2   Technology Evaluation

Understanding the gasification approach to co-firing requires a review of the current status of co-firing, the issues raised and the lessons learned, and the consequent market position of direct combustion co-firing. Identifying how gasification addresses the unresolved issues of direct combustion co-firing facilitates this understanding.

2.1   Overview of Co-firing Technologies

There are two principal co-firing technologies that have been tested in the power plant boilers with some success. But long-term continuous co-firing has not been adopted due to unresolved issues identified in Section 2.2.

2.1.1   Low Percentage Co-firing:

Low percentage co-firing is typically designated as blending <5 percent biomass (mass basis) with coal as primary fuel for the boiler. The biomass component is typically <2 percent of the heat input to the boiler.

There have been several low percentage co-firing tests and demonstrations, including the following:

- Colbert Fossil Plant, TVA
- Shawville Generating Station, GPU Genco
- Kingston Fossil Plant, TVA
- Plant Hammond, Georgia Power Co.
- Plant Yates, Georgia Power Co.

These tests and demonstrations provided critical results for co-firing. They demonstrated that co-firing at low percentages does not impact boiler stability, operability, or efficiency. Further, it does not impact airborne emissions.

2.1.2   Direct Combustion Co-firing with Separate Feed Systems

There have been several demonstrations of co-firing using separate feeding of biomass into the boiler. In these demonstrations the biomass is reduced in particle size to an acceptable level (typically 6 mm or <1/4" for wood waste) and then pneumatically transported into burner systems of the boiler. In these systems, biomass typically supplies about 5 to 10 percent of the heat input to the boiler, or 10 to 20 percent of the mass input of fuel to the boiler. This approach has been tested by co-firing with wood waste and with processed switch grass at following facilities:

- Seward Generating Station, GPU Generating Co (wood waste)

- Greenidge Station, NYSEG (wood waste)
- Plant Kraft, Savannah Electric (wood waste)
- Blount St. Station, Madison Gas & Electric (switch grass)

These tests all documented the fact that if separate feeding were employed and if there was no impact on the coal delivery system, boiler capacity would not be impaired by co-firing. In cases where biomass was substituted for coal in coal burners, capacity impacts did occur as a consequence of substituting a low Btu fuel for a high Btu fuel. However, in most cases the biomass injection was independent of the coal injection. Co-firing provided capacity assistance, particularly in conditions where wet coal was being burned. Particle size becomes a concern. Wood waste particles must be < 6 mm (<1/4") while switch grass must undergo maximum particle size reduction to achieve acceptable minor dimension values. Concerns are both for the kinetics of combustion and the aerodynamic properties of the fuel, keeping the fuel from simply falling in to the bottom ash pit.

While co-firing with separate feeding resolved the capacity issue, it provided additional benefits as well as concerns. Boiler efficiencies were reduced modestly, based upon the moisture in the fuel and the hydrogen content of the fuel. When co-firing at 10 percent by heat input, there was no need to increase the excess air to the system, and there was no increase in the air heater exit temperature. Unburned carbon increases were modest, and statistically insignificant. Emissions were reduced. SO_2 emissions were reduced as a function of co-firing a sulfur-free fuel. NOx, emissions were reduced consistently in wall-fired PC boilers and in cyclone boilers; the data on these emissions are not as consistent in tangentially fired PC boilers. Opacity emissions improved in some cases, but not in others.

2.1.3 Issues remaining to be resolved with co-firing

The low percentage co-firing tests identified two issues: pulverizer capacity and ash management. When the capacity of a boiler is limited by the capacity of the pulverizers, co-firing can have significant impacts on overall system capacity. Ball and race mills experienced increased feeder speeds and increased amps and power consumption. Bowl mills experience decreased mill outlet temperatures and increased amps. A 3 percent co-firing level can decrease capacity by as much as 6 to 8 percent when pulverizer limitations are severe. When co-firing is practiced, the biomass fly ash is commingled with the coal fly ash. While many types of biomass are very low in ash, some are not. Further, there is a definitional issue with respect to ASTM Specification C-618, the pozzolan specification. That document clearly defines fly ash as coal fly ash. While the history of that specification includes considerations for excluding municipal waste fly ash from use in concrete mixtures, the consequence is to prevent the sale of any co-firing or biomass firing fly ash in concrete mixtures.
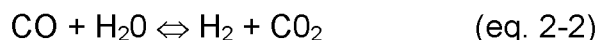
Co-firing that uses separate injection and direct combustion does avoid the fuel feed system limitations but does not address the issue of commingled ash. Consequently, for plants selling fly ash, the high-end concrete market may remain unavailable.

2.2 Gasification Technologies

Direct combustion does not represent the only method of co-firing biomass with an existing fuel. Biomass can be gasified to produce a combustible gaseous product that can also be used in existing boilers.

Biomass gasification and pyrolysis is a technology that has existed for over 100 years. Research into this technology was particularly active in the 1920's and 1930's, when the use of biomass for vehicular travel was being pursued. With the advent of low cost oil and natural gas, interest in biomass gasification waned. However, with the dramatic oil price shocks of the 1970's and with subsequent environmental pressures, interest in biomass gasification has become substantial and several new projects have been put forward for funding and financing.

The principles of thermal gasification for biomass have been well established. The reaction sequences include fuel-drying, pyrolysis to produce gaseous compounds and chars, and reactions of those gaseous compounds and chars to form the producer gas product. Pyrolysis of biomass is the degeneration of cellulous, lignin and the other biomass building blocks that produces a full range of compounds ranging from hydrogen and methane to long chain condensable hydrocarbons, commonly referred to as tars. Secondary reactions include the steam-carbon reaction producing CO and H_2 from the char (eq. 2-1), the water-gas shift reaction to increase the H_2 content in the gas (eq. 2-2), and the Boudouard reaction generating CO from the char and the CO_2 in the product gas (eq. 2-3).

$$C + H_2O \Leftrightarrow CO + H_2 \qquad \text{(eq. 2-1)}$$

$$CO + H_2O \Leftrightarrow H_2 + CO_2 \qquad \text{(eq. 2-2)}$$

$$CO_2 + C \Leftrightarrow 2CO \qquad \text{(eq. 2-3)}$$

The tars formed typically begin to condense out of the gas at about 425°C (800°F). To prevent this, the gas can be maintained at elevated temperatures so the tars can be combusted with the gas, cracked into non-condensable components by passing the tar laden gas over a catalyst at elevated temperatures, or scrubbed out of the gas.

Most of the char is combusted in the gasifier system to provide heat for the pyrolysis. Any char not completely converted to gas is usually discharged with

the ash products. Inorganic matter (e.g., potassium in the ash) may remain in the solid phase or may exit with the gas in the vapor phase.

Pyrolysis takes place without the presence of free oxygen, i.e. air; while gasification is done under sub-stochiometric conditions, with less than required amount of oxygen for complete combustion. The use of air will dictate the heating value of the product gas. Pyrolysis of biomass in the absence of air will provide a medium calorific value gas while air blown gasification systems will provide a low calorific value gas. If air is present, the ratio of free oxygen input to biomass feed is typically around 0.30.

The simplest air gasifier is the updraft (counter flow) gasifier, in which air is introduced to the biomass through grates in the bottom of the furnace. Rather high temperatures are generated initially where the air first contacts the char, but the combustion gases immediately enter a zone of excess char, where any CO2 or H20 present is reduced to CO and H_2 by the excess carbon. As the gases rise to lower temperature zones, they meet the descending biomass and pyrolyze the mass in the range of 205°C (400°F) to 480°C (900°F). Continuing to rise, they contact wet, incoming biomass and dry it. The counter flow of gas and biomass exchanges heat so that the gases exit at low temperatures.

Simplicity is a major advantage of these systems, and countercurrent gasification has long been employed both for biomass and coal. The original Lurgi gasification system is an updraft gasifier. However, the updraft gasifier has several drawbacks. First, the gasification zones, while maximizing mass transfer, also produce a gas sufficiently low in temperature to contain a wide variety of chemicals, tars, and oils that are generated in the pyrolysis zone. Because of the low gasifier exit temperatures, these contaminants can be allowed to condense in cooler regions of the gasifier exhaust pathway designed for this purpose, before the producer gas is transferred for co-firing in the boiler.

Alternatively, the producer gas can be partially oxidized to elevate its temperature above the tar condensation limit. For this reason, this gas is generally used in the "close-coupled" mode in which it is mixed immediately with air and a portion burned completely to CO_2 and H_2O. The close-coupled mode is quite suitable for supplying a biomass gas to existing coal, oil or gas furnaces. The higher temperature at the gasifier grate may melt the ash and produce slagging on the grates with feedstock such as rice hulls and corncobs.

Primenergy, of Tulsa, OK, currently is a leading supplier of updraft or countercurrent gasifiers. Their technology has been applied to a wide variety of biomass including wood waste, rice hulls, switch grass, and other biomass feedstocks. These types of gasifiers have been installed in a variety of applications throughout the world, including a significant number of cogeneration applications. Initial gasification runs using poultry litter in the Primenergy gasifier indicates that these environmental and operating issues can be controlled to

acceptable levels, but this performance needs to be verified for the conditions when the gasifier is coupled with existing boiler and can be tested.

The process proposed for this application is an air blown gasification. In this system, coarse biomass is processed in a thermal gasifier, with the product gas being fired in a boiler. The gas will be unconditioned and fired at elevated temperatures 540°C -875°C (e.g., 1,000°F -1,600°F). If conditioning is required, the gas may be cleaned and partially quenched prior to use.

When this technique is used in coal-fired boilers, separate gas burners are required. Similarly, if this technique were used in natural gas-fired boilers, separate burners designed for low Btu gas would be necessary. Air-fuel ratios for natural gas combustion and for low Btu gas combustion are sufficiently different, and gas volumes are different, to make this adjustment necessary.

Gasification-based co-firing has not been widely practiced. However it is the basis for this proposed activity.

2.3   Hot Gas Filtration System

Hot-gas cleanup and filtration technologies play an important role in the gasification process. The main difference between hot gas cleanup systems (HGCUs) and conventional particulate removal technologies (ESP and baghouses) is that HGCUs operate at higher temperatures (500 to 1,000°C) and pressures (1 to 2 MPa), which eliminates the need for cooling of the gas.

HGCU technologies include ceramic candle filters, ceramic cross-flow filters, screenless granular-bed filters, acoustic agglomerators and hot electrostatic precipitators.

In a ceramic candle filter system, the hot gases from the gasifier flows from the outside of the candle to inside. The particulates are collected on the outside surface of the candles, and the clean gas flows to the top of the pressure vessel and the stack through the gas outlet. Periodic cleaning of the candles is done by injecting nitrogen or other inert gases from the blowback air reservoir.

Typical HGCUs can meet up to 99.9 percent removal efficiency of particulates larger than 10 microns.

2.4   Environmental Impact of Gasification

The greenhouse gases, primarily carbon dioxide, (CO_2), methane (CH_4), and pollutants namely nitrous oxide (NO_x), sulfur dioxide (SO_2) and particulates which are associated with industrial and agricultural activities, affect earth's environment and have significant impact on the climate. Table 2-1 shows

selected greenhouse gasses that have been present in Earth's atmosphere due to both natural and human activities prior to pre-industrial period and the current period.[3]

Table 2-1 Selected Greenhouse Gases Prior to 1850 v/s 1994

	Carbon Dioxide	Methane	Nitrous Oxide
Pre Industrial Concentration (Prior to 1850)	278 ppmv	700 ppbv	275 ppbv
Concentration in 1994	358 ppmv	1720 ppbv	312 ppbv
% Change from Pre-industrial times	29%	146%	13%

One way to reduce these green house gases is to displace some of the carbon that is now emitted to the atmosphere from the combustion of fossil fuels with carbon derived from renewable resources. No new net atmospheric buildup of CO_2 or methane occurs in biomass combustion when the biomass is grown on a sustainable basis, because the released carbon dioxide is largely compensated by the amount of carbon dioxide withdrawn from the atmosphere during photosynthesis in the growth cycle.

Table 2-1 shows that the global average methane concentration in 1994 has more than doubled since pre-industrial times. One source of methane is from anaerobic decomposition of organic material in livestock and poultry manure. The reduction of methane released to the atmosphere can be achieved by installing recovery systems that extract methane as a fuel from the anaerobic digestion of liquid manure, but it is profitable only for large farms in warm climates where anaerobic processes can be more readily sustained. Alternatively, this manure can be converted in a gasification system to recover useful energy and, at the same time, reduce methane emissions.

The poultry litter has been gasified and tested for emission by Primenergy at their Tulsa, OK commercial size test facilities in accordance with US EPA standards. The unabated test data collected during the demonstration testing are presented here in Table 2-2 for evaluation.[4] The test was conducted on the stack after burning the producer gas from the gasifier in the heat recovery steam generator. This data were collected by a third party stack testing outfit for Primenergy.

As shown in the table, the gasification process can be used to reduce the amount of greenhouse gases and other pollutants that result from decaying biomass while producing useful thermal energy and displacing the fossil fuel.

Table 2-2 Unabated Emissions Data for Poultry Litter Test Gasification Run

Component	Value
NO, ppmvd	477
CO, ppmvd	0.88
SO_2, ppmvd	193
Non-methane hydrocarbons, ppmvd	2.46
Particulate matter, gr/dscf	0.33
O_2, ppm dry volume	11.5

Source: CETCON, INC. " Summary of Results: Test No. C1", September 15, 1997.

Under cofiring, application, the litter can be used to reduce other pollutants from the coal plant by reducing the amount of coal burned. The following table 2-3 provides a comparison between the coal plant emissions and expected emissions from gasification and controlled combustion of the producer gas in a boiler.

2.4.1 Comparison of Coal v/s Litter Burn

Typical coal and litter samples and expected emissions from the two sources can be estimated. In estimating the emissions presented in Table 2-3, following assumptions are made:

- S in coal is elemental S and hence ends up as SO_2 in complete oxidizing environment normally present in a coal fired boiler. S in the litter is compound S and as such, some of it remains in the ash as Alkaline sulfates. Hence, the calculated 1.02 kg/MJ (2.14 lbs/MMBtu SO_2) is high end SO_2 when gasifying litter. It is expected that may be 50% of the S will remain in the ash, as evident from elemental analysis of ash with 4% SO_3 in the ash. Thus, litter gasification in a cofiring application can reduce SO_2 from high sulfur burning coal plant.

- On GJ (MMBtu) basis, carbon is about the same in litter and coal, and hence CO_2 emissions from litter or coal are a wash. However, from life cycle perspective, CO_2/ Carbon is considered closed loop for biomass, and hence no new net CO_2 is introduced in to atmosphere from the chicken/ litter cycle.

- N in the coal is elemental N and all NOx produced is thermal NOx due to combustion in the air. Litter has high bound nitrogen that is gasified into amines, amines, urea, etc. If burned in regular boiler in an oxidizing atmosphere, it will generate very high NOx – as much as 2000 ppm. But by external after burn in a reducing atmosphere, the amines, amines,

urea, etc. are broken down into elemental N and water/CO2. Primenergy expects NOx from gasifier to be less than 0.40 lbs/MMBtu.

- Gasifier will generate about 4 times the ash on MMBtu basis. However, this is organic ash – with high P and K compound and as such has good value as fertilizer as well as supplement to animal feed. We are investigating after market for the ash to offset the cost of acquiring the litter.

- Litter does not have any detectable level of heavy metals, such as Hg, As, Pb, Cd, etc. Hence, there will not be any detectable level of these heavy metals in the gasifier producer gas.

Table 2-3 Coal and litter composition and expected emissions

Coal	per kG (per lb)	kg/MJ (lbs/MMBtu)	Expected Combustion Products	kg/MJ (lbs/MMBtu)	Comments
LHv kJ/kg (Btu/lbs)	11,826 (11,200)	-		-	
S	0.01 (0.03)	0.96 (2.23)	SO_2	1.92 (4.46)	
C	0.29 (0.64)	24.38 (56.72)	CO_2	89.39 (207.99)	
H	0.02 (0.05)	1.73 (4.02)	H_2O	15.55 (36.16)	
N	0.01 (0.02)	0.58 (1.29)	NOx	0.34 (0.78)	(as reported)
Ash	0.05 (0.12)	4.57 (10.63)	Ash	4.57 (10.63)	
Litter					
LHv kJ/kg (Btu/lbs)	4,435 (4,200)				
S	0.00 (0.01)	0.51 (1.07)	SO_2	0.60~1.02 (1.25 ~2.14)	Calculated Assuming 50% remain in ash
C	0.11 (0.25)	25.18 (58.57)	CO_2	92.34 (214.76)	
H	0.01 (0.03)	2.76 (6.52)	H_2O	24.88 (58.71)	
N	0.01 (0.03)	2.56 (5.95)	NOx	0.17 (0.36~0.40)	Estimate –after burn
Ash	0.09 (0.19)	19.66 (45.71)	Ash	19.66 (45.71)	

From Table 2-3, it is evident that the biomass offers a unique opportunity in energy production, with benefits of life cycle reduction in carbon dioxide and better management of methane from the agricultural waste.