EPI
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# REPOWERING OPTIONS:

## RETROFIT OF COAL-FIRED POWER BOILERS using Fluidized Bed Biomass Gasification

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## Abstract

The recent focus on renewable energy utilization and its environmental benefits has increased the interest in repowering existing boilers and converting to co-firing of biomass with coal. Many potential pulverized coal boiler conversions have been postponed due to concerns over capacity derating and reduced efficiency and reliability resulting from combining lower grade biomass fuels directly with coal. An alternative exists in fluidized bed gasification technology for biomass and wastes which has been demonstrated successfully for over fifteen years in systems installed by Energy Products of Idaho. Although relatively small in size as compared to utility sized power boilers, these gasifiers have displayed creditable performance and availability and paved the way for further application to repowering opportunities.

## Introduction

Global warming, acid rain, environmental pollution, human health risks and depletion of nonrenewable resources are a few of the issues that are being attributed, fairly or unfairly, to the fossil fuel fired power industry. Significant incentives exist, and are increasing, to displace existing fossil fuel power with “green” power, renewable, biomass fuel sources. There are approximately 1200 coal-fired power generating facilities in the United States, representing a capital investment in excess of $350 billion. Converting a portion of each of these facilities to environmentally and economically attractive renewable fuels offers a viable alternative to preserve this huge investment and meet evolving environmental challenges and mandates.

To date, a significant amount of time and resources have been expended in analyzing the opportunities for co-firing biomass with coal in these utility boilers. Most of those studies, however, have been focused on introducing the biomass as a shredded fuel into the boiler furnace through the existing pulverized coal burners. This has been accomplished either by introducing a minimal fraction of biomass into the coal stream ahead of the pulverizers and crushing the two fuels together, or by shredding the wood fuel separately, then pneumatically injecting it concurrent with the pulverized coal feed into one or more of the existing burners. The advantage of this second approach is the independence from the existing pulverizers and coal handling system and the resultant “zero impact” on that equipment. The advantage to the first option, however, is the lower capital costs achieved by utilization of more existing equipment for the fuel sizing. In both cases, however, the biomass fuel, typically wood, is required to be clean, dry, and small in size, to minimize the impact on the equipment and boiler performance. The results of most of these technical reviews has been to limit the percent of biomass input to something less than ten percent (10%). Even at these limited co-firing rates, the concerns about the impact to the boiler operation, the ash fouling tendencies, and the ash contamination from the biomass have hampered any serious efforts to implement any of these options.

This paper discusses another method of co-firing a utility boiler with biomass fuel which virtually eliminates the fuel management and sizing concerns and the negative impacts on the existing equipment previously discussed. This alternative takes advantage of the fuel flexibility and versatility of a fluidized bed gasification system to convert the energy from the biomass into a low BTU gas which can be introduced directly into the furnace or co-fired in an existing pulverized coal burner to positively influence the boiler thermal performance as well as the emission levels. This paper details out the basic design features of the EPI atmospheric fluid bed gasifier systems with specific attention given to utilization with biomass feedstock. A specific design comparison using an existing power boiler facility is presented and reviewed herein. The overall benefits in performance, fuel economy, and environmental parameters are presented.

## Opportunity - Renewable Energy

Tax incentives (current and proposed), emissions trading, emission offsets, government mandates, lower fuel costs, and consumer willingness to pay premium prices for green power have all combined to create a significant opportunity in the fossil fuel fired power market for renewable energy from biomass . EPI's fluidized bed biomass gasifiers present a unique technology for coal or oil fired facilities to convert a portion of the fuel to clean and renewable biomass. The fluidized bed gasification systems are totally independent from the balance of the boiler facility. Fuel receiving, storage, metering and gasification are all handled in a relatively compact site which minimizes the impact on the balance of the facility. Combined with EPI's proprietary char conversion cell (CCC), the gasifier system provides clean biomass gas to the existing utility boiler, off-setting coal or oil usage and significantly reducing greenhouse gas emissions. The systems can be brought on-line quickly with minimal downtime of the boiler to complete the interconnection. Injection and burning of the low-Btu biogas in the furnace is straightforward and requires no modifications to the pressure parts of the steam generator.

Unlike co-firing techniques where biomass is mixed directly with the coal supply, a separate fluidized bed gasifier does not require utilization of the existing PC equipment. Any fuel sizing for the gasifier is minimal, typically three inch minus, and can be completed offsite by the fuel supplier. With no concern for plugging of the coal feed system, the gasifier option enables the facility to convert a significant percentage of the total boiler capacity to biomass fuel versus the five to ten percent limitation imposed by the fuel mixing options. The percentage of conversion can be based on the availability of biomass fuel in the region and its economic benefit to the power generation costs rather than any restrictions imposed by existing coal handling and/or steam generating equipment. In addition, the gasifier alternative maintains the integrity and ability of the existing plant to fire on 100% coal, essentially creating added redundancy and reliability in the fuel handling system.

### Green Power - Biomass

While much has been published about the benefits of green power, such as wind and solar, as part of the overall national energy strategy, the use of biomass fuel represents a significant and proven technology which could become an increasingly important component in the future of green power. Biomass power plants today provide 2,410 MW of power to the national power grid, or roughly 2.5% of the total supply. Of the total energy consumed in 1997, coal accounted for 21 quads, or 23 percent. Conversion of as little as ten percent of these existing, coal fired powerplants to biomass co-firing represents a 100% increase in the biomass contribution to the power base over the current level.

## Fluidized bed Gasification

### Fluidized Bed Technology

Prior to a discussion of the gasification reactions, it is beneficial to present a brief discussion of the bubbling fluidization technology which enhances the fuel reactions and gasification process.

A fluidized bed consists of a vessel containing a bed of solid particles, generally inert material such as sand. Air, or some other medium, is blown upward through the solids to produce a buoyant force on the particles. When the buoyancy force of the air is sufficient to overcome the weight of the particles, the bed becomes suspended in the air stream. Further increase in the air flow creates a "bubbling" effect within the vessel which appears to be very similar to a pot of boiling water, hence the term, "fluidization," or "fluidized bed." This is portrayed in the accompanying Figure 1. This boiling action generates tremendous turbulence within the bed resulting in significant mixing of fuel and air within the system and creates very good characteristics for combustion or gasification reactions to occur. Because the sand and air mixture behaves more like a fluid, any foreign objects introduced into the

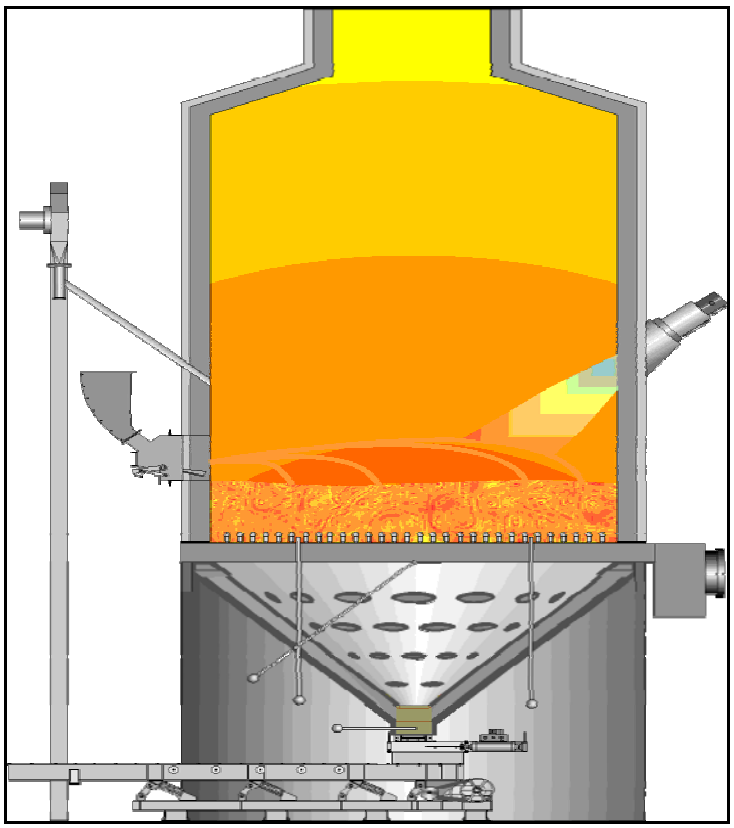

**Figure 1. Typical Fluid Bed**

bed will "float" or "sink" depending upon their density, much the same as if they were dropped into a tank of water.

In the EPI fluidized bed gasifier, the bed material is sand. The fluidizing medium is usually air; however, oxygen and/or steam have also been used. The fuel is fed into the system either above-bed or directly into the bed, depending upon the particle sizing and density. Under normal operation, the bed media is maintained at a temperature between 1000°F and 1800°F. When a fuel particle is introduced into this environment, its drying and pyrolyzing reactions proceed rapidly, driving off all gaseous portions of the fuel at relatively low temperatures. The remaining char is oxidized within the bed and provides the heat source for the drying and de-volatilizing reactions to continue. Within the bed, the wood particles are subjected to an intense abrasion action from the fluidized sand. This etching action removes any surface deposits (ash, char, etc.) from the particle and continually exposes a clean reaction surface to the surrounding gases. As a result, the residence time of a fuel particle is measured in seconds, as opposed to minutes or even hours in other types of gasifiers.

Once this bed sand has been heated, it provides a tremendous thermal capacity to maintain operating temperatures even with very wet fuels. This large thermal capacity plus the intense mixing within the fluid bed enable this system to handle a much greater quantity and/or a much lower quality of fuel. Experience with EPI's fluidized bed gasifier has indicated the ability to utilize fuels with up to fifty five percent moisture with high ash contents in excess of twenty five percent. The fluid bed can operate and control at much lower temperatures than other gasifiers thereby reducing the potential of slagging and ash fusion and enabling this unit to utilize high slagging fuels.

Energy densities in a fluid bed gasifier are dependent on the fuel characteristics and have been reported as high as four million BTU per hour per square foot (M BTU/hr-ft$^{2)}$. The dryer the fuel, the higher the energy density and the better the quality of low Btu gas produced. The reasons for this fuel dependence will be better understood from the following discussion of the gasification process in the fluidized bed.

## Gasification

In principle, gasification is the thermal decomposition of organic matter in an oxygen deficient atmosphere, producing a gas composition containing combustible gases, liquids and tars, charcoal, and air, or inert fluidizing gases. Typically, the term "gasification" refers to the production of gaseous components, whereas pyrolysis, or pyrolization, is used to describe the production of liquid residues and charcoal. The latter, normally, occurs in the total absence of oxygen, while most gasification reactions take place in an oxygen-deficient, or starved, environment.

In a gasifier, the wood particle is exposed to high temperatures of the fluidized sand generated from the partial oxidation of the wood char. As the particle is heated, the moisture is driven off, accounting for anywhere from below ten percent to over fifty percent of the incoming fuel weight.

Further heating of the particle begins to drive off the volatile gases. For wood, this volatile content could be as much as 75 to 80 percent of the total dry weight. Discharge of these volatiles will generate a wide spectrum of hydrocarbons ranging from CO and methane to long-chain hydrocarbons comprising tars, creosotes and heavy oils. After about 900°F, the wood particle is reduced to ash and char. In the early gasification processes, this was the desired by-product. For low BTU gas generation, however, the char provides the necessary energy to effect the heating and drying previously cited. Typically, the char is contacted with air, or oxygen and steam, to generate CO, $CO_2$ and heat.

The quality of gas generated is influenced by fuel characteristics, gasifier configuration, and the amount of air, oxygen or steam introduced. The output and quality of the gas is determined by the equilibrium between the heat of oxidation (combustion) and the collective heats of vaporization and volatilization plus the sensible heat (temperature rise) of the exhaust gases. The quality of the outlet gas (BTU/scf) is determined by the amount of volatile gases ($H_2$, CO, $CH_4$, $C_2$, etc.) in the flue gas stream. Considering the system equilibrium, it can be seen how the moisture content of the fuel can impact the gas quality. With the heat released by the char a fixed quantity (assuming a constant air flow), the more moisture in the fuel, the more heat consumed by evaporation. Less energy remains for volatilization and sensible heat, so the fuel rate must be decreased. Consequently, less volatiles are produced and the combustible gas quality and quantity is reduced. As the system output increases, the operating temperature is reduced. This is explained by the fact that, again for a fixed heat (of oxidation) release due to the constant air flow, the more fuel fed into the system, either wet or dry, the more energy is required for both volatilization and evaporation, and the less energy available to raise system temperatures via sensible heat increases. In effect, the latent heat fraction increases at the expense of the sensible heat. The result of this is that as more volatilization occurs, the combustible content of the outlet gas is increased and the overall heat content is improved. Thus, the highest gas quality occurs at the lowest temperatures; however, when the temperatures drop too low, the char oxidation reaction is suppressed and the overall heat release diminishes. Essentially, the "lights" go out! Optimum gas yields are obtained at operating temperatures around 1100°F to 1200°F. Higher gas heat contents (BTU/scf) can be obtained at lower system temperatures; however, the overall yield of fuel-to-gas is reduced by the unburned char fraction.

With this basic understanding of fluidization and gasification processes, it is possible to better understand the combined processes within a fluidized bed gasification system. The first design consideration is the fluidizing velocity to the bed. This is determined by the size of the bed media used and establishes the air flow into the system. Upper air flowrates are limited by the entrainment velocities of the bed particles. Lower flowrates are determined by the minimum fluidizing velocities at which acceptable mixing occurs. These boundary conditions typically limit the fluidizing air flow to a 2-to-1 operating range.

With a given fuel quality (moisture content and heat value), the output of the gasifier can be modulated over a 3-to-1 turndown ratio. At maximum output, both the fuel feedrate and the air flowrate are at maximum. The gasifier operates around 1100°F to 1200°F. As fuel is reduced, the output is reduced and the system temperature increases (constant air flow). To compensate, air flow is reduced, thereby reducing total energy release from the oxidation of the carbon, dropping the temperatures back to the 1200°F range. This ratcheting effect can continue until the air flow has been reduced to the minimum velocities. Further turndown beyond that point allows for reduction in the fuel feed only with a corresponding increase in operating temperatures once again. Theoretically, this temperature could increase to the adiabatic flame temperature of the fuel, often as high as 3000°F. Other operating constraints become limiting, such as ash slagging temperatures below 2000°F, materials of construction, i.e., ducting, dampers, below 1800 °F, etc.

Additional output modulation can be achieved by regulating the moisture content of the fuel. The wetter the fuel, the greater the fraction of available system heat required for evaporation. Thus, for a constant air flowrate, wetter fuel results in a lower energy output of the same sized unit. For comparison, the typical output of a gasifier on ten percent moisture fuel would approach 2.5 million Btu per hour per unit area of bed (M BTU/hr-$ft^2$). With forty five percent moisture fuel, the output would be 1.3 M BTU/hr-$ft^2$, or half that of the ten percent moisture fuel. The outlet gas quality drops from over 175 BTU/scf to around 100 BTU/scf. By adjusting the moisture of the inlet fuel, the output of the unit can be controlled from a dry-fuel maximum of 2.5 M Btu/hr-$ft^2$ to a wet fuel minimum of only 0.45 M Btu/hr-$ft.^2$ thereby creating an operating range of almost six to one.

With air-supplied systems, the outlet gas heat content is on the order of 100 to 200 BTU per standard cubic foot (BTU/scf) and is typically called low-Btu gas, or LBG. It is comprised of hydrogen, methane, carbon monoxide, carbon dioxide, and nitrogen. With the high dilution from the nitrogen introduced with the air, the optimum LBG quality is only around 200-250 BTU/scf. In some instances, use of another medium to replace some of the fluidizing air could increase gas quality and expand the operating window. Steam, for instance, would provide added potential to support methane production from carbon dioxide (water-gas shift reaction) and would be more readily removed from the output gases by cooling and condensing, thereby increasing the potential gas heat value. In some instances, the increased fuel gas quality will justify the use of steam in the process. In most instances, an air blown system can be simpler and more efficient to use.

## Gasifier Add-On to Power Boiler Facility

### Application

In general, gasification systems can be used in nearly every application in which natural gas, oil, or pulverized coal are currently being used. Low BTU gases can be used to fire cement or lime kilns, rotary dryers, wood veneer dryers or dry kilns, air heaters, steam boilers, and turbine or diesel generator sets. The simplest application for a fluidized bed gasifier, however, is to fire or co-fire an existing steam boiler. This also represents the most likely scenario where the steam load is also the supply of a fuel source. In food processing, wood processing, textiles, paper, and numerous other industries, a boiler system is already in operation which can be retrofitted to LBG produced from fuels generated by the plant wastes, or from external sources. In the utility industry, the pulverized coal (PC) fired power boilers present a very significant opportunity for co-firing with gasification of biomass fuels.

In a PC boiler, the burners release the combustion energy in an intense flame zone directly in the furnace. The design of the furnace utilizes this concentrated heat release to generate most of the steam within the water-wall surfaces of the furnace. Much the same holds true for oil and gas fired boilers. Once out of the furnace, the high temperature exhaust gases continue to generate steam and superheat through the remaining boiler sections. In the replacement of coal by an alternate fuel, the production capacity and superheat conditions of the boiler, both critical elements for optimum plant performance, are intimately determined by the burner heat release rates and temperature profile in the furnace. To maintain output conditions, any replacement of coal must be accomplished by a suitable fuel which will burn in suspension within the furnace and at the levels already established for the coal. In some instances, this can be accomplished by introducing some portion of the alternate fuel directly into the coal feed system, ahead of the pulverizers, and displace some of the coal feed directly into the burner unit. This concept is restricted by the ability of the existing coal handling and pulverizer units to handle very high fractions of alternate fuels (as has already been discussed). For five to ten percent co-firing rates this approach is possible and has already been demonstrated. It does have limitations to the fuel characteristics, their wear potential or plugging impact on the pulverizers, and the effective quality of the fuel, per pound and per cubic foot, as compared to the coal. It may require modifications to some parts of the coal firing system which pre-empt the reversal of operation back to 100 percent coal firing, if the need or desire should arise. Additionally, concerns about eutectic formations and slagging in the furnace from the wood ash and contamination of the coal ash have limited potential co-firing ratios to minimal levels.

As was discussed earlier, a fluidized bed gasification retrofit to a boiler has the specific advantage of maintaining total independence from the coal handling and processing equipment beginning at the storage system and continuing all the way to the boiler furnace, or the burners. Not only does this maintain complete capacity for 100 percent coal firing as a future option, it also provides additional reliability and redundancy to the overall firing system by providing a totally independent system of fuel delivery into the furnace. In addition, the fluid bed gasifier can use a variety of fuels ranging in size up to four inches, moisture contents as high as fifty percent and high in ash content. Having the gasification step prior to delivering the fuel into the boiler, most of the fuel variations are eliminated, and the boiler sees a constant and fairly uniform energy supply as LBG. An additional advantage is the incorporation of the hot gas cleanup equipment between the gasifier and the boiler. This device, typically a refractory lined cyclone, removes a majority of any ash introduced with the biomass and presents a much cleaner biomass energy to the boiler. Concerns over boiler slagging and ash contamination from the biomass fuel are minimized by significantly reducing the quantities of biomass ash allowed into the boiler.

In order to better understand the potential impact on the boiler when displacing a portion of the coal with LBG from an alternate fuel source, a comparison of the two fuels is helpful. From the accompanying Table I, it can be seen that the energy value per pound for coal is double that of wood. However, by the time the fuel (or fuel generated LBG) is converted to combustion by-products at twenty percent excess air, the wood fuel, at twenty percent moisture or less, represents as high an energy value as does the coal. This is due to the fact that the wood requires less combustion air than the coal per equivalent energy unit because of the increased amount of oxygen already present within the wood. Despite the lower heat value compared to coal, the combustion gases produced per unit

**TABLE I. FUEL COMPARISON BETWEEN COAL AND WOOD**

| Fuel: | **Coal** | **Wood** | | |
|---|---|---|---|---|
| | Dry Analysis: percent | | | |
| Carbon: | 74.00 | 49.7 | | |
| Hydrogen: | 5.1 | 5.4 | | |
| Sulfur: | 2.3 | .1 | | |
| Oxygen: | 7.9 | 39.30 | | |
| Nitrogen: | 1.60 | 0.20 | | |
| Chlorine: | 0.00 | 0.00 | | |
| Ash: | 9.1 | 5.30 | | |
| Total: | 100.00 | 100.00 | | |
| Heating Value, Btu/lb, dry | 13,230 | 8806 | | |
| moisture, percent, wet: | 5.2 | 15.0 | 30.0 | 50.0 |
| Low Heating Value, Btu/lb, as rec'd[1]. | 11,980 | 6908 | 5505 | 3638 |
| Comb. Gas Produced @ 20 percent XS Air, lb/M Btu[1] | 1030 | 1010 | 1075 | 1241 |

| | | | | |
|---|---|---|---|---|
| $CO_2$ generated, lb/M Btu[1] | 215 | 224 | 231 | 250 |
| $SO_2$ potential, lb/M Btu[1]: | 3.84 | 0.25 | .25 | .27 |
| Flue Gas moisture, %: | 4. | 8.1 | 10.8 | 16.4 |
| Flue Gas enthalpy, Btu/lb: | 970 | 990 | 930 | 806 |
| Adiabatic Temp, F @ 20%XS air: | 3365 | 3310 | 3065 | 2605 |

[1] Based on fuel lower heating value

of wood energy are comparable to coal. At moisture levels above thirty percent, the wood energy value drops below that of coal. Although the furnace temperature may be slightly lower when co-firing with high moisture biomass gas, the increased moisture content of the biomass combustion gases increases the heat capacity and improves the sensible heat content of the flue gases at comparable temperatures.

The above table also indicates the comparison of $CO_2$ and $SO_2$ emissions between coal and wood fuels. Although the $CO_2$ generated from wood combustion is slightly higher than coal, it actually results in a net zero impact to the environment and, therefore, a direct reduction in $CO_2$ from the displaced coal.. Unlike coal, the wood $CO_2$ emissions are negated by the photosynthetic contribution during the growth cycle of the wood when it was removing comparable quantities of $CO_2$ from the atmosphere and converting it to organic components. As expected, the $SO_2$ emissions from wood are only a fraction of the coal levels.

## Scope of Supply

Figures 2 and 3 illustrate the proposed gasification system concept described in the following paragraphs. The gasifier island is independent from the balance of the facility and connection of the low Btu gas line does not require any modifications to the pressure parts of the boiler.

The fluidized bed gasification (FBG) system includes a fuel receiving and storage facility compatible with the site conditions and regional fuel supply. It is necessary to maintain some on-site fuel storage; however, that would be determined by a number of factors including the space available on site for storage, the quantities required for inventory, and the proximity of an off-site fuel storage supply. As an alternative, it is possible to locate a fuel receiving and storage facility off site serving as a transfer station to receive the fuel supplies from whatever sources are available and process, as required, into a suitably sized feedstock to be used by the gasifier. Delivery to the utility could be made on an as-needed basis, thereby limiting the on-site storage to a day bin. From the day bin, the fuel is delivered into metering bin(s) and fed into the gasifier through an air lock system. The fuel sizing requirement is typically three inch minus.

The outlet gases from the gasifier are cleaned of most of the particulate entrainment through the refractory lined cyclones. Simple, but effective, the cyclones remove between 70-85% of the entrained particulate from the low Btu gas stream, including a majority of any char produced within the gasifier. The gases, minus most of the ash contaminants, are then conveyed in refractory lined ducting to the boiler furnace and introduced into the firing zone through the appropriate ports, either the existing coal burners, or some separate, dedicated burner for these gases. Existing burners or over-fire air injection ports can be modified and used as injection points for the biogas, eliminating any need to make modifications to the pressure parts of the boiler. The combustion of the LBG in the boiler furnace is similar to the combustion of the fossil fuel and does not detract significantly from the performance other than previously discussed.

The ash and char removed from the supply gases are captured and fed directly into a char conversion cell (CCC) located adjacent to the gasifier. The CCC provides the means to combust all of the char in the ash stream, recovering the energy therefrom as well as making the ash more benign and

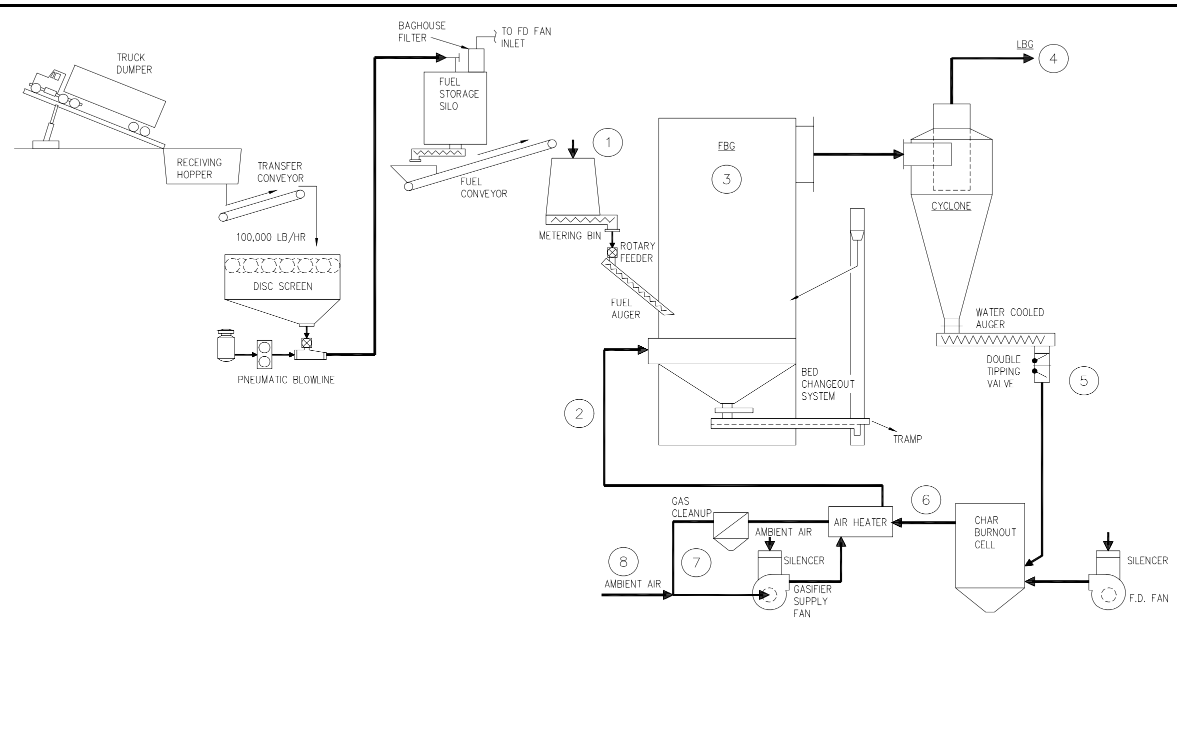


Figure 2. Typical Fluidized Bed Gasifier with Char Conversion Cell

reusable and/or disposable. High char levels in the ash are prone to spontaneous ignition and have been known to cause fires in landfills or storage piles if left to their own devices! In order to close the energy loop and eliminate any biomass energy losses from this char, the exhaust from the CCC is used to preheat the fluidizing air for the gasifier. Once the CCC exhaust gases have been cooled in this manner, they are cleaned in a multicyclone to remove essentially all of the incoming particulate. The exhaust gases, now cleaned of the ash, are blended into the fluidizing air supply at the FD fan inlet and are returned to the process.

Because of the high energy density capable from the gasifier, the size of the unit is relatively small for the energy output provided. In addition, the primary, or fluidizing, air for the unit is only a minor percentage of the total combustion air, resulting in minimal power requirements for the FD fan for the gasifier.

## The Market Potential for Repowering Coal-Fired Utility Boilers

Most of the 1200 coal fired power plants are likely candidates for biogas cofiring assuming a suitable source of biomass is economically available. Many of the oil and gas fired systems are also good candidates for this add-on biogas system because of the reduced ash loadings presented in these cases.

## Case Study

For purposes of comparing this biogas approach to some of the other co-firing possibilities, a study conducted in 1996 by the ANTARES Group and Parsons Power was referenced. ("Utility Coal-Biomass Co-firing Plant Opportunities and Conceptual Assessments", prepared for the NE Regional Biomass Program and DOE, Dec. 13, 1996.) In this study, the authors reviewed all of the coal fired utility facilities in the Northeast and selected four facilities to conduct a case study on the cost and technical impacts of co-firing with biomass. Most of the factors considered in their selection and evaluation were presented in the report, with the main consideration being a separate wood handling and sizing system which pneumatically conveyed the shredded fuel at 1/4" x 1/4" x 1/8" size into the boiler. Co-firing ratios up to 10% were considered as the maximum. Although not clearly established in the report, it does appear that the assumption was made that raw wood delivered to the plant would be sized to some nominal range of 3-6 inch minus, at least judging from the horsepower sizing estimated for the shredders.

The case study on the Portland Station Power plant, located in Eastern Pennsylvania on the Delaware River, near Stroudsburg, was selected for this comparison. This boiler is stated to be rated at 225 MW capacity. The results of that study are summarized in the following Table II.

## Discussion

Table II presents most of the information necessary to compare the performance of the gasifier co-firing option(s) with both the base case (100% coal fired operation) and the ANTARES co-firing option using wood at four and a half percent energy input. In all cases, the plant output has been established at approximately 225 MW, although the final number might vary slightly due to the differences in parasitic loads associated with the wood-fired add-on and the potential reduction in total capacity due to increased gas mass flow rates. Depending upon the wood heating value and moisture content, the flue gas volume (lb/hr) generated through the power boiler may increase slightly, especially at the higher wood moisture conditions. For the 50% moisture content wood, the calculated gas volumetric flowrate to the ID fan is actually about four percent above the base condition, creating a possibility for a minor de-rating of the boiler at that condition.

The final design of the boiler retrofit and the location of the furnace interface for the low Btu gases is dependent on the fuel characteristics of the biomass being utilized. Referring to Table I, it can be seen that the energy displaced by the wood is as good as, or better than, the coal energy, as long as the net heating value is at least as good as 15% moisture wood. It appears from some simple interpolation that wood at approximately 20% moisture is equivalent to the design coal condition, at least regarding gas mass flow (pounds per million Btu.) The theoretical temperatures achieved from the wood are slightly lower than the coal, even at the 20% condition, but the increased radiation of the flame in the furnace compensates for most of these minor variations. As the moisture content of the biomass approaches the upper range, the increased gas flow combined with the reduced adiabatic temperature combine to derate the boiler capacity. On the positive side, the added moisture content of the flue gases improves the effectiveness of the convective heating surfaces through the back passes of the boiler, including the superheater. When taken as a whole, it appears that only a minor derating would be likely even at the highest moisture biomass, under the co-firing conditions reviewed.

In a separate evaluation, at twenty five percent wood gas input which corresponds to over 56 MW electrical capacity from the biomass and based upon thirty percent moisture wood, the flue gas volume increased by only two percent at the ID fan. The same firing rate at fifty percent moisture indicated a potential derating of slightly over seven percent. While this appears to be a significant

**TABLE II. PERFORMANCE of the PORTLAND POWER STATION**

| | **ANTARES Study** | | **EPI Study** | | |
|---|---|---|---|---|---|
| | Baseline Coal | 15% moisture Biomass | 15% mc wood | 30% mc wood | 50% mc wood |
| Net Station capacity, MW | 225 | 225 | 225 | 225 | 225 |
| Alt Fuel Input, % Btu basis | 0 | 4.5 | 11. | 11. | 11 |
| Boiler Eff [1], % | 90.8 | 90.4 | 87.3 | 87. | 86. |

| | | | | | |
|---|---|---|---|---|---|
| Net Heat Rate, Btu/kw-h | 11,055 | 11,094 | 11,130 | 11,183 | 11,320 |
| Coal, TPD | 2,388 | 2,287 | 2113 | 2,114 | 2,118 |
| Biomass, wet TPD | --- | 202 | 479 | 596 | 908 |
| **EMISSIONS - (Tons per day)** | | | | | |
| Flue gas Flow | 30,836 | 31,090 | 31,053 | 31,030 | 31,670 |
| $CO_2$ - total (net - w/o biomass) | 6,144 | 6,198 (5,868) | 6,140 (5,394) | 6,132 (5,371) | 6,210 (5,383) |
| $SO_2$ | 57.2 | 55.0 | 52.5 | 51.2 | 51.3 |
| NOx | Not reported (EPI est. 20.2) | Not reported | 4.5[2] | 4.5[2] | 4.6[2] |
| Particulate | 0.90 | 1.0 | .90 | .90 | .90 |
| Flyash | 208.8 | 181.4[3] | 204 | 205 | 207 |
| **ECONOMICS** | | | | | |
| Conversion Cost | --- | $4,985,000 | $8,000,000 - $8,500,000[4] | | |
| Conversion Cost | | $492/ kW | $300-$320/kW ($260/kW w/o SNCR) | | |
| **Fuel Savings ($/year at 8500 hours/year)** | | | | | |
| @ $1.00/ M Btu | ------ | $883,750 | $2,290,000 | | |
| @ $1.50/ M Btu | ------ | $1,325,625 | $3,435,500 | | |
| simple payback, years | | 3.75-5.6 | 2.3-3.7 | | |

[1] EPI study calc'd base boiler efficiency at 87.8 %. For comparisons, EPI efficiencies should be compared to this efficiency for impact on boiler performance and net plant heat rate.
[2] Including SNCR Reduction
[3] Antares Study assumed very low ash level in wood
[4] Including costs for SNCR addition

penalty for co-firing with wet biomass, it might be more economical when compared to a reduced plant output or possible curtailing of operations. Use of the low-Btu gases for reburn and temperature suppression in the coal firing zone is beneficial in the area of NOx control.

Earlier discussions on the fluidized bed gasification theory indicated the variation in design performance with different levels of fuel moisture. In the case of this study, the three fuel moistures were evaluated to determine the impact on the boiler performance as outlined in the previous table. In considering the relative size of the gasifier facility, the unit size ranges from a thirteen foot diameter (OD) for the fifteen percent moisture fuel up to almost eighteen foot OD for an equivalent energy output with fifty percent moisture fuel. For obvious reasons, the fuel consumption increases from 20 tons per hour at fifteen percent moisture to 37 tons per hour at the high moisture. Not only is the gasifier size effected by the fuel quality, the downstream refractory ducting and other equipment is also increased as the moisture increases. For this case, the duct diameter for the dryer fuel is 60 inches ID but increases to 80 inches ID for the higher moisture fuel. Again, the reason for this is the reduction in low Btu gas quality accompanying the increased fuel moisture level. In all cases, the design of the char combustion cell is essentially constant due to the fact that the char recovery is presumed to be a fixed portion of the input energy level and does not vary significantly over the range of fuel moisture. From a practical equipment point of view, these unit sizes are well within the range of demonstrated fluidized bed technology from EPI, with units ranging from seven foot diameter to over 900 square foot bed area, equivalent to 35 foot OD. To accommodate the fuel capacity for these sizes of gasifiers, multiple fuel injection systems, each capable of 75-100 million Btu per hour fuel input are provided. The gasifier sizes resulting from this conversion evaluation do not reflect any variance from current operating systems and are well within these same size constraints.

## Economics

The preceding table compares the economics of two methods of co-firing based upon potential fuel savings only, and does not take into consideration additional economic benefits resulting from emission offsets or "Green Energy" credits.. The direct firing of the biomass as a shredded fuel, sized and injected directly into the furnace, was estimated to cost about $5.0 million dollars, corresponding to a unit cost of nearly $500 per kilowatt. The gasification approach minimizes the impact on the boiler and improves the economies of scale. It is estimated to cost about $8.0 million dollars for roughly two and a half times the energy production of the direct fired option, equating to a unit cost of slightly over $300 per kilowatt. The final comparison of the referenced table indicates a simple payback of four to six years for the direct fired case and only two to three years for the gasifier concept. This is based upon the ability of the facility to achieve a fuel savings over coal of $1.00 to $1.50 per million Btu. Essentially, the economic model is assuming the delivery of the biomass fuel to the facility at essentially no cost. That assumption is possible, but not probable, in the case of the direct fired option because the fuel is required to be relatively high quality material. Requirements such as clean, dry, whole tree chips, etc., which are the basis of the assumption for the direct fired option, typically carry a fairly expensive price tag, often as much as $10-$15 per dry ton, equal to $.50-$1.00 per million Btu. Having such costly fuel for the biomass supply results in a more probable payback for the direct firing option closer to six to ten years.

The same is not true for the gasification option, however. Because of the ability of the fluidized bed to handle a much wider range of fuel, especially in terms of ash and dirt as well as moisture content, the potential for sourcing a low cost fuel supply is much greater. The ability to receive poor quality fuel along with the high quality material enhances the supply side possibilities and provides the plant with the ability to have a better negotiating position for contracting short- and long-term fuel supplies at greatly reduced rates. The likelihood of maintaining the $1.00-$1.50 per million Btu fuel savings previously noted is thereby enhanced and the resulting economic projection of a two to three year simple payback remains a realistic projection. The fuel versatility of the gasification option opens the options to include other waste fuels which could generate a tipping fee for disposal or even a tax credit for waste reduction and energy conversion. Such is currently the case for some agricultural and animal byproduct derived fuels where a tax credit of up to $0.015 per kilowatt has been approved. Assuming such a scenario, the potential "revenue" from the biomass cofiring is doubled and the projected payout for the facility is closer to one year. Although this would apply to either type of co-firing option, the gasification option is more capable of utilizing these lower grade fuels and would, therefore, be more suited to take advantage of this significant economic incentive.

## Emissions

NOx - The summary of performance criteria in the preceding table compares the relative emission levels of the base coal-fired condition with the various biomass co-firing options. With the gasification system and additional SNCR technology included in the cost evaluation, the resulting NOx emission levels reflect the combined benefits of a) low-Btu gas reburn, b) staged combustion with overfire air modifications to the boiler, c) benefit from wood moisture and LBG content in initial NOx formation, and, finally, d) SNCR using ammonia-based reagent in appropriate temperature window in the boiler. EPI has utilized SNCR technology on numerous solid fuel fluidized bed power boilers with demonstrated success in reducing the NOx levels well below those projected for this study. Although not included in the ANTARES report, the baseline emissions for the coal-fired option were estimated to be in the range of 0.68 pounds per million Btu input, or approximately twenty (20) tons per day. With the combined reduction from the gasification co-firing plus SNCR addition, the NOx levels are predicted to be reduced by almost 80% to 0.15 pound per million Btu input, or approximately four and a half tons per day. This equates to a 5500 tons per year reduction in NOx levels in this comparison. Depending on the value of these offsets at today's "bank" prices, these volume represents a significant value to the plant. To comply with the recent SIPS mandates for coal fired plants to reduce their NOx levels to 0.15 pound per million, the facilities are facing imminent capital expenses projected to be between $50 and $150 per kilowatt. For the case of the previous example, this would equate to between $11.25 to $33.75 million. The projected cost for the incorporation of the EPI technology into the Portland Power Station boiler is estimated to be approximately $1.5 million, and was included in the previous capital cost estimate for the gasifier system. Additional boiler modifications for the burners and additional overfire air introduction have not been accounted for in the cost estimates. The predicted levels for the NOx are aggressive and optimistic; however, they do not exceed the reduction levels reported individually for the reduction methods, but are an indication of the cumulative reduction obtained from combining all of these concepts into one consolidated reduction program.

$\underline{SO_2}$ - The $SO_2$ reductions are most simply the proportionate displacement of high sulfur fuel with essentially no sulfur fuel. As shown in Table I, the sulfur levels drop from 3.8 lb/M Btu to 0.25 lb/MBtu. Given the fact that the preceding example considers the displacement of approximately 11% coal fuel with biomass, the overall sulfur input drops from 3.8 lb/M Btu to 3.44 lb/M Btu, roughly a 10% reduction. This is reflected in the Table II comparison where the daily $SO_2$ levels are reduced from 57 tons per day to 52 tons per day. As before, at any value for bankable offsets, even a 5 TPD reduction can result in a significant value over the project life. If the need arises for additional $SO_2$ reduction, the offsets result in cost savings for required reagent (lime, trona, etc.) And the potential disposal costs for that added ash quantity.

$\underline{CO_2}$ - Referring to the summary information in Table II, the resulting impact on $CO_2$ emissions, as with the $SO_2$ discussion previous, is almost a direct correlation to the quantity of coal fuel displaced by the biomass. Although the total $CO_2$ emissions are nearly constant for the coal only or the co-fired cases, the biomass contribution to $CO_2$ is actually zeroed out, making the net contribution to $CO_2$ emissions only about 88% of the original quantity. The net savings is approximately 750 tons per day.

Ash - The particulate emissions from the facility are assumed to be essentially the same considering comparable performance of the existing flue gas cleanup equipment. The amount of ash for disposal, however, will be comparable in both cases provided the wood ash is co-mingled with the coal ash. With the proposed design, the option is available to either combine the wood ash into the total ash stream or maintain it in a separate stream. The wood ash accounts for 24 tons per day of the 205 total daily tonnage. The cyclone will remove about 18 tons of the wood ash, leaving only about 6 tons per day to be mixed with the coal ash. Consequently, the remaining coal ash will contain only about 3% wood ash, even though the energy contribution from the wood is about 11%. The ash contamination from the wood ash is minimal and should have little impact on current disposal or beneficial uses of the coal ash.

Mercury - As with the other items in this category, mercury emission reductions is proportional to the amount of coal energy displacement by the wood gas. This conversion reduces expected mercury emissions by at least 11%.

## Conclusion

The opportunities for conversion of the vast number of coal fired boilers to biomass co-firing have been identified and explored for some time now. Concepts have been proposed and research, development and demonstration (RD&D) programs have been implemented to better identify the range of potential with these fuel mixtures. Fluidized bed gasification, already demonstrated on an industrial scale for the past fifteen years, represents another means of approaching these co-firing opportunities with potentially even more improvements and advantages and with fewer of the potential disadvantages of equipment limitations and ash interference. From the design example outlined in this study, gasification presents the ability to displace almost any proportion of the coal energy supply of the boiler while creating few, if any, negative interferences. By first processing the biomass fuel energy into a low Btu gas, the fluidized bed eliminates many of the fuel handling, sizing, and cleaning requirements currently viewed as limitations in direct fired applications. The low Btu gas generated from the biomass can be cleaned of most of the particulate and ash contamination prior to injection into the furnace, thereby eliminating the issues of ash fouling in the boiler and ash contamination of the coal ash from this alternate fuel. The simplicity of the technology and ability to implement larger conversion percentages makes the gasifier much more cost competitive than current direct firing methods, including those programs which intend to utilize existing coal pulverizers for wood fuel sizing. The projected costs per kilowatt for the gasifier add-on technology is estimated to be about half that of the proposed direct-fired systems.

Converting to biomass fuels is an exceptional means of improving the global environmental future and providing "Green Power" to meet the consumer demand. Emissions from biomass fuel co-firing, especially when combined with additional demonstrated control technologies, can reduce virtually all of the main pollutant levels generated by the boiler. NOx, SOx, CO2, and even some of the heavy metals levels found in coal fuel, can be reduced significantly by co-firing with biomass. The gasification process makes the range of compatible biomass fuels even broader and greatly expands the supply potential to include nearly any and all biomass materials, independent of ash or dirt content, moisture content, particle sizing, and quantity of supply. Utilizing this fluidized bed gasification add-on technology virtually opens the door for applying biomass co-firing to just about any existing coal fired power plant, independent of size. The emissions, economics, and other environmental benefits favor this approach as a viable means of retrofitting and upgrading current power boilers and enhancing the alternate fuel capabilities of the utility industry.

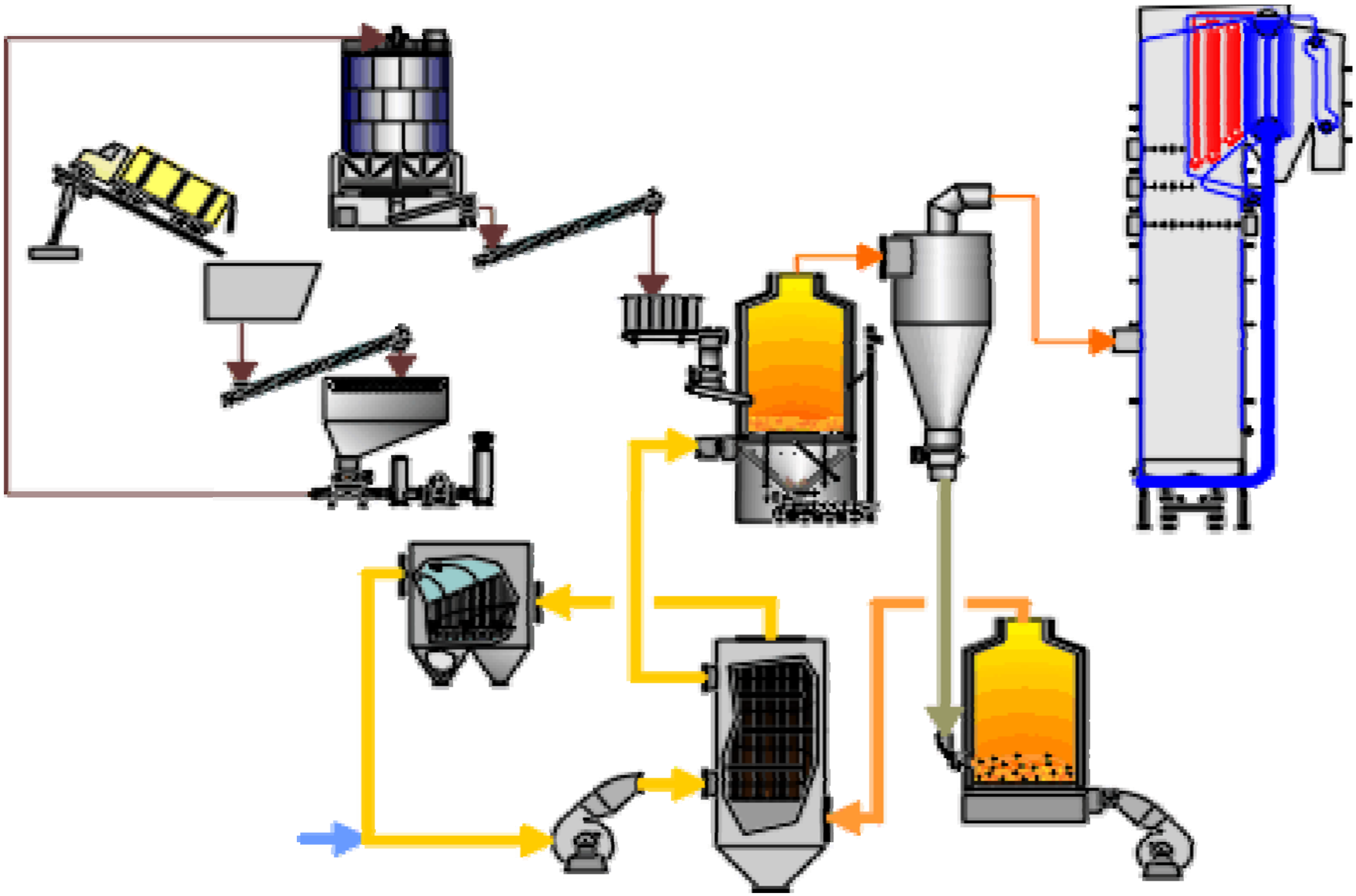

**Figure 3. EPI Fluidized Bed Gasification System Add-On to Coal Fired Power Boiler**