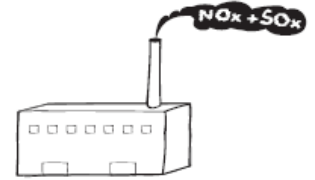


# ENVIRONMENTAL FOOTPRINT COMPARISON TOOL

A tool for understanding environmental decisions related to the pulp and paper industry



## TRADE-OFFS AND CO-BENEFITS ACCOMPANYING SO<sub>x</sub> CONTROL

### Power Boiler SO<sub>x</sub>

Apart from recovery furnaces, the pulp and paper industry draws upon power boilers to generate the steam and electrical energy required to sustain the manufacturing process. In the U.S., the industry uses nearly 1,000 of these auxiliary power boilers. Approximately one-third of these boilers are larger than 250 million Btu per hour; only 17 have heat capacities larger than  $1000 \times 10^6$  Btu/hr. The largest is  $1400 \times 10^6$  Btu/hr. Approximately one-half of the industry's power boilers were installed prior to 1970, and 292 were installed between 1971 and 1990. Fewer than 1 in 5 were installed in 1991 or later.

Wood products boilers are typically much smaller than boilers at pulp and paper plants, with the majority of boilers less than  $100 \times 10^6$  Btu/hr and very few over  $250 \times 10^6$  Btu/hr.

The most important determinant of SO<sub>x</sub> emissions from power boilers is the choice of fuel. Also influential are features of the boiler's design and the combustion conditions with which it can be operated. As for external controls, many of the same control technologies for utility boilers are candidates for consideration on industrial boilers in the pulp and paper industry. These include wet and dry flue gas desulfurization (FGD) or scrubber technology for SO<sub>2</sub>. In practice, however, their application has been limited due to skewed economics resulting from the much smaller sizes of industrial boilers relative to their utility counterparts. Furthermore, control performance is often diminished by the dynamic nature of industrial boiler operation (CIBO 2003).

### How does fuel choice affect emissions of SO<sub>x</sub>?

Coal, residual oil, distillate oil, natural gas, and wood residues account for the bulk of the fuels burned in conventional steam-generating boilers. Boilers are commonly configured to burn multiple fuels to ensure that steam demands can be met at the most favorable fuel cost.

A comparison of the relative sulfur content of various fuels is shown in Table S3.

**Table S3. Relative Sulfur Content of Fuels (Source: USEPA 1998)**

Fuel	Sulfur, %
Natural Gas	Insignificant
Distillate Oil	0.05 to 0.5
Residual Oil	0.3 to 3.0
Coal	0.4 to 4.0
Bark and Wood Residue	0.2 or less

At pulp and paper mills in 2005, wood fuels accounted for 39% of the total fuel heat input to boilers, followed by coal (28%), natural gas (24%), and fuel oil (10%) (Pinkerton 2007). Wood is most often burned in combination with fossil fuels in these boilers. Wood products mills that burn coal are rare and only a small percentage burn oil.

The combustion of wood brings advantages beyond its relatively low sulfur and nitrogen content. Alkaline wood ash resulting from combustion has the potential to scavenge SO<sub>x</sub> that would otherwise be emitted. There are other emission dividends as well. CO<sub>2</sub> from wood fuel combustion is considered "neutral" (see tab on Greenhouse Gases, on this website). Moreover, mercury emissions associated with biomass combustion are far lower than those associated with coal.

## Trade-offs and Co-benefits Accompanying SO<sub>x</sub> Control

### Power Boiler SO<sub>x</sub>

#### What factors constrain beneficial fuel substitutions on existing power boilers?

Fuel switching is an attractive option for reducing releases to the environment, but its application cannot be considered in isolation from a host of site-specific factors of importance to boiler performance, boiler integrity, and overall emissions control capability.

Switching to lower sulfur fuels can be an effective way to reduce SO<sub>2</sub> emissions. Apart from the greater cost typically associated with lower sulfur fuels, however, is the question of compatibility with the design of the existing boiler system and related equipment. Fuel changes may also compromise boiler efficiency and emissions control capability.

Oland (2002) cites as an example a switch from a) eastern bituminous coal, with a high heat value and low ash content, to b) a low-sulfur western sub-bituminous coal with a lower heating value and high ash content. Though beneficial for reducing SO<sub>x</sub> emissions, the change comes with potentially adverse effects:

- flame stability impacts consequential to boiler efficiency and pollutant emissions;
- diminished energy efficiency due to deposition and slagging on heat transfer surfaces;
- increased ash loading; and
- unsatisfactory performance of emissions control equipment.

Natural gas is recognized as a clean burning fuel, but its higher hydrogen content yields water vapor during combustion; that vapor contributes to greater heat loss out the stack. Biomass and wood are favorable fuels from the standpoint of SO<sub>x</sub> emissions, but firing them has been observed to lead to accelerated corrosion of boiler components. Fuel properties are best taken into account at the time of boiler design.

#### What is the magnitude of boiler SO<sub>x</sub> emissions?

Emissions depend on the composition of the fuel, the type and size of the boiler, boiler load, and firing conditions in the boiler. Representative emissions of SO<sub>x</sub> for various fuels and boiler configurations are shown in Table S4a.

**Table S4a. Representative Emissions of SO<sub>x</sub> for Various Fuels and Boiler Configurations**

Fuel Options	SO <sub>x</sub> Emissions	Comment
	lbs/MMBtu	
Natural Gas	Negligible	
Distillate Oil (0.5% S)	0.5	
Residual Oil (1%)	1.03 to 1.08	
Pulverized Coal (1% S)	1.46	Assumed Btu content of 13,000 Btu per pound
Pulverized Coal (2% S)	2.92	
Stoker Fed Coal (1% S)	1.35 to 1.65	
Stoker Fed Coal (2% S)	2.7 to 3.3	
Wet Wood	0.025	
Dry Wood	0.025	

The representative emission levels were derived from data compiled by EPA (USEPA 1998). The values were selected from those deemed most credible and reflective of performance for boilers that predate emission standards applicable to new or reconstructed sources that were adopted in the 1970s. As such, they reflect a baseline level of performance.

In 2005, the average sulfur contents of fuels burned by the pulp and paper industry were 1.2% for coal and 1.5% for No. 6 fuel oil (Pinkerton 2007). Coal is predominantly burned either in pulverized form or is stoker fed. SO<sub>x</sub> emissions are driven by fuel sulfur content.

## Trade-offs and Co-benefits Accompanying SO<sub>x</sub> Control

### Power Boiler SO<sub>x</sub>

SO<sub>x</sub> emissions from the wood products industry are small enough to be considered insignificant, as few wood products mills combust coal or oil and the amount of sulfur in wood is very small.

### What control options exist for reducing SO<sub>x</sub> emission levels?

Post-combustion flue gas desulfurization (FGD) techniques can be used to remove SO<sub>x</sub> formed during combustion of sulfur-bearing fuels. Approaches differ, but they share a common attribute in employing an alkaline reagent to absorb and convert SO<sub>x</sub> in the flue gas into liquid or solid sulfur-bearing compounds.

SO<sub>x</sub> FGD scrubber systems are characterized as either wet, dry, or semi-dry; as well as non-regenerable or regenerable in terms of whether the end products have viable commercial use. Attributes of various approaches are summarized in Table S6. Wet systems, the most commonly employed technique, achieve the greatest removals, with SO<sub>x</sub> reductions of 95% and more.

FGD is primarily used for reducing SO<sub>x</sub> emissions for large electric utility boilers. Generally, the technology cannot be cost-justified on industrial-scale boilers (Cleaver Brooks n.d.). A cost survey carried out by the Electric Utility Cost Group documents the sensitivity of cost to boiler size (Sharp 2009). As shown in Figure S5, costs for FGD systems for boilers smaller than 300MW are nearly double those for boilers greater than 300MW. Installed costs were reported to be 50% greater. The largest power boiler in the forest products industry would have an electric generating capacity of only 140 MW. Most boilers are significantly smaller, with the average size being equivalent to roughly 25 MW. As such, they would be subject to disproportionate costs were they to adopt this control technique.

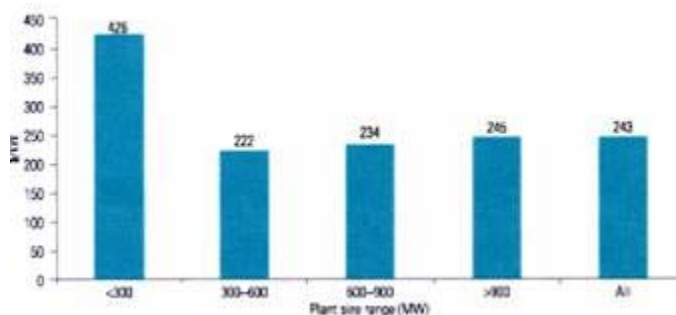


Figure S5. FGD-Only Costs among 49 FGD Systems

Space availability is another aspect that can skew the costs of FGD system installation. Pulp and paper mills house a vast array of large-scale process equipment concentrated on a relatively small footprint (Figure S6). Accommodating an FGD system would incur disproportionate construction costs. Such space constraints might favor a dry FGD system. However, the dynamic nature of mill boiler loadings would jeopardize performance, given the sensitivity of dry systems to operating conditions.



Figure S6. Example of Mill Site Footprint (courtesy of NewPage)

## Trade-offs and Co-benefits Accompanying SO<sub>x</sub> Control Power Boiler SO<sub>x</sub>

Within the pulp and paper industry, there are numerous fluidized bed boilers with lime injection for SO<sub>2</sub> removal, plus many more boilers with wet control devices (venturi scrubbers, wet electrostatic precipitators [ESPs], spray towers) and alkali addition for SO<sub>2</sub> removal. There are no lime/limestone wet FGD systems, of the type that dominate coal-fired electric utility boiler systems.

**Table S6. SO<sub>x</sub> Control Technologies (USEPA 2003a; Srivastava 2000)**

Control Option	Description	Performance	Application
<b>Wet Systems</b>			
<b>Lime/Limestone Sorbent</b>	An aqueous slurry of the sorbent is injected into the flue gas, saturating the gas stream. SO <sub>x</sub> dissolves into slurry droplets and reacts with alkaline particles. The slurry falls to the bottom of the reactor, is collected, and sent to a reaction tank to complete conversion to a neutral salt.	80 to 90% SO <sub>x</sub> removal with limestone; up to 95% removal with lime	Wet systems are applicable to high sulfur fuels, and produce a wet sludge byproduct requiring management and disposal. Though high in capital and operating cost, wet limestone scrubbing is the preferred process for coal-fired electric utility plants.
<b>Sodium Carbonate Sorbent</b>		80% to 98% reduction	High reagent cost a disadvantage
<b>Magnesium oxide/hydroxide</b>		80% to 95+% reduction	Sorbent can be regenerated
<b>Dual Alkali</b>		90% to 96% reduction	Uses lime to regenerate sodium-based scrubbing liquid
<b>Semi-Dry Systems (Spray Dryers)</b>			
<b>Calcium hydroxide slurry sorbent</b>	Like with wet systems, an aqueous sorbent slurry is injected into the flue gas stream. The sorbent is more concentrated in semi-dry system slurries, however. Hot flue gas evaporates water in the slurry, but sufficient remains on the solid sorbent to enhance SO <sub>x</sub> removal. The resulting dried waste product is subsequently captured with a standard particulate collection device.	70% to 90% SO <sub>x</sub> reduction	Applicable to low- and medium-sulfur fuels; produces a dry residual byproduct that is less difficult to manage than wet residuals. Performance is sensitive to operating conditions due to potential for wet solids to deposit on the absorber and downstream equipment. High temperatures and high SO <sub>x</sub> concentrations degrade performance. Typical applications are utility and industrial boilers burning low to medium sulfur coal and requiring 80% SO <sub>x</sub> control.
<b>Dry Systems</b>			
<b>Dry calcium carbonate/hydrate injected in upper furnace cavity</b>	Powdered sorbent is injected directly into the furnace. The waste product is removed with standard particulate control equipment.	50% to 60% SO <sub>x</sub> reduction	Even distribution of sorbent and adequate residence time within narrow temperature bands are critical for high SO <sub>x</sub> removal. Dry systems are less costly than wet systems, use less space, and are thought more suitable for retrofit applications. The technique is viewed as an emerging technology for medium-to-small industrial boiler applications.
<b>Dry sorbent injection into duct work</b>	Powdered sorbent is injected directly into downstream ductwork. Water can be injected to enhance SO <sub>x</sub> removal. The waste product is removed with standard particulate control equipment.	50% to 80% SO <sub>x</sub> reduction with sodium-based sorbent.	

## Trade-offs and Co-benefits Accompanying SO<sub>x</sub> Control Power Boiler SO<sub>x</sub>

### What are the trade-offs and co-benefits from power boiler SO<sub>x</sub> control?

#### Flue Gas Treatments for Boilers:

**Flue gas desulfurization (FGD)** involves injection of an alkaline sorbent into the flue gas stream that reacts with SO<sub>x</sub> to form subsequently separated liquid or solid sulfur-bearing compounds. Systems involve dry, semi-dry, or wet approaches.

Wet FGD has been the most widely applied technique for electric utility boilers, whereas dry systems have been characterized as an emerging technology for industrial-scale boilers.

Both wet and semi-dry FGD approaches impose a consumptive water demand ranging from 0.5 to 1.5 tons of water per ton of coal burned (Congressional Office of Technology Assessment 1979). Heating and evaporation of that water also imposes a significant energy demand. The need to reheat flue gas to preserve plume buoyancy poses an additional drain. Electrical energy required to drive process equipment has been estimated to range from 1% to 2.5% of boiler capacity (USEPA 2003b). Schemes exist to regenerate the chemical absorbent, but they are very energy-intensive. Once-through systems are most common, but they generate a large quantity of solid wastes. The accumulation of metals, including mercury, in wastewaters and sludges of FGD systems is of benefit to air emissions, but problematic with regard to the management of those waste streams. Removal of mercury from flue gas, however, is a co-benefit.

Comparisons made of wet and semi-dry approaches point out that

- the non-air quality environmental impacts and negative energy impacts are significantly greater for the wet FGD control technology, since it generates a visible plume, consumes more water, generates a wastewater stream requiring treatment and disposal, generates slightly more solid byproducts for landfill, and because the wet FGD requires significantly more auxiliary power consumption during operation; and
- compared to wet lime/limestone scrubbing technology, the spray dryer has the reported advantages of fewer major equipment items and thus lower capital cost, high reliability, lower space requirements, lower potential for corrosion, potential for lower energy consumption, absence of a wastewater stream, lower water consumption, and less sensitive and simpler process chemistry (Toole-O'Neil 1998).

Dry scrubbers typically do not achieve the SO<sub>x</sub> reduction levels associated with their wetter counterparts, but the technology does offer other relative advantages. Dry scrubbers have significantly lower capital and operating costs because they are simpler, demand less water, and involve less complex waste disposal (USEPA 2003b).

**Multi-Pollutant Reduction** involving the use of selective catalytic reduction (SCR) followed by wet FGD has gained credence as a potential means of reducing not only NO<sub>x</sub> and SO<sub>x</sub>, but also mercury emissions. The contribution of SCR technology to mercury reduction comes from the fact that SCRs have been shown to oxidize elemental mercury. Wet scrubbers, in turn, have been shown to be effective in removing oxidized mercury (Tavoulaareas and Jozewicz 2005).

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## Trade-offs and Co-benefits Accompanying SO<sub>x</sub> Control

### Power Boiler SO<sub>x</sub>

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