GASIFICATION vs COMBUSTION OF WASTE/BIOMASS IN FLUIDIZED BED REACTORS

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BACKGROUND

This paper presents a comparison of commercial fluidized bed gasifiers and combustors used to recover energy from municipal solid wastes and biomass. The work reported here is excerpted from four case studies prepared for the International Energy Agency's Bioenergy Agreement, under Task 23 (Energy from Thermal Conversion of MSW and RDF, 1998-2000) and Task 36 (Energy from Integrated Solid Waste Management Systems, 2001-2003). The four plants examined include the VERBUND BioCoComb gasifier in Zeltweg, Austria [1], Lahden Lämpövoima's Lahti gasifier in Finland [2], the Robbins Resource Recovery Facility (combustor) in Robbins, Illinois [3], and the DERL Energy-from-Waste Facility (combustor) in Dundee, Scotland [4].

INTRODUCTION

Case studies prepared for the IEA Bioenergy Agreement generally examined operation of and problems with the feed preparation and combustion technology, environmental control system, and residue recovery and disposition. Additionally, fuel characteristics, mass and energy balances, and environmental performance were evaluated. Finally, capital, operating and maintenance costs, and the sociological background for each project were examined. This summary of information from the four case studies compares and contrasts, where available, only the effectiveness and cost of the selected gasification/combustion/environmental control technologies. The full case study reports are/will be available through the IEA (see References).

VERBUND BIOCOCOMB GASIFIER, ZELTWEG, AUSTRIA [1]

Zeltweg Coal Boiler

The Zeltweg power plant (137 MWe) was commissioned in 1962. In 1982 the nearby lignite mine was closed, and the firing system was converted to utilize hard coal (tangential firing). In 1989 a selective non-catalytic reactor (SNCR) was added to handle NOx emissions, and in 1994 the Lurgi CFB desulphurization scrubber was added. Main steam data are 185 bar (high pressure) and 44 bar (reheat) at 535°C. As of 2001, the plant had operated for more than 110 000 h, in later years mainly for peak load energy production. Because of its location in Styria, surrounded by forest industry (sawmills), the plant was an ideal location for a biomass project.

Circulating Fluidized Bed Gasifier

The gasifier, designed and constructed by Austrian Energy, is of the CFB variety, constructed of steel with internal brick and concrete refractory. The gasification chamber is a simple vertical cylinder without internal mechanical components or heat exchangers. Air enters the gasifier via an open nozzle grid (distributor) situated at the bottom of the gasification chamber. The air is preheated to about 270°C in the coal boiler recuperator. Fine sand of a defined particle size is used as the bed material. No limestone is employed as sulphur sorbent; instead, SO_2 is scrubbed downstream of the coal boiler. A start-up oil burner is provided for initial heat-up of the gasifier and in the event of emergencies, e.g., a fuel feeding problem.

During gasification, feed particles partly combust in the lower part of the reactor, to produce the required temperature of 850°C. Because of the lack of sufficient oxygen in the upper part, gasification (partial) occurs. Variation in airflow thus controls the bed behaviour and the reaction temperature. Particles continue to circulate in the fluidized bed system until gasification and attrition render them small enough to pass through the hot gas cyclone. These small particles (char and ash) leave the gasifier with the gas through the hot gas duct to the coal boiler, while larger particles reenter the gasifier near the distributor where surplus oxygen is available for combustion. Carbon burnout in the gasifier is excellent, as less than 0.40% carbon reports to the discharged bed materials.

A water-cooled screw conveyor at the bottom of the gasifier handles the discharge of bed material and any noncombustible metals, stones and mineral content. This stream is not expected to carry significant ash, as the ash is fine and of low density, and is almost totally carried in the gas stream. In a typical setup, the bed sand could be separated from this stream for reuse, but at Zeltweg this is unnecessary. Sand consumption depends on the type of fuel being fired. Bark, used almost all the time, contains sand that is suitable for bed material, and instead of dosing, discharge must be carried out intermittently, to reduce the pressure drop in the fluidized bed. Firing of clean fuel (wood chips and sawdust) does require some sand dosing, however.

The gasifier has been designed for a thermal capacity of 10 MW, equivalent to approximately 3% load substitution in the coal boiler (344 MWt). Hot gases and char enter the coal boiler via a specially designed burner nozzle that provides rapid ignition, a stable flame, good penetration into the coal flame, and good mixing. The burner is situated above the existing coal burners to achieve maximum reburning effect (for NOx reduction). See Figure 1.

Environmental Performance

With 3% thermal substitution of coal with product gas in the coal boiler, most emissions from the boiler are substantially identical to those without substitution. Operating logs have indicated no increase in CO emissions when firing product gas, suggesting that gas burnout is very good. This is of special interest because the burner for product gas is atypical in that it does not have a separate supply of combustion air. Rather gas is burned in the excess oxygen present in the boiler.

Because the typical feedstocks contain less sulphur than does the boiler coal, there will be a minimal reduction in overall system SO_2 emissions. Also, depending on the type of feedstock, there will be up to 3% reduction in reportable CO_2 emissions. Of major impact, however, is the reduction in NOx emissions. This comes about as a result of the location of the gas burner in the boiler, above the coal burners. In this “reburning” mode, some of the NOx that has already formed lower down in the boiler is reduced, by a slight deficiency of oxygen, to N_2. The effect of this is that, to meet NOx emissions requirements set for the boiler, 10-15% less ammonia solution is required in the SNCR. This represents a 3x to 5x multiplier from the 3% product gas contribution, and should continue at this level, within limits, as the product gas substitution is increased.

Mass and Energy Balances

As stated above, a minimal substitution of approximately 3% of coal input on a thermal basis (5-13 MWt product gas vs a total of 344 MWt entering the boiler) has almost no negative impact on the net output of 137 MWe. The following information is available:

Table 1. Zeltweg Plant Data

	Coal	**Biofuel**
Thermal input	330 MW	10 MW
Origin	Polish coal	Wood chips, bark, sawdust
Fuel consumption	47 t/h	2-4 t/h
Lower heating value	27 MJ/kg	2-5 MJ/Nm^3 (gas)
Internal consumption	7 kW/MWt	14 kW/MWt
Unconverted carbon to boiler	10 mol%	
Particle size of char dust to boiler	200 µm	
Air consumption	3.7 Nm^3/h	

In addition, the following information was provided by VERBUND:
Input: Biomass - 10 MWt; Coal - 330 MWt
Output: 127 MWe (net to grid)
Losses: Gasifier/product gas duct radiation - 0.124 MWt; Boiler - 203 MWt (flue gas, ash, radiation, etc.); Internal consumption - 10 MWe
Efficiency: 127 MWe/340 MWt = 37.4%

Capital, Operating and Maintenance Costs

Total cost of the BioCoComb project was 5.1 MEUR. This amount includes engineering, biomass/waste storage, conveying system, feedstock preparation, gasifier, connection to the coal boiler, commissioning and test monitoring. Of this amount, EU THERMIE contributed 1.3 MEUR, about 25% of the total. It has been estimated that replication of the plant at the same scale (10 MWt) would cost 3.7 MEUR for preparation of the technical specifications, tenders, erection and commissioning. At 40% electrical efficiency (LHV basis), this is equivalent to a capital cost of 925 EUR/kWe, quite high due to the relatively small scale.

Several studies have been undertaken to estimate the cost of larger-scale plants. One detailed study by Austrian Energy for a 50 MWt plant is as follows:

- Plant life: 10 years
- Interest rate: 6%/a
- Power plant efficiency: 40% (LHV basis)
- Annual operation: 8 000 h
- Annual maintenance: 1.5% of investment cost
- Ash disposal cost: 75 EUR/t
- Fuel: biomass blend at 40% moisture
- Operation: 1 person per shift

The estimated investment cost was calculated as 400-500 EUR/kWe, equivalent to 9 MEUR for 20 MWe. Austrian Energy states that, from experience at Zeltweg, the power plant personnel can operate the gasification plant without additional manpower. Electricity production costs depend on the feedstock price. If feedstock is waste at zero cost, electricity can be produced for less than 0.02 EUR/kWh. This rises to 0.047 EUR/kWh if feedstock is purchased for 0.014 EUR/kWh.

A 100 MWt plant is expected to cost 10-14.5 MEUR, equivalent to a specific investment of 250-360 EUR/kWe. This shows the economies of scale. However, sufficient feedstock must be available locally to avoid high transportation costs. Also, a suitably sized boiler must be available, as a coal substitution much greater than 10-15% might adversely affect efficiency and operation of the boiler.

Averaged additional operating and maintenance costs of the complete plant to the end of 2000 were 17 EUR/h at a standard load of 10 MWt. This figure is high, but includes remedying the many system trips that occurred prior to modifications. In absence of the trips, maintenance costs were near zero, including only control, cleaning and lubricating. However, this might not be representative, considering the relatively low operating hours.

Unfortunately, the main boiler at Zeltweg has been shut down since April 2001, because electricity generation at the plant is too expensive (peaking plant) and there is an overcapacity in the area. However, we have been assured that gasifier operation played no part in the shutdown decision.

LAHDEN LÄMPÖVOIMA GASIFIER, LAHTI, FINLAND [2]

Circulating Fluidized Bed Gasifier

The gasifier concept employed at Lahti is quite simple. The Foster Wheeler circulating fluidized bed gasification system consists of a steel reactor, a uniflow cyclone and a return pipe, all refractory lined. Preheated gasification air, blown with a high-pressure air fan, enters the gasifier vessel at the bottom via an air distribution grid. Velocity of this air is sufficient to fluidize solid particles making up the bed. The bed expands and individual particles move rapidly, some conveyed out of the reactor into the uniflow cyclone. In the uniflow cyclone, gas and circulating solids flow downwards, with solids flowing down the return pipe, and gases going into the air preheater.

In normal operation, the fuel feed rate defines the capacity of the gasifier, while the air feed rate controls the gasifier temperature. Fuel is fed to the gasifier above the air distribution grid. This fuel is less than 5 cm in major dimension, and typically contains 20-60% moisture, 40-80% combustibles, and 1-2% ash.

Typically, the gasifier operating temperature is in the range of 800ºC-1000ºC, dependent on the fuel. As fuel particles enter the gasifier, rapid drying takes place, and the primary phase of reaction, pyrolysis, occurs. This involves driving off of volatiles and conversion of fuel particles into gas, char and tars. Some of the char falls to the bottom of the bed, where it is combusted, generating CO, CO_2 and heat. These products flow up the reactor, where secondary reactions occur: heterogeneous (char and gas); and homogeneous (gas only) reactions. These reactions result in production of a combustible product gas which enters the uniflow cyclone, and leaves with a small percentage of fine dust.

Solids (mainly char) are separated in the cyclone and return to the gasifier bed near the bottom. Char combustion in the oxygen-rich fluidizing air stream produces heat required for the pyrolysis, heterogeneous and homogeneous reactions. Coarse ash accumulates at the bottom of the gasifier and is removed with a water-cooled bottom ash screw.

The produced combustible gas enters a heat exchanger, lowering its temperature somewhat while preheating the fluidization air. The gas is then transported through a duct to two burners located below the coal burners in the main boiler. These burners are of a unique design developed through pilot-scale combustion tests and CFD modelling. Originally, it was envisioned that the burners would be placed above the coal burners, in the reburning mode, to control NOx; however, pilot testing showed that maximum heat and residence time for impurity destruction were produced with the gas burners below the coal burners. Figures 2-3 illustrate the gasifier and its connection to the boiler.

Environmental Performance

Table 2. Effect of the Gasifier on Main Boiler Emissions

Emission	Change Caused by Gasifier
NOx	Decrease by 10 mg/MJ (5-10%) [current limit - 240 mg/MJ]
SOx	Decrease by 20-25 mg/MJ [current limit - 240 mg/MJ]
HCl	Increase by 5 mg/MJ (base level low)
CO	No change
Particulates	Decrease by 15 mg/Nm^3
Heavy metals	Slight increase in some elements (base level low)
Dioxins/furans	No change
PAHs	No change
Benzenes	No change
Phenols	No change

Table 2 summarizes the changes in environmental emissions from the main boiler at Lahti as a result of cofiring gas produced in the gasifier. The fact that CO emissions do not change indicates that there has been no degradation in combustion caused by cofiring the produced gas. Reductions in NOx and particulates can be attributed to moisture in the product gas. Moisture content slightly lowers the flame temperature in the boiler, reducing NOx while moisture in flue gas enhances performance of the electrostatic precipitator, reducing particulates emissions. Other changes result from increases (e.g., Cl) or decreases (e.g., S) of a particular element in the biomass/waste feedstock compared to the coal/natural gas used.

Table 3 lists typical trace pollutant concentrations in the product gas when gasifying non-contaminated feedstocks. Contaminated fuels generally increase concentrations of ammonia, hydrogen cyanide and alkalis. For example, gasification of gluelam can increase ammonia to 3 000-5 000 mg/m^3, HCN to 200-300 mg/m^3 and total alkaline content to 0.3 ppmw.

Table 3. Typical Trace Pollutant Concentration of Product Gas

Gas Component	**Concentration Range (mg/m^3, dry)**
NH_3	800-1 000
HCN	25-45
HCl	30-90
H_2S	50-80
benzene	7-12
tars	7-12
alkalis	<0.1
particulates	6-10

Bottom ash from the gasifier consisted mainly of bed sand and limestone plus small amounts of metal chunks and concrete, etc. Carbon content was typically less than 0.5% and chlorine levels were negligible. The ash also contained trace amounts of certain heavy metals; however, leachability was low.

Gasifier ash makes up only a small proportion (3-5%) of total main boiler ash and, therefore, has little effect on quality. Unburned carbon and alkali levels were unchanged, but some heavy metal levels increased slightly, depending on the type of feedstock. For example, zinc content increased when shredded tires were gasified. No changes in trace organics, such as dioxins, were detected. Leachability test results were satisfactory, and the plant is permitted to use boiler ash as before.

Energy Balance

Efficiency of biomass/waste conversion to electricity is very nearly equivalent to that of the coal-fired unit itself. Based on a 15% fuel substitution by waste/biomass gas, it has been reported that net thermal efficiency for electricity production was reduced only from 31.3% to 31.1% and, for district heating, from 49.9% to 49.4% (on a HHV basis). One reason this occurs (despite the increased product gas moisture content and flue gas nitrogen content) is increased flame radiation in the furnace, and an improvement in the effectiveness of the convective heating surfaces through the back passes of the boiler and the superheater. Other explanations are, of course, possible.

During a site visit, the following operating data were recorded for the gasifier:

Input:

- 5.09 kg/s feed at 10.3 MJ/kg and 32.8% moisture (52.4 MWt)
- 3.45 Nm^3/s air at 365ºC (heat-exchanged with product gas)

Output:

- 19.2 Nm^3/s product gas at 2.48 MJ/Nm^3, 6 mbar and 810ºC (47.6 MWt)

Product gas enters the boiler, in equal streams, through two bottom burners at 712ºC, after heat-exchange with the input air stream. This gas has the following composition:

- CO – 9.6%
- CO_2 – 12.3%
- CH_4 – 3.3%
- H_2 – 6.7%
- H_2O – 35.0%
- Balance N_2

The overall energy balance (52.4/47.6) is 90.8%. The operator reported that the usual gasification efficiency is approximately 92%.

Capital, Operating and Maintenance Costs

Total capital cost of the Lahti gasification project was about 12 MEUR. This figure includes fuel preparation, civil works, the gasifier, instrumentation and control, electrification, and modifications to the main boiler. Of this amount, 3 MEUR (25%) was received under the EU THERMIE Programme. It has been reported that Foster Wheeler would charge a higher price for a second unit. This would suggest that FW had a vested interest in seeing the first of a kind plant succeed both technically and economically.

A number of studies, comparing projections for plant costs and other factors for different cofiring options, have been undertaken. One of the more interesting studies is presented below. Table 4 compares capital and operating cost projections for a 20 MWe biomass plant. In this analysis, the following assumptions have been made:

- Cost of capital – 10.3%
- Cost of biomass – zero
- Operating cost – 0.36 MEUR/a
- Maintenance cost – 2.5% of investment cost/a
- Overhead – 40% of O & M costs
- Coal cost – 50 EUR/t
- O & M and depreciation of existing coal-fired plant – 0.018 EUR/kWh
- Operation – 7 500 h/a

Table 4. Capital and Operating Costs for 20 MWe Biomass Plant

Concept	Specific Investment (EUR/kWe)	Total Cost (MEUR)	Annual Cost (MEUR/a)	Electricity Cost (EUR/kWh)
Direct cofiring	680	14	0.45	0.021
Upstream gasification	1270	25	1.7	0.029
Upstream combustion (steam-side integration)	1360	27	1.8	0.030

Direct cofiring (if feasible) is the cheapest option, with upstream gasification rating second. Note in Table 4 that all cost projections are based on economic factors and estimates specific to the study authors, and are inserted here to represent trends rather than firm quotes.

For the same 20 MWe biomass plant as outlined in Table 4, the following capital, operating and maintenance breakdown has been developed (MEUR/a, unless otherwise indicated):

- Capital charge – 2.7
- Personnel – 0.36
- Maintenance – 0.68
- Overhead – 0.41
- O & M sub-total – 1.5
- Biomass – 0.0
- Avoided coal – (2.5)
- Fuel sub-total – (2.5)
- Total costs – 1.7
- Electricity cost (gasifier contribution) – 0.011 EUR/kWh
- Electricity cost (coal boiler contribution) – 0.018 EUR/kWh
- Total electricity cost – 0.029 EUR/kWh

At Lahti presently, fuel costs depend on the type and quality. Forest residue is purchased for 7 EUR/MWh (LHV), while REF costs 2-3 EUR/MWh. Feedstocks are tested for chlorine content, and payment is on a sliding scale, with a tipping fee (also varying) applicable when chlorine content exceeds 0.5%. Coal currently consumed at the plant costs about 12 EUR/MWh. Four employees currently operate the plant. With a modern computer control system, three employees would suffice. One operator is in charge of the gasifier and boiler, and sits in a combined control room. Thus with no dedicated personnel and fuel cost savings, operating costs approach zero.

ROBBINS RESOURCE RECOVERY FACILITY (RRRF), ROBBINS, ILLINOIS [3]

The Robbins Resource Recovery Facility (RRRF), located in Robbins, IL, a suburb of Chicago, represented the largest such project in the world – a waste-to-energy plant capable of handling 1450 tonnes of MSW per day, diverting 25% to recycle, reducing landfill waste volume requirements by 95%, and producing 50 MWe. The RRRF, designed, constructed and operated by Foster Wheeler (FW), but owned by the community of Robbins, began operation in early 1997 and was shut down in 2001.

Circulating Fluidized Bed Combustors/Environmental Control System

In each of the two Foster Wheeler CFB boilers, RDF is fed to the front wall of the 3.7 m x 7.6 m furnace (Figure 4). The top-supported walls are water-cooled, welded tube and fin construction. Except for the furnace roof, no horizontal surface is located in the gas stream. The lower furnace walls are lined with a corrosion-resistant refractory material providing a degree of temperature stability to the bed, despite frequent variations in feed moisture and heating value. Combustion temperatures of 830°C-915°C at atmospheric pressure reduce the potential for ash slagging and tube fouling, as well as minimizing high-temperature chlorine corrosion.

A single, high-efficiency cyclone is attached to each furnace, cooled with steam from the drum. Its temperature is only slightly higher than the furnace waterwall, displaying expansion similar to that of the furnace, and is considered an integral part of the furnace. The cyclone is covered with 50 mm of refractory, retained on studs in a high-density pattern (similar to the furnace). Solids collected in the cyclone are returned to the furnace through a fluidized "J" valve. Downstream of the cyclone, a steam-cooled vestibule encloses the steam generating boiler bank and pendant finishing superheater. The heat recovery area is the final segment of the steam generator, comprised of the primary superheater and economizer. Tubes in the heat recovery area are designed on a large clear spacing with low intertube velocity to minimize accumulation of sticky ash deposits. Since flue gas leaves the economizer at 218°C, and the scrubber reduces the temperature further, to 135°C prior to entering the baghouse, an air heater is not required. Each furnace uses a single induced draft (ID) fan to draw flue gases to a common stack, while a single forced draft (FD) fan provides both primary and secondary combustion air.

At boiler startup, the bed material is sand; as operation progresses, screened bed ash replaces some of the sand. Sand/ash is fed to the furnace along the rear wall. Limestone can be fed into the sand/ash silo if the feed sulphur content warrants it, but this was not used as SO_2 emissions were well below the permit value of 30 ppm. The high proportion of inerts circulating in the CFB gives the furnace a thermal inertia, maintaining stable temperatures against variations in the fuel, while allowing 99% combustion efficiency (carbon burnout).

The concentration of chlorine in RDF and flue gases is higher than in MSW due to the concentrating effect of removing recyclables. Chloride corrosion is a function of tube metal temperature, and FW took steps to reduce superheat tube temperatures. A bank of boiler tubes is located upstream of the finishing superheater, which is in parallel flow to the gas stream to maintain low metal temperatures. Steam sootblowers can accelerate tube wastage when firing high-chlorine fuels, by removing the protective ash layer. Therefore, FW specified a mechanical rapping system for cleaning the vertical tube banks in the high-temperature vestibule.

The RRRF is equipped with an emissions control system comprised of a selective non-catalytic reduction (SNCR) system (urea injection), a spray dryer absorption flue gas scrubber, and a baghouse. Low CO emissions are achieved by operating the CFBs at 50% excess air, higher than typical for a coal-fired CFB. The dry flue gas scrubber/baghouse (one system for each CFB) is fed with an atomized lime slurry, which neutralizes the acid gas components (sulphur dioxide, hydrochloric acid and hydrofluoric acid) of the flue gas. Water in the slurry is evaporated by the hot flue gas, producing dry powder reaction products that are removed in the baghouse (fabric filter). Activated carbon is added to the lime slurry (at a rate of 9 kg/h per boiler train) to reduce emissions of trace heavy metals (mercury and others), dioxins/furans (to well below the permit limit of 30 ng/dNm^3), and organic compounds.

The treated/cooled flue gas passes through the fabric filters (multiple modular units, with redundancy) which collect particulate matter (flyash, dry scrubber reaction products, spent carbon, and unreacted lime). This material is periodically removed from the bag surface with reverse flow compressed air pulses. The SNCR system for NO_x reduction is capable of injecting aqueous urea into the ductwork between the cyclone inlet and the backpass. At this point, a temperature range of 870°C-1090°C occurs, ideal for 40-60% NO_x removal. In operation, however, NO_x emission levels were well below the permit limit of 130 ppm, such that the SNCR was not required.

Electrical Efficiency

High-pressure steam (6.2 MPa, 443°C, 28.9 kg/s per boiler) produced in the CFB boilers was used to produce approximately 50 MW of electricity in a condensing, extraction turbine generator. Net electrical generation efficiency, for a feed rate of 545 t/d RDF per boiler (heating value 14.3 MJ/kg) was approximately 23%, based on MSW input.

Capital, Operating and Maintenance Costs

Investment costs are based on the turnkey construction costs (US$226 million) plus US$75 million spent during construction for such items as payments to the Village of Robbins, site acquisition and clearing, permits, consulting, ash landfill reservation, capitalized interest (7%-9% during 33 month of construction), development costs and contingency (US$20 million). Investment cost per annual tonne of waste was US$550/t. Total O&M was US$15.9 million annually (US$29/t MSW). The RRRF was shut down for financial reasons in 2001. Combustor operation was not a factor in the decision.

DERL ENERGY-FROM-WASTE FACILITY, DUNDEE, SCOTLAND [4]

The Dundee Energy Recycling Ltd. (DERL) energy-from-waste facility, the first in the UK to use BFB technology for waste treatment, was handed over to DERL by Balfour Beatty/Kvaerner EnviroPower in April 2000. It is on the site of the former Baldovie incinerator. The new plant, with a capacity of 120 000 t/a, receives source-separated

MSW from Dundee & Angus Councils (population 270 000) together with some clinical waste from Greater Glasgow Health Board. The waste is processed into floc RDF, with recovery of ferrous and non-ferrous metals. Clinical waste is handled/treated in isolation.

Bubbling Fluidized Bed Combustors/Environmental Control System

Within the boiler house there are two 17 MW Kvaerner BFB incineration boiler units, each sized at a maximum continuous rating to match the incoming waste stream of 8 t/h at a heating value of 10 MJ/kg (gross). Each boiler comprises a combustion chamber, a back pass including radiation cavity, superheaters, evaporation stages and economizers (Figure 5). The fluidized bed is designed as an integral part of the boiler; surfaces are fabricated from membrane-wall tubing and the steam drum is close-coupled. The bed of hot sand and ash at the base of the boiler is kept in constant motion by fluidizing primary air injected through the bed from the wind box below via the bottom plate. Fuel is gravity fed and spread across the surface by recirculated flue gases via air-swept spouts.

Non-combustible material and bottom ash are continuously removed from the bed which has dolomite added to reduce boiler tube fouling and control SO_2 emissions. A mixture of ash and sand is continuously removed from the fluidized bed. Water-cooled screws recover heat from the bed material prior to the sand being separated and returned to the bed via an ash classifier. Typically the remaining carbon content of the bed ash is <0.5%.

Combustion air for the process is drawn from the waste storage areas to control emissions of dust and odor from the plant. The boilers are fitted with FD fans to supply primary, secondary and tertiary air for the staged combustion process and some flue gas is also recirculated to help control the formation of NO_x. Start-up is by a gas-oil burner below the bed, which initially heats the primary air and fluidizes the bed of sand. A secondary gas-oil burner above the bed raises the furnace temperature to 850°C, at which point fuel can be fed into the boiler.

The Kvaerner BFB boiler uses an Advanced Combustion Zone design, claimed to enable thermal efficiencies of 89% with typical steam conditions (40 bar and 400°C). Corrosion of heat recovery surfaces by chlorine, sulphur and heavy metals can be caused by reducing conditions and this is avoided by the ACZ furnace design. The lower furnace area is refractory lined to achieve uniform temperatures and reduce slagging. Superheater corrosion is avoided by the empty radiation cooling pass which conditions the flue gas prior to its entering the convective cooling surfaces.

A separate flue gas cleaning unit is provided for each boiler. Flue gases leaving the heat recovery sections of the boiler pass through cyclone pre-collectors where about 70% of the particulates are removed. Following this dry lime reacts with acid gases, and activated carbon is injected after the cyclone to trap dioxins/furans and mercury. Fabric filters then trap any remaining particulates together with the lime and activated carbon added previously. After the baghouse, flue gas emissions are continuously monitored, testing each boiler in turn. Flue gases are discharged to the atmosphere via a twin flue stack, 70 m high. Achieved emissions are as follows: dioxins – 0.05 ng/Nm^3 (limit is

1.0); SO_2 – 15 mg/Nm^3 (limit is 300); NO_x – 325 mg/Nm^3 (limit is 350); and CO – 4 mg/Nm^3 (limit is 100). Particulates, HCl, HF and heavy metals are well below the limits.

Electrical Efficiency

The steam turbine is a single-cylinder condensing machine designed by Austrian Energy & Environment, and the installation included the option for future steam export for use in nearby industrial processes. The generator (from ABB Sweden) is rated at 10.5 MWe. In-house demand is an estimated 2.2 MWe leaving 8.3 MWe for export. Overall net efficiency is 20.9%

Capital, Operating and Maintenance Costs

The plant was constructed (brownfield site) under a turnkey contract for £35 million (about US$56 million). Total O&M (including ash disposal) is expected to be £2.3 million (US$3.7 million), or about US$31/t MSW.

GASIFICATION vs COMBUSTION

Table 5 presents a comparison of pertinent details of the four plants discussed. Because the plants are in different countries with various economic conditions and environmental requirements, etc., and may include greater or lesser pretreatment of the feed, data should be used for qualitative comparisons only.

What is immediately apparent is that gasifiers have markedly lower costs (capital and O&M) than combustors; however, this is misleading as the gasifier takes advantage of an existing coal-fired boiler and its environmental control system. Although emissions are similar for both gasifiers and combustors (NOx removal through gas reburning at Zeltweg is the exception), the gasifiers achieve substantially higher efficiency, nearly equivalent to that of their coupled boilers. This results in recovery of energy from non-biomass wastes (sludge, plastics, tires, etc.) at a lower specific CO_2 emission rate than would be possible from the combustors. While these wastes could be directly co-fired in a conventional boiler, this might render the ash unmarketable, which is not a factor with waste-derived product gas co-firing. Feeding may also be problematic.

Both methods of waste destruction serve their purpose well. However, both suffer unjustly from the stigma attached to waste incinerators, and neither can really take advantage of economies of scale as they are limited by economically-available waste quantity (transportation costs).

Just as gasification of coal/petroleum coke is poised to take a major role in mitigating greenhouse gas-related concerns (the Kyoto Protocol), so too the author feels, in mitigating municipal solid waste-related concerns, gasification will be looked upon with favour.

Table 5. Gasification vs Combustion--Pertinent Details

	Zeltweg (BioCoComb)	Lahti	Robbins (RRRF)	Dundee (DERL)
FBC Type	Austrian Energy CFBG	Foster Wheeler CFBG	Foster Wheeler CFBCs (2)	Kvaerner BFBCs (2)
Input	10 MWt (3% coal subst.) 4.1 t/h (avg.)	65 MWt (15% coal/gas subst.) 17.9 t/h (avg.)	60 t/h (raw) 45.4 t/d (processed)	120 000 t/a
Feed Type	bark, wood chips, waste wood, sludge	REF, sawdust, bark, wood-working waste	refuse-derived fuel	source-separated coarse RDF
Output	4.5 MWe 9 800 MWh	59.5 MWt	50 MWe	10.5 MWe
Efficiency (net), %	37.4	31.1 (electrical) 49.4 (thermal)	23	20.9
Capital Cost, US$M/(US$/kW)	4.6 (1 022)	10.9 (approx. 590)	301 (6 000)	56 (5 300)
O&M Cost, US$/tonne feed	3.80	14.75	29	31

References

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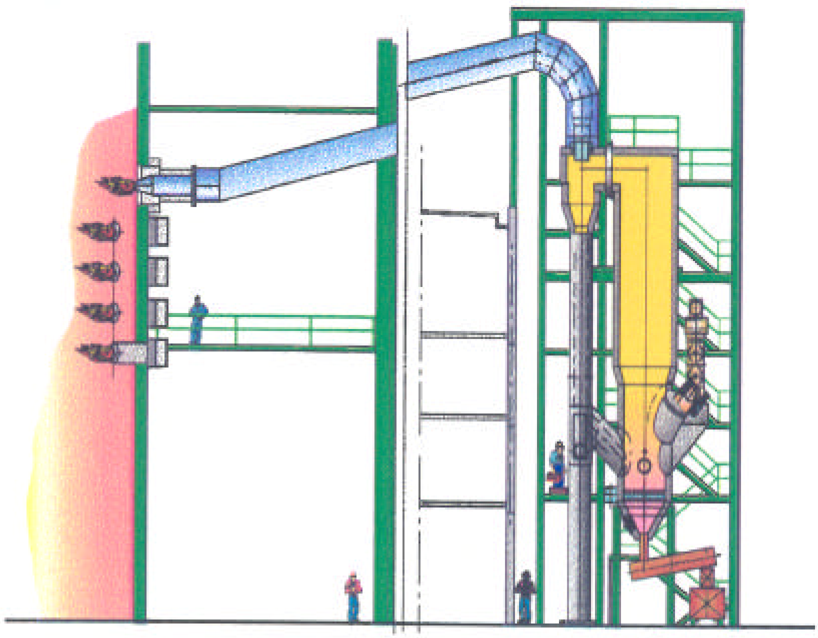

Figure 1. BioCoComb Gasifier and its connnection to the boiler

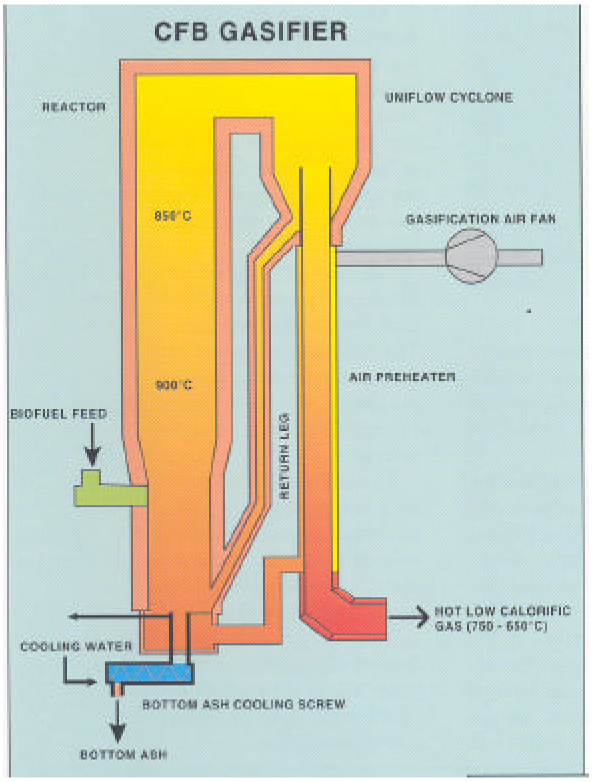

Figure 2. Cross-section of Lahti Gasifier

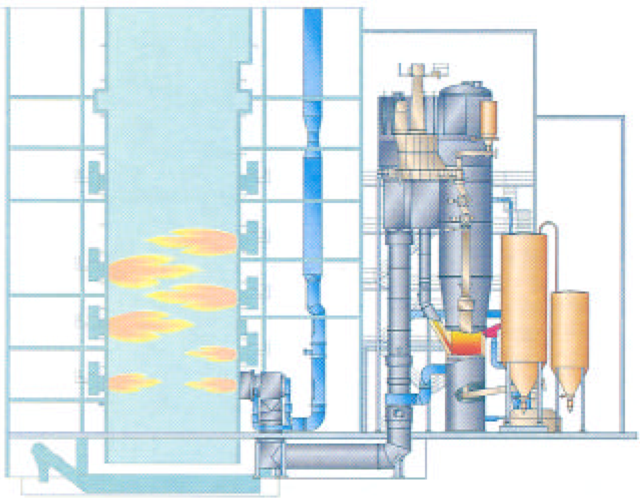

Figure 3. Gasifier Connection to Lahti Boiler

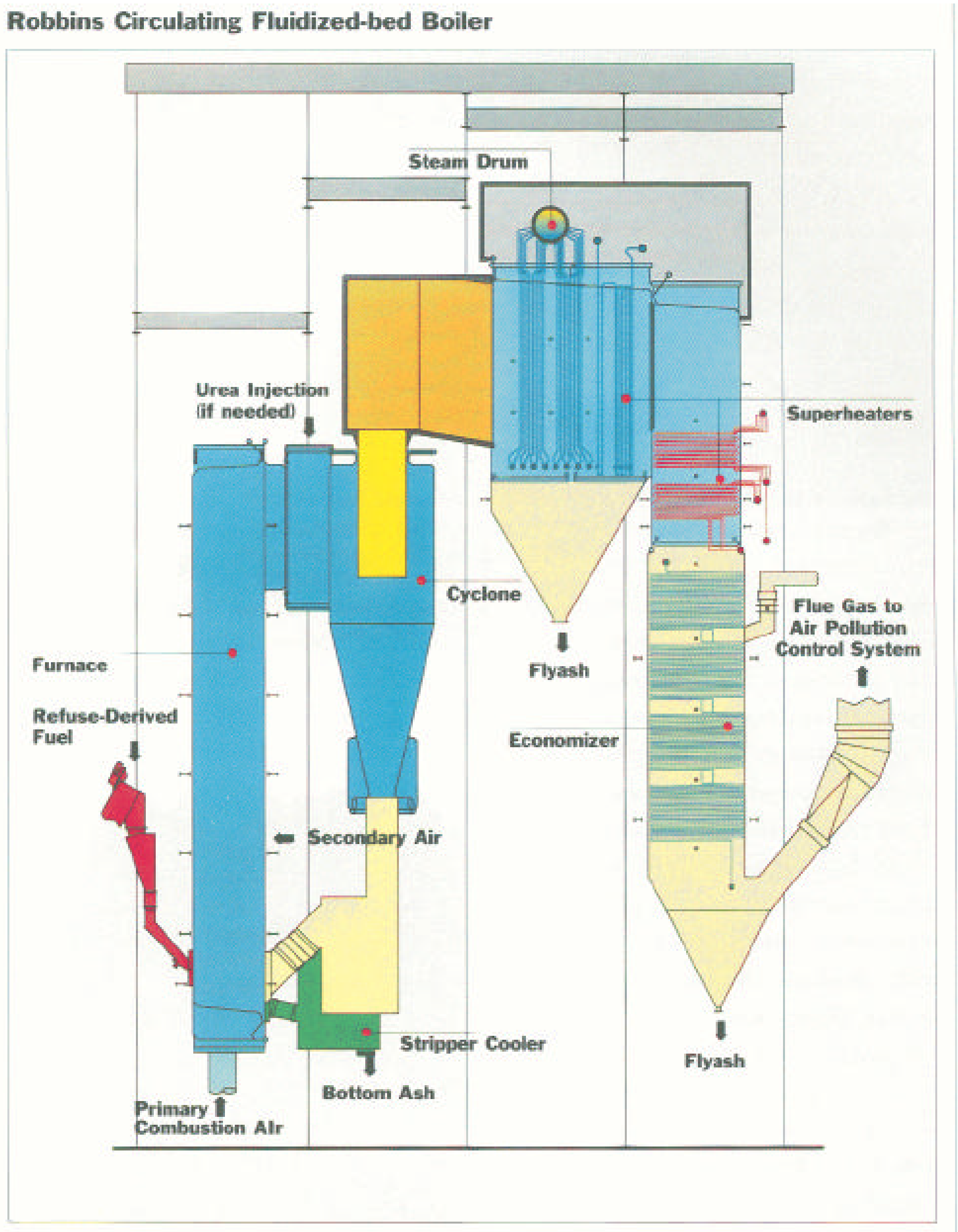

Figure 4. Circulating Fluidized Bed Combustor/Boiler at Robbins, Illinois

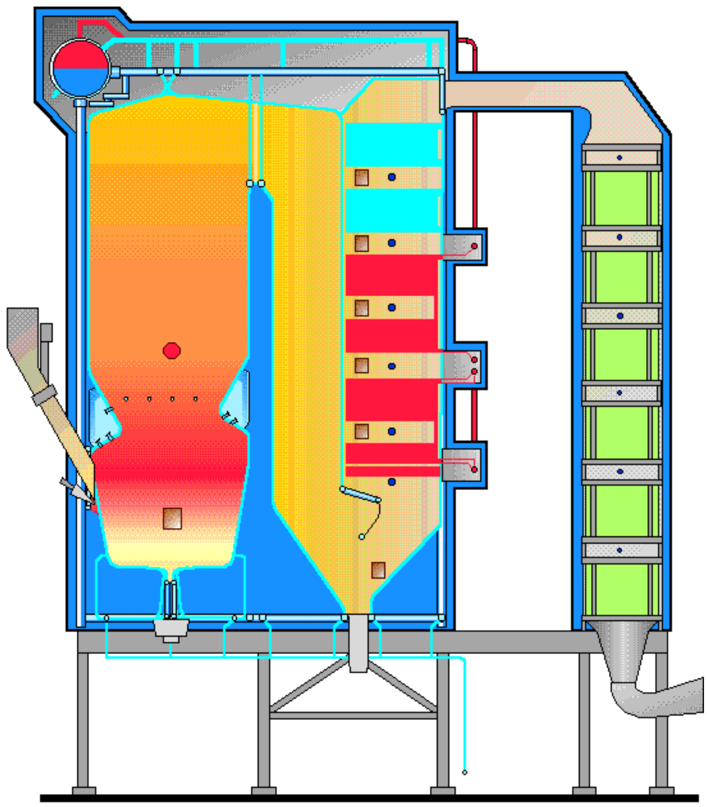

Figure 5. DERL Bubbling Fluidized Bed Combustor/Boiler, Dundee, Scotland