GP Consumer Products LP

Green Bay Broadway Mill

BEST AVAILABLE RETROFIT TECHNOLOGY ANALYSIS

Submitted to the
Wisconsin Department of Natural Resources

March 2009

1. EXECUTIVE SUMMARY

The GP Consumer Products LP Green Bay Broadway Mill submits this Best Available Retrofit Technology (BART) Analysis to address the requirements of 40 CFR Part 51 and Wisconsin Administrative Code NR 433 as requested by Wisconsin Department of Natural Resources (DNR).

The Mill and DNR have identified the following emission units at the facility which meet the applicability criteria promulgated by EPA:

- No. 6 Boiler (B26)
- No. 7 Boiler (B27)

The BART analysis includes consideration of the following factors to determine what additional emission reductions of visibility-affecting pollutants are appropriate, if any. These factors are: the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. The following table summarizes GP's BART analysis for these two sources:

Table 1. Summary of Highest Level of Technically and Economically Feasible Controls, Green Bay Broadway Mill

Emission Unit	Pollutant	Technically and Economically Feasible Control Option	Cost Effectiveness ($/ton removed)	Actual Tons Reduced (tpy)	Predicted change in Visiblity Impairment (dv)
No. 6 Boiler	SO_2	Clean Fuels	1,082	1,333	
No. 6 Boiler	NOx	None	0	NA	-0.4 total
No. 6 Boiler	PM_{10}	Existing Baghouse	0	NA	
No. 7 Boiler	SO_2	Electrical Upgrades + Fuel Switch	646	7,408	
No. 7 Boiler	NOx	Electrical Upgrades	2,088	2,290	-1.6 total
No. 7 Boiler	PM_{10}	Existing Baghouse	0	NA	

Attachments A and B present the air quality and control technology analyses, respectively.

2. INTRODUCTION

GP Consumer Products LP Green Bay Broadway Mill, a wholly-owned subsidiary of Georgia-Pacific LLC (GP), operates a recycle pulp (de-inking process) and paper mill classified under the Standard Industrial Classification (SIC) code 2621. Purchased market pulp is also accepted at the facility as raw material for papermaking operations. The facility operates under Title V Permit No. 405032870-P01.

2.1 Facility Location

The Green Bay Broadway Mill is located in the city limits of Green Bay, Wisconsin of Brown County. The Mill is at the eastern termination of Lombardi Avenue. The location is in an area south of Mason Street (Highway 54), east of Ashland Avenue (Highways 32 and Business 41), north of Highway 172, and bounded on the east side by the Fox River. The facility is located in an industrial area, but residential areas are in proximity to the location. Presently Brown County is designated by the Environmental Protection Agency (EPA) as being in attainment or unclassified for all criteria pollutants ($PM_{2.5}$ is under further consideration).

2.2 Process Description

Primary operations at the facility include steam and electrical generation, fiber recovery and bleaching, paper making, and converting. The original feedstock used by a paper mill can come from a variety of sources, including purchased market pulp and recycled paper (post-manufacturing and post-consumer). The Green Bay Broadway Mill purchases or obtains all of the pulp and recycled paper used at the facility since the Mill does not have the capability to produce pulp directly from virgin wood fiber. This recycled paper originates from a variety of sources, including curbside recycling programs, paper trimmings, and damaged paper (broke) within the plant. Fiber is recovered from this wastepaper to produce stock for the seven wet paper machines at the mill.

In addition to the seven wet paper machines, there are two dry paper machines that use nearly 100 percent virgin fiber. Most of the paper produced at the facility is converted on site. Many of the converted products are printed with inks for decoration during the converting process. Converted and unconverted products are ultimately wrapped, packaged, and distributed to customers. Products are distributed into the domestic commercial (away-from-home) and consumer markets.

2.3 BART Requirements

USEPA defined BART as:

Best Available Retrofit Technology (BART) means an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration:

- *the technology available,*
- *the costs of compliance,*
- *the energy and nonair quality environmental impacts of compliance,*
- *any pollution control equipment in use or in existence at the source,*
- *the remaining useful life of the source,*
- *and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.*

(40 CFR 51.301)

To complete the analysis, GP followed the following guidelines:

1. USEPA in 40 CFR Part 51, Appendix Y - Guidelines for BART Determinations Under the Regional Haze Rule - Part IV. The BART Determination: Analysis of BART Options, pages 39164 to 39172, published July 6, 2005.
2. Wisconsin Administrative Code Chapter NR433

The Guidelines present the following steps to address the case-by-case factors:

STEP 1 - Identify All[1] Available Retrofit Control Technologies,

STEP 2 - Eliminate Technically Infeasible Options,

STEP 3 - Evaluate Control Effectiveness of Remaining Control Technologies,

STEP 4 - Evaluate Impacts and Document the Results, and

STEP 5 - Evaluate Visibility Impacts.

[1] In identifying ''all'' options, EPA specifies that the most stringent option and a reasonable set of options for analysis that reflect a comprehensive list of available technologies must be identified. It is not necessary to list all permutations of available control levels that exist for a given technology – the list is complete if it includes the maximum level of control each technology is capable of achieving.

3. STEPS 1 THROUGH 4 - CONTROL TECHNOLOGY ANALYSIS

The BART engineering analysis in this application follows the "top-down" approach. The "top-down" approach starts with the most stringent control technology alternative that has been applied to same or similar sources and provides a basis for rejecting this alternative in favor of the next most stringent technology or proposing it as BART. Following are the basic steps of a "top-down" analysis:

1) Identify all control technologies
   a) All typically in use
   b) Determined as BACT and listed in USEPA *RACT/BACT/LAER Clearinghouse*
   c) In use at Georgia-Pacific facilities
2) Eliminate technically or economically infeasible options
3) Rank remaining control technologies by control effectiveness
4) Evaluate most effective controls and document results

GP performed the steps above for each visibility-affecting pollutant individually. Wisconsin DNR has determined that the relevant pollutants are limited to: sulfur dioxide (SO_2), nitrogen oxides (NO_x) and particulate matter (PM_{10}). Table 2 presents a summary of technically feasible control technologies ranked for each emission unit.

Table 2. Ranking of Technologically Feasible Control Technologies, Green Bay Broadway Mill

		Removal Rate	
Pollutant	Technology	Boiler No. 6	Boiler No. 7
SO_2	Fluidized Bed Dry Scrubber	90%	90%
SO_2	Wet Scrubber	90%	90%
SO_2	Electrical Infrastructure Upgrades + Fuel Switch	NA	85%
SO_2	In Duct Sorbent (SO_2 only)	50%	50%
SO_2	Low Sulfur Coal Substitution (a)	40%-62%	11%
SO_2	In Duct Sorbent by Mobotec	50%	50%
NOx	Electrical Infrastructure Upgrades	NA	83.6%
NOx	Tail End SCR	80%	80%
NOx	Combustion Control by Mobotec (ROFA/ROTAMIX™)	66%	66%
NOx	SNCR + OFA (with FGR for Boiler 6)	56%	70%
NOx	OFA Alone	20%	60%
NOx	SNCR alone	25%	35%

SNCR = Selective Non-Catalytic Reduction; SCR = Selective Catalytic Reduction; OFA = Overfire Air;
(a) Low Sulfur Coal represents the use of a lower sulfur coal blend compared to current permit fuels (up to 4.55 lb/MMBtu).

Attachment B presents detailed descriptions, a determination on technical feasibility of all control options and cost calculations to determine economic, energy, and non-air environmental impacts.

4. STEP 5 – VISIBILITY IMPAIRMENT ANALYSIS

EPA's Guidelines specify the use of CALPUFF, or other appropriate dispersion models to determine the visibility improvement expected at a Class I area from the potential BART control technology applied to the source. Modeling should be conducted for SO_2, NO_x, and direct PM emissions ($PM_{2.5}$ and/or PM_{10}). There are several steps for determining the visibility impacts from an individual source using a dispersion model:

- *Develop a modeling protocol.*

Critical items included in a modeling protocol are meteorological and terrain data, as well as source-specific information (stack height, temperature, exit velocity, elevation, and allowable and actual emission rates of applicable pollutants), and receptor data from appropriate Class I areas. WDNR provided a modeling protocol, prepared by Lake Air Directors Consortium (LADCO) in 2006.

- *For each source, run the model at pre-control and post-control emission rates according to the accepted methodology in the protocol.*

The Guidelines specify the use of 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the pre-control scenario). G-P used the model to calculate the model results for each receptor as the change in deciviews compared against natural visibility conditions. Table 3 presents the highest emitting day emission rates.

- *Make the net visibility improvement determination.*

The Guidelines specify an assessment of the visibility improvement based on the modeled change in visibility impacts for the pre-control and post-control emission scenarios. G-P compared the worst case single days for the pre- and post-control runs as provided by DNR.

Table 3 summarizes the predicted visibility impact compared to background for individual units and collectively under pre-BART and post-BART conditions at all Class I Areas within 300 km of the Mill.

Table 3. Summary of Predicted Visibility Impairment by BART-Eligible Emission Units at Green Bay Mill

	Total Actual Emissions (lbs/day) (a)			Maximum Impact
Emission Units	SO_2	NOx	PM_{10}	(dv) Seney
All BART Units Combined – 2002-2004 baseline				
	81,863	23,008	6,857	2.6
Individual BART Units – Post Control				
No. 6 Boiler	8,376	3,389	2,520	0.5
No. 7 Boiler (b)	0	0	0	0

(a) Baseline reflects actual maximum daily emissions 2002 – 2004 for SO2 and NOX. CALPUFF modeling files provided by WDNR applied a constant emission rate representative of the potential emissions of 0.3 lb PM_{10} /MMBtu

(b) No. 7 Boiler would not operate unless another boiler at the Mill is shut down due to a scheduled outage

5. BART CONCLUSION

GP has carefully considered the factors for the BART emission units. GP believes the following are technically and economically feasible:

1. Reduce current permit SO_2 emission limits by 62% for Boiler No. 6 through fuel substitution.

2. Reduce current permit NO_x and SO_2 emission limits by 83.6% and 85%, respectively for Boiler No. 7 through the construction of electrical infrastructure upgrades and limiting operation to eastern low fusion coal fuels for 60 calendar days per year.

The predicted impairment to visibility compared to background at the Class I Area will improve from 2.6 dv to 0.5 dv (worst case day basis over 3 years).

ATTACHMENT A

BEST AVAILABLE RETROFIT TECHNOLOGY

AIR QUALITY IMPACT ANALYSIS

GP CONSUMER PRODUCTS LP

GREEN BAY BROADWAY MILL

MARCH 2009

1.0 INTRODUCTION

1.1. Overview of the Regional Haze BART Process

Under regional haze regulations, the Environmental Protection Agency (EPA) issued final guidelines dated July 6, 2005, for Best Available Retrofit Technology (BART) determinations (70 FR 39104-39172). The regional haze rule includes a requirement for BART for certain large stationary sources, such as Boiler No. 6 and Boiler No. 7 at the Green Bay Broadway facility. A sources is BART-eligible if it meets three criteria concerning (1) potential emissions of visibility-impairing pollutants, (2) the date it was put in operation, and (3) whether it falls within one of the source categories listed in the guidance. The guidance requires a BART engineering evaluation using six statutory factors for any BART-eligible source that can be reasonably expected to cause or contribute to impairment of visibility in any Class I area protected under the regional haze rule. (Note that, depending on the six factors, the evaluation may result in no control.) Air quality modeling is an important tool available to the States to determine whether a source can be reasonably expected to contribute to visibility impairment in a Class I area.

The process of making a BART determination consists of four steps:

1) Identify whether a source is "BART-eligible", based on its source category, when it was put in service, and the magnitude of its emissions of one or more "visibility-impairing" air pollutants. The BART guidelines list 26 source categories of stationary sources that are BART-eligible. Sources must have been put in service between August 7, 1962 and August 7, 1977. Finally, a source is BART-eligible if potential emissions of visibility-impairing air pollutants are greater than 250 tons per year. Qualifying pollutants include primary particulate matter (PM_{10}), and gaseous precursors to secondary fine particulate matter, such as SO_2 and NO_x. WDNR has determined that neither ammonia nor volatile organic compounds (VOCs) should be included as visibility-impairing pollutants for BART eligibility.

2) Determine whether a BART-eligible source can be excluded from BART controls by demonstrating that the source cannot be reasonably expected to cause or

contribute to visibility impairment in a Class I area. The preferred approach is an assessment with an air quality model such as CALPUFF or other appropriate model followed by comparison of the estimated 24-hr visibility impacts against a threshold above estimated natural conditions to be determined by the States. The threshold to determine whether a single source "causes" visibility impairment is set at 1.0 deciview (dv) change from natural conditions over a 24-hour averaging period in the final BART rule (70 FR 39118). The guidance also states that the proposed threshold at which a source may "contribute" to visibility impairment should not be higher than 0.5 dv although, depending on factors affecting a specific Class I area, it may be set lower than 0.5 dv. The test against the threshold is "driven" by the contribution level, since if a source "causes", by definition it "contributes".

3) Determine BART controls for the source by considering various control options and selecting the "best" alternative, taking into consideration:

a) Available technology,
b) Any pollution control equipment in use at the source (which affects the availability of options and their impacts),
c) The costs of compliance with control options,
d) The remaining useful life of the facility,
e) The energy and non air-quality environmental impacts of compliance, and
f) The degree of improvement in visibility that may reasonably be anticipated to result from the use of such technology.

If a source agrees to apply the most stringent controls available to BART-eligible units, the BART analysis is essentially complete and no further analysis is necessary (70 FR 39165).

4) Incorporate the BART determination into the State Implementation Plan for Regional Haze.

Step 2 described above reflects 40 CFR Part 51 Appendix Y which states that, "*You can use dispersion modeling to determine that an individual source cannot reasonably be anticipated to cause or contribute to visibility impairment in a Class I area and thus is not subject to BART*." (70 FR 39162) This "individual source attribution approach" determines if a BART-eligible source (*i.e.,* collection of eligible emission units at a source) is predicted to cause or contribute to visibility impairment in a Class I area. As mentioned above, a predicted impact of 1.0 dv change or more is considered to "cause" visibility impairment, and a predicted impact of 0.5 dv change or more is considered to "contribute". Any source determined to cause or contribute to visibility impairment in any Class I area is subject to BART and will also need to complete additional visibility impact analyses.

1.2. Organization of the Report

Section 2 presents facility-specific information. Section 3 presents the contribution by WDNR for the BART analyses. Section 4 presents the criteria and processing of model results to demonstrate what impairment the facility is predicted to create in the Class I area.

2.0 SITE DESCRIPTION AND EMISSION INVENTORY

GP operates the Green Bay Broadway facility (Brown County) approximately 6 miles east of the Green Bay regional airport. The facility manufactures paper products. The facility is located in an industrial/developed area, with few residential areas adjacent to the Mill property. The Mill is located along the Fox River.

The Mill is located in nearly flat terrain, generally described as an area in which winds and temperature (hence dispersion) are not affected by the presence of mountains. Figure 1 depicts the location of Green Bay Broadway Mill.

The only BART-eligible emission units determined by WDNR are the No. 6 and No. 7 Boilers. Both boilers exhaust through a single common stack (Stack 10). Table 1 presents stack parameters and reflects the actual configuration and blending of the two boiler exhausts (along with other existing boilers).

Table A-1. Source Parameters, Green Bay Broadway Mill BART Eligible Units Stack 10

Location	latitude	deg.	44.49 N
	longitude	deg.	88.03 W
	Datum		NAR-C
Stack Height		ft	380 (a)
Base Elevation		ft	589
Diameter		ft	12.5
Gas Exit Velocity		ft/s	92.66
Stack Gas Exit Temp.		deg F	330

(a) Physical Stack is 400 ft though Good Engineering Practice height is 380 ft

Figure 1. Area Map of GP Green Bay Broadway Mill

• Green Bay Broadway Mill

Baseline Emissions

The Mill reviewed daily records of fuel use, Continuous Emission Monitor (CEM) records and daily fuel analysis to estimate the daily emission rates from each boiler[1]. Table A-2 summarizes the peak daily average emissions by considering several criteria and ranking all days in the baseline period.

Table A-2. Summary of Maximum Daily Emissions 2002-2004, Green Bay Broadway Mill Boiler Nos. 6 and 7

		Maximum Actual Daily Emissions (lbs/day) 2002-2004					
		Boiler No. 6			Boiler No. 7		
Criteria	Date	SO_2	NOx	PM	SO_2	NOx	PM
Highest NOx Boiler 6 +Boiler 7	3/23/04	17,854	3,389	358	63,296	19,619	739
Highest SO_2 Boiler 6 + Boiler 7	11/14/2003	22,043	4,048	899	59,819	18,086	1,474

Figure A-2 and A-3 present the 3 year trend of daily estimated NOx and SO_2 emission rates.

1 In accordance with USEPA BART guidance, periods of startup and shutdown have been excluded. CEM data only exists for the total SO_2 from Stack 10.

Figure A-2. Georgia-Pacific GB Broadway
Daily Sulfur Dioxide Emissions - Boilers 6 and 7: 2002-2004

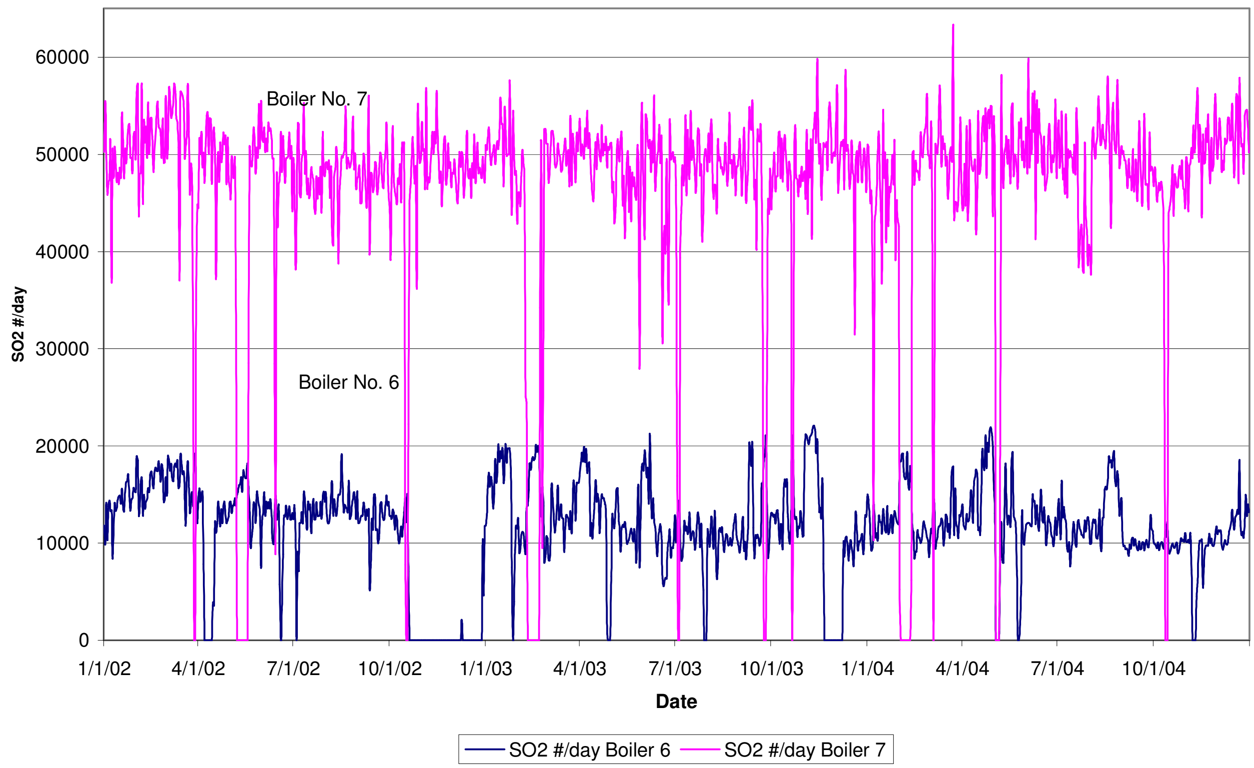
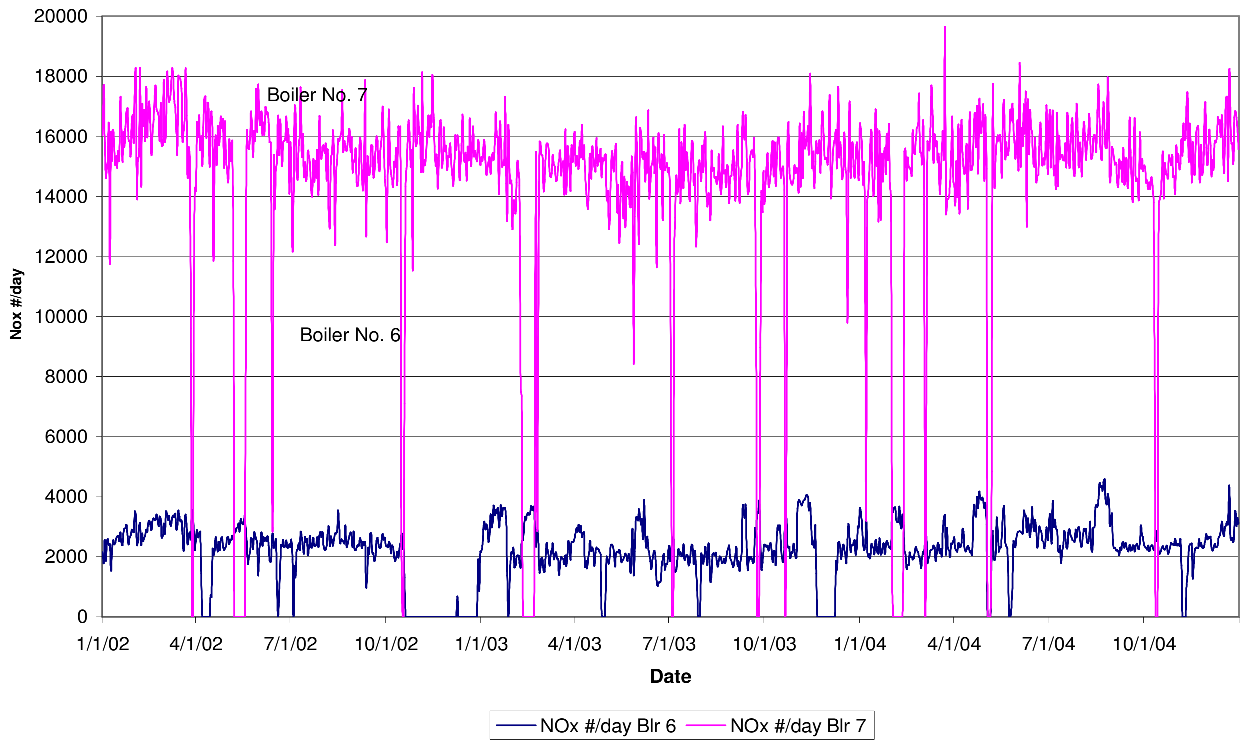


Figure A-3. Georgia-Pacific GB Broadway
Daily Estimated Nitrogen Oxide Emissions - Boilers 6 and 7: 2002-2004



The control technology analysis (see Attachment B) determined several technically feasible control technology options. Table A-3 presents the scenarios applied in the visibility impairment analysis. While some of the modeled emission scenarios are not economically feasible, the model results provide an additional factor to apply in the BART analysis.

Table A-3. Summary of Technically Feasible Control Technologies for GP Green Bay Broadway

	Control Technology	
Model Scenario	Boiler No. 6	Boiler No .7
Baseline	Existing Controls	Existing Controls
SO_2 Controls	Clean Fuels	Electrical Upgrades and Fuel Switch
SO_2 Controls	Clean Fuels	Gas Absorption
NOx Control	None	Electrical Upgrades
NOx Control	OFA + FGR + SNCR*	Electrical Upgrades

*Attachment B determined this technology was not economically feasible

As described in Attachment B, the engineering analysis developed two configurations for the gas absorption (*i.e.,* scrubbers). SO_2 scrubber control options include a configuration with a new stack and a configuration using the existing stack. As the lowest cost option for these two options will utilize the existing stack, the impact analysis for scrubber control will assume the existing stack. All other control options analyzed also employ the existing boiler stack. Table A-4 presents the emissions rate for three hypothetical control technology cases:

- Case 1: Clean Fuels on Boiler No. 6 for 62% SO_2 reduction (from 4.55 lb/MMBtu). Boiler No. 7 is offline for 305 days per year (annual average of 85% and 83.6% reduction for SO_2 and NOx, respectively).
- Case 2: Clean Fuels on Boiler No. 6 for 62% SO_2 reduction. Gas Absorption on Boiler No. 7 for 90% reduction

- Case 3: Clean Fuels, OFA+FGR+SNCR on Boiler No. 6 for a 62% and 56% reduction for SO_2 and NOx, respectively. Boiler No. 7 is offline 305 days per year (annual average of 85% SO_2 reduction).

Table A-4. Summary of Modeled Emission Rates, Control Scenarios Green Bay Broadway Mill

Model Scenario	Pollutant	Actual Emission Rates (lbs/day) [2]		
		Boiler No. 6	Boiler No. 7	Total
Existing Controls	SO_2	22,043	59,819	81,863
	NOx	3,389	19,619	23,008
Case 1 : Clean Fuels and Electrical Infrastructure Upgrades	SO_2	8,376	0 [3]	8,376
	NOx	3,389	0 [3]	3,389
Case 2 : Clean Fuels and Gas Absorption	SO_2	8,376	5,982	14,358
	NOx	3,389	19,619	23,008
Case 3: Clean Fuels, OFA+FGR+SNCR and Electrical Infrastructure Upgrades	SO_2	8,376	0 [3]	8,376
	NOx	1,491	0 [3]	1,491

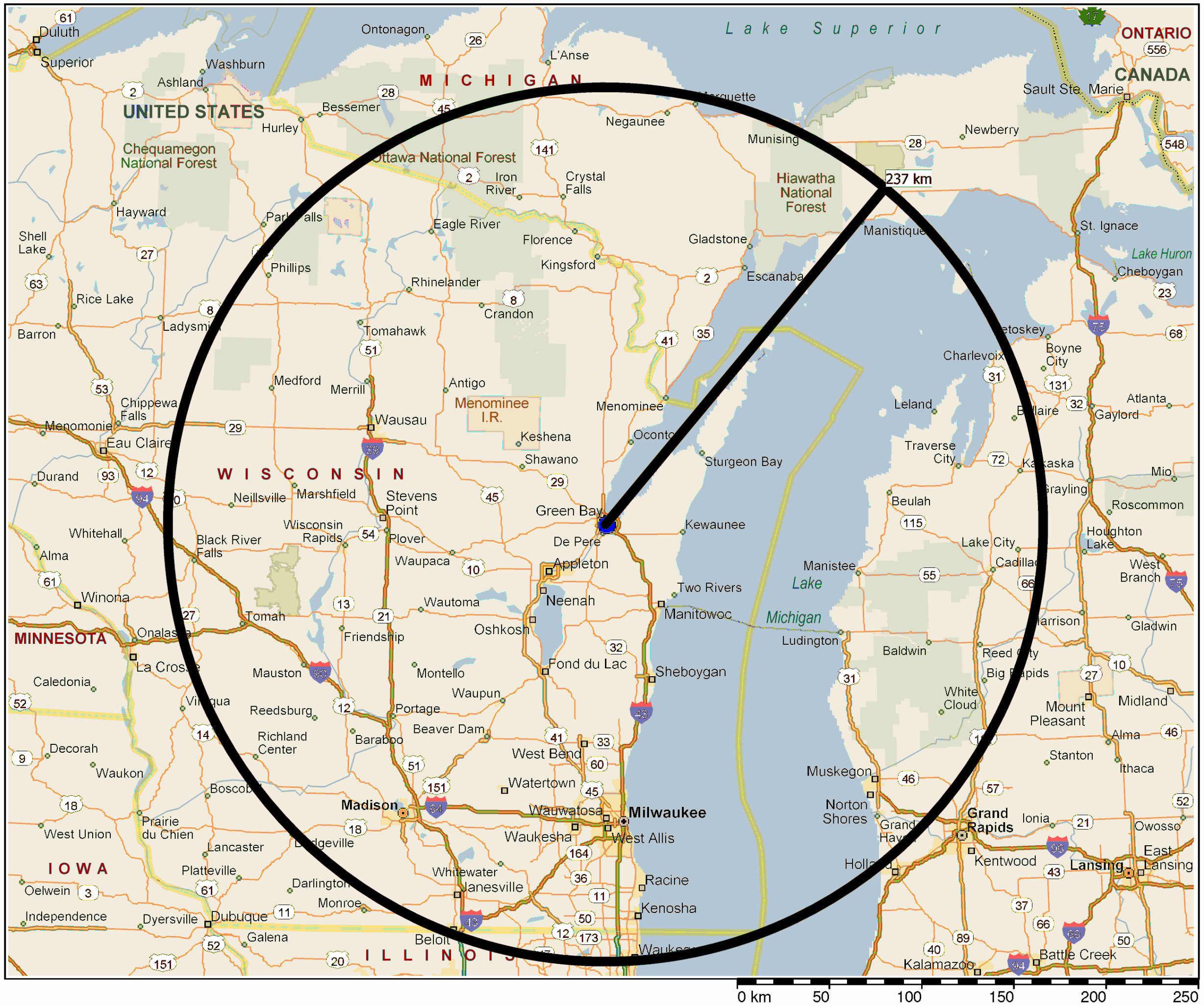
[2] Emission rates reflect the removal efficiency determined in Attachment B and the baseline actual emission rates presented in Table A-2. PM_{10} emissions are set to baseline emission rates for each run as a conservative assumption.

[3] Boiler No. 7 is offline for a minimum of 305 days per year. Boiler No. 7 only operates on eastern low fusion coal during periods when another boiler is offline due to a scheduled outage.

The analysis used POSTUTIL and CALPOST to post-process these emissions in accordance with the "Single Source Modeling to Support Regional Haze BART Modeling Protocol" by the Lake Michigan Air Director's Consortium (LADCO). The appendix presents this original document.

For the determination on impairment, only Class I areas within 300 kilometers (km) are evaluated. USEPA recommends CALPUFF for long-range modeling up to 300 km without individual case-by-case approval. The distance to the nearest Class I area is 237 km to Seney National Wilderness Refuge Class I area. There are no other Class I areas within 375 km of the Mill. Figure A-4 presents the arrangement of the Mill and the Seney PSD Class I Area. The analysis applied the receptor locations created by the National Park Service Class I dataset.

Figure A-4. Regional Map of Green Bay Broadway Mill and Seney National Wilderness Refuge.



3.0 WDNR CONTRIBUTION TO CALPUFF MODELING

For this application of BART Modeling, WDNR applied the model programs, meteorological dataset, and protocol prepared by LADCO. WDNR prepared a sensitivity table of 45 individual model runs. Table A-5 presents sensitivity analysis results by WDNR for the Green Bay Broadway Stack 10.

4.0 RESULTS AND DETERMINATION OF IMPAIRMENT

4.1 Impact Threshold

The final BART guidance recommends a threshold value of 0.5 dv change from natural conditions to define whether a source "contributes" to visibility impairment (although states may set a lower threshold). The 98th percentile (8th highest annual) 24-hr average predicted impact at the Class I area, as calculated using CALPOST Method 6 (monthly average relative humidity values), is to be compared to this contribution threshold value. For this comparison, the predicted impact at the Class I area on any day is taken to be the highest 24-hr average impact at any receptor in the Class I area on that day. (Note that the receptor where the highest impact occurs can change from day to day.)

Table A-5. Crosstab of Results of Sensitivity Analysis for Green Bay Broadway Mill Stack 10 to Seney Class I Area , Prepared by WDNR

SO_2 Emissions (lb/hr)	NOx Emissions (lbs/hr)									
	926	834	741	648	556	463	370	278	185	93
	Maximum Visibility Impairment (dv)									
4,391	2.92		2.87		2.8		2.74		2.67	2.63
3,952		2.73		2.66		2.58		2.5		
3,513	2.59		2.51				2.34		2.24	
3,074				2.26		2.16		2.06		
2,635	2.19	2.14			1.99		1.88			
2,196			1.86			1.7		1.59		1.48
1,757	1.73	1.68			1.51		1.4		1.28	
1,317			1.38	1.32		1.21		1.09		0.97
878	1.24						0.89	0.83	0.77	0.71
439	1.02					0.69		0.56	0.5	0.43

4.2 Presentation of Modeling Results

Table A-6 summarizes the results for the highest predicted impact by linear interpolation of the sensitivity data by WDNR. The results indicate a reduction of predicted impairment from 2.6 dv to 0.5 dv, 1.24 dv and 0.43 dv for cases 1, 2 and 3 respectively. Case 1 and 3 are below the cause or contribute threshold of 0.5 dv.

Table A-6. Summary of Predicted Model Impact, Seney Class I Area Green Bay Broadway Mill

Model Scenario	Predicted Impact (dv)	Pollutant	Total Actual Emissions lbs/day	lbs/hr
Existing Controls	2.6	SO_2	81,863	3410.9
		NOx	23,008	958.7
Case 1 : Clean Fuels and Electrical Infrastructure Upgrades and Fuel Switch	0.5	SO_2	8,376	349.0
		NOx	3,389	141.2
Case 2 : Clean Fuels and Wet Scrubber	1.24	SO_2	14,358	598.3
		NOx	19,619	817.4
Case 3: Clean Fuels, OFA+FGR+SNCR and Electrical Infrastructure Upgrades and Fuel Switch	0.43	SO_2	8,376	349.0
		NOx	1,491	62.1

ATTACHMENT B

ENGINEERING ANALYSIS FOR CONTROL TECHNOLOGY OPTIONS – GREEN BAY BROADWAY MILL

1.0 ENGINEERING ANALYSIS METHODOLOGY

NR 433 Wisconsin Administrative Code requires Best Available Retrofit Technology (BART) engineering analyses for emission units which meet eligibility requirements of source size, type, and date of initial operation. Wisconsin Department of Natural Resources (DNR) notified Georgia-Pacific Consumer Products LP – Green Bay Broadway Mill on July 9, 2008, of its eligibility for two emission units. As required by NR 433, the Green Bay Broadway Mill has prepared an engineering analysis for units we agree are eligible for BART. As explained in the July 9, 2008, notice, the two units are Boiler No. 6 and Boiler No. 7 (source IDs B26 and B27, respectively). The requirements of a BART engineering analysis are summarized in NR 433.

The Best Available Retrofit Technology (BART) engineering analysis in this application follows the U.S. EPA's BART guidelines[1] which reflect a "top-down" approach that is similar to analyses required by federal Prevention of Significant Deterioration regulations for Best Available Technology (BACT). The BART review is performed on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs for technologies determined to be technically feasible. The "top-down" approach starts with an assessment of the most stringent control technology. If the technology is shown not to be technically or economically effective, then the analysis provides a basis for rejecting this alternative in favor of the next most stringent technology as BART. Following are the basic steps of a "top-down" analysis:

1) Identify all control technologies
   a) Typically in use or shown to be technically feasible by an equipment vendor,
   b) Determined as BACT and listed in USEPA *RACT/BACT/LAER Clearinghouse,*
   c) Already in use at one of Georgia-Pacific's operating facilities.
2) Eliminate technically or economically infeasible options.
3) Rank remaining control technologies by control effectiveness.
4) Evaluate most effective controls (considering costs, energy and environmental impacts).
5) Select BART control technology.

GP performed the 5 steps for each visibility-affecting pollutant individually for each affected unit subject to BART. Wisconsin DNR has determined that the relevant pollutants are: sulfur dioxide (SO_2), nitrogen

[1] 70 Federal Register 39104 July 6, 2005

oxides (NO_x) and particulate matter (PM_{10})[2]. For each analysis of control technology costs, GP followed US EPA's Cost Control Manual [3] guidance. Generally, the Manual techniques reflect a "rough order of magnitude" with an accuracy of approximately +/- 30%. GP prepared site-specific cost estimates that meet or exceed this level of accuracy.

The following sections provide a detailed engineering analysis for Boiler No. 6 and Boiler No. 7 individually. To determine emission reduction efficiency and operating costs, the analyses used the BART baseline years selected by Wisconsin DNR (2002-2004). The estimated rates of reduction (efficiencies) reflect the design of control options. In contrast, the reduction in mass emissions (tpy) reflects the control option as it applies to the actual operating rates and actual fuel selections during the baseline period.

[2] NR 433.02 (13)
[3] EPA Air Pollution Control Cost Manual Sixth Edition EPA/452/B-02-001 January 2002

2.0 BART ENGINEERING ANALYSIS FOR BOILER NO. 6

2.1 SOURCE DESCRIPTION

Boiler No. 6 is a spreader stoker-fired unit manufactured by Babcock and Wilcox installed in 1962. It is a two drum, balanced draft furnace, with a maximum rated heat input capacity of 350 million British Thermal Units per hour (MM Btu/hr). Boiler No. 6 burns washed coal [4] (eastern high and low fusion and western coals) and petroleum coke. Boiler No. 6 provides steam for process heating and for the production of electrical energy using turbine generators. The boiler is designed for steam production at a maximum continuous rating (MCR) of 275,000 (lbs/hr) at 850 psig and 890 ^{o}F. The boiler exhaust gases pass through an air heater and then are discharged via the boiler's induced draft fan into a common duct connected with the flue gas discharge streams of several other boilers at the mill. The common duct is equipped with a baghouse to remove particulate matter emissions from the exhaust gases. Figure B-1 presents a side-view drawing of Boiler No. 6.

2.2 BASELINE EMISSIONS

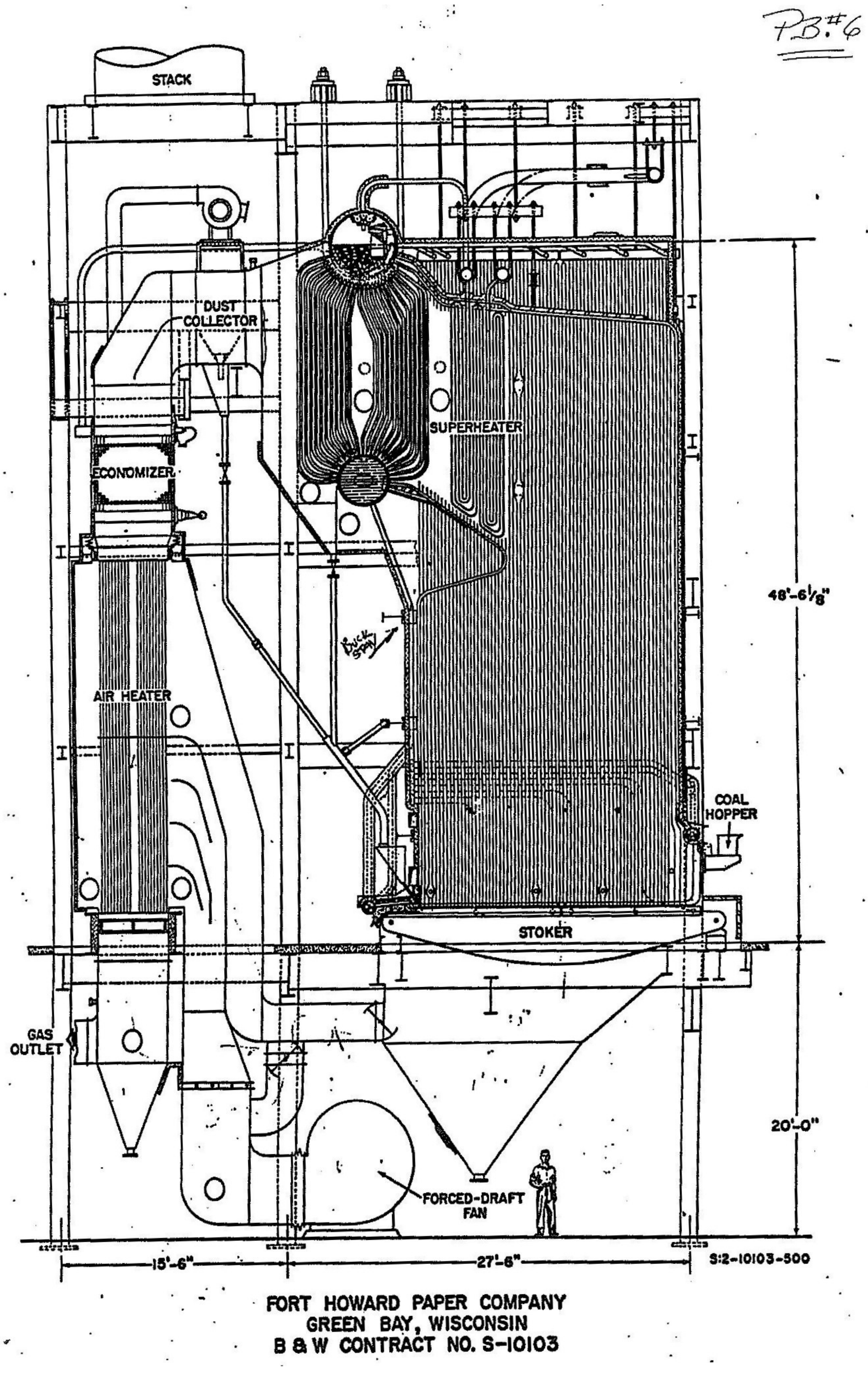
The following table presents the actual fuels fired, sulfur content of each fuel combusted, and the BART-regulated emissions generated from Boiler No. 6 during the baseline period of 2002 through 2004.

Table B-1. Summary of Baseline Fuels and Emissions, Boiler No. 6

Parameter	2002	2003	2004	3-yr Average
Total MMBtu All Fuels	1732160	1917674	1998835	1882890
Tons High Fusion Coal	45060	18112	894	
% S High Fusion Coal	1.01	0.96	0.96	
Tons Western Coal	9997	33588	64601	
%S Western Coal	0.54	0.49	0.5	
Tons Low Fusion Coal	0	8771	5009	
% S Low Fusion Coal	2.33	2.36	2.43	
Tons Pet Coke	10971	12084	14119	
% S Pet Coke	5.89	5.38	5.49	
Annual Average SO_2 (lb/MMBtu)	2.22	2.52	2.14	2.29
Actual SO_2 Emissions (tpy)	1926	2413	2141	2160
Actual NO_x Emissions (tpy)	375	432	477	428
Actual PM_{10} Emissions (tpy)	72	79	50	67

[4] Coal is washed prior to arrival at the mill as needed to reduce ash and achieve heat content specifications.

Figure B-1. Side View of Boiler No. 6, Green Bay Broadway Mill



2.3 PARTICULATE MATTER

Step 1a-Identification of Control Technologies-Typical Technologies in Use in the United States

Technology that may be considered for the control of particulate matter emissions from boilers includes the substitution and use of clean fuels, mechanical/gravity separation devices (*e.g.,* cyclones, settling chambers), electrostatic precipitators (ESPs), baghouses, and high efficiency wet scrubbers.

Step 1b-Identification of Control Technologies-Review of RACT/BACT/LAER Clearinghouse (RBLC)

Searches of the RBLC were conducted to identify control technologies for the control of PM_{10} emissions from stoker-fired boilers. The specific category searched was External Combustion- -11

The clearinghouse listed multiclones with ESPs, baghouses, good combustion practices and wet scrubbers as the PM_{10} control technologies.

Step 1c-Identification of Control Technologies-Review of Technologies in Use at Georgia-Pacific Corporation Facilities

GP operates numerous combination fuel-fired boilers and coal-fired boilers at its operating facilities within the United States. PM_{10} control devices in use at these mills include ESPs, baghouses and wet scrubbers.

Step 2-Technical Feasibility Analysis-Eliminate Technically Infeasible Options

All of the control options identified in Step 1 are technically feasible.

Step 3 – Ranking the Technically Feasible Alternatives to Establish a Control Hierarchy

The ranking of technologies for PM_{10} control is:

1. Baghouse with greater than 99% removal efficiency
2. ESP with multiclones at greater than 99% removal efficiency
3. High efficiency scrubbers with 98%+ removal efficiency
4. Wet scrubbers with 50 to 95% removal efficiency
5. High efficiency cyclones with 50-90% removal efficiency

Step 4- Cost Effectiveness Evaluation

GP currently operates a high efficiency (above 99%) baghouse to control PM_{10} emissions generated by Boiler Nos. 5, 6, 7, and 8. The baghouse design inlet particulate loading ranges from 1 to 3.5 grains/actual cubic foot (gr/acf) while the outlet loading is consistently at or below 0.01 gr/acf. The baghouse design exhaust gas flowrate is 772,000 acf/minute (ACFM) at 365 °F. The existing State limit of 0.3 lb PM_{10}/MM Btu from NR 415.06(1)(b), (equivalent to 105 lb/hr at Boiler No. 6's maximum rated capacity), is much greater than the baseline annual emission rate of approximately 17 lbs/hr[5] (equal to 0.07 lb/MM Btu) from Boiler No. 6. As the Mill presently operates the highest ranked PM_{10} control technology, no additional cost effectiveness evaluation is necessary.

Step 5-Select BART

GP is proposing to continue the use of the highest level of control, a baghouse with the current emission limit of 0.3 lb PM_{10}/MM Btu.

[5] Estimated with actual reported emissions presented in Table B-1 and the total operating hours for the baseline period (23520 hours). That is, [72 tons + 79 tons + 50 tons] x 2000 lbs/ton / 23,520 hours = 17.1 lbs/hr average.

Using the total MMBtu for the baseline period, the actual emissions are estimated as [72 tons + 79 tons + 50 tons] x 2000 lbs/ton / 5648669 MMBtu = 0.07 lb/MMBtu. These emissions include both filterable and condensible particulate matter.

2.4 SULFUR DIOXIDE

Step 1a-Identification of Control Technologies-Typical Technologies in Use in the United States

Emission control equipment that may be considered to control sulfur dioxide emissions from coal-fired boilers includes:

1. Gas absorption using wet and dry scrubbers (90% control),
2. Flue gas desulfurization techniques such as sorbent injection (50 to 65% control).
3. The use of clean substitute fuels can also be considered as an alternative to add-on controls.

Step 1b-Identification of Control Technologies-Review of RACT/BACT/LAER Clearinghouse (RBLC)

Searches of the RBLC were conducted to identify control technologies for the control of SO_2 emissions from stoker-fired boilers. The specific category searched was “External Combustion- -11”. The clearinghouse listed the use of clean fuels, wet and dry scrubbers, and flue gas desulfurization techniques such as limestone injection and spray dryer absorbers (SDA) as the control technologies.

Step 1c-Identification of Control Technologies-Review of Technologies installed at Georgia-Pacific Corporation Facilities

Georgia-Pacific operates numerous combination fuel-fired boilers and coal-fired boilers within the United States. SO_2 control technologies include dry scrubbing, limestone and sorbent injection on fluidized bed boilers, and the use of clean fuels. However, the company has limited experience with wet scrubbing with caustic on similar types of stoker coal-fired boilers.

Step 2-Technical Feasibility Analysis-Eliminate Technically Infeasible Options

The Green Bay Broadway Mill investigated several gas absorption technologies: wet scrubbing with caustic (sodium hydroxide) solutions, semi-dry scrubbing using a lime slurry with conventional scrubbers, Spray Dry Absorbers (SDAs), and circulating fluidized bed scrubbers. Scrubber vendors have indicated to the Mill that spray drying is not technically feasible because the allowable inlet sulfur concentration associated with the current fuel mix would be too high and the flue gas temperatures too low to support the water evaporation requirements in the hydrated lime slurry SDA. As a result, SDA vendors have informed GP that they cannot provide quotations for this particular application of the technology. All of the other SO_2 control technology options are technically feasible.

Step 3 – Ranking the Technically Feasible Alternatives to Establish a Control Hierarchy

The ranking of the technologies are:

1. Gas absorption with a wet spray tower or semi-dry scrubbing system with hydrated lime at 90%+ SO_2 removal efficiency,
2. In-Furnace Sorbent Injection at 65% removal efficiency,
3. In-duct absorption with sodium sesquicarbonate (Trona) injection with 50% removal efficiency,
4. Fuel substitution: Low SO_2/MMBtu coal in place of all higher sulfur containing fuels at 40-62% removal efficiency.

Step 4- Effectiveness Evaluation

Economic Evaluation

For each control technology cost estimate, the Green Bay Broadway Mill provided several general assumptions to the equipment vendors and engineering contractors for their use in determining site-specific cost estimates with a target accuracy of +/- 30% or better.

The Title V Permit for the Green Bay Broadway Mill limits the firing of petroleum coke to a rate demonstrated during a compliance stack test. As a result of these tests, the current fuel mix is limited to approximately 17% by weight petroleum coke and 83% coal, based on the heat content of the fuels currently combusted in the boiler. The cost analysis for Boiler No. 6 considers equipment that has been designed for the control to accommodate an SO_2 inlet loading of 760 to 1,300 lb/hr.[6] In instances that pumps are part of the equipment design, the cost estimates include redundant pumps to allow the control equipment to continue operating while one pump is being repaired or otherwise out-of service. In addition, the analysis applied a 15-year life to the capital recovery factor calculation for scrubber technologies. Other technologies with less equipment (*i.e.,* in furnace sorbent inject) applied a longer, conservative value of 20-year life for the capital recovery factor. The analysis also applied 8,400 hours/year and/or actual uncontrolled emissions to determine the direct operating costs. This approach is conservative in that an analysis using potential emissions would overstate direct operating costs such as reagent use.

<u>Wet Spray Tower with Sodium Hydroxide Cost Evaluation</u>

The Green Broadway Bay Mill worked with several control equipment vendors to review technical issues and challenges with SO_2 control by using either wet, dry, or semi-dry scrubbing technologies. Based on the

[6] Hourly emissions reflect the maximum heat input rate of 350 MMBtu/hr and a range of fuel mixes represented as 2.17 to 3.7 pounds sulfur dioxide per MMBtu. Though the stack is permitted for 4.55 pounds sulfur dioxide per MMBtu, this rate is limited by other permit conditions that restrict the amount of petroleum coke burned at any time.

technical reviews, the use of a wet spray tower demonstrates the best overall SO_2 removal efficiency of all the technologies reviewed and that were considered technically feasible. Jacobs Engineering provided the Green Bay Broadway Mill with a +/-30% cost estimate to install and operate a wet spray tower scrubber. The cost estimate for a wet spray tower scrubber assumed that the scrubber would be located downstream of the existing baghouse. This requirement is necessary to maintain low PM_{10} emissions entering the scrubber as the scrubber would not function properly if it was "overloaded" with PM_{10} emissions. Additionally, the proposed scrubber is not capable of replacing the baghouse since it is not capable of reducing PM_{10} emissions to the same levels achieved by the existing baghouse. For gas absorption, the control equipment was designed with a maximum flue gas exhaust gas flow rate of 235,000 acf per minute (ACFM). The scrubber was designed with an exhaust gas flow rate greater than the existing rate from Boiler No. 6 of approximately 140,000 ACFM. This was done to accommodate additional exhaust gases from a slip-stream during periods of lower SO_2 influent conditions. That is, when the fuels burned in the boilers yield a lower inlet air concentration of sulfur dioxide, the scrubber may need to treat a larger exhaust gas flowrate to achieve the same SO_2 removal efficiency.

The wet spray tower scrubber operates by directing the boiler exhaust gases through an alkaline liquid solution. The flue gas would enter the wet spray tower scrubber radially at the bottom of the unit flowing vertically upward through the scrubber vessel, and counter-current to the alkaline solution. The clean (scrubbed) flue gas would then be passed through a chevron-type mist eliminator for removal of large water droplets prior to exiting to the atmosphere through the top of the scrubber vessel. The mist eliminator would be equipped with an internal water wash header that is activated intermittently to wash away potential formations of reacted salts. The alkaline solution, by way of contacting the flue gas surface, promotes the absorption of the acid gases and the reduction of SO_2 from the exhaust gas stream. The alkaline solution used for this study is a 50% (wt.) solution of sodium hydroxide. The caustic solution would be introduced into the top of the scrubber vessel via multiple spray nozzles by a metering pump initiated by a pH analyzer loop located in the recycle reservoir. These nozzles would be arranged to ensure that the flue gas stream is in complete contact with the downward flowing caustic solution. The caustic solution would drain to the bottom of the absorber vessel's reservoir and be recycled back to the spray headers with recirculation pumps by blowing down some of the liquid based on reservoir conductivity and adding fresh makeup water as needed.

The clean flue gas would exit the wet spray tower scrubber and enter a new 16'-4" diameter, 316L stainless steel stack mounted on top of the new spray tower scrubber outlet. The stack would terminate at an elevation of 199 feet above grade. The stack would be sized for a flue gas velocity of approximately 34 ft/sec of saturated flue gas. The lower velocity in the stack is critical to prevent water carry-over from stack sidewalls (as would occur when operating at higher velocities) or what is referred to as "raining" from the stack exit. Stainless steel material was chosen for the stack to allow for good resistance to acid attack that is possible due to contact with the saturated flue gas. Acid attack occurs mainly in the wet-to-dry interface in a stack. Therefore, the stack would be designed on top of the scrubber to ensure any water formation on the internal stack wall will drain back to the scrubber.

The existing induced draft (ID) fan on the baghouse outlet and associated drive would be reused as presently installed. The existing fan curves and motor horsepower were reviewed and found to be adequately designed to account for the increased pressure drop created by the additional ductwork (4" w.c. drop through ductwork) and the spray tower scrubber (3" w.c. drop through scrubber). The incremental cost of the fan horsepower required for the additional scrubber and associated ductwork pressure drop is included in the operating cost for the spray tower scrubber. Money is included in the estimate as an allowance to evaluate and seal any air infiltration due to leakage from Boiler No. 6's physical structure and associated ductwork.

The cost estimate considered additional site-specific design conditions which have a significant impact on the control system design and cost:

- Mill process water would be used for scrubber make-up due to evaporation during operation and for supply of water to the mist eliminator wash water header. However, mill process water is not available at the required pressure (greater than 65 psi) in the new scrubber area, therefore, make-up water booster pumps would also be required as part of the new scrubber system .
- While no capital has been specifically identified for rerouting of underground lines, there are funds available in the cost estimate for "site improvements". Money for the labor and material cost for relocating process, sewer, and fire water lines would come from this estimate; however, without detailed information regarding the underground lines in the installation site this may not be sufficient. The funds included in the cost estimate are based on the typical amount of rerouting required for an installation such as this, based on experience Jacobs Engineering (working under contract for GP) has gained from other projects.
- The existing electrical control infrastructure is not adequate for the additional equipment in this option. Thus, a new Motor Control Center/Rack Room was also included in the factored estimate in order to provide an area to house the electrical equipment for the ID Fan new pump drives.

- The scrubber would be completely field-welded in place due to its large size. Lower-cost shop-welded scrubber vessels cannot be used for this project as they do not have the flow rate capacity required for this project.
- The 50% caustic solution storage tank would be equipped with in-tank electric heaters and caustic metering pumps. At this level of design, the residence time of delivered caustic is expected to be less than one day and the estimate does not include permanent buildings for the storage tank.

To prevent the buildup of sulfur compounds in the scrubber, a waste bleed stream would be required to remove concentrated solids. This waste stream would be rich in sodium and sulfur-bearing compounds created from the reaction of sulfur dioxide gases with the caustic solution. The waste bleed stream from the scrubber would be nominally comprised of 10% dissolved sodium salts including sodium sulfate, sodium sulfite, and sodium bi-sulfite. The Green Bay Broadway Mill has no allowance in their NPDES wastewater discharge permit for the additional dissolved ions present in the scrubber's wastewater stream, and therefore, simply combining the scrubber's wastewater with the mill's wastewater would exceed the mill's NPDES permit limit for conductivity. Furthermore, while the Mill's wastewater treatment system may remove most of the sulfate bearing compounds, Jacobs' analysis has determined that the plant's wastewater effluent will have the potential to discharge mercury above the current NPDES Permit limit. The Fox River is the receiving water for the wastewater plant effluent. GP believes the ongoing study to establish a total maximum daily limit (TMDL) of mercury discharges into the Fox River disqualifies the discharge of wet scrubber blow down into the plant's wastewater treatment system. To eliminate the mercury discharge issue, Jacobs' cost estimate has included a dedicated, separate wastewater treatment process to remove solids (including mercury and other metals) using concentration and evaporation methodology.

The preferred alternative for managing scrubber wastewater is the use of a recirculating evaporator/ condenser/ccentrifuge system. In this design, the wastewater bleed from the scrubber would enter a series of preheated steam condensing exchangers, and then move on to the evaporator crystallizer vvessels. By evaporating water, the salt solution would be concentrated past its solubility point, resulting in the formation of solid crystals. The wastewater stream from the evaporator crystallizer vvessel would be taken to a centrifuge, where any solid crystals present would be separated to form a solid waste stream. The solid waste stream would drop into a truck that will then be transported to a landfill. The evaporated water would be condensed with mill process cooling water. The condensed water would be the then used as a clean water stream for potential use at the mill.

The spray tower scrubber evaluated has a 24’ by 30’ footprint and the scrubber absorber vessel is 19’-3” in diameter and stands approximately 58’ tall. The bottom of the absorber would be raised several feet above grade to allow for access to auxiliary equipment located underneath at grade. The steel structure would terminate at the stack testing platform level. New 10’ x 10’ ductwork would be added to transfer flue gas from the existing roof-mounted dual chamber baghouse ID fans outlets to the spray tower scrubber’s inlet. Figure B-2 presents a simplified general equipment arrangement.

Table B-2 summarizes the estimated capital costs to install a complete wet spray tower scrubber system. The total installed cost is estimated to be equal to $33,062,714.

Figure B-2. General Arrangement of Wet Spray Tower System, Green Bay Broadway Mill

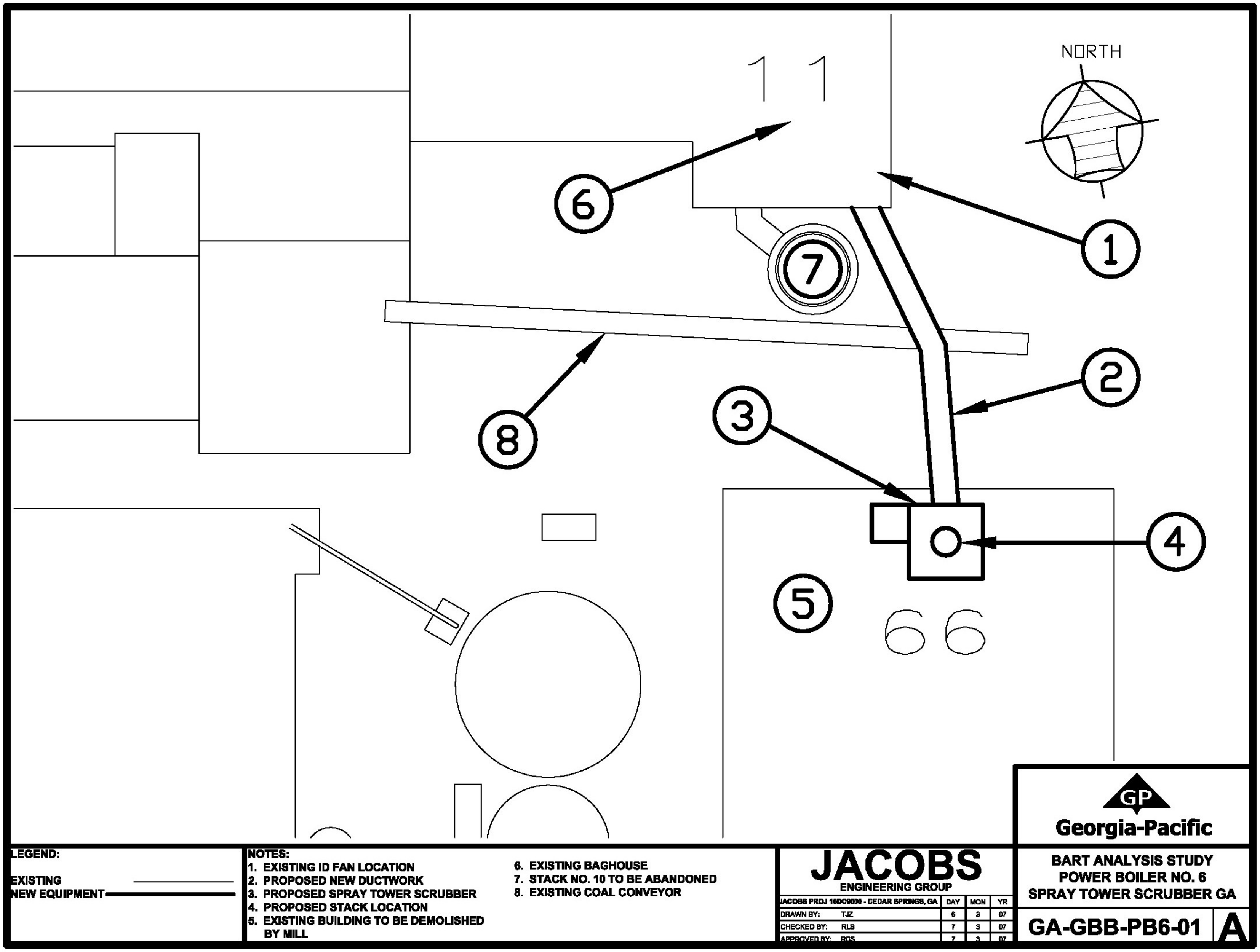


Table B-2. Summary of Capital Cost for Installation of Wet Spray Tower Scrubber System, Boiler No. 6 Green Bay Broadway Mill

Description[7]	Total Cost (2007$) [8]
Direct Costs	
Major Equipment	8,971,255
Demolition	14,522
Site Improvements	448,563
Piling, Caissons	627,988
Buildings	502,180
Concrete	741,100
Structural Steel	1,644,865
Piping	2,496,353
Insulation - Pipe, Equipment & Ductwork	643,899
Instrumentation	715,662
Electrical	1,088,346
Painting, Protective Coatings	89,713
Construction Indirect Costs	
Construction Support Labor	778,526
Premium Time	229,937
Craft Per Diem ($7/Hour On 100 % Of Time)	493,602
Non-Payroll Tax, Insurance & Permits	775,873
Craft Start-Up Assistance	32,717
Contractor's Construction Fee	1,441,756
Project Indirect Costs	
Construction Management	1,493,050
Engineering Professional Services	3,315,140
Study Cost	50,000
Outside Consultant Services	100,000
Owner's Cost	993,118
Spare Parts	343,840
Non-Craft Start-Up Assistance	89,306
Allowance For Unforeseen	2,804,624
Escalation	2,036,801
Air Infiltration Allowance [9]	$100,000
Total Installed Cost (TIC)(+/- 30%)	$33,062,714

[7] See Appendix for further description of estimator's cost categories
[8] Green Bay, WI BART Feasibility Study and Estimate, June 2007 Jacobs Engineering
[9] Modifications to the exhaust system are expected to require studies and upgrades to eliminate air infiltration.

To determine estimated operating costs for the scrubber, this cost analysis used the templates provided by EPA in their Cost Control Manual. Determining annual operating costs is sensitive to the amount of sulfur dioxide removed and the amount of scrubbant required to maintain the desired SO_2 removal efficiency. The 2002-2004 actual emissions are significantly lower than permitted emissions (*i.e.,*, 2.29 lbs SO_2/MMBtu in 2002-2004 compared to permit limit of 4.55 lb SO_2 /MMBtu) and thus represent a conservatively lower annualized cost estimate. Table B-3 presents operating costs for the spray tower technology.

Table B-3. Annual Operating Cost Calculations, Wet Spray Tower for Boiler No. 6, Actual 2002-2004 Conditions

Parameter	Methodology	Annual Cost ($)
Direct Costs		
Operating labor :	1 hours per shift x 1095 shifts/yr @ $40/hr	43,800
Supervisor Labor	15% of Operator costs	6,570
Maintenance labor:	0.5 hours per shift x 1095 shifts/yr @ $40/hr	21,900
Maintenance material	100% of Maintenance Labor	21,900
Electricity	0.059$/kWhr x 11,160,688 kWhr/yr	658,481
Caustic Solution[10]	$1,050/dry ton NaOH x 3,375 ton NaOH	3,543,750
Process water:	$0.06/kgal x 976,039 kgal	58,562
Landfill Scrubber system solids	$ 9.50/ton x 24,878 tons	236,341
Additional Process Steam	$2.45/klb steam x 186,588 klbs	457,141
Indirect Costs		
Overhead rate (fractional):	60% of total labor and material costs	56,502
Taxes, insurance, admin. factor:	4% of TIC (Table B-2)	1,322,509
Capital recovery factor (system):	0.1098 x TIC [11]	3,630,108
Total Annual Cost		10,057,563

[10] 2002-2004 actual SO_2 tons = 2,160 emitted; consumption is 2.5 lb-mol NaOH per lb mol of SO_2 emitted; 2008 average unit cost of caustic as delivered to Mill = $1,050/dry ton NaOH;

2,160 tons SO_2 x 2,000 lbs/ton x lbmol SO_2/64 lbs SO_2 x 2.5 lb-mol NaOH/lb-mol SO_2 x 40 lbs NaOH/lb-mol NaOH / 2,000 lbs/ton =3,375 tons dry NaOH

[11] 7% interest for the cost of capital and a scrubber life of 15 years using Equation 2.8a of USEPA Cost Control Manual yields: (0.07*(1+0.07)^15)/((1+0.07)^15-1) = 0.1098

The cost effectiveness of this technology is equal to the Annual Operating Costs/ Annual Quantity of SO_2 Removed.

The estimated cost effectiveness is: $ 10,057,563 / (90% x 2,160 tons) = $5,174/ton.

Dry Scrubbing with Hydrated Lime Fluidized Bed Absorber (FBA) Cost Evaluation

Dry scrubbers have significantly lower capital and annual operating costs than wet systems because they are simpler, demand less water, and waste disposal is less complex. Dry injection systems are easier to install and use less space; therefore, they are good candidates for retrofit applications, such as the one at the Green Bay Broadway Mill. In contrast to a wet spray tower, FBAs use a reactor vessel with a closely controlled temperature. Both an even distribution of sorbent across the reactor and adequate residence time at the proper temperature are critical for the best SO_2 removal rates [12].

Flue gas from the boiler would enter the bottom of the fluid bed absorber. Water would be first sprayed into the gas stream to cool the flue gas to near adiabatic conditions to improve adsorption. Once the flue gas stream is cooled, hydrated lime would be added to the reactor at a rate of approximately 5,000 lbs per hour. The SO_2 would react with the hydrated lime to form calcium sulfate. The unreacted hydrated lime, fly ash, spent lime, and calcium sulfate would then be captured in the fabric filter and then recirculated back to the inlet of the fluidized bed absorber. Fresh hydrated lime would be added to the circuit to maintain absorber SO_2 removal efficiency. The system would bleed out excess spent material for disposal using the same methods presently used for boiler ash disposal. Because the original design of the baghouse is much larger than the flue gas volume from the current boilers, the mill expects that the existing baghouse will collect the additional particulate loading and maintain its high removal efficiency from an FBA without significant modification.

ESI Inc. of Tennessee provided the Green Bay Broadway Mill with a +/-20% cost estimate to install an FBA system.

The FBA cost estimate reflects the installation and operation of the following new equipment:

- new fluidizing bed reactor 18' diameter x 100' overall height,
- solids recirculation systems,
- pre-piped lime slurry pump skids,
- booster fans,
- 210-ton powdered hydrated lime silos with fabric filter to collect dust from silo loading,
- a hydrated lime bulk pneumatic truck unloading station,
- rotary hydrated lime volumetric hydrated lime feeders,
- shutoff dampers (double sealing) with purge air blowers for safe access to confined spaces.

[12] Srivastava, 2001. Srivastava R. K., and W. Josewicz.. "Flue Gas Desulfurization: The State of the Art". Air and Waste Management Assoc., 51:1676-1688, 2001.

Table B-4 summarizes the total cost for installation of the FBA system.

Table B-4. Summary of Capital Cost for Installation of Fluidized Bed Absorber System, Boiler No. 6 Green Bay Broadway Mill

Description	Total Cost (2008$)[13]
Scrubber systems installation and duct modifications	10,158,367
Footings and foundation work	405,000
Electrical and controls	929,094
Structural steel	285,000
Engineering and commissioning	1,228,922
Construction management	829,523
General contractor overhead and mark-up	1,013,861
Contingency	1,536,153
Emission Monitoring systems	180,000
Piping	61,760
Freight	591,961
Miscellaneous	270,000
Total Installed Cost (TIC) (+/-20%)	**17,489,639**

[13] BART Preliminary Engineering Study (ESI Inc. of Tennessee March 2008)

Figure B-3 represents a simplified flow diagram of the required equipment for a generic case of any one of several boilers at the mill. In contrast to the wet spray tower scrubber technology, most of the equipment will be located within the existing buildings at a point upstream of the baghouse. Figure B-4 presents a footprint diagram.

Figure B-3. Schematic of Process Equipment for Fluidized Bed Absorber, Generic Case

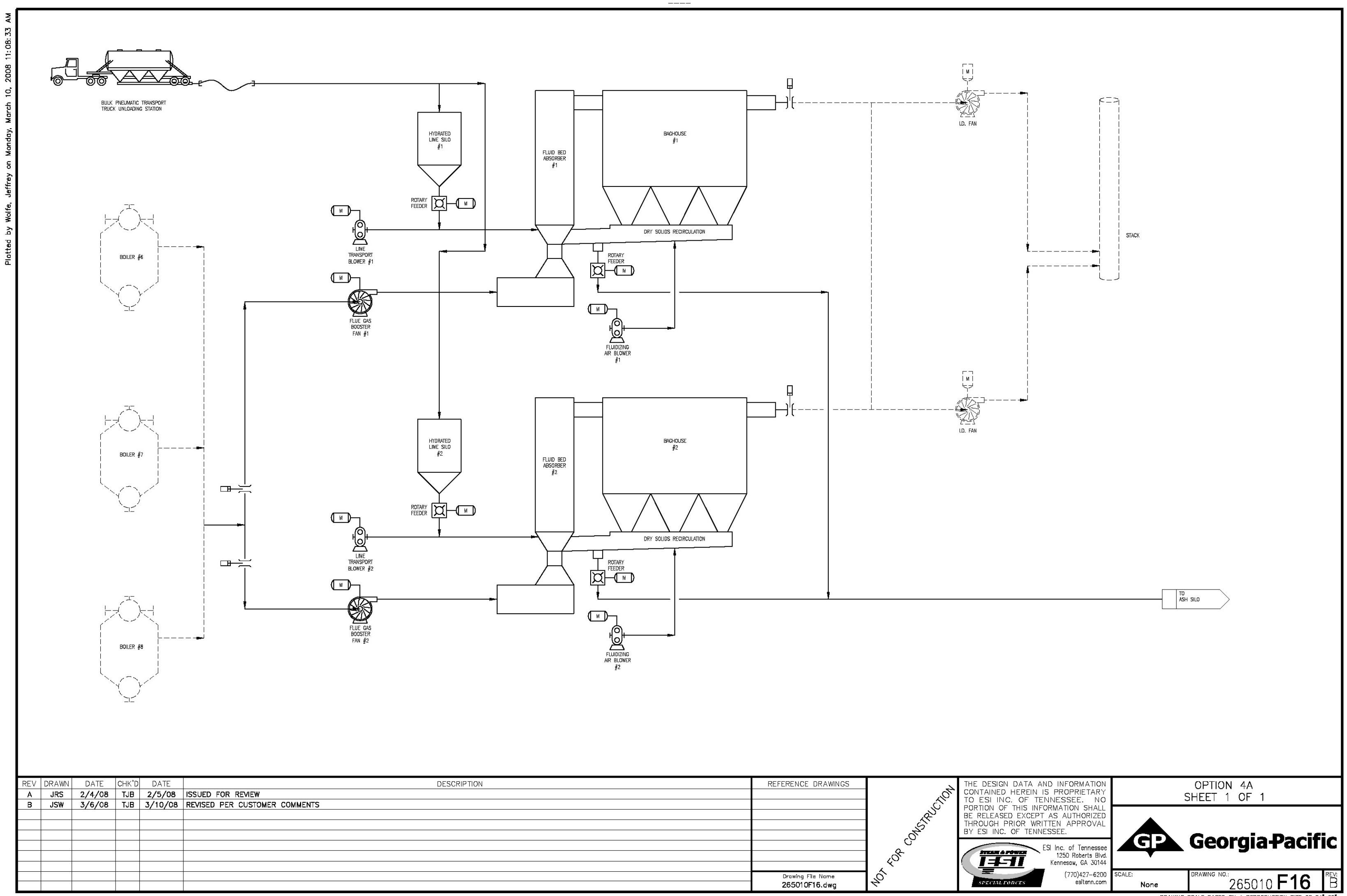
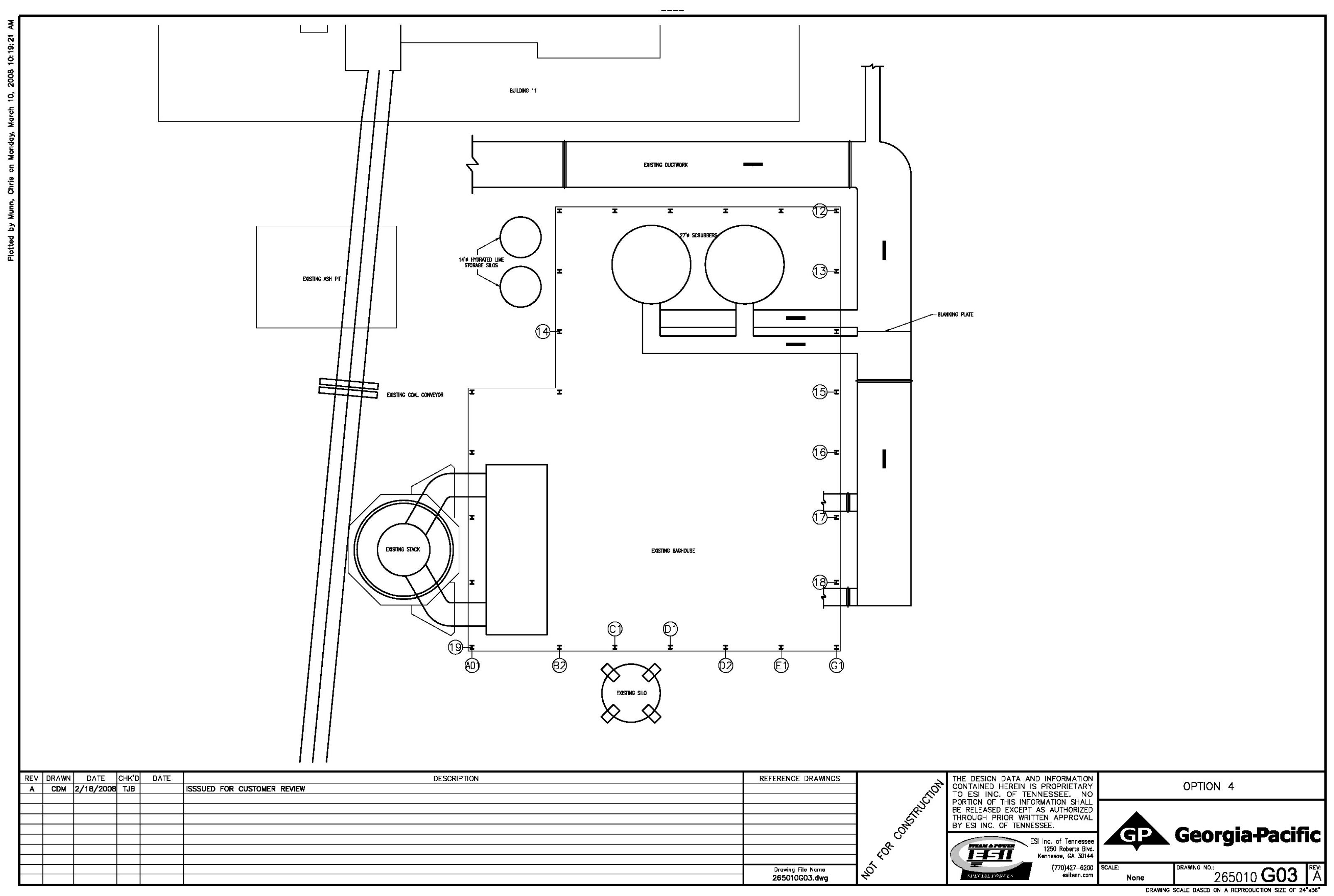


Figure B-4. Equipment Arrangement for Fluidized Bed Absorber, Generic Case



To determine annual operating costs, the analysis followed US EPA's Cost Control Manual templates [14] with some equipment-specific adjustments. Table B-5 presents the annual operating costs for the FBA technology.

Table B-5. Annual Operating Cost Calculations, Fluidized Bed Absorber for Boiler No. 6, Based on Actual 2002-2004 Emissions and Operating Conditions

Parameter	Methodology	Annual Cost ($)
Direct Costs		
Operating labor :	3 hour per shift x 1095 shifts/yr @ $40/hr	131,400
Supervisor Labor	15% of Operator Costs	19,710
Maintenance labor & equipment:	Vendor Estimate 10% of Equipment Costs	910,000
Electricity- direct	0.059$/kWhr x 6,864,000 kWhr/yr	404,976
Electricity- fan make-up	8 inches w.c	201,680
Hydrated Lime	$90/ ton hy. lime x 8,932 ton hy. Lime/yr[15]	803,853
Process water:	$0.06/kgal x 8,400 kgal	504
Landfill Scrubber system solids	$ 9.50/ton x 29,601 tons	276,080
Indirect Costs		
Overhead rate (fractional):	60% of total labor and material costs	636,666
Taxes, insurance, admin. factor:	4% of TIC (Table B-4)	699,586
Capital recovery factor (system):	0.1098 x TIC [16] (Table B-4)	1,920,268
Total Annual Cost		6,004,723

[14] EPA Air Pollution Control Cost Manual Sixth Edition EPA/452/B-02-001 January 2002

[15] 2002-2004 actual SO_2 tons = 2,160; consumption is 3.25 lb-mol hydrated lime per lb mol of SO_2 removed; 2008 average unit cost = $275 dry ton hydrated lime

2,160 tons SO_2 x 2,000 lbs/ton x lb-mol SO_2/64 lbs SO_2 x 3.25 lb-mol hydrated lime/lb-mol SO_2 x 74.1 lbs hydrated lime / lb-mol hydrated lime / 2,000 lbs/ton x 1ton pure CaCO3/0.91 ton hydrated lime = 8,932 tons hydrated lime

[16] 7% interest for the cost of capital and a scrubber life of 15 years using Equation 2.8a of USEPA Cost Control Manual yields: (0.07*(1+0.07)^15)/((1+0.07)^15-1) = 0.1098

Determining annual operating costs is sensitive to the amount of sulfur dioxide removed and scrubbant required. The 2002-2004 emission rates are significantly lower than permitted emissions and thus represent a conservatively lower annual cost (and operation) estimate.

The cost effectiveness of this technology is equal to Annual Costs/ Annual SO_2 Removed.

The estimated cost effectiveness is: $6,004,273/ (90% x 2,160 tons) = 3,089 $/ton.

Furnace Sorbent Injection (FSI) Cost Evaluation

As an alternative to "back-end" controls, the Green Bay Broadway Mill assessed control technologies further upstream. One such technique involves injecting a sorbent into the combustion chamber of the boiler with the fuel. As additional material in the boiler can significantly affect boiler performance, this technology is coupled with improving the air distribution system within the boiler. The technology has been demonstrated on stoker-fired boilers, however, an unknown risk to operations is the potential erosion of boiler furnace tubes due to the additional sorbent material injected into the combustion chamber of the boiler. The FSI technology is similar to the dry scrubbing system in that it eliminates management of wet streams and has a small equipment footprint relative to wet scrubbing systems. Limestone with a high $CaCO_3$ content would absorb SO_2 as the fuel sulfur is oxidized in the furnace. The resultant particulate would be carried out with the boiler flue gas and then captured in the existing baghouse. As mentioned earlier, the mill expects that the existing baghouse would collect the additional particulate and maintain its high removal efficiency from an FBA without significant modification, and the same expectation holds for any additional particulate resulting from FSI.

The Green Bay Broadway Mill selected Mobotec USA as a vendor to develop an equipment cost estimate for a Furnace Sorbent Injection (FSI) system. Mobotec USA would supply the injection equipment, mixing nozzles (ROTAMIX), and rotating overfire air fans (ROFA) for such a system, which would also be considered a technically feasible NOx control technology. Installation of the ROFA system includes a new overfire air fan that will take suction from the hot combustion air side of the boiler's existing air preheater, a new ductwork system, and multiple ROFA boxes installed on the furnace walls. A detailed study for appropriate placement of the FSI system nozzles and injection locations was not conducted for Boiler No. 6; however, the cost estimate includes a one time study cost of $50,000.

The installed equipment required for the FSI system includes a:

- Limestone storage silo with truck unloading connections, a baghouse to control loading emissions, feed hoppers, screw feeders and rotary valves, pulse system and isolation valves;
- A new blower with the pneumatic limestone feed piping system and injection devices mounted on the furnace wall, and;
- Additional fans, ductwork and controls for ROFA boxes.

The BART estimate includes additional (above those normally factored) allowances for demolition and relocation inside of the building around Boiler No. 6 due to the extensive amount of ductwork and injection piping required for the FSI system. Extensive layout and engineering planning would be required at the time of design to make the installation of this system functional in regards to good maintenance access and basic boiler walk-around access. The physical location of Boiler No. 6 is a congested area that is immediately adjacent to other boilers which in turn may limit the ability to locate ROFA boxes and injection lances in the optimum positions predicted by the study. The total installed cost (TIC) for the FSI system is $26,827,507. Table B-6 presents the total installed costs for an FSI system for Boiler No. 6.

Table B-6. Summary Of Capital Cost For Installation Of FSI System, Boiler No. 6 Green Bay Broadway Mill

Description[17]	Total Cost (2007$)[18]
Major Equipment	5,926,151
Demolition	811,138
Site Improvements	491,316
Piling, Caissons	631,692
Buildings	330,000
Concrete	828,031
Structural Steel	1,497,449
Piping	1,886,064
Insulation - Pipe, Equipment & Ductwork	296,308
Instrumentation	658,012
Electrical	1,014,583
Painting, Protective Coatings	59,262
Construction Indirect Costs	
Construction Support Labor	711,432
Premium Time	209,454
Craft Per Diem ($7/Hour On 100 % Of Time)	451,063
Non-Payroll Tax, Insurance & Permits	504,113
Craft Start-Up Assistance	43,650
Contractor's Construction Fee	1,242,334
Project Indirect Costs	
Construction Management	1,209,000
Engineering Professional Services	2,683,000
Study Cost	50,000
Outside Consultant Services	100,000
Owner's Cost	804,000
Spare Parts	245,193
Non-Craft Start-Up Assistance	119,150
Allowance For Unforeseen	2,275,240
Escalation	1,649,872
Air Infiltration Allowance	100,000
TOTAL INSTALLED COST (TIC) (+/-30%)	26,827,507

[17] See Appendix for further description of estimator's cost categories
[18] Green Bay, WI BART Feasibility Study and Estimate, June 2007 Jacobs Engineering

Table B-7 presents annual operating costs for the FSI system. Without a site-specific study by Mobotec, the economic analysis could not estimate what, if any, loss of steaming capacity would occur with the significant amount of "dead load" material (*i.e.,* sorbent) added into the furnace. The operating costs also do not include lost steam production due to increased wear on boiler tubes. Though the increased rate of tube erosion cannot yet be determined, the operation of the boiler will be affected by a significant increase in tube wall inspections following startup with an FSI system.

Table B-7. Annual Operating Cost Calculations, FSI for Boiler No. 6, Actual 2002-2004 Conditions

Parameter	Methodology	Annual Cost ($)
Direct Costs		
Operating labor :	1 hour/shift x 1,095 shifts/year @ $40/hr	43,800
Supervisor Labor	15% of Operator costs	6,570
Maintenance labor:	0.5 hrs/shift x 1,095 shifts/year @ $40/hr	21,900
Maintenance material	100% of Maintenance Labor	21,900
Electricity- direct	0.059$/kWhr x 3,437,500 kWhr	202,813
Limestone	$40/ton limestone x 10,978 tons[19]	439,189
Landfill Additional system solids	$ 9.50/ton x 10,978 tons	104,291
Indirect Costs		
Overhead rate (fractional):	60% of total labor and material costs	56,502
Taxes, insurance, admin. factor:	4% of TIC (Table B-6)	1,073,100
Capital recovery factor (system):	0.0944 x TIC[20] (Table B-6)	2,532,327
Total Annual Cost		4,502,391

[19] 2002-2004 actual SO_2 tons = 2,160; consumption is 3.25 lb-mol limestone per lb mol of SO_2; Average unit cost is $40/ton delivered.

2,160 tons SO_2 x 2,000 lbs/ton x lb-mol SO_2/64 lbs SO_2 x 3.25 lb-mol limestone /lb-mol SO_2 x 100.1 lbs limestone ($CaCO_3$)/ lb-mol limestone / 2,000 lbs/ton = 10,978 tons limestone

[20] 7% interest for the cost of capital and an equipment life of 20 years using Equation 2.8a of USEPA Cost Control Manual yields: (0.07*(1+0.07)^20)/((1+0.07)^20-1) = 0.0944

Determining annual operating costs is sensitive to the amount of sulfur dioxide removed and sorbent required. The 2002-2004 actual emissions are significantly lower than permitted emissions and thus represent a conservatively lower annual cost (and operation) estimate.

The cost effectiveness of this technology is equal to Annual Costs/ Annual SO_2 Removed.

The estimated cost effectiveness is: $4,502,391/ (50% x 2,160 tons) = 4,169 $/ton.

In-Duct Absorption System with Trona Cost Evaluation

In contrast to injecting sorbent into the boiler or using a wet spray tower scrubber vessel, in-duct absorption is an alternative capable of obtaining a 50% reduction in SO_2 emissions from Boiler No. 6. Unlike the other SO_2 removal technologies described above, this technology does not have many similar applications in commercial operation. With the use of this technology, offered by O'Brien and Gere, the sorbent is fed into the flue gas as a dry powder. The sorbent (sodium sesquicarbonate, or Trona) undergoes thermal decomposition and reacts with sulfur dioxide in the flue gases to form a particulate. Approximately one-third of the sorbent mass forms carbon dioxide and exhausts to the atmosphere while the other two-thirds of the particulate mass is captured in the existing baghouse. The supply market for this sorbent is limited to a few active mines in western United States. Without multiple sources for Trona, deliveries to the mill are at higher risk of supply interruptions (*e.g.,* natural or other external events) than sorbents with many suppliers.

For Boiler No. 6, Trona would be injected between into the flue gas stream between the boiler's economizer outlet and the air preheater inlet where the flue gas exhaust temperature is approximately 700°F. Vendor experience indicates that this is the optimum temperature for SO_2 removal for this sorbent application and type of boiler. The thermal decomposition at this temperature increases the amount of surface area on the Trona particle, and increases its SO_2 capture efficiency. The chemical reaction taking place in the flue gas stream with Trona injection is shown below:

$$2(Na_2CO_3{\bullet}NaHCO_3{\bullet}2H_2O) + 3SO_2 \rightarrow 3Na_2SO_3 + 4CO_2 + 5H_2O$$

As shown, the use of Trona will result in the release of 4 moles of CO_2 for every 2 moles of Trona.

The particle size specification for Trona injection is a minimum of 90% by weight shall be no larger than 10 microns in diameter. If the Trona particles are not ground properly, the consumption of Trona in the flue gas stream will be significantly higher, thereby resulting in higher operating costs.

Jacobs Engineering provided the Mill with a +/-30% cost estimate to install a Trona injection system. The capital cost estimate includes the following equipment:

- 2 Trona silos (approximately 16' diameter and 40' high),
- 3 Trona pulverizers, particle size classifiers, feeders and blowers, and
- Trona pneumatic truck unloading station with a baghouse for PM control.

Table B-8 presents a summary of installation the installed costs for the In-Duct Absorption System.

Table B-8. Summary of Capital Cost for Installation of In-Duct Absorption System, Boiler No. 6 Green Bay Broadway Mill

Description[21]	Total Cost (2007$)[22]
Direct Costs	
Major Equipment	$5,400,000
Demolition	$250,000
Site Improvements	$135,000
Piling, Caissons	$250,000
Buildings	$120,000
Concrete	$121,500
Structural Steel	$486,000
Piping	$459,000
Insulation - Pipe, Equipment & Ductwork	$243,000
Instrumentation	$135,000
Electrical	$297,000
Painting, Protective Coatings	$27,000
Construction Indirect Costs	
Construction Support Labor	$164,232
Premium Time	$47,350
Craft Per Diem ($7/Hour On 100 % Of Time)	$104,126
Non-Payroll Tax, Insurance & Permits	$223,644
Craft Start-Up Assistance	$43,650
Contractor's Construction Fee	$323,046
Project Indirect Costs	
Construction Management	$322,000
Engineering Professional Services	$715,000
Outside Consultant Services	$100,000
Owner's Cost	$378,000
Spare Parts	$279,450
Non-Craft Start-Up Assistance	$119,150
Allowance For Unforeseen	$1,074,315
Escalation	$603,026
Air Infiltration Allowance[23]	$100,000
Total Installed Cost (+/- 30%) (TIC)	**$12,520,489**

[21] See Appendix for further description of estimator's cost categories
[22] Green Bay, WI BART Feasibility Study and Estimate, June 2007 Jacobs Engineering
[23] Modifications to the exhaust system are expected to require studies and upgrades to eliminate air infiltration.

The total installed cost (TIC) is $12,520,489. Table B-9 presents the annual operating costs for the In-Duct Absorption System.

Table B-9. Annual Operating Cost Calculations, In-Duct Absorption System for Boiler No. 6, Actual 2002-2004 Conditions

Parameter	Methodology	Annual Cost ($)
Direct Costs		
Operating labor :	1 hr/shift x 1,025 shifts/yr @ $40/hr	41,000
Supervisor Labor	15% of Operator	6,150
Maintenance labor:	0.5 hrs per day x 350 days/yr @ $40/hr	7,000
Maintenance material	100% of Maintenance Labor	7,000
Electricity	0.059$/kWhr x 2,534,375 kWhr	149,528
Trona consumption	$150/ton Trona x 1.8 tons Trona/hr [24] x 8,400 hr/yr	2,268,000
Landfill Additional Baghouse solids	$ 9.50/ton x 1.5 tons solids/hr x 8,400 hrs/yr	119,700
Indirect Costs		
Overhead rate (fractional):	60% of total labor and material costs	36,690
Taxes, insurance, admin. factor:	4% of TIC (Table B-8)	500,820
Capital recovery factor (system):	0.0944 x TIC (Table B-8)	1,181,846
Total Annual Cost		4,317,733

[24] Reagent usage of 3600 lbs/hr estimated by vendor

Determining annual operating costs is sensitive to the amount of sulfur dioxide removed and sorbent required. The 2002-2004 actual emissions are significantly lower than permitted emissions and thus represent a conservatively lower annualized cost (and operation) estimate.

The cost effectiveness of this technology is equal to the Total Annualized Costs/ Annual Quantity of SO_2 Removed.

The estimated cost effectiveness is: $4,317,733/ (50% x 2,160 tons) = 3,998 $/ton.

Clean Fuels Cost Evaluation

As mentioned above, Boiler No. 6 combusts several fuels with the existing equipment: eastern coal (high / low fusion), western coal and petroleum coke. The only fuel limited by the air permit is the amount of petroleum coke to approximately 17-21% by weight of total fuel. All solid fuels are stored outdoors in a common area. Table B-10 presents the range of heat content, as well as ash and sulfur content of the various fuels combusted in the boiler.

Determining marginal costs of fuel with different sulfur concentrations is reasonably certain when using short-term "future" forecasts. As the period for fuel forecasting is extended, uncertainty rapidly increases. Therefore, the unit costs below are presented as a range where estimated. Subsequent calculations use the average of the high and low end of the range.

Table B-10. Comparison of Various Fuels Fired in Boiler No. 6, Green Bay Broadway Mill

Fuel	Sulfur %	MMBtu/ton	$/MMBtu 2007-2009 [25]
Petroleum Coke	5 to 6.5	27.6-28.4	1.71
Eastern Low-fusion Coal	2.5-2.7	25.4-27.0	3.35
Western Coal	0.4-0.7	20.6-23.6	4.55
Eastern High-fusion Coal	0.9 – 1.5	24-25.5	3.60

[25] Prices reflect cost from source delivered to the Mill between 2007 and 2009. Year-to-year prices are volatile.

An additional difference between the fuels is the estimated CO_2 emissions. CO_2 Emissions from petroleum coke combustion is approximately 10 to 15% above coal combustion (on a lb/MMBtu basis).
The cost evaluation compared the following three options with increasing emission reduction:

1. Switch 100% of petroleum coke to eastern high fusion coal
2. Switch 100% of petroleum coke to western coal
3. Switch 100% of all fuel to western coal

Table B-11 presents a summary of the sulfur dioxide emission estimates and fuel costs for each case.

Table B-11. Clean Fuel SO_2 Emission Calculations, Boiler No. 6, Green Bay Broadway Mill

Parameter	Eastern Coal High Fusion	Eastern Coal Low Fusion	Western Coal	Petroleum Coke	Total
2002-2004 MMBtu Estimate (annual)	528,545	120,345	796,970	346957	1,792,817
2002-2004 Tons (annual)	21,355	4,593	36,062	12391	74,402
Sulfur into the Boiler (tpy)	213	109.6	184	694	1200
Percent of total SO_2Emissions	18%	9%	15%	58%	
SO_2 Emission Estimate (tpy)	383	197	331	1249	2160
Fuel Cost (MM$)	1.903	0.40	3.63	0.59	6.53
Case 1 : Switch from Petroleum Coke to Eastern High Fusion					
MMBtu	875,502	120,345	796,970	--	1,792,817
Tons Fuel	35,374	4,593	36,062	--	76,029
Sulfur into the Boiler (tpy)	352	109.6	184	--	
SO_2 Emission Estimate (tpy)	704	219	368	--	1291
Fuel Cost (MM$)	3.15	0.40	3.63	--	7.18
Case 2 : Switch from Petroleum Coke to Western Coal					
MMBtu	528,545	120,345	1143928	--	1,792,817
Tons Fuel	20,251	4,593	51761	--	76,606
Sulfur into the Boiler (tpy)	251	110	264	--	
SO_2 Emission Estimate (tpy)	502	219	528	--	1,249
Fuel Cost (MM$)	1.90	0.40	5.20	--	7.51
Case 3 Switch All Fuels to Western Coal					
MMBtu Fuel	--	--	1,792,817	--	1,792,817
Tons Fuel	--	--	81,123	--	81,123
Sulfur into the Boiler (tpy)	--	--	414	--	
SO_2 Emission Estimate (tpy)	--	--	827	--	827
Fuel Cost (MM$)	--	--	8.16	0	8.16

Table B-12 summarizes the annual marginal fuel costs and emissions reductions relative to 2002-2004 actual emissions for these cases.

Table B-12. Summary of Fuel Cost Increases for Various Fuel Switch Cases, Green Bay Broadway Mill

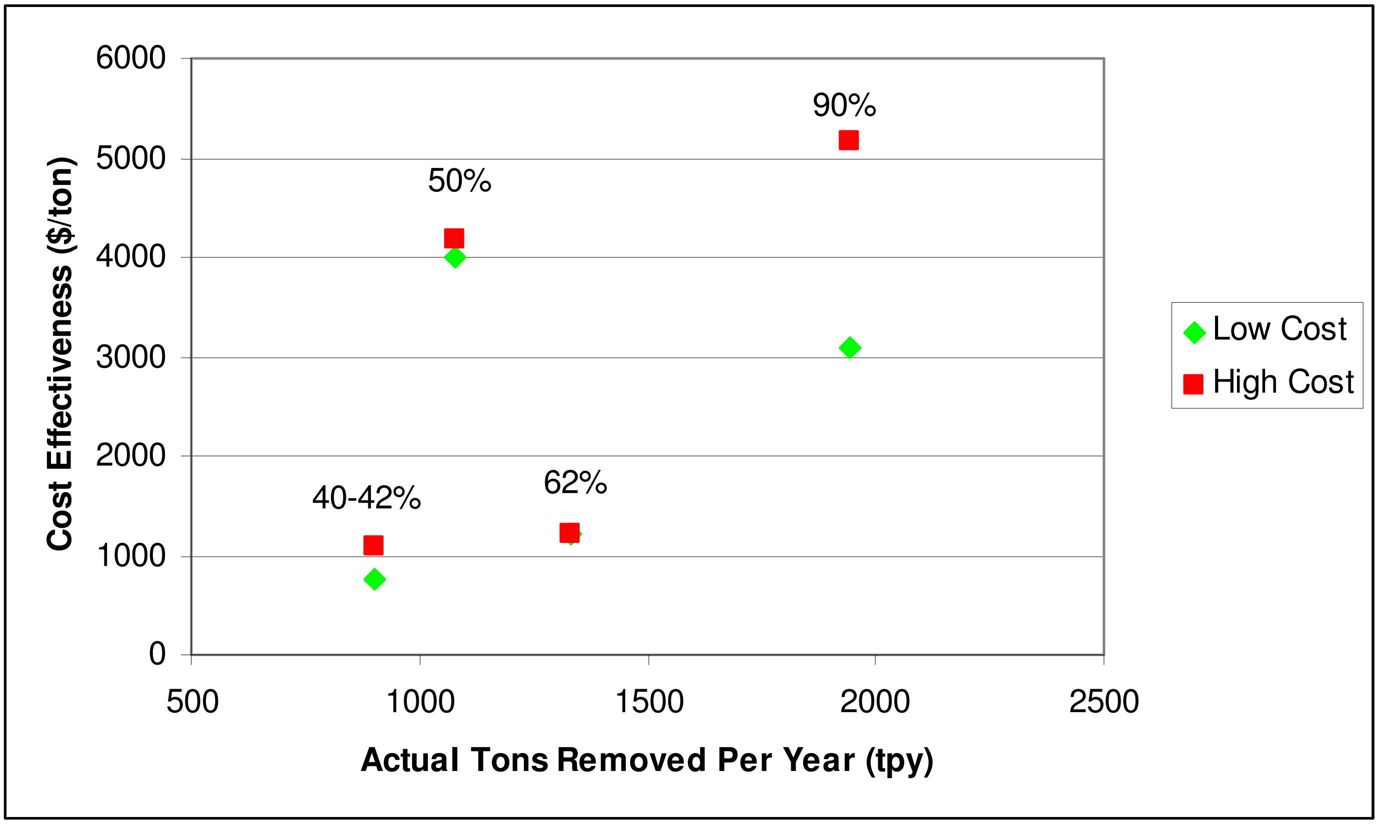
		Case		
Parameter	2002-2004	1	2	3
Average $/MMBtu	$3.64	$4.01	$4.19	$4.55
SO_2 Emissions (tpy)	2,160	1291	1249	827
Emission Change (tpy)	NA	869	911	1,333
Reduction Efficiency (%)		40%	42%	62%
Fuel Cost ($/yr)	$6,525,429	$7,181,178	$7,510,787	$8,157,319
Fuel Cost Increase ($/yr)	NA	$655,749	$985,359	$1,631,891
Cost Effectiveness Fuel Price Only ($/ton)	NA	755	1,082	1,225

Though Boiler No. 6 is equipped to handle the various fuel selections of the three cases above, the actual operating costs for ash hauling and disposal will increase. Petroleum coke ash content is near 0.5% compared to 12 % for western coal. Based on using the Mill's current unit cost for ash disposal of $9.50 per ton, additional operating costs of approximately 0.03 to 0.05 $/MMBtu will be incurred, or, an increase of approximately $90,00 per year.

Summary of Economic Evaluation, SO_2 Controls for Power Boiler No. 6

The economic evaluation determined a range of cost effectiveness values for the following levels of control: Less than 50%, 50%, 62%, and 90%. Figure B-5 presents a marginal cost curve for the cost estimates presented in Table B-2 through B-12.

Figure B-5 Marginal Cost Curve for SO_2 Control Options, Green Bay Broadway Mill Boiler No. 6



Note: Annual Actual tons removed shown is relative to 2002-2004 actual emissions
Control options: 42% removal by Clean Fuels (case 2); 50% removal by FSI or in-duct sorbent injection; 62% removal by Clean Fuels (case 3); 90% removal by wet or dry scrubber

Incremental Costs

In addition to marginal cost effectiveness, the incremental cost effectiveness can be used to compare the additional cost for a higher level of control. USEPA guidance indicates that "the incremental cost effectiveness should be examined in combination with the average cost effectiveness in order to justify elimination of a control option."[26] The incremental cost effectiveness formula is as follows:

(Annual Costs ($/yr)| $_{\text{Control Option}}$ – Annual Cost ($/yr)| $_{\text{Next Control Option}}$) / Change in Controlled Emissions (tpy)

[26] New Source Review Workshop Manual Draft (USEPA, 1980)

Figure B-5 graphically shows a large increment in cost effectiveness is between the 62% control option (clean fuels) and the 90% control option (scrubber). The incremental cost effectiveness between the two options is:

($8,031,143/yr for scrubbers (average of either wet or dry) – $1,631,891/yr for Clean Fuels) / ((1-62% x 2,160 tons) – (1-90% x 2160 tons))
= $6,399,253 additional annual cost/ 605 additional tons SO_2 removed
= $10,581 /ton for additional reductions in SO_2 emissions beyond the clean fuel option.

Energy and Environmental Impacts

Throughout the economic analysis, the cost estimates documented, where possible, the actual costs for additional energy consumption, additional water demand, and addition solid waste generated. Also in each technology discussion, the analysis discussed environmental impacts. Table B-13 summarized a comparison of energy and environmental impacts for each option.

Table B-13. Summary of Additional Impacts for SO_2 Control Technologies, Boiler No. 6

	Technology		
Impacts	Scrubber	FSI/ Induct Injection	Clean Fuels
Additional Energy (kWhr/yr)	up to 11,160,688	3,437,500	None
Additional Water (million gal)	up to 976	None	None
Additional Solid Waste (tons)	29,601	10,978	up to 7,900
Environmental Impacts	Treatment of metals in waste stream	Higher PM_{10} Loading to Baghouse	Higher PM_{10} Loading to Baghouse
Other Impacts	Wet Plume	Additional CO_2 from Trona decomposition; FSI may reduce NOx	Less CO_2 emissions

SO_2 Engineering Analysis Summary

Through a detailed comparison of many site specific issues and costs, the Mill believes a 62% level of control of SO_2 is economically feasible for Boiler No. 6. The incremental cost effectiveness for options greater than 62% control (*i.e.,* a scrubber) is greater than $10,000/ton and is economically infeasible. The expected annual cost to meet an SO_2 removal efficiency of 62%, compared to the baseline period of 2002 through 2004, is $1.63 million per year.

2.5 NITROGEN OXIDES

Step 1a-Identification of Control Technologies-Typical Technologies in Use in the United States

The following sections discuss the technologies typically available for multi-fuel stoker-fired boilers including reduction of nitrogen content in fuels with the use of clean fuels, chemical selective catalytic/noncatalytic reduction, combustion air improvements, reducing the residence time at peak combustion operating temperature, and reducing the peak combustion temperature inside of the boiler.

Removal of Nitrogen

Ultra-Low Nitrogen Fuel –The range of fuels typically combusted in stoker-fired boilers can range from wood/bark to coal and pet-coke. The combustion of fuel with lower nitrogen content may result in slightly lower emissions of NO_x. However, this relationship is not well understood [27]. The variety of solid fuels normally combusted in Boiler No. 6 (*i.e.,* petroleum coke and coal) are comparable in nitrogen content. A fuel substitution from conventional fuels to wood or bark would introduce lower levels of nitrogen, but a much higher moisture content. The high moisture content of bark results in lower combustion temperatures than that of petroleum coke or coal that may result in less thermal NO_x formation. However, fuel substitution using wood would result in a loss of heat from nearly 24 MMBtu/ton for coal to less than 10 MMBtu/ton for wood. Substituting wood for coal and/or pet coke would derate the boiler to less than 50% of its design capacity. Additionally, the boiler is not designed to accommodate bark as the lower heat release rate does not match the design of other boiler internal elements (*e.g.,* tube sections, economizer). Though lower in fuel nitrogen, the use of wood in the boiler would require an evaluation of the existing baghouse and may require additional equipment to continue to meet the current PM emission limits.

Chemical Reduction of NO_x

Selective Catalytic Reduction – Selective Catalytic Reduction (SCR) uses a catalyst to react with injected ammonia to chemically reduce NO_x to elemental nitrogen, carbon dioxide and water vapor. The catalyst has a finite life in the flue gas, and some ammonia slips through the boiler without reacting. SCR has historically used precious metal catalysts, which are quite expensive, but can now also use less costly base metal and zeolite catalyst materials. Important considerations in the design, operation and maintenance of an SCR application include physical access, flue gas temperature, flue gas velocity, sulfur content, and particulate matter loading. If a conventional catalyst system is used, the SCR reactor must be located at a point where the flue gas temperature is no greater than 780 degrees Fahrenheit (ºF)

[27] Fortune, D. "Influence of nitrogen content of coal on NOx emissions from pulverised fuel systems", Internal *Shell Coal* Report No. LMD03068.

and no lower than approximately 570ºF. Other options are available for using catalysts - higher temperature and lower temperature – but both of these options are more expensive.

If the SCR reactor can be located in a position where the flue gas temperature ranges between 570 to 780ºF (nominal), then no preheating of the flue gas is required. There are high-temperature (>800ºF) and low-temperature (250 to 650ºF) catalysts, however, the high-temperature catalysts are more effective at NOx removal and can accommodate a broader range of fuel characteristics, higher sulfur levels in the fuel, and trace metals in the flue gas. However, the selection of a high temperature catalyst usually means reheating the flue gas which is rarely a cost-effective approach since a large quantity of fuel must be used to heat the flue gas stream to the proper temperature for the catalyst to work effectively.

Another important consideration is the flue gas velocity through the SCR catalyst bed. For most applications, the flue gas velocity exiting the boiler is too high to provide sufficient residence time for the catalyst to provide the level of reaction required to reduce NO_x emissions. For this reason, the exhaust ductwork must be expanded to allow for a reduction in the flue gas velocity dictated by the catalyst vendor, which will be approximately 20 feet per second (ft/s) depending on the fuel.

Another key consideration is the additional pressure drop across the SCR reactor bed. The pressure drop due to the use of a catalyst bed is approximately 1 to 1.5 inches water (H_2O), but there will be additional pressure drop due to the expanded ductwork and the addition of a static mixing device to maintain a uniform flow across the catalyst bed.

The SCR catalyst design, and therefore life expectancy, is based on the particulate matter loading and sulfur content of the flue gas stream. The catalyst design takes into account the particulate matter loading and the expected contaminants in the flue gas – more difficult fuels are typically handled using a larger pitch (*e.g.,* pore size) which translates into an increase in treatment length and additional pressure drop. GP did receive one quotation for a "tail-end" SCR installation behind the current baghouse. Application of SCR is technically feasible in a "back-end" system approach with a typical removal efficiency of 70% to 80% for a retrofit installation.

<u>Selective Non-Catalytic Reduction</u> – In a SNCR system, ammonia or urea is injected in the combustion chamber of a boiler or in ductwork in a region where the temperature ranges between 1,600 and 2,000ºF. This technology is based on high temperature ionization of the ammonia or urea instead of using a catalyst. The temperature window for SNCR is very important because if the temperature is too low, there may be more ammonia slip through the system or, if the temperature is too high, more NO_x is

generated than is being chemically reduced. SNCR has been demonstrated as a feasible technology for stoker-fired boilers and can achieve variable reductions of 25 to 50 percent. Site-specific assessments are required by SNCR vendors for each application.

Based on the above discussion, SNCR is considered to be technically feasible for Boiler No. 6.

Reducing Residence Time at Peak Operating Temperature

Air Staging of Combustion – An overfire air (OFA) system modifies the combustion air system through the installation of air ports and potentially new fans. Air ports are designed to inject air at the proper velocity to complete combustion prior to the furnace exit. Combustion air inside of a boiler is divided into two streams. The first stream is mixed with fuel in a ratio that produces a flame in an oxygen-deprived zone. The second stream is injected downstream of the flame and creates an oxygen-rich zone where combustion is completed. OFA modifications lower the flame temperature, reducing thermal NO_x and reducing the amount of oxygen available in the flame zone for conversion of fuel nitrogen species to NO_x, reducing fuel NO_x. A sub-specialized application of this technology is rotating opposed fire air (ROFA) by Mobotec USA. The technology optimizes mixing with the use of air ports and fans. The OFA technology for this boiler is believed to reduce NO_x by up to 15% while the ROFA technology may reduce NO_x up to 66%.

Steam Injection - Steam injection causes the stoichiometry of the mixture to be changed and dilutes the heat generated by the combustion process. These actions cause the combustion temperature to be lower, and in turn reduces the amount of thermal NO_x formed. However, air staging accomplishes a very similar result.

Each of the techniques described above to reduce residence time at peak temperature are considered technically feasible.

Reducing Peak Temperature

Flue Gas Recirculation (FGR) – Recirculation of flue gas for use as combustion air reduces the combustion temperature by diluting the oxygen content of the combustion air and causing heat generated by combustion to be diluted in a greater mass of flue gas. For Boiler No. 6, FGR involves taking flue gas from the outlet of the economizer and injecting it in a number of locations in the stoker-fired boiler. The recirculated flue gas would be mixed with the under-grate combustion air to replace some of the air used to maintain grate velocities and to reduce the flame temperature on the grate. The recirculated flue gas will also be used to reduce excess oxygen in the combustion process in general to minimize overall NO_x formation. Injection of the recirculated flue gas will require additional boiler-specific evaluation. This reduction of temperature lowers the thermal NO_x generated but can adversely increase CO emissions. A NO_x reduction of 15 percent is estimated with a flue gas recirculation (FGR) system.

Reburn – In a boiler outfitted with reburn technology, a set of natural gas burners is installed above the primary combustion zone. Natural gas is injected to form a fuel-rich, oxygen-deficient combustion zone above the main firing zone. NO_x emissions created by the combustion process in the main portion of the boiler drift upward into the reburn zone and are converted to elemental nitrogen by combustion of the natural gas. The technology requires no catalysts, chemical reagents, or changes to any existing burners. Typical reburn systems also incorporate redesign of the combustion air system along with the water-cooled, pinhole grate to provide less excess air (LEA). Natural gas reburn is a feasible technology for stoker-fired boilers. However, the reduction efficiency is generally less than 15%.

Low-NO_x Burners (LNB) – A LNB system provides a stable flame that has several different zones. For example, the first zone can be primary combustion. The second zone can be fuel reburning (FR) with fuel added to chemically reduce NO_x. The third zone can be the final combustion in low excess air to limit the combustion temperature. LNB is not an option for stoker-fired systems where solid fuel is injected into the furnace above a traveling grate. In a stoker-fired traveling grate system, lighter particles burn in suspension and fuel not combusting in suspension falls to the grate where the combustion process is completed. Low-NO_x burners can only be used for supplemental gas or liquid fuels.

Step 1b-Identification of Control Technologies-Review of RACT/BACT/LAER Clearinghouse (RBLC)

Searches of the RBLC were conducted to identify control technologies for the control of emissions from stoker-fired boilers. The specific category searched was

- External Combustion- -11

GP reviewed previous BACT NO_x determinations for utility and non-utility coal-fired boilers. The RBLC database contains over 30 utility boiler NO_x determinations, and several non-utility boilers NO_x determinations, two of which are based on new circulating-fluidizied bed designs. The following table summarizes the technologies and emission limits from the RBLC database and recent permit rates for industrial coal and coal/combination fuel boilers:

Summary of RBLC and Recent NO_x Emission Limits for Various Coal Boilers

Source	Technology	NO_x Emissions (lb/MMBtu)
Utility Boilers	SCR/SCR+LNB	0.07 - 0.09
Utility Boilers	LNB+SNCR	0.1
Utility Boilers	SNCR	0.08 - 0.15
Industrial Boilers		
Circulating Fluid Bed	SNCR	0.08
Stoker/Other	None Economically Feasible	0.246 - 0.7
Recent Permits with Add On Technologies		
Temple Inland -Rome, GA	LNB	0.5
Smurfit-Stone (Maritime) Jacksonville, FL	SNCR	0.5

Step 1c-Identification of Control Technologies-Review of Technologies in Use at Georgia-Pacific Corporation Facilities

For several coal boilers at various facilities, GP uses a variety of NO_x reduction measures, including overfire air, FGR, and combustion controls. GP uses ammonia injection for NO_x control for one combination fuel fluidized bed boiler and one de-inked wastewater sludge-fired boiler.

Step 2-Technical Feasibility Analysis-Eliminate Technically Infeasible Options

All of the options identified above are technically feasible except for two options:
First, fuel substitution cannot be accommodated by the boiler due to its design and fuel properties.
Secondly, as this boiler does not employ burners, the use of Low NO_x burners is not feasible.
After eliminating the technically infeasible options, GP added a combination of SNCR and FGR or OFA as a control system to include in the evaluation.

Step 3 – Ranking the Technically Feasible Alternatives to Establish a Control Hierarchy

The ranking for NOx control is:

1. Tail-end SCR at 80% removal efficiency
2. ROFA and Rotamix at 66% removal efficiency
3. SNCR with FGR and OFA at 56% removal efficiency
4. SNCR alone at 25% removal efficiency (site-specific vendor estimate)
5. OFA or FGR alone at 15% to 20% removal efficiency

Step 4- Effectiveness Evaluation

Economic Effectiveness

For each cost estimate, the Green Bay Broadway Mill provided several general assumptions to equipment vendors and engineering contractors to determine site-specific cost estimates with a target accuracy of +/-30% or better. The Title V Permit for the site limits the firing of petroleum coke to a rate demonstrated during a compliance stack test. As a result of these tests, the current fuel mix is limited to approximately 17% by weight of petroleum coke and 83% coal, based on the heat content of the fuels currently combusted in Boiler No. 6.

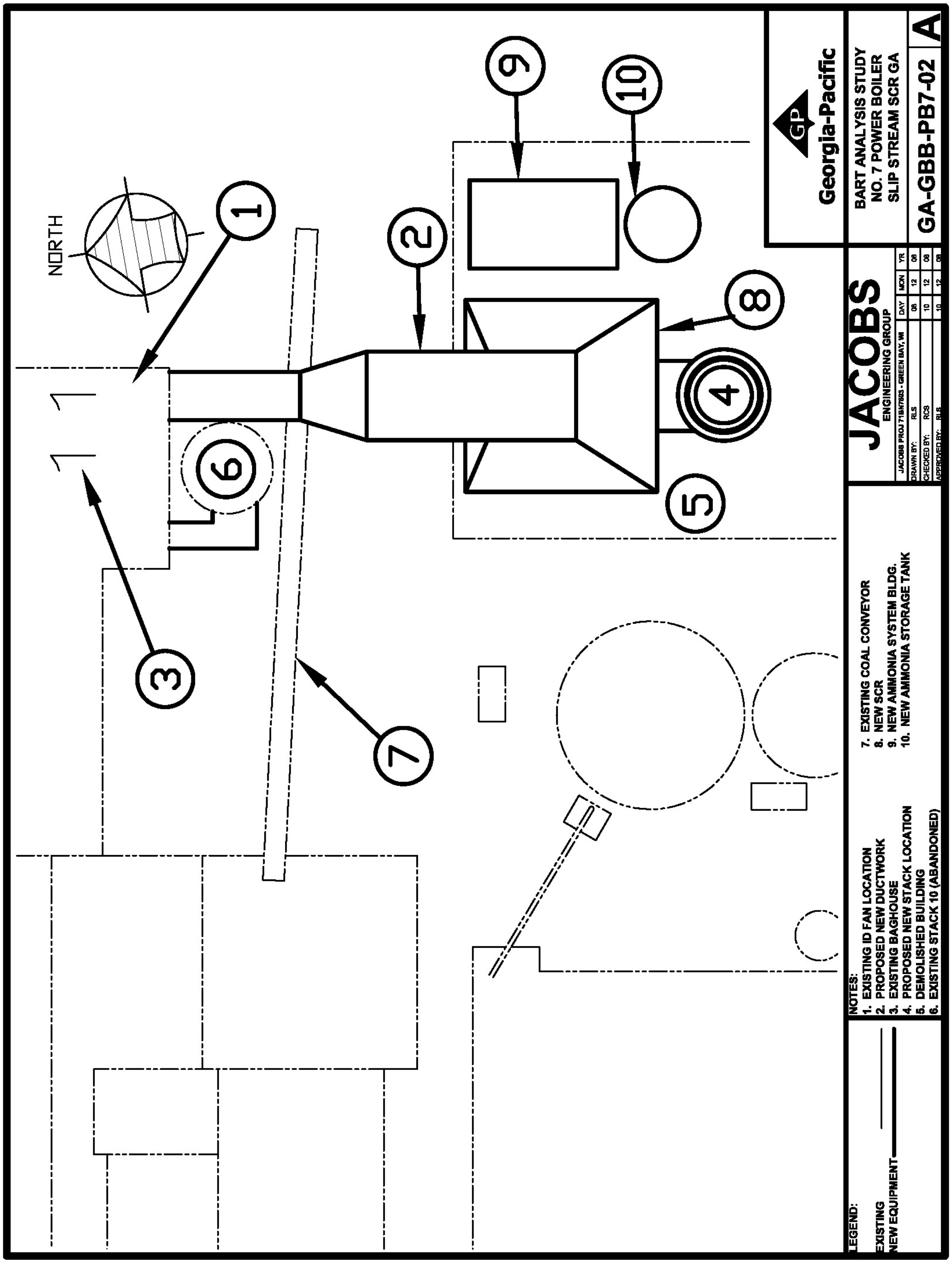
SCR Cost Evaluation

The NO_x removal technology with the highest removal efficiency studied is SCR. SCR technology is a post process NO_x control option used to remove NO_x after the combustion process rather than limit NO_x development at the source. In this case, a reactor filled with an application-specific catalyst is placed in the boiler outlet flue gas stream. The catalyst in these reactions is only effective in a narrow elevated temperature range. In this case, the flue gas needs to be between 600ºF and 650ºF in order to maximize the effectiveness of the catalyst without causing thermal damage. Two (2) SCR reactor installation locations that allow for the appropriate flue gas temperature were evaluated. The first option would be to modify the boiler's flue gas outlet path to accommodate placement of the SCR reactor prior to the boiler's existing air preheater. The second available reactor installation location is downstream of the existing baghouse.

Locating the SCR reactor between the boiler flue gas outlet and the existing air preheater provides the necessary flue gas temperatures; however, it also presents several key obstacles. These obstacles include high flue gas velocities, reduced residence time for the flue gas to pass through the catalyst bed, damage to the catalyst, and blinding of catalyst pores due to high particulate loading. Because of these factors as well as constructability issues, the Slip Stream SCR was estimated as a tail-end unit. Figure B-6 presents a general arrangement.

In this estimate, one of the existing Standard Havens Baghouse chambers would be disconnected from the existing Stack 10 and instead sent across a plant road to the old Building 66 area where a new Slip Stream SCR reactor would be located. The reactor would contain two layers of catalyst. Duct burners would be installed in the top inlet of the SCR reactor to reheat the flue gas to 625ºF in order to allow the catalyst to be as effective as possible. An ammonia injection grid would be installed between the duct burners and the top row of catalyst and be used to inject atomized ammonia across the entire plan area of the Slip Stream SCR reactor. A new aqueous ammonia system include a tank and a heated building for pumps and air blowers.

Figure B-6. General Arrangement of SCR Slip-Stream System, Green Bay Broadway Mill



The SCR Slip-Stream System reactor outlet would feed to a new free-standing 14'-0" diameter, 199' tall carbon steel insulated stack. Stack 10 would continue to serve one chamber of the Standard Havens baghouse. Table B-14 presents the cost estimate for a SCR for Boiler No. 6.

Table B-14. Summary of Capital Cost for Installation of SCR Slip-Stream System, Boiler No. 6
Green Bay Broadway Mill

Description		2009 Costs ($)
Direct Costs		
	Major Equipment	6,125,967
	Demolition	17,776
	Site Improvements	459,447
	Piling, Caissons	643,227
	Buildings	21,494
	Concrete	825,819
	Structural Steel	1,684,872
	Piping	1,704,620
	Insulation - Pipe, Equipment & Ductwork	1,612,124
	Instrumentation	689,171
	Electrical	720,352
	Painting, Protective Coatings	91,890
Construction Indirect Costs		
	Construction Support Labor	697,539
	Premium Time	208,332
	Craft Per Diem	426,485
	Non-Payroll Tax, Insurance & Permits	579,468
	Craft Start-Up Assistance	43,650
	Contractor's Construction Fee	1,345,967
Project Indirect Costs		
	Construction Management	1,299,178
	Engineering Professional Services	4,330,343
	Study Cost	50,000
	Outside Consultant Services	100,000
	Owner's Cost	817,255
	Spare Parts	217,099
	Non-Craft Start-Up Assistance	71,139
	Allowance For Unforeseen	2,467,524
	Escalation	1,621,194
	Air Infiltration Allowance	100,000
Total Installed Cost (+/- 30%) (TIC)		**28,971,933**

Table B-15 presents the annual operating costs for the SCR system.

Table B-15. Annual Operating Cost Calculations, SCR for Boiler No. 6, Actual 2002-2004 Conditions

Parameter	Methodology	Annual Cost ($)
Direct Costs		
Operating labor :	2 hours per shift x 1,025 shifts/yr @ $40/hr	82,000
Supervisor Labor	15% of Operator	12,300
Maintenance labor:	0.5 hours per day x 365 days/yr @ $40/hr	7,300
Maintenance material	100% of Maintenance Labor	7,300
Electricity	0.059$/kWhr x 3464778 kWhr	204,422
Ammonia consumption	$160/ton aq NH_3x 6619 tons aq NH_3 /yr	1,059,040
Natural Gas-duct burners	$10/MMBtu x 429,040 MMBtu/yr	4,290,400
Catalyst	$750,000/ 3 years	250,000
Indirect Costs		
Overhead rate (fractional):	60% of total labor and material costs	65,340
Taxes, insurance, admin. factor:	4% of TIC (Table B-14)	1,158,877
Capital recovery factor (system):	0.0944 x TIC [28] (Table B-14)	2,734,746
Total Annual Cost		9,871,725

[28] 7% interest for the cost of capital and an equipment life of 20 years using Equation 2.8a of USEPA Cost Control Manual yields: (0.07*(1+0.07)^20)/((1+0.07)^20-1) = 0.0944

Determining annual operating costs is sensitive to the amount of NOx removed and ammonia required. The 2002-2004 actual emissions are significantly lower than permitted emissions and thus represent a conservatively lower annual cost (and operation) estimate.

The cost effectiveness of this technology is equal to the Total Annualized Costs/ Annual Quantity of NOx Removed.

The estimated cost effectiveness is: $9,871,725/ (80% x 428 tons) = 28,831 $/ton.

ROFA and Rotamix Cost Evaluation

Section 2.4 presented the application of Mobotec's ROFA and Rotamix costs within its FSI technology. The total installed cost for targeting NO_x control only is estimated to be approximately $1.9MM lower by removing the limestone injection, handling, and storage equipment specifically needed for SO_2 removal. Thus, the expected total installed cost is $25,000,000. Table B-16 presents the annual operating costs without the limestone use or landfilling charges.

Table B-16. Annual Operating Cost Calculations, ROFA/ROTAMIX for Boiler No. 6, Actual 2002-2004 Conditions

Parameter	Methodology	Annual Cost ($)
Direct Costs		
Operating labor :	1 hours per shift x 1,025 shifts/yr @ $40/hr	41,000
Supervisor Labor	15% of Operator	6,150
Maintenance labor:	0.5 hours per day x 350 days/yr @ $40/hr	7,000
Maintenance material	100% of Maintenance Labor	7,000
Electricity- direct	0.059$/kWhr x 3437500 kWhr	202,813
Indirect Costs		
Overhead rate (fractional):	60% of total labor and material costs	36,690
Taxes, insurance, admin. factor:	4% of TIC	1,000,000
Capital recovery factor (system):	0.0944 x TIC [29]	2,359,823
Total Annual Cost		3,660,476

[29] 7% interest for the cost of capital and an equipment life of 20 years using Equation 2.8a of USEPA Cost Control Manual yields: (0.07*(1+0.07)^20)/((1+0.07)^20-1) = 0.0944

Determining annual operating costs is only sensitive to the number of hours the air mixing system is operated.

The cost effectiveness of this technology is equal to the Total Annualized Costs/ Annual Quantity of NOx Removed.

The estimated cost effectiveness is: $3,660,476/ (66% x 428 tons) = 12,958 $/ton.

SNCR Cost Evaluation

SNCR systems are most efficient in a single temperature window; therefore, in order to properly operate an SNCR system, a boiler study is required to map the gas temperatures at several locations during varying boiler operating points. A detailed SNCR study was not conducted for Boiler No. 6; however, the SNCR supplier requires such a study and the SNCR estimate includes a one-time cost of $50,000 to accomplish this task.

This system would consist of a new urea storage tank equipped with skid-mounted metering, circulating and booster pumps within a diked containment area. The new tank will be electrically heat-traced and insulated. The existing Boiler No. 6 furnace front wall would be modified to accept the new spray nozzles, and distribution module skids would be placed near the spray nozzles of the two (2) levels. For Boiler No. 6, tilting injectors would be installed at a single level. A pump would be used to circulate a steady stream of concentrated urea to a metering skid. The metering skid would then pump the diluted urea solution up to the distribution modules located at the boiler's injection nozzles.

Other than the addition of a diked containment area and the need to modify the existing boiler walls, there are few installation complications to consider in this system. Extra steel is considered in the factored installation cost to allow for reworking of platforms to accept control skids, and demolition dollars are included in the factored estimate for removal of items that may be in the way of the new platforms.

The only additional operational concern with a urea-based SNCR system is ammonia slip. Unreacted urea can degrade to nitrogen, carbon dioxide and ammonia in the boiler. This ammonia slip can be controlled with careful monitoring. Urea-based SNCR systems often operate at 1 ppm ammonia slip or less and are usually guaranteed at a 5 ppm ammonia slip rate. The most important factor in reducing ammonia carryover in these systems is proper distribution based on the boiler temperature gradient study. In this case, the preliminary data from the vendor indicates that ammonia slip is expected to be 2 ppm at the exit of the existing baghouse and 5 ppm exiting the boiler. These values would be revised once a boiler-specific study is completed.

Table B-17 presents the total installed cost estimate for an SNCR system alone.

Table B-17. Summary of Capital Cost for Installation of SNCR System, Boiler No. 6
Green Bay Broadway Mill

Description	TOTAL COST (2007$)
Direct Costs	
Major Equipment	1,531,501
Demolition	34,459
Site Improvements	76,575
Piling, Caissons	107,205
Buildings	270,000
Concrete	68,918
Structural Steel	275,670
Piping	260,355
Insulation - Pipe, Equipment & Ductwork	137,835
Instrumentation	38,288
Electrical	213,048
Painting, Protective Coatings	15,315
Construction Indirect Costs	
Construction Support Labor	125,805
Premium Time	36,854
Craft Per Diem ($7/Hour On 100 % Of Time)	79,763
Non-Payroll Tax, Insurance & Permits	113,499
Craft Start-Up Assistance	45,000
Contractor's Construction Fee	223,604
Project Indirect Costs	
Construction Management	268,000
Engineering Professional Services	594,000
Study Cost	50,000
Outside Consultant Services	100,000
Owner's Cost	179,000
Spare Parts	67,188
Non-Craft Start-Up Assistance	119,150
Allowance For Unforeseen	498,103
Escalation	350,665
Air Infiltration Allowance	100,000
Total Installed Cost (+/- 30%) (TIC)	**5,979,799**

Table B-18 presents the annual operating costs for the SNCR system.

Table B-18. Annual Operating Cost Calculations, SNCR for Boiler No. 6, Actual 2002-2004 Conditions

Parameter	Methodology	Annual Cost ($)
Direct Costs		
Operating labor :	1 hours per shift x 1,025 shifts/yr @ $40/hr	41,000
Supervisor Labor	15% of Operator	6,150
Maintenance labor:	0.5 hours per day x 350 days/yr @ $40/hr	7,000
Maintenance material	100% of Maintenance Labor	7,000
Electricity	0.059$/kWhr x 821763 kWhr	48,484
Urea Consumption	$1.35/gal x 10 gph x 8400 hr/yr	113,400
Mill Water	$0.06/kgal x 7,884 kgal/yr	473
Indirect Costs		
Overhead rate (fractional):	60% of total labor and material costs	36,690
Taxes, insurance, admin. factor:	4% of TIC (Table B-17)	239,192
Capital recovery factor (system):	0.094 x TIC (Table B-17)	562,101
Total Annual Cost		1,061,490

Determining annual operating costs is sensitive to the amount of NOx removed and the amount of urea required. The 2002-2004 actual emissions are lower than permitted emissions and thus represent a conservatively lower annual cost (and operation) estimate.

The cost effectiveness of this technology is equal to the Total Annualized Costs/ Annual Quantity of NOx Removed.

The estimated cost effectiveness is: $1,061,490/ (25% x 428 tons) = 9,920 $/ton.

FGR/OFA Cost Evaluation

An additional NOx control case that was studied and estimated for Boiler No. 6 was Flue Gas Recirculation (FGR) and Overfire Air (OFA). Both of these technologies are expected to provide the same approximate level of control and have similar costs. In FGR, flue gas would be taken from the outlet of the boiler's economizer section and directed to several injection locations in the stoker-fired boiler using ductwork. The exact location for the injection points of recirculated flue gas would be determined by boiler modeling. The price for this model is included in the cost estimate. Three main locations proposed for injection of the flue gas are (1) at the coal feeder level, (2) through the nozzles under the fuel feeder, and (3) at the under-grate air system. Other potential injection sites such as the fly ash reinjection ports would be evaluated during the study. The injected flue gas under the grate would replace some of the air used for over-fire air to maintain grate velocities and reduce flame temperatures on the grate. Feeding recirculated flue gas to the coal feeders and to the nozzles under the coal feeders would control the high temperatures at the air/coal interface above the grate. Reducing excess oxygen and flame temperature at or above the grate would help prevent the formation of thermal and fuel bound NOx.

The new FGR system would include an FGR fan located inside of the boiler house, ductwork from the economizer outlet to each point of injection, expansion joints, dampers and operators, flow indicators to major injection locations, boiler tube bends and injection wall boxes, and undergrate air mixing spargers. Money is included in the cost estimate for minor relocation and demolition to allow for installation of the FGR system ductwork. Table B-19 presents the total installed cost estimate for an FGR system alone.

Table B-19. Summary of Capital Cost for Installation of FGR System, Boiler No. 6 Green Bay Broadway Mill

Description		TOTAL COST (2007$)
Direct Costs		
	Major Equipment	$1,256,014
	Demolition	$43,454
	Piling, Caissons	$87,921
	Buildings	$270,000
	Concrete	$41,448
	Structural Steel	$91,061
	Insulation - Pipe, Equipment & Ductwork	$192,418
	Instrumentation	$17,270
	Electrical	$45,216
Construction Indirect Costs		
	Construction Support Labor	$85,575
	Premium Time	$25,563
	Craft Per Diem	$54,256
	Non-Payroll Tax, Insurance & Permits	$68,363
	Craft Start-Up Assistance	$10,400
	Contractor's Construction Fee	$159,898
Project Indirect Costs		
	Construction Management	$174,000
	Engineering Professional Services	$387,000
	Study Cost	$50,000
	Outside Consultant Services	$50,000
	Owner's Cost	$117,000
	Spare Parts	$40,279
	Non-Craft Start-Up Assistance	$57,288
	Allowance For Unforeseen	$327,442
	Escalation	$207,164
Total Installed Cost (+/- 30%) (TIC)		$3,859,031

Table B-20 presents the annual operating costs for the FGR system.

Table B-20. Annual Operating Cost Calculations, FGR for Boiler No. 6, Actual 2002-2004 Conditions

Parameter	Methodology	Annual Cost ($)
Direct Costs		
Operating labor :	1 hours per day x 350 days/yr @ $40/hr	14,000
Supervisor Labor	15% of Operator costs	2,100
Maintenance labor:	0.5 hours per day x 350 days/yr @ $40/hr	7,000
Maintenance material	100% of Maintenance Labor costs	7,000
Electricity	0.059$/kWhr x 927593 kWhr	54,728
Indirect Costs		
Overhead rate (fractional):	60% of total labor and material costs	18,060
Taxes, insurance, admin. factor:	4% of TIC (Table B-19)	154,361
Capital recovery factor (system):	0.094 x TIC (Table B-19)	362,749
Total Annual Cost		619,998

Determining annual operating costs for FGR is sensitive only to the number of hours the fan is used. The operating costs reflect a typical annual operation of 8,400 hours/year.

The cost effectiveness of this technology is equal to the Total Annualized Costs/ Annual Quantity of NOx Removed.

The estimated cost effectiveness is: $619,998/ (20% x 428 tons) = 7,242 $/ton.

SNCR with FGR and OFA Cost Evaluation

In an attempt to design a more successful combustion modification technology with urea injection, the Mill developed a cost estimate for the combination of FGR, OFA and SNCR. This combination is different than the ROFA/ROTAMIX option though the addition of urea injection. Table B-21 tabulates the cost estimate for this combination of technologies.

Table B-21. Summary of Capital Cost for Installation of FGR/OFA/SNCR System, Boiler No. 6 Green Bay Broadway Mill

Description	TOTAL COST
FGR FAN System (Table B-19)	3,859,031
OFA System (estimated by a ratio of equipment)[30]	2,371,174
SNCR System (Table B-17)	5,979,799
Total Installed Cost (+/- 30%) (TIC)	**12,210,004**

[30] OFA System Installation Cost = FGR Fan Installation x OFA Equipment Cost / FGR Equipment Cost; $3,859,031 x $757,000 / $1,232,000 = $2,371,174

Table B-22 presents the annual operating costs.

Table B-22. Annual Operating Cost Calculations, FGR+OFA+SNCR for Boiler No. 6, Actual 2002-2004 Conditions

Parameter	Annual Cost ($)			
Direct Costs	FGR	OFA	SNCR	Total
Operating labor :	14000	0	41000	
Supervisor Labor	2100	0	6150	
Maintenance labor:	7000	7000	7000	
Maintenance material	7000	7000	7000	
Electricity	54728	54728	48484	
Urea and Water	0	0	113873	
Indirect Costs				
Overhead rate (fractional):	18060	8400	36690	
Taxes, insurance, admin. factor:	154361	94847	239192	
Capital recovery factor (system):	364749	223839	562101	
Total Annual Cost	619998	395814	1061490	$ 2,077,302

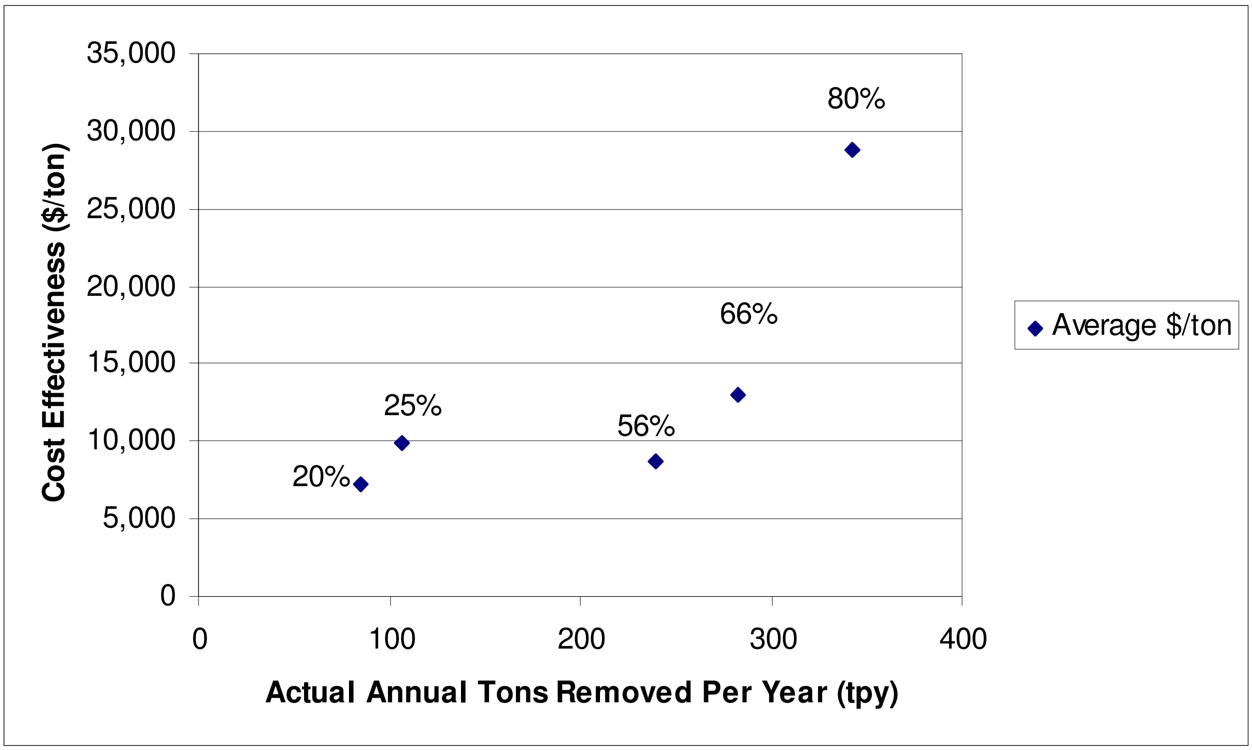
Determining annual operating costs for the combination is sensitive to the number of hours the fan is used as well as the urea consumption requirement. The cost effectiveness of this technology is equal to the Total Annualized Costs/ Annual Quantity of NOx Removed.

The estimated cost effectiveness is: $2,077,302/ (56% x 428 tons) = 8,666 $/ton.

Summary of Economic Evaluation, NOx Controls for Power Boiler No. 6

The economic evaluation determined a range of cost effectiveness values for the following levels of control: 20%, 25%, 56%, 66%, and 80%. Figure B-7 presents a marginal cost curve for all the cost estimates presented in Table B-14 through B-22.

Figure B-7 Marginal Cost Curve for NO_x Control Options, Green Bay Broadway Mill Boiler No.6



Note: Annual Actual tons removed shown is relative to 2002-2004 actual emissions
Control options: 20% removal by FGR or OFA; 25% removal by SNCR alone; 56% removal by a combination of FGR/OFA and SNCR; 80% removal by SCR

Energy and Environmental Impacts

Throughout the economic analysis, the cost estimates documented, where possible, the actual costs for additional energy consumption, additional water demand, and addition solid waste generated. Also in each technology discussion, the analysis discussed environmental impacts. Table B-23 summarizes a comparison of energy and environmental impacts for each option.

Table B-23. Summary of Additional Impacts for NO_x Control Technologies, Boiler No. 6

	Technology		
Impacts	SNCR Options	Combustion Modifications	SCR
Additional Energy (kWhr/yr)	2,676,949	1,855,186	3,464,778
Additional Water (million gal/yr)	7.884	0	0
Additional Natural Gas (MMcf/yr)	0	0	429.04
Environmental Impacts	NH_3 Emissions	None	NH_3 Emissions
Other Impacts	NH_3 Handling	None	NH_3 Handling

NO_x Engineering Analysis Summary

Through a detailed comparison of many site specific issues and costs, the Mill believes no additional controls meets the BART requirement for Boiler No. 6. While technologies do exist for stoker-fired boilers to reduce NO_x, the site-specific cost estimates indicate the retrofit nature of the installations proves to be economically infeasible. The cost effectiveness for the lowest cost option (OFA/FGR) is $7,242/ton removed for a reduction of 86 tons per year.

2.6 SUMMARY OF ENGINEERING ANALYSES FOR BOILER NO. 6

Using a “top-down” procedure, the engineering analysis determined that 62% SO_2 reduction technology is technically and economically feasible for Boiler No. 6. The analysis determined that no additional controls are feasible for PM_{10} and NO_x. Boiler No. 6 will continue to use the existing baghouse to remove PM.

3.0 BART ENGINEERING ANALYSIS FOR POWER BOILER NO.7

3.1 SOURCE DESCRIPTION

Boiler No. 7 is a two (2) drum cyclone-type boiler manufactured by Babcock and Wilcox and installed in 1969. The boiler has a heat input rating of 615 MM Btu/hr with a maximum continuous rated (MCR) steam flow of 500,000 lbs/hr and an ultimate maximum steam flow of 550,000 lb/hr for a one (1) - hour period over 24 hours of operation. The boiler's steam superheater outlet condition is 850 psig at 890 ^{o}F. Boiler No. 7 is permitted to burn coal, petroleum coke, natural gas, and No. 2 fuel oil. Natural gas is normally used for startup and maintaining stability. Boiler No. 7 typically operates in a swing-loaded mode and fires low fusion eastern coal with up to 25% petroleum coke. The Boiler's exhaust gases are discharged into a common duct connected with the flue gas discharge streams from several other boilers at the mill. The common duct is equipped with a baghouse to remove particulate matter emissions from the exhaust gases. Figure B-8 presents a side-view drawing of Boiler No. 7.

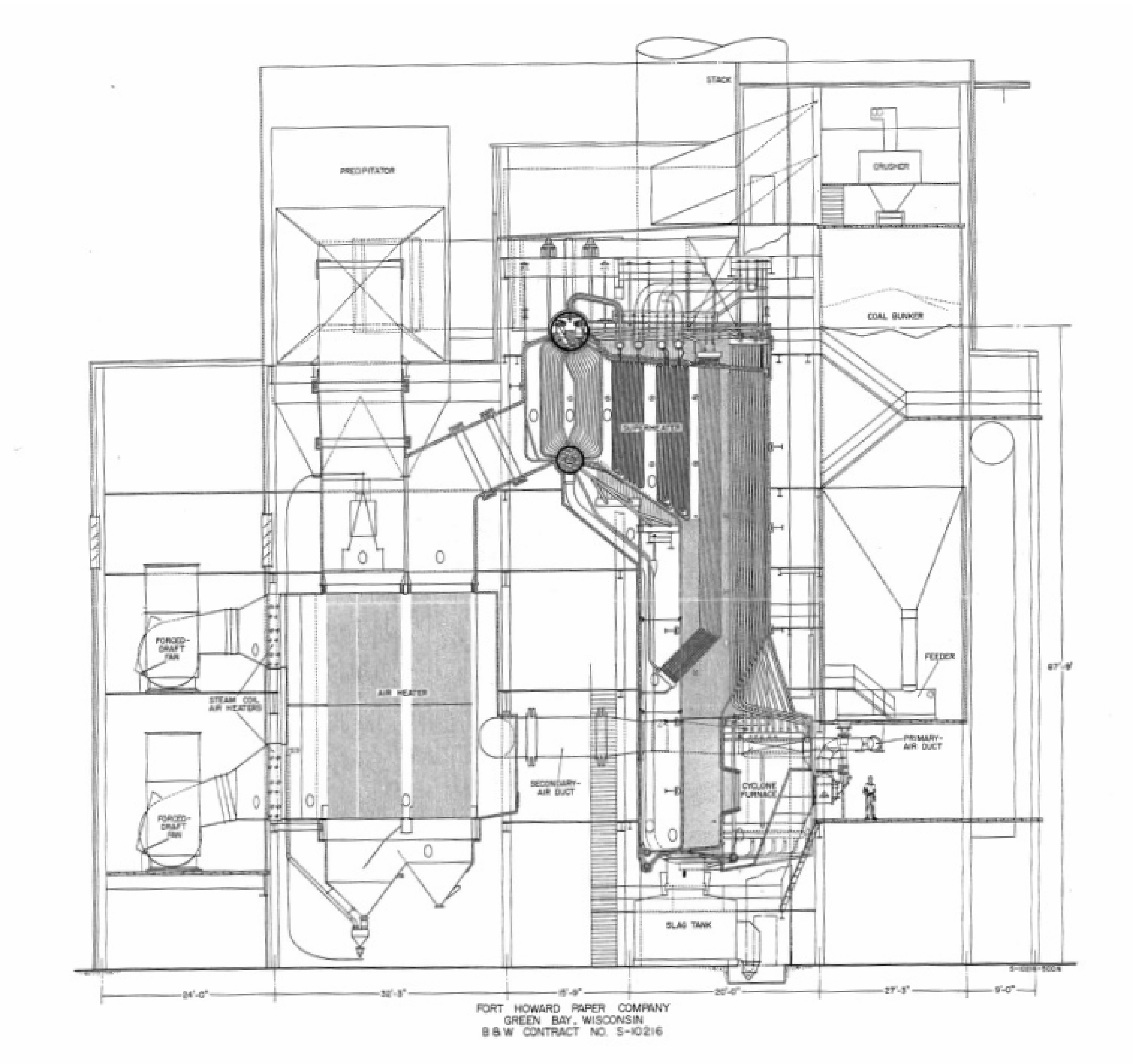
3.2 BASELINE EMISSIONS

The following table presents the actual fuels fired, sulfur content of each fuel combusted, and the BART-regulated emissions generated from Boiler No. 7 during the baseline period of 2002 through 2004.

Table B-24. Summary of Baseline Solid Fuels and Emissions, Boiler No. 7

Parameter	2002	2003	2004	3-yr Average
Total MMBtu All Solid Fuels	4550267	4298870	4251026	4366721
Tons Low Fusion Coal	132187	126175	131213	129858
%S Low Fusion Coal	2.33	2.37	2.43	2.38
Tons Pet Coke	32961	29212	30262	30812
%S Pet Coke	5.89	5.38	5.49	5.59
Annual Average SO_2 (lb/MMBtu)	3.87	4.10	4.01	3.99
Actual SO_2 Emissions (tpy)	8807	8810	8527	8715
Actual NOx Emissions (tpy)	2812	2673	2735	2740
Actual PM_{10} Emissions (tpy)	199	187	112	166

Figure B-8. Side View of Boiler No. 7, Green Bay Broadway Mill



3.3 PARTICULATE MATTER

Step 1a-Identification of Control Technologies-Typical Technologies in Use in the United States

Technology that may be considered for the control of particulate matter emissions from boilers includes the substitution and use of clean fuels, mechanical/gravity separation devices (*e.g.,* cyclones, settling chambers), electrostatic precipitators (ESPs), baghouses, and high efficiency wet scrubbers.

Step 1b-Identification of Control Technologies-Review of RACT/BACT/LAER Clearinghouse (RBLC)

Searches of the RBLC were conducted to identify control technologies for the control of PM_{10} emissions from cyclone boilers. The specific category searched was External Combustion- -11

The clearinghouse listed multiclones with ESPs, baghouses, good combustion practices, and wet scrubbers as the PM_{10} control technologies.

Step 1c-Identification of Control Technologies-Review of Technologies in Use at Georgia-Pacific Corporation Facilities

GP operates numerous combination fuel-fired boilers and coal-fired boilers at its operating facilities within the United States. PM_{10} control devices in use at these mills include ESPs, baghouses and wet scrubbers.

Step 2-Technical Feasibility Analysis-Eliminate Technically Infeasible Options

All of the control options identified in Step 1 are technically feasible.

Step 3 – Ranking the Technically Feasible Alternatives to Establish a Control Hierarchy

The ranking of technologies for PM_{10} control is:

1. Baghouse with greater than 99% removal efficiency
2. ESP with multiclones at greater than 99% removal efficiency
3. High efficiency scrubbers with 98%+ removal efficiency
4. Wet scrubbers with 50 to 95% removal efficiency
5. High efficiency cyclones with 50-90% removal efficiency

Step 4- Effectiveness Evaluation

GP currently operates a high efficiency (above 99%) baghouse to control PM_{10} emissions generated by Boiler Nos. 5, 6, 7, and 8. The baghouse design inlet particulate loading ranges from 1 to 3.5 gr/acf, while the outlet loading is consistently at or below 0.01 gr/acf. The baghouse design exhaust gas flowrate is 772,000 acf/minute (ACFM) at 365 °F. The baghouse meets the existing State limit of 0.3 lb

PM_{10}/MM Btu from NR415.06(1)(b), (equivalent to 184.5 lb/hr at Boiler No. 7's maximum rated capacity), is much greater than the baseline annual emissions rate of approximately 40 lbs/hr [31](equal to 0.08 lb/MM Btu) from Boiler No. 7. As the Mill presently operates the highest ranked PM_{10} control technology, no additional cost effectiveness evaluation is necessary.

Step 5-Select BART

GP is proposing to continue the use of the highest level of control, a baghouse with the current emission limit of 0.3 lb PM_{10}/MM Btu.

[31] [199 tons (2002) + 187 tons (2003) + 112 tons (2004)] x 2000 lbs/ton / 25,104 hours = 40 lbs/hr.
[(199 tons (2002) + 187 tons (2003) + 112 tons (2004))*2000 lb/ton] / 13,100,163 MMBTU total = 0.08 lb/MMBtu including both filterable and condensible.

3.4 SULFUR DIOXIDE

Step 1a-Identification of Control Technologies-Typical Technologies in Use in the United States

Emission control equipment that may be considered to control sulfur dioxide emissions from coal-fired boilers includes gas absorption using wet and dry scrubbers, and flue gas desulfurization techniques such as sorbent injection. The use of clean substitute fuels can also be considered as an alternative to add-on controls.

Step 1b-Identification of Control Technologies-Review of RACT/BACT/LAER Clearinghouse (RBLC)

Searches of the RBLC were conducted to identify control technologies for the control of SO_2 emissions from cyclone boilers. The specific category searched was "External Combustion- -11". The clearinghouse listed the use of clean fuels, wet and dry scrubbers, and flue gas desulfurization techniques such as limestone injection and spray dryer absorbers (SDA) as the control technologies.

Step 1c-Identification of Control Technologies-Review of Technologies installed at Georgia-Pacific Corporation Facilities

Georgia-Pacific operates numerous combination fuel-fired boilers and coal-fired boilers within the United States. SO_2 control technologies include dry scrubbing, limestone and sorbent injection on fluidized bed boilers, and the use of clean fuels. However, the company has limited experience with wet scrubbing with caustic on similar cyclone boilers.

Step 2-Technical Feasibility Analysis-Eliminate Technically Infeasible Options

The Green Bay Broadway Mill investigated several gas absorption technologies: wet scrubbing with caustic (sodium hydroxide) solution, semi-dry scrubbing using a lime slurry with conventional scrubbers, Spray Dry Absorbers (SDAs) and circulating fluidized bed scrubbers. Scrubber vendors have indicated to the Mill that spray drying is not technically feasible because the allowable inlet sulfur concentration associated with the current fuel mix would be too high and the flue gas temperatures too low to support the water evaporation requirements in the hydrated lime slurry SDA. As a result, SDA vendors have informed GP that they cannot provide quotations for this particular application of the technology. All of the other SO_2 control technology options are technically feasible.

Step 3 – Ranking the Technically Feasible Alternatives to Establish a Control Hierarchy

The ranking of the technologies are:

1. Gas absorption with a wet spray tower or semi-dry scrubbing system with hydrated lime at 90%+ SO_2 removal efficiency,
2. In-Furnace Sorbent Injection at 50% removal efficiency,
3. In-duct absorption with sodium sesquicarbonate (Trona) injection with 50% removal efficiency,
4. Fuel substitution: Low SO_2/MMBtu coal in place of all higher sulfur containing fuels at 11% removal efficiency

Step 4- Cost Effectiveness Evaluation

Economic Evaluation

For each control technology cost estimate, the Green Bay Broadway Mill provided several general assumptions to the equipment vendors and engineering contractors for their use in determining site-specific cost estimates with a target accuracy of +/- 30% or better. The cost analysis for Boiler No. 7 follows the conventions presented above for Boiler No. 6.

Wet Spray Tower with Sodium Hydroxide Cost Evaluation

The Green Broadway Bay Mill worked with several control equipment vendors to review technical issues and challenges with SO_2 control by using wet, dry, or semi-dry scrubbing technologies. Based on the technical reviews, the use of a wet spray tower demonstrates the best overall SO_2 removal efficiency of all the technologies reviewed and that were considered technically feasible. Jacobs Engineering provided the Green Bay Broadway Mill with a +/-30% cost estimate to install and operate a wet spray tower scrubber. The cost estimate for a wet spray tower scrubber presented in Table B-25 assumed that the scrubber will be located downstream of the existing baghouse and is parallel to the estimates presented for Boiler No. 6. The key design differences are:

1. The clean flue gas exits the Scrubber and enters a new 16' diameter, 316L stainless steel Stack mounted on top of the new Spray Tower Scrubber outlet. The Stack will terminate at an elevation of 199 feet above grade. The Stack is sized for a flue gas velocity of approximately 34 ft/sec with 395,000 cubic feet/minute of scrubbed and saturated flue gas.

2. The Spray Tower Scrubber has a 38' by 30' footprint and the Scrubber absorber vessel is 25'-0" in diameter and stands approximately 58' tall.

Table B-25. Summary of Capital Cost for Installation of Wet Spray Tower Scrubber System, Boiler No. 7 Green Bay Broadway Mill

Description[32]	Total Cost (2007$) [33]
Direct Costs	
Major Equipment	$11,969,285
Demolition	$19,375
Site Improvements	$598,464
Piling, Caissons	$837,850
Buildings	$670,000
Concrete	$988,762
Structural Steel	$2,194,549
Piping	$3,330,589
Insulation - Pipe, Equipment & Ductwork	$859,079
Instrumentation	$954,823
Electrical	$1,452,051
Painting, Protective Coatings	$119,693
Construction Indirect Costs	
Construction Support Labor	$1,038,695
Premium Time	$306,778
Craft Per Diem	$658,555
Non-Payroll Tax, Insurance & Permits	$1,035,129
Craft Start-Up Assistance	$43,650
Contractor's Construction Fee	$1,923,564
Project Indirect Costs	
Construction Management	$1,992,000
Engineering Professional Services	$4,423,000
Study Cost	$50,000
Outside Consultant Services	$100,000
Owner's Cost	$1,325,000
Spare Parts	$458,745
Non-Craft Start-Up Assistance	$119,150
Allowance For Unforeseen	$3,741,878
Escalation	$2,717,463
Air Infiltration Allowance [34]	$100,000
Total Installed Cost (TIC)(+/- 30%)	$44,028,127

[32] See Appendix for further description of estimator's cost categories
[33] Green Bay, WI BART Feasibility Study and Estimate, June 2007 Jacobs Engineering
[34] Modifications to the exhaust system are expected to require studies and upgrades to eliminate air infiltration.

To determine estimated operating costs for the scrubber, this cost analysis used the templates provided by EPA in their Cost Control Manual. Determining annual operating costs is sensitive to the amount of sulfur dioxide removed and the amount of scrubbant required to maintain the desired SO_2 removal efficiency. The 2002-2004 actual emissions are significantly lower than permitted emissions (*i.e.*., 3.99 lbs SO_2/MMBtu in 2002-2004 compared to permit limit of 4.55 lb SO_2 /MMBtu) and thus represent a conservatively lower annualized cost estimate. Table B-26 presents operating costs for the spray tower technology.

Table B-26. Annual Operating Cost Calculations, Wet Spray Tower for Boiler No. 7, Actual 2002-2004 Conditions

Parameter	Methodology	Annual Cost ($)	
Direct Costs			
Operating labor :	1 hours per shift @ $40/hr	$	43,800
Supervisor Labor	15% of Operator	$	6,570
Maintenance labor:	0.5 hours per shift @ $40/hr	$	21,900
Maintenance material	100% of Maintenance Labor	$	21,900
Electricity	0.059$/kWhr x 11963492 kWhr	$	705,846
Caustic Solution[35]	$1050/dry ton NaOH x 13,617 ton NaOH	$	14,298,047
Process water:	$0.06/kgal x 4518951 kgal	$	271,137
Landfill Scrubber system solids	$ 9.50 /ton x 100,377 tons	$	953,582
Additional Process Steam	$2.45/klb steam x 752,831 klbs	$	1,844,436
Indirect Costs			
Overhead rate (fractional):	60% of total labor and material costs	$	56,502
Taxes, insurance, admin. factor:	4% of TIC (Table B-25)	$	1,761,125
Capital recovery factor (system):	0.1098 x TIC [36] (Table B-25)	$	4,834,052
Total Annual Cost		$	24,818,896

[35] 2002-2004 actual SO_2 tons emitted = 8715 emitted; consumption is 2.5 lb-mol NaOH per lb mol of SO_2 removed; 2008 average unit cost of caustic as delivered to Mill = $1,050/dry ton NaOH;

8715 tons SO_2 x 2,000 lbs/ton x lbmol SO_2/64 lbs SO_2 x 2.5 lb-mol NaOH/lb-mol SO_2 x 40 lbs NaOH/lb-mol NaOH / 2,000 lbs/ton =13,617 tons dry NaOH

[36] 7% interest for the cost of capital and a scrubber life of 15 years using Equation 2.8a of USEPA Cost Control Manual yields: (0.07*(1+0.07)^15)/((1+0.07)^15-1) = 0.1098

The cost effectiveness of this technology is equal to the Annual Operating Costs/ Annual Quantity of SO_2 Removed.

The estimated cost effectiveness is: $24,818,896 / (90% x 8,715 tons) = $3,164 /ton.

Dry Scrubbing with Hydrated Lime Fluidized Bed Absorber (FBA) Cost Evaluation

Dry scrubbers have significantly lower capital and annual operating costs than wet systems because they are simpler, demand less water, and waste disposal is less complex. Dry injection systems are easier to install and use less space; therefore, they are good candidates for retrofit applications, such as the one at the Green Bay Broadway Mill. In contrast to a wet spray tower, FBAs use a reactor vessel with a closely controlled temperature.

The cost estimate for a FBA scrubber assumes that the scrubber will be located downstream of the existing baghouse and is comparable to the estimates presented for Boiler No. 6 although equipment size is scaled for the higher airflow rate.

Table B-27 summarizes the total cost for installation of the FBA system.

Table B-27. Summary of Capital Cost for Installation of Fluidized Bed Absorber System, Boiler No. 7 Green Bay Broadway Mill

Description	TOTAL COST (2008$)
Scrubber systems installation and duct modifications	15,357,754
Footings and foundation work	684,809
Electrical and controls	1,680,120
Structural steel	536,569
Engineering and commissioning	2,370,307
Construction management	1,623,336
General contractor overhead and mark-up	2,001,420
Contingency	3,048,333
CEM systems	358,312
Piping	123,172
Miscellaneous	539,087
Freight	919,121
Total Installed Cost	29,242,339

Figure B-3 represents a simplified flow diagram of the required equipment for a generic case of any one of several boilers at the mill. In contrast to the wet spray tower scrubber technology, most of the equipment will be located within the existing buildings at a point upstream of the baghouse. Figure B-4 presents a footprint diagram. Table B-28 presents the operating costs for the FBA specific to Boiler No. 7.

Table B-28. Annual Operating Cost Calculations, Fluidized Circulating Absorber for Boiler No. 7, Actual 2002-2004 Conditions

Parameter	Methodology	Annual Cost ($)
Direct Costs		
Operating labor :	3 hour per shift @ $40/hr	131,400
Supervisor Labor	15% of Operator	19,710
Maintenance labor & equipment:	Vendor Estimate 10% of Equipment Costs	1,838,242
Electricity- direct	0.059$/kWhr x 6864000 kWhr	404,976
Electricity- fan make-up	8 inches w.c	201,680
Hydrated Lime	$90/ton hy lime x 36,037 tons hy lime/yr[37]	3,243,322
Process water:	$0.06/kgal x 36,600 kgal	2,196
Landfill Scrubber system solids	$ 9.50 /ton x 58,575 tons	556,458
Indirect Costs		
Overhead rate (fractional):	60% of total labor and material costs	1,193,611
Taxes, insurance, admin. factor:	4% of TIC (Table B-27)	1,169,694
Capital recovery factor (system):	0.1098 x TIC [38] (Table B-27)	3,210,652
Total Annual Cost		11,971,942

[37] 2002-2004 actual SO_2 tons = 8,715; consumption is 3.25 lb-mol hydrated lime per lb mol of SO_2 removed; 2008 average unit cost = $90/ ton hydrated lime (91% active)

8,715 tons SO_2 x 2,000 lbs/ton x lb-mol SO_2/64 lbs SO_2 x 3.25 lb-mol hydrated lime/lb-mol SO_2 x 74.1 lbs hydrated lime / lb-mol hydrated lime / 2,000 lbs/ton 1ton pure CaCO3/0.91 ton hydrated lime = 36,037 tons hydrated lime

[38] 7% interest for the cost of capital and a scrubber life of 15 years using Equation 2.8a of USEPA Cost Control Manual yields: (0.07*(1+0.07)^15)/((1+0.07)^15-1) = 0.1098

The cost effectiveness of this technology is equal to the Annual Operating Costs/ Annual Quantity of SO_2 Removed.

The estimated cost effectiveness is: $11,971,942/ (90% x 8,715 tons) = $1,526 /ton.

Furnace Sorbent Injection (FSI) Cost Evaluation

As an alternative to “back-end” controls, the Green Bay Broadway Mill assessed control technologies further upstream. One such technique involves injecting a sorbent into the combustion chamber of the boiler with the fuel. As additional material in the boiler can significantly affect boiler performance, this technology is coupled with improving the air distribution system within the boiler. The technology has been demonstrated on stoker-fired boilers (further demonstration on cyclone boilers is expected in 2009), however, an unknown risk to operations is the potential erosion of boiler furnace tubes due to the additional sorbent material injected into the combustion chamber of the boiler. The FSI technology is similar to the dry scrubbing system in that it eliminates management of wet streams and has a small equipment footprint relative to wet scrubbing systems. Limestone with a high $CaCO_3$ content would absorb SO_2 as the fuel sulfur is oxidized in the furnace. The resultant particulate would be carried out with the boiler flue gas and then captured in the existing baghouse. As mentioned earlier, the mill expects that the existing baghouse would collect the additional particulate and maintain its high removal efficiency from an FSI without significant modification.

The cost estimate for an FSI system is comparable to the estimates presented for Boiler No. 6, though equipment size is scaled for the higher airflow rate. However, Mobotec has very little experience with this type of system on cyclone boilers at this time.

Table B-29. Summary Of Capital Cost For Installation Of FSI System, Boiler No. 7 Green Bay Broadway Mill

Description[39]	Total Cost (2007$)[40]
Major Equipment	$7,018,799
Demolition	$661,504
Site Improvements	$491,316
Piling, Caissons	$631,692
Buildings	$330,000
Concrete	$828,031
Structural Steel	$1,497,449
Piping	$2,233,812
Insulation - Pipe, Equipment & Ductwork	$350,940
Instrumentation	$658,012
Electrical	$1,035,904
Painting, Protective Coatings	$70,188
Construction Indirect Costs	
Construction Support Labor	$758,232
Premium Time	$223,596
Craft Per Diem	$480,735
Non-Payroll Tax, Insurance & Permits	$564,881
Craft Start-Up Assistance	$43,650
Contractor's Construction Fee	$1,315,374
Project Indirect Costs	
Construction Management	$1,320,000
Engineering Professional Services	$2,931,000
Study Cost	$50,000
Outside Consultant Services	$100,000
Owner's Cost	$878,000
Spare Parts	$288,461
Non-Craft Start-Up Assistance	$119,150
Allowance For Unforeseen	$2,485,548
Escalation	$1,814,693
Air Infiltration Allowance	$100,000
TOTAL INSTALLED COST (TIC) (+/- 30%)	$29,280,967

[39] See Appendix for further description of estimator’s cost categories
[40] Green Bay, WI BART Feasibility Study and Estimate, June 2007 Jacobs Engineering

Table B-30 presents annual operating costs for the FSI system. Without a site-specific study by Mobotec, the economic analysis could not estimate what, if any, loss of steaming capacity would occur with the significant amount of "dead load" material (*i.e.,* sorbent) added into the furnace. The operating costs also do not include lost steam production due to increased wear on boiler tubes. Though the increased rate of tube erosion cannot yet be determined, the operation of the boiler will be affected by a significant increase in tube wall inspections following startup with an FSI system.

Table B-30. Annual Operating Cost Calculations, FSI for Boiler No. 7, Actual 2002-2004 Conditions

Parameter	Methodology	Annual Cost ($)
Direct Costs		
Operating labor :	1 hour/shift x 1,095 shifts/year @ $40/hr	43,800
Supervisor Labor	15% of Operator costs	6,570
Maintenance labor:	0.5 hrs/shift x 1,095 shifts/year @ $40/hr	21,900
Maintenance material	100% of Maintenance Labor	21,900
Electricity- direct	0.059$/kWhr x 3,801,797 kWhr	224,306
Limestone	$40/ton limestone x 44,300 tons[41]	1,772,005
Landfill Additional system solids	$ 9.50/ton x 44,300 tons	420,850
Indirect Costs		
Overhead rate (fractional):	60% of total labor and material costs	56,502
Taxes, insurance, admin. factor:	4% of TIC (Table B-29)	1,171,239
Capital recovery factor (system):	0.1098 x TIC (Table B-29)	3,214,893
Total Annual Cost		6,953,964

[41] 2002-2004 actual SO_2 tons = 8,715; consumption is 3.25 lb-mol limestone per lb mol of SO_2; Average unit cost is $40/ton delivered.

8,715 tons SO_2 x 2,000 lbs/ton x lb-mol SO_2/64 lbs SO_2 x 3.25 lb-mol limestone /lb-mol SO_2 x 100.1 lbs limestone ($CaCO_3$)/ lb-mol limestone / 2,000 lbs/ton = 44,300 tons limestone

Determining annual operating costs is sensitive to the amount of sulfur dioxide removed and sorbent required. The 2002-2004 actual emissions are significantly lower than permitted emissions and thus represent a conservatively lower annual cost (and operation) estimate.

The cost effectiveness of this technology is equal to Annual Costs/ Annual SO_2 Removed.

The estimated cost effectiveness is: $6,953,964 / (50% x 8,715 tons) = 1,596 $/ton.

In-Duct Absorption System with Trona Cost Evaluation

In contrast to injecting sorbent into the boiler or using a wet spray tower scrubber vessel, in-duct absorption is an alternative capable of obtaining a 50% reduction in SO_2 emissions from Boiler No. 7. Unlike the other SO_2 technologies described above, this technology does not have many similar applications in commercial operation. With the use of this technology, offered by O'Brien and Gere, the sorbent is fed into the flue gas as a dry powder. The sorbent (sodium sesquicarbonate, or Trona) undergoes thermal decomposition and reacts with sulfur dioxide in the flue gases to form a particulate. Approximately one-third of the sorbent mass forms carbon dioxide and exhausts to the atmosphere while the other two-thirds of the particulate mass is captured in the existing baghouse. The use of Trona will result in the release of 4 moles of carbon dioxide for every 2 moles of Trona. The supply market for this sorbent is very limited to a few active mines in the western United States. Without multiple sources for the sorbent, deliveries to the mill are at higher risk of supply interruptions (*e.g.,* natural or other external events) than other technologies with many suppliers.

The cost estimate for an In-Duct Absorbtion System is comparable to the estimates presented for Boiler No. 6, although equipment size is designed for the higher airflow rate. Table B-31 presents a summary of installation the installed costs for the In-Duct Absorption System for Boiler No. 7.

Table B-31. Summary of Capital Cost for Installation of In-Duct Sorbent System, Boiler No. 7 Green Bay Broadway Mill

Description[42]	Total Cost (2007$)[43]
Direct Costs	
Major Equipment	12,600,000
Demolition	250,000
Site Improvements	157,500
Piling, Caissons	450,000
Buildings	120,000
Concrete	141,750
Structural Steel	567,000
Piping	535,500
Insulation - Pipe, Equipment & Ductwork	283,500
Instrumentation	157,500
Electrical	346,500
Painting, Protective Coatings	47,250
Construction Indirect Costs	
Construction Support Labor	184,480
Premium Time	53,062
Craft Per Diem	116,965
Non-Payroll Tax, Insurance & Permits	438,838
Craft Start-Up Assistance	43,650
Contractor's Construction Fee	406,796
Project Indirect Costs	
Construction Management	478,000
Engineering Professional Services	1,058,000
Outside Consultant Services	100,000
Owner's Cost	700,000
Spare Parts	641,025
Non-Craft Start-Up Assistance	119,150
Allowance For Unforeseen	1,999,647
Escalation	1,044,328
Air Infiltration Allowance[44]	100,000
Total Installed Cost (+/- 30%) (TIC)	**23,140,441**

[42] See Appendix for further description of estimator's cost categories
[43] Green Bay, WI BART Feasibility Study and Estimate, June 2007 Jacobs Engineering
[44] Modifications to the exhaust system are expected to require studies and upgrades to eliminate air infiltration.

Table B-32 presents the annual operating costs for the In-Duct Absorption system.

Table B-32. Annual Operating Cost Calculations, In-Duct Absorption System for Boiler No. 7, Actual 2002-2004 Conditions

Parameter	Methodology	Annual Cost ($)
Direct Costs		
Operating labor :	0.5 hrs/shift x 1,095 shifts/yr @ $40/hr	21,900
Supervisor Labor	15% of Operator	3,285
Maintenance labor:	0.5 hrs per day x 365 days/yr @ $40/hr	7,300
Maintenance material	100% of Maintenance Labor	7,300
Electricity	0.059$/kWhr x 2,534,375 kWhr	149,528
Trona consumption	$150/ton Trona x 5.2 tons Trona/hr[45] x 8,400 hr/yr	6,552,000
Landfill Additional Baghouse solids	$ 9.50/ton x 4.4 tons solids/hr x 8,400 hrs/yr	351,120
Indirect Costs		
Overhead rate (fractional):	60% of total labor and material costs	23,871
Taxes, insurance, admin. factor:	4% of TIC (Table B-31)	925,618
Capital recovery factor (system):	0.1098 x TIC (Table B-31)	2,540,696
Total Annual Cost		10,582,618

[45] Based on vendor estimate

Determining annual operating costs is sensitive to the amount of sulfur dioxide removed and sorbent required. The 2002-2004 actual emissions are significantly lower than permitted emissions and thus represent a conservatively lower annualized cost (and operation) estimate.

The cost effectiveness of this technology is equal to the Total Annualized Costs/ Annual Quantity of SO_2 Removed.

The estimated cost effectiveness is: $10,582,618 / (50% x 8,715 tons) = 2,428 $/ton.

Clean Fuels Cost Evaluation

As mentioned above, Boiler No. 7 combusts eastern low fusion coal and petroleum coke. The only fuel limited by the air permit is the amount of petroleum coke to approximately 24% by weight of total fuel. Table B-33 presents the range of heat value, ash and sulfur content of the various fuels.

Determining marginal costs of fuel with different sulfur concentrations is reasonably certain for a short "future". As the period for a fuel forecast is extended, uncertainty rapidly increases. Therefore, the unit cost is presented as a range where estimated. Subsequent calculations use the average of the high and low end of the range.

Table B-33 Unit Costs for Various Fuels Fired in Boiler No. 7, Green Bay Broadway Mill

Fuel	Sulfur %	MMBtu/ton	$/MMBtu 2009-2013
Petroleum Coke	5 to 6.5	27.6-28.4	1.71
Eastern Low-fusion Coal	2.5-2.7	25.4-27.0	3.35

The cost evaluation determined the costs of substituting all petroleum coke with eastern low-fusion coal.

Table B-34 presents a summary of the sulfur dioxide emission estimates for this case.

Table B-34. Clean Fuel Emission Calculations, Boiler No. 7, Green Bay Broadway Mill

	Low Fusion	Petroleum Coke	Total
2002-2004 MMBtu Estimate (annual)	3402280	871980	4274259
2002-2004 Tons (annual)	129858	30812	160670
Sulfur into the Boiler (tpy)	3091	1722	4813
Percent of Emissions	64%	36%	
SO_2 Emission Estimate (tpy)	5596	3119	8715
Fuel Cost (MM$)	11.4	1.5	12.9
Case 1 : Switch Petroleum Coke to Eastern Low Fusion			
MMBtu	4274259	--	4274259
Tons Fuel	163140	--	163140
Sulfur into the Boiler (tpy)	3883	--	
SO_2 Emission Estimate (tpy)	7765	--	7765
Fuel Cost (MM$)	14.3	--	14.3

Table B-35 summarizes the annual marginal fuel costs and emissions reductions relative to 2002-2004 actual emissions for these cases.

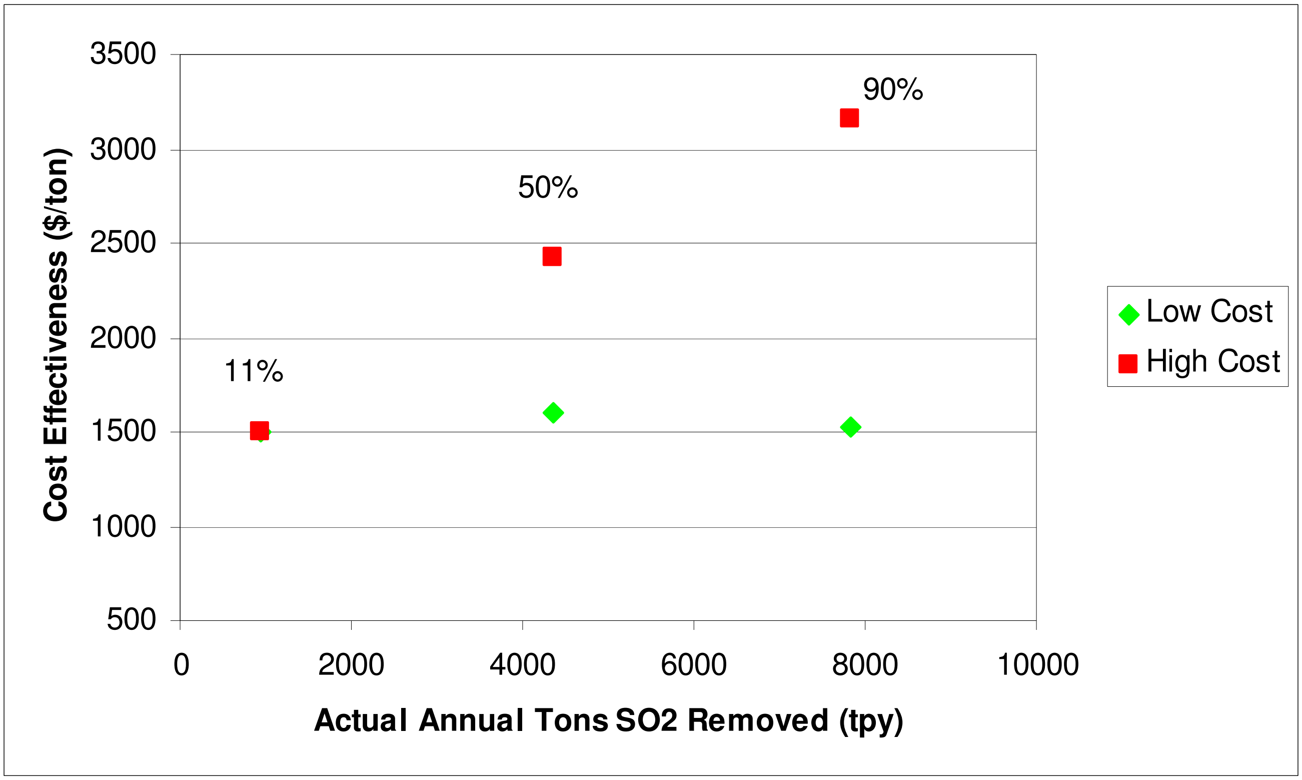
Table B-35. Summary of Fuel Cost Increases for Various Fuel Switch Cases, Green Bay Broadway Mill

Case	2002-2004	1
Average $/MMBtu	$3.02	$3.35
SO2 Emissions	8,715	7765
Emission Change (tpy)	NA	950
% Reduction		11%
Fuel Cost ($/yr)	$12,888,722	$14,318,768
Fuel Cost Increase ($/yr)	NA	$1,430,047
Cost Effectiveness Fuel Price Only ($/ton)	NA	1,506

Summary of Economic Evaluation, SO_2 Controls for Power Boiler No. 7

The economic evaluation determined a range of cost effectiveness values for the following levels of control: Less than 50%, 50%, and 90%. Figure B-9 presents a marginal cost curve for all the cost estimates presented in Table B-25 through B-35.

Figure B-9. Marginal Cost Curve for SO_2 Control Options, Green Bay Broadway Mill Boiler No.7



Note: Annual Actual tons removed shown is relative to 2002-2004 actual emissions
Control options: 11% removal by Clean Fuels; 50% removal by FSI or In Dusct Sorbent Injectionremoval by gas absorption (scrubber)

Energy and Environmental Impacts

Throughout the economic analysis, the cost estimates documented, where possible, the actual costs for additional energy consumption, additional water demand, and addition solid waste generated. Also in each technology discussion, the analysis discussed environmental impacts. Table B-36 summarizes a comparison of energy and environmental impacts for each option.

Table B-36. Summary of Additional Impacts for SO_2 Control Technologies, Boiler No. 7

	Technology		
Impacts	Scrubber	FSI/ Induct Injection	Clean Fuels
Additional Energy (kWhr/yr)	11,963,492	3,801,797	None
Additional Water (million gal)	4,519	None	None
Additional Solid Waste (tons)	100,377	44,300	None
Environmental Impacts	Treatment of metals in waste stream	Higher PM_{10} Loading to Baghouse	Higher PM_{10} Loading to Baghouse
Other Impacts	Wet Plume	Additional CO_2 from Trona decomposition; FSI may reduce NOx	Less CO_2 emissions

3.5 NITROGEN OXIDES

Step 1a-Identification of Control Technologies-Typical Technologies in Use in the United States

The technologies typically available for multi-fuel cyclone boilers are equivalent to the technologies presented in Section 2.5 for Boiler No. 6. These technologies are:

- Low Nitrogen Fuel
- Selective Catalytic Reduction
- Selective Non-Catalytic Reduction
- Air Staging of Combustion
- Flue Gas Recirculation
- Low-NOx Burners

Step 1b-Identification of Control Technologies-Review of RACT/BACT/LAER Clearinghouse (RBLC)

Searches of the RBLC were conducted to identify control technologies for the control of emissions from cyclone power boilers. The specific category searched was External Combustion- 11. Table B-37 summarizes recent retrofit technologies determinations.

Table B-37. Summary of RBLC and Recent NO_x Emission Limits for Various Coal Boilers

Source	Technology	NO_x Emissions (lb/MMBtu)
Utility Boilers	SCR/SCR+LNB	0.07 - 0.09
Utility Boilers	LNB+SNCR	0.1
Utility Boilers	SNCR	0.08 - 0.15
Industrial Boilers		
Circulating Fluid Bed	SNCR	0.08
Stoker/Other	None	0.246 - 0.7
Recent Permits with Add On Technologies		
Temple Inland -Rome, GA	LNB	0.5
Smurfit-Stone (Maritime) Jacksonville, FL	SNCR	0.5

Step 1c-Identification of Control Technologies-Review of Technologies in Use at Georgia-Pacific Corporation Facilities

For several coal boilers at various facilities, GP uses a variety of NO_x reduction measures, including overfire air, FGR, and combustion controls. GP uses ammonia injection for NO_x control for one combination fuel fluidized bed boiler and one deinked wastewater sludge-fired boiler.

Step 2-Technical Feasibility Analysis-Eliminate Technically Infeasible Options

All of the options identified above are technically feasible except for low-Nitrogen fuel substitution and the use of low NO_x burners.

Step 3 – Ranking the Technically Feasible Alternatives to Establish a Control Hierarchy

The ranking for NO_x control is:

1. Tail-end SCR at 80% removal efficiency
2. SNCR with OFA at 70% removal efficiency
3. ROFA and Rotamix at 66% removal efficiency
4. OFA at 60% removal efficiency
5. SNCR alone at 35% removal efficiency

Step 4- Effectiveness Evaluation

Economic Effectiveness

For each cost estimate, the Green Bay Broadway Mill provided several general assumptions to equipment vendors and engineering contractors to determine site-specific cost estimates with a target accuracy of +/- 30% or better.

SCR Cost Evaluation

The NO_x removal technology with the highest removal efficiency studied is SCR. SCR technology is a post-process NO_x control option used to remove NO_x after the combustion process rather than limit NO_x development at the source. In this case, a reactor filled with an application-specific catalyst is placed in the boiler outlet flue gas stream. The catalyst in these reactions is only effective in a narrow elevated temperature range. In this case, the flue gas needs to be between 600ºF and 650ºF in order to maximize the effectiveness of the catalyst without causing thermal damage. Two (2) SCR reactor installation locations that allow for the appropriate flue gas temperature were evaluated. The first option would be to modify the boiler's flue gas outlet path to accommodate placement of the SCR reactor prior to the boiler's existing air preheater. The second available reactor installation location is downstream of the existing baghouse.

Locating the SCR reactor between the boiler flue gas outlet and the existing air preheater provides the necessary flue gas temperatures; however, it also presents several key obstacles. These obstacles include high flue gas velocities, reduced residence time for the flue gas to pass through the catalyst bed, damage to the catalyst, and blinding of catalyst pores due to high particulate loading. Because of these factors as well as constructability issues, the Slip Stream SCR was estimated as a tail-end unit. Figure B-6 presents a general arrangement.

The estimate for Boiler No. 7 follows a similar methodology as Boiler No. 6 with a re-design of equipment due to size of the boiler and its level of emissions. Stack 10 will continue to serve one chamber of the Standard Havens baghouse. Table B-38 presents the capital cost estimate for a tail-end SCR for Boiler No. 7.

Table B-38. Summary of Capital Cost for Installation of SCR Slip-Stream System, Boiler No. 7 Green Bay Broadway Mill

Description		2009 Costs ($)
Direct Costs		
	Major Equipment	9,158,122
	Demolition	20,773
	Site Improvements	686,859
	Piling, Caissons	961,603
	Buildings	36,000
	Concrete	1,249,240
	Structural Steel	2,518,690
	Piping	2,548,351
	Insulation - Pipe, Equipment & Ductwork	2,447,224
	Instrumentation	1,030,289
	Electrical	1,076,904
	Painting, Protective Coatings	137,372
Construction Indirect Costs		
	Construction Support Labor	1,044,553
	Premium Time	311,917
	Craft Per Diem ($7/Hour On 100 % Of Time)	638,654
	Non-Payroll Tax, Insurance & Permits	864,094
	Craft Start-Up Assistance	43,650
	Contractor's Construction Fee	2,029,476
Project Indirect Costs		
	Construction Management	1,949,000
	Engineering Professional Services	6,500,000
	Study Cost	50,000
	Outside Consultant Services	100,000
	Owner's Cost	1,225,000
	Spare Parts	319,000
	Non-Craft Start-Up Assistance	119,150
	Allowance For Unforeseen	3,701,594
	Escalation	2,422,800
	Air Infiltration Allowance	100,000
Total Installed Cost (+/- 30%) (TIC)		**43,290,315**

Table B-39 presents the annual operating costs for the SCR system.

Table B-39. Annual Operating Cost Calculations, SCR for Boiler No. 7, Actual 2002-2004 Conditions

Parameter	Methodology	Annual Cost ($)
Direct Costs		
Operating labor :	2 hours per shift x 1,025 shifts/yr @ $40/hr	82,000
Supervisor Labor	15% of Operator	12,300
Maintenance labor:	0.5 hours per day x 365 days/yr @ $40/hr	7,300
Maintenance material	100% of Maintenance Labor	7,300
Electricity	0.059$/kWhr x 6737068 kWhr	397,487
Ammonia consumption	$160/ton aq NH_3x 33899 tons aq NH_3 /yr	5,423,840
Natural Gas	$10/MMBtu x 822,326 MMBtu/yr	8,223,260
Catalyst	$936,224/ 3 years	312,075
Indirect Costs		
Overhead rate (fractional):	60% of total labor and material costs	65,340
Taxes, insurance, admin. factor:	4% of TIC (Table B-38)	1,731,613
Capital recovery factor (system):	0.094 x TIC (Table B-38)	4,086,299
Total Annual Cost		20,348,814

Determining annual operating costs is sensitive to the amount of NO_x removed and ammonia required.

The cost effectiveness of this technology is equal to the Total Annualized Costs/ Annual Quantity of NOx Removed.

The estimated cost effectiveness is: $20,348,814/ (80% x 2,740 tons) = 9,283 $/ton.

ROFA and Rotamix Cost Evaluation

Section 3.4 presented the application of Mobotec's ROFA and Rotamix costs within its FSI technology. The total installed cost for targeting NO_x contol only is estimated to be approximately $1.9MM lower by removing the limestone injection, handling, and storage equipment specifically needed for SO_2 removal. Thus, the expected total installed cost is $27,000,000. Table B-40 presents the annual operating costs without the limestone use or landfilling charges.

Table B-40. Annual Operating Cost Calculations, ROFA/ROTAMIX for Boiler No. 7, Actual 2002-2004 Conditions

Parameter	Methodology	Annual Cost ($)
Direct Costs		
Operating labor :	1 hours per shift x 1,025 shifts/yr @ $40/hr	41,000
Supervisor Labor	15% of Operator	6,150
Maintenance labor:	0.5 hours per day x 365 days/yr @ $40/hr	7,300
Maintenance material	100% of Maintenance Labor	7,300
Electricity- direct	0.059$/kWhr x 3801797 kWhr	224,306
Indirect Costs		
Overhead rate (fractional):	60% of total labor and material costs	37,050
Taxes, insurance, admin. factor:	4% of TIC	1,080,000
Capital recovery factor (system):	0.094 x TIC ($27MM)	2,548,609
Total Annual Cost		3,951,715

Determining annual operating costs is only sensitive to the number of hours the air mixing system is operated.

The cost effectiveness of this technology is equal to the Total Annualized Costs/ Annual Quantity of NOx Removed.

The estimated cost effectiveness is: $3,951,715/ (66% x 2,740 tons) = 2,185 $/ton.

SNCR Cost Evaluation

SNCR systems are most efficient in a single temperature window; therefore, in order to properly operate an SNCR system, a boiler study is required to map the gas temperatures at several locations during varying boiler operating points. A detailed SNCR study was not conducted for Power Boiler No. 7; however, the SNCR supplier requires such a study and the SNCR estimate includes a one-time cost of $50,000 to accomplish this task.

The estimate for Boiler No. 7 follows a similar methodology as Boiler No. 6 with a re-design of equipment due to size of the boiler and its level of emissions. The vendor has indicated that an SNCR system on a cyclone boiler can achieve 35% reduction. Table B-41 presents the total installed cost estimate for an SNCR system alone.

Table B-41. Summary of Capital Cost for Installation of SNCR System, Boiler No. 7 Green Bay Broadway Mill

Description	TOTAL COST (2007$)
Direct Costs	
Major Equipment	1,704,630
Demolition	38,354
Site Improvements	85,232
Piling, Caissons	119,324
Buildings	270,000
Concrete	76,708
Structural Steel	306,833
Piping	289,787
Insulation - Pipe, Equipment & Ductwork	153,417
Instrumentation	42,616
Electrical	232,092
Painting, Protective Coatings	17,046
Construction Indirect Costs	
Construction Support Labor	140,891
Premium Time	41,289
Craft Per Diem	89,328
Non-Payroll Tax, Insurance & Permits	124,932
Craft Start-Up Assistance	45,000
Contractor's Construction Fee	245,577
Project Indirect Costs	
Construction Management	295,000
Engineering Professional Services	652,000
Outside Consultant Services	100,000
Owner's Cost	197,000
Spare Parts	74,279
Non-Craft Start-Up Assistance	119,150
Allowance For Unforeseen	546,048
Escalation	386,091
Air Infiltration Allowance	100,000
Total Installed Cost (+/- 30%) (TIC)	6,492,624

Table B-42 presents the annual operating costs for the SNCR system.

Table B-42. Annual Operating Cost Calculations, SNCR for Boiler No. 7, Actual 2002-2004 Conditions

Parameter	Methodology	Annual Cost ($)
Direct Costs		
Operating labor :	1 hours per shift x 1,025 shifts/yr @ $40/hr	41,000
Supervisor Labor	15% of Operator	6,150
Maintenance labor:	0.5 hours per day x 350 days/yr @ $40/hr	7,000
Maintenance material	100% of Maintenance Labor	7,000
Electricity	0.059$/kWhr x 821763 kWhr	48,484
Urea Consumption	$1.35/gal x 34.4 gph x 8400 hr/yr	390,096
Mill Water	$0.06/kgal x 7,884 kgal/yr	473
Indirect Costs		
Overhead rate (fractional):	60% of total labor and material costs	36,690
Taxes, insurance, admin. factor:	4% of TIC (Table B-41)	259,705
Capital recovery factor (system):	0.094 x TIC (Table B-41)	610,307
Total Annual Cost		1,406,905

Determining annual operating costs is sensitive to the amount of NOx removed and urea required.

The cost effectiveness of this technology is equal to the Total Annualized Costs/ Annual Quantity of NOx Removed.

The estimated cost effectiveness is: $1,406,905/ (35% x 2740 tons) = 1,467 $/ton.

OFA Cost Evaluation

An additional NOx control case that was studied and estimated for Power Boiler No. 7 was Overfire Air. The installation of OFA reduces the formation of NO_x by staging combustion into two zones. The first combustion stage created by this process control system redistributes some of the combustion air away from the cyclone burners allowing the burners to operate fuel rich. The subsequent fuel rich zone prevents the formation of thermal NO_x by providing a low oxygen concentration in the cyclone burner. Thermal NO_x is caused by the reaction of nitrogen and oxygen in areas of high flame temperatures. In the fuel-rich stage, the formation of NO_x is low but the formation of CO and combustibles is high. The second stage of the OFA system allows for the completion of combustion by adding combustion air to the furnace downstream of the cyclone burners. The second stage combustion in the furnace occurs at a lower temperature with subsequent reduction in formation of thermal and fuel bound NO_x. Fuel bound NO_x is the result of the oxidation of fuel bound nitrogen.

The new OFA system would include ductwork from the existing high pressure forced draft (FD) fans' outlet to each port location; expansion joints, dampers and operators, annubars for delta-P measurement to major port locations, as well as boiler tube bends and injection wall boxes. Due to the cyclone boiler's high pressure FD Fans, no booster OFA fan would be required for the system. Combustion air port design would be dependent on the supplier. Several different designs are available in the market place to ensure that the appropriate amount of air and air penetration could be achieved during boiler swings. Money is included in the BART estimate for the supplier to perform a study to determine the appropriate location for the OFA ports. Money is included in the BART estimate for minor relocation and demolition to allow for the OFA system ductwork installation.

Table B-43 presents the total installed cost estimate for an OFA system alone.

Table B-43. Summary of Capital Cost for Installation of OFA System, Boiler No. 7 Green Bay Broadway Mill

Description		TOTAL COST (2007$)
Direct Costs		
	Major Equipment	992,465
	Demolition	38,749
	Site Improvements	49,623
	Buildings	270,000
	Concrete	29,774
	Structural Steel	148,870
	Insulation - Pipe, Equipment & Ductwork	45,021
	Instrumentation	24,812
	Electrical	99,168
	Painting, Protective Coatings	9,925
Construction Indirect Costs		
	Construction Support Labor	86,960
	Premium Time	25,969
	Craft Per Diem	55,135
	Non-Payroll Tax, Insurance & Permits	56,507
	Craft Start-Up Assistance	45,000
	Contractor's Construction Fee	143,014
Project Indirect Costs		
	Construction Management	162,000
	Engineering Professional Services	358,000
	Study Cost	50,000
	Outside Consultant Services	100,000
	Owner's Cost	108,000
	Spare Parts	32,742
	Non-Craft Start-Up Assistance	59,575
	Allowance For Unforeseen	294,131
	Escalation	190,808
	Air Infiltration Allowance	100,000
Total Installed Cost (+/- 30%) (TIC)		3,576,246

Table B-44 presents the annual operating costs for the OFA system.

Table B-44. Annual Operating Cost Calculations, OFA for Boiler No. 7, Actual 2002-2004 Conditions

Parameter	Methodology	Annual Cost ($)
Direct Costs		
Operating labor :	1 hours per day x 350 days/yr @ $40/hr	14,000
Supervisor Labor	15% of Operator	2,100
Maintenance labor:	0.5 hours per day x 350 days/yr @ $40/hr	7,000
Maintenance material	100% of Maintenance Labor	7,000
Electricity	0.059$/kWhr x 890,491 kWhr	52,539
Indirect Costs		
Overhead rate (fractional):	60% of total labor and material costs	18,060
Taxes, insurance, admin. factor:	4% of TIC (Table B-43)	143,050
Capital recovery factor (system):	0.094 x TIC (Table B-43)	336,167
Total Annual Cost		579,916

Determining annual operating costs for OFA is sensitive only to the number of hours the fan is used. The operating costs reflect a typical annual operation of 8,400 hours/year (350 days/yr).

The cost effectiveness of this technology is equal to the Total Annualized Costs/ Annual Quantity of NOx Removed.

The estimated cost effectiveness is: $579,916/ (60% x 2,740 tons) = 353 $/ton.

SNCR with OFA Cost Evaluation

In an attempt to design a more successful combustion modification technology with urea injection, the Mill developed a cost estimate for the combination of both OFA and SNCR. Table B-45 tabulates the cost estimate for this combination of technologies.

Table B-45. Summary of Capital Cost for Installation of OFA/SNCR System, Boiler No. 7 Green Bay Broadway Mill

Description	TOTAL COST
OFA System (Table B-43)	3,576,246
SNCR System (Table B-41)	6,492,624
Total Installed Cost (+/- 30%) (TIC)	**10,068,870**

Table B-46 presents the operating costs for a combination of OFA and SNCR.

Table B-46. Annual Operating Cost Calculations, OFA+SNCR for Boiler No. 7, Actual 2002-2004 Conditions

Parameter	Annual Cost ($)		
Direct Costs	OFA	SNCR	Total
Operating labor :	14,000	41,000	
Supervisor Labor	2,100	6,150	
Maintenance labor:	7,000	7,000	
Maintenance material	7,000	7,000	
Electricity	52,539	48,484	
Urea and Water	0	390,569	
Indirect Costs			
Overhead rate (fractional):	18,060	36,690	
Taxes, insurance, admin. factor:	143,050	259,705	
Capital recovery factor (system):	336,167	610,307	
Total Annual Cost	579,916	1,406,905	1,986,821

Determining annual operating costs for the combination is sensitive to the number of hours the fan is used as well as the urea consumption requirement.

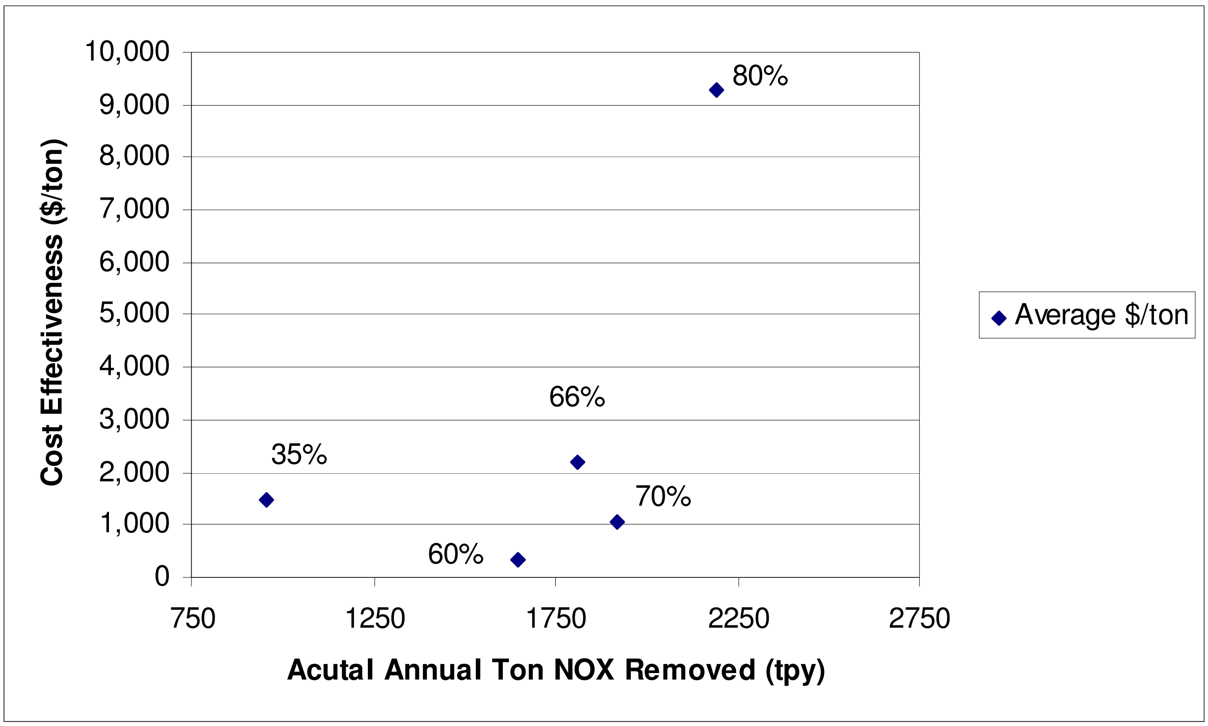
The cost effectiveness of this technology is equal to the Total Annualized Costs/ Annual Quantity of NOx Removed.

The estimated cost effectiveness is: $1,986,821/ (70% x 2,740 tons) = 1,036 $/ton.

Summary of Economic Evaluation, NOx Controls for Power Boiler No. 7

The economic evaluation determined a range of cost effectiveness values for the following levels of control: 35%, 60%, 66%, 70%, and 80%. Figure B-10 presents a marginal cost curve for all the cost estimates presented in above.

Figure B-10 Marginal Cost Curve for NOx Control Options, Green Bay Broadway Mill Boiler No. 7



Note: Annual Actual tons removed shown is relative to 2002-2004 actual emissions
Control options: 35% by SNCR; 60% by OFA; 66% by ROFA/ROTAMIX; 70% by SNCR and OFA; 80% by SCR

Energy and Environmental Impacts

Throughout the economic analysis, the cost estimates documented, where possible, the actual costs for additional energy consumption, additional water demand, and addition solid waste generated. Also in each technology discussion, the analysis discussed environmental impacts. Table B-47 summarizes a comparison of energy and environmental impacts for each option.

Table B-47. Summary of Additional Impacts for NOx Control Technologies, Boiler No. 7

	Technology		
Impacts	SNCR Options	Combustion Modifications	SCR
Additional Energy (kWhr/yr)	82,1763	1,712,254	6,737,068
Additional Water (million gal/yr)	7.884	0	0
Additional Natural Gas (MMcf/yr)	0	0	822
Environmental Impacts	NH_3 Emissions	None	NH_3 Emissions
Other Impacts	NH_3 Handling	None	NH_3 Handling

3.6 ADDITIONAL MULTI-POLLUTANT CONTROL OPTION FOR BOILER NO. 7

As mentioned above, Boiler No. 7 provides significant energy to the Mill. The steam that Boiler No. 7 produces can be viewed as being directly used for electricity generation through condensing this steam in the mill's steam turbine condensers. Boiler No. 7 has the capacity to produce 550,000 lbs steam per hour and, by passing this steam through the mill's turbines to its condensers, can yield an output of approximately 55 megawatts (MW) for use in the plant. An additional multi-pollutant option for Boiler No. 7 is to replace the electrical generation with purchased electricity while reserving its steam production capacity for intermittent operation (*i.e.,* scheduled downtime of other steam-producing units at the Mill). Increasing the use of purchased electricity will require a one-time upgrade to electrical infrastructure. The Electrical Infrastructure Upgrade option is technically feasible. The cost evaluation is provided for comparison purposes. This option is not a conventional control technology as it drastically reduces the ability for the source to operate as it does presently.

Cost Evaluation

Through its current arrangement with Wisconsin Public Service Corporation (WPS), (the mill's utility service provider), two potential electrical infrastructure upgrades could be considered for the mill. One upgrade would involve the installation of a new transmission level (138 Kilovolt) connection to the utility with the substation being located on the mill property. The other upgrade would involve the installation of one or two additional primary voltage level (13.8 Kilovolt) connections to the mill property from existing or new WPS substations. Both solutions have distinct advantages and disadvantages which need to be further evaluated before a solution is chosen. The estimated total installed cost for either one of these solutions is $5 million.

The annual operating cost of the Electrical Infrastructure Upgrade is limited to the marginal cost of purchased electricity and indirect costs. Direct operating costs associated with the electrical equipment is shared with WPS.

The average steam production across the 2002-2004 baseline period was 3,441,735 klbs/steam per year. Assuming all of the steam from Boiler No. 7 was used to generate electricity through condensing in the mill's turbine generators, the mill would convert this amount of steam into approximately 344,173 MW for an annual period, and 39.29MW/hr (annual average). The incremental unit cost of purchased electricity from WPS above the cost for Boiler No. 7 to produce the power is $25/MW-hr for on-peak hours. The incremental cost of purchased electricity from WPS is approximately equal to the Boiler No. 7 generation cost during off-peak hours. The annual average incremental unit cost is:

$25/MW-hr x 3900 on-peak hr/yr + $0.00/MW-hr x 4860 off peak hr/yr / (8,760 hours/yr) =
= $11.13/MW-hr (annual average)

The electrical infrastructure upgrade option would require the mill to operate Boiler No. 7 as a steam source when another boiler is down. Based on the number of boilers at the mill, their steam usage and scheduled outage durations, the mill estimates that Boiler No. 7 would operate up to 60 days or 16.4% of the year. This would result in an 83.6% emissions reduction for all pollutants on a pollutant-by-pollutant basis, including those not subject to BART.

The direct annual operating cost associated with electrical energy charges is estimated to be:
39.29 MW-hr/hr x (83.6%) x 8760 hr/yr x $11.13/MW-hr = $3,202,488/yr ($2009).

In addition to the electrical energy charges detailed above, the mill would also incur electrical demand-related charges. Electrical demand charges from WPS are billed monthly and consist of an annual demand-related charge and a monthly demand-related charge. The annual (customer) demand charge would be largely unchanged. However, monthly (system) demand charges would be affected for approximately 10 months of the year.

Based on a 4 MW firm demand nomination, the additional demand-related costs resulting from reducing the operation of Boiler No. 7 to 60 days per year are:
[39.29 MW – 4 MW] x 10-months x $3,139/MW = $1,107,753/yr ($2009)

The estimated indirect annual cost is the capital recovery for the installed equipment. For this option, the analysis used a capital recovery factor of 7% interest over 20 years. As described above, the capital recovery factor is 0.0944. Thus the indirect annual cost for capital recovery is:
0.0944 x $5,000,000 = $472,000/yr.

The total annual cost is $3,202,488/yr + $1,107,753 + $472,000 = $4,782,241/yr. ($2009)

In addition to the limited operating schedule, the option will include the exclusive use of low fusion eastern coal. As presented above, the reduction in actual emissions from this fuel switch is approximately 11%. When combined with the 83.6% reduction, the total annual average reduction is:
83.6% + (1-83.6%) x 11% = 85% for SO_2.

The cost effectiveness is equal to the Annual Cost per Ton removed. Though this is a multi-pollutant option, the analysis calculated cost effectiveness for each pollutant individually for direct comparison to other technologies.

The cost effectiveness for SO_2 is: $4,782,241/ (85% x 8,715 tons SO_2) = $646
The cost effectiveness for NO_x is: $4,782,241/ (83.6% x 2,740 tons NO_x) = $2,088

The actual cost effectiveness is lower than these calculated values as the total annual cost is only spent once and achieves the reduction of both pollutants simultaneously.

4.0 BART ENGINEERING ANALYSIS SUMMARY

Table B-48 presents the summary of the technically feasible options for the BART eligible emission units.

Table B-48. Summary of BART Engineering Analysis Green Bay Broadway Mill

Emission Unit	Pollutant	Technology	Maximum Reduction (%)	Annual Operating Cost ($)	Effectiveness ($/ton)
Boiler No. 6	SO_2	Wet Scrubber	90	10,057,563	5,174*
Boiler No. 6	SO_2	Semi Dry Scrubber	90	6,004,723	3,089*
Boiler No. 6	SO_2	Clean Fuels	62	$1,631,891	1,082
Boiler No. 6	SO_2	Furnace Sorbent Injection	50	4,502,391	4,169
Boiler No. 6	SO_2	In Duct Sorbent Injection	50	4,317,733	3,998
Boiler No. 6	NOx	SCR	80	9,871,725	28,831*
Boiler No. 6	NOx	ROFA - ROTAMIX	66	3,660,476	12,958*
Boiler No. 6	NOx	SNCR+ OFA +FGR	56	2,077,302	8,667*
Boiler No. 6	NOx	SNCR	25	1,061,490	9,920*
Boiler No. 6	NOx	OFA/FGR	20	619,998	7,243*
Boiler No. 7	SO_2	Wet Scrubber	90	24,818,896	3,164*
Boiler No. 7	SO_2	Semi Dry Scrubber	90	11,971,942	1,526*
Boiler No. 7	SO_2	Electrical Upgrades + Fuel Switch	85	4,782,241	646
Boiler No. 7	SO_2	Furnace Sorbent Injection	50	6,953,964	2,429
Boiler No. 7	SO_2	In Duct Sorbent Injection	50	10,582,618	1,596
Boiler No. 7	SO_2	Clean Fuels	11	1,430,047	1,506
Boiler No. 7	NOx	Electrical Upgrades + Fuel Switch	83.6	4,782,241	2,088
Boiler No. 7	NOx	SCR	80	20,348,814	9,283*
Boiler No. 7	NOx	SNCR+ OFA	70	1,986,821	1,036
Boiler No. 7	NOx	ROFA - ROTAMIX	66	3,951,715	2,185
Boiler No. 7	NOx	OFA	60	579,916	353
Boiler No. 7	NOx	SNCR	35	1,406,905	1,467

* Technologies which are not economically feasible due to marginal or incremental cost effectiveness.

Appendix A:
Basis of Estimated Costs

GENERAL

The purpose of these cost estimates is to provide Georgia Pacific with a Feasibility Study Level Report in 2007 dollars with an accuracy range of ± 30 % for the Regional Haze/ Boiler BART Program at the Greenbay, Wisconsin Mill.

Estimates were prepared by Jacobs for various SO_2 and NO_X control technologies for the boilers which where put in place or under construction between August 7, 1962 and August 7, 1977. These cost estimates were prepared in such a manner to ensure that each boiler proposed control technology and related cost estimate would stand alone on its own merit. This approach was selected to better address the uncertainty that will exist between which project or combination of projects might ultimately be implemented to meet the emissions targets established for the EPA Regional Haze / Boiler BART 2013 compliance date. Certain site specific conditions and / or the presence of alternate control technologies in the future may ultimately impact the overall project costs and feasibility of these projects if several of these projects are implemented concurrently on any given site.

In addition, the numbers used in this estimate for equipment cost do not always reflect the exact dollar amount that was provided by a vendor and reported in Appendix D. In many cases, Jacobs has used their sound engineering judgment and previous experience to change these prices. These changes may be for many reasons including but not limited to: adding or removing installation costs, adjusting for construction with a more expensive material, adding or removing options, increasing the controls included, etc.

In order to allow for air in-leakage in the existing Boilers, $100,000 has been added to each estimate to locate and repair any areas where excessive air infiltration may be occurring. This is required to ensure that any control technologies installed operate as they were designed.

GP plans to utilize the results from this feasibility study report and cost estimate(s) to support the Regional Haze / Boiler BART documentation submittal requirements to the individual States. This will establish the viability for installing the Boiler BART Control Technologies on these respective site boilers or whether to de-rate or decommission them to a capacity level below BART-eligibility.

At the time of issue, this estimate reflects the fair market value for construction costs, based upon 2007 dollars, in the Greenbay, Wisconsin area.

ESTIMATE APPROACH

The estimate is based on Jacobs providing Engineering, Construction Management and Procurement Services.

For the basis of the cost estimate, detailed engineering, procurement and construction activities are assumed be completed by December 31, 2007.

WAGE RATES

The wage rates used in this estimate are composite, union all-in rates. The base journeyman rate ranges from $25.53 to $29.11. Jacobs established a crew mix for each craft, ranging from 97.98 % to 99.89 % of the base journeyman rate - see the All-In Wage Rate Sheet in the Estimate Detail Printout. Included in the wage rates are the following:

- **81 - PAYROLL TAXES AND INSURANCE**

  Payroll Taxes and Insurance are included at 33.6 % of bare craft labor.

- **79 - CRAFT FRINGE BENEFITS**

  Craft Fringe Benefits are included and range from 37.95 % to 62.01 % of bare craft labor.

- **76 - TEMPORARY CONSTRUCTION FACILITIES**

  Temporary Construction Facilities include Contractor's office supplies, PC's, copiers, postage, phones, Fed Ex, temporary sanitary facilities, mobilization, trash removal and temporary lights. These items are calculated at 7.5% of bare craft labor.

- **83 & 84 - SMALL TOOLS AND CONSUMABLES**

  Small tools are included in the estimate at 7.5 % of bare craft labor. Construction consumables are included in the estimate at 7.5 % of bare craft labor.

- **87 - CONTRACTORS FIELD STAFF**

  Field staff includes all contractors' field support staff except for craft foremen which are included in the crew mix calculations. Contractors Field Staff is calculated at 25 % to 35 % of bare craft labor based on the type of work being performed.

- **85 - CONSTRUCTION EQUIPMENT RENTAL**

  Construction equipment rental includes the contractors' automotive equipment, general equipment and small cranes. This construction equipment cost is calculated at 25 % to 40 % of bare craft labor based on the discipline - concrete, steel, pipe, electrical, etc. - being supported - see the All-In Wage Rate Sheet in the Estimate Detail Printout for the percent used for each discipline. If required, a line item is listed in the estimate for situations that require large cranes not covered by the allowance carried in the rate.

- **93 – CONTRACTOR'S HOME OFFICE**

Contractor's Home Office cost includes time for Project Manager, accounting, safety, quality control, etc. is included in the Contractor's Fee.

- **99 - CONTRACTOR'S FEE**

  Contractor's fee is included in the estimate at 10 % of contractor's construction cost.

- **75 - CONTRUCTION SUPPORT LABOR**

  Construction Support Labor includes drug testing, safety training, fire watch, final cleanup, yard crews, etc. This cost is calculated as 20 % of bare craft labor.

DIRECT COSTS

50 - MAJOR EQUIPMENT

Vendor budget quotes were received for the Major Equipment.

Pump and motor installation hours are from Jacobs Standards. Other equipment installation cost items are based on historical experience.

Freight cost is included at 6 % of equipment cost.

51 – DEMOLITION AND RELOCATION

Demolition cost is factored from installed process equipment cost but have been adjusted, as required, to reflect specific site requirements.

53 - SITE IMPROVEMENTS

Site Improvement costs are factored from installed process equipment cost but have been adjusted, as required, to reflect specific site requirements.

54 – PILING

Piling costs are factored from installed process equipment cost but have been adjusted, as required, to reflect specific site requirements.

56 – CONCRETE

Concrete costs are factored from installed process equipment cost but have been adjusted, as required, to reflect specific site requirements.

58 – STRUCTURAL STEEL

Structural Steel costs are factored from installed process equipment cost but have been adjusted, as required, to reflect specific site requirements.

62 – PIPING

Piping costs are factored from installed process equipment cost but have been adjusted, as required, to reflect specific site requirements.

63 – INSULATION

Insulation costs are factored from installed process equipment cost but have been adjusted, as required, to reflect specific site requirements.

64 – INSTRUMENTATION

Instrumentation costs are factored from installed process equipment cost but have been adjusted, as required, to reflect specific site requirements.

65 – ELECTRICAL

Electrical Costs are factored from installed process equipment cost but have been adjusted, as required, to reflect specific site requirements.

66 – PAINTING

Painting costs are factored from installed process equipment cost but have been adjusted, as required, to reflect specific site requirements.

INDIRECT COSTS

70 – SPARE PARTS

An allowance for Spare Parts of 5 % of the process equipment cost is included.

78 - PREMIUM TIME

Premium Time is included based on the assumption that 100 % of the craft labor hours will be worked on a 50-hour week.

XX - CRAFT PER DIEM

Craft Per Diem is included at $7.00 per craft hour for all workers.

81 - NON-PAYROLL TAXES, INSURANCE AND PERMITS

Sales Tax is included at 6.5 % on equipment, materials and 6.5 % on 50 % of subcontract costs.

88 - CONSTRUCTION MANAGEMENT

Construction Management is estimated at 4.5 % of Total Installed Cost.

90 – ENGINEERING PROFESSIONAL SERVICES

Detail Design Engineering is estimated at 10 % of Total Installed Cost.

91 – OWNER'S COST

Owner's Cost is included at approximately 3 % of Total Installed Cost.

96 – OUTSIDE CONSULTANT SERVICES

An allowance of $100,000 is carried in the estimates for Outside Consultant Services.

98 – CONTINGENCY

Contingency is included in the estimate at 10 % of labor, equipment, material and subcontract costs.

This Contingency is part of the estimated project cost and is to cover unusual weather conditions, productivity issues, increases in costs not covered by contractual provisions, delays in delivery of equipment or materials, etc. It does not cover cost of additional work or scope changes after the definition of the project has been frozen for the estimate.

98 – ESCALATION

Escalation is based on the assumption that all work will be completed by December 31, 2007. Escalation is included at 7 % on labor, 10 % on equipment, 10 % on all material except for concrete, steel, pipe, instrumentation and electrical material which is included at 15 % and 5 % on subcontract cost**.**

ITEMS NOT INCLUDED

The following is a list of items not included in this estimate:

Cost of Land
Cost of borrowing money
Cost of operating supplies
Property taxes
Hazardous materials handling or disposal
All Risk Insurance
Payment and Performance Bond
Permits, Fees and Licenses

ITEMS AFFECTING THE COST ESTIMATE

Items, which may change the estimated construction cost, include, but are not limited to:

Modifications to the scope of work included in this estimate
Above normal escalation in material costs due to market availability and demands
Special phasing requirements
Restrictive technical specifications
Volume discounts on National agreements
Sole source specifications of materials or products
Bids delayed beyond the projected schedule
Sales and Use Tax exemptions
Labor disputes or difficulties