

# **Biomass-coal Co-combustion: Opportunity for Affordable Renewable Energy**

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## **Abstract**

This investigation explores the reasons for and technical challenges associated with co-combustion of biomass and coal in boilers designed for coal (mainly pulverized coal) combustion. Biomass-coal co-combustion represents a near-term, low-risk, low-cost, sustainable, renewable energy option that promises reduction in effective CO<sub>2</sub> emissions, reduction in SO<sub>x</sub> and often NO<sub>x</sub> emissions, and several societal benefits. Technical issues associated with cofiring include fuel supply, handling and storage challenges, potential increases in corrosion, decreases in overall efficiency, ash deposition issues, pollutant emissions, carbon burnout, impacts on ash marketing, impacts on SCR performance, and overall economics. Each of these issues has been investigated and this paper summarizes the state-of-the-art in each area. The focus is on fireside issues. While each of the issues can be significant, the conclusion is that biomass residues represent possibly the best (cheapest and lowest risk) renewable energy option for many power producers.

## Primary motivations for cofiring

Concerns regarding the potential global environmental impacts of fossil fuels used for power generation and other energy supplies are increasing worldwide. One means of mitigating these environmental impacts is increasing the fraction of renewable and sustainable energy in the national energy supply. Traditionally, renewable energy sources struggle to compete in open markets with fossil energy, due to low efficiencies, high costs, and high technical risk.

Co-firing biomass with coal in traditional coal-fired boilers represents one combination of renewable and fossil energy utilisation that derives the greatest benefit from both fuel types. It capitalises on the large investment and infrastructure associated with the existing fossil-fuel-based power systems (e.g. fuel shipment and storage facilities as well as flue gas cleaning installations), while requiring only a relatively modest investment of typically \$50-\$300/kW of biomass capacity to include a fraction of biomass in the fuel [1]. These costs compare favorably with essentially any other available (hydropower being regarded as largely unavailable) renewable energy option. However, as cofiring usually displaces fossil power without increasing total capacity, the capital costs with which to compare the previously quoted numbers is \$0/kW rather than the more typical \$900/kW for coal. In cases where additional capacity is anticipated, capital costs for cofiring are much higher when, for example, induced draft fans and other common capacity limiting subsystems must be replaced or upgraded.

Operating costs are typically higher for biomass than for coal. The most sensitive factor is the cost of fuel, resulting in energy crops suffering large economic disadvantages relative to residues. Even if the fuel is nominally free at the point of its generation (as many residues are), its transportation, preparation, and on-site handling typically increase its effective cost per unit energy such that it rivals and sometimes exceeds that of coal. A general conclusion is that biomass cofiring is commonly slightly more expensive than dedicated coal systems. If there are no motivations to reduce CO<sub>2</sub> emissions, the rationale for cofiring is difficult to establish. If compared to alternative renewable energy sources however, biomass cofiring generally turns out to be significantly cheaper.

Due to the high steam parameters and technical measures for efficiency improvement available in coal power plants, conversion efficiencies ranging from 30-38 % (higher-heating value basis) can be achieved, easily exceeding efficiencies in dedicated biomass systems and rivaling or exceeding the estimated efficiencies of many future, advanced biomass-based systems. Addition of biomass to a coal-fired boiler does not impact or at worst slightly decrease the overall generation efficiency of a coal-fired power plant [2]. Minor changes in efficiency (either positive or negative) may occur due to more or less energy intensive fuel preparation and handling, while the typically increased moisture content in the fuel will slightly reduce the overall efficiency.

When proper choices of biomass, coal, boiler design, and boiler operation are made, traditional pollutants (SO<sub>x</sub>, NO<sub>x</sub>, etc.) and net greenhouse gas (CO<sub>2</sub>, CH<sub>4</sub>, etc.) emissions decrease. Ancillary benefits include a reduced dependency on imported fuels and decreased demand for disposal of residues. These advantages can be realised in the very near future with relatively low technical risk. Therefore, commercialization of cofiring technologies offers among the best short- and long-term solution to greenhouse gas emissions from power generation. Since cofiring is not an option in all localities, a robust biomass utilization strategy requires development of alternative technologies as well. However, the effectiveness of the cofiring option, combined with its low cost and low technical risk, should place it high on a priority list of institutions considering an array of greenhouse gas options.

## Current status

There has been remarkably rapid progress over the past 5-10 years in the development of the co-utilisation of biomass materials in coal-fired boiler plants. Several plants have been retrofitted for demonstration purposes, while another number of new plants are already being designed for involving biomass co-utilisation with fossil fuels. A recent inventory on the application of co-firing worldwide [3] shows that over 80 coal-powered plants have experience with cofiring biomass or waste. Typical power stations where co-firing is applied are in the range from approximately 50 MW<sub>e</sub> (a few units are between 5 and 50 MW<sub>e</sub>) to 700 MW<sub>e</sub>. The majority are equipped with pulverised coal boilers (tangentially fired, front-wall fired, back-wall fired, dual-wall fired and cyclone). Furthermore, bubbling and circulating fluidised bed boilers, cyclone boilers, and stoker boilers are used. Tests have been performed with every commercially significant (lignite, subbituminous coal, bituminous coal, and opportunity fuels such as petroleum coke) fuel type, and with every major category of biomass (herbaceous and woody fuel types generated as residues and energy crops).

Basically one can distinguish three different concepts for cofiring biomass in pulverised coal boilers, all of which have already been implemented either on a demonstration or a fully commercial basis, and each with its own particular merits and disadvantages. Direct cofiring is the most straightforward applied, most commonly applied and low-cost of all. Biomass fuel and coal are burned together in the same furnace, using the same or separate mills and burners depending on the biomass fuel characteristics. In the concept of indirect cofiring, a biomass gasifier can be used to convert solid biomass raw materials into a clean fuel gas form, which can be burned in the same furnace as coal. This offers the advantages that a wider range of biomass fuels can be used (e.g. difficult to grind) and that the fuel gas can eventually be cleaned and filtered to remove impurities before it is burned. Experiences with this option are rather limited. Examples are the Zeltweg plant in Austria and the AMERGAS project in the Netherlands.

Finally it is also possible to install a completely separate biomass boiler and increase the steam parameters in the coal power plant steam system. An example is the Avedore Unit 2 Project in Denmark.

## Main barriers

If not carefully designed, firing biofuels in an existing coal fired power plant involves risks of increased plant outages, possible interference with the operation of the burners, the furnace, the boiler convective section, and the environmental control equipment. The major technical challenges associated with biomass cofiring include:

- fuel preparation, storage, and delivery
- ash deposition,
- fuel conversion,
- pollutant formation,
- increased corrosion rates of high temperature components,
- fly ash utilization,
- impacts on SCR systems, and
- formation of striated flows.

Previous reports have focused on many of these issues (primarily the first five), the conclusions of which are summarized in the sections below. A detailed description of all of the above barriers can be found in the Handbook of Biomass Combustion and Cofiring [4].

## Fuel preparation, storage, and delivery

The preparation, storage, and handling properties of biomass impact are different from coal. Biomass has low bulk energy density, is generally moist and strongly hydrophilic, and is non-friable. Biomass heating values generally are slightly over half that of coal, particle densities are about half that of coal, and bulk densities are about one fifth that of coal. This results in an overall fuel density roughly one tenth that of coal. Consequently, cofiring biomass at a 10% heat input rate results in volumetric coal and biomass flow rates of comparable magnitudes. Consequently, biomass demands shipping, storage, and on-site fuel handling technologies disproportionately high compared to its heat contribution.

Biomass produces a non-friable, fibrous material during comminution. It is generally unfeasible (and unnecessary) to reduce biomass to the same size or shape as coal. In many demonstration plants, biomass firing occurs with particles that pass through a ¼" (6.4 mm) mesh, which measurements indicate results in a size distribution dominantly less than about 3 mm. Depending on the type of biomass and preparation technique, average aspect ratios of these particles range from three to seven, with many particles commonly having much higher aspect ratios. Such particles have very low packing densities and create challenges when pneumatically or otherwise transporting biomass fuels.

## Ash deposition

Although the ash contents of both wood and straw materials are significantly lower than those of most power station coals, the ash chemistry and mineralogy are very different. In general terms, biomass ashes have relatively low ash fusion temperatures, with deformation temperatures commonly in the range of 750 to 1000°C, compared to values in excess of 1000°C for most coal ashes. Even at modest cofiring ratios, the co-firing of biomass materials can have a major impact on the ash fusion behaviour. The rate and extent of coal ash slag formation on surfaces in the boiler furnace tends to increase, due principally to the decrease in the fusion temperatures of the mixed biomass-coal ashes, since fused or partially fused slag deposits tend to be more receptive to oncoming particles and grow more rapidly. The impact of co-firing on slag deposition depends largely on the chemistry and the fusion behaviour of the coal ash and the co-firing ratio.

A simple index has been developed [5], which can be used to assess the fouling propensity of a fuel or mixed fuel ash. The index is based on the mass in kg of alkali metal oxides ( $K_2O + Na_2O$ ) introduced into the system per GJ heat input to the furnace. At index values above 0.17 kg per GJ, significant fouling of the boiler convective section is probable. At index values in excess of 0.34 kg per GJ, severe fouling is to be anticipated. Most biomass materials, and particularly those from fast-growing plants, will have index values in excess of 1 kg per GJ, whereas most coals have relatively low values, generally less than 0.1 kg per GJ.

## Fuel conversion

These large and non-spherical particles pose challenges for fuel conversion efficiency. Coal particles of such size would not nearly burnout in a coal boiler, but there are compensating properties of biomass. Biomass yields a much higher fraction of its mass through devolatilization than does coal. Typically biomass of the size and under the heating rates typical of pc-cofiring yields 90-95% of its dry, inorganic-free mass during devolatilization, compared with 55-60% for most coals.

Devolatilization occurs rapidly and is temperature driven, therefore most biomass fuels will yield at least this fraction of mass so long as they are entrained in the flue gases. Biomass particles too large or dense to be entrained sometimes enter the bottom ash stream with little or no conversion beyond drying. However, these are generally the exception for well-tuned fuel preparation systems. Secondly, the low particle densities help biomass particles oxidize at rates much higher than coal. However, excessive moisture or excessive size particles still may pose fuel conversion problems for biomass cofiring despite these mitigating effects.

## **Pollutant formation**

Pollutant formation during biomass cofiring exhibits all the complexities of pollutant formation during coal combustion.  $\text{SO}_x$  generally decreases in proportion to the sulfur in the fuel, which is low for many (but not all) biomass fuels.  $\text{NO}_x$  may increase, decrease, or remain the same, depending on fuel, firing conditions, and operating conditions. However, the  $\text{NO}_x$  chemistry of biomass shows the same, complex but conceptually well understood behavior as  $\text{NO}_x$  chemistry during coal combustion with the exception that biomass appears to produce much higher  $\text{NH}_3$  content and a lower HCN content as a nitrogen-laden product gas compared to coal. Some of the commercially most mature biomass fuels, notably wood, contain relatively little fuel nitrogen and cofiring with such fuels tends to decrease total  $\text{NO}_x$ . However, general industrial experience is not consistent with the sometimes suggested truism [1, 2] that  $\text{NO}_x$  reduction when cofiring biomass exceeds the fuel nitrogen displacement effect by 10%. Biomass fuels also commonly contain more moisture than coal, decreasing peak temperatures and leading to commensurate decreases in  $\text{NO}_x$ .

## **Corrosion**

Figure 1 and Figure 2 indicate previously reported results [6,7,8] illustrating how sulfur from coal helps mitigate chlorine-based corrosion in boiler deposits from biomass. The principal result is that alkali chlorides that sometimes condense from chlorine-laden biomass fuel flue gases react with  $\text{SO}_2$ , generated primarily from coal, to form alkali sulfates, which are significantly less corrosive.

Figure 3 illustrates theoretical (equilibrium) predictions that illustrate that this only occurs under oxidizing conditions. Under reducing conditions, chlorides, not sulfates, and the stable form of alkali species under typical boiler heat transfer conditions. Therefore, the ameliorating effects of coal-derived sulfur on corrosion during cofiring do not occur in regions of boilers where deposits are exposed to reducing conditions. Further experimental data indicates that even under oxidizing conditions, chlorine deposits may persist for many hours if deposit temperatures are very cool, reducing the kinetic rates of conversion to sulfates.

## **Fly Ash Utilization**

The concrete market presents among the best fly ash utilization opportunities for coal-derived fly ash. However, the ASTM specification (ASTM Standard C618) for use of fly ash in concrete requires that the fly ash be derived entirely from coal combustion. Many processes in modern boilers result in coal fly ash mingled with other materials, including ammonia from pollutant control devices, sorbents or other injected materials from scrubbers, residual sulfur or other compounds from precipitator flue gas treatments, and fly ash from cofired fuels such as biomass. There is a broad, but not universal,

recognition that the standard should be modified, but it is not clear what modifications should be made. Here some preliminary results regarding the impact of biomass-derived ash on concrete properties are presented.

This systematic investigation of the impact of biomass- and coal-derived fly ash on concrete involves both Class C (subbituminous) and Class F (bituminous) fly ash as well as similar fly ashes mingled with herbaceous and woody biomass fly ash. In all cases, 25% of the cement originally used in the concrete is displaced by fly ash, with the fly ash containing 0-40% biomass-derived material. Tests of concrete air entrainment, flexural strength, compressive strength, set time, freeze thaw behavior, and chlorine permeability determine the extent of the biomass impact. Only selected results are presented here and, as the tests require up to a year to conduct, all results are preliminary. The focus is on the herbaceous biomasses, since many woody fuels contain so little ash that practical cofiring is not likely to have a measurable impact on fly ash properties.

Figure 4 illustrates the impact of fly ash on the required amount of aerating agent to establish ASTM-compliant air entrainment levels in concrete. Air entrainment in concrete is essential to prevent failure during freeze-thaw cycles. As is apparent, the amount of aerating agent increases with increasing herbaceous biomass content. This dependence arises from the effect of water soluble components (higher in herbaceous biomass than in coal fly ash) tying up the aerating agent (generally surfactants), preventing them from forming films that support bubble growth. The impact illustrated is of minor economic concern but is of major process concern. That is, if fly ashes from cofired units were treated the same way as fly ashes from coal, the resulting concrete would likely fail under freeze thaw cycles. Increasing the surfactant to an acceptable level is of little economic impact, but failure to recognize the need to adjust it is of major impact.

Figure 5 illustrates the impact of biomass-coal commingled fly ash on flexural strength. In these test little significant difference is seen among the various samples. Additional data on set time and compressive strength indicate that all fly ashes delay set time by 2-4 hours compared to concrete made from cement only but the biomass-containing fly ash does not delay set times significantly more than the non-biomass containing fly ash. Early compressive strength (in the first month or so) is compromised by all fly ashes, again with the biomass-containing fly ash similar to coal fly ashes. However, late strength (longer than 2 months or so) is enhanced by the presence of all fly ashes.

In conclusion, there appear to be only manageable impacts of biomass-containing fly ash on concrete properties based on these preliminary data, with amount of aerating agent being an example of one issue that requires monitoring. Otherwise, biomass-containing fly ash behaves qualitatively similar to coal fly ash with no biomass in terms of structural and performance properties when incorporated into concrete.

## **Formation of Striated Flows**

Many boilers do not mix flue gases effectively in furnace sections, resulting in gas compositions near the boiler exit that reflect burner-to-burner variations in stoichiometry and other properties. The impact of such behavior during cofiring can be an issue if one is hoping, for example, that sulfur from coal will mix with biomass-derived flue gases to ameliorate corrosion. Biomass is commonly injected in only a few burners. If the gases do not mix thoroughly, many regions of the boiler will be exposed to much higher biomass cofiring percentages than suggested by the overall average.

Advanced computational fluid mechanics models illustrate the impact of striations on ash deposition. Figure 6 illustrates the deposition patterns predicted on superheater tubes under conditions where such striations exist. As illustrated, there are large local variations in the rate of deposit accumulation. These arise from lack of complete mixing and striation in gas composition, gas temperature, gas velocity, particle loading, and other similar properties (not illustrated). Such results are highly system dependent but are believed to be a common feature of biomass-coal combustion as well as both dedicated coal and dedicated biomass combustors.

## Impacts on SCR Systems

There is evidence from cofiring demonstrations conducted in European SCR-equipped boilers that cofiring biomass with coal results in significant deactivation of SCR catalysts. The reasons for this deactivation are not definitive, but laboratory analyses confirm that alkali and alkaline earth metals are significant poisons to vanadium-based catalysts (which would include all commercial SCR systems) when the metals are in intimate association with the catalyst. Essentially all biomass fuels contain high amounts of either alkali or alkaline earth metals or both as a percentage of ash. Some biomass fuels, however, have remarkably low ash contents, clean heartwood such as sawdust being a classical example. It is possible that the commercially observed SCR deactivation arises from such poisoning or from catalyst fouling, which is also associated with such poisoning.

Figure 7 illustrates results from surface composition analyses from a catalyst exposed to the slipstream of a combustor firing alkali- and alkaline-earth-rich fuels. These normalized compositions and detection limits show that this catalyst, which experienced significant deactivation, is enriched in sulfur and alkali and alkaline earth metals after exposure relative to the pre-exposure concentrations. By contrast, the surface vanadium content decreased (by dilution). These results are consistent with the general hypothesis that alkali and alkaline earth metals can cause catalyst deactivation, but they do not indicate by what mechanism such deactivation occurs.

This issue will become increasingly important as increased numbers of boilers install SCR system to comply with lower NO<sub>x</sub> emission limits. The authors are engaged (with others) in several investigations to more fully explore this phenomenon, including advanced laboratory and field tests.

## Conclusions

Biomass cofiring with coal represents an attractive option for reducing greenhouse gas emissions from coal-fired boilers. In general, there are compelling reasons to pursue this option as reviewed in the introduction. However, there are many issues that, if not carefully managed, could compromise the boiler or downstream processes. Results to date indicate that these are all manageable but that they require careful consideration of fuels, boiler operating conditions, and boiler design.

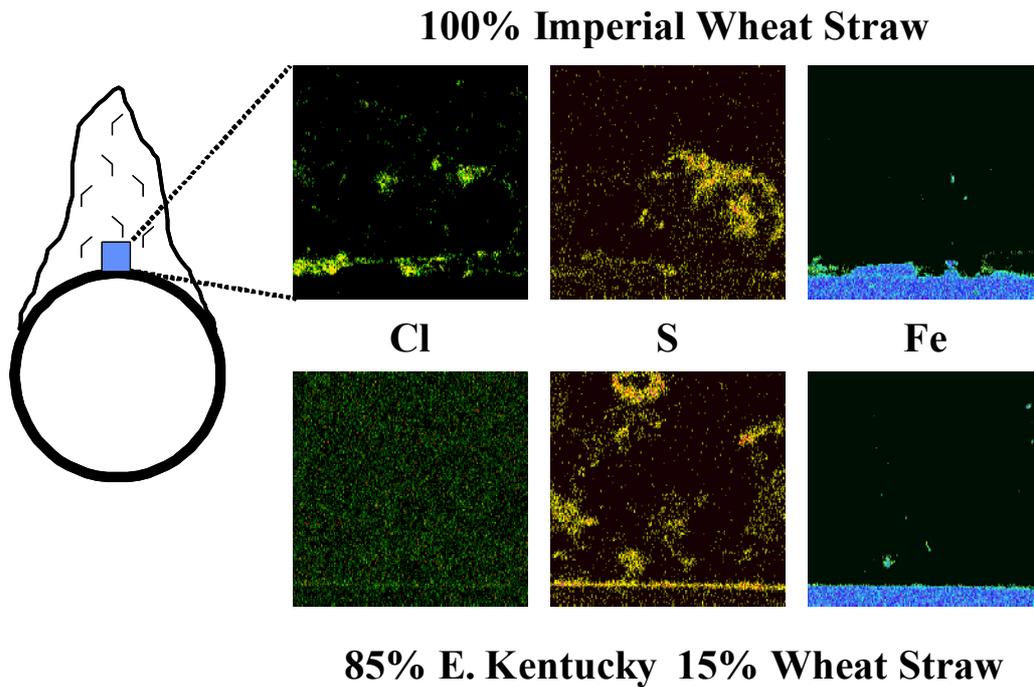


Figure 1 SEM images illustrating formation of chlorine layers on simulated boiler tubes and the effect of coal-derived sulfur during cofiring in eliminating the chlorine layers [6, 7, 8].

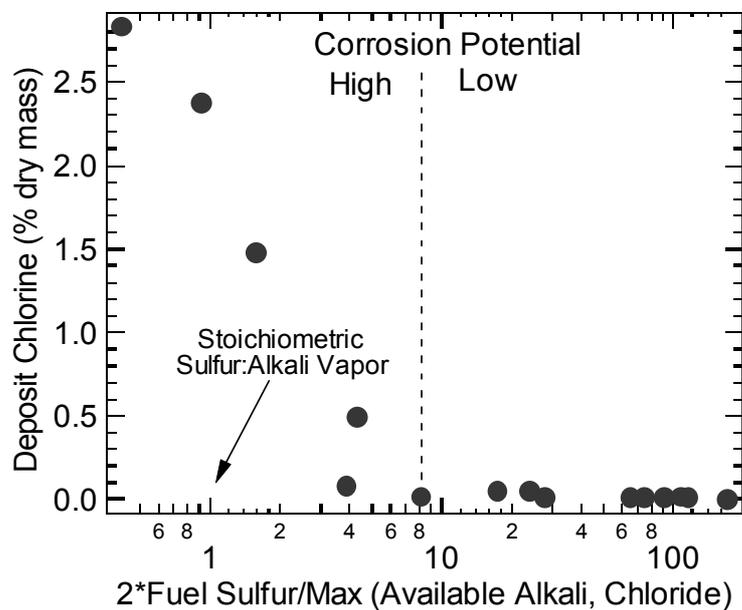


Figure 2 Results from systematic variation of fuel chlorine to sulfur ratios and the resulting chlorine content of deposits under standardized testing conditions [6,7,8].

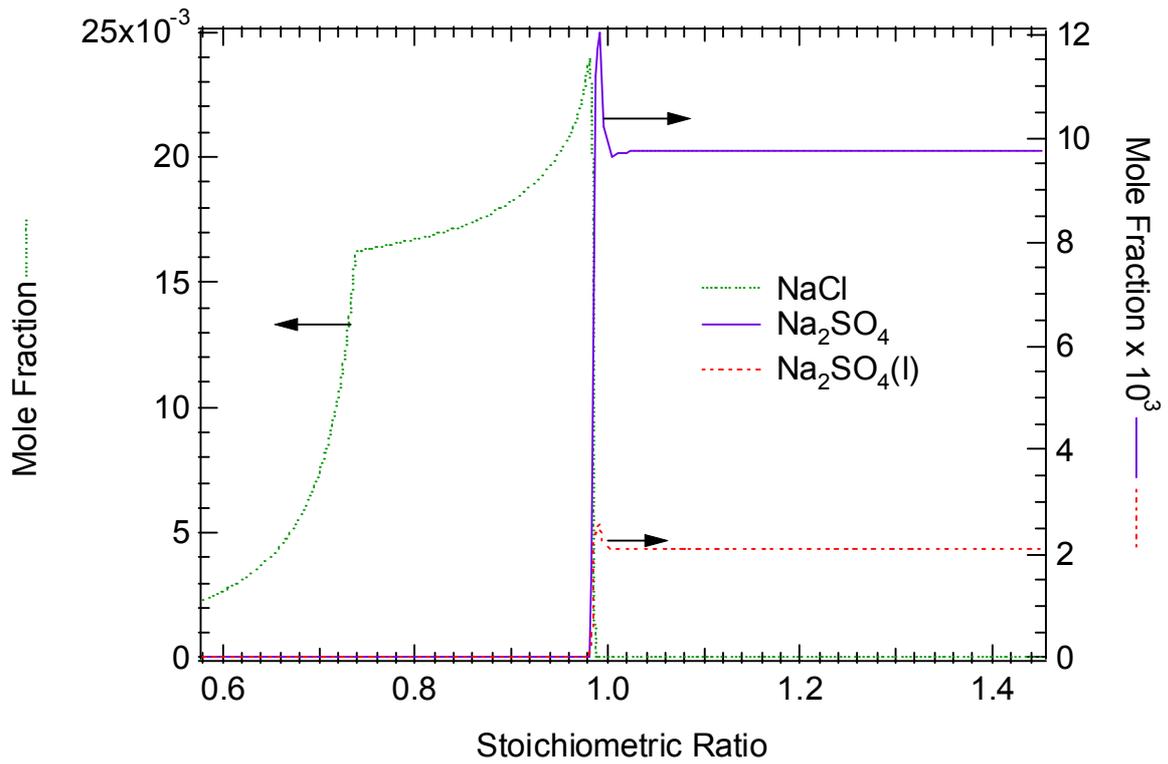


Figure 3 Illustration of predicted stoichiometric dependence of chlorine concentration in deposits.

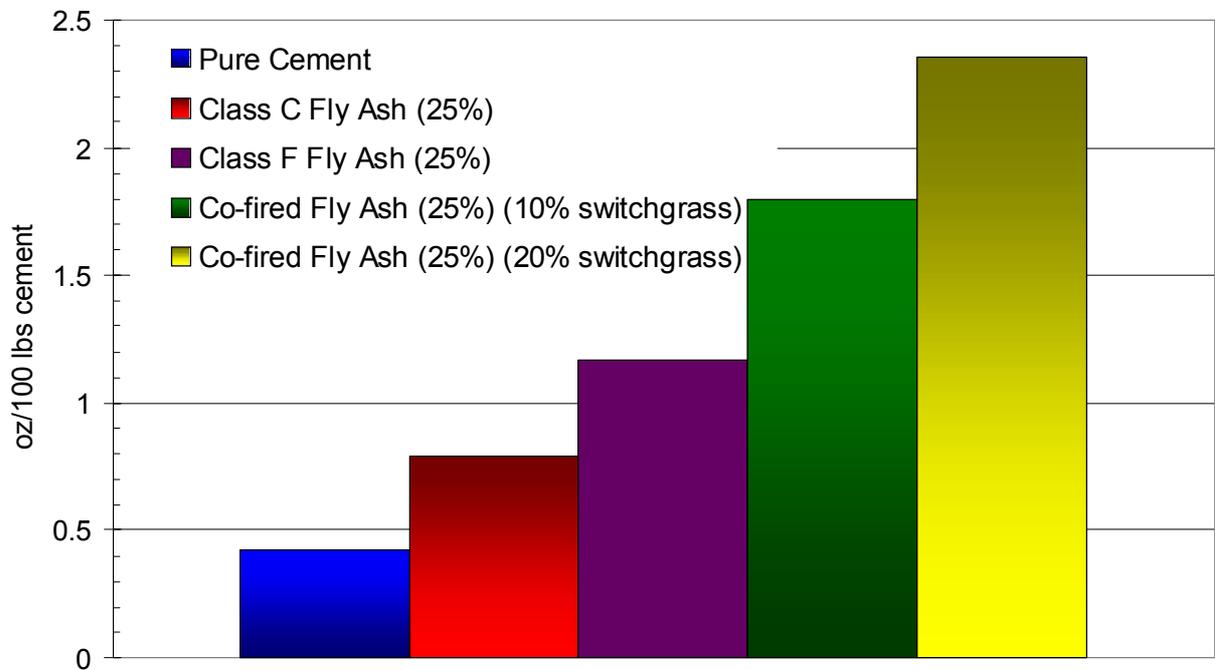


Figure 4 Required amount of aerating agent required to generate air entrainment within ASTM specifications for a variety of fly ash compositions.

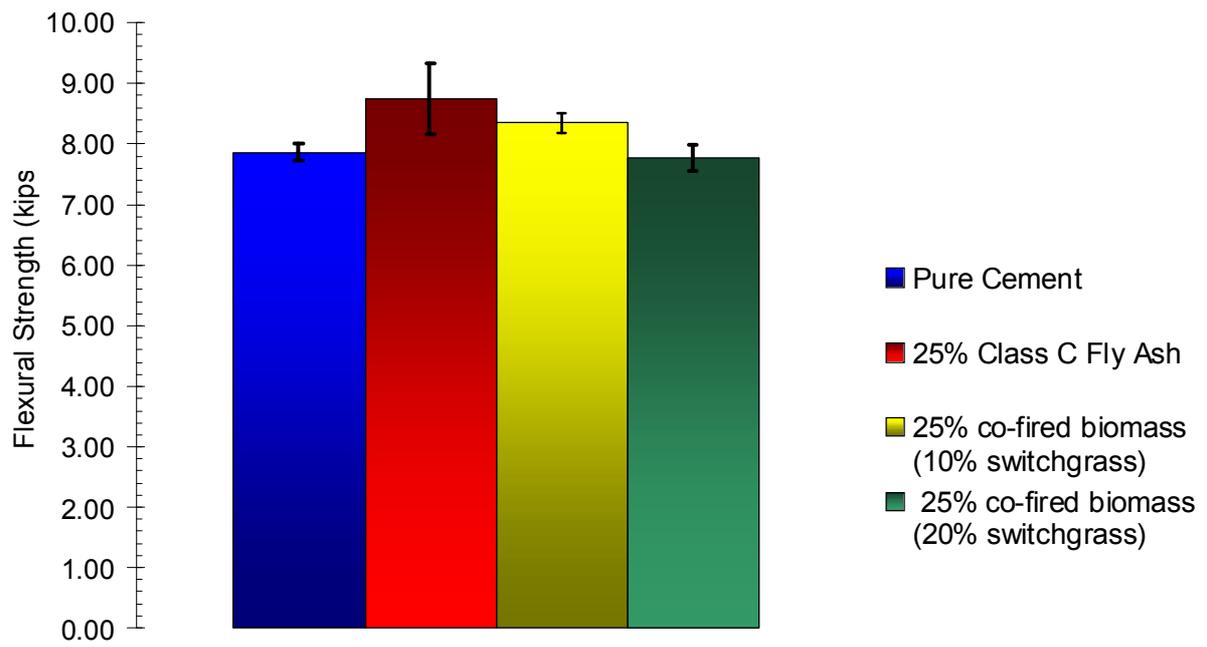


Figure 5 Flexural strength and its dependence on fly ash composition.

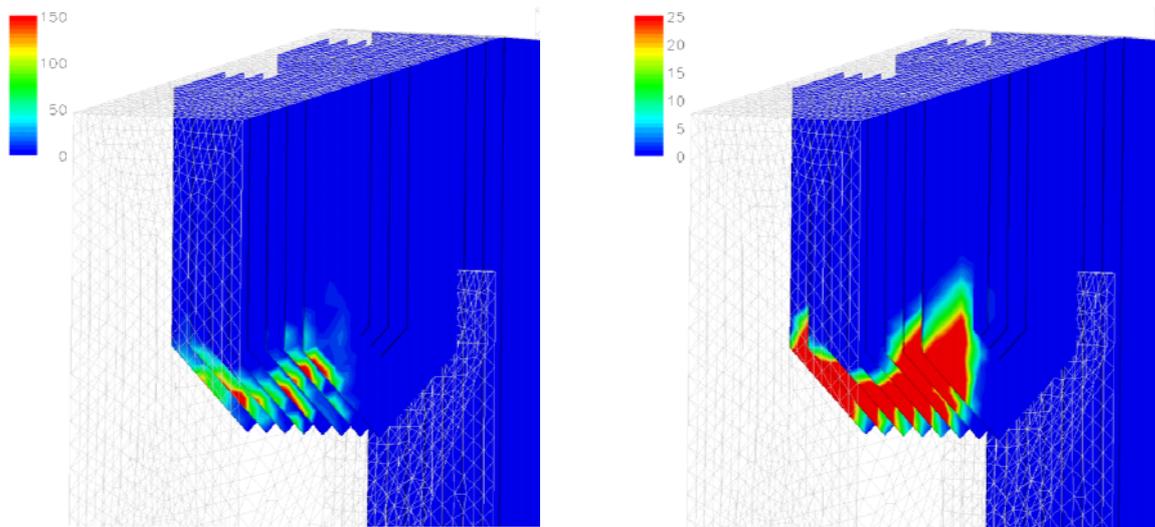


Figure 6 Impacted of temperature, velocity, and gas composition striations on two major classes of deposit formation mechanisms: impaction mechanisms (left) and boundary-layer mechanisms (right).

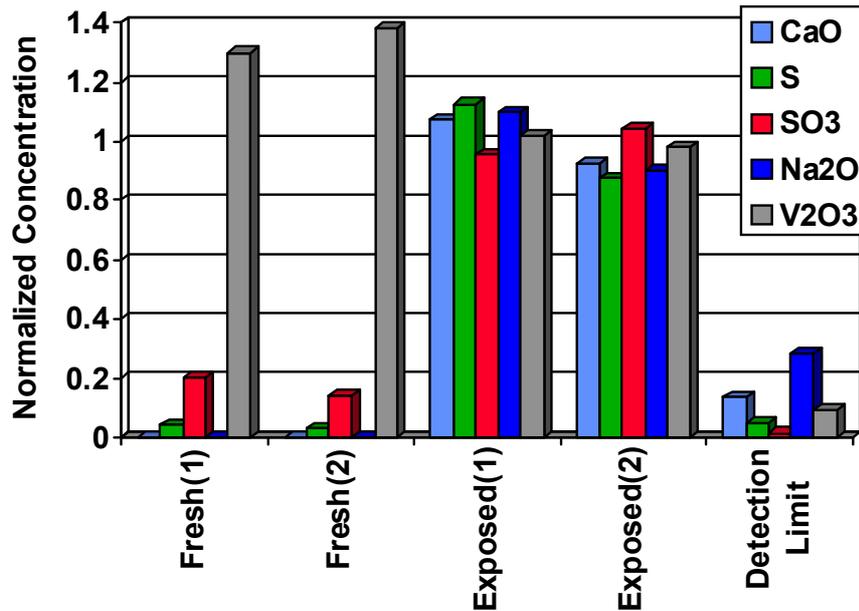


Figure 7 Concentrations of key elements (reported as oxides) in pre- and post-exposed catalyst from a slip-stream reactor.

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