NO. 4 POWER BOILER FOUR-FACTOR ANALYSIS REPORT

Prepared for:

TEMPLE-INLAND ROME LINERBOARD MILL

ROME, GEORGIA

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1.0 INTRODUCTION

The Temple-Inland Rome Linerboard Mill (Temple-Inland) received a letter dated March 21, 2007 from the Georgia EPD requesting that a four-factor analysis be completed on the No. 4 Power Boiler. MACTEC Engineering & Consulting Inc. (MACTEC) has completed the attached regional haze four-factor analysis. The regional haze rule establishes certain benchmarks whereby Class I areas will achieve natural visibility by 2064. The straight line reduction haze concentration from now to the goal of zero by 2064 is referred to as the "glide path." Federal rules require that EPD establish goals in terms of deciviews inside the Class I area that establish "reasonable progress" in achieving the overall goal. To that end, the EPD has issued letters to several industrial sources requesting an engineering study to evaluate the potential emission reduction projects to assist EPD in establishing these interim goals.

According to the Georgia EPD, the SO_2 emissions from the No. 4 Power Boiler located at the Temple-Inland mill in Rome, Georgia could convert to sulfates in the atmosphere that, in turn, could potentially contribute to more than 0.5% of the total visibility impairment at the Cohutta Wilderness Class I area. Therefore, the EPD requested an engineering analysis on this boiler to evaluate alternatives for reducing SO_2 emissions by considering four factors. The "fourth" factor, "remaining useful life of existing source", is considered first. If the remaining useful life of the unit extends beyond 2018, then the other factors must be considered. In Temple-Inland's case, the No.4 Power Boiler is expected to be needed well past 2018, so this study provides the analysis of the other three factors (1) cost, (2) time necessary for compliance, and (3) energy or other non air quality impacts. This study was completed using a "top-down" approach as follows:

Step 1: Identification of all control technologies;
Step 2: Elimination of technically infeasible options;
Step 3: Ranking of remaining control technologies by control effectiveness;
Step 4: Application of the first three statutory factors (cost of compliance, time necessary for compliance, energy and non air quality environmental impacts) to control technologies identified in Step 3 and documentation of the results; and
Step 5: Selection of the control technology.

2.0 NO. 4 POWER BOILER DESCRIPTION

2.1 PROCESS DESCRIPTION

The No. 4 Power Boiler produces both steam and power for use in the mill. The unit generates high pressure steam to drive steam turbines at the mill, which, in turn, generate electricity that is used to drive electrical equipment throughout the mill for the production of linerboard. The low pressure steam exiting the steam turbines is further used in the process (digesters, paper machine drying, etc.). The boiler is equipped with low NO_x burners that have a total heat input rating of 565 MMBtu/hr, and is capable of burning pulverized coal and fuel oil (No. 2 or low sulfur No. 5).

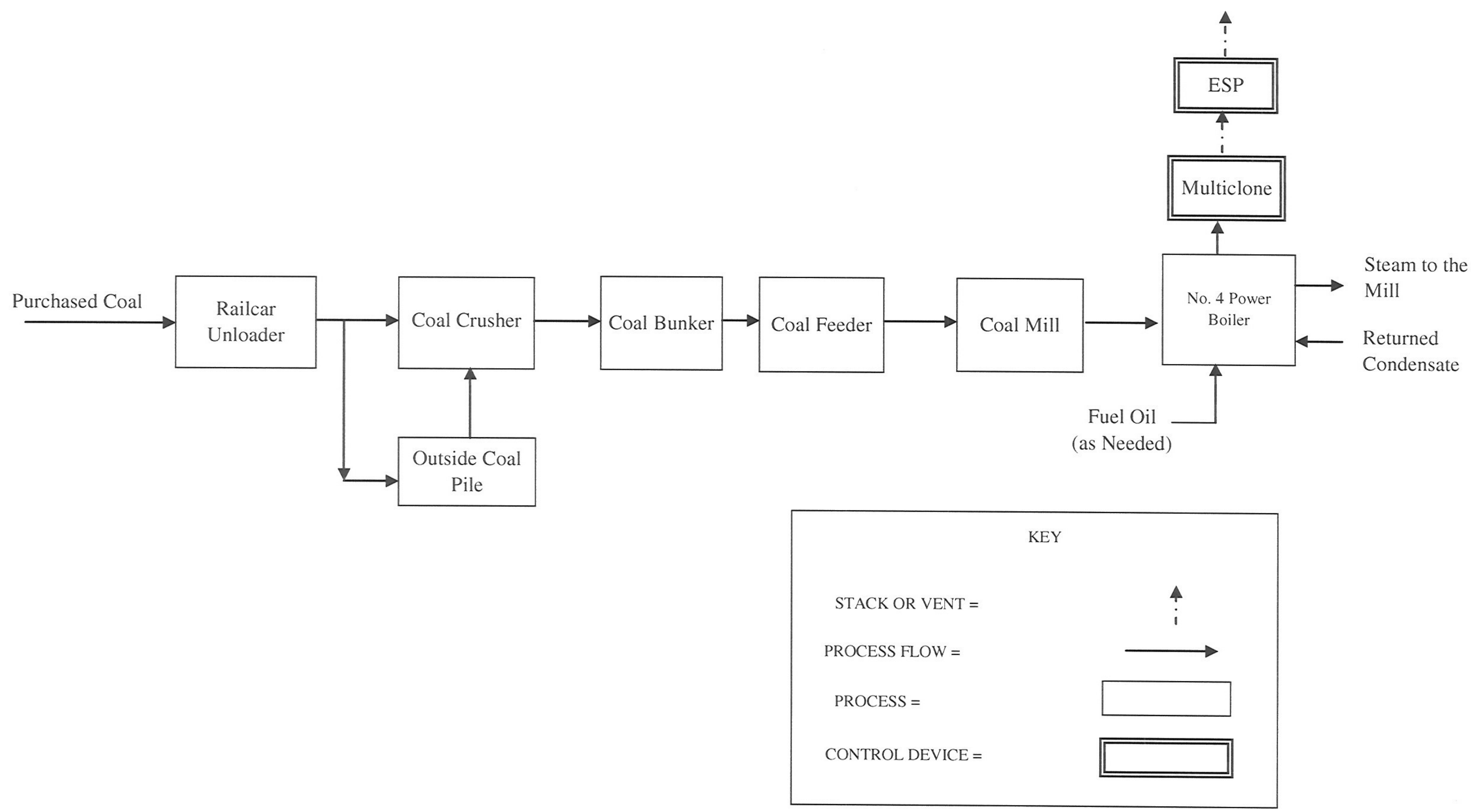
Particulate matter emissions from the boiler are controlled through a multiclone, which is integrated into the boiler, and a dry plate dual chamber electrostatic precipitator (ESP). The particulate laden gases are drawn into one of the two sides of the ESP and go through a perforated plate and diffusers to evenly distribute the exhaust gas. Inside the ESP, high voltage electrodes impart a negative charge to the particles entrained in the gas. These negatively charged particles are then attracted to collecting plates, which are positively charged. At periodic intervals, the plates are rapped causing the particles to fall into hoppers. Figure 1 shows the schematic flow chart of the existing No. 4 power boiler.

2.2 CURRENT PERMIT LIMITS

The No. 4 Power boiler has the following emission and production limitations in the mill's current Title V operating permit:

- Particulate (PM) emissions limited to 0.050 lb/MMBtu
- Carbon monoxide limited to 300 ppm (corrected to 3% oxygen),
- NO_x limited to 0.50 lb/MMBtu,
- VOCs limited to 0.010 lb/MMBtu,
- Fuel oil combustion is limited to 35,352,857 gallons of fuel per any twelve month consecutive period,
- The coal fired in the boiler is limited to 1.29 percent sulfur (by weight),
- The fuel oil is limited to 0.5 percent sulfur (by weight),
- SO_2 emissions are limited to 1,130 lb/hr and 3,837 tons/year.

Figure 1: No. 4 Power Boiler Process Flow Diagram



3.0 STEP 1: IDENTIFICATION OF ALL SO_2 CONTROL TECHNOLOGIES

Gaseous SO_2 emissions from coal and fuel oil combustion occur as the organic and pyretic sulfur contained in the fuels are oxidized during the combustion process. On average, about 95 percent of the sulfur present in bituminous coal will be emitted as gaseous SO_2. The more alkaline nature of the ash in some sub-bituminous coals causes some of the sulfur to react in the furnace to form various sulfate salts that are retained in the bottom ash or fly ash and removed with the control devices. Other than this natural control, there are several techniques used to reduce SO_2 emissions even further. The following outlines the most common techniques in use.

3.1 FUEL SWITCHING

The most direct way to reduce SO_2 emissions would be to switch to lower sulfur coals, since SO_2 emissions are proportional to the sulfur content of the coal (coal provides the bulk of the fuel burned in the No. 4 power boiler). Most of the lower sulfur coals are located in western states. Therefore, there are significantly greater costs associated with the shipping of the lower sulfur coal to the Rome mill site. Besides the additional shipping costs the inherent problem with fuel switching of this sort is that western coal has a much lower heating value than eastern coal. This means more coal will have to be processed, more coal ash will be generated, and more solid waste will have to be disposed. Fuel switching would be technically feasible for the control of SO_2 from the No. 4 Power Boiler.

3.2 COAL WASHING

Coal washing involves removing the sulfur from the fuel before combusting it in a boiler. The process involves grinding the coal into small pieces and passing it through a process called gravity separation. The technique involves feeding the coal into barrels containing a fluid that has a density which causes the coal to float, while unwanted material sinks and is removed from the fuel.

The majority of the sulfur in the coal burned in the No. 4 power boiler is organic (according to the supplier of the coal) and is chemically bonded in the molecular structure of the coal itself. A small fraction of the sulfur in the coal is within an iron compound called "pyrite" that can be removed by this washing of the coal before it is shipped. Generally, pyritic sulfur content is insignificant in the Smoky Mountain coal which is burned in No. 4 power boiler. Assuming its pyritic sulfur content is 1% of the sulfur content in the coal burned and coal washing would remove 40% of the pyritic sulfur in the coal, coal washing would only reduce 0.4% of the SO_2 emissions from the boiler. Coal washing would, therefore, not be practical for the effective control of SO_2 from the No. 4 Power Boiler.

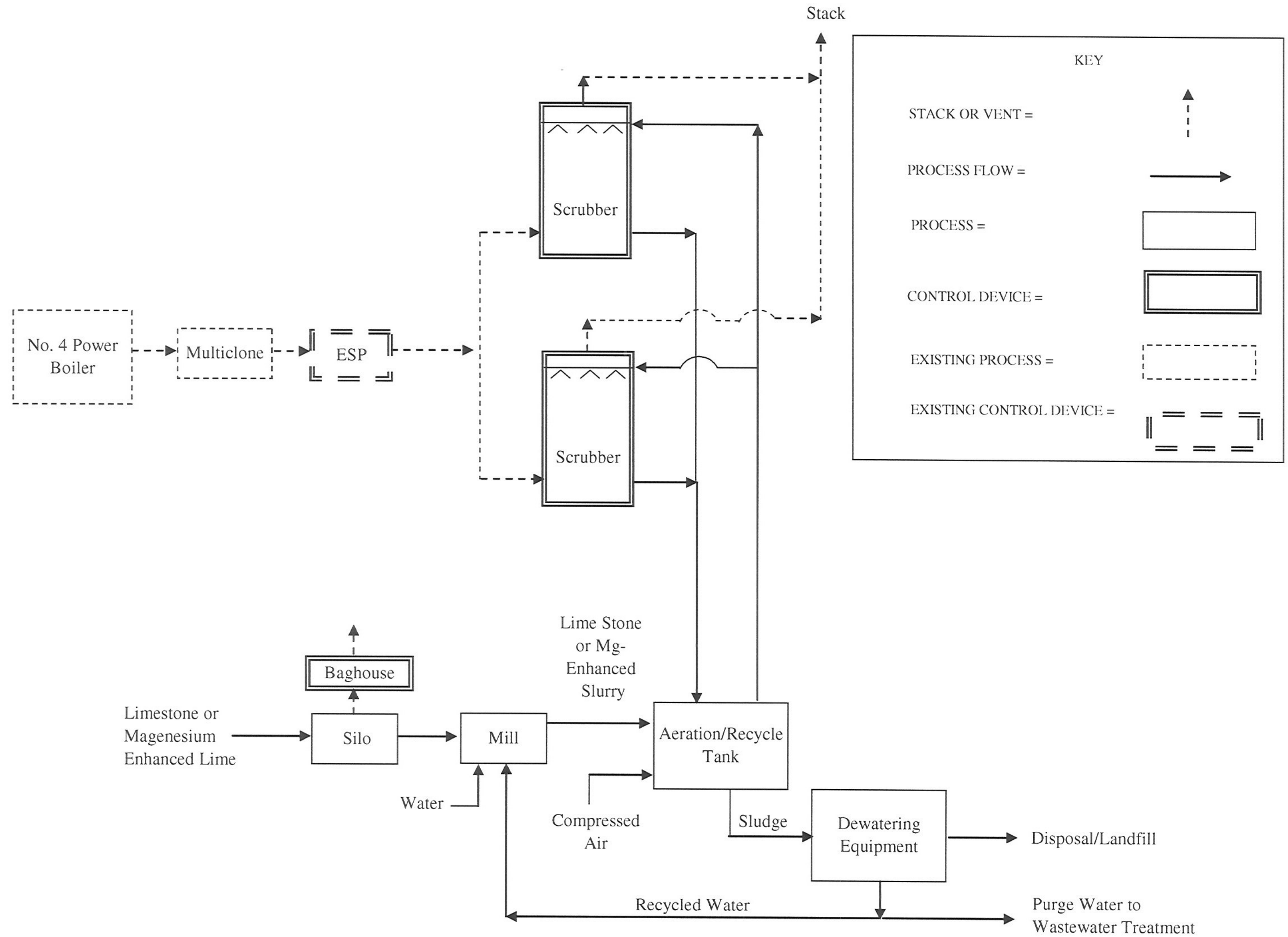
3.3 WET FLUE GAS DESULFURIZATION (FGD) – WET SCRUBBING

Post combustion flue gas desulfurization (FGD) techniques can remove SO_2 formed during combustion by using an alkaline reagent to absorb SO_2 in the flue gas. Flue gases can be treated using wet, dry, or semi-dry desulfurization processes of either the throwaway type (in which all waste streams are discarded) or the recovery/regenerable type (in which the SO_2 absorbent is regenerated and reused). Approximately 85% of the flue gas desulfurization systems installed in the United States are wet FGD throw away systems. Wet systems generally use alkali slurries as the SO_2 absorbent medium and can be designed to remove greater than 90 percent of the incoming SO_2 emissions. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbers are among the commercially proven wet FGD systems. In the wet FGD processes, flue gas contacts alkaline slurry in an absorber. The absorber may take various forms (spray-tower, tray-tower, or packed tower), depending on the manufacture and desired process configuration. However, the most often-used absorber application is the counter-flow vertically oriented spray tower. A flow diagram of a typical wet FGD system as it would be applied to the No. 4 power boiler is shown in the Figure 2. This system is an add-on technology which is feasible for most applications where there are physical space to locate the equipment and a means to treat the wastewater, both of which are available at the Rome mill.

3.4 DRY FGD - SPRAY DRYING

In dry FGD technologies, SO_2-containing flue gas contacts an alkaline sorbent (most often lime). As a result, dry waste is produced with handling properties similar to fly ash. The sorbent can be delivered to flue gas in an aqueous slurry form or as a dry powder. Spray dryers inject an aqueous sorbent slurry similar to a wet scrubber system; however, the slurry is at a much higher concentration. As the hot flue gas mixes with the slurry, water from the slurry is evaporated. The

Figure 2: Wet Scrubber



water that remains on the solid sorbent enhances the reaction with SO_2. The process forms a dry waste product, which is collected with a standard particulate matter (PM) collection device such as a baghouse or ESP. For a process configuration where the particulate control device is a baghouse, a significant additional SO_2 removal may occur in the filter cake on the surface of the bag. Figure 3 shows the schematic flow diagram of a typical lime spray drying FGD system as it would be applied to the No. 4 power boiler. The existing ESP is not sufficient to remove the sulfite absorbent so a new baghouse would need to be installed.

Various calcium and sodium based reagents can be utilized as sorbents. The spray drying FGD process typically injects lime since it is more reactive than limestone and less expensive than sodium based reagents.

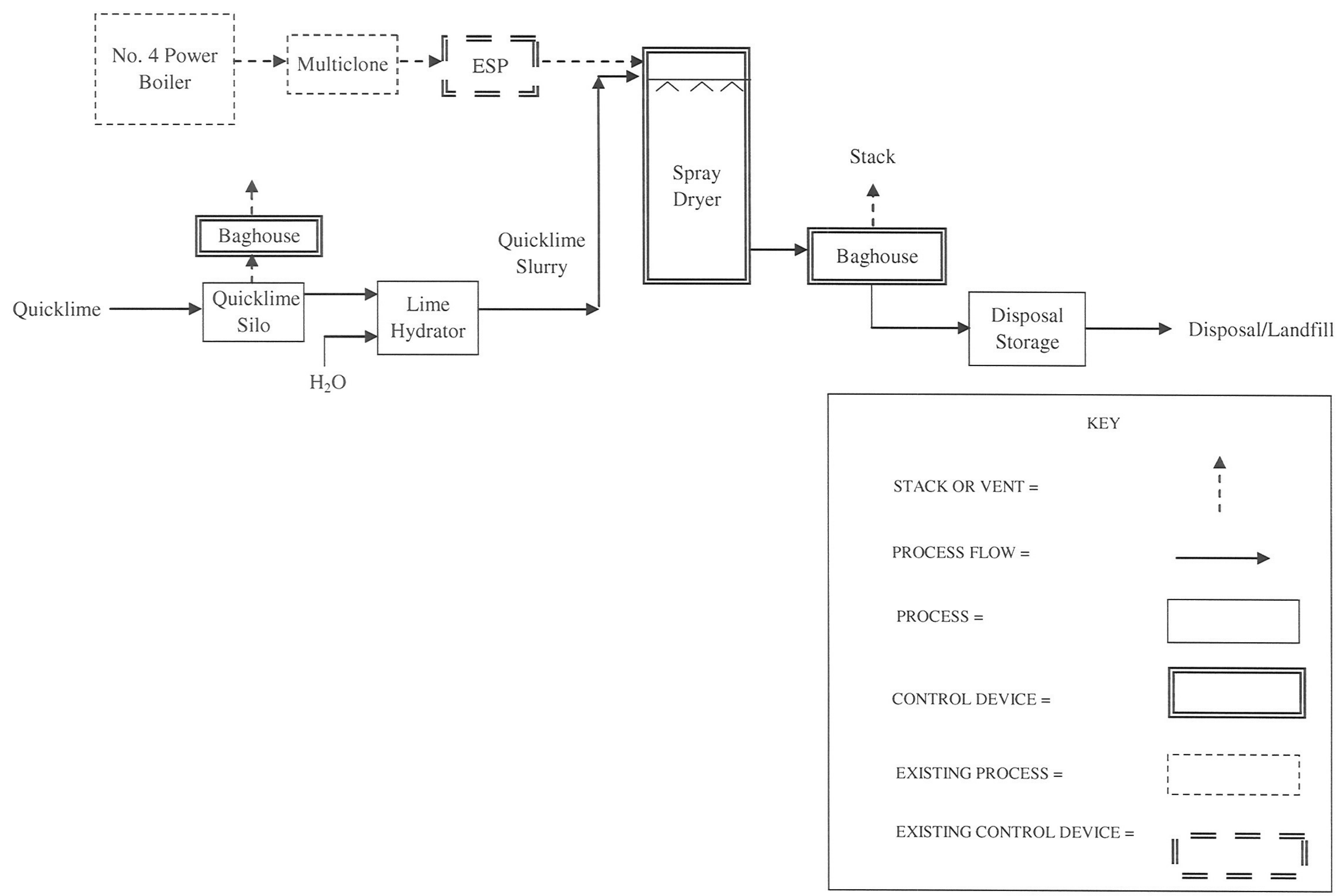
The performance of a lime spray drying FGD process is more sensitive to operating conditions. Flue gases with high SO_2 concentrations or high temperatures reduce the performance of the scrubber. The outlet flue gas temperature is controlled by the amount of water injected into the spray atomizer with the absorbent solution or slurry. As the outlet flue gas temperature approaches the adiabatic saturation temperature, the residual moisture level in the spray-dried solids increases. The residual moisture aids the mass transfer of unreacted absorbent from the center of the particle toward the surface, where it can react with the absorbed SO_2. Therefore, SO_2 removal rates and absorbent utilization increases as the approach to saturation is narrowed. The optimum temperature of the exhaust flue gas from the spray dryers is 10°C to 15°C (20°F to 50°F) above saturation temperature. The extent of alkali usage in a spray dryer is limited by its available residence time for a gas-solid reaction. Typical residence time in a spray dryer is 8 to 12 seconds.

The advantage of this process over the wet system is that it does not require wastewater treatment since only dry solids are produced. A spray dryer would be technically feasible for the control of SO_2 from the No. 4 Power Boiler.

3.5 FURNACE SORBENT INJECTION

Furnace sorbent injection involves the injection of the sorbent (most often calcium hydroxide), together with combustion air, above the combustion zone (preferably where the gas temperature is approximately 2,200 °F), together with combustion air, through special injection ports.

Figure 3: Lime Spray Drying Scrubber



Alternatively, but less effectively, the sorbent may be injected before the economizer, where the gas temperature is approximately 1,100 ^{o}F.

The sorbent decomposes into lime, which reacts in suspension with SO_2 to form calcium sulfate. The calcium sulfate, unreacted sorbent, and fly ash are removed at the particulate control device (either an ESP or baghouse) downstream from the boiler. Furnace sorbent injection, however, affects the properties of the particulate, which in turn adversely affects the performance of the ESP[1]. Gas conditioning (humidification or ammonia injection) may be needed to maintain the ESP performance. This technology has been attempted in only a few applications, and then only in boilers much larger than the No. 4 Boiler, so this technology is not being considered feasible for the purposes of this study.

3.6 DUCT SORBENT INJECTION

The duct sorbent injection FGD process pneumatically injects powdered sorbent directly into the downstream ductwork. Fly ash, reaction products, and any unreacted sorbent are collected in the particulate control devices such as a baghouse or electrostatic precipitator. Sorbent used in duct sorbent injections is typically hydrated lime or, occasionally, sodium bicarbonate. A typical injection system uses several injection lances protruding from the duct walls. Since no dedicated absorber vessel and wastewater treatment devices are required, the equipment needed to control SO_2 is minimized for duct sorbent injection. The flue exhaust needs to be treated with a baghouse or electrostatic precipitator (ESP) to collect the fly ash and entrained solids. Particulate control devices (multiclone and ESP) currently exist on the No. 4 Power Boiler. The duct sorbent injection FGD process can achieve 70% SO_2 removal. A duct sorbent injection system would be technically feasible for the control of SO_2 emissions from the No. 4 power boiler. Figure 4 shows the schematic flow chart of a duct lime sorbent injection process as it would be applied to the No. 4 power boiler. As mentioned above, sorbent injection decreases ESP performance. An ESP upgrade or the addition of a baghouse to remove particulates resulting from the sorbent injection would therefore be required.

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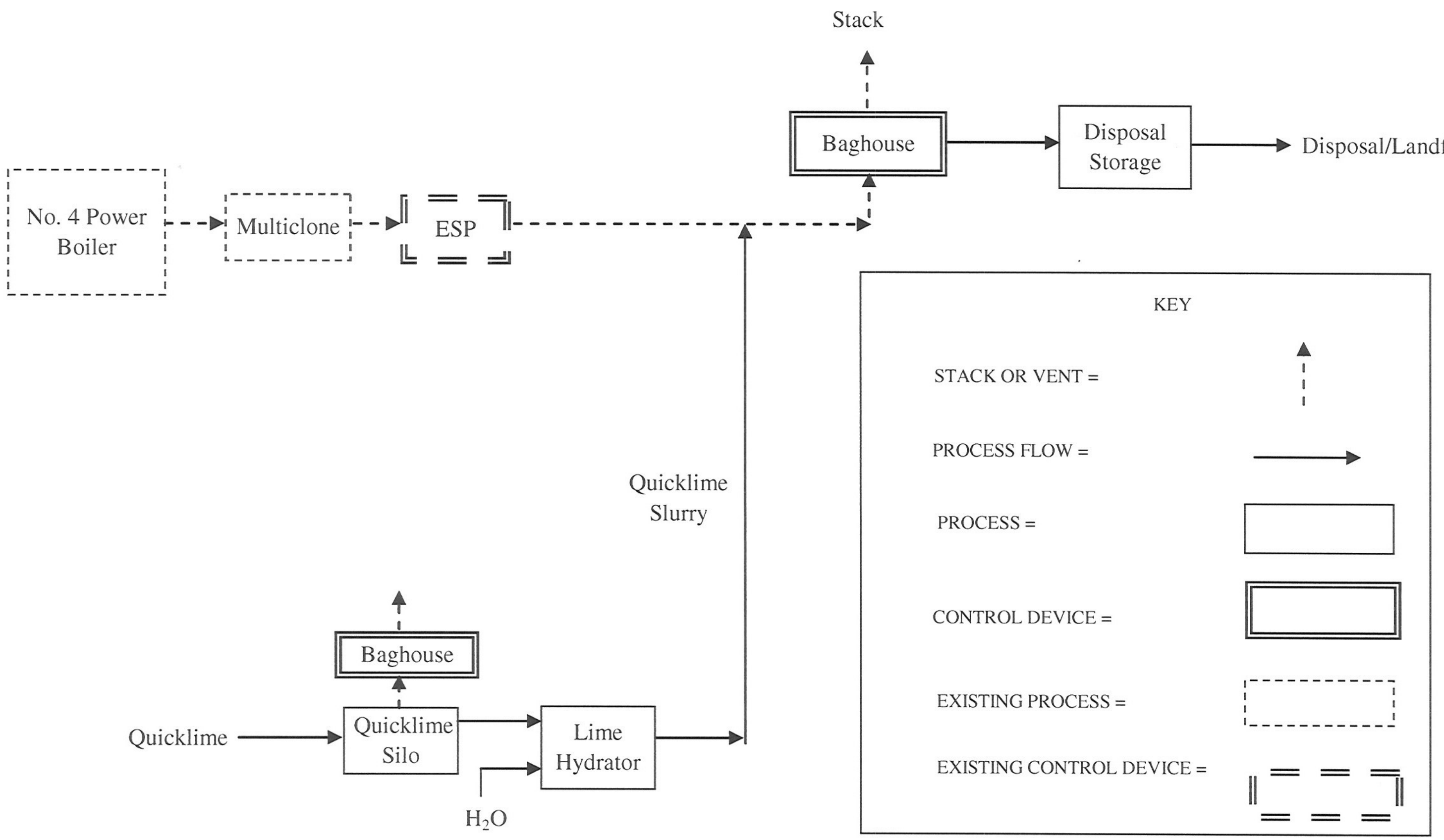
[1] http://www.worldbank.org/html/fpd/em/power/EA/mitigatn/aqsosoij.htm

Figure 4: Duct Lime Sorbent Injection



4.0 STEP 2: ELIMINATION OF TECHNICALLY INFEASIBLE OPTIONS

Though technically feasible, coal washing is not considered practically feasible. The use of coal washing on the type of coal burned at the Temple-Inland mill would have negligible effects on the emissions of SO_2 from the boiler (a 0.4% reduction).

The SO_2 removal efficiency of furnace sorbent injection typically is 25% to 50+%[2]. Based on a review conducted by EPA, the furnace sorbent injection FGD process is not widely used in the United States[3]. This technology is in the demonstration phase, and only a few large-scale demonstration projects have ever been completed in the United States[4]. Because this technology is still in the development phase, and it has significantly lower efficiencies than the technologies already discussed (wet FGD and spray drying), the furnace sorbent injection FGD process is not considered practically feasible for No. 4 power boiler. This technology was not evaluated further.

[2] EPA, AP42, Page 1.1-13
[3] EPA-600/R-00-093, Page 24
[4] DOE/NETL-2001/1141

5.0 STEP 3: RANKING OF REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

Various control alternatives were reviewed for technical feasibility in controlling SO_2 emissions from the No. 4 Power Boiler. Table 1 below ranks the technically feasible control options in descending order based on their control efficiencies as found in EPA and vendor literature.

According to the literature, wet scrubbing is the most efficient SO2 control technology and coal washing (which we have eliminated as infeasible) is the least efficient.

Table 1 Control Effectiveness Ranking

	Control Technology	Efficiency	Feasibility
1	Wet Scrubbing (Magnesium-Enhanced Lime or Limestone based)[1]	80-95%	Most Frequently Chosen Add-on Control Technology
2	Lime Spray Drying Scrubber[1]	70-90%	Feasible
3	Fuel Switching	65%[2]	Most Widely Considered Alternative because of the low capital cost
4	Duct Lime Sorbent Injection[1]	50-60%	Feasible

1 AP 42, Fifth edition, Page 1.1-13
2 Calculated specifically for Temple-Inland Fuel switching for Wyoming Coal

6.0 STEP 4: APPLICATION OF THE FIRST THREE STATUTORY FACTORS (COST OF COMPLIANCE, TIME NECESSARY FOR COMPLIANCE, ENERGY AND NON AIR QUALITY ENVIRONMENTAL IMPACTS)

6.1 COST OF COMPLIANCE

Each of the feasible control technologies were evaluated for both their estimated capital and annualized cost. Tables A-1 through A-5 located in Appendix A provide a cost summary for each of the feasible control technologies.

Fuel switching in the No. 4 Power Boiler would entail burning coal with lower sulfur content than the 1.29% sulfur coal that is currently used as fuel. A likely candidate for lower sulfur fuel would be Wyoming coal from the Powder River Basin which contains on average 0.24% sulfur with an average heat content of 8,800 Btu/lb. The 1.29% sulfur coal that is currently burned in the No. 4 Power Boiler has an average heat content of 12,900 Btu/lb. Therefore 47% more Wyoming coal would need to be burned in order to maintain the same amount of energy input that is currently achieved. Considering this, the SO_2 emissions would be reduced by approximately 56% if Temple-Inland switched to Wyoming coal. The cost of fuel switching was estimated by the price, transportation fee, and the amount of coal needed. The total amount of coal burned was calculated by using the heat content of the coal and heat input rating of No. 4 power boiler. The total O&M cost was calculated by the price plus the transportation fee times the total amount of coal to be burned. The SO_2 emissions were calculated by the sulfur content and the total amount of coal burned.

Table A-5 in Exhibit A provides the annual cost differences between Wyoming coal and the coal currently burned by the mill. Because of the significant increase in the amount of coal required to be burned to achieve the same amount of energy input, the annual fuel-related costs for the operation of the boiler would increase by roughly $7,000,000/year. (This does not include increased cost for additional ash handling and disposal, nor any cost for coal conveying/processing equipment that might be necessary to handle the additional amount of low sulfur coal that would be required.)

The estimated capital cost for wet scrubbing (both Magnesium enhanced lime and limestone based), duct lime sorbent injection, and lime spray dry scrubbing were all evaluated. These costs include the cost of reagent feed equipment, SO_2 removal equipment, flue gas handling equipment, waste handling equipment, and support equipment. Installation costs, which is assumed to be 1.5 times the costs of the equipment that is purchased, and a 6% sales tax are also factored into the estimated capital costs. The O&M cost includes the costs of sorbent, the costs associated with disposal or utilization of the by-products, and power costs. The O&M costs were split into variable and fixed costs. Fixed O&M cost incorporate operating labor, maintenance labor and materials, administration and support labor. Variable O&M costs consist of reagent, dibasic acid, disposal, steam, and electrical energy. An annual interest rate of 10% and a lifetime estimate of 20 years were used to amortize the capital costs for the equipment.

Table 2 below ranks the estimated cost in ascending order based on the cost per ton of SO_2 reduction. The estimated cost of dry sorbent injection and spray drying in Table 2 includes the cost of particulate control devices.

Table 2 Estimated Cost Ranking

Control Technology	Technical Feasibility	Capital Cost	Annualized Cost	Comparison Total Cost ($/ton)
				SO_2 Reduction
Wet Scrubber - Magnesium Enhance Lime	Feasible	$9,500,000	$2,900,000	$859
Wet Scrubber - Limestone Force Oxidation	Feasible	$11,000,000	$3,100,000	$918
Lime Spray Drying Scrubber	Feasible	$27,000,000	$5,700,000	$1,857
Duct Lime Sorbent Injection	Feasible	$19,000,000	$4,100,000	$1,943
Fuel Switching	Feasible	-	$7,000,000	$2,803

6.2 TIME REQUIRED TO INSTALL EQUIPMENT

Of the technologies evaluated, fuel switching would likely require the shortest time to accomplish since it is speculated that no major new equipment would be required. A further evaluation would, however, need to be completed in order to determine if the boiler would be capable of burning the low sulfur fuel. Some modifications of the coal conveying and coal processing equipment may be required in order to deliver this coal and to burn this coal in the No. 4 power boiler. It may take 6 months to a year before final specifications and contracts could be finalized to allow for continuous operation on low sulfur content coal.

The application of any of the scrubber technologies or the spray drying equipment would likely require an estimated 2-3 years to become operable. Table 3 lists the estimated time schedule for completing such a project.

An adder to any of these installation periods would be the time it would take to permit the changes. This could be a significant factor, especially for fuel switching, which could result in emission increases of other pollutant, potentially triggering a PSD review. In that case, and any other case where significant permitting would be required, an additional year needs to be added to the project schedule.

Table 3 Time Necessary for Compliance

Activity	Time
Engineering Design	6 months
Equipments Delivery	6 – 18 months
Construction, Installation, and Commissioning	6-12 months
Total time for Project Completion	18-36 months

6.3 ENERGY AND NON AIR QUALITY ENVIRONMENTAL IMPACTS

The wet scrubber systems would generate a significant increase in wastewater treatment demand for the existing hydraulically limited wastewater treatment plant. This would require an increase in wastewater treatment chemicals as well as an increase in electrical demand used in the treatment of waste- water. There will be a residual amount of sulfate in the wastewater, which adds to the waste load burden that is discharged to the Coosa River. All scrubbers would also require an increase in electrical demands for the operation of exhaust fans. The scrubbers would have a significant pressure drop and new exhaust fans would be required to overcome this increase in pressure drop. The sorbent injection and spray drying operations would also have electrical demands for the operation of pumps for the injection of the absorbent material. Lastly, all these technologies would result in a significant amount of solid waste which would need to be disposed of in a landfill.

6.4 STEP 5: SELECTION OF THE CONTROL TECHNOLOGY

The conclusions from all of these analyses are presented in one comparison summary Table 4. This table includes both cost and estimated emissions for each control option. Also listed are estimated times that such options could be initiated. One thing of concern is the relevance of the estimated costs in this analysis for a situation ten years from now. The costs and availability of equipment in ten years cannot be accurately determined. Also the availability of low sulfur coal in ten years cannot be accurately predicted. Although the supply of low sulfur coal is not in question now there is uncertainty what the transportation cost will be and whether it can be made available if there is a large demand in the future. From inspection of Table 4, it is apparent that only two logical choices, wet scrubbing or fuel switching, should be considered. Both control options are well demonstrated so either choice is considered technically feasible. However, both options are costly. Fuel switching will cost the mill more than $6 million per year in coal costs alone in current dollars, which will likely escalate in the future due to transportation costs. A wet scrubbing system will cost the mill $2 million per year to operate and cost more than $9 million to install. The time to implement the controls is very different. For fuel switching it is likely that a permanent switch could be made within a year, but to install a scrubber could take 3 years.

From an environmental standpoint, both options have a cost. The use of low sulfur fuel with its lower fuel value requires more to be burned because of its poor heating value. With increased fuel firing, there will likely be more emissions of other pollutants such as metals, NOx and VOC's. This could aggravate other aspects of regional air quality (potential ozone formation). For the scrubber option, both a solid and wastewater stream is generated. The additional wastewater will add to the burden of the existing wastewater treatment facility and to eventual discharge to the Coosa River.

Considering the distance between the mill and the Class I area in question (95 km), and all the other sources of fine particulate emissions which could impact the Class I area, plus the uncertainty of the models used to predict haze, Temple-Inland does not believe either option is justified. A detailed analysis of the relative benefits of these controls measures needs to be assessed before the impacts of adding such controls can be appropriately evaluated.

Table 4 Overall Comparisons of Control Options

Control Technology	Efficiency	Capital Cost	Emission of SO_2 after Control tpy	$/ton	Time for Implementation
Wet Scrubber - Magnesium Enhance Lime	88%	$9,500,000	384	$859	3 year
Wet Scrubber - Limestone Force Oxidation	88%	$11,000,000	384	$918	3 year
Lime Spray Drying Scrubber	80%	$27,000,000	767	$1,857	3 year
Duct Lime Sorbent Injection	55%	$19,000,000	1727	$1,943	3 year
Fuel Switching	65%	-	2494	$2,803	1 year

Exhibit A: Cost Summary

Table A-1: Limestone Forced Oxidation Wet Scrubber Cost Analysis

	Suggested Factor	Unit Cost ($/EA)	Costs ($)
Direct Costs			
Two (2) Counter-flow absorption towers in 316L construction approximately 14'-0" ID each with Stellite-type spray nozzles. One (1) recycle/aeration tank in 316L construction. Four (4) rubber lined solids handling recycle pumps with motors. Four (4) agitators (for forced oxidation sump). One (1) sparger blower with humidification spray. One (1) sparger header system for the forced oxidation tank. One (1) solids transfer pump (to pump from the sump out to dewatering equipment). One (1) liquid cyclone to separate the recycle into a water stream that is able to be used to wash the chevron droplet eliminators in the towers. Basic access platforms and ladders. Basic instrumentation (recycle and blow-down rate, level control, temperature control, pH control, and density control). Local fiberglass piping from tank to pumps, pumps to spray headers, a NEMA 4 control panel with PLC, limestone silo, limestone feeder, mill to ground limestone under 325 mesh, a fan (usually a "hot" mounted ahead of the scrubbers), a stack, and dewatering equipment or disposal pond.	Vendor quote - Bionomic Industries Ken Schifftner Phone No. (201) 529-1094 ext 113 E-mail: kschifftner@bionomicind.com		$3.000.000
Piping to Wastewater Treatment	1400 feet from No. 6 ESP to Wastewater Treatment Plant	$10.00 /ft	$14.000
Limestone Silo Baghouse		$50.000	$50.000
Stack Costs	Engineering Estimate for 65 m Stack	$1.000.000	$1.000.000
Installation Costs	1.5 times the costs of scrubber system		$6.100.000
6% Sales Tax on Equipment Purchase			$610.000
Total Capital Investment (TCI)			$11.000.000

	Suggested Factor	Unit Cost	
Direct Annual Costs, DC			
Operating Labor			
Operator	4 hr/shift	$22.00 /hr	$69.000
Supervisor	15% of operator	--	$10.000
Maintenance			
Labor	2 hr/shift	$22.00 /hr	$34.000
Material	100% of maintenance labor	--	$34.000
Power Usage (fans, pumps, agitator, & spargers)	650 kW to power scrubber system	$0.11 /kw-hr	$630.000
Raw Water Feed	75 gpm	$0.75 /1000 gal	$29.399
Limestone costs	6.166 ton CaCO3 Vendor : O-N Minerals-Georgia Hydrate, Bobby Sutphin 1-800-467-5463 Ext. 125	$42.00 /ton	$260.000
Disposal Costs	Density of gypsum @ 1.29 g/cm^3 and volume of waste generated 1.9 MM gal/yr	$3.95/35 gal	$220.000
Total Direct Costs, DC			$1.286.399

Table A-1 (continued): Limestone Forced Oxidation Wet Scrubber Cost Analysis

Indirect Annual Costs, IC				
Overhead	67% of Operating and Maintenance costs	--	$99,000	
Administrative Charges, Taxes, and Insurance	4% TCI	--	$430,000	
Capital Recovery	(TCI*0.1175)		$1,300,000	
(Based on a lifetime of 20 years and an interest rate of 10%)				
Total Indirect Costs, IC			$1,800,000	
Total Annual Costs = DC + IC			$3,100,000	
Total Uncontrolled SO_2			3837	tons/yr
Estimated Control Efficiency			88%	
Total Controlled SO_2			3377	tons/yr
$/ton Controlled			**$918**	**/ton SO_2 reduced**

Table A-2 Magnesium Enhanced Lime Wet Scrubber Cost Analysis

Direct Costs	Suggested Factor	Unit Cost ($/EA)	Costs ($)
Two (2) Counter-flow absorption towers in 316L construction approximately 14'-0" ID each with Stellite-type spray nozzles, One (1) recycle/aeration tank in 316L construction, Four (4) rubber lined solids handling recycle pumps with motors, Four (4) agitators (for forced oxidation sump), One (1) sparger blower with humidification spray, One (1) sparger header system for the forced oxidation tank, One (1) solids transfer pump (to pump from the sump out to dewatering equipment), One (1) liquid cyclone to separate the recycle into a water stream that is able to be used to wash the chevron droplet eliminators in the towers, Basic access platforms and ladders, Basic instrumentation (recycle and blow-down rate, level control, temperature control, pH control, and density control), Local fiberglass piping from tank to pumps, pumps to spray headers, a NEMA 4 control panel with PLC, limestone silo, limestone feeder, mill to ground limestone under 325 mesh, a fan (usually a "hot" mounted ahead of the scrubbers), a stack, and dewatering equipment or disposal pond.	Vendor quote - Bionomic Industries Ken Schifftner Phone No. (201) 529-1094 ext 113 E-mail: kschifftner@bionomicind.com Magnesium Enhanced Lime Systems are 10% - 15% less in capital costs than Limestone Forced Oxidation systems. MEL systems can operate at lower L/G ratios which results in smaller absorbers, smaller pumps, and smaller fans are required for these systems. Calculated capital costs is a 15% reduction in $3,000,000 quote for the Limestone Forced Oxidation System		$2,600,000
Piping to Wastewater Treatment	1400 feet from No. 6 ESP to Wastewater Treatment Plant	$10.00 /ft	$14,000
Limestone Silo Baghouse		$50,000	$50,000
Stack Costs	Engineering Estimate for 65 m Stack	$1,000,000	$1,000,000
Installation Costs	1.5 times the costs of scrubber system		$5,400,000
6% Sales Tax on Equipment Purchase			$480,000
Total Capital Investment (TCI)			$9,500,000

Direct Annual Costs, DC	Suggested Factor	Unit Cost	
Operating Labor			
Operator	4 hr/shift	$22.00 /hr	$69,000
Supervisor	15% of operator	--	$10,000
Maintenance			
Labor	2 hr/shift	$22.00 /hr	$34,000
Material	100% of maintenance labor	--	$34,000
Power Usage (fans, pumps, agitator, & spargers)	450 kW to power scrubber system	$0.11 /kw-hr	$430,000
Raw Water Feed	75 gpm	$0.75 /1000 gal	$29,000
Magnesium Enhanced Lime	4,286 ton MEL assumed 92% CaO & 8% MgO Chemical Lime Co, Bill Johnson 1-205-937-9513	$120.00 /ton	$510,000
Disposal Costs	Density of gypsum @ 1.29 g/cm^3 and Density of $MgSO_4$ @ 1.67 g/cm^3	$3.95/35 gal	$210,000
Total Direct Costs, DC			$1,300,000

Table A-2 (continued) Magnesium Enhanced Lime Wet Scrubber Cost Analysis

<u>**Indirect Annual Costs, IC**</u>				
Overhead	67% of Operating and Maintenance costs	--	$99,000	
Administrative Charges, Taxes, and Insurance	4% TCI	--	$380,000	
Capital Recovery	(TCI*0.1175)		$1,100,000	
(Based on a lifetime of 20 years and an interest rate of 10%)				
Total Indirect Costs, IC			$1,600,000	
Total Annual Costs = DC + IC			$2,900,000	
Total Uncontrolled SO_2			3837	tons/yr
Estimated Control Efficiency			88%	
Total Controlled SO_2			3376.6	tons/yr
$/ton Controlled			**$859**	**/ton SO_2 reduced**

Table A-3: Lime Spray Drying Scrubber Cost Analysis

	Suggested Factor	Unit Cost ($/EA)	Costs ($)	
Direct Costs				
Spray Dryer, Fabric Filter, Booster Fan, Lime Hydrator, Quicklime Storage, and By-product Storage	Vendor quote - Ellison Consultants Bill Ellison Phone No. (301) 865-5302 E-mail: ellisoncon@aol.com		$9,000,000	
Quicklime Silo Baghouse		$50,000	$50,000	
Stack Costs	Engineering Estimate for 65 m Stack	$1,000,000	$1,000,000	
Installation Costs	1.5 times the costs of scrubber system		$15,000,000	
6% Sales Tax on Equipment Purchase			$1,500,000	
Total Capital Investment (TCI)			$27,000,000	
	Suggested Factor	**Unit Cost**		
Direct Annual Costs, DC				
Operating Labor				
Operator	4 hr/shift	$22.00 /hr	$69,000	
Supervisor	15% of operator	--	$10,000	
Maintenance				
Labor	2 hr/shift	$22.00 /hr	$34,000	
Material	100% of maintenance labor	--	$34,000	
Power Usage (fans, pumps, agitator)	600 kW to power scrubber system	$0.11 /kw-hr	$580,000	
Quicklime costs	4,030 ton CaO Vendor : O-N Minerals-Georgia Hydrate, Bobby Sutphin 1-800-467-5463 Ext. 125	$112.00 /ton	$450,000	
Disposal Costs	Density of gypsum @ 1.29 g/cm^3 and volume of waste generated 1.9 MM gal/yr	$3.95/35 gal	$220,000	
Total Direct Costs, DC			$1,400,000	
Indirect Annual Costs, IC				
Overhead	67% of Operating and Maintenance costs	--	$99,000	
Administrative Charges, Taxes, and Insurance	4% TCI	--	$1,100,000	
Capital Recovery (Based on a lifetime of 20 years and an interest rate of 10%)	(TCI*0.1175)		$3,100,000	
Total Indirect Costs, IC			$4,300,000	
Total Annual Costs = DC + IC			$5,700,000	
Total Uncontrolled SO_2			3837	tons/yr
Estimated Control Efficiency			80%	
Total Controlled SO_2			3069.6	tons/yr
$/ton Controlled			**$1,857**	**/ton SO_2 reduced**

Table A-4: Duct Lime Sorbent Injection Cost Analysis

	Suggested Factor	Unit Cost ($/EA)	Costs ($)	
Direct Costs				
Reverse Air Fabric Filter, Injection Lances, Pumps, Lime Hydrator, Quicklime Silo, and Disposal Storage (Based on 1990 $)	565 MMBtu/hr Boiler, 30% Efficient Boiler	$75.00 per kW(e)	$3,700,000	
Inflation	3% Inflation Rate		$2,400,000	
Quicklime Silo Baghouse		$50,000	$50,000	
Stack Costs	Engineering Estimate for 65 m Stack	$1,000,000	$1,000,000	
Installation Costs	1.5 times the costs of scrubber system		$11,000,000	
6% Sales Tax on Equipment Purchase			$650,000	
Total Capital Investment (TCI)			$19,000,000	
	Suggested Factor	**Unit Cost**		
Direct Annual Costs, DC				
Operating Labor				
Operator	4 hr/shift	$22.00 /hr	$69,000	
Supervisor	15% of operator	--	$10,000	
Maintenance				
Labor	2 hr/shift	$22.00 /hr	$34,000	
Material	100% of maintenance labor	--	$34,000	
Power Usage (fans, pumps, agitator)	250 kW to power scrubber system	$0.11 /kw-hr	$240,000	
Quicklime costs	4,030 ton CaO	$112.00 /ton	$450,000	
	Vendor : O-N Minerals-Georgia Hydrate, Bobby Sutphin 1-800-467-5463 Ext. 125			
Disposal Costs	Density of gypsum @ 1.29 g/cm^3 and volume of waste generated 1.9 MM gal/yr	$3.95/35 gal	$220,000	
Total Direct Costs, DC			$1,100,000	
Indirect Annual Costs, IC				
Overhead	67% of Operating and Maintenance costs	--	$99,000	
Administrative Charges, Taxes, and Insurance	4% TCI	--	$750,000	
Capital Recovery	(TCI*0.1175)		$2,200,000	
(Based on a lifetime of 20 years and an interest rate of 10%)				
Total Indirect Costs, IC			$3,000,000	
Total Annual Costs = DC + IC			$4,100,000	
Total Uncontrolled SO_2			3837	tons/yr
Estimated Control Efficiency			55%	
Total Controlled SO_2			2110.4	tons/yr
$/ton Controlled			**$1,943**	**/ton SO_2 reduced**

Table A-5: Fuel Switching Cost Analysis

	Suggested Factor	Unit Cost ($/ton)	Total Cost
Direct Annual Costs - Wyoming Coal			
Coal Costs	2.80×10^5 ton/yr with 8829 lb/Btu heat rating	9.05	$2,500,000
Transporation Costs		67	$19,000,000
Disposal Costs	3.78E+06 gallons of waste generated	$3.95/35 gal	$430,000
	9% Ash content and ash density 2.15 g/cm^3		
Total Direct Costs			$22,000,000
Direct Annual Costs - Smokey Mountain Coal			
Coal Costs	1.92×10^5 ton/yr with 12,900 lb/Btu heat rating	56	$11,000,000
Transportation Costs		22	$4,200,000
Disposal Costs	2.88E+06 gallons of waste generated	$3.95/35 gal	$320,000
	10% Ash content and ash density 2.15 g/cm^3		
Total Direct Costs			$15,000,000
Current SO_2 Emissions			3,837 tons/yr
SO_2 Emissions - Fuel Switching			1,340 tons/yr
$\Delta$$/ton Collected			**$2,803** $/ton SO_2 Reduced