BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	R08-19
NITROGEN OXIDES EMISSIONS FROM	)	(Rulemaking - Air)
VARIOUS SOURCE CATEGORIES:	)	
AMENDMENTS TO 35 ILL. ADM. CODE	)	
PARTS 211 and 217	)	

NOTICE OF FILING

TO: Mr. John T. Therriault
Assistant Clerk of the Board
Illinois Pollution Control Board
100 W. Randolph Street
Suite 11-500
Chicago, Illinois 60601
(VIA ELECTRONIC MAIL)

Timothy Fox, Esq.
Hearing Officer
Illinois Pollution Control Board
100 W. Randolph Street
Suite 11-500
Chicago, Illinois 60601
(VIA FIRST CLASS MAIL)

(SEE PERSONS ON ATTACHED SERVICE LIST)

PLEASE TAKE NOTICE that I have today filed with the Office of the Clerk of the Illinois Pollution Control Board the **SUPPORTING MATERIALS FROM UNITED STATES STEEL CORPORATION**, a copy of which is herewith served upon you.

Respectfully submitted,

By: /s/ Katherine D. Hodge
Katherine D. Hodge

Dated: January 30, 2009

Katherine D. Hodge
Monica T. Rios
HODGE DWYER ZEMAN
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(217) 523-4900

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	R08-19
NITROGEN OXIDES EMISSIONS FROM	)	(Rulemaking - Air)
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SUPPORTING MATERIALS FROM
UNITED STATES STEEL CORPORATION

NOW COMES UNITED STATES STEEL CORPORATION ("U.S. Steel"), by and through its attorneys, HODGE DWYER ZEMAN, and submits the attached SUPPORTING MATERIALS in the above-referenced matter.

1. On December 10, 2008, Mr. Larry Siebenberger on behalf of U.S. Steel, as well as U.S. Steel's consultant, URS Corporation ("URS"), presented testimony in the above-referenced matter. During the course of U.S. Steel's testimony, the Illinois Environmental Protection Agency ("Agency") or the Illinois Pollution Control Board ("Board") requested additional documents or information in response to testimony by Mr. Siebenberger or U.S. Steel's consultants.

2. The following materials are being provided in response to Agency or Board requests at hearing:

a. On page 18 of the December 10, 2008 transcript, the Agency requested data calculations regarding expected NOx emissions for Boilers 11 and 12 if only desulfurized coke oven gas ("COG") were used in combination with flue gas recirculation ("FGR"). U.S. Steel has provided a "Description of NOx RACT Emission Rate For Boilers 11 and 12 (Assuming all Coke Oven Gas is Scrubbed)" as Attachment A. Attachment A is a supplement to Exhibit A of the Pre-filed Testimony of Larry G. Siebenberger filed with the Board on November 25, 2008.

b. On pages 29 through 30 of the December 10, 2008 transcript, the Agency requested data calculations regarding expected NOx emissions for reheat furnaces if only desulfurized COG were used in combination with the low NOx burner configuration now being installed. U.S. Steel has provided an "Estimation of NOx Emissions for Slab Furnaces 1, 2, 3 and 4 assuming All Coke Oven Gas is Desulfurized" as Attachment B. Attachment B is a supplement to Exhibit B of the Pre-filed Testimony of Larry G. Siebenberger filed with the Board on November 25, 2008.

c. On page 25 of the December 10, 2008 transcript, the Agency requested historical data on COG combusted in Boilers 11 and 12. U.S. Steel has provided a spreadsheet of historical data on COG combusted in Boilers 11 and 12 as Attachment C.

d. On page 28 of the December 10, 2008 transcript, Mr. Larry Siebenberger verbally revised Exhibit A to his prefiled testimony changing the percentage of COG in the fuel mix from 60 percent to 40 percent. U.S. Steel has provided a correction to its boiler calculation submittal as Attachment D.

e. On pages 28 through 29 of the December 10, 2008 transcript, the Agency requested information regarding URS's emissions calculations. U.S. Steel has provided a summary of the "Boilers 11 & 12 NOx Reduction Study" performed by URS as Attachment E.

f. On page 31 of the December 10, 2008 transcript, the Agency requested a copy of the technical proposal from Bloom for reheat furnaces. U.S. Steel has provided a summary of the Bloom Engineering proposal as Attachment F.

g. On pages 32 through 33 of the December 10, 2008 transcript, the Agency requested information regarding uncontrolled NOx rates for slab reheat furnaces heated by COG and natural gas. U.S. Steel has provided such information as Attachment G.

3. U.S. Steel reserves the right to supplement these supporting materials.

Respectfully submitted,

By: /s/ Katherine D. Hodge
Katherine D. Hodge

Dated: January 30, 2009

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USSC:001/Fil/R08-19/Supporting Materials

ATTACHMENT A

United States Steel Corporation
Granite City Works
Description of NO_X RACT Emission Rate
For
Boilers 11 and 12
(Assuming all Coke Oven Gas is Scrubbed)

USS' Granite City Works has estimated the emissions for its boilers 11 and 12 in response to the Illinois Environmental Protection Agency's proposed rule to require that the emissions units employ Reasonably Available Control Technology (RACT) on these two units.

The Illinois Pollution Control Board has proposed revisions to Title 35 Part 217 which would require these units to meet emissions limits that have been proposed as RACT. While these units meet the definition of industrial boilers in which would be regulated under Subpart D of the proposed rule, the fuel mix that they fire is unlike that of a typical industrial boiler. Therefore, an evaluation was undertaken by URS Corporation for USS to evaluate potential control technologies applicable to the units and estimate the resulting emissions for technologies that are found to be feasible.

The URS evaluation found that because of the unique mixture of fuels fired by the units, the only technically feasible control technology is Flue Gas Recirculation (FGR). The potential emissions and emissions reductions related to the use of FGR were evaluated. The evaluation method is described below.

RACT emissions estimates for NO_X emissions from boilers 11 and 12 were developed as three distinct components that represent three distinct operational conditions that the boilers operate under. These are:

- Normal operations,
- Operations while a blast furnace is out of service (limiting the supply of one of the fuels (blast furnace gas (BFG) used by the boilers), and
- Operations while the desulfurization unit that is being constructed to treat the coke oven gas (COG), one of the fuels used by the boilers is off-line in maintenance mode.

This analysis was done for the two boilers in combination since that is the way the steam produced by the boilers is used. Each boiler has a heat input capacity of 225 MMBtu per hour. Therefore, the analysis has been done based on the total heat input of 450 MMBtu per hour.

The calculation of estimated emissions for each of these operational modes is described below.

Normal Operations

For this analysis, normal operations were calculated as operations during those times when the two blast furnaces at the facility are in operation and providing the full potentially available BFG.

Key assumptions for this mode of operations include:

- Blast furnace maintenance time as shown in table below:

Ozone Season	Annual	
15	15	days Blast Furnace Rebuild
	55	days Blast Furnace Down (15%) of time annual basis
23		days Blast Furnace Down (15%) of time ozone season basis
2	2	days maintenance outage
40	72	days Total Maintenance Outage

- a fuel mix on the boilers of:
  - 25% natural gas (NG)
  - 35% BFG
  - 40% COG
- a capacity factor of 100%
- controlled NO_X emission rates (lbs/MMBtu) of:
  - 0.084 NG
  - 0.0288 BFG
  - 0.144 COG

Furnace Downtime Operations

- Furnace downtime
  - 15 days furnace rebuild
  - 15% downtime per furnace (55 days for annual and 23 days for ozone season)
  - 2 days maintenance outage
- Fuel Mix
  - NG 40%
  - COG 60%
- Capacity factor 40%
- Same emission rates per fuel as for normal operations

Coke Oven Gas Scrubber Maintenance Mode

The Illinois EPA requested information on an emission rate that does not include coke oven gas scrubber maintenance mode. Therefore, this mode was not included in the results described below.

Baseline conditions were calculated using the same assumptions presented above but with the following emission rates in lb/MMBtu:

- 0.3 NG
- 0.066 BFG
- 0.729 COG

Results

Based on the assumptions and calculations shown above, the resulting ozone season average controlled emission rate, for Boilers 11 and 12 is 0.093 lb/MMBtu.

ATTACHMENT
B

United States Steel Corporation
Granite City Works
Estimation of NO_X Emissions
for
Slab Furnaces 1, 2, 3 and 4
assuming
All Coke Oven Gas is Desulfurized

USS' Granite City Works has estimated the emissions for it's slab furnaces 1, 2, 3, and 4 in response to the Illinois Environmental Protection Agency's proposed rule to require that the emissions units employ Reasonably Available Control Technology (RACT) on these four units.

The Illinois Pollution Control Board has proposed revisions to Title 35 Part 217 which would require these units to meet emissions limits that have been proposed as RACT. These units meet the definition of recuperative reheat furnaces which would be regulated under Subpart H of the proposed rule. Therefore, an evaluation was undertaken by USS to evaluate potential control technologies applicable to the units and estimate the resulting emissions for technologies that are found to be feasible.

The evaluation found that for these particular units, the only technically feasible control technology is the installation of low NO_X burners. The potential emissions and emissions reductions related to the use of low NO_X burners were evaluated. The evaluation method is described below.

RACT emissions estimates for NO_X emissions from slab furnaces 1 through 4 were developed based on a set of key assumptions. These are:

- Emission rates developed by manufacturer of low NO_X burners designed for these furnaces (Bloom);
-

Furnace No.	Projected Thermal Input (MMBtu/yr)	Ozone Season Emission Rate (lb/MMBtu)
1	1,654,304	0.162
2	1,654,304	0.162
3	1,654,304	0.214
4	2,206,238	0.212

- Furnace downtime for maintenance is assumed to occur during the ozone season;
- At the request of the IEPA, this calculation does not consider the impact of COG desulfurization being down for maintenance 35 days per year during the ozone season.

Results

Assuming that all COG is desulfurized, the average controlled emission rate for slab furnaces 1 through 4 is 0.156 lb/MMBtu.

ATTACHMENT C

KE OVEN GAS

	JAN		FEB		MAR		APR		MAY		JUN		JUL		AUG		SEP		OCT		NOV		DEC		
96	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	Total
10 Boilers	109,954	28.66%	91,696	29.06%	104,507	31.85%	100,242	32.54%	96,642	27.80%	39,299	13.83%	70,020	24.09%	103,496	39.07%	91,695	28.63%	136,917	43.47%	127,990	39.46%	116,841	40.51%	########
Boiler	39,872	31.03%	46,602	39.01%	50,527	35.79%	50,147	38.77%	40,764	30.29%	25,567	26.58%	43,405	59.28%	21,300	45.72%	38,120	30.62%	40,039	31.34%	48,446	42.40%	56,405	40.38%	501,194
Boiler	46,991	37.19%	48,613	40.34%	56,007	42.01%	50,668	41.16%	13,180	25.62%	14,724	15.28%	81,198	65.79%	90,415	73.24%	81,047	64.12%	85,514	66.99%	89,766	72.95%	61,447	47.32%	722,570

	JAN		FEB		MAR		APR		MAY		JUN		JUL		AUG		SEP		OCT		NOV		DEC		
97	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	Total
10 Boilers	113,161	31.78%	66,304	20.71%	99,583	28.49%	94,619	28.11%	111,276	34.05%	87,026	25.14%	76,230	22.89%	61,053	17.44%	73,018	22.59%	66,297	19.25%	78,035	22.95%	93,213	26.38%	########
Boiler	40,454	26.69%	14,890	10.74%	3,695	2.61%	33,932	29.92%	10,233	31.47%	29,282	34.34%	8,675	8.19%	15,798	17.88%	10,180	13.40%	35,881	28.23%	20,198	15.87%	34,519	27.84%	257,737
:Boiler	31,427	29.52%	8,373	10.69%	569	1.38%	73,836	67.15%	85,347	75.90%	65,961	65.73%	14,764	29.86%	20,865	25.72%	49,083	51.72%	47,797	44.25%	45,671	47.86%	56,106	52.92%	499,799

	JAN		FEB		MAR		APR		MAY		JUN		JUL		AUG		SEP		OCT		NOV		DEC		
98	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	Total
10 Boilers	97,842	29.55%	96,563	31.64%	97,015	31.91%	93,438	29.38%	95,918	27.99%	113,602	36.14%	67,673	23.64%	41,462	13.51%	80,373	29.23%	82,057	27.41%	97,602	31.11%	110,118	34.28%	########
I Boiler	21,756	16.27%	21,805	19.30%	26,749	21.93%	27,073	28.35%	13,719	20.66%	40,566	36.51%	18,214	19.44%	42,157	38.89%	48,453	40.88%	52,420	48.34%	33,115	41.13%	34,101	35.54%	380,167
:Boiler	50,668	47.73%	37,296	41.21%	51,357	45.50%	47,585	42.92%	66,139	65.83%	0	0.00%	34,135	41.20%	34,100	31.72%	34,100	27.75%	34,100	29.83%	32,906	43.47%	34,100	35.64%	456,466

	JAN		FEB		MAR		APR		MAY		JUN		JUL		AUG		SEP		OCT		NOV		DEC		
99	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	Total
-10 Boilers	108,500	33.78%	97,297	32.55%	138,091	41.90%	70,016	28.47%	97,585	33.36%	80,900	28.32%	68,746	22.28%	96,367	28.80%	87,000	27.17%	126,237	31.42%	102,995	32.17%	91,386	28.31%	########
I Boiler	34,142	28.85%	30,855	26.99%	36,337	34.83%	32,338	34.75%	3,277	64.89%	24,538	41.80%	38,143	41.40%	41,113	32.71%	32,960	29.09%	54,725	40.29%	38,234	31.42%	40,423	28.32%	407,135
2 Boiler	19,671	16.81%	27,101	24.06%	34,531	33.54%	35,103	36.65%	37,836	32.14%	26,019	25.82%	31,774	32.88%	12,199	13.35%	9,615	11.21%	239	1.94%	33,869	37.24%	35,308	31.68%	303,265

	JAN		FEB		MAR		APR		MAY		JUN		JUL		AUG		SEP		OCT		NOV		DEC		
00	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	Total
-10 Boilers	92,357	28.46%	81,252	24.84%	68,832	19.73%	102,980	31.26%	92,931	26.90%	85,325	24.60%	94,751	28.53%	102,467	29.28%	96,288	26.64%	109,023	29.02%	139,709	43.87%	124,064	36.50%	########
1 Boiler	21,245	14.38%	12,298	9.45%	20,291	14.74%	26,803	22.18%	35,105	31.55%	26,606	25.90%	30,815	26.11%	28,998	24.04%	28,765	26.08%	4,596	13.17%	15,193	13.77%	16,982	14.04%	267,904
2 Boiler	12,017	10.04%	745	0.71%	7,845	6.87%	16,394	15.32%	17,816	17.16%	15,991	16.75%	30,657	28.67%	24,521	32.46%	6,184	34.43%	22,088	20.65%	3,229	3.49%	3,704	3.58%	161,191

	JAN		FEB		MAR		APR		MAY		JUN		JUL		AUG		SEP		OCT		NOV		DEC		
01	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	Total
-10 Boilers	98,588	29.23%	81,030	25.31%	61,580	16.01%	63,183	17.72%	53,133	15.24%	44,920	13.52%	63,116	17.85%	69,578	18.88%	66,904	20.25%	47,510	12.70%	54,210	17.91%	60,279	17.50%	764,031
1 Boiler	13,970	11.36%	26,801	23.03%	45,765	35.29%	23,829	21.58%	24,921	20.78%	22,085	19.82%	20,736	16.63%	27,377	19.67%	25,559	25.52%	9,294	15.07%	26,789	19.73%	25,925	18.10%	296,051
2 Boiler	4,464	4.11%	24,709	27.04%	37,530	38.40%	36,156	37.30%	42,200	48.11%	27,279	36.13%	26,749	44.73%	4,108	23.18%	18,572	21.83%	23,450	20.80%	8,036	7.97%	27,668	26.88%	280,920

	JAN		FEB		MAR		APR		MAY		JUN		JUL		AUG		SEP		OCT		NOV		DEC		
02	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	Total
-10 Boilers	62,532	17.33%	48,696	14.40%	50,360	13.81%	54,229	15.73%	67,887	17.71%	53,314	14.76%	58,427	16.44%	59,053	16.32%	43,403	11.94%	66,975	16.92%	47,704	13.54%	53,170	14.87%	665,752
1 Boiler	3,098	2.21%	2	0.00%	892	0.70%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	447	1.39%	1,733	1.64%	4,478	4.13%	10,650
2 Boiler	38,396	33.09%	37,747	35.80%	47,937	44.92%	44,404	47.78%	16,382	40.24%	30,960	36.05%	37,613	38.19%	45,532	47.41%	25,832	36.00%	24,958	22.67%	38,000	37.52%	53,283	49.40%	441,044

	JAN		FEB		MAR		APR		MAY		JUN		JUL		AUG		SEP		OCT		NOV		DEC		
03	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	Total
-10 Boilers	60,670	15.69%	36,885	10.48%	35,731	9.97%	51,792	15.99%	60,887	16.17%	52,250	14.11%	44,443	12.55%	48,567	14.10%	44,831	13.37%	58,578	14.54%	27,945	7.93%	41,889	12.18%	564,455
1 Boiler	11,310	10.31%	0	0.00%	120	0.13%	12	0.01%	1	0.00%	15,193	13.86%	11,178	10.65%	5,827	5.65%	4,837	4.61%	2,461	5.19%	0	0.00%	0	0.00%	50,939
2 Boiler	28,306	27.91%	33,229	36.44%	43,322	46.68%	49,392	51.15%	16,484	40.41%	5,343	7.28%	10,849	10.38%	25,461	24.35%	12,637	12.89%	11,990	13.12%	6,117	6.06%	27,117	24.66%	270,247

	JAN		FEB		MAR		APR		MAY		JUN		JUL		AUG		SEP		OCT		NOV		DEC		
04	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	Total
1-10 Boilers	52,402	15.46%	49,623	15.86%	48,292	15.43%	34,674	12.78%	38,668	12.06%	39,304	11.41%	19,376	6.27%	47,118	16.93%	40,492	15.80%	23,630	7.01%	38,016	12.93%	41,968	13.69%	473,563
11 Boiler	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	31,200	28.44%	2,400	4.32%	0	0.00%	0	0.00%	33,600
12 Boiler	35,466	30.40%	30,632	27.76%	39,117	31.44%	34,629	33.15%	32,001	32.46%	9,040	9.67%	15,464	15.13%	8,502	17.63%	3,464	19.22%	23,037	20.44%	13,295	13.35%	22,189	19.86%	267,039

	JAN		FEB		MAR		APR		MAY		JUN		JUL		AUG		SEP		OCT		NOV		DEC		
005	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	Total
1-10 Boilers	25,416	7.77%	36,068	11.49%	36,166	10.96%	34,885	10.74%	37,634	17.93%	41,500	15.47%	49,363	16.30%	55,842	18.07%	39,736	12.03%	49,606	14.10%	56,042	15.90%	59,148	15.46%	521,406
11 Boiler	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	-	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0
12 Boiler	22,916	21.96%	11,488	14.74%	20,083	19.29%	17,706	18.40%	9,263	40.94%	6,830	16.60%	13,430	15.32%	13,271	24.04%	20,859	21.13%	12,719	12.85%	12,437	12.98%	14,719	14.39%	175,521

	JAN		FEB		MAR		APR		MAY		JUN		JUL		AUG		SEP		OCT		NOV		DEC		
006	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	Total
1-10 Boilers	50,705	14.90%	43,550	14.55%	46,853	16.70%	31,841	9.96%	43,701	12.69%	45,992	15.87%	46,815	16.27%	46,820	13.74%	41,316	13.25%	56,361	21.43%	36,673	20.50%	40,494	20.87%	531,121
11 Boiler	1,308	1.29%	-	0.00%	505	0.46%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	1,813
12 Boiler	35,647	32.42%	19,293	22.53%	26,574	27.92%	29,405	29.94%	2,195	4.46%	25,299	24.74%	19,690	19.72%	30,010	29.71%	30,084	37.31%	9,933	16.26%	33,626	36.55%	30,363	32.19%	292,218

	JAN		FEB		MAR		APR		MAY		JUN		JUL		AUG		SEP		OCT		NOV		DEC		
007	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	Total

-10 Boilers	68,783	34.79%	41,596	18.30%	38,165	14.06%	14,287	4.83%	28,177	9.45%	25,082	9.22%	19,892	8.33%	13,917	5.22%	8,705	3.48%	13,786	4.06%	13,703	4.81%	25,973	9.78%	312,066
1 Boiler	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0
2 Boiler	18,515	18.61%	24,596	24.11%	22,581	20.57%	19,326	19.94%	15,189	21.50%	17,960	17.88%	27,449	25.03%	19,720	19.36%	19,381	17.58%	5,307	14.13%	34,773	35.42%	11,856	10.41%	236,653

	JAN		FEB		MAR		APR		MAY		JUN		JUL		AUG		SEP		OCT		NOV		DEC		
)08	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	MMBtu	%	Total
-10 Boilers	23,248	8.48%	16,492	5.65%	18,964	5.95%	25,045	8.87%	32,549	10.25%	36,429	11.84%	34,992	11.86%	12,746	4.53%	11,450	4.34%	7,925	3.33%	20,893	6.71%	53,969	24.69%	240,733
1 Boiler	0	0.00%	0	0.00%	0	0.00%	78	0.07%	0	0.00%	0	0.00%	41	0.03%	32	0.03%	6,272	5.03%	0	0.00%	20,476	31.94%	0	0.00%	26,899
2 Boiler	25,513	21.46%	18,561	16.45%	20,482	17.55%	23,290	22.28%	5,784	7.04%	336	0.29%	12,763	10.76%	13,968	12.03%	9,599	8.44%	44,682	50.14%	10,126	29.28%	26,930	62.75%	185,494

United States Steel Corporation
Granite City Works
Description of NOX RACT Emission Rate
and
Emission Reduction Calculations

USS' Granite City Works has estimated the emissions for its boilers 11 and 12 in response to the Illinois Environmental Protection Agency's proposed rule to require that the emissions units employ Reasonably Available Control Technology (RACT) on these two units.

The Illinois Pollution Control Board has proposed revisions to Title 35 Part 217 which would require these units to meet emissions limits that have been proposed as RACT. While these units meet the definition of industrial boilers in which would be regulated under Subpart D of the proposed rule, the fuel mix that they fire is unlike that of a typical industrial boiler. Therefore, an evaluation was undertaken by URS Corporation for USS to evaluate potential control technologies applicable to the units and estimate the resulting emissions for technologies that are found to be feasible.

The URS evaluation found that because of the unique mixture of fuels fired by the units, the only technically feasible control technology is Flue Gas Recirculation (FGR). The potential emissions and emissions reductions related to the use of FGR were evaluated. The evaluation method is described below.

RACT emissions estimates for NO_X emissions from boilers 11 and 12 were developed as three distinct components that represent three distinct operational conditions that the boilers operate under. These are:

- Normal operations,
- Operations while a blast furnace is out of service (limiting the supply of one of the fuels (blast furnace gas (BFG) used by the boilers), and
- Operations while the desulfurization unit that is being constructed to treat the coke oven gas (COG), one of the fuels used by the boilers is off-line in maintenance mode.

This analysis was done for the two boilers in combination since that is the way the steam produced by the boilers is used. Each boiler has a heat input capacity of 225 MMBtu per hour. Therefore, the analysis has been done based on the total heat input of 450 MMBtu per hour.

The calculation of estimated emissions for each of these operational modes is described below.

Normal Operations

For this analysis, normal operations were calculated as operations during those times when the two blast furnaces at the facility are in operation and providing the full potentially available BFG.

Key assumptions for this mode of operations include:

- Blast furnace maintenance time as shown in table below:

Ozone Season	Annual	
15	15	days Blast Furnace Rebuild
	55	days Blast Furnace Down (15%) of time annual basis
23		days Blast Furnace Down (15%) of time ozone season basis
2	2	days maintenance outage
40	72	days Total Maintenance Outage

- a fuel mix on the boilers of:
  - 25% natural gas (NG)
  - 35% BFG
  - 40% COG
- a capacity factor of 100%
- controlled NO_X emission rates (lbs/MMBtu) of:
  - 0.084 NG
  - 0.0288 BFG
  - 0.144 COG

Furnace Downtime Operations

- Furnace downtime
  - 15 days furnace rebuild
  - 15% downtime per furnace (55 days for annual and 23 days for ozone season)
  - 2 days maintenance outage
- Fuel Mix
  - NG 40%
  - COG 60%
- Capacity factor 40%
- Same emission rates per fuel as for normal operations

Coke Oven Gas Scrubber Maintenance Mode

- 35 days per year
- occurs when COG represents 40% of the fuel mix

- since NO_X emissions are higher in this mode of operation, emissions are treated as a delta based on the COG emissions rate without COG desulfurization minus COG emission rate with COG desulfurization
  - COG emission rate with desulfurization 0.144
  - COG emission rate without desulfurization 0.336

Baseline conditions were calculated using the same assumptions presented above but with the following emission rates in lb/MMBtu:

- 0.3 NG
- 0.066 BFG
- 0.729 COG

Results

Based on the assumptions and calculations shown above and the resulting ozone season controlled emission rate, the following emission reductions are anticipated due to the installation of FGR on Boilers 11 and 12.

	NO_X Emissions (tons/year)		**NO_X Emissions (tons/ozone season)**	
	Baseline	Controlled	Baseline	Controlled
Normal Operations	616.6	179.4	237.8	54.1
Furnace Downtime Operations	86.69	17.6	48.16	10.37
COG Desulfurization Down Delta		14.5		14.52
Total	703.3	211.6	286.0	79.0
Reduction in Emissions		491.7		207.0

USS proposes to meet NO_X requirements by averaging emissions between boilers 11 and 12 and among fuels and meet an average controlled rate of 0.113 lb/MMBtu.

US Steel
Granite City, IL

Boilers 11 & 12 NO_X Reduction Study

REVISION 1

Prepared for:

US Steel
Granite City, IL

Prepared by:

URS

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1.0 EXECUTIVE SUMMARY

The Illinois Pollution Control Board is proposing new limits for NO_X sources that will affect Boilers 11 and 12 at the Granite City, IL plant. URS Corporation (URS) was contracted by US Steel to evaluate the boilers and recommend the optimum NOx control technology to meet thc proposed limits. The evaluation included two major parts. The first was to conduct an on-site inspection of the two boilers. The second was to collect and analyze the available design and operating information. The results of these analyses were compared to the NO_X emission limits and the applicable NO_X control technologies to arrive at the most cost-effective, technically feasible solution. For the purposes of this initial evaluation, only those control technologies that have been sufficiently demonstrated as successful for these types of boilers were considered.

As part of the evaluation, a plan was developed that addressed the NO_x controls technology required for each boiler.

2.0 INTRODUCTION

URS has been commissioned to assess the optimum NOx control technology for Boilers 11 and 12 at the US Steel plant in Granite City, IL. Both boilers are field erected boilers rated at a steam flow of 150,000 lb/hr. Boiler 11 is a Combustion Engineering (ABB) corner fired boiler with a single level of burners. Boiler 12 is a front wall fired boiler built by Riley with two circular burners. Relevant data for the two boilers are shown in Table 1 and 2.

Natural Gas (NG), Coke Oven Gas (COG) and Blast Furnace Gas (BFG) can all be fired on both boilers 11 and 12.

GRANITE CITY
BOILERS 11 & 12
NO_X REDUCTION STUDY

TABLE 1: SYSTEM DESIGN INFORMATION – BOILER 11

	DESIGN DATA @ MCR	FIELD DATA AS FOUND
CUSTOMER DESIGNATION	BOILER 11	
BOILER TYPE (D,A,O, FIELD ERECT, FT)	FIELD	
MANUFACTURER/MODEL NO	CE	
DATE OF ORIGINAL CONSTRUCTION	1959	
HEAT RELEASE BTU/FT3	21,400	
PRESENT NO./TYPE BURNERS	4	
FD FAN DATA	41,400@7.2"@100F	
ID FAN DATA	138,000@8"@475F	
DESIGN STEAM FLOW, KLB/HR	150	
OPERATING STEAM PRESSURE, PSIG	250	
OPERATING STEAM TEMPERATURE, F	470	
SUPERHEATER YES/NO	YES	
INDOOR/OUTDOOR INSTALLATION	OUTDOOR	
PLANT ELEVATION, FASL	<500	
BOILER STACK TEMPERATURE, F	350	
BURNER DRAFT LOSS, " WC	2.75	
AIR HEATER AIR SIDE DRAFT LOSS " WC	2.35	
BOILER DRAFT LOSS, " WC	1.55 (NG) 4 (BFG)	
FURNACE PRESSURE, " WC	0	
ECONOMIZER (YES/NO)	N0	
AIR HEATER (YES/NO)	YES	
COMB. AIR TEMPERATURE, F	360	
ECON./AIR HT. PRESSURE DROP, " WC DRAFT SIDE	0.7 (NG) 1.9 (BFG)	
BURNER FUEL PRESSURE, PISG		
STACK O2 % (PLANT WET BASIS)	2	
GAS FUEL TYPE/HEATING VALUE, BTU/FT3	NG,COG,BFG	
OIL (YES/NO)/TYPE	NOT FIRED	
GAS PRESSURE AVAILABLE		
TYPE CONTROLS		
FD TURBINE HP	75	
ID TURBINE HP	236	
INSURANCE REQUIREMENTS	NFPA	
O2 % (DRY BASIS)		
NOx EMISSIONS (GAS), PPM @ 3% O2	NA	
CO EMISSIONS (GAS), PPM @ 3% O2	NA	

TABLE 2: SYSTEM DESIGN INFORMATION – BOILER 12

	DESIGN DATA @ MCR	FIELD DATA AS FOUND
CUSTOMER DESIGNATION	BOILER 12	
BOILER TYPE (D,A,O, FIELD ERECT, FT)	FIELD	
MANUFACTURER/MODEL NO	RILEY VO	
DATE OF ORIGINAL CONSTRUCTION	1975	
HEAT RELEASE, BTU/FT3		
PRESENT NO./TYPE BURNERS	2/Peabody	
DESIGN STEAM FLOW, KLB/HR	150	150
OPERATING STEAM PRESSURE, PSIG	300	
OPERATING STEAM TEMPERATURE, F	480	531
SUPERHEATER YES/NO	YES	
INDOOR/OUTDOOR INSTALLATION	OUTDOOR	
PLANT ELEVATION, FASL	<500	
BOILER STACK TEMPERATURE, F	325	352
BURNER DRAFT LOSS, " WC	6.6	
BOILER DRAFT LOSS," WC	1.9 (NG), 6.2 (BFG)	
FURNACE PRESSURE, " WC	-0.1	
ECONOMIZER (YES/NO)	NO	
AIR HEATER (YES/NO)	YES	
COMB. AIR TEMPERATURE, F	500	377
ECON./AIR HT. PRESSURE DROP, " WC	1.22 (NG) 4.3 (BFG)	
BURNER FUEL PRESSURE, PSIG		
STACK O2 % (PLANT WET BASIS)	2	
GAS FUEL TYPE/HEATING VALUE, BUT/FT3	NG, BFG,COG	
OIL (YES/NO)/TYPE	NOT USED	
GAS PRESSURE AVAILABLE	30 PISG	
TYPE CONTROLS	FULLY METERED	
FD DATA	46,825@14.3"@100F	
ID DATA	196,800@8"@475F	
FD TURBINE HP	135	
ID TURBINE HP	272	
INSURANCE REQUIREMENTS	NFPA	
O2 % (DRY BASIS)	2	
NOx EMISSIONS (GAS) PPM @ 3% O2	NA	
CO EMISSIONS (GAS) PPM @ 3% O2	NA	

Table 3 shows the COG and BFG analysis used for this study. The COG analysis is shown both before and after the H_2S scrubber. According to US Steel the scrubber may be out of service up to 35 days/year. Natural gas is also fired on both boilers. A typical natural gas analysis of 92% CH_4, 5% higher hydrocarbons, 3% inerts and a HHV of 1030 Btu/ft^3 was used. The values of HCN, post scrubber, need to be confirmed.

Table 3: Fuel Analysis

	COG Before H2S scrubber VOL %/PPM	COG After H2S scrubber VOL%/PPM	BFG VOL %/PPM
Hydrogen	58.7	58.7	10.2
Argon	<0.1	<0.1	
Oxygen	<0.3	<0.3	0.4
Nitrogen	<0.3	<0.3	41.9
Methane	29.7	29.7	
Carbon Monoxide	5.5	5.5	25
Carbon Dioxide	1.4	1.4	22.5
Ethylene	2.4	2.4	
Ethane	0.7	0.7	
Hydrogen Sulfide	5508 PPM	370 PPM	26 PPM
Propane	0.2	0.2	
Carbonyl Sulfide	107 PPM	20 PPM	27 ppm
Sulfur Dioxide	8 PPM	0 PPM	1 PPM
C4-C6	<1	<1	
Aromatics	6352 PPM	6352 PPM	
Ammonia	2 PPM	0 PPM	0
Hydrogen Cyanide	1960 PPM	130 PPM	0
HHV	576 BTU/FT3		80 - 120 BTU/FT3

3.0 STUDY APPROACH AND PROCEDURES

Analysis Approach

The analysis approach consisted of two major efforts. The first was to conduct an on-site inspection of the two boilers. The second was to collect and analyze the available design and operating information. The results of these analyses were compared to the future NO_X emission limits, and the applicable NO_X control technologies to arrive at the most cost-effective, technically feasible solution. For the purposes of this initial evaluation, only those control technologies that have been sufficiently demonstrated as successful for these types of boilers were considered.

3.1 On-Site Inspection

URS personnel conducted an on-site inspection of the operational units. This information was reviewed with engineering personnel. Information was collected and verified. The following types of information were collected:

- Boiler drawings showing existing burner layout, burner wall details (in particular tube locations on the burner wall)
- Boiler data sheets giving heat release rates, furnace volume, existing stack temperatures, maximum heat input, steam conditions (pressure and temp.)
- Existing heat recovery equipment and design data (inlet and outlet temperatures)- economizer or air heater
- Fuels burned (natural gas, blast furnace gas, COG)
- Existing NO_X levels
- Target NO_X levels
- Existing controls hardware and burner management
- Fan manufacturer and model
- Burner manufacturer and model
- Number of burners
- Burner Spacing
- Draft type
- Configuration of ducting and pre-heaters

Field inspections were made to collect information that was critical to determining the feasibility and cost for applying the latest technologies to the boilers. This information included, but was not limited to, the following:

- General arrangement and area layout
- General condition of the boiler
- Burner accessibility
- Number of operative burners

3.2 Technologies Considered

The practical available technologies considered were:

Flue Gas Recirculation (FGR) Evaluation for Boilers

Factors considered in the assessment included:

- Boiler geometry and ancillary equipment layout.
- Fan sizing.
- Existing burner design and suitability for use with FGR.
- Suitability of existing combustion controls.

Burner Retrofit Evaluation

With respect to the boilers controlled via low-NO_X burner technology, issues that were considered include:

- The ability for the burner technology to meet the target NO_X emission limit for each unit.
- Burner-to-burner spacing, and burner-to-tube dimensions.
- Matching low-NO_X burner flame characteristics with the available physical envelope.

Feedwater Economizer

Factors considered in this assessment included:

- Boiler geometry and ancillary equipment layout.
- Existing ductwork configuration and space limitations.

SCR Evaluation

Factors considered for the application of SCR:

- Fuel type and sulfur level.
- Upstream temperature and impact on SCR catalyst volume.
- Existing ductwork configuration and space limitations.
- Fan and/or draft requirements/limitations.

SNCR Evaluation

- Fuel type and sulfur level.
- Existing ductwork configuration and space considerations.
- Fan and/or draft requirements/considerations.
- Potential for ammonia slip.
- Temperature variations.
- Load variations.

The following section further describes the NO_X reduction technologies considered in this evaluation.

4.0 NO_X REDUCTION OPTIONS

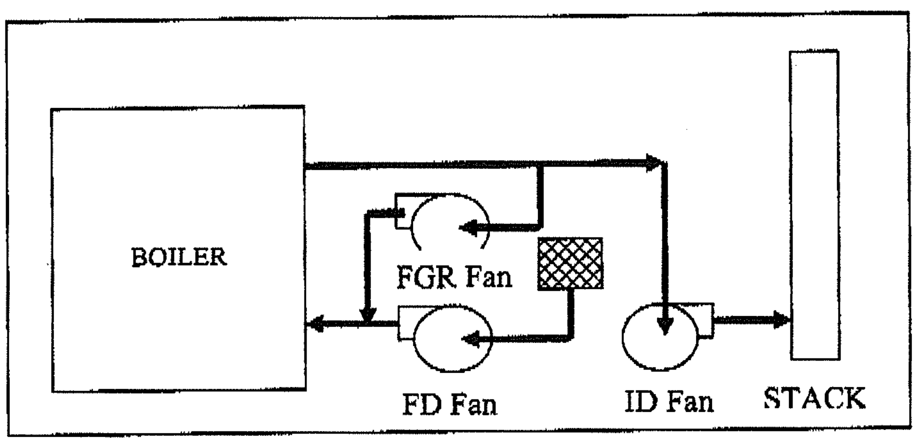
The NO_X control technologies that were evaluated for application to the affected combustion units included flue gas recirculation, low-NO_X burners, feedwater economizer, selective noncatalylic reduction and selective catalytic reduction. A description of each of these technologies is presented in the following sections.

4.1 FLUE GAS RECIRCULATION

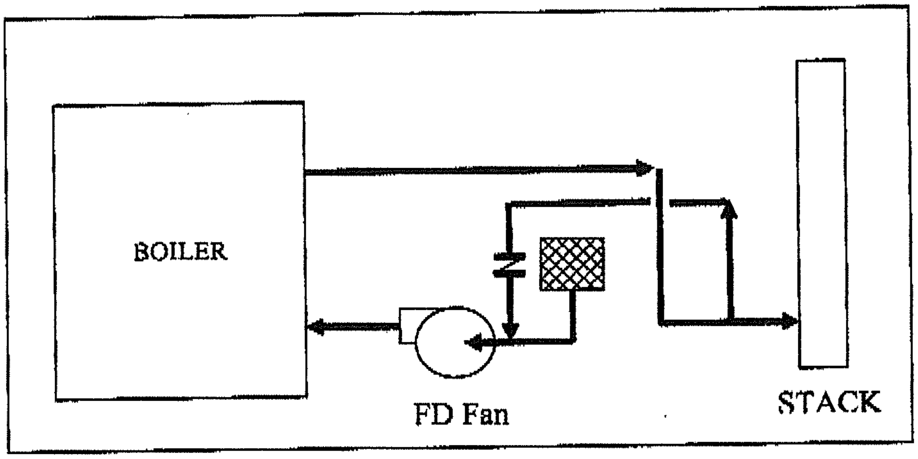
Flue Gas Recirculation (FGR) seeks to reduce NO_X emissions by reducing the peak temperatures that occur during combustion. Relatively cool, inert flue gas that does not contribute to combustion is recirculated through the windbox. This has the effect of stretching the flame, and reducing peak flame temperatures that contribute to NO_X formation. FGR has been employed successfully for 25 years, and is one of the most cost-effective methods for reducing NO_X emissions, primarily from boilers.

There are three basic types of flue gas recirculation systems that have been applied to boilers:

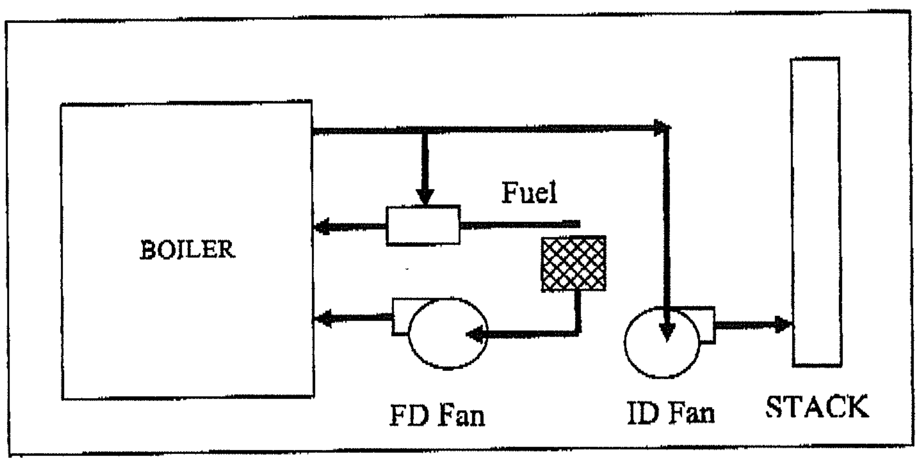
- **Forced FGR (FFGR),** where a separate FGR fan is used to extract flue gas from a location upstream of the ID fan and inject it into the combustion air downstream of the FD fan.



- **Induced FGR (IFGR)**, where the negative pressure at the FD fan inlet is used to induce flue gas flow into the FD fan, where it mixes with the combustion air.



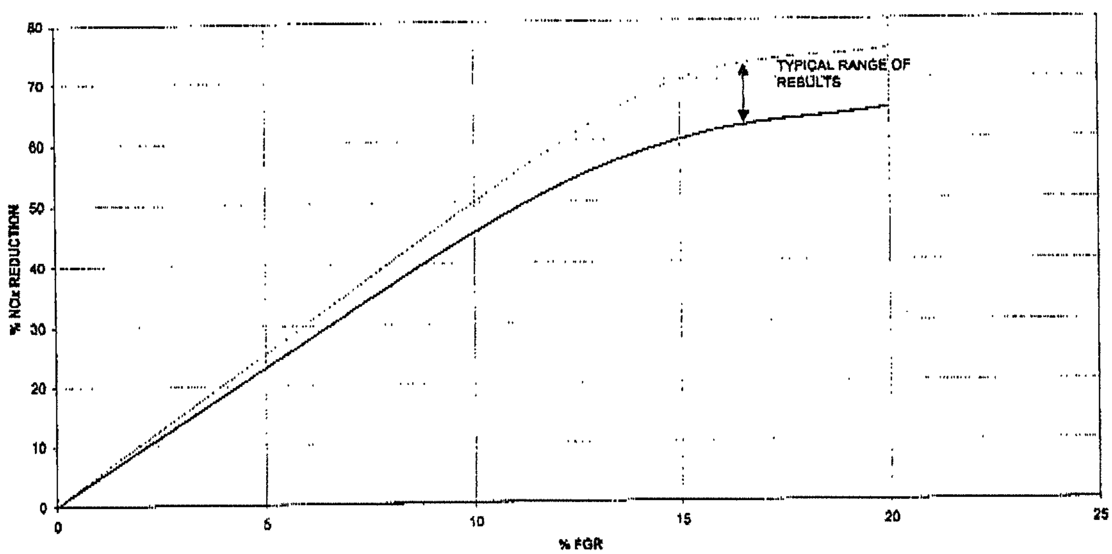
- **Fuel Induced FGR (FIR)**, where the motive force of the fuel is used to mix flue gas into the fuel stream, rather than the combustion air.



FGR is very effective in reducing thermal NO_X but has very little effect on fuel NO_X.

Figure 1 shows typical NO_X reductions using FGR for a wide range of industrial boiler types and sizes.

FIGURE 1: TYPICAL NOx REDUCTION RESULTS FOR FGR APPLICATION TO EXISTING BURNERS



FGR may be an effective tool for Boilers 11 and 12 since the amount of FGR can be easily controlled depending on the fuel fired. For example if the fuel is primarily BFG, the flame temperature is already quite low, and it may not be necessary to recirculate flue gas. In fact, when the boiler fuel is largely BFG, flame stability would become problematic if FGR is applied to the boiler. When the fuel is primarily COG or NG, the FGR rate can be increased to meet the desired NO_X target.

If the FGR system is designed correctly, there would not be an affect on CO or PM emissions.

4.2 LOW NO_X BURNERS (LNBs) AND ULTRA LOW NO_X BURNERS (ULNBs)

Burners have been undergoing rapid development due to pressures to reduce NO_X emissions, and they resulting technologies may be referred to as either low-NO_X burners (LNB), or ultra-low-NO_X burners (ULNB)

If new burner technology meets the emission limit for a particular combustion unit, it will often be the most economical NO_X reduction alternative. This is especially true if the new burners can fit in the existing burner openings, the installation cost may be very low, and the installation time may be relatively short. However, new burners alone will usually not be able to meet the most stringent emission limits.

It is worth noting that a major drawback of LNB retrofits is that the flames are generally larger and more diffuse than conventional burner flames. This stems from the diffusion mixing and delayed combustion, which are characteristic of the air staging and/or fuel staging combustion processes. Such flame characteristics mean that flame impingement on tubes becomes a concern.

NO_X emissions for LNBs are generally very sensitive to airflow control to the primary and secondary combustion zones of the flame and care must be taken to maintain the proper fuel/air ratios to achieve the optimum NO_X reductions. This often requires an upgrade of the combustion control system. In addition, LNBs will often require upgrades to the existing burner management system. Depending on the current system, the cost of these control upgrades can be as much as that for the burners.

Particularly for Boiler 11, a low NO_X burner does not really exist. Even for Boiler 12, a viable low NO_X burner without FGR that could fire the mix of fuels fired on Boiler 12 and generate a significant NO_X reduction does not exist. Of course a low NO_X burner combined with FGR would produce significant NO_X reductions, but it is unlikely that the NO_X reduction would be any greater than application of FGR to the existing burners.

4.3 AIR PREHEAT REPLACEMENT WITH A FEEDWATER ECONOMIZER

Replacing the air heater with a feedwater economizer can also be an effective technique for reducing thermal NO_x. Reducing the combustion air temperature from 500°F to ambient would also reduce thermal NO_x by about 60%. However (much like FGR), removing the air preheat would have little effect on fuel NO_x. One difficulty with removing the air preheaters would be that the flame stability with the BFG might become a problem. If the air preheater is removed a higher percentage of NG or COG co-firing may be required. Another key consideration for removal of the air preheaters with economizers is the cost, which would be significantly higher than other options, such as FGR.

One advantage of removing the air heater would be that a significant reduction in the pressure drop for both the FD and ID fans would be obtained, eliminating current issues with fan limitations while firing BFG.

4.4 SELECTIVE CATALYTIC REDUCTION (SCR)

SCR Technologies

In the field of NO_X reduction, Selective Catalytic Reduction (SCR) is considered a mature, proven technology. It has been applied to achieve NO_X reduction on stationary combustion sources since the 1970's. Most of the applications have been on coal, oil, and gas fired utility boilers and gas turbines.

SCR utilizes catalyst to promote the reactions to occur at reduced temperatures. The temperature range for SCR applications is 300-1000°F. The most efficient application of this technology occurs in the 525-875°F range and uses conventional Vanadium/Titanium catalyst. Application of this technology at lower temperatures results in a significant increase in the amount of catalyst required. Application at temperatures above 875°F typically requires the use of a special zeolite catalyst.

SCR, regardless of the application temperature, employs a reagent that, in the presence of the catalyst, converts NO_X to N_2 and H_2O. The ammonia or urea-reducing reagent is thoroughly mixed with the flue gas (in a nearly stoichiometric ratio with NO_X) upstream of a catalyst bed. In order to achieve high levels of NO_X reduction, a small amount of "NH_3 slip" (unreacted ammonia) is designed.

In addition to promoting the reduction of NO_X, the catalyst will also convert a small (typically <1%) percent of the SO_2 in the flue gas to SO_3.

The catalyst bed is contained in a reactor vessel or frame that suspends the catalyst modules in the flue gas stream. Normally the linear velocity of flue gas is limited to 20 ft/sec due to catalyst erosion considerations. Typically, the gas velocity at the catalyst is 15 ft/sec. Consequently, the catalyst cross section is greater than the typical duct cross section. Additional transition ducts provide the transition from the existing ducts to the SCR bed. This new ducting configuration needs to provide an area of mixing the reagents with the flue gas.

Several aspects of the USS boiler 11 and 12 operation would complicate an SCR installation. Issues that must be considered in an SCR design include:

- The USS steel boilers are load following,
- The inlet NO_X to the SCR vary considerably based on the fuels used,
- The COG, particularly if the scrubber is out of service, has a high fuel sulfur content.

The fact that the boilers are load following and the inlet NO_X varies with the fuel blend fired, make control of the NH_3 injection rate much more complex than for a boiler firing only one fuel at a time. Normally the NH3 rate is controlled based on firing rate with a trim of the NH_3 rate based on the outlet NO_X. For the USS steel boilers, since the inlet NO_X is not only a function of firing rate, but also a function of the fuel blend and the fuel nitrogen content of the COG. This would mean that the SCR control would need to be based on measurement of the inlet and outlet NO_X. Since NO_X measurement has an inherent time lag, during rapid load swings the NH_3 rate will either be high or low, resulting in either higher NO_X emissions or NH_3 slip issues.

The presence of sulfur in the COG gas complicate the situation further since unreacted NH_3 will react with SO_3 in the flue gas to form ammonium salts. These salts can deposit in the air heater resulting in reduced boiler efficiency and increase pressure drop or exit the boiler at $PM_{2.5}$ emissions.

The presence of a high sulfur concentration in the flue gas would involve using catalyst that is resistant to poisoning by sulfur compounds. This would increase the catalyst cost and would probably also reduce the catalyst lifetime.

Although these technical issues in applying an SCR to the USS boilers can most likely be solved, an SCR installation on these boilers would be a very costly, custom installation. Consequently, application of SCR on these boilers is not recommended.

4.5 Selective Non-Catalytic Reduction (SNCR)

Selective Non-Catalytic Reduction (SNCR) systems entail the injection of a reducing agent (ammonia/urea) into the flue gas stream to produce a NO_X reducing atmosphere at proper temperatures. The systems are common on large baseloaded utility boilers. SNCR systems require ample residence time and good mixing of ammonia and flue gases at the ideal temperature range for satisfactory NO_X reductions to occur. If these conditions are not met, it can result in higher NO_X, or the emission of unreacted ammonia ("ammonia slip").

The ideal temperature range for the SNCR reactions to occur is from about 1,700°F to 2,100°F. If the ammonia/urea is injected where the temperature is higher, it will be oxidized, and will result in higher NO_X emissions. If the ammonia/urea is injected where the temperature is too low, the reaction will not occur, and ammonia will be emitted from the stack. Improper mixing of the ammonia/urea and the NO_X can also result in poor SNCR performance. If the molar ratio of ammonia/urea to NO_X is too high at a given location, then the excess ammonia will be emitted.

In sulfur-containing fuel firing applications, ammonia slip results in the creation of ammonium compounds which are emitted as condensable particulate. These compounds typically condense at temperatures that are commonly found in the air heaters, and the deposits that form can lead to plugging, fouling, and corrosion. Air heater pluggage increases the pressure drop, and acts to reduce the maximum steam production from the boiler. Air heater fouling results in decreased thermal efficiency of the boiler process. Air heater corrosion decreases the equipment life, and results in more frequent maintenance. Each of these outcomes will ultimately require that the unit be shut down. Recent studies on utility boilers that inject ammonia when firing sulfur-containing fuels suggest that even very low amounts of ammonia slip may result in air heater fouling.

Boilers 11 and 12 are not good candidates for an SNCR application because their operating characteristics do not match up well with the characteristics required for SNCR operation. The specific characteristics of the boiler operation that preclude SNCR as a viable control option are as follows:

- Load variations;
- Changes in the bound-nitrogen content of the fuel;
- Fluctuations in fuel heating value;

- Sulfur content of the COG; and,
- Stratification that varies with load and fuel composition

The steam loads for boilers 11 and 12 vary significantly, because they are affected by other parts of the process. When both blast furnaces are in operation, the steam demand is high. However, when only one blast furnace is in operation, the steam demand is relatively low. There are other parts of the process that require steam, that cause the boiler load to swing. When the load changes, the flue gas temperature also changes. As such, the location of the optimum temperature window for the SNCR reactions changes. Since the ammonia/urea injection grid is fixed, the flue gas temperature at the injection point may not be ideal. On large utility-scale boilers, multiple injection locations may be used to overcome this problem, but it is not practical on smaller units (boilers 11 and 12).

The COG contains bound nitrogen, in the form of hydrogen cyanide, which is of particular concern when the H_2S scrubber is out of service for maintenance purposes. The presence of bound-nitrogen compounds in the COG means that changes in the COG firing rate will also produce dramatic changes in the uncontrolled NO_X concentration. Variations in the NO_X cause an improper molar ratio of ammonia/urea to NO_X, resulting in either higher NO_X emissions or ammonia slip as the COG component of the fuel changes.

The heating value of the three fuels being fired in boilers 11 and 12 is quite different, with the BFG having a heating value about one tenth that of natural gas, and the COG being somewhere in between. As the fuel blend being fired in the boilers varies, the flame temperature in the boiler fluctuates. The fuel blend also affects mass flow rate through the boiler, which is much higher for the BFG than for natural gas. The changes in the flame temperature and mass flow rate not only cause the location of the ideal SNCR injection temperature window to change, they also cause the NO_X mass emission rate to fluctuate. Variations in the NO_X cause an improper molar ratio of ammonia/urea to NO_X, resulting in either higher NO_X emissions or ammonia slip during fuel composition transitions.

The scrubbed COG contains a significant amount of hydrogen sulfide, and other sulfur-containing compounds. These concentrations are much higher when the boilers are being operated while the H_2S scrubber is out of service for maintenance purposes. In either case, some of the sulfur compounds will react with the ammonia/urea that is injected to form condensable ammonium compounds. These compounds will then form deposits on the air heater surfaces, and will negatively affect the boiler operation, as described previously.

At least to the knowledge of URS, SNCR has never been applied to a boiler with the fuel blends and operating characteristics of boilers 11 and 12. Since the technical issues involved with applying SNCR to these boilers are significant and complex, SNCR would not be recommended for these boilers

5.0 NO_X ESTIMATES

Both the baseline and Retrofit NO_X has been estimated using the following method.

First the thermal NO_X was estimated by calculating the adiabatic flame temperature for the various fuels using the STANJAN thermal equilibrium program and data base. The flame temperatures were then used to calculate NO_X emissions based on a URS data base of theoretical flame temperatures and NO_X emissions.

Thermal NO_X emissions were calculated for a baseline air preheat temperature of 500°F with FGR rates of 10% and 20%. Calculations were done for each fuel alone. Calculation of emission rates for fuel combinations were done using a heat input weighted average of individual fuel emission rates for the fuels used in the combined emission rate.

It was estimated that approximately 50% of the HCN would be converted to NO_X when the concentration was 1960 PPM and 100% would be converted to NO_X when the concentration was 130 PPM. For the COG the overall NO_x emissions were estimated by adding the thermal and fuel NO_X together. For the natural gas and BFG the NO_X was assumed to be thermal NO_X alone.

Baseline NO_X emissions for a given fuel were assumed to be the same on both boilers.

Table 4 shows the calculated flame temperatures for each case and Tables 5 and 6 show the NO_X emissions that were estimated based on a particular COG HCN concentration and/or FGR rates. Calculations were done for two HCN concentrations 1960 ppm corresponding to the value before the H_2S scrubber and 130 ppm corresponding to the value after the scrubber.

Table 4: Calculated Flame Temperatures

FUEL	FLAME TEMP FOR 500 F AIR PREHEAT IN DEG F
NG	3581
COG	3677
BFG	2717
NG/10% FGR	3309
NG/20% FGR	3103

Table 5: Estimated NO_x Emissions

AIR TEMP	THERMAL NOx LB/MMBTU100% NG	THERMAL NOx LB/MMBTU100 % COG	THERMAL NOx LB/MMBTU100% BFG	NOX LB/MMBTU COG W/1900 PPM HCN	NOx LB/MMBTU COG W/ 130 PPM HCN
500 F	0.252	0.312	0.0288	0.54	0.348

Table 6: Estimated NO_x Emissions with and without FGR with 500°F preheat

% FGR (500 F AIR PREHEAT)	THERMAL NOx LB/MMBTU100% NG	THERMAL NOx LB/MMBTU100 % COG	THERMAL NOx LB/MMBTU100% BFG	NOX LB/MMBTU COG W/1900 PPM HCN	NOx LB/MMB COG W/ PPM HC
0% FGR	0.252	0.312	0.0288	0.54	0.348
10% FGR	0.156	0.168	0.0288	0.396	0.204
20% FGR	0.084	0.108	0.0288	0.336	0.144

Emission Rate Calculation – Future Operations

Emissions for fuel mixes that are consistent with planned future operations that include the cogen boiler and the new coke plant were based on the emission rates listed in Table 6. Emission rates for planned fuel mixes were calculated by weighting the fuel specific emission rate by the proportion of the heat input that the fuel provides. This is consistent with the way the Illinois Environmental Protection Agency (IEPA) rules provide for calculating mixed fuel emission rates.

RACT emissions estimates for NO_X emissions from boilers 11 and 12 were developed can be developed as three distinct components that represent three distinct operational conditions that the boilers operate under. These are:

- Normal operations,
- Operations while a blast furnace is out of service (limiting the supply of one of the fuels (blast furnace gas (BFG) used by the boilers), and
- Operations while the desulfurization unit that is being constructed to treat the coke oven gas (COG), one of the fuels used by the boilers is off-line in maintenance mode.

This analysis was done for the two boilers in combination since that is the way the steam produced by the boilers is used. Each boiler has a heat input capacity of 225 MMBtu per hour. Therefore, the analysis has been done based on the total heat input of 450 MMBtu per hour.

The calculation of estimated emissions for each of these operational modes is described below.

Normal Operations

For this analysis, normal operations were calculated as operations during those times when the two blast furnaces at the facility are in operation and providing the full potentially available BFG.

Key assumptions for this mode of operations include:

- Blast furnace maintenance time as shown below:

Ozone Season	Annual	
15	15	days Blast Furnace Rebuild
	55	days Blast Furnace Down (15%) of time annual basis
23		days Blast Furnace Down (15%) of time ozone season basis
2	2	days maintenance outage
40	72	days Total Maintenance Outage

- a fuel mix on the boilers of:
  - 25% natural gas (NG)
  - 35% BFG
  - 40% COG
- a capacity factor of 100%
- controlled NO_X emission rates (lbs/MMBtu) of:
  - 0.084 NG
  - 0.0288 BFG
  - 0.144 COG

Furnace Downtime Operations

- Furnace downtime
  - 15 days furnace rebuild
  - 15% downtime per furnace (55 days for annual and 23 days for ozone season)
  - 2 days maintenance outage
- Fuel Mix
  - NG 40%
  - COG 60%
- Capacity factor 40%
- Same emission rates per fuel as for normal operations

Coke Oven Gas Scrubber Maintenance Mode

- 35 days per year
- occurs when COG represents 40% of the fuel mix
- since NO_X emissions are higher in this mode of operation, emissions are treated as a delta based on the COG emissions rate without COG desulfurization minus COG emission rate with COG desulfurization (emission rates in lb/MMBtu)
    - COG emission rate with desulfurization 0.144
    - COG emission rate without desulfurization 0.336

Baseline conditions were calculated using the same assumptions presented above but with the following emission rates based on previous emission reporting (in lb/MMBtu):

- 0.3 NG
- 0.066 BFG
- 0.729 COG

Results

Based on the assumptions and calculations shown above and the resulting ozone season controlled emission rate, the following emission reductions are anticipated due to the installation of FGR on Boilers 11 and 12.

	NO_X Emissions (tons/year)		NO_X Emissions (tons/ozone season)	
	Baseline	Controlled	Baseline	Controlled
Normal Operations	616.6	179.4	237.8	54.1
Furnace Downtime Operations	86.69	17.6	48.16	10.37
COG Desulfurization Down Delta		14.5		14.52
Total	703.3	211.6	286.0	79.0
Reduction in Emissions		491.7		207.0

Based on these calculations, USS GCW can meet NO_X requirements by averaging emissions between boilers 11 and 12 and among fuels and meet an average ozone season controlled rate of 0.113 lb/MMBtu.

6.0 CONCLUSIONS & RECOMMENDATIONS

This study evaluated five NO_X control techniques that could potentially be employed on the Granite City Works boilers 11 and 12 in order to comply with a proposed rule to require Reasonably Available Control Technology (RACT) on the units. The control techniques evaluated included:

- Low NO_X Burner Retrofit;
- Air preheater replacement with a feedwater economizer;
- Selective Catalytic Reduction;
- Selective Non-catalytic Reduction; and
- Flue Gas Recirculation.

Recommended NO_X RACT Control System

Flue gas recirculation is a technically viable control system for boilers 11 and 12. It can produce significant reductions in NO_X levels when compared to existing emission rates. Of all of the control techniques evaluated, it is uniquely suited as a RACT control because it will work with the changing fuel mix and load demands that these boilers see when in operation. The amount of fuel gas recirulation can be adjusted to match the particular load and fuel mix at any point in time.

Based on projected future operating conditions, the calculated NO_X ozone season emission rate is 0.113 lb/MMBtu. When compared to emissions based on existing emission rates, this will produce a reduction in ozone season NO_X emissions of 207 tons and on an annual basis, the emission reduction would be 492 tons.

Control Techniques Considered and Rejected

Control Technique	Considerations
Low NO_X burner retrofit	Particularly for Boiler 11, a low NO_X burner does not really exist. Even for Boiler 12, a viable low NO_X burner without FGR that could fire the mix of fuels fired on Boiler 12 and generate a significant NO_X reduction does not exist. A low NO_X burner combined with FGR would produce significant NO_X reductions, but the NO_X reduction would not be significantly greater than application of FGR alone to the existing burners.

Control Technique	Considerations
Air preheater replacement with a feedwater economizer	Reduction of the combustion air temperature will result in flame stability issues when firing BFG.
Selective Catalytic Reduction	Several aspects of the USS boiler 11 and 12 operation would complicate an SCR installation. Issues that must be considered in an SCR design include: • The USS steel boilers are load following, • The inlet NO_X to the SCR vary considerably based on the fuels used, • The COG, particularly if the scrubber is out of service, has a high fuel sulfur content. Although these technical issues in applying an SCR to the USS boilers can most likely be solved, an SCR installation on these boilers would be a very costly custom installation. Consequently, application of SCR on these boilers is not recommended.
Selective Non-Catalytic Reduction	Boilers 11 and 12 are not good candidates for an SNCR application because their operating characteristics do not match up well with the characteristics required for SNCR operation. The specific characteristics of the boiler operation that preclude SNCR as a viable control option are: • Load variations; • Changes in the bound-nitrogen content of the fuel; • Fluctuations in fuel heating value; • Sulfur content of the COG; • Stratification that varies with load and fuel composition.

F

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United States Steel
Granite City Works

FOR:

Ultra Low NOx Burner Retrofit Project for
Hot Strip Mill Furnaces 1 through 4
UGC1-0073 HSM Reheat Furnaces Low NOx Burners

Date:	**22 January 2009**
Proposal Numbers:	**P-107-0046 and P-B004243**
From:	**Stephen P. Pisano**
Phone:	**412.653.3500 x3245**
Fax:	**412.653.2253**
Email:	**spisano@bloomeng.com**

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January 22, 2009

United States Steel Corporation
Granite City Works
20th and State Streets
Granite City, IL 62040

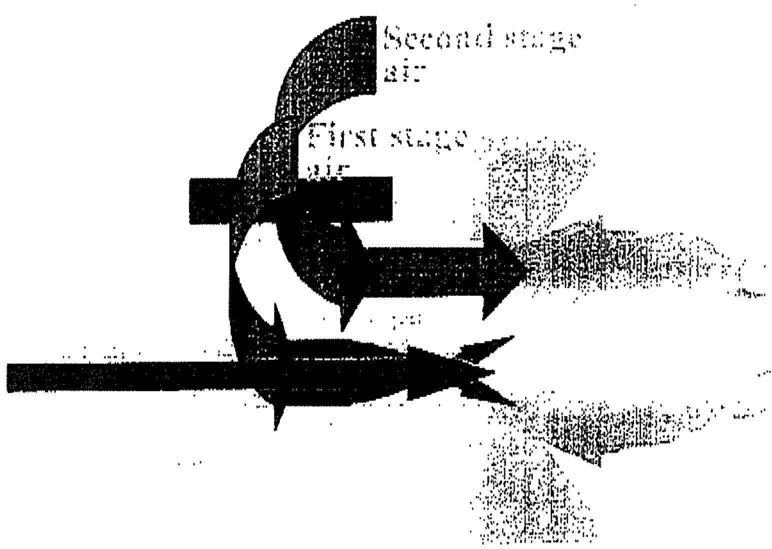
Attention: Mr. Kevin Anderson
Project Manager
(klanderson@uss.com)

Subject: UGC1-0073 HSM Reheat Furnaces Low NOx Burners
Low NOx Burner Retrofit Project for HSM Furnaces 1 - 4

Dear Mr. Anderson:

Below is the detailed information we discussed concerning our Bloom series 1619 Ultra Low NOx Cyclops Burner. These burners are a result of the continuous testing and improvements of Bloom's industry leading low NOx line of burners. Over the past 75 years Bloom has continually invested much time and effort in the research and development of low NOx burners. Our increasing understanding and knowledge in the formation of NOx emissions relative to steel reheat furnace combustion systems has led to the development of this latest design.

The patented* series 1619 Cyclops burner combines advanced air staging, time delayed fuel staging, swirl stability control and port reduction technologies to provide a stable burner with Ultra Low NOx emissions on various fuels. The employment of the high port energy densities to this project makes for a burner design which provides both ultra low NOx emissions along with heating and uniformity results that mimic your existing burners.



* US Patent No. 6,471,508

The air staging technology can be visually described in the image above. The air is split into first and second stage air. The first stage air supplies sufficient air to anchor the flame on the burner face. The second stage air mixes with

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the fuel and then completes combustion further out in the flame development. This provides lowest NOx emissions and a very uniform heat release pattern.

The fuel is introduced into the burner offset from the burner centerline. This provides a controlled delay of air/fuel mixing and further reduces the NOx emissions. The special burner design also provides for reasonable fuel pressures (<3PSIG COG, <1PSIG NAT GAS) to be supplied to the burner.

Attached is a one page bulletin further detailing these burners' benefits.

The table below provides a general summary of Bloom's predicted NOx values for furnaces 1 through 4 by applying Bloom 1619 Cyclops burner ultra low NOx technology. These values consider the following furnace conditions: atmosphere at 2.1% oxygen (10% excess air), burner placement and capacity duplicate existing burners, furnaces 1-3 have 800°F combustion air, furnace 4 has 650°F combustion air, wall thickness for furnaces 1-3 is 12", furnace 4 walls are 15" thick (doghouses removed), treated COG with less than 350ppm fuel bound nitrogen, untreated COG with less than 1800ppm fuel bound nitrogen, furnaces 1 and 2 use COG fuel on the intermediates zones only(natural gas on all others), furnace 3 uses COG fuel on intermediate and heat zones only(natural gas on all others), furnace 4 uses mixed 70%COG/30%NG fuel on all zones (current maximum COG ratio).

Furnace	Burner Series	Fuel	NOx (#/MM BTU, HHV)
1	Bloom 1619 Cyclops	Varies (see above) Treated COG	0.145
2	Bloom 1619 Cyclops	Varies (see above) Treated COG	0.145
3	Bloom 1619 Cyclops	Varies (see above) Treated COG	0.179
4	Bloom 1619 Cyclops	Treated Mixed COG/NG	0.174

Furnace	Burner Series	Fuel	NOx (#/MM BTU, HHV)
1	Bloom 1619 Cyclops	Varies (see above) Untreated COG	0.220
2	Bloom 1619 Cyclops	Varies (see above) Untreated COG	0.220
3	Bloom 1619 Cyclops	Varies (see above) Untreated COG	0.330
4	Bloom 1619 Cyclops	Untreated Mixed COG/NG	0.280

These NOx values above represent predicted NOx emissions obtainable by applying our Bloom 1619 Cyclops Ultra Low NOx burner technology to your current HSM furnaces and specified conditions.

We thank you for this opportunity to provide our products and services for your furnace combustion needs. Please do not hesitate to contact us should any questions or concerns arise.

Very truly yours,
Bloom Engineering Company, Inc.

Stephen P. Pisano
Product Manager – Steel Industry

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3/08

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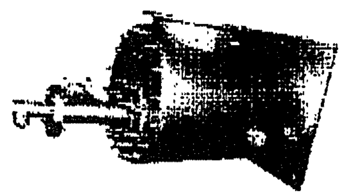
1610 SERIES – CYCLOPS™ ULTRA⁴ LOW NOX™ HOT AIR BAFFLE BURNER
FERROUS APPLICATIONS

CAPABILITIES
- Very low NOx emissions
- High release rates with moderate main combustion air pressure
- Good turndown with flame characteristics and direction maintained
- Operation at 5-10% excess air is recommended to minimize NOx



FEATURES
- Rugged fabricated construction
- Patented Cyclops™ refractory baffle flame stabilization shields the burner internals from flame and furnace radiation and is a self support structure
- Standard design is suitable for operation at 400°F-1000°F (205°C-538°C) air preheat and 2600°F (1427°C) furnace temperatures. Special construction is available for higher temperatures
- Heat resistant alloy nozzle
- Provisions for flame monitoring
- Port blocks do not require wide flare

CONTROL
- External Diverter Valves
- Metered Air/Gas Ratio Control

FLAME MONITORING
- U.V. Detector during staged mode below 1800°F (980°C). U.V. bypassed in Cyclops mode above 1800°F (980°C)

TURNDOWN
- Standard 3:1
- With Air Lance 10:1
  Air lance @ 1 psig (70 mBar)

APPLICATIONS
- Slab Reheating Furnaces using longitudinal or side firing
- Billet Reheating Furnaces using longitudinal or side firing
- Sodium Silicate Melters
- Forge Furnaces
- Reheat Furnaces

BURNER IGNITION
- Pilot
- Manual
- Air Cooled Direct Spark

FUEL CAPABILITIES*
- #2 and #6 Fuel Oils (staged mode only)
- Natural Gas
- Propane
- Coke Oven Gas
- Mixed BFG/COG

*gas pressure required – 10psig (700 mBar)

The Bloom 1610 Series refractory baffle burner is designed for gaseous and liquid fuels and is suitable, without change, for any gas having a heating value gas of approximately 500 Btu per cubic foot or greater. For designs using a lower heating value, contact your local representative or Bloom Pittsburgh.

Manufactured under U.S. Patent 6,471,508 – w/ O_2 enrichment 6,793,486

CAUTION: The improper use of combustion equipment can result in a condition hazardous to people and property. Users are urged to comply with National Safety Standards and/or Insurance Underwriters recommendations

G

Information regarding uncontrolled NOx rates for slab furnaces heated by COG and NG.

Existing Slab Furnace NOx Emission Factors.

The original emission factors were:	Natural gas	0.393 lbs/MMBTU
	Coke Oven Gas	0.563 lbs/MMBTU

The NG factor is based on a 1992 test of #4 Slab Furnace. The COG factor is an estimate based on the assumption that the ratio of COG to NG NOx emissions is the same at the slab furnaces as it was at the boilers based on earlier test at the boilers.

CERTIFICATE OF SERVICE

I, Katherine D. Hodge, the undersigned, hereby certify that I have served the attached SUPPORTING MATERIALS FROM UNITED STATES STEEL CORPORATION upon:

Mr. John T. Therriault
Assistant Clerk of the Board
Illinois Pollution Control Board
100 West Randolph Street, Suite 11-500
Chicago, Illinois 60601

via electronic mail on January 30, 2009; and upon:

Timothy Fox, Esq.
Hearing Officer
Illinois Pollution Control Board
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Chicago, Illinois 60601

Matthew J. Dunn, Esq.
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by depositing said document in the United States Mail, postage prepaid, in Springfield, Illinois on January 30, 2009.

/s/ Katherine D. Hodge
Katherine D. Hodge

USSC:001/Fil/R08-19/NOF-COS – Supporting Materials