	x
MN	211227	CAMBRIDGE 5ESE	45.5506	-93.1264	960	x	x	x
MN	212166	DODGE CENTER	44.0419	-92.8814	1250	x	x	x
MN	212248	DULUTH INTL AP	46.8369	-92.1833	1433	x	x	x
MN	212543	ELY	47.9239	-91.8586	1382	x	x	x
MN	212645	EVELETH WASTE WATER PLA	47.4581	-92.5303	1445	x	x	x
MN	212842	FLOODWOOD 3 NE	46.9728	-92.8700	1260	x	x	x
MN	213202	GOLDEN VALLEY	44.9944	-93.4075	910	x	x	x
MN	213417	GUNFLINT LAKE 10 NW	48.1603	-90.8842	1455	x	x	x
MN	213793	HINCKLEY	45.9919	-92.9928	1035	x	x	x
MN	213863	HOLYOKE	46.4675	-92.3903	1034	x	x	x
MN	214418	LA CRESCENT DAM 7	43.8658	-91.3100	647	x	x	x
MN	215435	MINNEAPOLIS/ST PAUL AP	44.8831	-93.2289	872	x	x	x
MN	215987	NORTHFIELD 2 NNE	44.4761	-93.1486	890	x	x	x
MN	216213	ORR	48.0553	-92.8425	1390	x	x	x
MN	216822	RED WING DAM 3	44.6103	-92.6100	677	x	x	x
MN	217004	ROCHESTER INTERNATIONAL	43.9042	-92.4917	1304	x	x	x
MN	217184	RUSHFORD	43.8053	-91.7500	770	x	x	x
MN	217460	SANDY LAKE DAM LIBBY	46.7953	-93.3211	1234	x	x	x
MN	217941	SPRING VALLEY	43.6933	-92.3925	1280	x	x	x
MN	218280	TOFTE RANGER STATION	47.5681	-90.8500	680	x	x	x
MN	218613	WALES 2E	47.2561	-91.7017	1675	x	x	x
MO	230022	ADVANCE 1 S	37.0956	-89.9058	360	x	x	x
MO	230088	ALLEY SPRING RGR STA	37.1528	-91.4439	700	x	x	x
MO	230789	BOLIVAR 1 NE	37.6167	-93.3911	1034	x	x	x
MO	231283	CAP AU GRIS LOCK & DAM	39.0031	-90.6886	450	x	x	x
MO	231600	CLARENCE CANNON DAM	39.5253	-91.6450	702	x	x	x
MO	231640	CLARKSVILLE L&D 24	39.3731	-90.9053	460	x	x	x
MO	231674	CLEARWATER DAM	37.1319	-90.7756	660	x	x	x
MO	231711	CLINTON	38.3950	-93.7711	770	x	x	x
MO	231791	COLUMBIA REGIONAL AP	38.8169	-92.2183	893	x	x	x
MO	232302	DORA	36.7797	-92.2328	990	x	x	x
MO	232318	DOWNING	40.4822	-92.3636	870	x	x	x
MO	232809	FARMINGTON	37.7922	-90.4103	928	x	x	x
MO	233079	FULTON	38.8581	-91.9300	870	x	x	x

Table A-4 Precipitation Stations used in CALMET Processing

State	ID	Station Name	Latitude	Longitude	Elevation (m)	2002	2003	2004
MO	233601	HANNIBAL WATER WORKS	39.7233	-91.3719	712	x	x	x
MO	234271	JEFFERSON CITY WTR PL	38.5850	-92.1825	670	x	x	x
MO	234273	JEFFERSON BARRACKS	38.5039	-90.2800	490	x	x	x
MO	234544	KIRKSVILLE	40.2058	-92.5747	970	x	x	x
MO	234825	LEBANON 2W	37.6850	-92.6936	1279	x	x	x
MO	234919	LICKING 4N	37.5544	-91.8831	1180	x	x	x
MO	235050	LONG BRANCH RESERVOIR	39.7506	-92.5064	820	x	x	x
MO	235130	LURAY 2 N	40.4892	-91.8781	740	x	x	x
MO	235207	MALDEN MUNICIPAL AP	36.5994	-89.9894	290	x	x	x
MO	235298	MARSHALL	39.1342	-93.2225	790	x	x	x
MO	235307	MARSHFIELD	37.3381	-92.9097	1490	x	x	x
MO	235415	MC CREDIE EXPERIMENT ST	38.9500	-91.9000	850	x	x	x
MO	235562	MIDDLETOWN	39.1244	-91.4142	680	x	x	x
MO	235594	MILLER 1 E	37.2147	-93.8228	1296	x	x	x
MO	235671	MOBERLY	39.4194	-92.4369	860	x	x	x
MO	235834	MOUNTAIN GROVE 2 N	37.1528	-92.2636	1450	x	x	x
MO	236012	NEW FRANKLIN 1 W	39.0172	-92.7558	641	x	x	x
MO	236460	OZARK BEACH	36.6597	-93.1261	700	x	x	x
MO	236777	POMME DE TERRE DAM	37.9050	-93.3169	900	x	x	x
MO	236826	POTOSI 5 SW	37.8908	-90.8600	1030	x	x	x
MO	237263	ROLLA UNI OF MISSOURI	37.9572	-91.7758	1167	x	x	x
MO	237300	ROSEBUD	38.4506	-91.3756	960	x	x	x
MO	237452	ST LOUIS SCIENCE CENTER	38.6292	-90.2706	545	x	x	x
MO	237455	ST LOUIS LAMBERT INTL	38.7525	-90.3736	531	x	x	x
MO	237506	SALEM	37.6331	-91.5364	1200	x	x	x
MO	237976	SPRINGFIELD REG AP	37.2397	-93.3897	1259	x	x	x
MO	238043	STEELVILLE 2 N	38.0053	-91.3706	700	x	x	x
MO	238051	STEFFENVILLE	39.9714	-91.8872	690	x	x	x
MO	238082	STOCKTON DAM	37.6967	-93.7722	873	x	x	x
MO	238223	SWEET SPRINGS	38.9631	-93.4000	670	x	x	x
MO	238252	TABLE ROCK DAM	36.5972	-93.3075	820	x	x	x
MO	238466	TRUMAN DAM & RESERVOIR	38.2581	-93.3989	632	x	x	x
MO	238609	VIBURNUM	37.7119	-91.1328	1276	x	x	x
MO	238620	VIENNA 2 WNW	38.2017	-91.9811	770	x	x	x
MO	238700	WAPPAPELLO DAM	36.9231	-90.2836	410	x	x	x
MO	238712	WARRENSBURG 4 NW	38.7842	-93.8008	796	x	x	x
MO	238746	WASHINGTON	38.5425	-90.9719	490	x	x	x
MO	238827	WENTZVILLE	38.8128	-90.8561	580	x	x	x
MO	238880	WEST PLAINS	36.7425	-91.8347	1010	x	x	x
OH	330058	AKRON CANTON WSO AP	40.9167	-81.4333	1208	x	x	x
OH	330059	AKRON WPCS	41.1500	-81.5667	750	x	x	x
OH	330107	ALLIANCE 3 NNW	40.9550	-81.1169	1055	x	x	x
OH	330256	ASHLAND 2 SW	40.8333	-82.3500	1265	x	x	x
OH	330493	BEACH CITY LAKE	40.6333	-81.5667	985	x	x	x
OH	330639	BERLIN LAKE	41.0333	-81.0167	1040	x	x	x
OH	330862	BOWLING GREEN WWTP	41.3831	-83.6111	675	x	x	x
OH	331042	BRYAN 2 SE	41.4619	-84.5272	730	x	x	x
OH	331197	CAMBRIDGE	40.0167	-81.5833	800	x	x	x
OH	331404	CENTERBURG 2 SE	40.3000	-82.6500	1205	x	x	x
OH	331466	CHARLES MILL LAKE	40.7400	-82.3569	1025	x	x	x
OH	331528	CHILLICOTHE MOUND CITY	39.3744	-83.0036	650	x	x	x
OH	331536	CHILO MELDAHL L&D	38.7983	-84.1731	500	x	x	x
OH	331541	CHIPPEWA LAKE	41.0517	-81.9361	1180	x	x	x
OH	331592	CIRCLEVILLE	39.6106	-82.9547	673	x	x	x
OH	331651	CLEVELAND EASTERLY	41.5667	-81.5833	550	x	x	x
OH	331657	CLEVELAND WSFO AP	41.4050	-81.8528	770	x	x	x
OH	331786	COLUMBUS WSO AIRPORT	39.9914	-82.8808	810	x	x	x
OH	331905	COSHOCTON AGRI RS STA	40.3708	-81.7908	1140	x	x	x
OH	332075	DAYTON WSO AIRPORT	39.9061	-84.2186	1000	x	x	x
OH	332090	DEER CREEK LAKE	39.6253	-83.2128	860	x	x	x
OH	332098	DEFIANCE	41.2778	-84.3853	700	x	x	x
OH	332124	DELAWARE LAKE	40.3667	-83.0667	930	x	x	x
OH	332272	DOVER DAM	40.5667	-81.4167	930	x	x	x
OH	332485	EATON	39.7347	-84.6336	1002	x	x	x
OH	332651	FAIRFIELD	39.3500	-84.5833	575	x	x	x
OH	332791	FINDLAY WPCC	41.0461	-83.6622	768	x	x	x
OH	332956	FREDERICKTOWN 4 S	40.4167	-82.5333	1050	x	x	x
OH	332974	FREMONT	41.3333	-83.1167	600	x	x	x
OH	333021	GALION WATER WORKS	40.7167	-82.8000	1170	x	x	x

Table A-4 Precipitation Stations used in CALMET Processing

State	ID	Station Name	Latitude	Longitude	Elevation (m)	2002	2003	2004
OH	333120	GERMANTOWN DAM	39.6358	-84.4003	740	x	x	x
OH	333356	GREENFIELD 1 WNW	39.3542	-83.4056	970	x	x	x
OH	333375	GREENVILLE WATER PLANT	40.1000	-84.6500	1024	x	x	x
OH	333758	HILLSBORO	39.2000	-83.6167	1100	x	x	x
OH	334004	JACKSON 3 NW	39.0775	-82.7053	800	x	x	x
OH	334189	KENTON	40.6489	-83.6061	995	x	x	x
OH	334403	LANCASTER	39.7156	-82.6072	840	x	x	x
OH	334459	LEBANON 4 SE	39.3689	-84.2394	680	x	x	x
OH	334473	LEESVILLE LAKE	40.4667	-81.2000	980	x	x	x
OH	334551	LIMA WWTP	40.7247	-84.1294	850	x	x	x
OH	334672	LOGAN	39.5292	-82.3850	722	x	x	x
OH	334681	LONDON	39.8833	-83.4500	1020	x	x	x
OH	334865	MANSFIELD WSO AP	40.8203	-82.5178	1295	x	x	x
OH	334942	MARION 2 N	40.6167	-83.1333	965	x	x	x
OH	334979	MARYSVILLE	40.2411	-83.3669	1000	x	x	x
OH	334992	MASSILLON	40.7667	-81.5333	930	x	x	x
OH	335029	MC ARTHUR	39.2503	-82.4822	785	x	x	x
OH	335041	MC CONNELSVILLE LOCK 7	39.6539	-81.8569	760	x	x	x
OH	335297	MILLERSBURG	40.5500	-81.9167	819	x	x	x
OH	335398	MOHAWK DAM	40.3486	-82.0908	865	x	x	x
OH	335585	MOUNT VERNON	40.3833	-82.4667	980	x	x	x
OH	335747	NEWARK WATER WORKS	40.0875	-82.4131	835	x	x	x
OH	336123	NORWALK 5 SE	41.1833	-82.5667	925	x	x	x
OH	336196	OBERLIN	41.2667	-82.2167	816	x	x	x
OH	336375	OXFORD	39.5167	-84.7333	860	x	x	x
OH	336616	PIEDMONT LAKE	40.1833	-81.2167	940	x	x	x
OH	336650	PIQUA WWTP	40.1311	-84.2342	800	x	x	x
OH	336702	PLEASANT HILL LAKE	40.6167	-82.3333	1125	x	x	x
OH	336781	PORTSMOUTH SCIOTOVILLE	38.7569	-82.8872	540	x	x	x
OH	336949	RAVENNA 2 S	41.1333	-81.2833	1107	x	x	x
OH	337383	ST MARYS 3 W	40.5447	-84.4375	875	x	x	x
OH	337559	SENECAVILLE LAKE	39.9222	-81.4347	875	x	x	x
OH	337698	SIDNEY HIGHWAY DEPT	40.2983	-84.1633	1030	x	x	x
OH	337935	SPRINGFIELD NEW WTR WKS	39.9667	-83.8167	930	x	x	x
OH	338240	TAPPAN DAM	40.3561	-81.2281	950	x	x	x
OH	338313	TIFFIN	41.1167	-83.1667	740	x	x	x
OH	338357	TOLEDO EXPRESS WSO AP	41.5886	-83.8014	669	x	x	x
OH	338378	TOM JENKINS DAM-BURR OA	39.5444	-82.0589	760	x	x	x
OH	338539	UPPER SANDUSKY WATER WK	40.8167	-83.2833	820	x	x	x
OH	338552	URBANA WWTP	40.1000	-83.7833	1000	x	x	x
OH	338810	WATERLOO	38.7003	-82.4736	625	x	x	x
OH	339211	WILLS CREEK LAKE	40.1500	-81.8500	780	x	x	x
OH	339224	WILMINGTON	39.4333	-83.8500	975	x	x	x
OH	339312	WOOSTER EXP STN	40.7833	-81.9167	1020	x	x	x
OH	339357	XENIA TREATMENT PLANT	39.7167	-83.9667	820	x	x	x
OH	339422	ZANESVILLE WWTP	39.9125	-82.0042	700	x	x	x
TN	401094	BRISTOL AP	36.4731	-82.4044	1500	x	x	x
TN	401561	CELINA	36.5408	-85.4594	540	x	x	x
TN	401663	CHEATHAM LOCK & DAM	36.3244	-87.2244	392	x	x	x
TN	405332	LIVINGSTON RADIO WLIV	36.3772	-85.3394	975	x	x	x
TN	407359	PORTLAND SEWAGE PLANT	36.5875	-86.5258	794	x	x	x
TN	407884	ROGERSVILLE 1 NE	36.4161	-82.9839	1355	x	x	x
TN	408065	SAMBURG W. L. REFUGE	36.4528	-89.3028	310	x	x	x
TN	408562	SPRINGFIELD EXPERIMENT	36.4739	-86.8472	745	x	x	x
TN	409219	UNION CITY	36.3925	-89.0317	350	x	x	x
VA	444180	HURLEY 4 S	37.3653	-82.0561	1088	x	x	x
VA	449215	WISE 3E	36.9986	-82.5389	2549	x	x	x
WV	461570	CHARLESTON YEAGER AP	38.3794	-81.5914	910	x	x	x
WV	461579	CHARLESTON WSFO	38.3139	-81.7186	918	x	x	x
WV	463749	GRIFFITHSVILLE	38.2381	-81.9853	780	x	x	x
WV	464393	HUNTINGTON TRI/STATE	38.3650	-82.5550	824	x	x	x
WV	465323	LIVERPOOL	38.8956	-81.5311	665	x	x	x
WV	465353	LOGAN	37.8611	-81.9961	640	x	x	x
WV	468351	SOUTHSIDE 3 NNW	38.7506	-81.9808	576	x	x	x
WI	470045	AFTON	42.6475	-89.0644	742	x	x	x
WI	470124	ALMA DAM 4	44.3272	-91.9194	670	x	x	x

Table A-4 Precipitation Stations used in CALMET Processing

State	ID	Station Name	Latitude	Longitude	Elevation (m)	2002	2003	2004
WI	470308	ARLINGTON UNIV FARM	43.3008	-89.3269	1080	x	x	x
WI	470349	ASHLAND EXP FARM	46.5728	-90.9714	650	x	x	x
WI	470456	BABCOCK 1 WNW	44.2994	-90.1306	980	x	x	x
WI	470855	BLACK RVR FALLS SWG	44.2903	-90.8536	810	x	x	x
WI	470890	BLANCHARDVILLE	42.8169	-89.8628	830	x	x	x
WI	471416	CHARMANY FARM	43.0603	-89.4781	910	x	x	x
WI	471568	CHILTON	44.0328	-88.1469	840	x	x	x
WI	471578	CHIPPEWA FALLS	44.9278	-91.4081	850	x	x	x
WI	471667	CLINTON	42.5492	-88.8753	960	x	x	x
WI	471676	CLINTONVILLE	44.6225	-88.7483	800	x	x	x
WI	471897	CRIVITZ HIGH FALLS	45.3581	-88.1925	1050	x	x	x
WI	471913	CUBA CITY 2NW	42.6253	-90.4592	900	x	x	x
WI	472447	EAU PLEINE RESERVOIR	44.7247	-89.7567	1138	x	x	x
WI	472973	FRIENDSHIP	43.9750	-89.8308	945	x	x	x
WI	473038	GENOA DAM 8	43.5706	-91.2294	639	x	x	x
WI	473269	GREEN BAY A S INTL AP	44.4794	-88.1378	687	x	x	x
WI	473453	HARTFORD 2 W	43.3311	-88.4114	980	x	x	x
WI	473511	HAYWARD RANGER STA	46.0003	-91.5075	1200	x	x	x
WI	473636	HILES	45.6811	-88.9603	1633	x	x	x
WI	473756	HORICON	43.4406	-88.6325	880	x	x	x
WI	474370	LA CROSSE MUNICIPAL AIR	43.8789	-91.2528	652	x	x	x
WI	474396	LADYSMITH WTP	45.4431	-91.0894	1160	x	x	x
WI	474404	LA FARGE	43.5753	-90.6417	810	x	x	x
WI	474546	LANCASTER 4 WSW	42.8278	-90.7889	1040	x	x	x
WI	474894	LUCK	45.5733	-92.4850	1220	x	x	x
WI	474937	LYNXVILLE DAM 9	43.2117	-91.0986	633	x	x	x
WI	474961	MADISON DANE COUNTY AP	43.1406	-89.3453	866	x	x	x
WI	475120	MARSHFIELD EXP FARM	44.6322	-90.1314	1250	x	x	x
WI	475255	MEDFORD	45.1308	-90.3439	1470	x	x	x
WI	475335	MENOMONIE	44.8742	-91.9364	780	x	x	x
WI	475352	MERCER RANGER STN	46.1683	-90.0722	1600	x	x	x
WI	475364	MERRILL	45.1706	-89.6614	1253	x	x	x
WI	475479	MILWAUKEE MITCHELL AP	42.9550	-87.9044	670	x	x	x
WI	475524	MINONG RANGER STN	46.1006	-91.8178	1080	x	x	x
WI	475948	NEW RICHMOND	45.1167	-92.5639	1000	x	x	x
WI	476398	PARK FALLS DNR HQ	45.9336	-90.4506	1525	x	x	x
WI	476510	PESHTIGO	45.0203	-87.7342	600	x	x	x
WI	476518	PHELPS	46.0658	-89.0756	1776	x	x	x
WI	476718	PORTAGE	43.5278	-89.4342	775	x	x	x
WI	476854	PRENTICE	45.5478	-90.2883	1540	x	x	x
WI	476939	RAINBOW RSVR-LK TOMAHAW	45.8342	-89.5494	1600	x	x	x
WI	477132	RICE LAKE	45.4164	-91.7719	1103	x	x	x
WI	477140	RICE RESERVOIR TOMAHAWK	45.5406	-89.7481	1465	x	x	x
WI	478027	SPOONER EXPERMNT FARM	45.8236	-91.8761	1100	x	x	x
WI	478259	STRUM 4 S	44.4964	-91.3964	976	x	x	x
WI	478267	STURGEON BAY EXP FARM	44.8722	-87.3353	656	x	x	x
WI	478316	SULLIVAN 3SE	42.9675	-88.5497	933	x	x	x
WI	478515	TOMAH RANGER STATION	43.9908	-90.5053	960	x	x	x
WI	478589	TREMPEALEAU DAM 6	43.9994	-91.4378	660	x	x	x
WI	479176	WHITE LAKE 3 NE	45.1817	-88.7344	1285	x	x	x
WI	479218	WILLARD	44.7314	-90.7217	1490	x	x	x
WI	479304	WINTER	45.8231	-91.0139	1397	x	x	x
x - Data is used in CALMET								