

Power production from biomass II
with special emphasis on gasification
and pyrolysis R&DD

Edited by

Kai Sipilä & Maija Korhonen

VTT Energy



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ABSTRACT

The Seminar on Power Production from Biomass II with special emphasis on gasification and pyrolysis R&DD, was organized by VTT Energy on 27 - 28 March 1995 in Espoo, Finland. All seminar speakers were invited in order to give a high-level overview of the achievements of biomass combustion, gasification and flash pyrolysis technologies. The sessions included presentations by all key industrial entrepreneurs in the field. The poster session was open to all groups interested.

Globally bioenergy covers about 3 % of the primary energy consumption. Locally it has a significant role in many countries like in Finland, where bioenergy covers almost 15 % and peat 5 % of primary energy consumption. Today's cost-effective heat and power production is based on industrial wood residues and spent cooking liquors in relatively large industrial units or municipal heating and power stations. Agricultural residues like straw and especially energy crops are becoming more interesting in co-utilization with other biomasses or fossil fuels.

The seminar successfully displayed the status of present technologies as well as development targets for new gasification and flash pyrolysis technologies in the coming years. The many industrial participants showed that there are growing business possibilities in many countries all over the world.

The proceedings include the most oral presentations given at the Seminar and also abstracts of poster presentations.

FOREWORD

The Seminar on Power Production from Biomass II, with special emphasis on gasification and pyrolysis R&DD, was organized by VTT Energy on 27 - 28 March 1995 in Espoo. The first seminar on the same subject was held in December 1992 to finalize the Finnish Bioenergy R&D Programme JALO on Thermochemical Conversion Technologies.

The seminar was financially supported by the European Commission DG XII and the IEA Bioenergy Agreement. Dr. Wolfgang Palz, Head of Re-newable Energy of EC, gave an overview of the EC research programmes and the future strategies. Dr. Raymond Costello of Department of Energy, the United States, Chairman of the IEA Agreement, presented the newly published Strategic Plan for the Agreement as well as the main project results. All seminar speakers were invited in order to obtain a high-level overview of the achievements in biomass combustion, gasification and flash pyrolysis technologies. The sessions included presentations by all key industrial entrepreneurs in the field. The poster session was open to all groups interested. The Proceedings include the most oral presentations and also abstracts of poster presentations.

Globally bioenergy covers about 13 % of the primary energy consumption (55 EJ in 1990). Locally it has a significant role in many countries like in Finland, where bioenergy covers almost 15 % and peat 5 % of primary energy consumption. In some developing countries it accounts for over 90 % of energy use. Today's cost-effective heat and power production is based on industrial wood residues and spent cooking liquors in relatively large industrial units or municipal heating and power stations. Agricultural residues like straw and especially energy crops are becoming more interesting in co-utilization with other biomasses or fossil fuels.

The high number of participants, about 200 specialists from 22 countries, showed the high international interest in the field of power production from biomass. The many industrial participants showed that there are growing business possibilities in many countries all over the world. For example, the goal of the EC Altener Programme is to double the share of renewable energy by the year 2005.

The seminar successfully displayed the status of present technologies as well as development targets for new gasification and flash pyrolysis technologies in the coming years. Organising the next seminar on this special subject in 1998 is under consideration.

Espoo January 1996

Kai Sipilä & Maija Korhonen

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THE IEA/BIOENERGY IMPLEMENTING AGREEMENT AND OTHER ACTIVITIES

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1 INTRODUCTION

The oil crisis of 1973 and 1978 heightened the world's realization that deriving its energy sources from multiple resources, especially those that stem from domestic and renewable resources, would provide a more energy secure and economically stable world. As a result, the newly formed International Energy Agency quickly decided that more could be done in the near and long term to diversify the sources of energy for the world's economies, by utilizing the abundant resource of biomass which represents a very real opportunity for many of the IEA member countries.

In 1975, Article III of the Guiding Principles for Cooperation in the Field of Energy Research and Development was adopted by the Governing Board of the International Energy Agency. These articles are the genesis from which several of the IEA's Implementing Agreements in alternative energy research are founded.

Implementing Agreements (IAs) are used widely in international collaborative work within the International Energy Agency (IEA). These agreements are meant to be very flexible depending on the nature of the work and the interests of the participating countries. Many IAs are directed at the development of specific technologies, while a number of IAs are primarily used to facilitate information collection and dissemination. There are also a number of agreements that do not deal directly with technology development, but deal with environmental, economic and safety aspects of the technologies under development.

The IEA Bioenergy Agreement is a prime example of how Implementing Agreements can be utilized to establish and expand cooperative research for the effective leveraging of technical knowledge and financial resources in finding solutions to the future needs of a growing energy dependent world. As

will be illustrated, these activities are important to the commercialization and deployment of bioenergy technologies, which increasingly are being visualized as one of the few options that can maintain and promote economic and environmental stability.

2 ENERGY DEMANDS AND THE RENEWABLE SOLUTION

OECD oil demand in the transportation sector is expected to grow at an annual average rate of 1.5 percent per annum through the year 2010, rising from 892 million tons of oil equivalent in 1991 to 1176 million tons of oil equivalent in 2010, accounting for most of total incremental demand. In the power generation sector, the economics of oil fired generation are not favorable for base load. The building of new and more efficient power generating capacity means that the role of oil in meeting peak demand is also likely to be reduced with comparable increases in the use of solid or gaseous fuels.

The growing concentration of oil demand in the transport sector underlines the trend towards a lighter product barrel, which, together with enacted fuel quality legislation, implies the necessity of large investments in the refining sector if alternatives are not utilized. In addition, as the OECD nations move toward unification and national borders become transparent to commercial trade and demographic shifts, transportation will play an even greater role in the economics of the European community.

The world's biomass resources represent a large sustainable base to meet the world's current and future energy demands, especially in the electric power and transportation end-use sectors. In fact, approximately ten percent of the earth's cropland, pastures, and forests could provide 267 exajoules of energy which is equivalent to 44 billion barrels of oil annually.

The most important source of carbon dioxide emissions is the release of this gas during the combustion of fossil fuels. Worldwide, liquid and solid fuels accounted for 80 percent of the carbon dioxide emissions from fossil fuel burning in 1991, and gaseous fuels (e.g., natural gas) accounted for 16.5 percent during the same year.

Currently, the world's biomass resource base sequesters 80 billion tons of carbon per year. This environmental benefit is increasingly becoming more important as a renewable means of globally fixing carbon dioxide through photosynthesis. Obviously, how countries manage and utilize their biomass resources will have far reaching implications worldwide.

3 EVOLUTION OF IEA BIOENERGY

The Bioenergy Implementing Agreement has evolved over the past 16 years, from examining conventional forestry resources to dedicated energy crops, and from four original member countries to 15. The following is a brief discussion covering the history and evolution of Bioenergy Implementing Agreement within the IEA.

Under the Forestry Energy Implementing Agreement, there were originally four activity areas: systems analysis; growth and production; harvesting, processing and transport; and conversion, with the overall focus being the utilization of existing conventional forestry resources. There were four original member countries to this agreement in 1978 which included Canada, Ireland, Sweden, and the United States. By the end of this agreement in 1986, membership had grown to 11 countries with the addition of Austria, Belgium, Denmark, Finland, New Zealand, Norway, and the United Kingdom.

In 1986, it was decided that a new agreement was needed to embody a more determined course of cooperative efforts. Additionally, it was decided that, while the overall "Bioenergy Implementing Agreement" would be in effect as long as the member countries wished, specific activity areas would be held to a three-year cycle. This proviso allowed for the review of progress made over the preceding years and, based on the findings, provided a mechanism to re-define subsequent three-year efforts. The Bioenergy Implementing Agreement was established under the Committee of Energy Research and Development's Renewable Energy Working Party (REWP). As with the other IEA Implementing Agreements, there is an Executive Committee which provides the link between a particular agreement and the rest of the IEA organization.

While this was a new implementing agreement and structure for multilateral cooperative bioenergy research, it was decided to continue the annex system initiated under the previous agreement. As such, the 1986 - 1989 period of the Bioenergy Agreement was composed of the following three annexes:

- Annex II Improvement of Biomass Growth and Production Technology in Short Rotation Forestry for Energy
- Annex III Development of Improved Methods for Harvesting, Processing and Transport of Forest Biomass for Energy
- Annex IV Converting Biomass Feedstocks into Usable Energy Forms

Under these three annexes, 11 cooperative research activity areas were established which represented a three-fold increase over the number under the Forestry Energy Implementing Agreement. Additionally, this three-year

period can be characterized as the beginning of a shift in research efforts beyond conventional forestry and into energy crops.

The original members to the IEA Bioenergy Agreement were the same members as at the end of the Forestry Energy Implementing Agreement. But, by the end of 1989, membership grew to 13 countries, with the addition of Japan and Italy.

The 1989-1991 period of the Bioenergy Agreement was composed of the following three annexes:

Annex V Improvement of Energy-Dedicated Biomass Production Systems

Annex VI Biomass Supply from Conventional Forestry

Annex VII Improvement of Methods for Conversion of Biomass Feedstocks

These three annexes continued the work started under previous annexes through 20 cooperative research activities. Additionally, the trend toward development of new bioenergy crops was enhanced with increased attention to ecophysiology and pest and disease control/ management. Also, the scope of bioenergy crop research was expanded to include dedicated agricultural and herbaceous crop types. Finally, the development of standards for testing and economic evaluations were initiated to enhance relevance and value to member country domestic research efforts.

By the end of 1991, membership had grown to 15 with the additions of the Netherlands, Switzerland, and the European Union, minus the loss of Ireland, who discontinued cooperative research efforts under this agreement.

The most recent set of activities under the bioenergy agreement started in 1992 and just expired at the end of 1994. It was composed of the following four annexes:

Annex VIII Efficient and Environmentally-Sound Biomass Production Systems

Annex IX Harvesting and Supply of Wood Biomass for Energy

Annex X Biomass Utilization

Annex XI Conversion of MSW Feedstocks to Energy

These four annexes comprised 30 cooperative research activities. During this period, there was a much greater emphasis placed on environmental considerations and the use of municipal solid waste (MSW) as a low-cost, near-term biomass feedstock for the early introduction of bioenergy technologies.

4 CURRENT ACTIVITIES

At present, another step in the evolution of the Bioenergy Agreement is occurring. In June 1993, the IEA Ministers announced the nine "Shared Goals" for international energy cooperative activities. In direct support of these Shared Goals, the Executive Committee for the Bioenergy Implementing Agreement has promulgated a strategic plan. This effort seeks to set down a strategic approach for achieving an adopted Vision and Mission for the Bioenergy Agreement. Furthermore, this Strategic Plan summarizes the joint views of the member-country participants (currently 15 countries and the European Commission) who collaborate in the Bioenergy Agreement. In addition, this plan seeks to motivate the participation of industry and other private sector groups, as well as broaden public awareness and support for these activities.

The Vision of bioenergy utilization for sustainable development is as follows:

VISION

REALIZE THE USE OF ENVIRONMENTALLY-SOUND AND COST-COMPETITIVE BIOENERGY ON A SUSTAINABLE BASIS, TO PROVIDE A SUBSTANTIAL CONTRIBUTION TO MEETING FUTURE ENERGY DEMANDS.

This Vision will be pursued over the remainder of the 1990s through conduct of the following Programme Mission.

MISSION

MAINTAIN, COORDINATE, AND FACILITATE BIOENERGY RESEARCH & DEVELOPMENT THROUGH INTERNATIONAL CO-OPERATION AND INFORMATION EXCHANGE, LEADING TO THE DEPLOYMENT AND COMMERCIALIZATION OF ENVIRONMENTALLY-SOUND, SUSTAINABLE, EFFICIENT AND COST-COMPETITIVE BIOENERGY TECHNOLOGIES.

The Vision and Mission concepts that emerged from the strategic planning process focus on overcoming the environmental, institutional, technological, and financial barriers to the near and long-term deployment of bioenergy technologies. The importance of these concepts is emphasized by their support to:

- The potential of widespread commercial application of biomass energy to assist participating nations in meeting the Shared Goals of the IEA.
- The evolutionary forces that support the enhanced use of bioenergy for sustainable development.
- The efforts to identify the differences and barriers which must be addressed to help make the bioenergy vision a reality.

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- The potential of widespread commercial application of biomass energy to assist participating nations in meeting the Shared Goals of the IEA.
- The evolutionary forces that support the enhanced use of bioenergy for sustainable development.
- The efforts to identify the differences and barriers which must be addressed to help make the bioenergy vision a reality.

5 ORGANIZATIONAL STRUCTURE

As we have seen, under the prior organizational structure, four annexes - each composed of a number of separate and discrete activities - were examined for a life span or duration of three years. This structure (Figure 1) worked well as a method of facilitating information exchange among participating member countries and provided a vehicle for the leveraging of research resources.

5.1 CURRENT/ADOPTED ORGANIZATIONAL STRUCTURE

Several options were examined for the out-year organizational structure with the objectives of maintaining continuity, enhancing collaboration and fostering synergism.

For future research, the possible merger of Tasks was examined as a means of streamlining the organization structure and reducing management costs. The rationale for merging the work of Production, and Harvesting and Supply was to obtain greater efficiency in operation and management. The advantages of such a structure are as follows:

- greater potential linkage between production and mechanization;
- potentially more cost effective and efficient Task management;

- potentially greater degree of linkage between activities within Tasks;
- better focus on meeting data and information needs of Special Projects; and
- potential for giving greater concentration on needs of practitioners than academics.

Figure 1
IEA Bioenergy Agreement Organizational Structure

Current

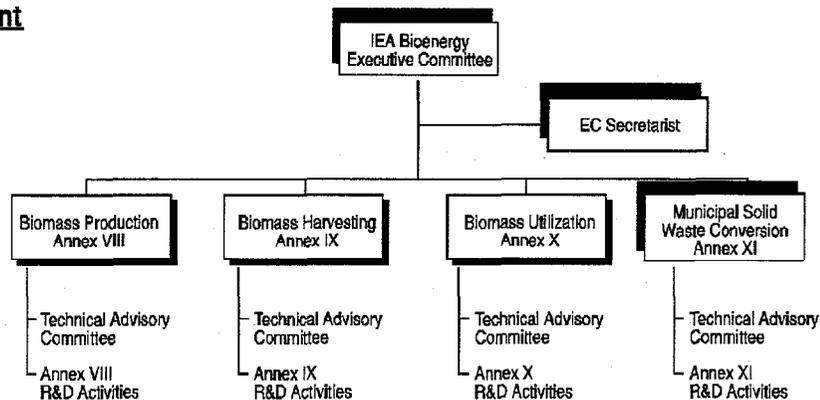


Figure 2

Future

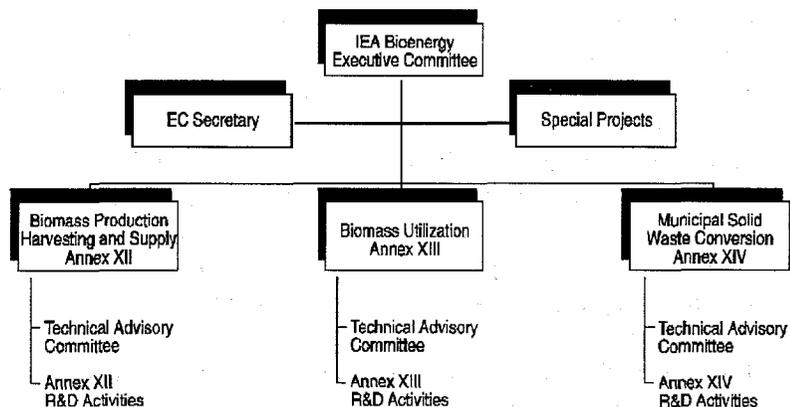


Figure 1. IEA Bioenergy Agreement Organizational structure.

5.2 CORE PROGRAM

Under this structure the core program of R&D is maintained, a mechanism for industrial involvement is provided, and synergism between basic R&D elements and industrial development of mature technologies is enhanced. The Core Tasks are similar in number and type to the set of Annexes under the current structure and allow for a continuation of current research efforts which require additional attention. This arrangement ensures that results from research and development activities undertaken within the Core Annexes are incorporated into specific projects in a cohesive manner.

5.3 SPECIAL PROJECTS

Under this reorganization, Special Projects will allow more specific project oriented work as collaboration to be undertaken by two, three or more member countries and can be of various types, lifetimes and costs.

A Special Project can be defined as any project that, for various reasons, does not conform to the organizational structure depicted in Figure 2. This may be for a number of reasons:

- the project has significant industrial input;
- the project may have significant intellectual property rights considerations;
- the project may be of short duration with a large budget; and
- the project does not fit neatly into any of the existing Task areas.

As discrete activities, each Special Project would have its own Special Project Manager, responsible for all financial, legal and administrative aspects of the project. It is envisioned that selection of the Special Project Manager would be at the discretion of participating countries. The scope of work, appropriate manpower/cost schedules, dates of deliverables, progress reports and matters relating to intellectual property rights, etc., will be clearly defined. This would also include project duration and evaluation of results.

It is also envisioned that special project activities will have the full support of IEA Office of Legal Counsel in developing the necessary contractual documentation.

5.4 ONE-TIME EVENTS

Over the past several years, the IEA Bioenergy Agreement has arranged numerous one-time events, often in collaboration with other bodies. These

include workshops on Bioenergy and the Greenhouse Effect, Non-Technical Barriers to the Deployment of Bioenergy, and Environmental Impacts to Bioenergy. In addition, several symposia conducted on Bioenergy for Lignocellulosics Conversion, and three international conferences were held on various aspects of thermochemical biomass conversion.

During the next period, additional one-time events will be sponsored for disseminating information and encouraging international collaboration. An example of such an event will be developments in Thermochemical Biomass Conversion scheduled for Canada in May 1996.

The conferences provide delegates with a unique opportunity to hear about recent and ongoing developments in bioenergy, as well as the chance to meet other researchers and industrialists to exchange information and ideas, and establish new contacts, collaborations and opportunities for exploitation. This vehicle for technology transfer should be viewed as complementary to the various other biomass-based meetings that are held, in that it focuses on one major topic, and provides an opportunity to explore all the facets in as much depth as possible.

6 THE FUTURE OF BIOENERGY

Energy technology progress is critical to meeting IEA needs for energy security, environmental stability, and economic and social development. A fundamental restructuring of the global energy balance is in progress. The substantially higher economic growth rate in developing regions of the world ensure that, in the near-term these regions will account for an increasingly larger share of world energy demand.

This factor, coupled with the economic restructuring underway within Central and Eastern Europe and the former Soviet Union, will have significant effects upon both the supply and demand sides of international energy markets. Furthermore, environmental policies are now major factors affecting world energy production, transport, processing and consumption.

Achieving both energy and environmental objectives is one issue that has increasingly preoccupied the IEA and will continue to do so in the foreseeable future. Another is preserving open trade in energy. Looking beyond the 1990's, IEA also stresses the importance of maintaining the momentum in energy research and development programs through increased collaboration.

7 GOALS AND OBJECTIVES

The recently approved and implemented bioenergy strategy aims at establishing increased program and project co-operation among participants. The program to be carried out within the framework of the Bioenergy Agreement consists of co-operative research, development, demonstrations, joint work products, and exchange of information regarding bioenergy. This effort is designed to identify, facilitate and implement collaborative research that further the development and demonstration of bioenergy technologies of high priority. The overall strategy is to assist participants in achieving the Vision and Mission of the Bioenergy Agreement, while supporting the IEA Shared Goals. Collaborative work elements to accomplish this includes the following:

- Gather, exchange, and evaluate information on bioenergy technologies;
- Encourage and facilitate collaborative research and development;
- Conduct demonstration projects that assist in market deployment; and
- Promote joint work projects, information exchange and technology transfer through international collaboration.

8 A NEW PHILOSOPHY

As a means of carrying out the goals and objectives that have been set out by the Bioenergy Implementing Agreement and are in support of the overall mission of the IEA, a business philosophy has been adopted that allows the Bioenergy Agreement to:

- Enhance flexibility and mobility to changing environments;
- Increase leveraging of knowledge/experience and funding; and
- Amplify communications in support of the Agreement.

Within this context, a corporate philosophy is evolving which provides for a more flexible forum in supporting a more competitive and effective energy market place.

Current estimates predict there will be a fundamental change in the global energy balance during this decade. While energy demand in non-OECD countries was almost equal to that of the OECD countries in 1990, the substantially higher economic growth rates in the non-OECD regions will ensure that by the mid- to late 1990s these countries will account for more than half of the world energy demand. In this arena, the Bioenergy Agreement will be strengthening its relations with both developing countries and the economies in transition. In addition, this growing fundamental energy requirement will

have strong influences upon both the supply and demand sides of international energy markets. Although this tendency will persist, collectively, we must meet this challenge by setting a true course. One that meets the needs of energy security in an environmentally neutral manner while ensuring continued economic growth.

9 A CLOSING COMMENT

With the world around continually changing, no one can accurately predict the future. As such, we must be prepared to face change. As we have seen, change is not new to the Bioenergy Agreement. Much of our progress in the past and present has come from our ability to successfully respond to and manage change. We have also made it possible to progress because we have taken bold actions. The future, however, will require that we become even better at managing a changing environment as well as moving in a more decisive manner to ensure sustainable bioenergy economies.

Gasification of biomass for power

BIOMASS IGCC

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Abstract

Enviropower Inc. is developing a modern power plant concept based on pressurised fluidized-bed gasification and gas turbine combined cycle (IGCC). The process is capable of maximising the electricity production with a variety of solid fuels - different biomass and coal types - mixed or separately. The development work is conducted on many levels. These and demonstration efforts are highlighted in this paper. The feasibility of a pressurised gasification based processes compared to competing technologies in different applications is discussed. The potential of power production from biomass is also reviewed.

1 BACKGROUND

Enviropower is a joint venture of Tampella Power, a major Finnish boiler manufacturer, and Vattenfall AB, a large Swedish utility and energy technology company. Enviropower was founded to develop, commercialise and market the Integrated Gasification Combined Cycle (IGCC) technology based on pressurised gasification of solid fuels.

The IGCC process is an efficient way to convert bioenergy into electricity and heat. The high efficiency of power and heat generation is due to the combined-cycle configuration of the process, the optimised integration of the gasification plant into the gas/steam process and in the case of biomass, the optimised integration of the fuel dryer into the system.

Enviropower's IGCC concept is called simplified IGCC process, applying air-blown pressurised fluidized-bed gasification and hot gas cleanup. The simplified IGCC has the advantage of high power generation efficiency, high power to heat ratio at cogeneration, excellent environmental performance, simple plant concept and modularity. The IGCC process consists of clearly defined parts, which makes staged construction possible, in pre-fabricated modules shortening the erection time and lowering the investment costs.

Enviropower also puts a special effort on the development of hot gas cleanup systems. The development work concentrates on sulphur removal in coal gasification and on tar and ammonia destruction and removal in biomass gasification. In co-operation with acknowledged research institutions like IGT and Technical Research Centre of Finland significant progress was achieved in this field. The R&D work related to the cleanup of biomass-derived gas led to the development of a new type of gas cleaning train (hot gas cleanup) which incorporates gas cooling and dust filtration.

The process development work gets firm support from Enviropower's Gasification Pilot Plant, which includes all the main components of a real gasification island. Vattenfall is also conducting a significant program to develop several subprocesses of the IGCC process.

2 PROCESS DESCRIPTION

Since simplified IGCC systems derive one of their main advantages from the close coupled integration of the various subsystems, an optimised integration is a key feature to reach high plant efficiency. The flow diagram of the basic process is shown in Figure 1.

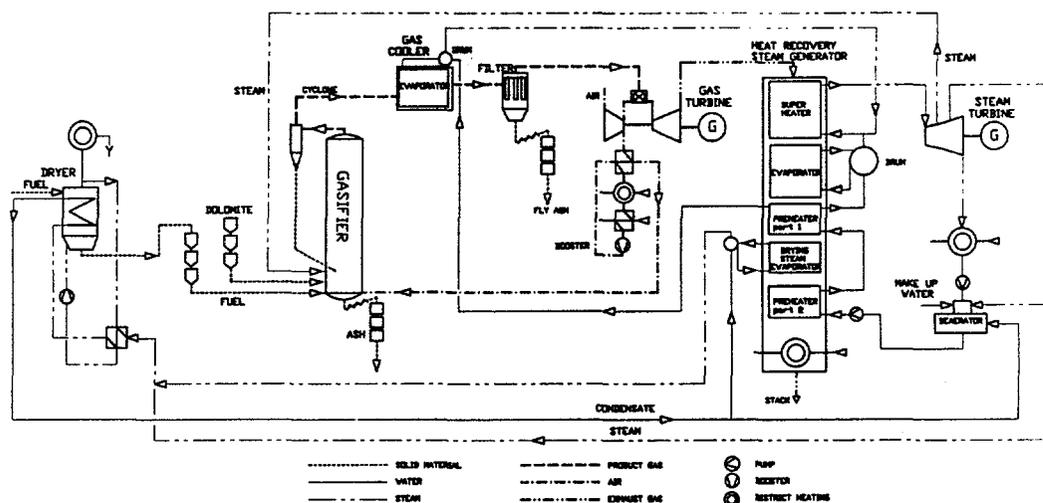


Figure 1. Enviropower's IGCC concept.

Fuel drying and gasification are inseparable parts of the IGCC process for biomass. In Enviropower's gasification system biomass is gasified air-blown. Biomass has to be dried to 20 - 30 % moisture content to generate a gas of reasonably high heating value. Applying steam drying an efficient integration of the drying and steam process can be realised. The dried fuel is fed through feeders into the fluidized bed of the gasifier. Since the ash content of biomass is low, inert bed material such as sand or dolomite is used.

The gasifier operates at the temperature level of 800 - 950 °C and generates a low calorific value gas of 4 - 6 MJ/kg lower heating value. The gasifier ranges 15 to 25 bar determined by the gas turbine requirements. The product gas leaving the gasifier is cooled in a simple fire tube gas cooler to 400 - 550 °C, which is a acceptable temperature for the gas turbine and other downstream equipment.

Hot Gas Cleanup is one of the key parts of a simplified IGCC process. In biomass gasification tar formation, destruction and removal are the main issues. In Enviropower's IGCC concept tar cracking occurs in the gasifier at high temperature and pressure (using dolomite as long residence time catalyst), and efficient circulation in the bed and recirculation of entrained fines are essential features of efficient gasification.

The final gas-cleaning step before the gas turbine is high-temperature/high pressure filtration where the dust heavy metal and alkali metal loading is reduced to a negligible amount. The filter can be of ceramic or metal candle type.

The low-calorific-value gas application of the commercially available gas turbines requires certain modifications to the gas turbine hardware. The gas turbine has to be equipped with a modified combustion chamber combusting the biomass-derived gas efficiently and with low emissions (low-NO_x burner). Air has to be extracted from the gas turbine after the compressor for the gasification process. The pressure and temperature of the gasification air are adjusted in a booster compressor/heat exchanger system to the appropriate level.

The steam cycle section of the process (gas turbine/steam turbine) includes mainly commercial technologies, as a usual combined-cycle plant. The product gas cooler, operating as an evaporator, is coupled to the high-pressure section of the HRSG. The steam process coupled to the gasification plant/gas turbine complex is designed to maximise the electricity production of the process with high efficiency allowing also the required heat production.

3 PROCESS PERFORMANCE

The size of the IGCC plant is determined by the gas turbine selected. The number of suitable gas turbines is very limited today. The main issue is the development of the GT combustion systems to burn LHV gas. The manufacturers who quote their turbines for biomass IGCC today are listed in Table 1.

Aeroderivative gas turbines with small combustors and without a possibility of low-NO_x combustion (i.e. low ammonia to NO_x conversion) are not considered as a potential choice.

The power output and the calculated efficiency of IGCC in condensing mode and biomass amounts (wood based) needed for each size of IGCC are also given in Table 1.

Table 1. Gas turbine manufacturers.

GAS TURBINE	MWe/GT	MWe/IGCC	NET EFFICIENCY (LHV) (CONDENS.)	BIOMASS NEED* tn/m ³ /a
Allison, Ruston	5	7,5	42	64.000/200.000
Mitsubishi, MW151	21	39	45	300.000/940.000
GE, Frame 6	43	62	48	465.000/1.5 million
Westinghouse, CW251	50	72	48	540.000/1.7 million
GE, Frame 6 FA	70	110	49	810.000/2.53 million

* Assumptions: 8.000 h/a, 50% moisture (AR)

The IGCC process incorporates advanced control systems that will significantly reduce the level of gaseous pollutants emitted. Furthermore, the better efficiency of the plant as compared to conventional and competing technologies will also reduce the amount of so-called greenhouse gases. The anticipated emissions, when gasifying wood-based residue are as follows:

SO ₂	< 10 mg/MJ
NO _x	< 50 mg/MJ
Particulate	< 5 mg/MJ
CO ₂	< 780 gCO ₂ /kWh

4 BIOMASS IGCC PROCESS DEVELOPMENT

Enviropower's biomass-fuelled IGCC process is based on the extensive gasification know-how and experience of biomass use of the mother companies, Tampella Power and Vattenfall. To minimise the technical and economical risks related to the design and operation of a demonstration plant, a development and test program (1) was established to verify the critical process steps in the IGCC concept. A test program has been accomplished covering all aspects of a biomass-based IGCC process. The test program includes tests, in pilot or full scale, of the following process parts in an IGCC:

- drying of biomass in three different types of steam dryers
- feeding of biomass to a pressurised system
- pressurised gasification and gas cleaning
- combustion of low calorific value gas in a gas turbine combustor.

4.1 BIOMASS DRYING TESTS

A test program has been carried out by Vattenfall with three different manufacturers to clarify the performance of steam dryers when drying biomass. There were two main test objectives with the test program:

- to study the technical function of steam dryers for drying of biomass
- to give basis for estimation of performance data concerning
 - drying capacity
 - power consumption
 - environmental impact, emissions to air and water.
 -

All dryers were tested with the same type of biomass, logging residues including bark and green parts, with a moisture content of 50 %. The fuel was dried to a moisture content of 10 - 15 %.

All three types of dryers worked well for drying of biomass. There were only small differences in the performance depending on the specific design of the test facilities. The low content of organic material and impurities in the condensed water from the dryer indicates that only a biological waste water treatment is necessary for this kind of plant.

4.2 BIOMASS FEEDING TESTS

Enviropower biomass feeding system was developed to feed a large variety of biomass to the 15 MW_{th} capacity pilot plant in Tampere, Finland. The

development work combined the experiences from the pilot coal feeding system and biomass-related specific data generated in conventional combustion systems.

The biomass feeding system includes a weigh hopper, two parallel lock hoppers and a surge hopper. Two parallel lock hoppers minimise the inert gas consumption during pressurisation because part of the depressurized gas from the first lock hopper can be reused for pressurisation of the other lock hopper. The feeding system also includes valves of equal size to the future large-scale system. The biomass is fed from the surge hopper into the gasifier through the surge hopper discharge screw bottom, a collector screw and a constant speed feeding screw. The feeding rate of biomass is controlled by the surge hopper discharge screws and collector screw.

The biomass feeding system has been tested successfully with forest residue, dry/wet lignite, dried/wet coal and straw mixture as well as with paper mill residue consisting of bark, sludge and paper.

The disadvantage of the lock hopper feeding system is the consumption of inert gas which causes extra operating costs for a power plant. In parallel with the gasification test program Vattenfall started the development of a new type of feeding system for feeding fibrous fuels to a pressurised system. The system, called "screw-piston feeder", was invented by Vattenfall Energisystem AB and is patented in several countries.

The feeder consists of a cylindrical chamber housing a conveyor screw. The screw works as a conveyor screw transporting the fuel to the pressure chamber and also as a piston, pushing the fuel to form a plug in the pressure chamber. After one cycle the screw is axially returned and a new cycle starts. The pressure drop is formed over the dense plug in the pressure chamber.

The test program with the prototype has shown that the feeding principle works as expected in a pressurised system for low-density fuels like biomass, peat and straw. The inert gas consumption of the feeding system can be reduced by 50 - 60 % compared with a lock hopper system.

4.3 BIOMASS GASIFICATION TESTS

The biomass gasification test program in 1993 was a part of the joint development project of Vattenfall and Enviropower to demonstrate the IGCC technology for biomass fuels using air-blown gasification and hot gas cleanup. A test program for the demonstration plant in Finland started at the

beginning of 1995. The main objective of the test runs was to verify and demonstrate the ability of the gasifier process and hot gas cleanup system in commercial-scale IGCC plant operating conditions.

Enviropower's pressurised fluidized-bed gasification pilot plant is located in Tampere, Finland. The pilot plant includes all essential modules for research, component testing and the completion of the development of the gasification process for IGCC applications. The pilot plant converts 15 MW thermal input of fuel to a product gas suitable for combustion in a gas turbine. The gasifier operates at pressure up to 30 bar and temperatures up to 1 100 °C. The process flow diagram of the pilot is shown in Figure 2.

The plant is equipped with separate coal and biomass feeding lines, which allow the testing of a variety of feedstocks like biomass, coal, lignite and straw. The fuel and additives are fed to the gasifier from separate lock hopper systems or with the fuel.

The gasifier is an air-blown, single-stage pressurised fluidized-bed gasifier. The gasification agents, air and steam, if needed, are fed through the bottom of the fluidized bed to maintain the proper conditions for simultaneous fluidisation and ash removal. Freeboard temperature can be controlled by air injection. Gasification steam is produced in the gas coolers and superheated in the heat recovery boiler. The bottom ash is removed through the bottom of the gasifier through a cooling screw and a lock hopper system.

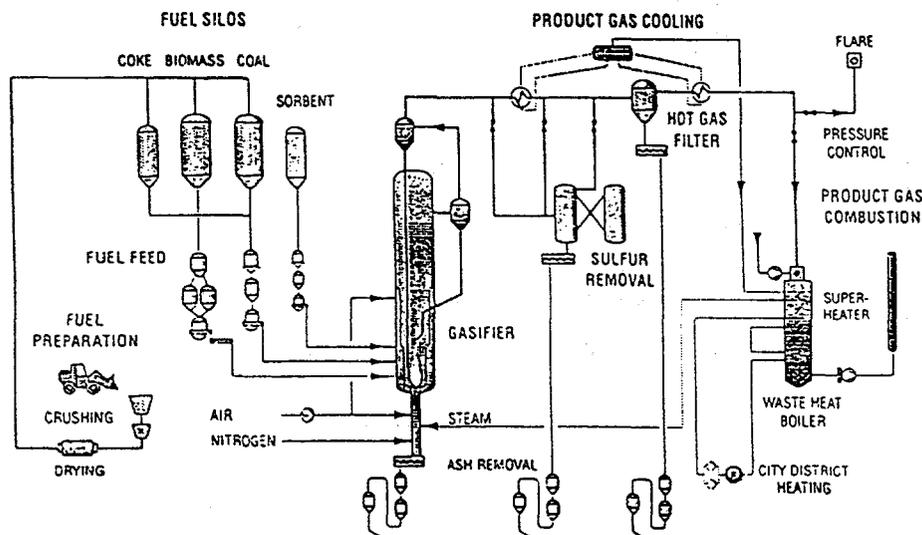


Figure 2. The Enviropower 15 MW_{th} pilot plant.

The bulk of the entrained fines from the gasifier is separated from the product gas in an external cyclone. The fines are returned from the cyclone to the fluidized bed. The product gas leaving the cyclone is cooled in two steps: first to 400 - 650 °C and after hot gas cleanup to 200 - 350 °C. After the first gas cooling stage, the dust particles are removed from the gas stream by a ceramic candle filter cleaned by gas pulsing. Sulphur compounds (in coal case) can be cleaned in a post-gasification desulfurisation system. The pressure of the cooled product gas is reduced before the burner of the waste heat recovery boiler, which is connected to the district heating system of the city of Tampere. The flue gas of the boiler is led to the stack.

The pilot plant is equipped with a state-of-art data acquisition and control system. More than 1 000 positions are measured continuously, product gas and flue gas quality is analysed on-line and all solid flows are sampled.

A total of 3 000 tons of wood-based biomass (as received) was gasified during 900 test hours in 1993. Long, stable set points were achieved under demo plant operating conditions. The testing conditions and fuels/amounts gasified are presented in Table 2 and the first results in Table 3.

Table 2. Biomass pilot test runs.

Operation pressure	14 - 18 - 22 bar
Operation temperature	800 - 950 °C
Plant capacity	15 - 17 MJ/s (MWth), 100 tn/day
FUELS GASIFIED (1993 - 1995)	
	amount/tn
Wood chips	1630
Forest residue	1650
Paper mill waste (bark, paper, sludge)	460
Straw with coal	20 (+120 tn coal)

Table 3. Biomass gasification pilot test program, test results.

		Forest residue	Bark
Pilot plant fuel input	MJ/s	15	15
Product gas LHV (dry)	MJ/m ³	4,5 - 5,6	4,5 - 5,6
Fuel conversion	%	97 - 99	97 - 99
Product gas dust content after ceramic filter	mg/m ³ N	<5	<5
Alkalines (K+Na)	ppm(w)	0,01	0,01
Product gas H ₂ S content	mg/m ³ N	15 - 50	- 200
Product gas NH ₃ content	mg/m ³ N	500 - 1500	- 2200

Fuel testing for the Finnish demonstration project, called "Summa IGCC Demonstration Project" started in February 1995 and continued in May 1995. The ceramic filter unit functioned well with an excellent filtration efficiency. Generally the combined dust and tar loading was less than 4 ppm(w) after filtration. This level of dust loading is lower than the dust concentration specified by gas turbine manufacturers and much lower than the limit required by environmental regulations.

4.4 GAS TURBINE COMBUSTION TESTS

The purpose of this part of the program was to verify that the span of possible product gas compositions from the gasifier can be satisfactorily combusted in the combustion system of the gas turbine, and also to investigate the resulting gaseous emissions of environmental concern.

The gas turbine selected for this study/project was the GE Frame 6B. The Frame 6 combustor and the similar Frame 7 and 9 combustors have been used in several low Btu gas test series, but since the biomass gasification product gas was not within the span of gases an earlier tested program included, a number of screening test were defined to meet the objectives. The tests were performed during 1994 at the GE Power Generation GT Development Laboratory in Schenectady, USA. The program was financed by Vattenfall.

The program verified that the modified F6B combustor model is well suited for biomass application.

- Temperatures and dynamic pressure levels are well within the design limit and combustion characteristics are good through the operating load range. Thermal NO_x , CO and UHC emissions are very low.
- The acceptable fuel gas composition includes a range of possible fuel gas heating values, down to and below 5 MJ/m^3 .
- Conversion rate of fuel bound nitrogen to NO_x is lower than expected. No catalyst after the turbine seems to be needed.

There are also plans to continue testing of the Westinghouse advanced MASB low- NO_x burner with biomass-derived gas. Westinghouse testing shows already excellent results with ammonia decomposition up to 90 %.

According to the data available and development strategies of GT manufacturers it is quite obvious that the combustion technology will further develop rapidly in the near future.

5 OPTIMISATION OF THE IGCC PROCESS

The IGCC process has to compete with conventional well developed boiler/steam cycle technology. The efficiency of today's biomass power plants is already 40 % and investment cost very moderate. This makes the competition difficult for IGCC.

The only factor which can make IGCC competitive is the high efficiency of electricity production. This has to be maximised to keep the specific investment cost and power production costs low.

The IGCC concept has been developed to take advantage of the modern high-efficiency gas turbine technology. The correct component selection and integration of drying, gasification, gas turbine, and steam process are the key questions in IGCC process design. The main principles to maximise the IGCC efficiency are presented in Table 4. The schematic process flow diagram is presented in Figure 3.

One of the main observations is that energy/mass of biomass moisture must not be lost. By using steam drying the condensing heat of the moisture can be recovered. Also the pressurised steam flow produced in the gasifier must be utilised in the gas turbine because the mass flow through the turbine determines the output. The compression losses must also be minimised by

compressing the already pressurised clean air flow from the gas turbine - not the large gas flow.

Table 4. Main principles in biomass IGCC process design.

- Condensing heat from fuel drying to be utilized
 - steam drying, safety aspects, LHV in efficiency calculations
- Air to be pressurized
 - not aggressive large gas volume
 - pressurized fluidized bed gasification
- Pressurized air from GT to be utilized
 - small additional booster compressor for air
- Watervapour in gas not to be condensed, gas mass flow determines the output of GT
 - hot gas cleanup
- Heavy duty gas turbines with advanced combustion technology to be used

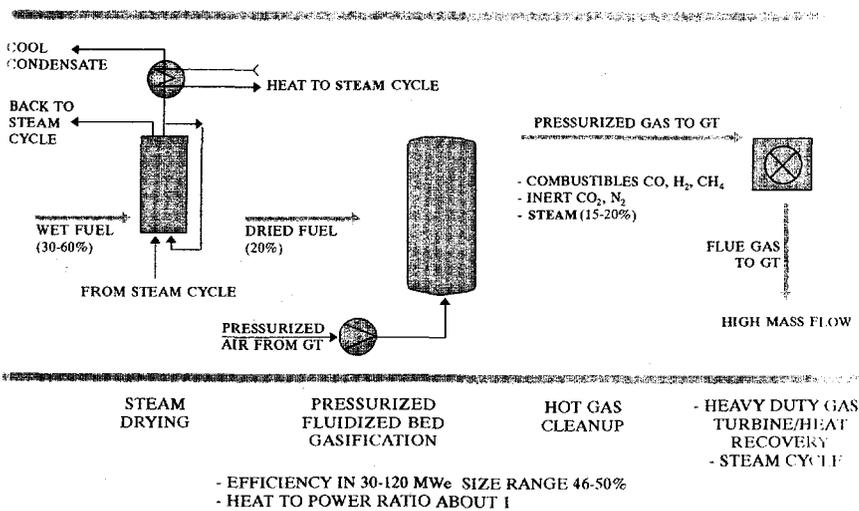


Figure 3. Biomass IGCC with high efficiency.

6 FEASIBILITY OF POWER PRODUCTION FROM BIOMASS

The economical feasibility of a power production method should be calculated case by case due to different conditions in each country and at each case. The following examination gives trends for power price formation in Finnish conditions. In countries like Finland where biomass is available in large quantities and power is produced from many sources the fuel and power prices are low. Higher prices would give a further advantage for the IGCC process.

The relative specific investment costs of Enviropower's IGCC and conventional fluidized bed (CFB) combustion technology are shown in Figure 4.

The message of Figure 4 is that the specific investment cost of an IGCC plant starts to grow in small size (smaller than 40 MWe) much more rapidly than with conventional steam plants. The investment cost for IGCC is "demo-plant" cost, which is expected to decrease by 15 - 20 % after the 10th plant has been built.

The results of electricity production cost calculations for two cases - condensing power and process heat generation in pulp and paper industry - are presented below.

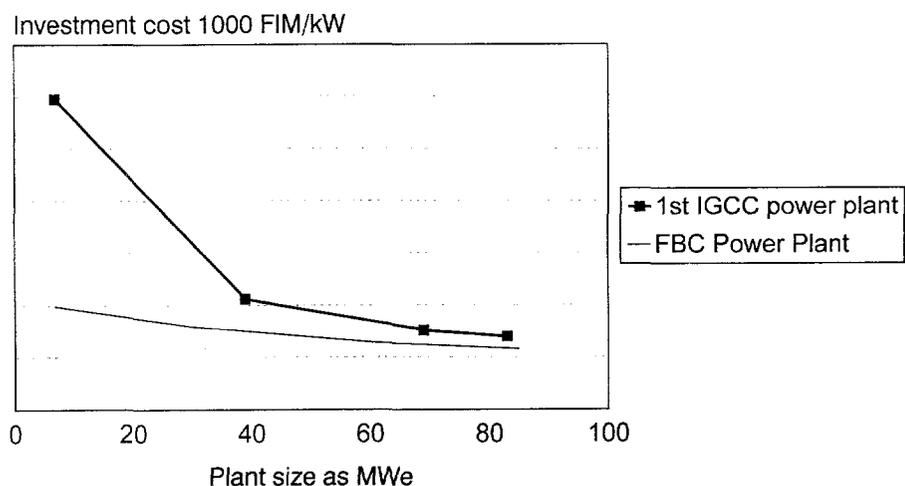


Figure 4. Relative investment costs.

The calculation basis is: operating time per year 8 000 h, 20 years life time, similar fuel price and internal rate of Return (IRR) is expected for each project. Typical efficiencies, availabilities and operation costs for each plant are considered.

Figure 5 shows the cost of electricity (COE) production of both IGCC and fluidized bed combustion (FBC) power plants as if these were condensing power plants. The power plant size is shown as megawatts of electricity production. Separate IGCC plants up to 80 MW_e are marked on COE curves. COEs of IGCC plants decrease more rapidly than that of a FBC plant as the power plant size increase. Results from calculations predict that the COE of the first of the kind IGCC power plant will be equal to the COE of a fluidized bed power plant at 35 MW_e plant size.

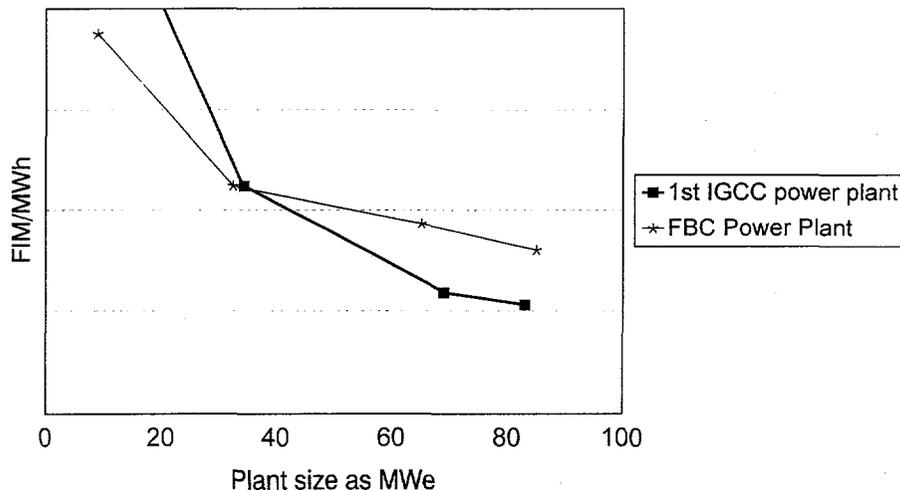


Figure 5. The cost of electricity, condensing power plants.

6.1 INDUSTRIAL POWER PLANTS

Most of the power plant projects, especially in industrial applications, are based on heat demand. Figure 6 shows COE curves as if power plants were supplying process steam to a paper mill with typical process conditions of a Finnish paper mill. Existing steam cycle of the power plant is designed to produce 2.8 bar(a) and 5 bar(a) process steam. The excess steam is used for power generation in a condensing steam turbine.

Power plant size is shown as a function of heat production. Electricity production is shown as an area in the background. IGCC power plants will

be more feasible than FBC plants at larger than 20 MJ/s power plant size and produce more than twice as much electricity as FBC plants.

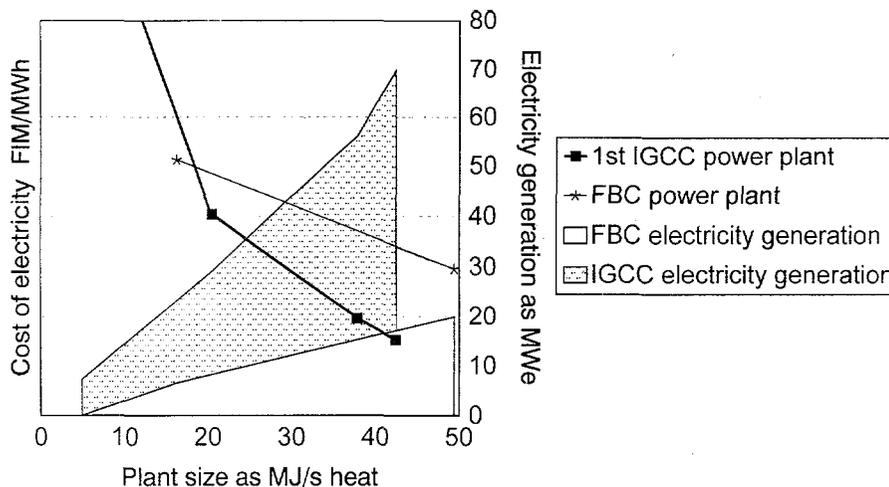


Figure 6. Process heat generation in pulp and paper industry.

7 POTENTIAL OF BIOMASS IGCC POWER PRODUCTION

A rough estimate of biomass availability and the potential IGCC market share can be predicted by using the information from World Energy Council (2), Commission of the European Communities (3) and the U.S. Department of Energy (4).

In short term the most realistic potential seems to be in countries where biomass waste is generated by large industrial sites using biomass as raw material. The two major industries are pulp and paper and sugar production (wood waste/bagasse).

There exists a large political potential around the world but this was excluded in this study.

The conclusion was that about 10 % of biomass from the national potential estimates could be used as a fuel for IGCC in plant size (30 - 80 MW_e). The

estimated biomass IGCC potential in short term potential areas by 2010 is shown in Figure 7.

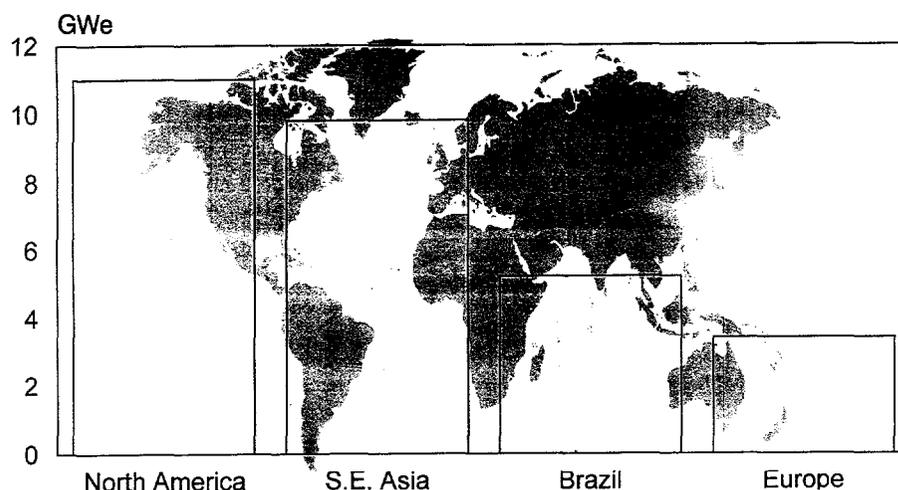


Figure 7. Estimated biomass IGCC potentials by 2010.

8 IGCC DEMONSTRATION IN FINLAND

The development of the biomass-fuelled simplified IGCC process has achieved the maturity for demonstration in full scale. Enviropower plans to demonstrate this technology on a fast schedule participating in the initiation of demonstration projects both in Europe and the USA.

In Finland the pulp and paper industry typically utilises all the in-house wood waste (black liqueur, bark, etc.). Thus the repowering of a paper mill power plant gives an excellent opportunity for the demonstration of the biomass fuelled IGCC process like in the case of the Summa IGCC Demonstration Project where the steam turbines of the existing power plant are utilised. The IGCC plant of 60 - 70 MW power generation will supply about 30 MJ/s heat for the paper mill. However, the amount of available biomass, waste from the mill, is not enough to provide the total fuel input of the IGCC plant thus the feedstock is made up of 40 % biomass waste from the mill and the rest from forestry residues. The 120 MUSD project is cofunded by the Finnish government. The engineering of the project was started at the end of 1994 and the construction work is scheduled to start

during 1996. The IGCC plant placed in the paper mill environment is shown in Figure 8.

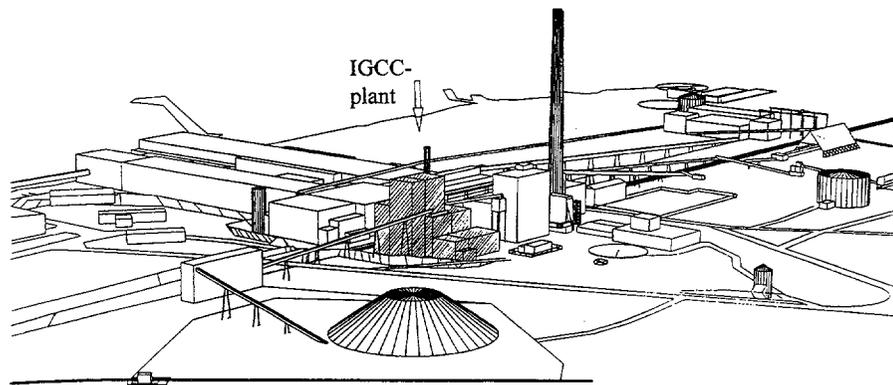


Figure 8. IGCC plant at a paper mill.

9 CONCLUSIONS

Power production by an IGCC process is a niche market area with high market entry barriers but a lot of expectations. The development of the gasification technology has taken a long time and is highly capital-intensive, which limits the number of potential developers.

The relatively high investment cost of an IGCC plant means that the efficiency and reliability of the plant must be maximised to reach a low specific cost (per kilowatt). This is possible only by using pressurised gasification technology, hot gas cleanup and advanced heavy duty gas turbines.

The minimum size of an IGCC plant is determined by the plant economy which, however, differs from country to country. In small size up to 20 - 30 MW_e the conventional boiler/steam turbine process seems to be the right choice in most cases. The maximum size of the plant seems to be determined by the availability of huge amounts of biomass at a reasonable price level. In countries with large forestry and pulp and paper industry plant sizes of 80 - 100 MW_e seem to be feasible.

The IGCC technology is entering the phase of demonstration and commercialisation, it will be ready for large-scale use in the end of this century.

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IGCC TECHNOLOGY AND DEMONSTRATION

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Abstract

Future energy production will be performed by advanced technologies that are more efficient, more environmentally friendly and less expensive than current technologies. Integrated gasification combined cycle (IGCC) power plants have been proposed as one of these systems. Utilising biofuels in future energy production will also be emphasised since this lowers substantially carbon dioxide emissions into the atmosphere due to the fact that biomass is a renewable form of energy.

Combining advanced technology and biomass utilisation is for this reason something that should and will be encouraged. A. Ahlstrom Corporation of Finland and Sydkraft AB of Sweden have as one part of company strategies adopted this approach for the future. The companies have joined their resources in developing a biomass-based IGCC system with the gasification part based on pressurised circulating fluidized-bed technology. With this kind of technology electrical efficiency can be substantially increased compared to conventional power plants.

As a first concrete step, a decision has been made to build a demonstration plant. This plant, located in Värnamo, Sweden, has already been built and is now in commissioning and demonstration stage. The system comprises a fuel drying plant, a pressurised CFB gasifier with gas cooling and cleaning, a gas turbine, a waste heat recovery unit and a steam turbine. The plant is the first in the world where the integration of a pressurised gasifier with a gas turbine will be realised utilising a low calorific gas produced from biomass. The capacity of the Värnamo plant is 6 MW of electricity and 9 MW of district heating. Technology development is in progress for design of plants of sizes from 20 to 120 MW_e.

The paper describes the Bioflow IGCC system, the Värnamo demonstration plant and experiences from the commissioning and demonstration stages.

1 BACKGROUND

Power production has been associated with equipment development throughout the years and more and more efficient and environmentally friendly technologies have been or are being developed. The integrated gasification combined cycle (IGCC) system is one of the technologies that has recently been proposed for future energy production due to its high efficiency and potential low emissions. The emphasis with this technology has been on utilising coal, which can be seen from the number of demonstration plants that have or are being built in the United States and in Europe. Only in the most recent years more focus has been put on utilising biomass in IGCC systems, mostly due to its low impact on the emission of the greenhouse gas carbon dioxide, CO₂.

Circulating fluidized bed (CFB) technology has been associated with catalytic cracking processes in the petrochemical industry or with combustion in the energy production industry. During the last decades the CFB combustion technology has really become one of the successful power production tools on the energy market due to low gaseous emissions and multi-fuel capability. The size of the plants has increased and is now approaching 300 to 400 MW_e.

The utilisation of the CFB technology for energy production has mostly been concentrated on combustion. Other energy production ways with CFB systems have existed but these cases have been rare. One of these applications go back to the early 1980s when the oil price was high and there was an incentive to substitute cheaper biofuels for oil. This particular example describes a system where biofuels such as bark, wood waste etc. are gasified in a refractory lined atmospheric CFB gasifier and the produced low-calorific gas is brought to a lime kiln as a fuel substitute for oil. A few of these systems have been built and are still in successful operation. This application has been very successful technically, but as the oil price dropped in the mid-1980s this application lost its attractiveness.

The potential of the IGCC system with its high efficiency, biomass as an environmentally favourable fuel and the CFB technology as a powerful tool for conversion of the fuel was one of the reasons why A. Ahlstrom Corporation of Finland and Sydkraft AB of Sweden decided in 1991 to join forces in developing an IGCC system based on biofuels. Both companies had initiated independent studies already in the late 1980s but soon found that the development of the pressurised IGCC system utilising AHLSTROM PYROFLOW® CFB technology and biomass as fuel was best accomplished in co-operation.

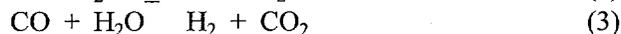
As an essential part of this co-operation between these two companies was the decision to build a full-scale demonstration power plant to the city of Värnamo in southern Sweden. This plant, owned by Sydkraft AB, is the first in the world utilising biomass in a complete IGCC system.

2 ATMOSPHERIC CFB GASIFICATION

In order to understand the biomass-based IGCC it is essential to understand the CFB gasification principle. The atmospheric system is very simple. The fuel is fed into the entirely refractory lined Pyroflow CFB gasifier above a certain distance from the air grid. As the fuel enters into the reactor containing fluidized hot solids and gas, the first primary stage of reaction, namely, pyrolysis occurs. This chemical reaction taking place can be described as



at operating temperatures varying from 800 to 1000 °C depending on the fuel and application. After this, as these aforementioned products flow upwards in the reactor, the secondary stage of reactions takes place, which can be divided into heterogeneous reactions, where char is one ingredient in the reactions, and homogenous reactions where all the reacting components are in the gas phase. An example of the first mentioned reactions is shown in equation (2), the water-gas reaction, and for the latter mentioned reactions in equation (3), the water-gas shift reaction.



Due to these reactions among with other reactions a combustible gas is produced, which enters the hot cyclone and escapes the system together with some of the fine dust. Most of the solids in the system are separated in the cyclone and returned to the lower part of the gasifier reactor. These solids contain char, which is combusted with the air that is introduced through the grid nozzles to fluidise the bed. This combustion process generates the heat required for the pyrolysis process and subsequent mostly endothermic reactions.

Four of these Pyroflow CFB gasifiers have been delivered before the mid-1980s to the pulp and paper industry with capacities ranging from 15 to 35 MW based on fuel input. These utilise waste wood and bark as feedstock and the units are still successfully operational today. Despite reliable operation the low oil price prevented any further commercialisation. However, the systems provided the experience and data to take the next step, which is discussed below.

3 PRESSURISED CFB GASIFICATION

In pressurised gasification the system is the same as for the atmospheric gasification except for increased pressure. The concept and configuration is the same but naturally the design and gasifier hardware change to meet the requirements from the pressure. New technical solutions and an innovative approach are for this reason required. This applies to the gasifier itself, which is now a pressure vessel but also to auxiliary equipment like fuel feeders and ash discharge systems. The chemistry of the process also changes to some extent with pressure. It affects to some extent the tar and ammonia formation but overall it determines the form of the bed material.

The pressure in the system is determined by the gas turbine that the gas is produced for and, hence, it will vary in future commercial applications. This means that the designs may differ to some extent depending on the size of the power plant.

4 THE BIOFLOW ENERGY SYSTEM

A. Ahlstrom Corporation, one of Finland's largest, privately owned and diversified industrial companies, has for more than half a century built co-generation, industrial and utility power plants. Sydkraft AB, the largest privately owned utility company in Sweden, builds, owns and operates power plants and has been a fore-runner in investigating new energy production technologies. With this background a good match was found between these two companies and the good experiences from CFB gasification and factors as the greenhouse effect triggered the co-operation and development of the Bioflow Energy System. This co-operation started in 1991. A joint venture company, Bioflow Ltd, for marketing purposes was formed in 1992.

The Bioflow system itself is simply an IGCC plant, which utilises biomass as fuel in a pressurised CFB gasifier. The idea itself is not new but it has never been implemented for biomass. The system comprises of a fuel drying plant, a pressurised CFB gasifier with gas cooling and cleaning, a gas turbine, a waste heat steam recovery unit and a steam turbine. The system outline is shown in Figure 1.

The fuel is dried from a moisture content of typically 50 % to approximately 10 - 20 % in the dryer in order to produce a gas of reasonable heating value in the gasifier. The drying can be achieved either with an integrated system, which utilises, as drying medium, the flue gas from the heat recovery steam generator or low pressure steam from the steam cycle or by a totally external drying facility.

The dried fuel is fed into the gasifier at a certain location above the fluidising grid. The biomass is pyrolysed immediately according to reaction (1) as it enters the hot reactor. The gas travels upwards in the gasifier together with the fluidized solids comprised of ash, char and sand, dolomite or limestone while reactions an examples of which were shown earlier. The gas/solids mixture enters the cyclone and most of the solids are directed back through a non-mechanical return leg to the lower part of the gasifier reactor. Air enters through the grid comprising of nozzles and the air fluidises the bed. The solids returning from the cyclone contain char, which is combusted providing the heat required for the process. In essence the gasifier can be divided into an endothermic and an exothermic region, the boundary of which is the fuel feed point.

The gas leaving the cyclone flows into a gas cooler that utilises water as cooling medium from the water/steam cycle. The cooler acts as an evaporator for the water and flows to a steam drum connected to the rest of the water/steam circuit within the plant. The cooled gas is cleaned in a ceramic filter vessel where the particulates are removed. Tars in the gas are minimised by the gasification temperature being high to enhance thermal cracking. The bed material of the system itself also provides a catalytic cracking effect.

Ash generated in the process is discharged from the bottom of the gasifier reactor and from the ceramic filter vessel through lock-hopper systems. The ash is also cooled by means of screw coolers.

The cleaned gas is led through a governing valve to the gas turbine for combustion. As the gas has a low calorific heating value some modifications are needed to the combustion chambers in commercially available gas turbines in order to achieve efficient combustion and low emissions of nitric oxides, NO_x . Some air is extracted from the turbine compressor to provide air to the gasification process. The pressure of air is increased with the help of a booster compressor. The gas turbine typically generates two-thirds of the electricity produced in the plant.

The flue gas from the turbine enters a conventional heat recovery steam generator (HRSG). It contains evaporative and superheating surfaces as well as an economiser. The system is connected to the gas cooler, which produces saturated steam. The superheated steam is led into a steam turbine where the balance of electricity is generated. The water/steam system can also e.g. provide heat in form of warm water to a district heating package or steam to an adjacent industrial process.

5 THE BIOMASS IGCC ADVANTAGE

IGCC systems in themselves bring advantages compared to conventional technologies. Typical advantages listed are high electric efficiency, low emissions and also lower capital costs as the technology becomes more mature. For biomass IGCC systems the efficiency is also very high. In the co-generation concept it offers a total efficiency in excess of 85 % with a ratio between electricity and produced process heat ranging from 0.8 to 1.2. This means 100 % more electricity based on the same amount of back pressure heat compared to conventional technology. In condensing mode the power production efficiency exceeds 45 %.

The biomass IGCC systems offer advantages beyond the aforementioned. First of all, a low heat value renewable energy source can be used. Wood waste like forest residues and wood chips are excellent fuels for this application. As biomass typically contain very low sulphur, the emissions of this element is negligible. Since the efficiency is much higher than conventional technologies the absolute emissions from the plants are lowered substantially per produced kW electricity.

Last but not least is the fact that the net effect of the emissions to the atmosphere of the greenhouse gas carbon dioxide, CO₂, which contributes to the global warming, is almost zero when utilising biofuels. This is due to the fact that plants growing, i.e. the fuel, consume atmospheric CO₂ in the photosynthesis process. Furthermore when using forest residues the process of oxidation by decay is substituted with oxidation within an energy recovery system. These phenomena will leave the CO₂ balance essentially unchanged.

Typical plant performance data for future plants are shown in Table 1.

6 THE VÄRNAMO DEMONSTRATION PLANT

6.1 PLANT DESIGN

As an essential part of the co-operation between Ahlstrom and Sydkraft was the decision in 1991 to construct a demonstration plant based on the aforementioned technology. The plant location selected was the city of Värnamo in southern Sweden and the owner is Sydkraft AB. The chosen plant capacity was 6 MW of electricity and 9 MW of district heating. The general plant data is shown in Table 2.

The process components and the principle of the plant are the same as mentioned earlier. However, being the first plant, the unit in Värnamo has

certain unique features that are worth mentioning in order to avoid any confusion and misunderstanding. Furthermore, due to being the first in the world, the design is characterised by some conservatism and redundancy.

The fuel received to the site is dried in an external drying and fuel preparation facility. Almost two-thirds of the fuel prepared is delivered to other facilities in the neighbouring cities. The sizing of the drying equipment is, therefore, larger than what the IGCC plant would require. The drying takes place in a rotary drum dryer. Flue gas used as drying medium is generated in a small grate-fired boiler and prior to being discharged in the stack the flue gas is scrubbed with water. The fuel handling also contains the crushing of the fuel to the sizes suitable for the gasifier and for the plants where the fuel is delivered. The preparation plant is designed to handle all kinds of wood fuels.

The feeding of biofuels is handled with lock-hopper systems as well as feeding of the bed material. The gasifier including cyclone and return leg is totally refractory lined. The cyclone is designed in such a way that both the solids and the gas are discharged from the bottom of the cyclone and, thus, saves space and piping work. Operating pressure exceeds 20 atmospheres and the temperature is as high as 950 °C to 1000 °C to enhance the thermal catalytic cracking effect. Coarser ash generated in the system is discharged from the bottom of the gasifier and is cooled before entering the depressurisation system.

The gas cooler is of a fire-tube design and cools the gas to temperature of approximately 350 °C before it enters the ceramic filter vessel where the particulate clean-up occurs. The gasifier train is presented in Figure 2.

The clean gas then enters the gas turbine, is combusted and expanded generating 4.1 MW_e of electricity in the generator. The flue gas flows into a waste heat steam generator with evaporative and superheating surface. The generated superheated steam enters a steam turbine that generates approximately 2 MW_e at 100 % MCR. The steam turbine has moderate process performance but has been included to demonstrate the whole IGCC system. Steam pressure is 40 bar and temperature 470 °C. The major duty in the district heating system is handled in the steam condenser while some heat is transferred to the net by the district heating economiser, booster air cooling and the cooling water circuit for the gasification train. The percentile duties of these vary with load.

6.2 TIME SCHEDULE

Plant commissioning started in late 1992 by start-up of the fuel preparation plant. In early spring 1993 the gas turbine was commissioned on diesel oil

and it has been in operation since then. Gasifier commissioning started in late spring and the first combustible gas at elevated pressure was produced in the end of June 1993. After this the unit was shut down for the summer period. Commissioning of the gasifier continued after the summer season in September. The strategy in the commissioning during the fall was to raise pressure in steps in order to assure proper operation of the plant and to evaluate the performance. Some problems were, however, experienced during these steps which have prolonged the commissioning phase.

These problems have mostly been associated with auxiliary equipment. The fuel feeding in the conventional part as well as in the pressurised parts have caused some problems with leaking seals and shaft boxes for the augers. The gasifier system is built with a by-pass line for the ceramic filter which has been used when new process conditions and/or values have been approached. This by-pass line was equipped with a ball-valve to control the pressure. Unfortunately the ball itself, which was made of a ceramic material broke and caused a substantial delay. Ash valves have also experienced some leakage of gas through the seals. This was found to be caused by too large actuators creating uneven forces on the valves themselves and, hence, misalignment. Although these problems have been relatively easy to correct it has taken time due to long delivery times and installation work of some new equipment. Very good progress has despite this been experienced and some results are discussed below.

After commissioning the plant will initially be in test use to demonstrate the technology as well as for development work of the power plant concept. Actually this demonstration phase has already started and relevant data has been obtained about the gasification process. The demonstration phase consists of optimisation of the process performance and control, improving hardware and process design and monitoring plant reliability and availability will take place. The demonstration program will be conducted jointly by Ahlstrom and Sydkraft.

6.3 RESULTS

The commissioning as well as the testing work within the framework of the demonstration program is as mentioned in progress. Gasification to normal operating pressure has been reached, i.e. close to 22 bar(g). Data has been collected at this pressure and at lower pressures as well and the gas quality has been evaluated. The product gas composition has been as expected at higher pressures corresponding the expectations that were set for the project. Typically, the heating value of the product gas has been aprx 5 MJ/m³ n. The material and energy balances indicate an extremely high carbon conversion in

the system (in excess of 98 - 99 %). This means a low carbon content of the ash produced in the system.

One of the important questions concerning the operational costs at the plant is the minimisation of the nitrogen consumption. Concerning different sub-systems on site, the fuel feeding system is considered to be the most nitrogen-consuming system. The optimising work comprising of optimisation of the feeding sequences and the pressure difference control system between the pressurised fuel silo and the gasifier has given good results as regards the nitrogen consumption.

The testing work during the commissioning phase within the framework of the demonstration program has so far been comprising of optimisation of different process parameters: Gasification temperature, bed pressure, fluidisation velocity, etc. Upper and lower limit values has been determined for these parameters with respect to the process stability. Furthermore, the effect of the fuel quality has been examined. Also different types of bed materials has been tested: During the optimisation tests both bed material types and properties (e.g. particle size distribution) has been varied.

The ceramic filter has been tested and so far the experiences have been very good. The operation of the ceramic filter has been good and stable at high pressure and the basic level of the pressure difference has been low and stable during the test runs. The dust measurements after the filter have indicated extremely low values and the inspections of the filter have not indicated any deposit formation, blocking or failures in the filter elements. The dust measurements that have been taken after the hot gas filter have indicated extremely low dust emissions in the product gas which supports the good experiences that has been gained concerning the operation of the hot gas filter.

Despite the before mentioned problems that were experienced during the first steps of the commissioning and which have delayed the commissioning phase, very good progress has been experienced.

7 TECHNOLOGY DEVELOPMENT

Through atmospheric CFB gasification and combustion as well as pressurised CFB combustion thorough knowledge and experience have been gained for CFB processes in general. This applies for the chemistry, heat and mass transfer, fluid dynamics as well as mechanical engineering. The Värnamo demonstration unit will generate more data on gasification and combined cycle operation during the two-year test program. Data will be collected on

the entire plant process and hardware performance and this information will be used directly for design purposes of the next units. The unit can also be used at later times in the program to test other fuels for the Bioflow system.

The operation and demonstration tests at Värnamo are, although being an extremely good opportunity, not enough to develop the technology further. Certain conservatism has been applied for the plant due to being the first in the world. There is a need for further development of the process itself as well as finding better and cheaper solutions of the hardware in order to maximise efficiency, minimise emissions and costs.

This other development work will naturally also be conducted by Ahlstrom and Sydkraft. The hardware will be dissected and equipment developed to generate more cost-effective solutions, which will impact on the cost per kW_e positively. Part of the development work will be conducted at national laboratories and universities in Finland and Sweden through government and industry funded programs such as the Finnish LIEKKI 2 and BIOENERGY programmes. Institutions like VTT Energy, one of the Research Institutes of the Technical Research Centre of Finland, have for long conducted research and development work concerning biomass gasification in fluidized bed units. A large number of tests with biofuels, peat and coal have been conducted in the Process Development Unit at this laboratory. Projects such as the study of "Safety Technical Aspects of Biomass in Pressurised Systems" have provided valuable data for design of fuel handling systems. Furthermore, a project "Development of catalytic hot gas cleaning for biomass gasification systems" has provided valuable data on a wide range of different tasks related to the hot gas cleaning processes to Biomass-IGCC processes. Universities such as Åbo Akademi University in Finland with projects like "Ash Behaviour in CFB Systems" and Lunds Technical University in Sweden with a pressurised gasification CFB pilot are other examples of institutions that contribute to the total development of the technology. Common for all these institutions is that results are often directly applicable and available for technology development.

8 COMMERCIALISATION

Not only the technology itself needs to be developed but also the commercial aspect of it. This is done in parallel and/or close conjunction with the technology development work. The feasibility of the IGCC system for various applications and for various sizes needs to be evaluated. This is the case for the 30 MW_e Brazilian Wood BIG-GT Demonstration Project where Bioflow Ltd. is conducting a process and basic engineering study as well as development work for components and gasification tests with the Brazilian

fuel, eucalyptus. The design basis for the aforementioned case is a condensing system with a General Electric LM 2500 aero-derivative gas turbine. Here both technical and economical aspects are evaluated. This project is executed by United Nations Development Program on behalf of the Global Environmental Facility.

When these studies prove that the systems are economically sound the next step will be to build these larger units, naturally pending on customer response. As these units have proven their capabilities and with the results from other development work the investment and operating costs can be brought further down which will enhance the attractiveness of the technology.

9 CONCLUSIONS

Starting from CFB combustion going through atmospheric CFB gasification and pressurised CFB combustion the time has come that the first complete IGCC system in the world utilising biomass as fuel and pressurised CFB technology will soon be in operation in the city of Värnamo. This demonstration unit will be a step to prove the concept of high efficiency, high ratio between power and heat output and low emissions from a low heat value fuel source, which is renewable.

The Värnamo demonstration plant, which is now in its commissioning phase, will give an excellent opportunity to further develop the technology in order to increase efficiency, optimise process performance, improve hardware and process design and monitor plant reliability. This work in addition to other work such as the Brazilian Wood BIG-GT Demonstration Project and other related projects will further develop and commercialise the technology.

The next unit with an anticipated contract award before the middle of the decade is expected to be in a larger size range than the Värnamo plant. A scale-up to 20 to 80 MW_e is realistic and is very much depending on the low calorific turbine size available. The commercialisation of the technology to scales from 20 to 120 MW_e is also very much dependent of the existence of sufficient amounts of fuel for the life-time of the plant.

The IGCC system is suitable for regions where there exist a surplus of biomass such as in connection of the pulp and paper industry, saw and lumber mills, agricultural wastes etc. and possibly in the future in regions where energy crops are available.

Table 1. Bioflow technical data.

Gasification pressure	24 bar
LHV of product gas	5 MJ/m ³ n
Total efficiency	85-90 %
Electrical efficiency	
-cogeneration	40-45 %
-condensing	44-50 %
Power to heat ratio (cogeneration processes)	0.8-1.2
Typical plant size	20-150 MW _e
NO _x	< 50 mg/MJ _{fuel}
SO _x	< 25 mg/MJ _{fuel}
Particulates	< 10 mg/MJ _{fuel}

Table 2. Värnamo process data.

Plant size	18 MW fuel input
Fuel	Wood waste & chips
Gasification pressure	22 bar
Gasification temperature	950-1000 °C
Product gas heat value	5 MJ/m ³ n
Power production	6 MW
District heating	9 MW
Steam temperature	470 °C
Steam pressure	40 bar
Plant wwner	Sydkraft
Gasifier	Ahlstrom boilers
Ceramic filter	Schumacher
Gas turbine	European Gas Turbine
Steam turbine	Nadrowski
Waste heat steam generator	Ahlstrom Termoflow
Booster compressor	Ingersoll-Rand

BIOFLOW PROCESS DIAGRAM

(VÄRNAMO PLANT CONFIGURATION)

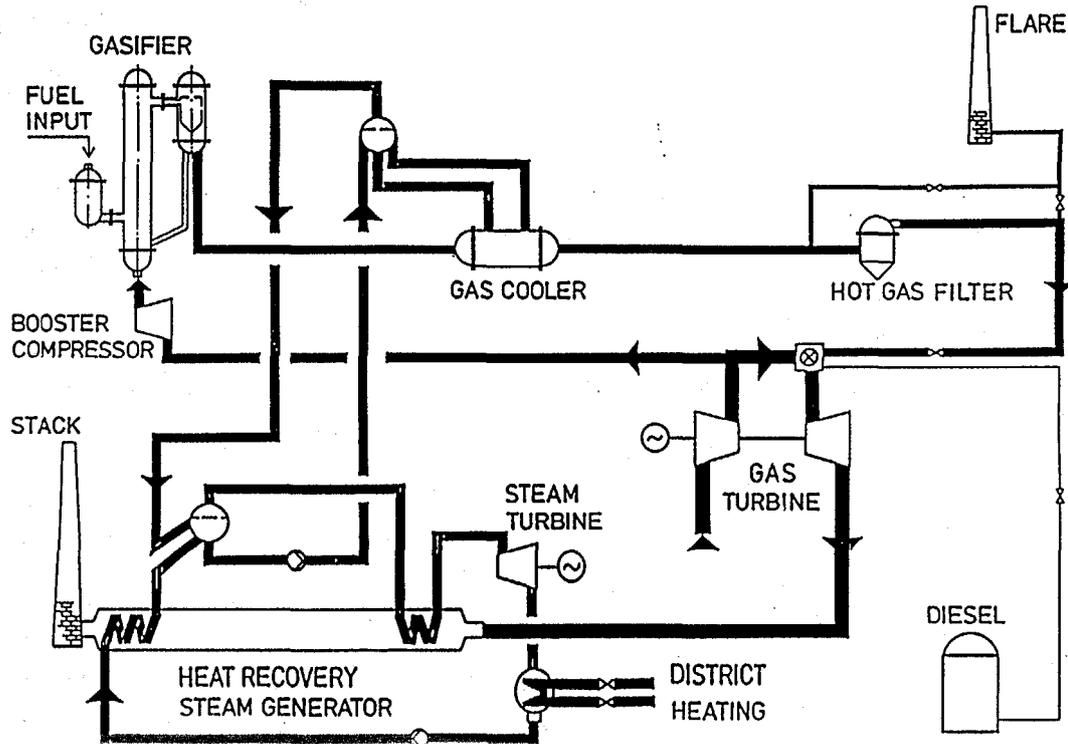


Figure 1. Process diagram of CFB based IGCC-system.

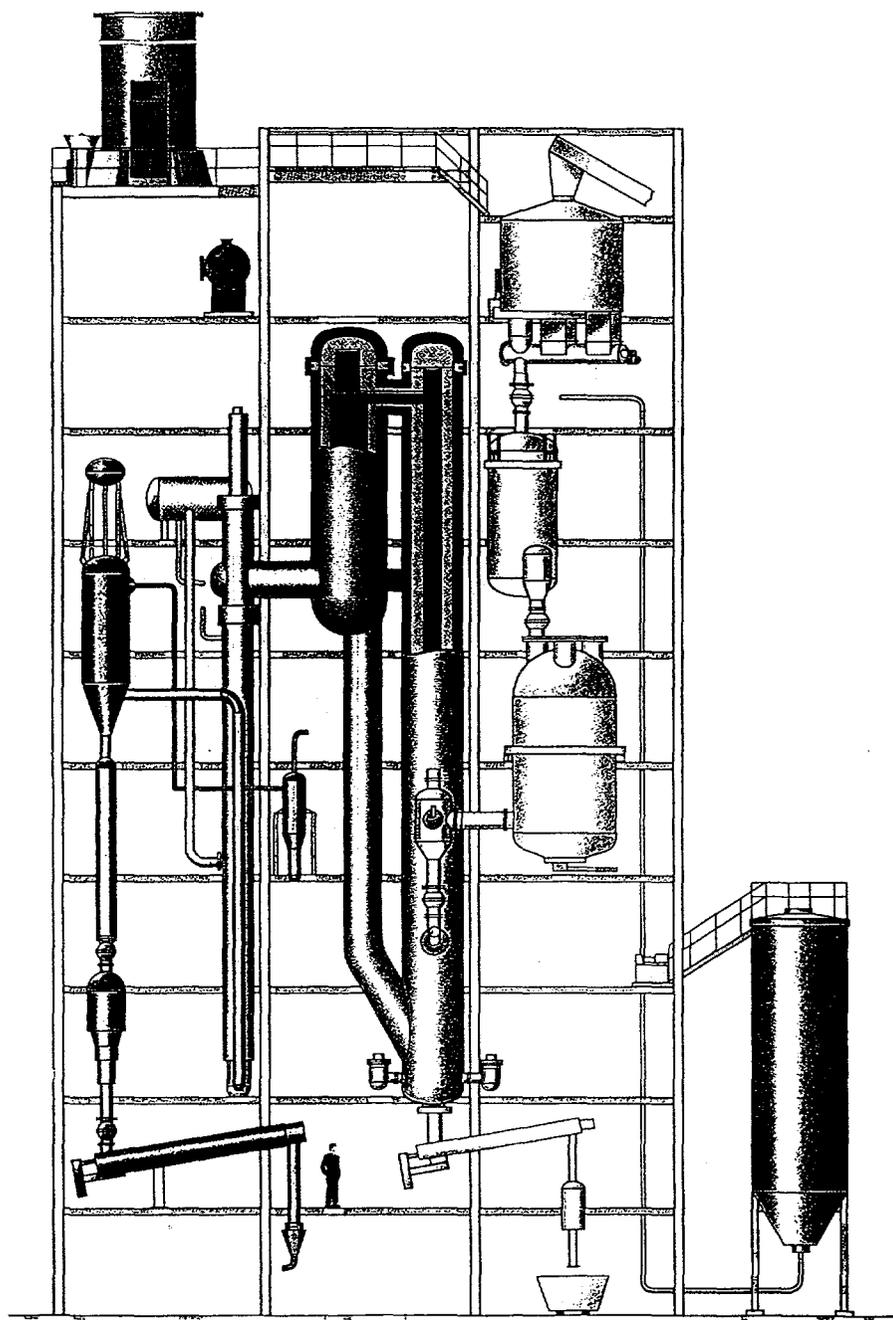


Figure 2. Värnamo CFB-gasifier train.

THERMAL GASIFICATION OF BIOMASS TECHNOLOGY DEVELOPMENT IN THE U.S.A.

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1 INTRODUCTION

In the U.S.A., the widely recognized importance of biomass utilization in controlling carbon build-up in the biosphere and the potential benefit of creating new industries associated with new job opportunities, particularly in the rural areas, have added impetus to the development and commercialization of advanced biomass energy conversion methods. Recent analyses and evaluations have shown that many short rotation energy crops (SREC) produce significant net-energy (i.e., energy yield greater than the energy input for plant growth).¹ SREC such as willow, poplar, and miscanthus may yield up to 20 dry tonnes/yr/ha/year of biomass feedstocks, some with about 20% moisture, after the third year of plantation.² Implementation by U.S. EPA of the recent Clean Water Act Federal Biosolids Rules specified as Code 40 of Federal Register 503, should make available large quantities of high nitrogen content, pathogen-free municipal sludges ideally suited as an inexpensive source of organic fertilizer, thus improving the economics of SREC. The concept of herbaceous SREC can be further augmented when value-added byproducts, such as cattle feed, could be produced along with biomass energy feedstocks.

Notwithstanding the full exploitation of the potential benefits stated above, since 1978 the United States biomass-power industry has installed about 7 GW of grid connected generating capacity, much of it associated with the forest and forest-products industries, which obtain more than half of their electricity and thermal energy from biomass.³ More than 70% of the installed biomass-based power is produced on a cogeneration basis. Wood-fired systems represent 88 % of total capacity, followed by landfill gas at 8 %, agricultural wastes at 3 %, and anaerobic digesters at 1 %.⁴ Biomass power plants use technology that is similar to coal-fired plants, but normally at smaller scale with resulting loss of efficiency. Today's boiler/steam tur-

bine plants average about 20 MWe in size and have efficiencies in the 15 % to 20 % range. Electricity costs are U.S. \$0.065 to \$0.08/kWh. Since 1990, there has been renewed interest in the United States in developing advanced power-generating cycles utilizing biomass gasification.⁵ The advanced systems have the potential for higher generation efficiencies, 35 % to 40 %, and lower costs of electricity, \$0.045 to \$0.055/kWh, compared to conventional direct-combustion systems. The efficiency of power production can be even higher (~55 %) when the fuel gas is converted to hydrogen followed by electrochemical conversion to electricity in a fuel cell.

The Energy Policy Act of 1992 includes a number of provisions to promote the commercialization of biomass power production. These are 1) authorization up to \$50 million to U.S. DOE for cost-shared demonstration and commercial applications projects; 2) incentive payments of 1.5 ¢/kWh for electricity sold from renewable resources by qualified facilities; and 3) tax credit of 1.5 ¢/kWh of electricity produced from 'closed-loop biomass,' which is defined as biomass that is planted, grown, and harvested on a dedicated basis for electricity production. The recent Global Climate Change Action Plan also includes several programs and incentives for biomass power production.⁶

2 A CASE FOR BIOMASS GASIFICATION

Through the gasification of biomass, a very heterogeneous solid material with numerous impurities and difficult handling characteristics can be converted into a consistent gaseous fuel that can be used reliably for heating, industrial process applications, electricity generation, and liquid fuels production. As received, biomass can range from very clean wood chips at 50 % moisture content, to urban wood residues that are dry but contaminated with ferrous and other materials, to animal residues, sludges, and organic components of municipal solid waste (MSW). The process of gasification can convert these materials into carbon and hydrogen-rich fuel gases that can be more easily utilized, often with a gain in combustion efficiency and environmental performance compared to direct combustion of biomass.

In general, fuel gas from biomass gasification has to be treated so that it matches the end-use application. For close coupled gasifier-combustor systems, there is no need for any cleanup. For gas turbine applications in a power system, the gas has to be free of particulates, tars, sulfur, and chlorine compounds, as well as alkali metals, to ensure the integrity of the turbine's hot section. Particulate removal to protect the turbine blades from erosion requires filtration technology, while the removal of tars reduces the likelihood of filter plugging and ensures an even and less luminous com-

bustion process to avoid radiative heat transfer problems at the turbine. Alkali metal removal is required to avoid deposition and corrosion of the turbine blade materials and has to be carried out down to levels of potassium and sodium less than 1 ppm to ensure long turbine blade and hot-section lifetimes. The tolerance to alkali metals is a function of the temperature of operation of the turbine inlet section; at very high temperature, above 1370 °C, the level has to be below 25 ppb. The deposition and corrosion problems can also be addressed by means of turbine blade coatings, and it is likely that both coating/ruggedizing of components as well as enhanced gas cleanup developments will be undertaken. For internal combustion engine applications, it is necessary to cool the gas to ensure that a sufficient charge of energy can be put into each cylinder. Particular attention has to be given to both tar and particulate contents to ensure that the valves and cylinders are protected. The fuel gases should be processed or upgraded to produce mainly hydrogen without any significant sulfur or chloride contamination to protect the electrodes in fuel cell applications and a clean synthesis gas is essential for producing chemicals, fertilizers, and liquid fuels.

Typical gas energy contents measured on a dry basis are less than those of natural gas ($\sim 39 \text{ MJ/Nm}^3$). In thermal gasification with air as the oxidant, the value is usually less than 6 MJ/Nm^3 , while gasification with oxygen and steam, which eliminates the nitrogen dilution of the product, results in a heating value of 12 to 14 MJ/Nm^3 , and in indirect gasification systems values are in the range 14 to 18 MJ/Nm^3 . The typical fuel components are hydrogen, carbon monoxide, carbon dioxide, methane, and some higher hydrocarbons.

The potential advantages of gasification include increased conversion efficiency which results in reduced feedstock costs per unit of generation, reduced environmental impact, and beneficial cofiring opportunities. The direct environmental benefits includes the reduced gas volume, in comparison with direct combustion flue gas, that must be handled in gas cleanup equipment, resulting in lowered equipment costs. This and the generally lower temperature of treatment of the biomass results in retention of metals (including alkali) in the ash and cyclone as compounds that can be disposed. In addition, gas cleanup processes can be optimized for temperature and pressure of operation because the gasifier island is decoupled from the power island. Removal of contaminants prior to combustion results in lowered environmental concerns for contaminants such as dioxins. The gas can easily be cleaned of acid-gas components, including hydrogen chloride, before combustion, and thus, is environmentally superior to direct combustion. Product gases are compatible with natural gas, leading to cofiring opportunities in natural gas combined cycle power stations.

3 COMMERCIAL GASIFIERS

The following commercial-scale biomass gasifier systems have been operated in the United States to produce low-Btu fuel gas:

- Energy Products of Idaho (EPI), Coeur d'Alene, Idaho
- SEI, Inc., Quincy, Florida
- Producers Rice Mill (PRM) Energy, Stuttgart, Arkansas
- Sur-Lite Corporation, Santa Fe Springs, California
- Morbark Industries, Inc., Winn, Michigan
- Halcyon Associates, East Andover, New Hampshire
- The EPI system, owned by Catalyst, Inc., is an 84-GJ/h (80 MMBtu/h) fluidized-bed wood gasifier located in North Powder, Oregon. The unit is designed to produce 5 MWE of power through a gasification-combustion-steam cycle.

The SEI system was built and operated by Southern Electric International (SEI), a subsidiary of the Southern Company, and was owned by Citicorp Industrial Credit, Inc. The plant, located at the site of the Floridian Company clay processing plant in Quincy, Florida, was designed to produce 257 GJ/h (244 MMBtu/h) of low-Btu gas for use in Floridian Dorr-Oliver clay driers. The plant has two separate atmospheric fluidized bed gasifiers, each of which is capable of producing 129 GJ/h (122 MMBtu/h) of gas from wood chips or residues. Operation of the plant started in late 1986, and continued successfully for 3½ years. Because of the low price of natural gas, the plant was operated at a loss and was shut down in 1990. It is estimated that natural gas prices would need to rise to approximately \$2.85/GJ (\$3.00/MMBtu) before that plant could again be operated economically.

A 1.8 tonne/h (2.0 ton/h) stirred-bed PRM rice husk gasifier is in operation at Stuttgart, Arkansas. Three gasifiers of 9 to 18 tonnes/day (10 to 20 tons/day) capacity have been built in Malaysia to produce a low-Btu gas intended to displace diesel fuel. Sur-Lite Corporation has built small fluidized-bed gasifiers, sized up to 1 GJ/h (1 MMBtu/h), for processing cotton wastes, rice hulls, wood, and coal. Morbark units, which are two-stage gasifier/combustion systems, presently are in operation in the 1 to 4 GJ/h (1 to 4 MMBtu/h) range.

4 BIOMASS GASIFICATION TECHNOLOGY DEVELOPMENT

4.1 COMPOSITION AND DESTRUCTION OF OILS AND TARS

There has been a considerable amount of bench-scale and pilot plant research conducted in Europe and the United States to determine the characteristics of gasification oils and tars and the methods to crack and gasify them in order to avoid carbon deposition downstream from the gasifier. The composition of oils and tars produced in a gasifier is mainly dependent on the biomass gasification process. In general, the indirectly heated gasifiers and perhaps the updraft moving bed gasifiers produce more light oils and some tars, while the air-blown fluidized-bed and circulating-fluidized-bed (CFB) biomass gasification processes produce more tars and less oils. The high temperatures within the oxygen-or air-blown gasifiers thermally crack the lighter oils into gaseous components, aromatics, and polynuclear aromatics. The current pilot plant tests conducted in support of the demonstration projects should provide more insight into the susceptibility of the different types of oils and tars to catalytic cracking and carbon deposition, in particular on the hot gas cleanup (HGCU) ceramic candle filters.

With DOE support, the Hawaii Natural Energy Institute (HNEI) at the University of Hawaii is using a laboratory-scale gasifier to test catalysts for conditioning hot raw product gas to determine catalyst suitability to produce synthesis gas for methanol production and for gas turbine/fuel cell applications. Current work is being conducted with Ni-based catalysts. Studies are also underway with nitrogen-rich leguminous tree species, *Leucaena* spp, on the fate of nitrogen in biomass gasification systems and to establish nitrogen speciation and destruction of nitrogen compounds.

4.2 HOT-GAS FILTRATION

Westinghouse Electric Corporation (WEC) is currently evaluating several commercial HGCU filter elements at their research and demonstration coal conversion facilities in the U.S. WEC has developed proprietary seal designs for improving the endurance and performance of candle filters. The design also includes preheating pulse gas to reduce thermal shock and a shut-off mechanism to isolate a filter element when it fails. So far, the filter elements have been tested up to 24 bar operating pressure, 500°C, and for 4500 hours. The filter elements were obtained from Schumacher, Coors, 3M, and DuPont.

4.3 FUEL GAS UTILIZATION

The medium calorific value (MCV) fuel gas, obtained from indirectly heated gasifiers, can be used in existing gas burners, IC engines, and gas turbine burners, with little or no modifications. Low calorific value (LCV) fuel gases 6 MJ/Nm^3 ($>160 \text{ Btu/SCF}$) can be combusted in many industrial burners without downrating, but some burner modification may be required. For a gas with $\text{LCV} < 120 \text{ Btu/SCF}$, significant burner modifications may be required besides downrating. Preheating fuel gas and/or combustion air would help improve combustibility of LCV fuel gases. WEC reported that with LCV fuel gas, the changes made to the combustor in a gas turbine include replacing the fuel gas pipeline with a larger diameter pipeline, increasing burner nozzle size, and slightly increasing the combustion basket size. The air compressor remained the same, while a slight change was made to the stationary part of the gas turbine inlet.

Because fuel cells offer modularity and very high energy conversion efficiency, the DOE is planning to develop gasification/fuel cell and pyrolysis/catalytic upgrading/fuel cell systems. The strategy will involve formation of cooperative research and development agreements (CRADAs) with industry to address specific fuel cell developmental issues, such as molten carbonate fuel cell material problems, sulfur tolerance problems, and carbon dioxide availability issues. These issues can be evaluated at laboratory scale. Research will concentrate on defining and solving issues related to interfacing gas production systems with fuel cell systems. The commercialization of biomass gasification and fuel cell combinations depends on the satisfactory development of gas conditioning and treatment to link the gasifier with the fuel cell while reducing labor and capital requirements in what will initially be small scale systems of less than 1 MW output. A first-generation commercial prototype will be constructed by mid-1998 and the evaluation completed in the year 2000, at which time it is anticipated that the development of economical fuel cells will be completed.

4.4 PILOT-PLANT PROGRAMS

Under a United States Department of Energy-sponsored (USDOE) program, the 9 tonnes/day (2 MWth) RENGAS[®] pilot plant gasifier at IGT in Chicago has recently completed pressurized air-blown gasification tests with bagasse to test the WEC train and to characterize the fuel gases for gas turbine applications. During the recent tests, a bench-scale molten carbonate fuel cell was successfully operated on the raw product gas slip stream. The HGCU assembly will be installed in the 50 - 100 tons/day capacity demonstration gasifier in Hawaii for long duration tests.

Battelle's multi-solid fluidized bed (MSFB) pilot plant biomass gasifier has been operated with DOE support at throughput rates of 14.6 tonnes/m²/hr (3000 lbs/ft²/hr) at West Jefferson, Ohio. The capacity of the pilot plant is 9 tonnes/day (2 MWth). Recent pilot plant tests showed that 90 % tar removal was accomplished with a proprietary Battelle catalyst (DN34) at 1 500 °F. The tar conversion increased to 97 % at 1 600 °F without any coke formation. DN34 also serves as a good water-gas-shift catalyst, as indicated by the nearly complete conversion of CO to produce a fuel gas with about 60 % H₂. The pilot plant tests also included the successful operation of a 200-kW SOLAR gas turbine.

Manufacturing and Technology Conversion International (MTCI), Columbia, Maryland, has recently completed a series of tests in its pilot gasifier in Baltimore, Maryland. The MTCI process is a pulse-enhanced, indirectly-fired steam reformer gasifier for all types of carbonaceous materials. Since the combustion zone is isolated from the reformer/gasifier, the low-in-volume and high-in-heating value fuel gases could be economically cleaned. The combustion of a part of the product gases instead of biomass to sustain the steam reforming reactions results in reduced NO_x emissions. The steam reformer/gasifier employs 72 resonators or pulse combustors to supply the endothermic process heat. During the test program, wood chips and wheat straw were gasified at rates up to 6 tons/day (1.2 MWth). The MTCI process has been scaled up to 50 tons/day (10 MWth) and is presently undergoing tests at the Weyerhaeuser paper mill at New Bern, North Carolina for the gasification of black liquor, a Kraft pulping coproduct, with the sponsorship of Weyerhaeuser and the DOE Office of Industrial Technology.

5 BIOMASS GASIFICATION TECHNOLOGY DEMONSTRATION

A summary of the U.S. demonstration projects is given below. The specifications of these projects are given in Table 1, along with the specifications available for the European and Brazilian demonstration projects.

5.1 HAWAII BIOMASS GASIFICATION DEMONSTRATION PROJECT

The Hawaii Biomass Gasification Facility (BGF) project is part of a major U.S. DOE initiative to demonstrate high-efficiency biomass gasification systems. The project will provide a near-term demonstration for total system integration of gasification and HGCU components, with gas turbines

for power generation. The objective of the project is to scale up the 9 tonnes/day (2 MWth) IGT RENUGAS[®] pressurized air-blown fluidized-bed gasification pilot plant to a 45 to 90 tonnes/day (10 to 20 MWth) demonstration unit using bagasse (sugar cane residue) and wood as feed. The BGF is located at the Hawaii Commercial and Sugar Company's (HC&S) Paia sugar mill on the island of Maui in Hawaii, U.S.A.

Process scale-up will be completed in several phases. Phase 1, which is now underway, consists of the design, construction, and preliminary operation of the gasifier to generate hot, unprocessed gas, which will be flared. The gasification system is presently undergoing commissioning. The gasifier has been designed to operate with either air or oxygen at pressures up to 300 psia (2.07 MPa) at typical operating temperatures of 850° to 900°C. In Phase 2, to begin later in 1995, the gasifier will be operated at a feed rate of 45 tonnes/day (10 MWth) and 1.03 MPa (150 psia). The slip-stream HGCU, tested by WEC and IGT and described above, will be installed in the demonstration gasifier and operated to obtain long-term performance evaluation information. At the same time, the necessary design and environmental permitting will be completed for the succeeding full-scale HGCU and gas turbine operation. The turbine may utilize supplementary fuel to obtain an output that would permit commercial operation at the completion of the demonstration phase. In mid-1996, a HGCU and gas turbine will be added to the system. Options are being evaluated for up to 5 MWe of electrical capacity. In this phase, the gasifier feed rate will be a minimum of 90 tonnes/day (20 MWth), and the system will operate at pressures up to 300 psia (2.07 MPa). A third phase is being considered in which the gasifier will be operated in an oxygen-blown mode to produce electricity and a clean synthesis gas for methanol production.

Participants in the project are the Pacific International Center for High Technology Research, IGT, WEC, HC&S, HNEI, and Parsons, the architectural and engineering firm for the project. Industry and the State of Hawaii have contributed US \$4.2 million to Phase 1, with DOE contributing \$6.0 million. In Phase 2, the project will be co-founded by the State of Hawaii, industry, and DOE.

5.2 THE VERMONT BIOMASS GASIFICATION PROJECT

The Vermont project is part of a major DOE initiative to demonstrate biomass gasification. The Vermont Project has been undertaken to demonstrate the integration of the Battelle "indirectly-heated" gasifier with a high efficiency gas turbine. The goal of the Vermont project is to scale up the Battelle pilot plant gasifier from its present 9 tonnes/day (2 MWth) capacity to

180 tonnes/day (40 MWth) demonstration project to provide MCV gas for a nominal 15 MWe gas turbine. The demonstration and validation of this gasification/gas turbine system is being undertaken at the existing McNeil Power Generating Power Station, a 50 MWe wood-fired boiler/steam turbine station in Burlington, Vermont, thereby significantly reducing the time-scale for deployment. The industrial partner is Future Energy Resources Company (FERCO), Atlanta, Georgia, which is putting up the 50% non-DOE cost share for the overall project. Other project participants include the co-owners of the McNeil generating station located in Burlington, Vermont, and operated by the Burlington Electric Department. Currently, Zurn Nepco, a Portland, Maine-based engineering company with extensive experience in the design and construction of biomass-fired power plants, is preparing the detailed engineering design and permitting process for the start of construction, which is scheduled for late 1995. Operation of the gasifier is forecast for late 1996, and the addition of the gas turbine is forecast for late 1997.

5.3 BIOMASS POWER FOR RURAL DEVELOPMENT

It is the mutual goal of DOE and the U.S. Department of Agriculture (USDA) to demonstrate and deploy cost-competitive renewable biomass power systems that spur rural development. A key aspect of this goal is to demonstrate sustainable biomass energy feedstocks, e.g., woody and herbaceous crops such as hybrid poplars or switchgrass, coupled with high-efficiency power conversion systems. In support of this, DOE initiated through the National Renewable Energy Laboratory (NREL) ten 50/50 cost-shared subcontracts with private industry to conduct feasibility studies and develop business plans for integrated biomass feedstock production and advanced power/liquid fuel conversion systems. States included for study are California, Florida, Hawaii (2 systems), Kansas, Iowa, Minnesota, New York, and North Carolina, plus the Commonwealth of Puerto Rico. The systems being studied include gasification with gas turbines or fuel cells, advanced direct combustion, repowering or cofiring, pyrolysis, and ethanol production via simultaneous saccharification and fermentation. Following these efforts and given the high level of private-sector interest in pursuing integrated biomass power projects, DOE in collaboration with USDA is planning to select through competitive solicitation up to five integrated biomass power projects with 50/50 cost-shared cooperative agreements with private industry. These projects will be the first step in demonstrating the successful integration of biomass feedstock production with advanced energy conversion technologies. It is expected that the average plant size will be between 25 to 75 MW while utilizing an environmentally and economically sustainable biomass feedstock. Through this collaborative DOE/

USDA effort, these projects will also emphasize rural economic development and job creation and the introduction of alternative industrial/energy crops for the nation to potentially offset federal agricultural subsidy payments.

5.4 COST PROJECTIONS

The competition for electricity from biomass fuels, as it is the case with other renewable forms of energy, is the cost of electricity from conventional fuels. The current estimates for cost of electricity production from natural gas combined-cycle plants is in the range of U.S. 2.7 ¢ to 3.5 ¢/kWh. Obviously, for implementing commercial biomass-based power systems, the cost of producing electricity from biomass, along with all types of tax or power sale incentives, should come close to this target. The first goal to meet is the capital cost, which for natural gas combined-cycle and pulverized coal steam cycles is \$600/kW and \$1600/kW, respectively. At present it is believed that the mature and ideal biomass based IGCC system will have an efficiency of 40 % or greater, and a capital cost of \$1300/kW or lower. The capital cost for the first demonstration plants, such as the 18 Mwe capacity Bioflow plant which is already built, or the planned >20 Mwe capacity BIG-GT plant, may be in the range of \$2 500 to \$3500/kW, with an efficiency of 30 % to 33 %. Being the first such plants, they would be built in a very conservative fashion, with many redundancies to ensure safety and success. Therefore, the real challenge lies with the project teams to incorporate the knowledge they gained through RD&D and the experience of designing, constructing, and achieving successful operation with the pioneer plants that is systematically incorporated in reducing risk and improving investor confidence. Some of the significant technology development needs required to achieve these goals are:

- Tar destruction
- Hot-gas cleanup to remove particles and alkalis
- Raising gas turbine inlet temperature
- Developing multiple stage heat recovery steam generators to raise steam pressure for the combined steam turbine operation
- Developing steam injected gas turbine operation

It is believed that with these improvements, 100 Mwe capacity pressurized gasification IGCC/STIG systems may be able to raise the efficiency to about 40% and bring the capital costs down to a competitive range of approximately \$1300/kW. In addition to these technological developments, the real reduction in the operating cost could very well come from improvements in the management of SREC to provide economical gasification

feedstocks and through the use of residues which are in abundant supply and which are normally quite inexpensive.

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Table 1. Summary of targeted biomass gasification demonstration ⁷.

Title	Vermont	BIG-GT	BGF	ARBRE	Biocycle	Energy Farm
Location	Burlington, VT	Brazil	Hawaii, U.S.A.	Yorkshire, U.K.	Denmark	Italy
Process	Battelle	TBD	RENUGAS	TPS	U-GAS/RENUGAS	Lurgi
Proposers	FERCO	CIENTEC	PICHTR	Yorkshire, U.K.	Elsam DK	ENEL IT
	USDOE	CHESEF	USDOE; State of HI; HC&S	Niro DK	Elkraft DK	Lurgi DE
	Burlington Elec. Dept.	CVRD	Ralph Parsons	ESB IR	Fynsvaekei DK	Le Rene IT
	Zurn Nepco	Electrobras	IGT	TPS SW	Veag DE	Sweb UK
	Battelle	Shell Brazil, SIPC, GE				EDP PO
Gasifier	Atm. MSFB	TBD	Press. Fluid. Bed	Atm. CFB	Press. Fluid. Bed	Atm. CFB
Tar Removal	Dolomite	TBD	TBD	Catalytic-Dolom.	Dolomite/Hot Gas	Water Scrubbing
Gas Cleaning	TBD	TBD	Ceramic Filter	Water Scrubbing	Ceramic Filter	Bag Filter
Gas Turbine	TBD	GE	TBD	EGT/Typhoon	EGT/Typhoon	EGT/Typhoon
Steam Turbine	TBD	GE	TBD	Siemens	TBD	TBD
Net Electric Output, MWe	12	30	5.0	8.0	7.2	11.9
Net Heat Output, MWth	40	NA	NA	0	6.78	0
Electrical Efficiency, %	30-35	37	30-35	30.6	39.8	33
Plantation, ha	NA	NA	NA	2800	1325	3680
SRF Productivity, odt/y.ha	NA	NA	NA	12	9	15 (10)
Selling Price, kWe X 10⁻², ECU/kWh	NA	NA	NA	11.57	6.88	12.13
Selling Price, kWe X 10⁻², ECU/kWh	NA	NA	NA	NA	2.38	NA
TBD = To be determined.						
NA = Not available.						

GASIFICATION EXPERIENCE WITH BIOMASS AND WASTES

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1 INTRODUCTION

Co-utilisation of biomass and waste materials together with coal offers the possibility of an overall reduction of CO₂ per kWh of coal-based power generation. In addition to other technologies, gasification processes offer significant potential for an efficient utilisation of biomass or with a wide range of waste materials.

The Rheinbraun High-Temperature Winkler (HTW) process is a second-generation gasification process for the Gasification of solid fuels. It represents a further development of the Winkler Gasification principle. Solid feedstocks are gasified in a fluidized bed at elevated pressure using oxygen plus steam or air as Gasification agents. In the meantime the HTW process has been employed on an industrial scale for the production of synthesis gas and has furnished proof of its high efficiency and reliability. In addition, the development of the HTW process concentrated on the generation of fuel gas for gas turbines applying the IGCC principle and on the use of low-rank feedstock like biomass, sewage sludge and other wastes.

Compared with coal, biomass and waste materials often incorporate a higher amount of volatile matter, different proportions and compositions of inorganic matter and a significant variety of physical properties. Therefore, Gasification or co-gasification of peat, wood, sewage sludge, or waste plastics has consequences with regard to feedstock preparation, Gasification behaviour, corrosion, emissions and residues.

During various tests - performed in bench-scale, pilot-scale and industrial-scale units - such effects were carefully studied for a large number of different feedstocks. Information is now available for optimal utilisation of several types of biomass and waste materials in relation to plant operation, emission and residue utilisation.

Thus, the HTW process is particularly favourable for the conversion of biomass. Co-gasification of sewage sludge, waste plastics, or loaded coke

with dried brown coal also offers significant potential for disposing these wastes without impairing plant efficiency and emissions.

2 HIGH TEMPERATURE WINKLER (HTW) GASIFICATION PROCESS

2.1 TECHNICAL FEATURES

The HTW process was developed for an efficient Gasification of solid fuels. Solid feedstocks are gasified in a fluidized bed at elevated pressures of up to approximately 30 bar using oxygen plus steam or air as Gasification agents. The Gasification temperature is kept well below the ash softening point and adjusted at levels of about 900 to 1 000 °C in order to avoid agglomeration in the gasifier and in the downstream facilities [1 - 2].

A schematic of an HTW gasifier is shown in Figure 1. The feedstock is pressurised in a lock hopper system and fed into the gasifier by a screw feeder or a gravity pipe. The gasifier is a cylindrical refractory-lined carbon steel pressure vessel which is conically shaped in the bottom part. Gasification agents are introduced at different levels into the fluidized bed and into the freeboard above. Entrained carbon is partially oxidised in the freeboard and higher hydrocarbons are decomposed at an elevated temperature. The major portion of the entrained dust is separated from the raw gas in a hot cyclone and returned into the fluidized bed via a recycling pipe. The bottom product - residual coke containing unreacted carbon and ash - is withdrawn via a lock hopper system at the bottom of the gasifier.

2.2. DEVELOPMENT OF THE HTW GASIFICATION PROCESS

The advantages of the HTW process as compared to the traditional Winkler process are largely the result of the increased Gasification pressure, higher temperatures and dust recycling from the hot cyclone, yielding a more favourable carbon conversion rate (up to about 98 %), a considerably improved specific gasifier capacity and avoiding by-product formation. At elevated pressures the specific coal throughput could be raised by a factor of more than ten compared to the Winkler gasifier operating at atmospheric pressure. This corresponds to a thermal gasifier capacity of more than 100 MW/m² when using oxygen as the oxidant and 50 MW/m² when using air [3 - 4].

The design and performance data of the plants described in the following are listed in Table 1.

2.2.1 Pilot plant

Based on the results of pre-tests with a process development unit (PDU) a pilot plant operating at a pressure of 10 bar was commissioned in July 1978 at the Wachtberg plant site near Cologne. In addition to the Gasification tests performed with dried brown coal, tests with other feedstocks were conducted. For instance, Finnish peat and South Australian brown coal with a high salt content have been gasified in this plant. By the end of June 1985 the test program was finished and the plant was shut down [2].

From 1978 until June 1985 about 21 000 tons of dried brown coal were processed in about 38 000 hours of operation. The specific synthesis gas yield reached up to $1\,580\text{ m}^3_{\text{STP}}/\text{t}_{\text{maf}}$ corresponding to 96 % of the thermodynamically calculated value for dried brown coal. At feed rates of about $1\,800\text{ kg/h}$ a synthesis gas capacity of more than $7\,700\text{ m}^3_{\text{STP}}/\text{h}\cdot\text{m}^2$ was achieved, which is three times higher than the capacity of a former atmospheric Winkler gasifier.

2.2.2 HTW demonstration plant

The results obtained in the pilot plant served as a basis for the design and construction of industrial-scale plants. The first industrial-scale plant was erected on the site of the Berrenrath factory at Hürth near Cologne. This so-called HTW demonstration plant has a synthesis gas capacity of approximately $37\,000\text{ Nm}^3/\text{h}$ and operates at a Gasification pressure of 10 bar [2].

2.2.3 HTW Gasification unit at Oulu, Finland

After various Gasification tests with Finnish peat in the HTW pilot plant had been successfully completed in spring 1988, the Kemira Oy company of Finland decided to rebuild an existing ammonia production plant at Oulu from heavy oil to peat Gasification. Thus, a commercial-scale plant according to the HTW process was designed and constructed by Uhde GmbH, Dortmund, for the Oulu site with hot gas cooling in a waste heat boiler, followed by wet scrubbing for removal of particulates and tars (Figure 3). The plant was designed to gasify dried peat at a pressure of 10 bar, producing ammonia synthesis gas. Gasification of peat with 25 % sawdust was also demonstrated. It was commissioned in 1988 and operated until 1991, when it was shut down because of the availability of cheap natural gas from Russia [6].

2.2.4 Pressurised HTW gasification plant

With a view to using the HTW process in conjunction with a gas turbine process, an advanced pilot plant, the pressurised HTW Gasification plant, was commissioned at the Wesseling site south of Cologne in October 1989. It was designed to convert up to 160 t/d of dried brown coal at a Gasification pressure of 25 bar, using either oxygen or air as the Gasification agent. From mid-November 1989 to early July 1990, the plant was operated at pressures between 10 and 25 bar, using oxygen as the Gasification agent. In mid-1990, the plant was modified to permit tests using air as the gasifying agent. Until the end of January 1992 the plant was operated for 8 753 hours and had converted about 30 000 t of dried brown coal.

Typical results obtained are: up to 95 % coal conversion, over 70 % cold-gas efficiency and 50 MW_{th} specific fuel gas flow per square meter air blown and 79 % cold-gas efficiency and 105 MW_{th} specific fuel gas flow per m² oxygen blown.

From February to September 1992 tests with different types of caking hard coal (German hard coal from the Saar area and Pittsburgh No. 8 coal) were successfully performed again using oxygen and air Gasification agents. The pressurised HTW Gasification plant was shut down in November 1992 [3].

2.2.5 KoBra - Integrated gasification combined cycle

At present, an IGCC demonstration project, called the KoBra demonstration plant, is in its engineering phase. The capacity of the KoBra demonstration plant will exceed 300 Mwe. The fuel gas will be produced by an air-blown gasifier and burned by a gas turbine, which will have a rated capacity of more than 200 Mwe, and the overall plant is expected to reach a net efficiency of some 45 % [7 - 8].

In 1994, RWE Energie AG decided to postpone the KoBra demonstration project and to start an additional three-year R&D program focusing on component and processes reliability, reduction of operational and investment costs and further improvement increasing the net power plant efficiency [9].

2.2.6 Engineering partners

In order to enhance the development and marketing of the HTW technology Rheinbraun AG co-operates closely with *Uhde GmbH* in Dortmund and *Lurgi Energie and Umwelt GmbH* in Frankfurt as engineering partners.

3 FEEDSTOCK

3.1 FEEDSTOCK TESTED FOR HTW GASIFICATION

Extensive operational experience on a commercial scale under pressurised conditions is available for brown coal, peat, used plastics, sewage sludge and loaded coke. In addition, successful bench-scale and pilot-plant tests have been performed for a variety of other feedstocks, e.g., other types of coal (special types of brown coal, lignite, hard coal), wood, grasses and various residues and waste materials. Table 2 shows a selection of different low-rank feedstock tested for HTW Gasification and certain levels of experience achieved to date. Proximate and ultimate analysis data of these feedstocks is listed in Table 3.

3.2 CONVERSION POTENTIALS

The HTW process permits efficient conversion of various coals, in particular of non-caking low-rank coals, biomasses or waste materials into syngas, fuel gas or reducing gas, which in turn can be used as feedstocks in the chemical industry, in advanced power plant technology, or in metallurgical processes. Syngas can be used to produce different chemical raw materials, such as methanol or ammonia. In advanced power plant technology, the HTW process is primarily feasible for integrated Gasification combined-cycle power plants and for power plants operating on the basis of the fuel cell technology.

Depending on the particular application (plant size, possible utilisation's of the coal gas, quantity and quality of the available fuels), mono-gasification or co-gasification constitutes the practicable solution. It is above all biomasses and waste materials that are expected to yield varying qualities. In these cases, the coal portion helps stabilise the gasification conditions and ensures constant coal gas quantity and quality.

Existing plants would permit pure biomass or residues gasification only, if substantial modifications and additions to various plant sections were performed, since due to the diversity of the feedstocks the design limits of the existing plant would be exceeded. In general, such expenditure cannot be justified under economic aspects.

4 GASIFICATION EXPERIENCE WITH BIOMASS AND WASTE MATERIALS

4.1 GENERAL REMARKS

Biomass has a content of volatile matter of 80 to 90 % by weight and forms a very reactive char. It can therefore be gasified effectively in a fluidized bed at a moderate temperature. Gasification experience with biomass is available from screening tests performed at a HTW PDU and from the industrial-scale plant operated by Kemira Oy in Oulu, Finland.

In order to determine whether co-gasification of waste materials with dried brown coal offers a reasonable potential for disposing them without impairing plant efficiency and emissions, research efforts were initiated both at laboratory and industrial scales.

The aim of the research activities performed most recently was to determine and evaluate the impact especially of sewage sludge, loaded coke and used plastics. These research efforts concentrated on the following objectives:

- To test and evaluate co-gasification with dried brown coal both under laboratory-scale and industrial-scale test conditions.
- To test and evaluate the environmental impact and the handling of Gasification residues in order to specify data for authority approval procedures.
- To determine the technical and economic aspects of an industrial-scale application.

4.2 BIOMASS

Industrial-scale experience is available from the Gasification plant at Oulu, Finland, which operated from 1988 to 1991 producing ammonia synthesis gas from dried Finnish peat. The properties of Finnish peat are rather close to those of lignite or brown coal (Table 3). The application of the HTW process developed for brown coal was a natural approach to the Gasification of peat [10].

Sod peat was chosen for the feedstock of the Oulu Gasification unit. Prior to Gasification the peat sods were crushed to a particle size of less than 4 mm to make the peat properties suitable for the fluidized bed. Before the Gasification process the peat had to be dried to about 15 % moisture content, in order to achieve the synthesis gas quality required. The improved handling and feeding characteristics of crushed and dried sod peat also increased the

operational reliability. In addition to the Gasification of crushed and dried sod peat, test runs were performed with a mixture of peat and sawdust [10]. Figure 3 shows a simplified flow diagram of the peat drying and Gasification unit installed at Oulu.

4.3 WASTE MATERIALS (GENERAL REMARKS)

In Germany, more stringent environmental regulations and increasingly scarce landfill space have created the need to utilise residues and/or waste materials. Thus, the current requirement to be met by technology is to develop suitable processes which allow these critical materials to be utilised and/or recycled in an environmentally compatible way. That is why this paper will place particular emphasis on the tests made in respect of residues' Gasification. Statistics, in particular those for used plastics and sewage sludges, show that there is an immediate demand for utilisation and/or recycling processes in order to utilise the occurring residues' quantities in an ecologically reasonable way. This need to act seems all the more urgent because the regulations governing landfills are expected to be tightened up on a medium-term basis.

4.4 SEWAGE SLUDGE [11]

According to the Federal Environment Agency approx. 2.7 mill. t of sewage sludge occurred in Germany in 1989; in Western Germany approx. 70 % of the sewage sludge was dumped on landfills (43 %) and used in agriculture (26 %). Only approx. 30 % of the sewage sludge occurring in Western Germany is used for combustion, composting or other utilisation processes. In Eastern Germany 100 % of the sewage sludge is still dumped on landfills or used in agriculture [5].

4.4.1 Results from industrial-scale test runs at the HTW demonstration plant

Based on the results of screening tests industrial-scale gasification tests were carried out at the HTW demonstration plant with dried municipal sewage sludge of different origins and with different compositions. Typical data of these sludges are listed in Table 3. Due to the high ash and low carbon contents, sewage sludge has a significantly lower heating value compared with dried brown coal and loaded coke. However, the amount of volatile matter and fixed carbon available in sewage sludge provide the reactivity necessary for the Gasification process.

Sewage sludge with a grain size ranges of 0 - 10 mm was delivered in silo trucks and unloaded into an existing solids silo. The right half of Figure 4 shows the coal feeding system used at the HTW demonstration plant; it consists of a dried brown coal silo, several feeding devices and a pneumatic conveying system. The left side of the figure shows the components used for sewage sludge handling.

In 1993 and 1994, several one-day test runs and a one-week test were carried out. A total amount of 504 tonnes of dried sewage sludge was handled. The feeding rate was adjusted to up to 5 t/h.

Dried sewage sludge was delivered as pellets or dust. To some extent, the pellets disintegrated into dust during unloading. However, during all test runs, the sewage sludge's flow behaviour in the conveying system including the lock hopper and coal feeding systems did not involve any problems. Upon almost complete conversion of the organic portion in the gasifier, the inorganic solids were discharged and the gasified components were processed into synthesis gas. The synthesis gas produced was always to specification. Due to the higher ash content the total feedstock amount and the gasifier's bottom product discharge had to be increased correspondingly. This operating mode was thus very similar to that of high-ash power plant coal Gasification. As the sewage sludge was usually very fine-grained and had a high dust portion, the dust load of raw gas increased considerably when sewage sludge was admixed. To ensure the dust's reliable discharge from the hot gas filter it was necessary to temporarily limit the admixing rate to a maximum of 3 t/h and somewhat reduce the plant load. The raw gas produced was very similar to that obtained during standard operation. As far as the emissions are concerned, the permissible limit values were adhered to without any problems.

Benzene and naphthalene concentrations increased to some extent during the Gasification of sewage sludge. In order to prevent clogging problems, to meet the syngas specification and to observe the emission limit values, gas treatment and conditioning facilities downstream of the gasifier unit have to be capable of not being affected and ensuring sufficient removal of these components.

Trace elements - especially heavy metals - were detected very carefully in order to monitor their distribution in the different Gasification products and by-products. Since the gasifier bottom product is fired in the neighbourhood power plant where two circulating fluidized bed combustors (CFBC) are installed, corresponding by-products (like bed material and fly ash) and the flue gas were also introduced into the trace element balance. Figure 5 indicates how, for example, cadmium is introduced and transferred from the

feedstock into products and by-products. Except for antimony, cobalt, manganese and thallium - which are available in dried brown coal in reasonable concentrations as well - the intake of trace elements is mainly determined by co-gasification of sewage sludge. There are significant differences detectable concerning the distribution of the trace elements in gasifier bottom product and filter dust from the HGCU. For example, only a very small amount of cadmium remains in the gasifier bottom product. About 98 % of the total cadmium was found in the filter dust. Finally, all trace elements and heavy metals studied during co-gasification of sewage sludge were captured by either of the solid by-products. None of them were detectable in the syngas, waste water or flue gas.

The investigations made into the use of sewage sludge in the HTW process were financially supported by the European Community within the scope of a multilateral research project (APAS) [12].

4.5 LOADED COKE [11]

Due to its high separation capacity (sorption) in respect of many organic and inorganic substances, brown coal coke produced according to the rotary hearth furnace process is used for off-gas cleaning and waste water purification. Since technical and economic aspects preclude regeneration of the loaded coke in various cases, processes are required that permit safe and low-cost disposal or utilisation. For cokes loaded with hazardous organic substances this can, in principle, be achieved by HTW Gasification, because the process configuration will ensure the decomposition of organic compounds and reliably prevent any new formation of additional hazardous substances. For this purpose, the use of loaded brown coal coke was tested at the HTW demonstration plant.

4.5.1 Industrial-scale test runs

During the co-gasification test runs performed at the HTW demonstration plant different types of loaded coke were tested. typical data of these loaded cokes are listed in Table 3. Although there is only a small amount of volatile matter available in loaded coke, the low ash and water contents provide a reasonable heating value and reactivity.

A total amount of 32 tonnes of coke loaded with organic substances such as styrene, pitch, benzene, toluol, xylol or lubricant in water emulsion was handled during several co-gasification test runs. Loaded coke was handled as described for the sewage sludge without any problems. All cokes used

were uncritical in terms of Gasification behaviour and in respect of the emissions after Gasification. The cokes were converted almost completely into synthesis gas. The environmentally relevant compounds were eliminated completely by Gasification and were not detected in the products and by-products. It was only the unloading and pneumatic conveying of the coke loaded with the benzene, toluol and xylol solvents that produced inadmissibly high benzene concentrations in the off-gas of the pneumatic conveying system.

The investigations on the use of loaded coke in the HTW process were financially supported by the European Community within the scope of a multilateral research project (APAS) [12].

4.6 FEEDSTOCK RECYCLING OF USED PLASTICS [13]

4.6.1 Introduction

In the last year, a total amount of around 7 million tonnes of packaging material occurred in the Federal Republic of Germany. Mixed plastics household waste had a share of approx. 830 000 tonnes. With account taken of the quotas applicable according to the packaging ordinance as of July 1995, a minimum of 64 % of this total amount, i.e., approx. 530 000 tonnes, will have to be recycled. In addition to material recycling, which accounts for a share of around 150 000 tonnes, approx. 380 000 tonnes of this mixed plastics household waste is planned to be subjected to feedstock recycling.

Material recycling requires unmixed and clean material and is feasible with justifiable expenditure only for a limited quantity of mixed plastics household waste. Mixed plastics household waste that does not meet the requirements of material recycling is subjected to feedstock recycling. In industrial-scale plants the material is cracked into liquid or gaseous petrochemical raw materials, which in turn can be used to produce plastics or other chemical products.

For the feedstock recycling of mixed plastics household waste and other mixed and contaminated used plastics the most diverse processes are feasible. Besides hydrogenation, pyrolysis and visbreaking, it is in particular gasification in the fluidized bed that offers the required potential.

4.6.2 Feedstock properties

The packaging materials collected within the scope of kerbside collection systems by Duales System Deutschland GmbH (DSD = German agency en-

gaged in the management of mixed plastics recycling) are subjected to the sorting process - presented schematically in Figure 6 - during which they are divided into different material groups. Foils, hollow bodies, tubs, foamed plastics, ferrous metals and non-ferrous metals are subsequently subjected to material recycling as secondary raw materials. Downstream of the sorting and classification steps negative fractions remain which are called mixed plastics. The latter account for around 23 % of the feedstock material and are subjected to feedstock recycling. Mixed plastics have an extremely heterogeneous composition, which is characterised by numerous contaminants. Its plastic portion amounts to approx. 60 %. In addition, mixed plastics contain considerable portions of paper, composites, metals and tailings. The HTW process is particularly capable of processing such a heterogeneous feedstock.

Feedstock recycling usually requires pre-treatment of the mixed plastics. Preparation for the HTW process is done in comparatively easy processing steps. Crushing and subsequent granulating, extruding, palletising or agglomerating produce a dry and flowable bulk material from the mixed plastics. During this process the mostly loose constituents of the mixed plastics are compacted and processed to pellets or agglomerates which are fused together on the surface and have grain sizes of 0 - 10 mm. Mixed plastics can be produced in grain size ranges comparable to that of dried brown coal. Compacting yields a bulk density of around 300 kg/m³. Heating value, volatile and ash contents are considerably higher than those of dried brown coal (Table 3).

4.6.3 Procedure for test execution

Testing of feedstock recycling was carried out with the aim of making long-term use of mixed plastics from Duales System and other plastics waste in the HTW demonstration plant. Dried brown coal will, however, remain the primary feedstock. For the above reasons, the plastics are planned to substitute only part of the dried brown coal and will be admixed to it in appropriate portions. The investigations dealing with the long-term application of the HTW process have been and will be conducted in several phases from the first preliminary investigations up to commercial application (Figure 7). Preliminary investigations were aimed at finding out whether plastics waste is generally suitable as a feedstock for the HTW process and what data in terms of process and safety engineering will have to be considered in the case of potential additions and modifications to the HTW demonstration plant. For this purpose, PDU scale tests were run and external appraisals were prepared.

Upon receipt of the notification granting the operating licence for the temporary use of plastics in the HTW demonstration plant, single test runs were first carried out in the period from June 1993 to February 1994. For these tests, modifications or additions to the HTW demonstration plant were first dispensed with. The plastics were delivered batchwise in silo trucks and plastics were conveyed via a screw feeder and a star feeder to the solids pump where they were mixed with the dried brown coal. This was followed by pneumatic conveying to the lock-hopper system (Figure 4).

Upon successful completion of the single test runs, the results were to be definitely verified in an extended time test with continuous plastics feed. This was also to include testing of the facility finally required for safe plastics handling. Moreover, the admixing rates were to be varied during that extended time test.

For plastics handling the facility presented schematically in Figure 8 was installed. The right half of the figure shows the HTW gasifier's already existing coal feeding system, which consists of the dried brown coal silo as well as dosing and conveying systems. The left half of the figure shows the additional facility that was installed. In contrast to the single test runs, the plastics are delivered by dump trucks during the extended time test.

4.6.4 Test results

The PDU tests proved the general suitability of plastics mixed with brown coal as a feedstock for the HTW process. The PDU tests also served to prepare industrial-scale tests in the HTW demonstration plant.

In the single test runs performed in the HTW demonstration plant during a total of 280 hours, more than 800 t of mixed plastics were used. The test duration ranged 10 - 200 hours. The single test runs showed that mixed plastics are a suitable feedstock for the HTW process even under industrial-scale operating conditions. The admixing rate varied between 1 and 5 t/h. Due to the positive test results, reliable operation is expected to be ensured even if the admixing rate is increased to up to 12 t/h. One tonne of plastics can substituted for around 1.3 t of dried brown coal.

On the basis of the operating experience gained in the single test runs the finding was made that using plastics does not call for any substantial modifications to the existing plant and that industrial-scale application requires modifications only in the plastics handling and stockpiling facilities and in the benzene and naphthalene removal system.

No significant impairments of the operating behaviour and performance were detected in the HTW gasifier - including its feeding and discharging systems - nor in the downstream coal gas cleaning and treatment units. Use of mixed plastics did not have any impact on the syngas quality.

Compared with standard operation, the use of plastics did not involve higher emissions. The gasification residues bottom product and hot gas filter dust as well as the process waters were slightly changed but not to such an extent that the limit values admissible for brown coal-based operation were exceeded.

Compared with standard operation, the coal gas leaving the gasifier has a higher benzene content and contains small traces of naphthalene, which is probably a result of the plastics' higher volatile content. The impact on benzene and naphthalene contents was investigated, depending on the admixing rate. It was found out that at a plastics feed of around 3 t/h the design limits of the downstream plant units are reached.

Within the scope of an extended time test running since September 1994 a plant unit especially installed for plastics handling has been tested at a continuous feeding rate of 3 to 5 t/h and operational optimisations have been performed. During this extended time test, more than 5 000 t of mixed plastics have already been used in the form of pellets and agglomerates.

The HTW demonstration plant is planned to serve as a permanent facility for the feedstock recycling of mixed plastics waste. Commercial-scale operation will start in mid-1995.

4.6.5 Conversion efficiency of the HTW process

In the schematic of Figure 9 the recycling process for plastics waste by fluidized-bed gasification according to the HTW process and downstream methanol synthesis has been reduced to two process steps. This representation only shows the substances participating in the chemical conversions as well as the products of gasification, gas treatment and methanol synthesis.

The HTW process is characterised by a yield of around 850 kg of syngas per tonne of mixed plastics. Gasification of the mixed plastics and processing of the syngas mainly require the gasification agents oxygen and steam as well as make-up water having the quality of boiler feed water. The by-products obtained are CO₂, bottom product, dust and waste water as well as small amounts of condensate. In terms of the total recycling process 1 000 kg of mixed plastics thus yields around 660 kg of directly saleable pure methanol.

5 SUMMARY

The HTW process is particularly favourable for the Gasification of low-rank feedstocks. During various tests - performed in bench-scale, pilot-scale and industrial scale units - consequences with regard to feedstock preparation, Gasification behaviour, corrosion, emission and residual matter were carefully studied for a large number of different feedstocks. Information is now available for optimal utilisation of several types of biomass and waste materials in relation to plant operation, emission and residue utilisation.

Different types of biomass were tested in bench-scale conditions in an atmospheric HTW process development unit. Industrial-scale experience concerning biomass is available from the Gasification plant at Oulu, Finland, which operated from 1988 to 1991, producing ammonia synthesis gas from dried Finnish peat.

During several test campaigns performed at the HTW demonstration plant sewage sludge, loaded coke and used plastics were co-gasified at feeding rates of up to 5 t/h. Testing was accompanied by a detailed analytical programme. Thus, topics like operability, conversion efficiency, syngas contaminants, solid residue characteristics and emissions were monitored very carefully. Co-gasification in a dried lignite mixture allows synthesis gas for methanol production to be obtained also from waste materials. Thus, waste is converted into a useful chemical feedstock.

For both sewage sludge and loaded coke, conversion efficiency and syngas yield were sufficient. Within the scope of a solid residue characterisation various contaminants, including chlorine, sulphur, heavy metals and other trace elements or organic compounds, their formation and/or release were detected. Emissions were well below the limits. However, an increase in the benzene and naphthalene concentrations in the crude gas occurred. Thus, a commercial application requires additional gas treatment.

In the next few years, feedstock recycling of mixed plastics household waste from Duales System Deutschland GmbH will call for a plant capacity of 350 000 to 400 000 annual tonnes in Germany. For this, suitable and industrial-scale tested processes are required which should be available as soon as possible. These underlying conditions offer a new application potential, in particular for the HTW process.

Under real industrial-scale conditions the HTW process demonstrated its general suitability. Process-specific requirements for a continuous operation were determined.

For feedstock recycling according to the HTW process, mixed plastics waste with a comparatively low quality is suitable as well. The tests carried out so far have shown that even a plastics share of only 60 % permits a sufficient synthesis gas yield and trouble-free operation. The process is insensitive to a high inert portion, waste, ferrous metal residues and heavy metals. Emissions were well below the limits. As with sewage sludge, an increase in the benzene and naphthalene concentrations in the crude gas occurred. Thus, high feeding rates would probably require additional gas treatment.

Within the scope of an extended time test which has been run since September 1994 a plant unit especially installed for plastics handling has been tested at a continuous admixing rate of 3 t/h and operational optimisations have been performed. During this extended time test, more than 5 000 t of mixed plastics processed by DSD has already been used in the form of pellets and agglomerates.

Co-gasification of waste materials like sewage sludge, loaded coke or used plastics with dried brown coal offers significant potential for disposing such wastes without impairing plant efficiency and emissions.

The HTW demonstration plant is planned to serve as a permanent facility for the feedstock recycling of waste materials and, in particular, used plastics.

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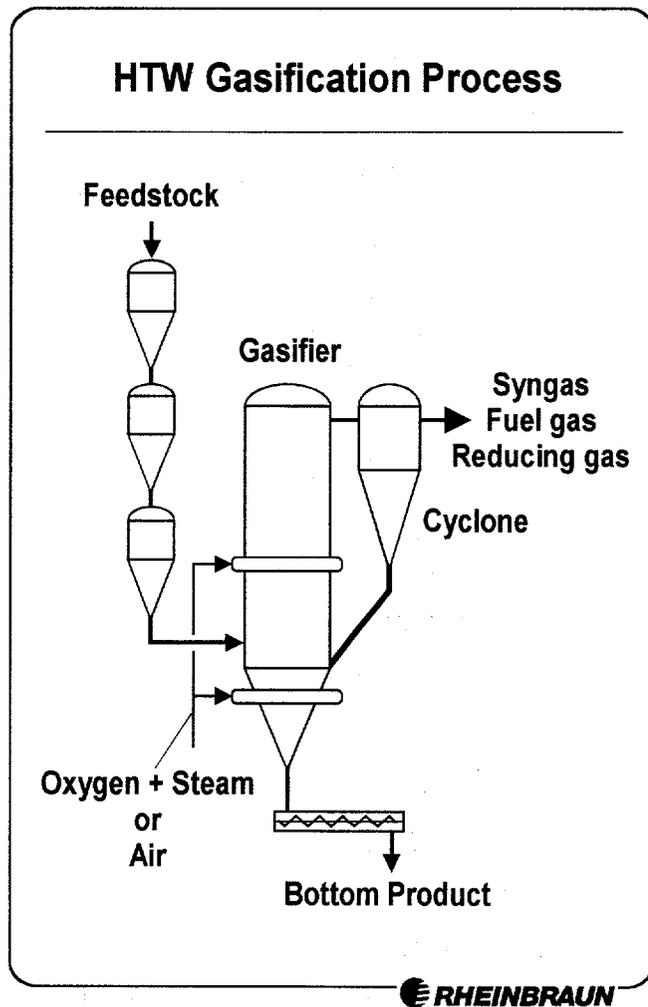


Figure 1. HTW gasification process.

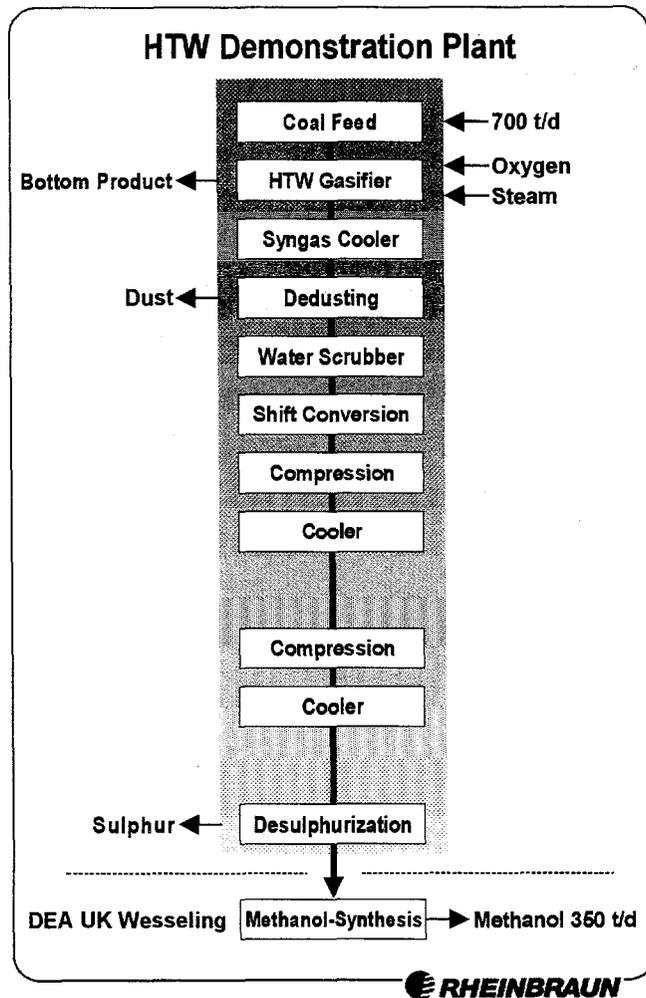


Figure 2. HTW Demonstration plant.

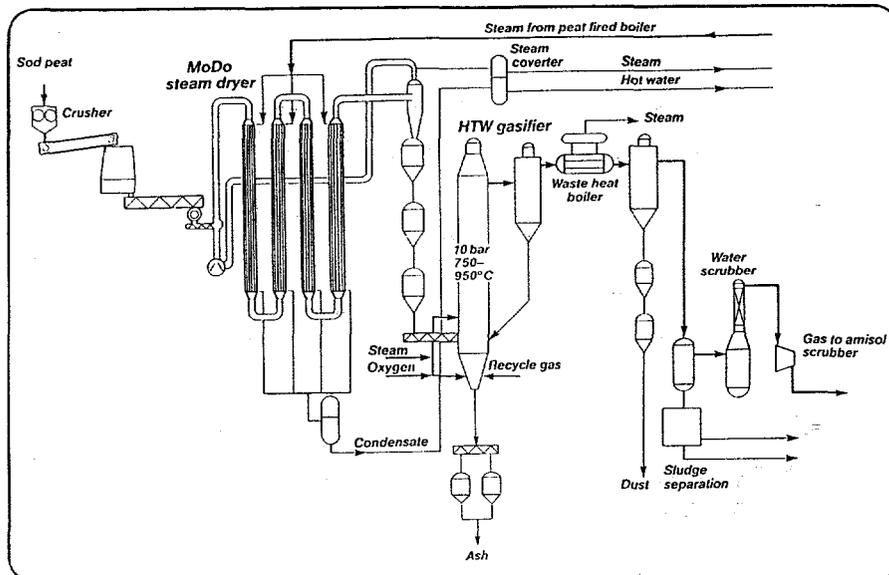


Figure 3. Flow sheet of the drying and gasification unit at Oulu, Finland.

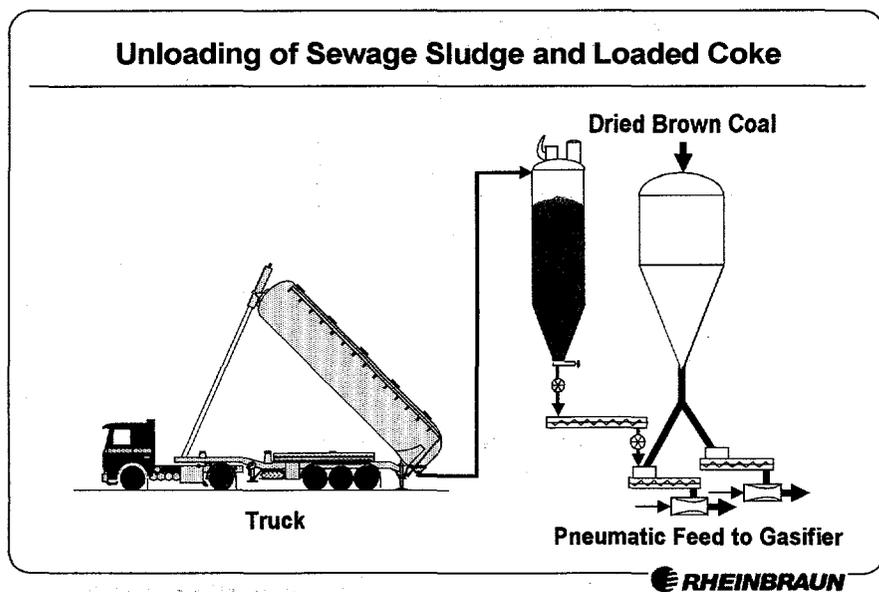
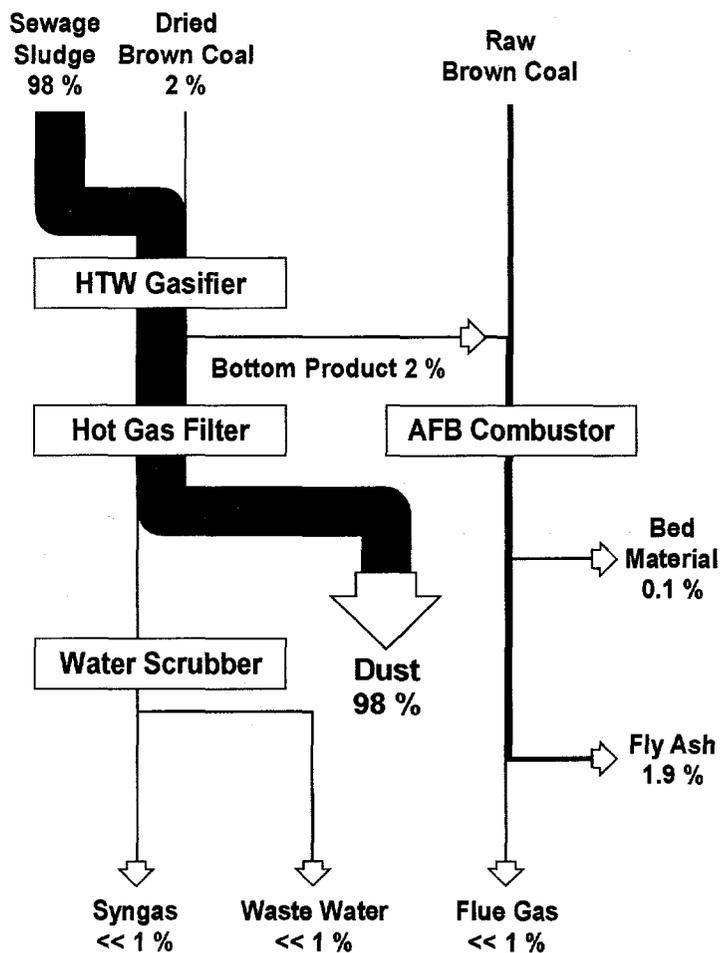


Figure 4. Unloading of sewage sludge and loaded coke.

HTW Demonstration Plant Berrenrath Power Station

Total Cadmium Intake: 0.3 - 1.1 kg/d



BF2-160-0-E

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Figure 5. Cadmium balance during co-gasification of sewage sludge.

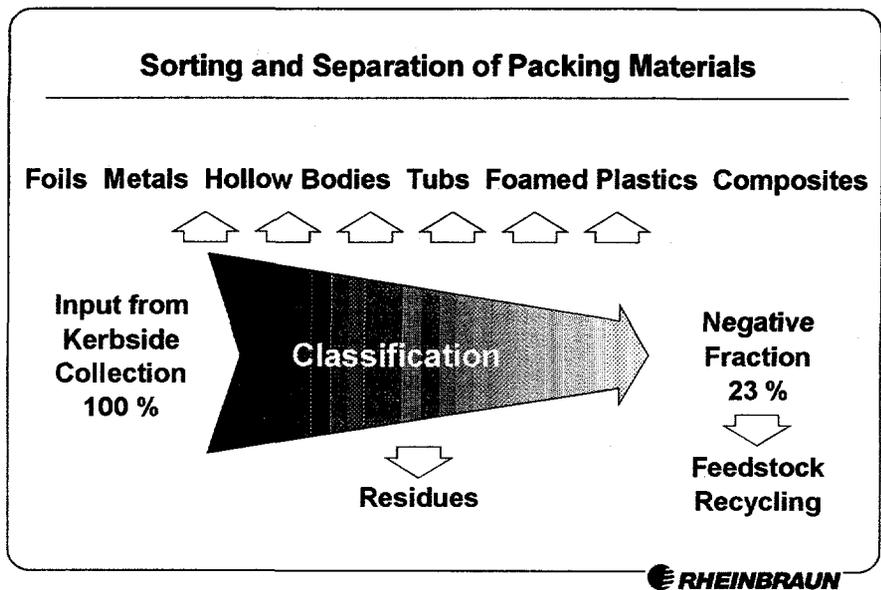


Figure 6. Sorting and separation of packing materials.

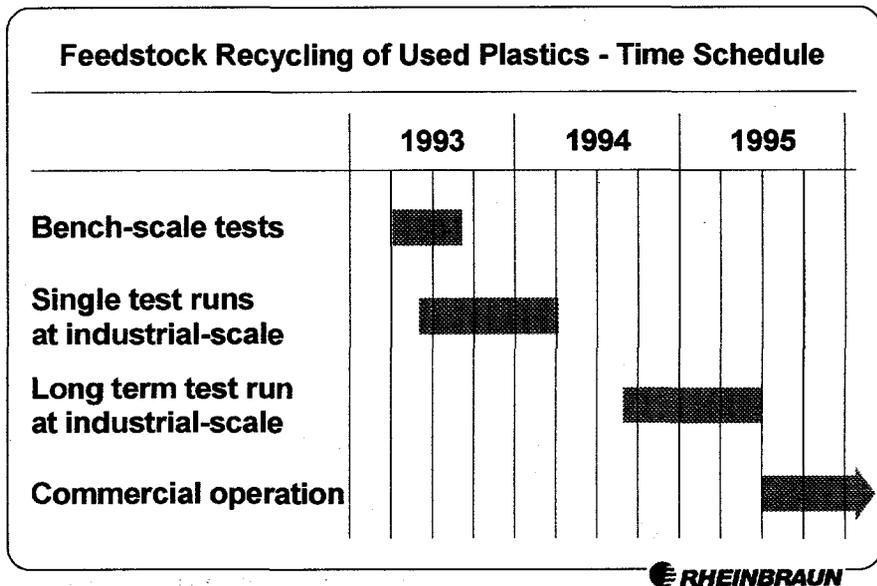


Figure 7. Feedstock recycling of used plastics - time schedule.

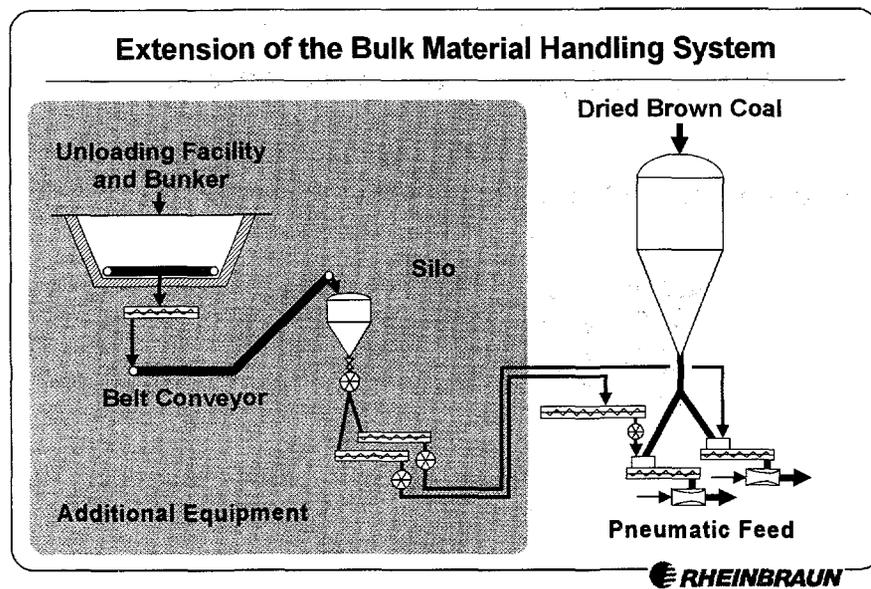


Figure 8. Extension of the bulk material handling system.

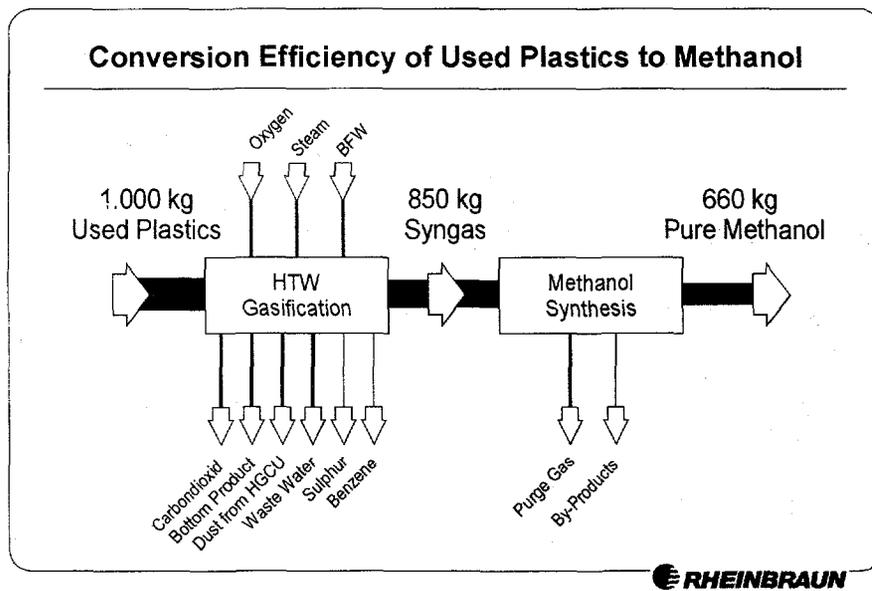


Figure 9. Conversion efficiency of used plastics to methanol.

Table 1. Design and operational data of HTW gasification units.

	PDU	Pilot plant	Demonstration plant	Kemira Oy Gasification unit	Pressurized gasification plant	KoBra demonstration plant
	Aachen	Wachtberg	Berrenrath	Oulu - Finland	Wesseling	RWE Energie
Date of commissioning	1973	1978	1986	1988	1989	not decided
Date of shut down	available	1985	in operation	1991	1992	-
Gasification pressure	1 bar	10 bar	10 bar	10 bar	10 - 25 bar	27 bar
Gasification agents	Oxygen/steam or air	Oxygen/steam	Oxygen/steam	Oxygen/steam	Oxygen/steam or air	Air
Nominal feedstock	Dried brown coal	Dried brown coal	Dried brown coal	Peat	Dried brown coal	Dried brown coal
Feedstock capacity	50 kg/h	1,800 kg/h	30,000 kg/h	30,000 kg/h	7,000 kg/h	160,000 kg/h
Optional feedstock	various	Peat High-salt brown coal	Used plastics Sewage sludge Loaded coke	Peat + sawdust	Hard coals	none

Table 2. Feedstocks tested for HTW gasification.

	PDU	Pilot plant	Industrial plant	Mono-gasification	Co-gasification	Gasification agent	
						Oxygen	Air
Low-rank coal							
Brown coal							
High-sulphur brown coal							
Lignite							
Sub-bituminous coal							
Hard coal¹							
Ensdorf - Saar							
Pittsburgh No. 8							
Other low-rank fuels (biomass and energy plants)							
Peat + sawdust							
Wood ²							
Grasses ³							
Waste materials							
Sewage sludge							
Loaded coke							
Used plastics							
Used rubber							

¹ high-volatile bituminous coal

² various sources (pine wood from Sweden, Eucalyptus from Brasil), chips, sawdust

³ straw, Miscanthus, pasture grass, Trictale

Table 3. Proximate and ultimate analysis of low-rank feedstock tested for HTW gasification.

	Dried brown coal	Dried Finnish peat	Dried sewage sludge	Loaded coke	Used plastics
Moisture content [%]	12	15	2 - 10	3 - 13	1 - 10
Ash content [%]	4	6	20 - 30	5 - 10	3 - 15
Volatile matter [%]	44	70	20 - 50	5 - 10	75 - 90
LHV [MJ/kg]	21	17	8 - 12	26 - 29	25 - 40
C [%]	59	46	20 - 30	80 - 85	55 - 80
H [%]	4	5	1.5 - 5	0.3 - 1	8 - 10
O [%]	20	26	8 - 16	1 - 7	5 - 20
N [%]	1	2	1 - 5	0.2 - 0.3	0.2 - 0.5
S [%]	0.3	0.2	1 - 2	0.3 - 0.5	0.2 - 0.6
Cl [%]	0.03	0.03	0.05 - 0.3	0.03 - 1	1 - 2
F [mg/kg]	10 - 50		200 - 700		20 - 100
Bulk density [kg/m ³]	560	300 - 400	600 - 850	300 - 550	280 - 400

EXPERIENCE WITH UNCONVENTIONAL GAS TURBINE FUELS

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Abstract

Low grade fuels such as Blast Furnace Gas, biomass, residual oil, coke, and coal - if used in conjunction with appropriate combustion, gasification, and clean-up processes and in combination with a gas turbine combined cycle - offer attractive and environmentally sound power generation.

Recently, the Bao Shan Iron and Steel Company in Shanghai placed an order with Kawasaki Heavy Industries, Japan, to supply a combined-cycle power plant. The plant is to employ ABB's GT 11N2 with a combustor modified to burn blast furnace gas. Recent tests in Shanghai and at Kawasaki Steel, Japan, have confirmed the burner design. The same basic combustor concept can also be used for the low BTU gas derived from air-blown gasification processes.

ABB is also participating in the API project: a refinery-residual gasification combined-cycle plant in Italy. The GT 13E2 gas turbine employs MBTU EV burners that have been successfully tested under full operating conditions. These burners can also handle the MBTU gas produced in oxygen-blown coal gasification processes.

ABB's vast experience in burning blast furnace gas (21 plants built during the 1950s and 1960s), residuals, crude, and coal in various gas turbine applications is an important asset for building such power plants. This paper discusses some of the experience gained in such plants.

1 INTRODUCTION

Gas turbines today play a major role in power generation world-wide. The past decade, during which natural gas has been easily available, has seen tremendous development in and installation of gas turbine combined-cycle power plants. This generation system offers the most attractive power plant: lowest costs, highest efficiency, lowest emission levels, and very short installation times (Figures 1 and 2).

Combustion on natural gas fulfils stringent emission level requirements. With a low dry NO_x combustion system, no water or steam need be injected to suppress NO_x emissions. The fuel flexibility of gas turbines in burning fuels other than natural gas has been widely demonstrated. No. 2 oil is frequently used either as a back-up fuel for the natural gas, or as the primary fuel itself. Other than NO_x , which results from the high combustion temperatures, this clean fuel does not produce any other pollutant emissions. Water or steam is injected into the combustor to suppress the NO_x emission levels. Development currently in progress is aimed at meeting the NO_x levels allowed under environmental regulations in "dry" operation, i.e., without water or steam injection.

In several countries, there never has been, and sometimes still is not, any regulatory pressure demanding restriction of emission levels. In those countries, it was, or still is, common to burn crude or residual oils in gas turbines. As regulatory pressure increases, operators are being forced to consider the installation of gas clean-up equipment. In addition, refineries in industrial nations are considering gasifying their residual oil or coke - the refinery "bottoms" - to produce a medium BTU gas. For economic reasons, consideration of a combined-cycle power plant using this MBTU gas appears to be an attractive option.

Processes have been developed for gasifying not only residual oils, but also coal and biomass. These processes produce medium or low BTU gas. Many demonstration projects are currently in the planning stage for studying the economic feasibility of such plants. Modern, high-efficiency gas turbines are capable of burning such fuels. Although this fact, together with the advantages of combined cycle operation, offers significant promise for economical power generation, a major cost reduction effort will still be needed to turn it into a real option for the future.

Another low grade fuel, blast furnace gas, has found wide use in gas turbines for power generation. Recently, economic factors have led many steel mills to consider installing a modern combined-cycle power plant to enable efficient utilisation of their blast furnace gas.

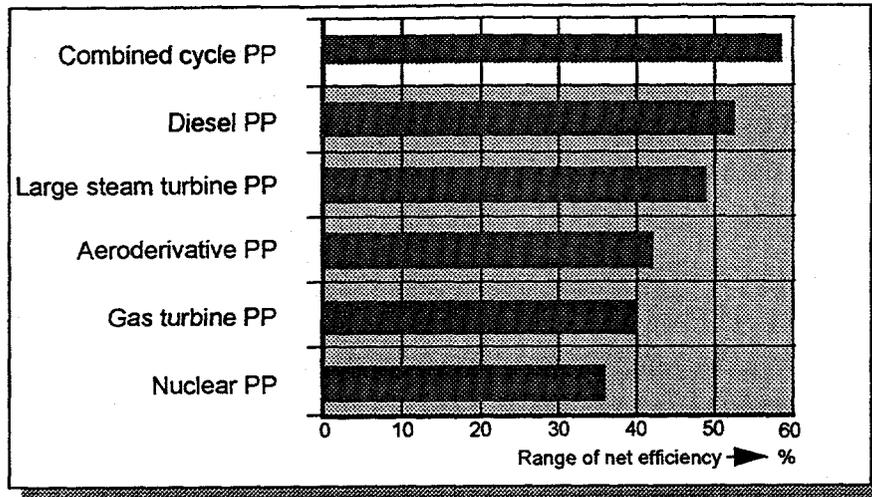


Figure 1. Efficiencies of different CC power plants.

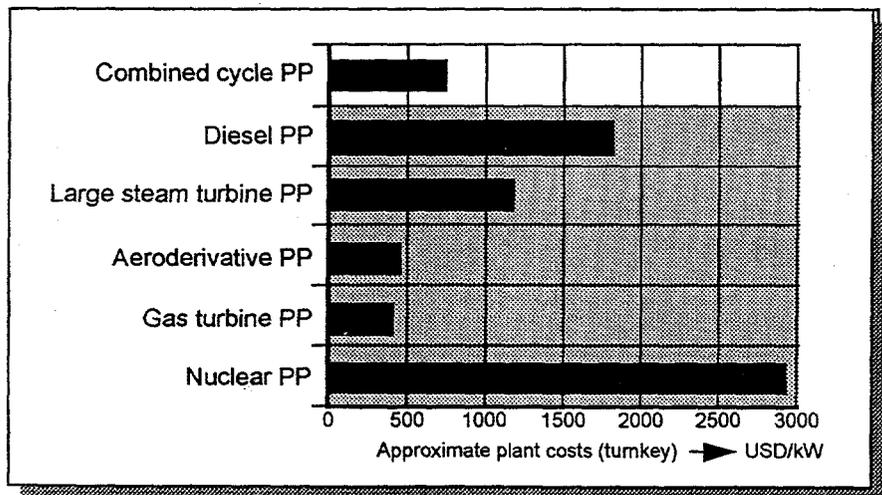


Figure 2. Cost of different CC power plants.

2 EXPERIENCE WITH BLAST FURNACE GAS

Between 1949 and 1959, ABB installed 21 gas turbine plants fired on Blast Furnace Gas (1). Most of these gas turbines were dual-fuel machines using oil as a back-up fuel. Their moderate turbine inlet temperatures represent the then state-of-the-art. Several of these machines have now logged more than 200 000 service hours.

Blast furnace gas usually has a low calorific value in a range from 2 to 4 MJ/kg. Table 1 shows its usual composition, as well as a comparison of this blast furnace gas with various other gases. The first blast furnace gas turbine built for the Altos Hornos de Vizcaya steel works in Baracaldo (Spain) was commissioned in 1949.

Even for this plant, a dual-fuel burner was developed to enable a switch over to fuel oil so as to ensure continuous operation of the converters when no blast furnace gas was available (Figure 3). An alarm is set off as soon as pressure in the gas line drops below a certain level, and the oil burner starts into operation immediately. During operation on the blast furnace gas, the oil nozzle is withdrawn to protect it from becoming overheated by the flame.

Various arrangements have been built over the years [1], for example:

- with a blast furnace blower or compressed air generation plant, without a generator
- with a blast-furnace blower and a generator, and
- with a generator only.

Long-term performance of the machines has been very satisfactory.

The "Niederrheinische Hütte" plant in Duisburg, Germany - commissioned in 1956 - was equipped with a power turbine driving both a generator and a blast-furnace blower. The first stage in the power turbine has variable guide vanes to permit speed variation. The gas turbine inlet temperature in this plant is 750 °C. Most of the problems arising in this and other plants have been discussed extensively in [1, 2]. Some of the most important results are presented briefly below.

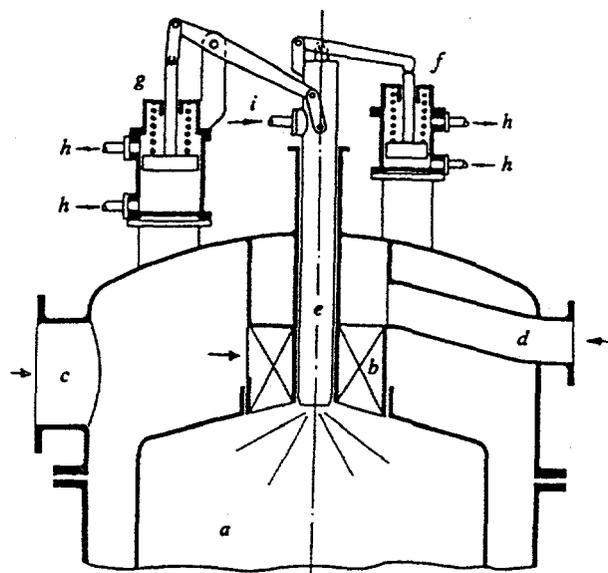


Figure 3. Cross-sectional diagram of a dual-fuel burner for blast furnace gas and oil. a = combustor, b = gas and air swirl basket, c = air intake, d = gas intake, e = fuel nozzle, f = fuel nozzle control valve, g = piston for withdrawal or insertion of the fuel nozzle, h = control system oil supply and drain, i = fuel supply.

Table 1. Composition of blast furnace gas.

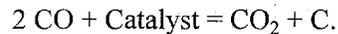
Fuel gases	Natural gas	Syngas from coal gasif. oxygen blown	Syngas from coal gasif. air blown	Syngas from oil gasif.	Coke oven gas	COREX gas	Blast furnace gas	Bio-mass gas
<u>Gas composition, vol%</u>								
Hydrogen	0	27	16	44.8	59.6	15.8	2.8	11.6
Carbon monoxide	0	60	11	46.5	6.8	42.3	22.9	17.4
Methane	87.8	0	4	0	32	1.6	0.5	8.2
Carbon dioxide	0	4	11	6.8	2.3	35.9	21.3	13.1
Nitrogen	3.7	9	30	0.6	2.9	2.7	53.0	38.2
Density	0.79	0.965	0.98	0.78	0.465	1.31	1.37	
Actual H ₂ /CO ratio	-	0.45	1.45	0.96	8.76	0.37	0.12	0.67
LHV range	35 - 50	10 - 13	4 - 5	13 - 15	38 - 44	5.5 - 6.5	2 - 4	5 - 6

2.1 DEPOSITION OF CARBONS IN THE GAS PREHEATER

Terminal output from the gas turbine dropped off increasingly after 4 800 service hours. After several investigations, the gas preheater was inspected. The bottom ends of some of its tubes had been squeezed and broken off,

allowing blast furnace gas to escape. Detailed analysis showed the following:

Blast furnace gas containing CO is stable only at temperatures below 300 °C or above 600 °C. If there is iron dust present, or if the gas comes into contact with oxidised surfaces, the following reaction takes place at temperatures between 300 and 600 °C:



The wall temperature of the lower tube plate in the preheater is 400 °C. There is a microscopically narrow gap present at the rolled joint between the tube and the tube plate. Carbon deposited there squeezes the tube. No similar phenomenon was observed at the upper tube plate, where the temperature is 250 °C. This has also been confirmed in other gas preheaters in low temperature machines with more than 100 000 hours in operation. For this reason we dispensed with gas preheating and supplied the gas to the combustor directly from the gas compressor.

2.2 CORROSION AND CONTAMINATION

Because of the high dust load in the air in a steel mill environment, the gas turbine air filters and inlet duct must be free from oil leaks. ABB has experienced fouling on compressor bladings due to oil leakage from an air filter. The average dust content of the air varies between 0.5 and 0.8 mg/m³, reaching a maximum of up to 3 mg/m³ before the air filter. The blast furnace gas contains between 8 and 40 mg/m³ of dust. Usually, an electrostatic precipitator is used upstream from the gas compressor to reduce dust levels to between 1 and 2 mg/m³.

Severe corrosion and fraying on the trailing edges of turbine blades were found in the first plants after only about 4 500 service hours. First stage vanes of Nim80A proved to have an incubation period of about 10 000 hours before severe corrosion was found.

Corrosion behaviour differed greatly from one plant to another. The blast furnace gas dust can contain such corrosive substances as alkaline sulphates, zinc sulphates, lead compounds, vanadium oxides, and sodium vanadates. Its composition varies widely, primarily due to the source of iron ore, which may itself contain differing compounds.

The furnace dust at the Knutange plant contained neither zinc oxides nor lead oxide, little sodium oxide, and practically no vanadium pentoxide. Its

melting point was 1 560 °C, and sintering started at 1 450 °C. As a result, this blast furnace gas caused no corrosion. On the other hand, the blast furnace gas dust at the Cornigliano plant contains 19.5 % zinc oxide and 9.5 % lead oxide. Its melting point is 400 °C. Moreover, since the plant is located on the coast, the compressor draws in saline air that contains sodium chloride. In addition, the crude gas was occasionally washed with seawater. Consequently, the combustion process produced $ZnSO_4$ and Na_2SO_4 . Laboratory tests have shown that a mixture of 4.5 mol $ZnSO_4$, 3.5 mol Na_2SO_4 , and 0.2 mol K_2SO_4 has a sintering point of 395 °C and is highly corrosive. The initial severe corrosion found in this plant was caused by a mixture of Zn, Na and K sulphates. The use of a chrome-based coating and a silicon-based additive as provided the corrosion resistance needed. Less corrosion has been found in cases where the blast furnace gas contains silicon oxide, which tends to raise the melting point and inhibit corrosion. Aluminium and magnesium are likewise corrosion inhibitors.

Figure 4 shows ABB's experience in operating gas turbines with dust-loaded flue gases from blast furnace gas and other fuels.

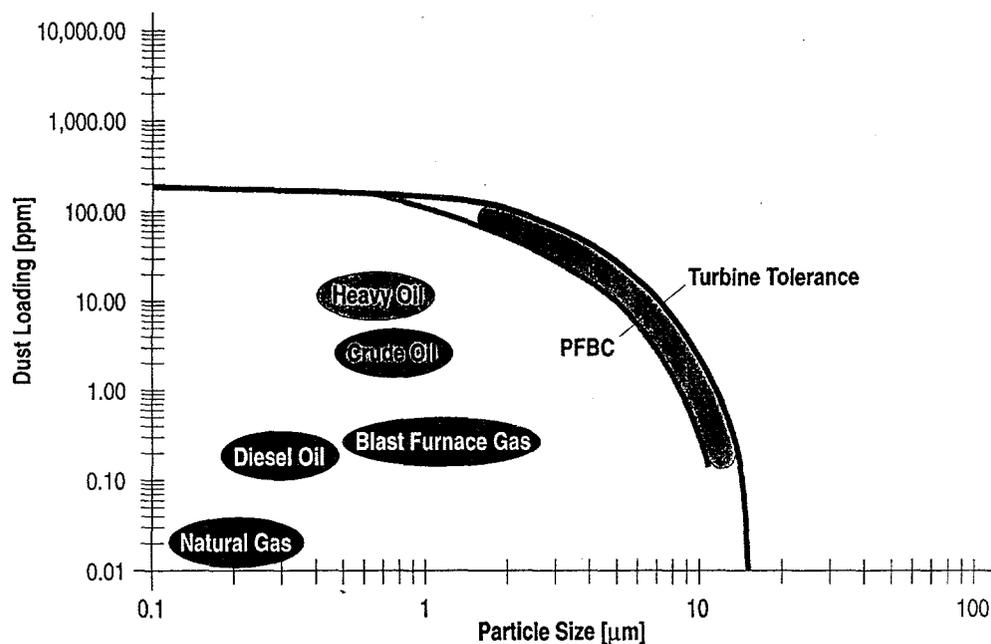


Figure 4. Comparison of dust loadings in gas turbine flue gases and limitations based on ABB experience.

3 EXPERIENCE WITH RESIDUAL AND CRUDE OIL

ABB's operating experience with gas turbines burning crude or residual fuel oil has been published extensively in various papers [3].

The critical properties of the fuel (refer to Table 2) are its specific gravity, viscosity, pour point, nitrogen content, ash content, and its content in alkaline metals and salt or other sodium compounds (refer to [3]). Some of the key problem areas are discussed below.

3.1 CORROSION AND DEPOSITION

As already seen from gas turbines burning blast furnace gas, salt and other sodium compounds cause corrosion from sulphates in general and sodium sulphate in particular. Many ABB gas turbines (built close to the seashore) burn heavy oil containing vanadium and zinc in an environment where the combustion air contains high concentrations of salt. In these turbines, the injection of silicon-based additives has basically stopped corrosion. The additives form a continually renewed coating of SiO_2 . No products of any chemical reaction between the corrosive compounds and SiO_2 have been found, which shows that the protective effect attained in such cases is a purely physical one. The high concentration of silicon oxide dilutes and dries out the corrosive deposits. For higher metal temperatures, however, extremely high concentrations of silicon are needed to maintain protection against corrosion. Economical studies have shown that inhibiting the attack of sodium compounds by the addition of silicon-based additives should be limited to fuels that contain less than 5 ppm Na. Above that point, the fuel should be washed.

Magnesium has been added to the combustion gas for some time now to combat such oxidising agents as vanadium pentoxide, sodium vanadates, and other compounds with similar effects. Magnesium forms high-melting magnesium vanadates. Magnesium-based additives can also inhibit corrosion caused by lead contaminants. However, magnesium oxide, magnesium sulphate, and magnesium vanadates form hard deposits on the surfaces of the blades, thereby increasing the fouling of the turbine and associated performance losses. The use of a combination of silicon and magnesium additives is, therefore, recommended whenever corrosion inhibitors are needed.

The minimum dosage of additive can be determined from the concentrations of corrosive elements in the fuel and air, the ash concentrations in the fuel, and the maximum blade metal temperatures in the type of turbine installed. However, the fuel specifications and limits on sodium and potassium levels must be maintained throughout operation.

3.2 NO_x EMISSIONS

The nitrogen content of a fuel is also one of its critical properties because of the "fuel NO_x" that it produces [1, 2]. Fuel NO_x emission levels can be controlled by limiting the nitrogen content of the fuel or by making adaptations in the combustor design. With the large, single-can combustor design used in many ABB gas turbines, it is possible to keep the fuel nitrogen conversion rate below, a fact which can be essential when burning residuals and crude oils, since these very often - as can be seen from Table 2 - contain quite high nitrogen levels.

3.3 POWER DROP DUE TO FOULING

Deposits on the surfaces of gas turbine blades - due to the high ash content in the fuel - lower the turbine's performance. Figure 5 shows the drop in output suffered in one gas turbine fired on residual oil.

It was necessary to wash the gas turbine every 200 hours in order to improve its performance, which, from the standpoint of the operator, was unsatisfactory. He therefore decided to inject a silicon additive. Figure 6 shows the resulting improvement in operation, and the far smaller power degradation. Silicon oxide deposits adhere less firmly to the surfaces of the blades, resulting in less fouling. An almost steady state in power output is attained within 500 hours, and any deposits that do form can be removed easily.

Table 2. Critical fuel properties, comparison of typical residual, crude and diesel fuels.

Property	Units	Residual	Crude	Diesel
Specific gravity (15 °)	g/cm ³	0.97	0.87	0.83
Viscosity (20 °C)	cst	-	32	6
Viscosity (50 °C)	cst	100	11	3.4
Viscosity (100 °C)	cst	16	3.8	-
Pour point	°C	20	-10	-30
Carbon	weight%	87.0	86.0	85.6
Hydrogen	weight%	9.2	12.1	13.5
Sulphur	weight%	2.8	1.9	0.4
Nitrogen	ppm	5 400	3 500	500
HHV	Kcal/kg	9 780	10 050	10 240
Water + sed.	vol%	1.2	0.2	0.05
Conradson	weight%	8.5	3	0.7
Ash	ppm	500	100	20
Na + K	ppm	50	5	0.5
V	ppm	35	7	0.5
Pb	ppm	4	0.2	0.1
Ni	ppm	3	2	0.1
Zn	ppm	5	2	0.1

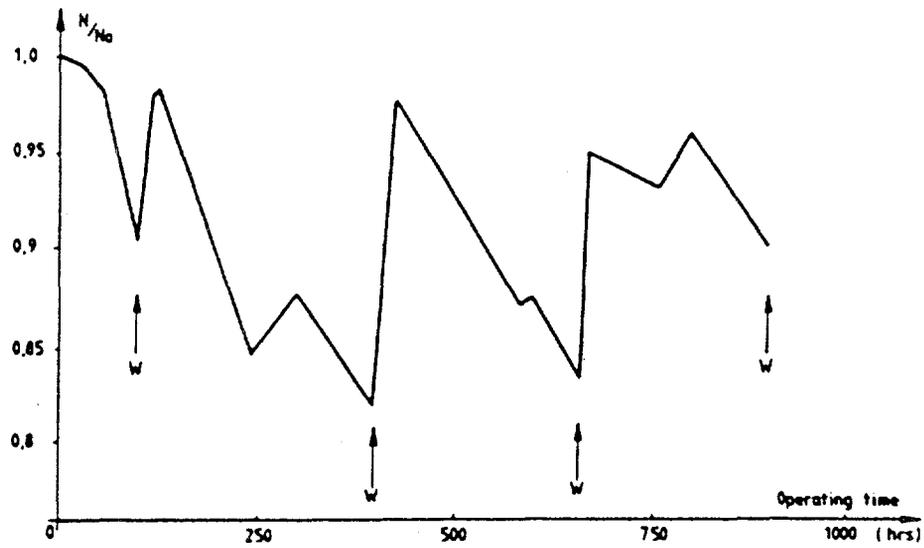


Figure 5. Without additive, with washing (BBC Type 12/12, Beznau II).

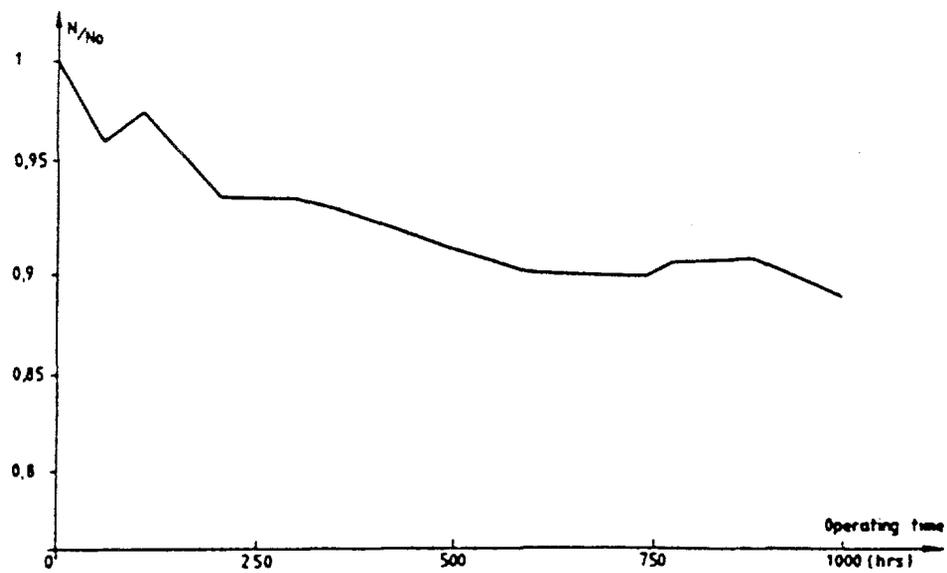


Figure 6. With silicon additives (BBC Type 12/12, Beznau II).

4 PRESSURISED FLUIDIZED-BED COMBUSTION

ABB has successfully developed and build Pressurised Fluidized Bed Combustion (PFBC) plants. Operation at four plants (Tidd, Värtan, Escatron, and Wakamatsu) has shown that gas turbines with a 2-stage cyclone downstream from the PFB combustor can handle the dust-laden gas. Due to the modest bed temperatures, no sintering of the ash takes place within the bed. The ash is relatively soft. The four plants mentioned have accumulated a total of 53 000 hours of service, 15 000 of them in one plant alone. After some necessary initial "debugging", ABB is confident that the special turbine design adapted to meet problems of corrosion, erosion, and contamination will succeed in attaining all goals set for it.

5 RECENT DEVELOPMENTS

5.1 RESIDUAL-GASIFICATION COMBINED-CYCLE PLANTS

Several residual-oil gasification projects have been in a process of development during recent years. ABB is participating in the API project in Italy [4]. The residual gas is an MBTU gas with the composition and key features shown in Table 1. The API plant will use a GT 13E2 with a 165 MW rating (ISO conditions, natural gas), equipped with an annular combustor and EV burners. The EV burner has been further developed in order to burn MBTU gas in a premix mode [5, 6]. This burner has been thoroughly tested under full gas turbine operation conditions in a high pressure rig, using a fuel gas that simulated the MBTU gas. The burner and the GT 13E2 were proven quite capable of handling the MBTU gas.

5.2 THE BAO SHAN BLAST-FURNACE GAS COMBINED-CYCLE PLANT

The Bao Shan Iron and Steel Company, Shanghai (China), has placed an order with Kawasaki Heavy Industries, Japan /ABB Power Generation, Baden, Switzerland, for supplying a combined-cycle power plant. Figure 7 shows a schematic diagram for the intended plant. The machine train comprises the ABB GT11N2 with its blast furnace gas combustor, the blast furnace gas compressor, a gear box, the steam turbine, and the generator. The main performance data are:

Power output at the generator terminals	149.6 MW
Plant efficiency at the generator terminals	45.5 %

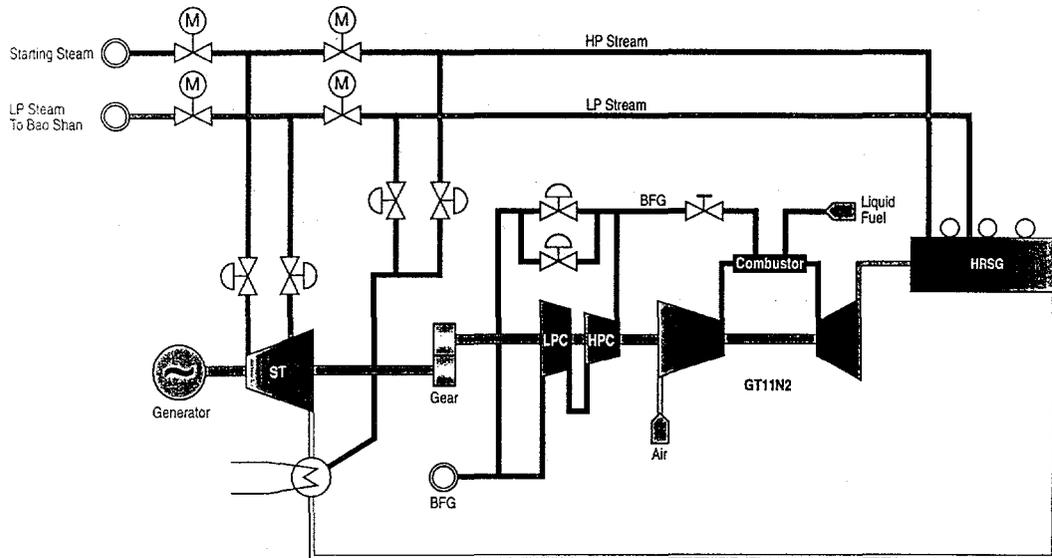


Figure 7. BAO Shan - System diagram.

ABB's and Kawasaki's past experience in the building and operation of such plants is being put to full use in the design and construction of this plant.

The GT11N2 has a power output of 109 MW (ISO conditions) when fired on natural gas. The combustor design, adapted for burning blast furnace gas, employs the low BTU burner. This burner was designed, of course, based on the design technology employed in the 1950s, but it has been modified for the higher firing temperatures needed for the GT11N2.

To verify the capabilities of the low BTU burner, ABB and KHI conducted a series of tests at the Bao steel works in Shanghai. A scale model burner was designed and thoroughly tested on simulated low BTU fuels in the laboratory at Baden (Switzerland). This burner was then also tested at the Bao steel site. The customer provided the fuel: a "pure" blast furnace gas (BFG), and BFG diluted with N_2 , for purposes of determining the lowest possible heating value needed from the blast furnace gas. A special test rig was constructed for testing the model burner.

Composition of the blast furnace gas (gas chromatographic measurements by Bao Steel):

CO	21.67 - 22.56	vol%
CO ₂	20.52 - 20.97	vol%
H ₂	3.43 - 3.83	vol%
N ₂	49.10 - 50.88	vol%
Lower heating value	3253.3 - 3355.8	kJ/nm ³

The test conditions and ranges were as follows:

Air flow rate	53 - 167	g/s
Air inlet temperature	320 - 377	°C
BFG flow rate	30 - 271	g/s
BFG inlet temperature	173 - 258	°C

The main results obtained were:

- 1) It has been demonstrated successfully that ABB's low BTU burner can burn "pure" blast furnace gas stably over a wide range of flow velocities and equivalence ratios. NO_x emission levels are low (Figures 8 and 9).
- 2) The combustor also operates safely on a heating value of 3 056 kJ/MN³ (attained by admixture of N₂), which is well below the lowest level possible with the Bao Steel blast furnace gas.
- 3) During a sustained operation test, the combustor was operated continuously for more than 6 hours on pure blast furnace gas without any problems.

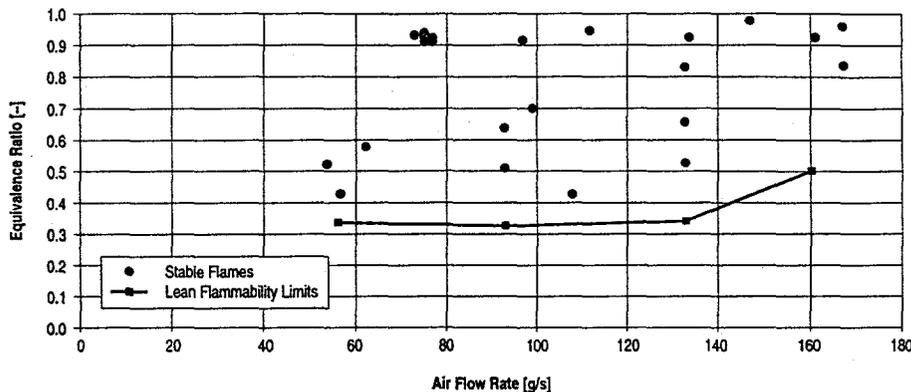


Figure 8. Low Btu Bao Steel site test: Flame stability (Swirler 1).

$241^{\circ}\text{C} < T_{\text{air inlet}} < 327^{\circ}\text{C}$, $87^{\circ}\text{C} < BFG_{\text{inlet}} < 239^{\circ}\text{C}$,
 $6 \text{ m/s} < C_{\text{main BFG}} < 61 \text{ m/s}$, $790 \text{ kcal/Nm}^3 \text{ dry}$

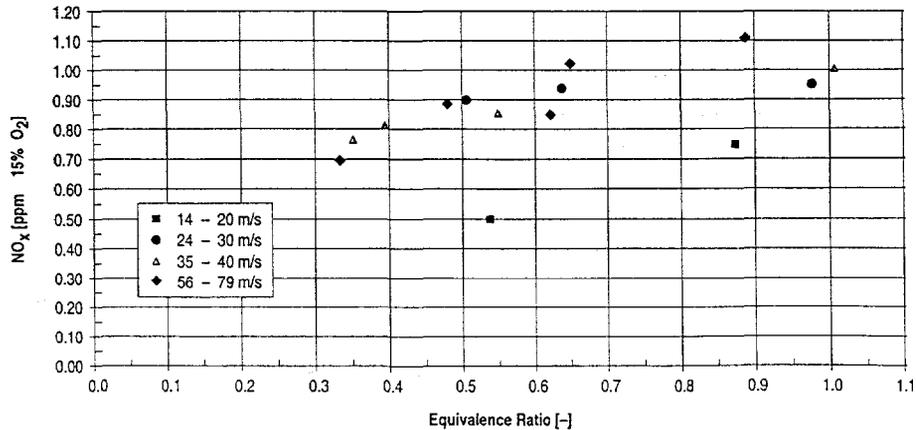


Figure 9. Low Btu test (Swirler 1), pure BFG, NO_x at emission probe No. 2.

6 CONCLUSIONS

Based on its experience gained over the past 50 years in burning various unconventional fuels, ABB is in a position to offer gas turbine plants that can be fired on blast furnace gas, crude or residual oil, or the synthetic gas (Syngas) obtained from residual, biomass, or coal gasification processes.

Most ABB gas turbines are compatible with such medium or low BTU gases. The single-can combustor can burn residual oil, crude oil, beside natural gas and oil. The low BTU burner, as described earlier, can handle a wide range of LBTU fuel - blast-furnace gas and the low BTU gas obtained from the air-blown gasification process. EV burners installed in either the single-can combustor or an annular combustor can burn the medium BTU gas obtained from an oxygen-blown gasification plant.

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COMBUSTION OF LOW HEATING VALUE GAS IN A GAS TURBINE

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Abstract

Advanced coal and/or biomass based power generation systems offer the potential for high efficiency electricity generation with minimum environmental impact. An important component for many of these advanced power generation cycles is the gas turbine, for which development of a combustion system to burn low calorific value coal derived fuel gas, at turbine inlet temperatures of typically 1 100 - 1 260 °C and with minimum pollutant emissions, is a key issue.

A phased combustor development programme is under-way burning low calorific value fuel gas (3.6 - 4.1 MJ/m³) with low emissions, particularly NO_x derived from fuel-bound nitrogen. The first and second phases of the combustor development programme have been completed. The first phase used a generic tubo-annular, prototype combustor based on conventional design principles. Combustor performance for this first prototype combustor was encouraging. The second phase assessed five design variants of the prototype combustor, each variant achieving a progressive improvement in combustor performance. The operating conditions for this assessment were selected to represent a particular medium sized industrial gas turbine operating as part of an Air Blown Gasification Cycle (ABGC). The test conditions assessed therefore included the capability to operate the combustor using natural gas as a supplementary fuel, to suit one possible start-up procedure for the cycle.

The paper presents a brief overview of the ABGC development initiative and discusses the general requirements for a gas turbine operating within such a cycle. In addition, it presents full combustor performance results for the second phase of turbine combustor development and discusses the rationale for the progressive design modifications made within that programme. The strategy for the further development of the combustor to burn low calorific value fuel gas with very low conversion of fuel-bound nitrogen to NO_x is presented.

1 INTRODUCTION

Advanced coal based power generation systems offer the potential to meet increasing world energy demand burning the world's most abundant fossil fuel. This approach has the benefit of preserving premium fuels, principally natural gas, for applications in which their natural advantages can be exploited most appropriately. More recently, there has been considerable interest in the development of these advanced systems to utilise biomass fuels. However, limitations on the local availability of potential biomass fuels such as sewage sludge or straw, mean that for power generation applications, economic electricity production may only be achievable by co-firing these fuels with coal. For example, in the Air Blown Gasification Cycle (ABGC), formerly known as the British Coal Topping Cycle and described briefly below, the mass ratio of sewage sludge to coal for a plant size of around 350 MWe would be typically 10 - 25 %.

1.1 ABGC DEVELOPMENT INITIATIVE

A consortium of several European industrial companies, under the chairmanship of GEC ALSTHOM, has formed to promote the ABGC with the aim of commercialising the technology early in the next century. Known as the Clean Coal Power Generation Group (CCPGG), the consortium comprises the GEC ALSTHOM subsidiaries of European Gas Turbines Ltd, EVT GmbH and Stein Industrie SA, together with British Coal Corporation's Coal Technology Development Division (CTDD), Babcock Energy Ltd, and PowerGen plc. The ABGC is being developed through an initiative to build and operate a demonstration plant and through an associated R&D programme targeted at developing the plant systems to the necessary stage of development for demonstration. To achieve demonstration on the timescale proposed, a 75 MW_e process integrated plant (PIP) is planned. The decision to build the plant is expected this year with a specification available by March 1996. The R&D programme aims to provide the information required for the plant specification by March 1996 and to provide further support for the plant during detailed design.

This programme, which is co-funded by the European Coal and Steel Community, the European Union, the UK Government's Department of Trade and Industry (UK DTI), and the consortium members, includes work on all aspects of the process: gasifier development; hot gas cleaning; emissions control; circulating fluidised bed combustion development; cycle integration and control; and the subject of this paper, gas turbine development for low calorific value fuel gas, in particular the combustion of the gas for low NO_x emissions. Most of this R&D represents a continuation of the programme

carried out for many years by CTDD (formerly the Coal Research Establishment of British Coal). The low NO_x combustion programme is an example of how CTDD's pre-competitive R&D has been absorbed into this larger, targeted development programme for demonstration of the ABGC.

1.2 ABGC SYSTEM DESCRIPTION

The system has been described in detail elsewhere (Minchener, 1990 and Arnold et al, 1991). In brief, the system, shown in Figure 1, is based on the partial gasification of coal in air using a spouted bed gasifier operating at temperatures of up to 1 000 °C. Sorbent is added to the gasifier to retain sulphur. The process converts typically 70 - 80 % of the coal into a low calorific value (LCV) fuel gas. This gas is cleaned to very low levels of dust using ceramic candle filters at 400 -600 °C and burned in a gas turbine to produce electrical power. The char residue from the gasifier is burned in a Circulating Fluidised Bed Combustor (CFBC) at atmospheric pressure to raise steam to produce further electrical power.

The high cycle efficiency and low cost of electricity for the ABGC (Dawes et al, 1989) are due primarily to the use of an air blown rather than an oxygen blown system (with its high auxiliary power requirement), the use of hot gas filtration rather than aqueous scrubbing to clean the fuel gas and the relatively high proportion of high grade steam produced in the cycle allowing the use of a single high pressure steam system. In addition, the development of supercritical steam cycles (for which the ABGC is particularly suited) and the ongoing development of industrial gas turbines, have the potential to increase significantly the efficiency of the ABGC. Such advances are predicted to raise the efficiency of the ABGC to in excess of 52 % (lower heating value basis).

2 GAS TURBINE REQUIREMENTS

Integration of a gas turbine package within an ABGC requires design changes to a range of components, including the combustion system, compared with those found in a conventional natural gas fired system. These changes are primarily due to the additional requirement to supply a portion of the compressor air to the air blown gasifier, and due to the very different properties of the LCV fuel compared with that of natural gas. The range of design changes to turbine components are discussed briefly in this Section, before concentrating on turbine combustor development in more detail.

2.1 GAS TURBINE COMPRESSOR BLEED

The gasifier within the ABGC requires typically 10 - 20 % of the gas turbine compressor air output. Assuming full plant integration, this air would be extracted from the pressure casing downstream of the gas turbine compressor where the static pressure would be at a maximum. The air would then be boosted in an additional compression stage prior to admission to the gasifier. The implication for the gas turbine would be the requirement to penetrate the pressure casings using an appropriately sized air off-take system, which must not have an adverse impact on the air flow to the combustion system.

The positive impact of gas turbine and gasifier air systems integration is that the gas flow-rates through the turbine compressor and expander sections would not differ significantly from those experienced in conventional applications, thus reducing the potential for compressor surge.

2.2 GAS TURBINE FUEL CHARACTERISTICS

Effects of major constituents

The LCV fuel gas presented to the gas turbine contains significantly more inerts than pipeline quality natural gas. Natural gas contains typically 2 - 15 % free nitrogen by volume compared with an inerts content of between 67 - 78 % by volume for LCV fuel gas. Consequently, the heating value for the LCV fuel gas of 3.6 - 4.1 MJ/nm³ (LHV basis) is an order of magnitude lower than that for natural gas, where the heating value is typically 35 MJ/nm³ (LHV basis). The differences between LCV fuel gas and natural gas has a number of implications for the gas turbine:

- The substantially increased fuel flow to achieve an equivalent firing temperature means that the incoming fuel and air momenta are more evenly balanced. Thus, the aerodynamic aspects of the fuel injector design need to be incorporated appropriately into the overall combustor design.
- The high level of inerts in the fuel gas act to reduce the range of air:fuel mass ratios that burn stably (the weak and rich extinction limits). However, this effect is offset by the high concentration of hydrogen (typically 10 - 15 % volume) contained within the fuel gas; this component burning over a much wider range of air:fuel ratios compared with the other combustible components.
- The high level of inerts also reduce the flame temperature in a manner analogous to steam injection or flue gas re-circulation, thus suppressing thermal-NO_x formation. However, this beneficial effect is more than offset by the formation of fuel-NO_x from nitrogen components contained within the fuel, as described below.

Effect of trace components

Trace contaminants of potential concern to the gas turbine fall broadly into two categories; those which affect gas turbine performance and component lifetimes, and those which affect pollutant emissions.

The first category essentially comprises heavy metals (such as alkalis and vanadium), particulates and tars. Historically, the trace presence of alkali metals and vanadium in ash particulate matter from crude and residual oils has caused serious problems in hot component deposition and corrosion. However, ash sticking coefficients and gas phase effects, including the influence of sulphur and chlorine components, will be different for the ABGC application. These effects are under review and have been investigated initially as part of the Grimethorpe Topping Cycle Project (Clark et al, 1991 and Fackrell et al, 1994). To avoid the potential contamination of the gas turbine fuel system by fuel gas trace contaminant deposits, it would be necessary to ensure that the temperature of the fuel gas and the 'gas swept' surfaces would not fall below the contaminant dew-point temperatures. A hot inert gas purge would also be required for start-up and shut-down to avoid condensation of stationary gases and to eliminate the possible presence of toxic species during maintenance operations.

The main concern with regard to the second category of atmospheric pollutant emissions is the oxidation of fuel-bound nitrogen, principally ammonia, to NO_x . The fuel gas within an ABGC is predicted to contain between 500 - 1 500 ppmv of ammonia. The lower level corresponds to an ABGC using a hot catalytic ammonia removal system, and the higher level corresponds to that produced by the air blown gasifier without further ammonia removal. In the absence of an ammonia removal system and if fully converted, a NO_x emission of up to 250 ppmv (15% O_2 , dry) may be produced. NO_x legislation for gas fired gas turbines operating in Europe is likely to require values an order of magnitude below this by the turn of the century. To achieve this low level of NO_x emission in the ABGC application, a reduction in the fuel-bound nitrogen level by means of catalytic ammonia removal, together with novel gas turbine combustor design would be clearly required.

Gas turbine fuel quality acceptance specification

The traditional vehicle for establishing clear lines of commercial responsibility between the gas turbine manufacturer and fuel supplier has been the 'Gas Turbine Fuel Acceptance Specification'. Produced by the gas turbine manufacturer, this document identifies the fuel characteristics likely to have an impact on gas turbine performance, emissions and life guarantees. The specification would be developed through consensus and would contain as a

minimum, limiting values against; main constituent composition, heating value, trace contaminant concentration, dew-point temperature and fuel supply temperature and pressure. These limits would be set against specific gas turbine design values of pressure ratio and firing temperature.

Fuel temperature

In order to optimise the cycle efficiency of the ABGC, the fuel gas temperature delivered to the gas turbine will be substantially higher than conventional practice; in the range 400 - 600 °C. This has a design implication with regard to the selection of fuel control valves, pipe-work materials of construction and selection of process control instrumentation.

Supplementary fuel

During plant start-up, the integrated air system imposes the need for the gas turbine compressor to supply air to the gasifier in the absence of a LCV fuel gas. This requires the use of a supplementary fuel which may be distillate oil or natural gas, dependent on economic and site-specific reasons. This means that any modification to the gas turbine combustion system to achieve low NO_x emissions must not preclude the effective use of a supplementary fuel.

3 TURBINE COMBUSTOR DEVELOPMENT

Turbine combustor development for power generation systems such as the ABGC has been ongoing since the late 1980s. The first phase of combustor development, carried out by Aero and Industrial Technology (AIT) Ltd on behalf of CTDD, assessed the performance of a generic prototype combustor design. Based on the tubo-annular principle and at approximately one-half geometric scale (125 mm combustor diameter), this work has been reported in full elsewhere (Kelsall et al, 1991 and 1993). The interim conclusion from Phase 1 was that the prototype combustor design had achieved acceptable combustor performance within the operating envelope assessed.

The second phase, also carried out by AIT on behalf of CTDD, was targeted at a currently available, specific industrial engine with a combustor outlet temperature of around 1 150 °C. This machine was chosen as its availability would be consistent with the proposed construction and operational time-frame for the 75 MWe PIP. Five design variants of the prototype combustor, each variant achieving a progressive improvement in combustor performance were assessed, primarily at Full Load and Full Speed No Load (FSNL) conditions. Full Load represents the condition when the gas turbine is

connected to the generator and producing 100 % of its generating capacity, and FSNL occurs when the turbine has been accelerated to the required operating speed but without electricity being produced (ie, no nett energy output). The performance of these five design variants are presented in Section 3.2.

The third phase, in progress currently, will include engine specific tests carried out by European Gas Turbines (EGT) Ltd at full geometric scale. In addition, CTDD will further develop the prototype combustor at one-half geometric scale, to enhance the NO_x emissions performance of the prototype combustor. This improved design would then be available as a potential retrofit to the PIP.

3.1 PHASE 2 DEVELOPMENT APPROACH

The design philosophy for the combustor has been reported elsewhere by Kelsall et al, 1991 and is described here briefly. It is based on a rich/lean combustor design, whereby the air is added in stages. The flame-tube for the fifth design variant tested as part of Phase 2, showing the location of the air holes to achieve staged air addition, is shown as Figure 2 (the flame-tube also shows combustor metal temperatures which are described in Section 3.2).

Primary combustion air enters the combustor through air swirlers and the first set of holes. Secondary air enters through holes further along the combustor and finally dilution air enters further downstream. Intermediate air may be added between the secondary and dilution air. This staged air approach produces zones of varying fuel concentration. At Full Load operation, the primary zone (the area up to the first set of holes), is fuel rich, ensuring that this area of the combustor is a reducing environment, thus minimising fuel-NO_x formation. Air is added through the secondary holes to produce a stoichiometric mixture. Intermediate air may then be added to raise the oxygen concentration and enhance CO burnout. Finally the dilution air is added to produce the required gas turbine firing temperature.

As in Phase 1, this programme used a synthetic fuel gas (syngas) composition which simulated the essential features of a fuel gas produced by an air-blown gasifier. The syngas had a similar calorific value and average molecular weight to that predicted for an ABGC plant and was supplied in high pressure gas cylinders, manifolded together to give the high flow-rates of syngas required. The combustible components of the fuel gas were represented by carbon monoxide, hydrogen and methane. For ease of preparation, the inerts were represented by nitrogen only. The syngas composition used for this programme is shown in Table 1.

Table 1. Comparison of typical air blown gasifier fuel gas and nominal synthetic fuel gas compositions.

	Typical fuel gas	Synthetic fuel gas
CO vol%	7.9 - 14.7	7.9
H ₂ vol %	13.2 - 15.0	13.2
CH ₄ vol %	1.5 - 2.8	2.8
N ₂ vol %	45.9 - 47.3	76.1
H ₂ O vol %	11.5 - 18.4	0
CO ₂ vol %	10.0 - 12.0	0
Ammonia ppmv	500 - 1 500	0 - 3 000
Gross calorific value MJ/m ³	3.6 - 4.1	3.6

Combustor development during Phase 2 involved changing the air distribution with the intention of improving the performance of the combustor. Where these air flow changes involved the reduction or removal of film cooling air along the flame-tube metal surface, the deleted air was added downstream of the dilution holes so that it could not take part in any combustion processes. This approach ensured that the effects of any design change could be clearly assessed, but also meant that any metal temperatures measured could be improved subsequently by the redistribution of this deleted air more effectively.

The first prototype combustor was a lengthened version of that tested during Phase 1. It was lengthened by adding extra cylindrical sections to the end of the combustor to give a length:diameter ratio of 3:1 compared with a ratio of 2:1 for the previous combustor. These cylindrical sections contained cooling holes only, to provide a combined flame-tube and transition duct length representative of the targeted gas turbine.

The second combustor design assessed the effects of increasing the residence time in the secondary zone. The intermediate air holes were deleted and the dilution holes were moved further downstream. This modification took advantage of the increased length of the combustor, allowing longer residence time at near stoichiometric conditions prior to the addition of dilution air, to achieve enhanced CO burnout.

For the third combustor design, the secondary air holes were reduced in size. New intermediate holes were produced at the same position as the dilution holes of the first design. This was intended to provide a substantially increased primary zone residence time, which would be fuel rich at Full Load conditions to reduce NO_x, whilst enhancing CO burn-out at FSNL conditions by reducing the excess air level in the primary zone.

There was some indication during the programme that CO may have been entrained in the primary zone air cooling films. This would cause reduced combustion efficiency as this CO could pass through the combustor, effectively 'by-passing' the combustion zones. It was therefore decided to reduce the amount of cooling air in the primary zone. This was done for the fourth design of combustor. The cooling flows to the first sections were halved, the balance of this air being added down-stream of the dilution holes. In all other respects the air distribution was identical to the previous design variant.

Reduction of the film cooling flows was taken a step further in the fifth combustor design. Film cooling was eliminated totally from the primary zone and an impingement cooling system installed; again this deleted film cooling air was redirected downstream of the dilution holes. In an impingement cooling system, air is directed onto the outside of the combustor metal surface. An impingement cooling system would be the preferred approach for a tubo-annular type combustion system in an ABGC application.

3.2 TURBINE COMBUSTOR TEST PROGRAMME

Each combustor configuration, described above, was assessed in terms of combustor performance at conditions representing turbine Full Load and FSNL. In addition, two of the combustors, the first and the fifth design variants, were tested using natural gas fuel. Tests were carried out at ignition through to FSNL conditions.

Combustion efficiency

The combustion efficiencies of all five design variants were high at the Full Load condition, being consistently greater than 99.98 % at the design air:fuel ratio of 2.29:1.

At the FSNL condition, combustion efficiency decreased with increasing air:fuel ratio. Figure 3 shows the variation of combustion efficiency with air:fuel ratio for all the design variants at the FSNL condition. For the first design, efficiency was disappointing, reducing from 98.5 % at an air:fuel ratio of 3.5:1, to under 93 % at an air:fuel ratio of 4.7:1. For the second design, combustion efficiency was much improved. At an air:fuel ratio of 3.7:1, efficiency was 99.3 %, reducing to 95.2 % at an air:fuel ratio of 6.5:1. This improvement is attributed to the increased residence time in the high temperature secondary zone. For the next two designs, efficiency at the FSNL condition remained constant. This may have been due to the presence of film cooling layers in the primary zone. The cooling air flows were thought to be quenching combustion reactions and possibly carrying unburnt CO through the combustor in the cooling layers. For the fifth design, film cooling was

removed completely in the primary zone, being replaced by an impingement cooling scheme. This helped to improve CO burn-out and thus combustion efficiency. At the FSNL condition, combustion efficiency was excellent, being greater than 99.7 % for a range of air:fuel ratios between 3.0-5.7:1.

NO_x emissions

To simulate fuel-bound nitrogen species, ammonia was added to the syngas in varying amounts. A Conversion Ratio (CR) can be used to assess the proportion of ammonia in the fuel that is converted to NO_x. This ratio is defined as:

$$\text{CR(\%)} = \frac{[\text{Total NO}_x] - [\text{Thermal-NO}_x]}{[\text{NH}_3]} \times \frac{\text{Exhaust Flow}}{\text{Fuel Flow}} \times 100$$

where flows are volumetric and corrected to standard temperature and pressure, and thermal-NO_x is the amount of NO_x produced at the same conditions, but with no ammonia addition. Thus, the conversion ratio may be used for comparison of results more effectively than the absolute NO_x levels. For all the combustor designs, levels of thermal-NO_x were below 6 ppmv (15 % O₂, dry). There was some variation in thermal-NO_x levels between different designs, but these were not significant and were within experimental limits. As experienced during the Phase 1 programme, there was no evidence of prompt-NO_x emissions.

Fuel-NO_x and conversion ratio did vary between combustor designs (Figures 4 and 5). At the 1 500 ppmv of ammonia level, the second design gave a total NO_x emission of about 172 ppmv (15 % O₂, dry) corresponding to a conversion ratio of 64%. The richer and larger primary zone of the third design gave a lower total NO_x emission of 160 ppmv (15 % O₂, dry) corresponding to a conversion ratio of 54 % for the same ammonia level. The fourth and fifth designs utilised reduced film cooling in the primary zone. As well as producing an overall richer primary zone, the local oxygen concentration close to the surface of the combustor was lower. Thus, local NO_x forming zones were reduced, leading to a further improvement in NO_x emissions. At the 1 500 ppmv of ammonia level, total NO_x was 128 ppmv (15 % O₂, dry) corresponding to a conversion ratio of 48 %. At the 500 ppmv of ammonia level (that predicted for an ABGC application with a catalytic ammonia removal system), total NO_x was about 65 ppmv (15 % O₂, dry) with a conversion ratio of about 75 %. 65 ppmv (15 % O₂, dry) therefore represents the minimum NO_x emission that could be achieved for the prototype combustor in an ABGC application. Further modification would therefore be required to meet European legislation likely to be in force by the end of the century.

Exhaust temperature profile

To reduce thermal stress on turbine blades, a uniform combustor outlet temperature profile would be essential. Two temperature distribution factors are defined, the Radial Temperature Distribution Factor (RTDF) and the Overall Temperature Distribution Factor (OTDF):

$$\text{RTDF} = \frac{(\text{Peak Circumferential Temperature} - \text{Tex}) \times 100\%}{(\text{Tex} - \text{Ti})}$$

and

$$\text{OTDF} = \frac{(\text{Peak Temperature} - \text{Tex}) \times 100\%}{(\text{Tex} - \text{Ti})}$$

where:

Tex = Mean Combustor Exit Temperature

Ti = Mean Combustor Inlet Temperature

The RTDF describes the variation of circumferential temperatures that the turbine blades would experience. It is particularly important in the design of the gas turbine as it represents the thermal stress to which the turbine blades would be exposed. A low OTDF is an essential development aim for any gas turbine.

For all combustor designs, the OTDF and RTDF were satisfactory. The OTDF varied from 6.6 to 12.6 % while the RTDF varied from 2.6 to 4.5 %.

Metal temperature tests

For each design variant, thermal paint tests were carried out. It was therefore possible to assess metal temperature distribution at specific conditions. The Full Load test on the fifth design variant is shown as Figure 2. Temperatures in the impingement cooled primary zone were in the range 515 - 814 °C, whilst temperatures in the film cooled secondary/intermediate zones were largely below 860 °C. This test indicated that the impingement cooling system for the primary zone was very effective. The next stages of development of the prototype combustor, in progress currently, will address the issue of reducing these metal temperatures further. As a target, the temperatures downstream of the primary zone should be reduced to around 800 °C, by the better utilisation of film cooling air and/or an extension of the impingement cooling approach beyond the primary zone.

Air pressure loss

For the Phase 2 programme, air-side pressure loss values (air pressure loss as a percentage of air delivery pressure) of typically 2.9 % for the Full Load condition, rising to 6.7 % at the FSNL condition were achieved for the first through to the fourth designs. These values increased to 3.9 % and 8.9 % respectively for the fifth design variant where the impingement cooling approach was adopted. These values compare favourably with 5.0 % and 7.3 % for the targeted gas turbine operating at Full Load and FSNL conditions respectively.

Natural gas tests

Supplementary fuel tests using natural gas were carried out on the first and fifth combustor configurations. Tests were conducted at a range of conditions from ignition through to FSNL. These tests showed a great improvement in combustor performance between the first and fifth designs, both in terms of combustion efficiency and exhaust temperature profiles.

The first design variant achieved a combustion efficiency of 98.6 % to 99.6 % over the range of conditions tested. OTDF and RTDF were 18.5 % and 2.0 % respectively. The RTDF value in particular was encouraging for a first design combustor.

The fifth design variant showed a marked improvement in performance over the first design. For all conditions tested, combustion efficiency was greater than 99.7 % while OTDF and RTDF were 12.9 and 3.0 % respectively. This represents very encouraging performance burning supplementary fuel for a combustor designed and developed specifically for LCV gas combustion.

4 CONCLUSIONS

Utilisation of a gas turbine in the ABGC application would require design changes, particularly with respect to the air compressor and fuel delivery and combustion systems. Regarding the latter turbine component, a prototype combustor design has been achieved, representative of a particular industrial gas turbine combustion system, which represents an encouraging start-point from which to proceed. For this design of combustor burning a low calorific value synthetic fuel gas, combustion efficiency was 99.98 % and greater than 99.70 % at Full Load and FSNL conditions respectively. Exhaust temperature profiles were also good, with the OTDF varying from 6.6 to 12.6 % whilst the RTDF varied from 2.6 to 4.5 %. For a range of ammonia in fuel gas levels

between 500 - 1 500 ppmv, predicted to be delivered to the gas turbine in the ABGC application, NO_x emissions were between 65 ppmv (15 % O₂, dry) and 128 ppmv (15 % O₂, dry) respectively. These emissions correspond to a conversion ratio of 75 % at the lower ammonia level, reducing to about 48 % at the higher ammonia level. Combustor metal temperatures were also acceptable, being largely below 860 °C at the most arduous operating condition of Full Load. There is scope to reduce these temperatures further by the better utilisation of cooling air, possibly by an extension of the impingement cooling approach beyond the primary zone.

Performance burning natural gas as a supplementary fuel was also very encouraging.

5 FURTHER WORK

As indicated in Section 3.2, further development of the prototype combustor would be required to meet the NO_x emissions legislation likely to be in place at the time of operation of the proposed 75 MWe PIP. This further development will be carried out by CTDD at the 125mm combustor diameter scale. In addition, full-scale development at a combustor diameter of 267 mm will be carried out by EGT as a parallel activity. This approach will ensure that a fully characterised combustor design, based closely on the Phase 2 fifth design variant, will be available for the proposed PIP, whilst offering the potential to retrofit an enhanced low-NO_x version at some later date.

5.1 HALF GEOMETRIC SCALE

125 mm diameter combustor tests are being carried out by CTDD using a purpose built Gas Cleaning and Combustion facility. This facility is capable of providing either a coal/biomass derived fuel gas or a synthetic fuel gas, at typically 0.3 kg/s, 400 - 600 °C temperature and 1 - 14 bar_a pressure. Initial tests have been carried out on the fifth design variant from the Phase 2 programme, but with some modifications to the impingement and film cooling provisions. These tests will form the datum from which to proceed to modify the design to achieve enhanced low NO_x performance.

Studies of LCV fuel chemistry will also be made at a fundamental level with particular emphasis on the effect of fuel gas components on the conversion of fuel-bound nitrogen to NO_x. The information produced will be used in conjunction with a computational fluid dynamics based mathematical model of the combustor, to investigate combustor modifications that may be successful in achieving low NO_x emissions. These modifications could then

be carried out to the prototype combustor and tested at the 125 mm diameter scale.

In addition, CTDD's facilities will allow the low-NO_x combustor technology to be tested at conditions applicable to F-series machines (ie those fired at around a 1260 °C turbine inlet temperature).

5.2 FULL GEOMETRIC SCALE

Prior to application of the prototype combustor design in the targeted gas turbine for the PIP, rigorous testing at the full geometric scale of 267 mm combustor diameter will be undertaken. These tests are considered necessary to remove the uncertainty of scale-up on combustor performance and to extend the characterisation of the prototype combustor carried out at half geometric scale. Substantial new facilities, to include a synthetic fuel supply system, are being installed and tests will be carried out to identify design weaknesses requiring further detailed consideration. The performance criteria to be investigated will include:

- Ability to ignite and increase to FSNL using supplementary fuel
- Ability to operate smoothly and efficiently across the full load range using syngas
- Metal temperature and exhaust gas temperature profiles
- Measurement of exhaust emission levels over the operating range
- Carbon deposition and smoke emissions
- Combustion generated dynamic pressure pulsations
- Potential to decrease turbine load without causing 'flame-out'.

ACKNOWLEDGEMENTS

The studies described in this paper form part of the CCPGG initiative to promote the ABGC technology. Funding is being provided by the industrial consortium that comprise the CCPGG, the UK DTI, the European Union, and the European Coal and Steel Community. The contributions of colleagues at CTDD and EGT, and Mr A Wheatley and Dr A Al-Shaikhly of AIT are gratefully acknowledged. Any views expressed are those of the authors and not necessarily those of CTDD, EGT, AIT, or those of the supporting organisations.

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Temperature range	Colour code
Below 515 °C	B
515 - 542 °C	C
542 - 695 °C	D
695 - 814 °C	E
814 - 860 °C	F
Above 860 °C	G

Figure 2. Combustor flame-tube showing metal temperatures at full load.

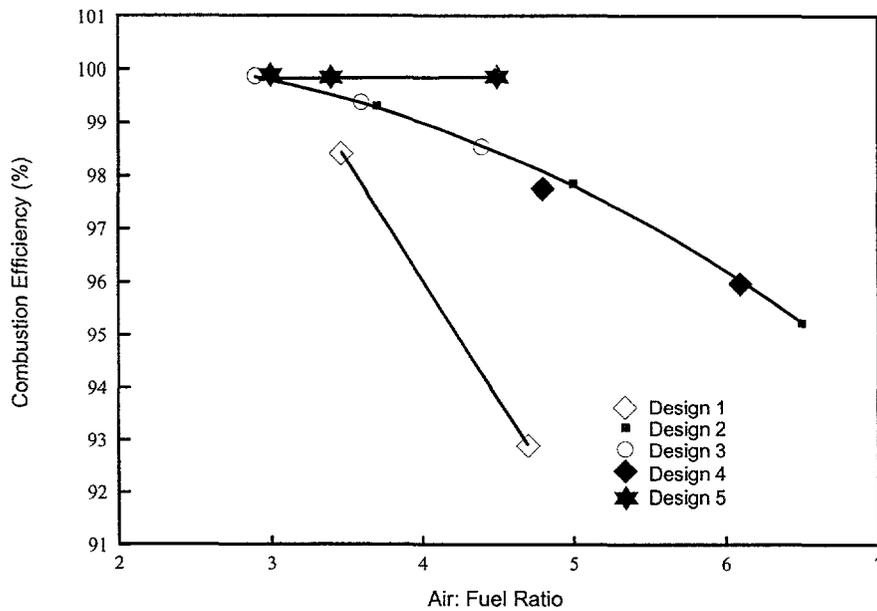


Figure 3. Effect of air:fuel ratio on FSNL combustion efficiency.

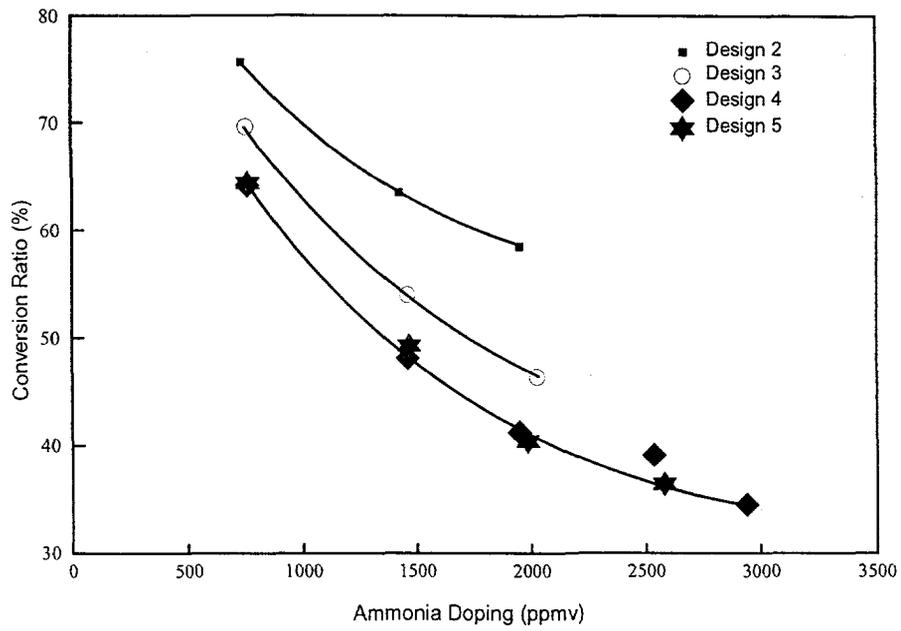


Figure 4. Effect of ammonia doping on conversion ratio.

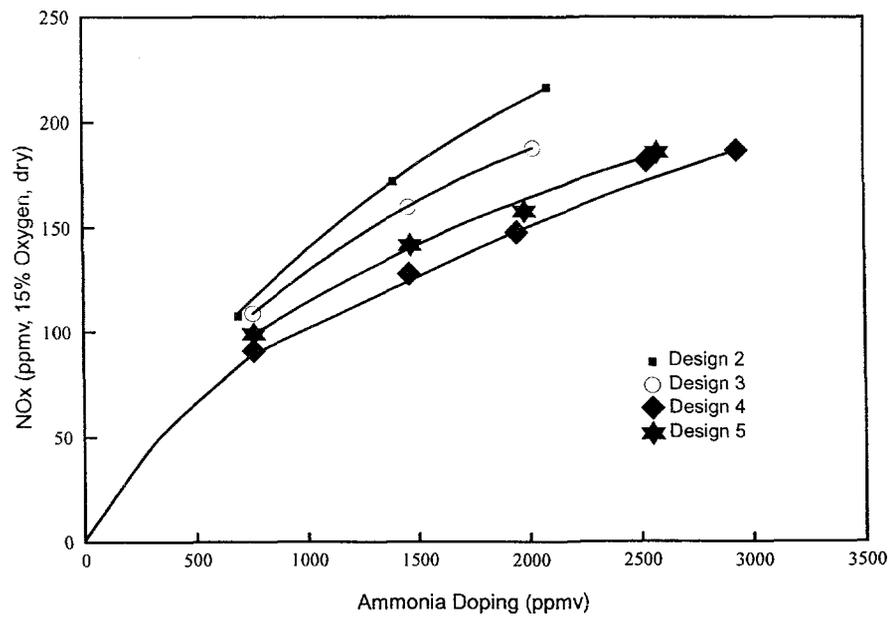


Figure 5. Effect of ammonia doping on corrected NO_x.

FIXED BED GASIFICATION OF SOLID BIOMASS FUELS

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1 FIXED BED GASIFICATION

Gasification of different solid fuels in fixed bed is an old technology used before the period of oil and natural gas in glass and metallurgical furnaces and several other applications, where direct burning of solid fuels was not applicable.

As a result of the oil crisis in the 1970s, development of fixed bed gasification was initiated in Finland. Co-current and counter-current gasifiers were developed at the Technical Research Centre of Finland. Very soon it was found, that in the effect range of 1 - 10 MW only counter-current gasification could be applied for technical reasons.

The initial aim of the development work was to replace oil in applications, where solid indigenous fuels could not be directly used because of contamination, need of accurate control, etc. The technology reported for coal gasification was applied for wood chips and sod peat.

The first commercial result was a fixed-bed gasifier producing raw gas that contained an abundance of dust and especially tar (Figure 1). This gasifier plus a gas burner also developed were applied for burning indigenous Finnish fuels in an inexpensive oil boiler, instead of using a moving-grate boiler or fluidized-bed boiler. The development work was carried out in 1980 - 1982. In this period, automatic unmanned operation of district heating plants fired with indigenous solid fuels was on one side the very condition for the economy of heating plants in the effect range 1 - 10 MW and, on the other side, unmanned operation had proved to be problematic in conventional moving-grate boilers or fluidized-bed boilers. Unmanned operation was easy and reliable with the counter-current gas producer.

In total about 10 commercial plants were commissioned in Finland and in Sweden by the year 1986. Since then, due to a change in the oil price and also a political change in Finland no further gasification heating plants have been constructed. The concept of gasification heating plant is shown in Figure 2.

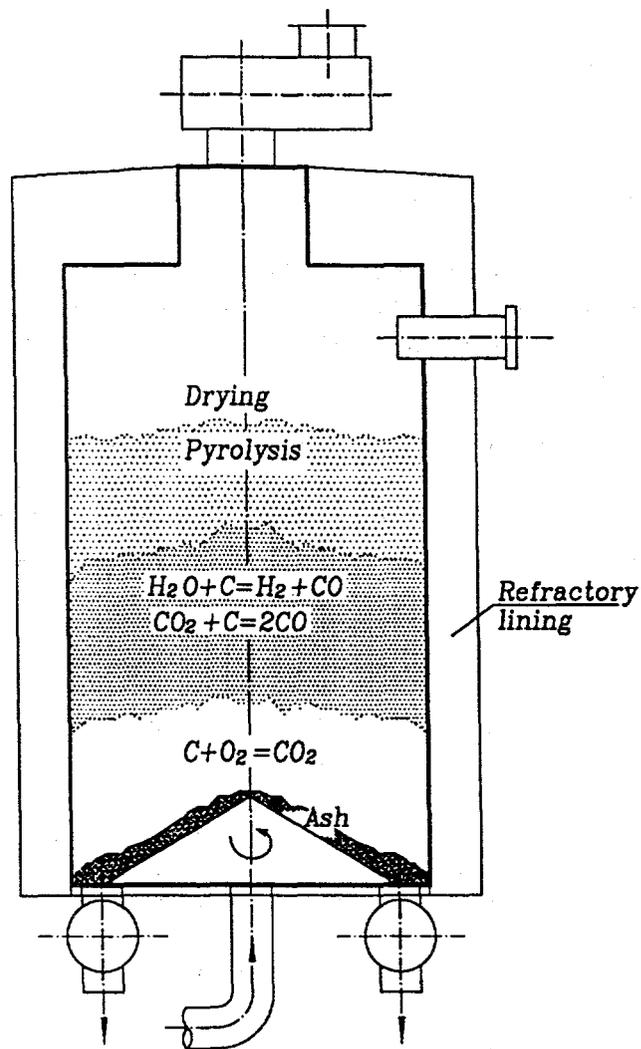


Figure 1. The first fixed-bed gasifier producing raw gas.

Since the year 1993 Condens Oy has had fixed-bed gasification in its programme. The main target is to develop gas cleaning for the needs of motor use and for small-scale local distribution of gas, while some conventional gasification heating plants will no doubt also be commissioned in the near future.

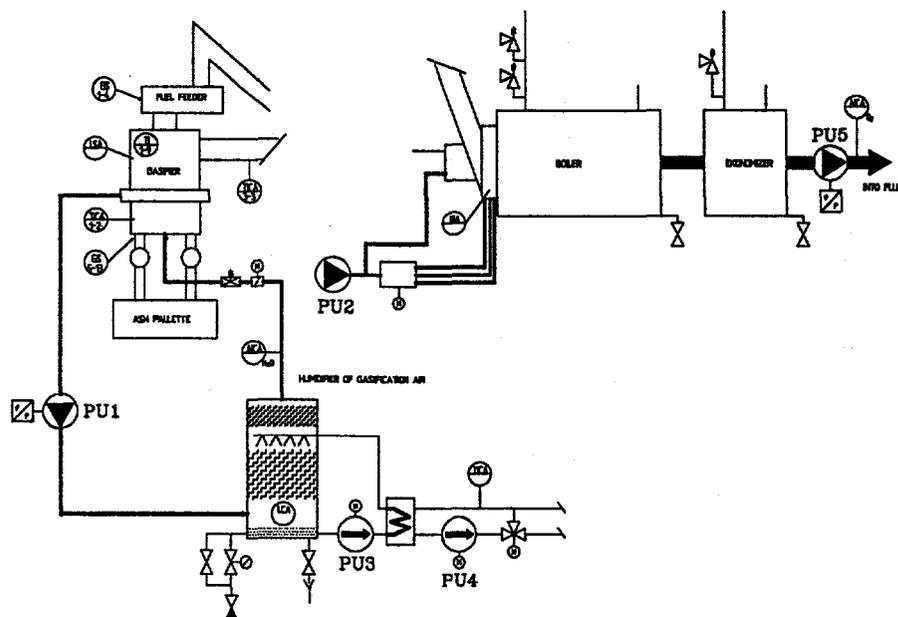


Figure 2. The concept of the gasification heating plant.

2 CHEMICAL PROCESSES IN THE GASIFICATION PROCESS

Chemistry and thermodynamics of gasification are basically well-known and simple. If the process is seen from the viewpoint of a lump of fuel fed into the gasifier the sequence of processes can be described somewhat simplified as follows:

- Drying; the lump of fuel is taken into a hot atmosphere initiating immediate melting and vaporising of fuel moisture
- Pyrolysis; the volatile matter of the fuel is released in the temperature range 200 - 600 °C and charcoal remains.
- At temperatures above 800 °C charcoal reacts with water vapour and carbon dioxide of the gas atmosphere, producing carbon monoxide and hydrogen.
- Should oxygen still be present, carbon monoxide and hydrogen react again into carbon dioxide and water vapour.

The reaction sequence depends on the process type; in counter-current processes all processes are naturally separated into different reaction zones in the gas producer shaft; in co-current gasification all processes take place

more or less simultaneously. Therefore, counter-current gasification gives a more effective carbon conversion than co-current.

3 STATE-OF-THE-ART OF FIXED-BED COUNTER-CURRENT GASIFICATION

The gasifiers built in 1981 - 1986 have since then been in commercial operation. The technical and economical operation data on the gasification heating plants is very convincing:

- availability of the plants 96 - 98 %
- minimum number of operational and service persons, as a rule to guarantee the operation there are only three persons responsible for continuous heat production in a plant over 24 hours a day, 8 000 hours yearly
- good efficiency, reported efficiencies around 90 %, on annual basis efficiencies of 85 - 88 % have been reported
- the control range of gasification heating plants overcomes all other reported data; for 5 MW nominal effect a control range of 500 kW to 8 MW *in continuous unattended operation* is normal. This is more than even an oil boiler can do in continuous operation
- stop-and-go operation with a gasification heating plant is easy; the respond to effect changes is very quick
- very low maintenance cost in comparison to other boiler types, especially to the moving-grate boiler.

According to the economic results of small district heating companies in Finland, the gasification heating plants are among the most profitable ones in the very common size class of 5 MW.

Possible fuels are different biomasses or peat with a moisture content of max 45 % of the total weight. Fuel pellets and other very dry fuels can also be used. The fuels must form a bed penetrable by gas, therefore the average grain size must be at least 10 - 20 mm.

4 POTENTIAL APPLICATIONS FOR THE ESTABLISHED COUNTER-CURRENT GASIFIER

The most likely commercial applications are those from which experiences have already been obtained:

- Typical thermal effect 3 - 10 MW

- New gasification heating plants. Especially, when the heating system includes only one biomass fuel boiler, the large control range results in a higher degree of oil or natural gas replacement than any other single burning device. This is of crucial importance when the demand for heat effect varies substantially, like in the case of district heating
- Gasifier is a quick and handy way of converting existing oil or natural gas fired plants into burning of biomass fuels
- Hot gas generation. The gasifier has been applied for hot gas generation for flue gas dryers in a particle board factory in Sweden. Similar applications could be used for different rotating kilns, etc.

New applications are expected to be commercialised in the near future:

- Gas cleaning enables the use of lean gas in local short distribution networks, see Figure 3.
- Several smaller boilers or motors can be connected to the network.

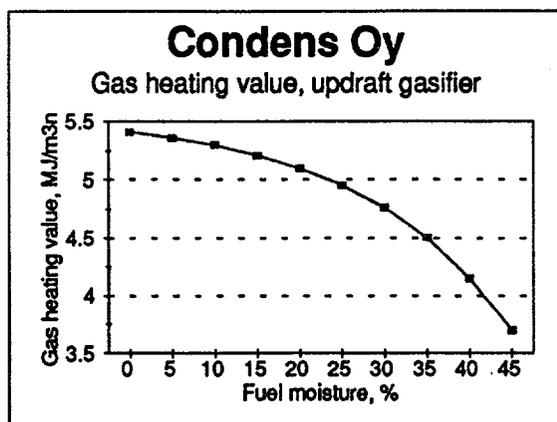


Figure 3. Gas heating value, updraft gasifier.

5 CO-CURRENT GASIFICATION

Traditional co-current gasifiers have been developed for mobile motor use. The main problem with these gasifiers is that they are rather demanding for the grain size and quality of the fuel.

Therefore, a smaller gasification unit, less sensitive to fuel quality, for effect range 100 kW - 1 MW, is under development. The work was initiated with respect to the motor use of the gas. The final aim is simultaneous production

of heat and electricity. The estimates of plant economy indicate a reasonable economy at domestic electricity price (about FIM 0.40/kWh), assuming that the fuel (biomass, sorted waste) cost be extremely low.

In smaller scale the plant economy does not allow an extensive gas cleaning plant. Therefore, co-current gasification can be applied as it produces almost tarfree gas. The main disadvantages of co-current gasification are lower conversion of carbon into gas, high gas temperature and problematic scale-up into effects over 800 kW - 1 MW.

6 GAS CLEANING

In co-current gasification the gas cleaning step is rather simple: the gas is cooled down and filtered. The products from the filter can be fed to the gasifier with the fuel.

Alternatives for cleaning the tar-rich updraft gasifier gas are thermal cracking or wet scrubbing. In wet cleaning, the tar and dust separated are fed back into the hot zone of the gas producer and destructed there. In order to avoid environmental problems with phenol water, the fuel has to be rather dry; moisture contents of 5 - 15 % are anticipated.

7 SUMMARY

Fixed bed biomass gasifiers are feasible in the effect range of 100 kW - 10 MW. Co-current gasification is available only up to 1 MW for technical reasons.

Counter-current gasifiers have been used in Finland and Sweden for 10 years in gasification heating plants, which are a combination of a gasifier and an oil boiler. The plants have proved to have a wide control range, flexible and uncomplicated unmanned operation and an excellent reliability. Counter-current gasifiers can be applied for new heating plants or for converting existing oil and natural gas boilers into using solid fuels.

There is a new process development underway, aiming at motor use of the producer gas. The development work involves a new, more flexible co-current gasifier and a cleaning step for the counter-current producer gas.

DEVELOPMENT OF CATALYTIC GAS CLEANING IN BIOMASS GASIFICATION

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Abstract

Gasification gas containing dust can be efficiently purified from tars and ammonia with a nickel monolith catalyst. Temperatures of >900 °C and a residence time of about 1 s (SV 2 500 l/h) were needed at 5 bar pressure to achieve complete tar decomposition and 80 % ammonia conversion. Catalyst deactivation was not observed during test runs of 100 h. At lower pressures dolomites and limestones can also be applied for tar removal at about 900 °C temperatures.

1 INTRODUCTION

Power production from biomass and peat by gasification is a focus of intense research and development in Finland. In the power range of 50 - 150 MW_e the economically most interesting alternative is Simplified Integrated Gasification Combined Cycle (IGCC) process. Most process concepts are based on fluidised-bed air gasification and hot gas cleaning (particulate removal) followed by a gas turbine with a steam turbine connected to it to recover the energy of exhaust gases. On a smaller scale, biomass-derived power can be generated with a combination of a gasifier and a diesel engine. This process can be based on fluidised bed or updraft gasification at atmospheric pressure followed by a (hot) gas cleaning unit and a set of diesel engines for power generation.

However, the gasification gas contains, in addition to the main gas components (H_2 , CO, CH_4 , CO_2 , H_2O , N_2), also impurities like tars, ammonia and dust. The tars are harmful because they can easily block up particulate filters or other downstream units like engine suction inlets by condensing or by polymerising to sootlike deposits. On the other hand, ammonia is a source of NO_x emission when the gas is burned.

These problems can be avoided by using a catalytic gas purification unit for decomposing tars and ammonia. The operating temperature of this unit

applications). The gas cleaning unit should also tolerate the high particulate content of gasification gas. Various catalytic gas cleaning options have been studied at VTT using laboratory and PDU-scale facilities [1 - 5]. These options include the use of cheap bulk materials such as limestones and dolomites in a separate catalyst reactor as well as a specially designed honeycomb catalyst reactor. In this presentation, an overall view of these studies is given.

2 EXPERIMENTAL

A laboratory-scale atmospheric testing unit, comprising two tube reactor (i.d. 25 mm) systems operated in parallel, was used for catalyst screening studies. A slip-stream (dust-free) from an industrial-scale updraft gasifier and from a PDU fluidised-bed gasifier were used as feeds. Compositions typical of these experiments are presented in Table 1. The catalyst volume of the reactor was 50 cm³, the residence time of gas ranged 0.1 - 1.5 s and the temperature range was 700 - 1 000 °C. The particle size of catalyst ranged 2 - 4 mm in these tests.

For studies of catalyst deactivation and hot gas cleaning chemistry, a laboratory-scale pressurised tube reactor system was used. It was fed by a simulated mixture of gasification gas (N₂, CO, CO₂, CH₄, H₂, H₂O, NH₃, H₂S, toluene as tar model) made from bottle gases. The reactor was a quartz tube (i.d. 12 mm) having a 5 cm³ sample volume. The pressure range studies was 5 - 20 bar and the temperature range 700 - 1 000 °C at 0.5 residence time. The particle size of catalyst was 0.3 - 0.35 mm.

The bulk material catalysts studied were dolomites, limestones and iron sinter. The commercial catalysts and catalyst carriers studied were nickel catalysts (Ni/Al₂O₃ and Ni on refractory material, alumina and alumina silicate. Silicon carbide and alpha-alumina were used as reference materials. The both fixed-bed tube reactor systems, catalyst materials and analytical methods are described in more detail in [1 - 8].

A bench-scale pressurised reactor was used for monolith catalyst testing using a slip-stream (dust containing) gas from the PDU fluid-bed gasifier as feed (Figure 1). The reactor comprised a pressure vessel, a three-zone furnace and the actual reactor tube, within which the gas preheater, the combustion chamber and the monolith catalyst were sited. Ceramic monoliths (Ni/Al₂O₃) of 300 mm x 50 mm x 50 mm having square channels were used in the tests. Details of the catalyst are of proprietary information. Two such monoliths were placed on top of each others. Due to sealing of the elements a cross-sectional area of 31 x 31 mm was in use. The inside temperatures of

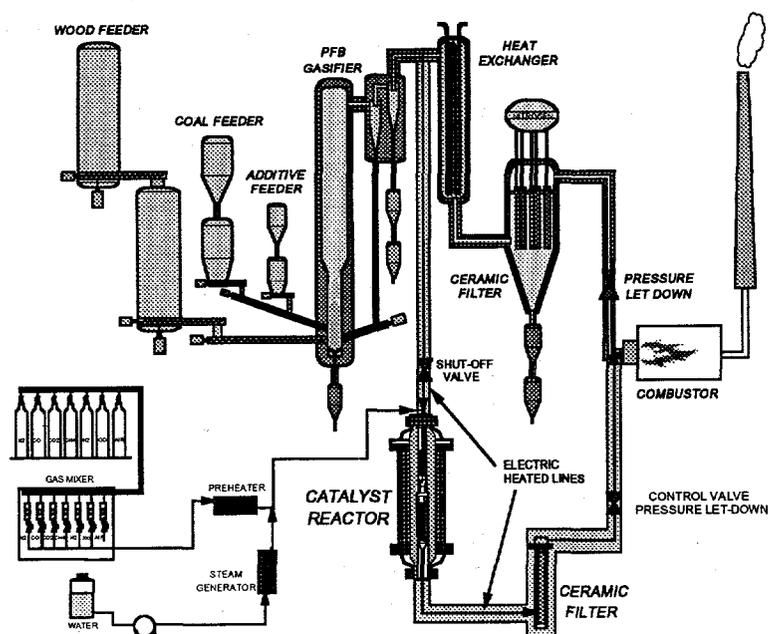


Figure 1. Pressurised fluidised-bed gasifier test rig and monolith catalyst test reactor. Technical data: Gasifier: pressure 3 - 10 bar, temperature 800 - 1 100 °C, capacity 100 - 400 kW. Gas cleaning: cyclones, ceramic filters, by-pass catalyst reactor. Catalyst reactor: max. pressure 10 bar, max. temperature 1 000 °C, max. gas flow 2.6 m³/h.

the monoliths were measured by three thermocouples placed in the centre channels near the inlet, in the middle and at the bottom part of the monolith assembly. The temperature values presented in this study are the mean of these three thermocouple readings.

Various biomass fuels were used as gasifier feedstocks in the monolith catalyst tests: forest residue wood, bark, wood chips and peat. These yielded feed gases of different compositions (a typical gas from peat is presented in Table 2) that contained 1 - 7 g/m³ tar, 600 - 6 000 ppmv NH₂, 30 - 250 ppmv H₂S and 0.6 - 6 g/m³ dust. The temperature range studied was 880 - 960 °C and pressure 5 bar. The total gas flow rate (dry) was varied in the range of 4.5 - 32 dm³/min resulting in a residence time range of 0.5 - 2 s (space velocity 1 000 - 5 000 l/h). Three test runs of 45, 95 and 98 h were carried out. Sampling and analytical methods have been described elsewhere [1].

Before the first two test run weeks the catalysts were pre-reduced in situ with an H₂/N₂ mixture. The reduction procedure was as follows: heating rate 50 °C/h, total gas flow 10 l/min, heating to 200 °C to 700 °C in the N₂/N₂ mixture (20 % H₂), from 700 °C to the test temperature again in N₂ flow. In the last test run, reduction directly in the gasification gas was applied. The catalyst was heated up in N₂ flow (heating rate 50 °C/h) to the test temperature (900 °C) after which it was exposed directly to gasification gas.

3 RESULTS AND DISCUSSION

The catalyst screening tests performed with the laboratory-scale fixed-bed reactors in constant conditions (900 °C, 1 bar, residence time 0.3 s) with sample gas feeds from the updraft gasifier and from the PDU fluid-bed gasifier indicated that carbonate rocks and nickel catalysts were efficient in tar decomposition (Table 1) [1, 2]. The tar from the updraft gasifier was thermally fairly unstable unlike the tar from the fluid-bed gasifier and thus decomposed easily also with the inert reference material (SiC). Ammonia decomposition was facilitated with nickel catalysts and with updraft gas also with iron-containing materials (Table 1) [3, 4]. The reason for the different conversions with the gases tested can most likely be attributed to differences in gas and tar composition (Table 2).

Table 1. Conversion of tar and ammonia with the tested materials. Laboratory-scale fixed-bed tube reactor, temperature 900 °C, residence time 0.2 - 0.3 s, pressure 1 bar. Feed gas from updraft and fluid-bed gasifiers.

	Conversion %			
	Updraft		Fluidised bed	
	Tar	NH ₃	Tar	NH ₃
SiC	77	0	4	44
Alumina-silicate	88	N.A.	N.A.	N.A.
Iron sinter	91	87	N.A.	N.A.
Dolomite	100	0	99	53
Iron-containing dolomite	100	75	99	53
Nickel catalyst	100	100	100	100

N.A. = not analysed

With the most active catalysts, gas was almost equilibrated and thus the yields of combustible gas components (CO, H₂) was increased and those of oxidising components (H₂O, CO₂) were decreased (Table 2) [1, 2]. This as well as laboratory experiments with individual gas components suggested that the hydrocarbons were decomposed via steam or CO₂ (dry) reforming reactions producing CO and H₂ with both nickel catalysts and with dolomites and limestones [8]. In addition, a water-gas shift reaction took place

Table 2. Gas composition at the inlet and at the outlet of the catalyst reactor with nickel catalyst ($\text{Ni}/\text{Al}_2\text{O}_3$) and calculated equilibrium composition. Updraft and fluid-bed gasifier gases were used as feed, feedstock was peat. Laboratory-scale fixed-bed tube reactor, temperature 900 - 910 °C, residence time 0.2 - 0.3 s, pressure 1 bar.

Component	Gas from updraft gasifier			Gas from fluid-bed gasifier		
	inlet	outlet	equilibr.	inlet	outlet	equilibr.
CO, vol%	17.2	20.8	21.4	9.8	17.2	18.0
CO ₂ , vol%	8.0	8.7	8.6	14.6	9.6	9.2
CH ₄ , vol%	1.6	<0.1	<0.1	3.6	0.3	<0.1
LHC, vol%	0.4	0	0	0.5	0	0
H ₂ , vol%	13.2	27.0	27.4	9.8	18.6	18.3
H ₂ O*, vol%	25.9	14.4	13.9	13.7	10.9	11.5
N ₂ , vol%	32.6	29.0	28.7	47.4	43.3	43.1
NH ₃ , ppmv	1 700	<50	16	4 100	12	11
Tar, ppmv	9 800	<10	0	1 400	<10	0

* calculated from material balance; LHC = light hydrocarbons ($\text{C}_2 - \text{C}_3$)

with these materials [9 - 11]. Ammonia was most likely decomposed with the metal catalysts (nickel catalysts and iron material) via the reverse of ammonia synthesis reaction [12].

Screening tests demonstrated that nickel catalysts are efficient and technically the most promising gas cleaning catalysts for an IGCC process. Cracking temperatures around 900 °C are needed to achieve effective decomposition of both tars and ammonia. At temperatures below 750 °C they were deactivated almost completely. Preliminary extended time tests of 100 - 200 h were performed with the fixed-bed reactors (900 °C, 1 bar, 0.2 - 0.3 s residence time), which indicated that no deactivation of the catalysts took place in the conditions applied [2, 4].

Dolomites and limestones were efficient tar-decomposing catalysts if they were calcined [1 - 3]. In atmospheric gasification conditions, calcination takes place at about 800 °C, thus enabling their use above this temperature, for example, in gasifier-diesel motor applications. However, in the IGCC process conditions (pressure 20 - 25 bar) the partial pressure of CO₂ in the gas is sufficiently high (about 3 bar) to prevent calcination even at 900 °C. Consequently, experiments in these conditions (900 °C, 20 bar, 0.5 s residence time, N₂/CO₂/H₂O atmosphere) with limestones and dolomites resulted in almost complete deactivation of these materials. Temperatures in the range of 950 - 1 000 °C were required at 20 bar pressure to keep them in activated state in the gasification gas [6].

Biomass-derived gasification gas contains about 100 ppm H₂S that is a well-known poison for nickel catalysts. In laboratory experiments with

simulated gasification gas, deactivation of catalysts was studied in the H_2S range of 0 - 500 ppmv, in the temperature range of 800 - 950 °C and at 5 and 20 bar pressures. High pressure and low temperature seemed to enhance deactivation of nickel catalysts. This deactivation could, however, be compensated by using high temperatures (900 - 950 °C). The ammonia-decomposing function of the catalyst was more susceptible to poisoning by H_2S than the tar-decomposing function [7].

With the novel monolith catalyst reactor fed with dusty fluid-bed gasification gas, complete tar decomposition and about 80 % ammonia conversion were achieved at 900 °C, with 1 s residence time (SV 2 000 l/h) and at 5 bar pressure. An increase in temperature increased ammonia conversion, whereas an increase in residence time seemed not affect so much (Figs 2 and 3). Hence, ammonia was a more sensitive indicator of catalyst performance than the hydrocarbons. Similarly to the tests with the fixed-bed laboratory reactors, an almost equilibrium gas composition was achieved at the highest test temperatures.

Composition of gasification gas was dependent on feedstock. The greatest differences were found in the contents of tar, ammonia, H_2S and water (Table 3). However, catalytically treated gas was almost equilibrated in the conditions applied, and hence, the residual amounts of ammonia and tar in the outlet gas were about the same regardless of the feedstock.

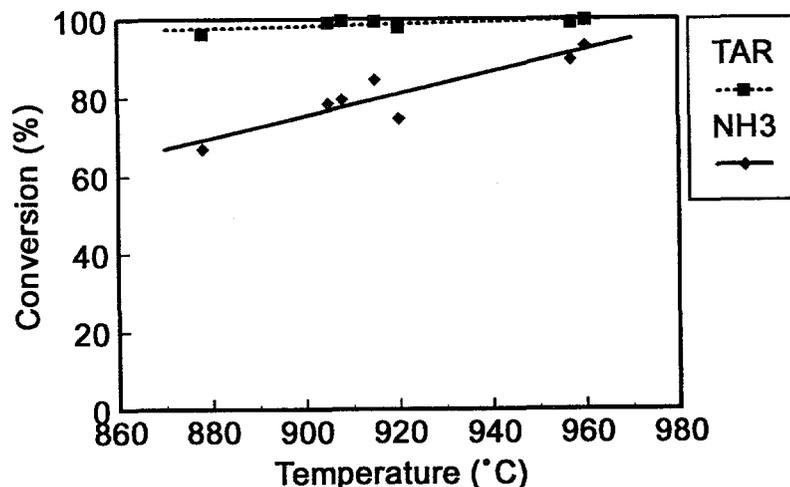


Fig. 2. Effect of temperature on tar and ammonia conversion with the monolith catalyst. Pressure 5 bar.

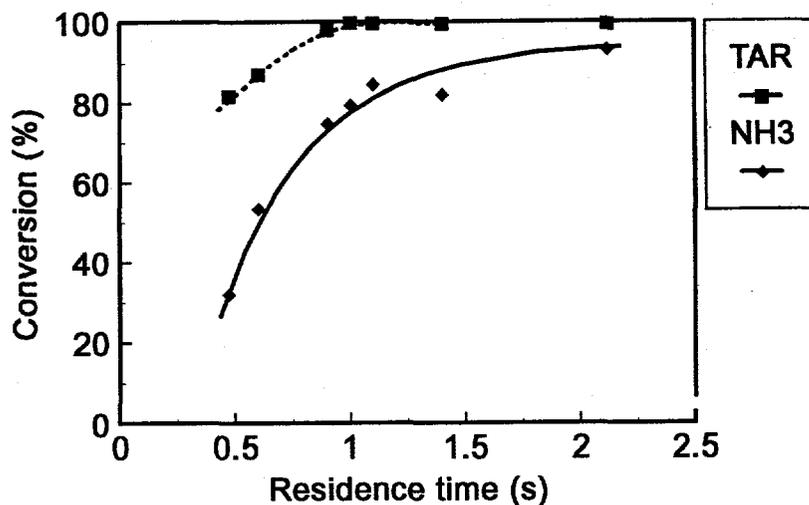


Fig. 3. Effect of residence time on tar and ammonia conversion with the monolith catalyst. Pressure 5 bar.

Table 3. Gas composition at the inlet and outlet of the monolith catalyst reactor for the fuels tested. Pressure 5 bar, temperature 910 - 920 °C, residence time 0.9 - 1.2 s.

Component	Gasifier fuel and content of gas component, vol%									
	wood chips		eucalyptus chips		forest waste wood		bark		peat	
	in	out	in	out	in	out	in	out	in	out
CO	12.6	18.1	13.5	19.2	11	16	11.4	16.4	8.6	13
CO ₂	10.8	7.9	12.5	8.5	12.3	9.5	12.4	9.6	12.8	10.3
CH ₄	3.4	0.2	3.8	0.3	3.2	0.6	3	0.5	2.3	0.4
H ₂	8.9	17.1	10.1	17.2	8.5	14.7	8.8	14.3	9.1	15.2
H ₂ O*	19.3	15.5	11.6	10.1	12.7	10.6	11.4	9.6	17.5	14.5
N ₂	44.7	41.3	48.3	44.7	51.9	48.6	52.8	49.7	49.4	46.6
NH ₃ ,ppm	560	140	510	140	1 900	290	1 200	230	2 700	170
tar, ppm	1 500	<10	1 600	<10	1 200	<10	1 000	<10	880	<10
H ₂ S, ppm	30	30*	30	20*	80	70*	90	80*	170	160*

* calculated from material balance

The use of a monolith-type reactor seems to be the most promising way of avoiding plugging problems typical of fixed or moving-bed reactors with high particulate loadings. During the test runs, the dust content of the gas ranged 0.6 - 6 g/m³, and the H₂S content was mainly <100 ppmv. No cata-

lyst blocking, carbon deposition or catalyst deactivation was observed during the slip-stream test runs of about 100 h in such a reactor. However, longer-term deactivation tests (>1 000 h) are needed to demonstrate the suitability of this type of process for IGCC or other gasification process applications.

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Modern biomass combustion technology

BIOMASS POTENTIAL

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Abstract

Biomass resources of the industrialised countries are enormous, if only a small fraction of set-aside fields were used for energy crops. Forest resources could also be utilised more efficiently than at present for large-scale energy production. The energy content of the annual net growth of the total wood biomass is estimated to be 180 million toe in Europe without the former USSR, and about 50 million toe of that in the EC area, in 1990.

Presently, the harvesting methods of forest biomass for energy production are not yet generally competitive. Among the most promising methods are integrated harvesting methods, which supply both raw material to the industry and wood fuel for energy production. Several new methods for separate harvesting of energy wood are being developed in many countries.

1 FOREST RESOURCES

The amount of forest biomass has increased in the most European countries during the last decades. The total growing stock of the exploitable forest land in Europe without the former USSR in 1990 was 18 500 million m³, which is 16 % higher than the estimation for year 1980 and 41 % higher than that for year 1950. The most significant change during years 1980 - 1990 occurred in the EC area, where the increase on net increment of the growing stock was estimated at about 30 %, although a part of the increase is assumed to result from more accurate statistical data. The energy content of the net growth of the total wood biomass is estimated to be 180 million toe in Europe, and 50 million toe of that in the EC area, in 1990, using the approximate distribution of stemwood and other parts of the tree.

Harvesting after the 1950s has been clearly smaller than the growth of forests and the forest area has stayed nearly unchanged. The growing stock is, however, possible to maintain in the future only by means of silvicultural practices, such as thinnings (Figure 1).

The opportunities to increase the use of wood are significant in many European countries, and not only in the northern area. Wood is an important raw material for sawmills, paper and pulp mills (Figure 2), but large quantities

of tree biomass are wasted if the stemwood is only utilised. Stemwood, including 10 - 15 % bark, represents 60 - 65 % of the total biomass of typical softwood. Branches make 10 - 15 %, stump 5 - 10 %, top 5 % and roots 10 - 20 %. A certain amount of harvest residues is necessary to be left on the ground in order to maintain the nutrient balance. However, large quantities of residual biomass could be utilised in energy production, e.g., by means of new cost-effective integrated harvesting methods being developed.

Forest biomass is also a significant storage of carbon, which can be utilised in two different ways: forests can extract from the atmosphere large amounts of CO₂ and forest biomass can substitute for fossil fuels. When the estimated annual fluxes of the net change of living biomass and energy-related CO₂ emissions are compared in different European countries, the potential of the forest sector to affect the net national emissions of CO₂ varies very much due to the variation of the relative shares of forest areas.

In the late 1980s, the share of the net increase of carbon in living biomass of forests was 30 - 80 % of the CO₂ emissions from fossil fuels in the Nordic countries. Afforestation possibilities are, however, greatest in central and southern Europe and possibilities of increasing carbon sequestration of the forests exist in every country.

2 POWER PLANT TECHNOLOGY FOR BIOMASS

In Finland, the annual growth of forest biomass corresponds to nearly 80 % of the total annual energy consumption. The use of wood for energy in 1993 was 4.3 million toe, which consists to a great extent of black liquor (2.4 million toe) and other by-products or waste wood of the forest industry (1.1 million toe). The energy content of potential forest residues (51 million m³/a), which are not utilised, has been estimated to be about 10 million toe/a.

The total installed power generation capacity, where wood and wood-derived fuels are important, is about 1 300 MW_e in the Finnish paper and pulp industry and in the wood products industry over 50 MW_e. The major share of electricity is generated by cogeneration plants.

2.1 FBC BOILERS

New solid fuel boilers are based on fluidised-bed combustion (FBC) technology, which allows multi-fuel use (chips, bark, waste sludge, peat, coal, oil, natural gas) and wide variations of fuel particle size and moisture. The

installed capacity of fluidised-bed boilers has reached 1 200 MW_{th} in the Finnish industry. Typical power-to-heat ratios are relatively low, 0.3 - 0.3 within the industry, as steam values are moderate, 65 - 110 bar/480 - 530 °C.

The conversion of several grate and pulverised fuel fired boilers to FBC boilers during the last ten years has made it possible to use a wider variety of biomass in many boilers. The largest bubbling fluidised-bed boiler, 270 MW_{th} fired by peat, biomass and coal, has been constructed in Jyväskylä (Tampella Power Inc.), where the pulverised fuel fired boiler was converted to FBC. The use of wood fuels of this boiler corresponded to 11 % (nearly 200 GWh) of the total fuel consumption in 1994.

2.2 SMALL-SCALE COGENERATION

Six smaller-scale cogeneration power plants (<10 MW_e), which produce electricity, district heat to the municipality and/or process heat to the industry have been built during the recent years in Finland (Table 1). Main fuels are peat, and wood waste and chips. Power-to-heat ratios are about 0.35 when steam pressure is 60 bar and temperature 510 °C.

Table 1. New small cogeneration power plants in Finland.

Plant	Take-over	Capacity power/heat MW/MW	Steam values °C/bar	Type of boiler	Investment cost million ECU
Pieksämäki	1992	9/25	510/60	BFBC	9.5
Kankaanpää	1992	6/16	510/60	BFBC	8.0
Kuhmo	1992	5/13	49/81	CFBC	12.3*
Ylivieska	1993	5/15	510/60	BFBC	8.7
Kuusamo	1993	6/17	510/61	BFBC	8.0
Lieksa	1994	8/22	510/61	CFBC	11.3*

**demonstration of new boiler technologies*

Kuhmo: Ahlstrom Pyroflow Compact

Lieksa: Tampella Power, CYMIC

The smallest capacity level with a conventional coupling of a boiler and a steam turbine, which has proved to be economic as far, is 5 MW_e with 15 - 20 % investment subsidies. The cost level of the plants has decreased considerably during the last few years. The cogeneration power plant of Pieksämäki is an excellent example of the positive development of costs (Table 2). As the main reasons, moderate operating values and design requirements compared to those of large power plants, and simplified construction of boilers and buildings can be mentioned.

Table 2. Cost estimates on the Pieksämäki power plant (cost level = year 1991).

Year of estimate	1979	1987	1989	1990	1991
Power/heat, MW/MW _h	10/23	15/35	10/21	7/23	9/25
Total costs, million ECU	33	31	25	11	10
Specific costs, MECU/MW _e	3.3	2.1	2.5	1.6	1.1
Power, ECU/MW _h	5.3	33	38	20	15

2.3 NEW TECHNOLOGIES

Several new technologies are being developed for increasing the utilisation of biomass for power generation. According to the Finnish experience, power production in small cogeneration plants (>5 MW_e) based on the conventional steam boiler and turbine could be applied immediately in a cost effective way. The cogeneration potential of the Finnish industry and district heating has been utilised almost completely and new possibilities for cogeneration with conventional technology do not exist. In order to increase power production at cogeneration plants, it would be important to develop processes of higher power-to-heat ratios. Combined-cycle processes are one solution to this, as well as higher steam values with conventional processes.

3 CONCLUSIONS

The European exploitable forest resources are large and the utilisation of forest biomass for large-scale energy production could be increased considerably, up to millions of toe per year, in many countries according to the principles of sustainable development. The efficient and competitive utilisation of wood fuels would require further development of harvesting and supply systems.

Small-scale cogeneration plants are presently built mainly based on FBC boilers and steam turbines. The construction of FBC boilers will be simplified and the plants of the capacity range down to 3 - 5 MW_e will be competitive. The new concepts for power production under development will offer, in particular, higher efficiencies and power-to-heat ratios for cogeneration.

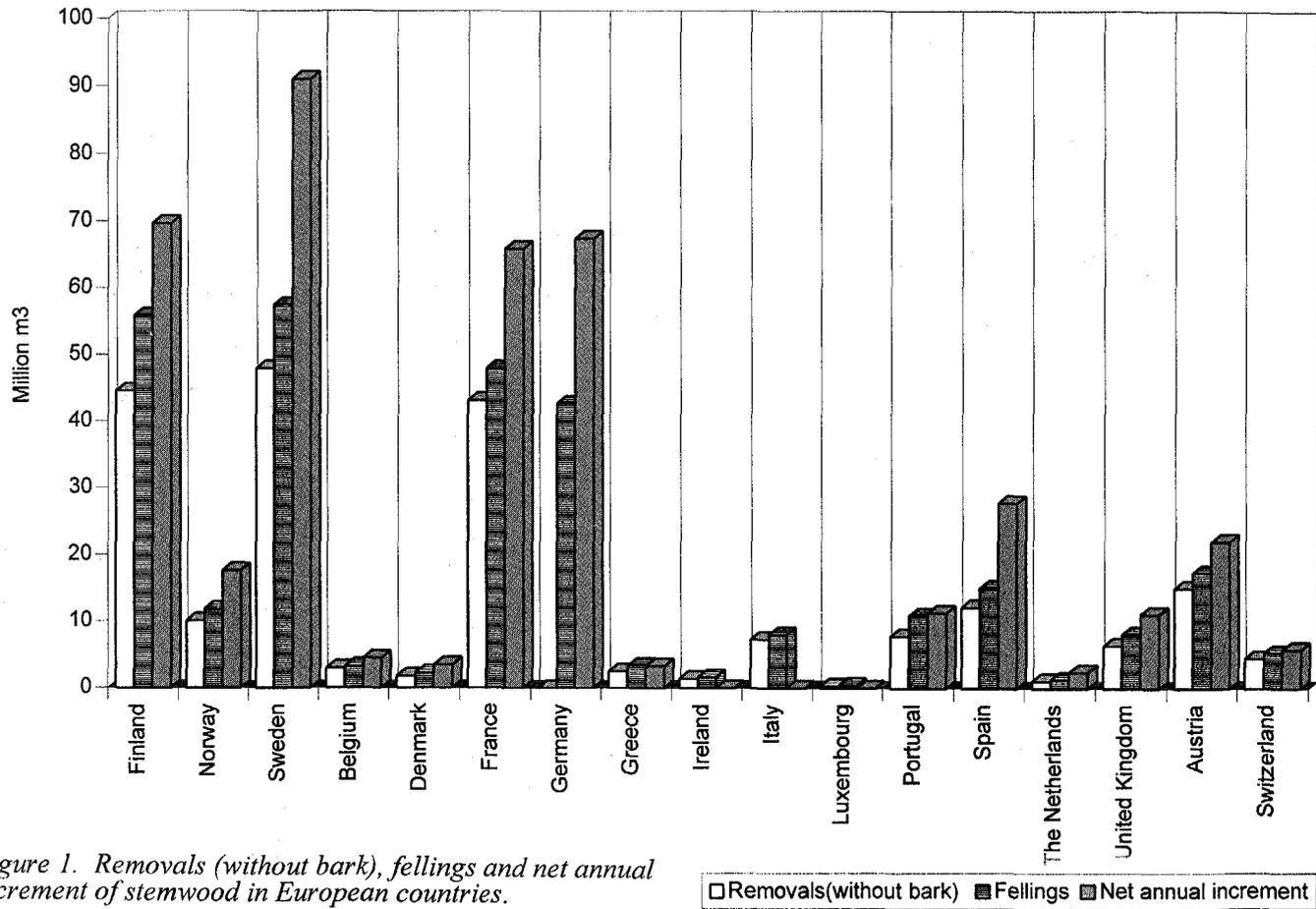
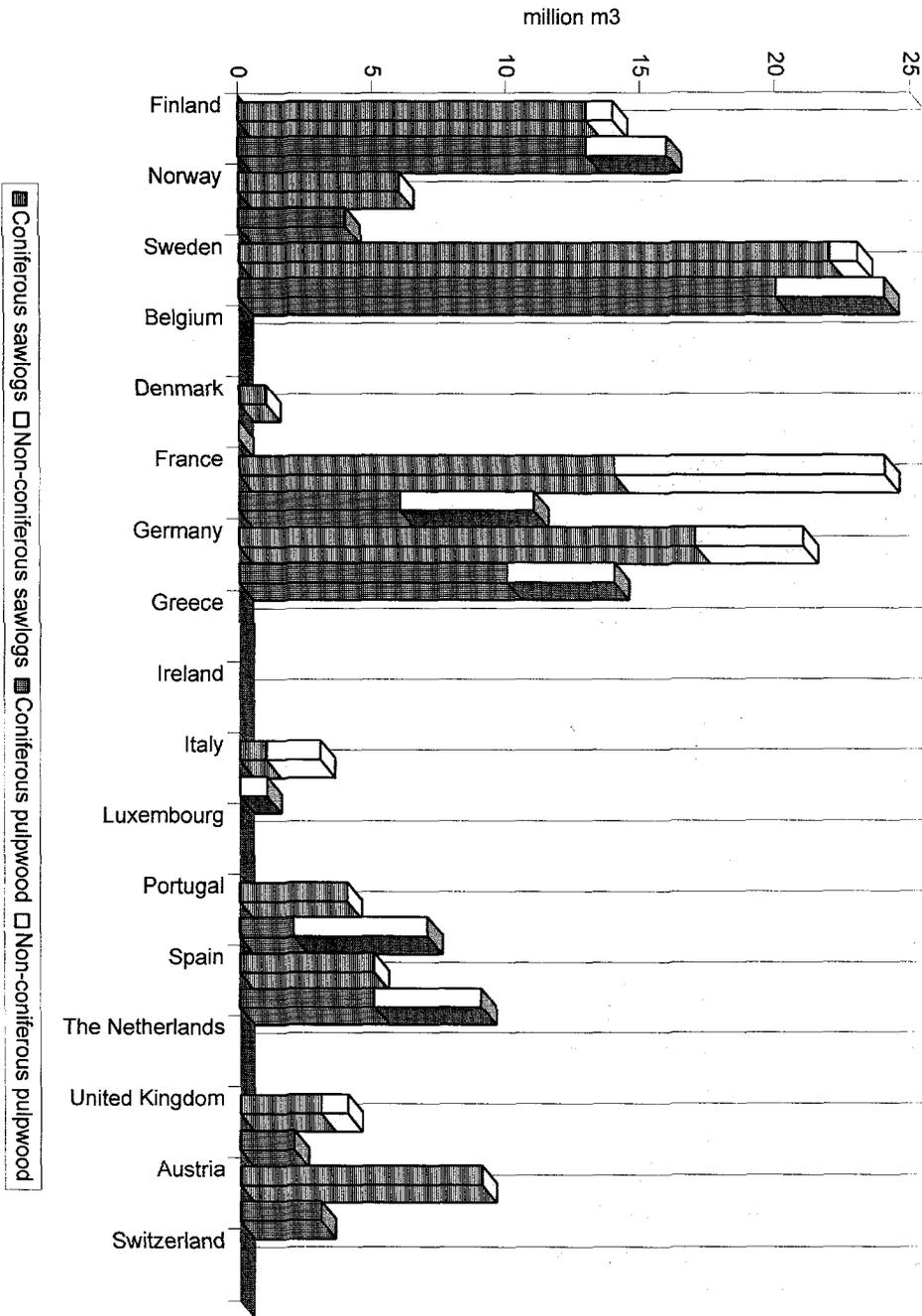


Figure 1. Removals (without bark), fellings and net annual increment of stemwood in European countries.

Figure 2. Pulpwood and sawlogs production in some European countries.



BOILER CONVERSIONS FOR BIOMASS

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Abstract

Boiler conversions from grate- and oil-fired boilers to bubbling fluidized bed combustion have been most common in pulp and paper industry. Water treatment sludge combustion, need for additional capacity and tightened emission limits have been the driving forces for the conversion. To accomplish a boiler conversion for biofuel, the lower part of the boiler is replaced with a fluidized bed bottom and new fuel, ash and air systems are added. The Imatran Voima Rauhalahti pul-verized-peat-fired boiler was converted to bubbling fluidized bed firing in 1993. In the conversion the boiler capacity was increased by 10 % to 295 MWth and NO_x emissions dropped. In the Kymmene Kuusankoski boiler, the reason for conversion was the combustion of high chlorine content biosludge. The emissions have been under general European limits. During the next years, the emission limits will tighten and the boilers will be designed for most complete combustion and compounds, which can be removed from flue gases, will be taken care of after the boiler.

1 BASIS FOR BOILER CONVERSION

The majority of boiler conversions for biomass have been grate- and oil-fired boilers converted to bubbling fluidized bed firing. The main justifications for the conversion have been:

- new fuel mixtures
- need for additional solid fuel combustion capacity
- tightened emission limits.

In the pulp and paper industry, the typical power boiler has been a grate-fired boiler using oil burners for additional capacity. As the water treatment has increased, more and more sludge has been produced. The old boilers were not designed for high moisture sludge combustion. The price and the sulphur content of oil have also given pressure to increase biofuel capacity. The latest trend is the combustion of different wastes, both municipal and industrial. Particularly in Sweden, the forest residues are an important biofuel.

Figure 1 shows the heating value and moisture content of typical biofuels. The high moisture content fuel mixtures lead to a larger fluidized bed cross-section so that a sufficient percentage of the combustion takes place in the bed area and the bed temperature remains at the desired 750 - 900 °C level. With drier fuels, peat and RDF, the fluidized bed acts as a gasifier and most of the combustion takes place in the freeboard. A typical temperature curve for bubbling fluidized bed combustion is shown in Figure 2.

Above the bed, the particle suspension does not prevent good horizontal mixing. With well-designed overfire air introduction it is also possible to get complete combustion for waste fuels in this high temperature zone. The German 17th BImSchV emission limits for waste combustion, which are the guideline for the proposed EU limits, can be achieved with all typical biofuels. In many countries there are additional requirements stipulating the waste combustion conditions, such as a 2 seconds residence time at over 850 °C after the last air introduction and a 6 % oxygen content, which are the old design criteria for after-burning chambers in grate firing. The use of these criteria for fluidized bed firing leads to an decrease in thermal efficiency and lower NO_x reduction without notable advantages.

Reduction of nitric oxide (NO_x) emissions has been a criterion for conversion, especially from pulverised peat firing. The majority of NO_x formation in fluidized bed combustion comes from fuel nitrogen. Peat has a high nitrogen content, 1.5 to 2.5 % of dry substance. In order to reduce NO_x in peat firing, the combustion needs to be sharply staged at multiple levels in the furnace and the excess oxygen has to be kept low. To complete the combustion, 20 % excess air equivalent to 3.5 % oxygen in the flue gas is sufficient. By staged combustion the Finnish emission limit of 150 mg/MJ is also achieved with peat.

The high temperature above the bed leads to minimum, typically less than 10 ppm, nitrous oxide (N₂O) formation. In circulating fluidized bed combustion, if the furnace temperature is kept below 900 °C, a substantial part of the fuel nitrogen is converted to N₂O.

The conversion for biofuel normally reduces the SO₂ emissions radically, as the need for sulphur containing fuels, like oil, decreases. In co-combustion of peat, bark and sludge, the ash alkalines give a 30 - 0 % sulphur reduction without sorbent injection. For additional sulphur removal, limestone can be injected into the furnace. Figure 3 shows results from one bubbling fluidized bed boiler firing peat with a 0.2 % sulphur content. It is notable that even if the Ca/S molar ratios may become high for higher reductions, the absolute limestone consumption is moderate, as the biofuel sulphur contents are low.

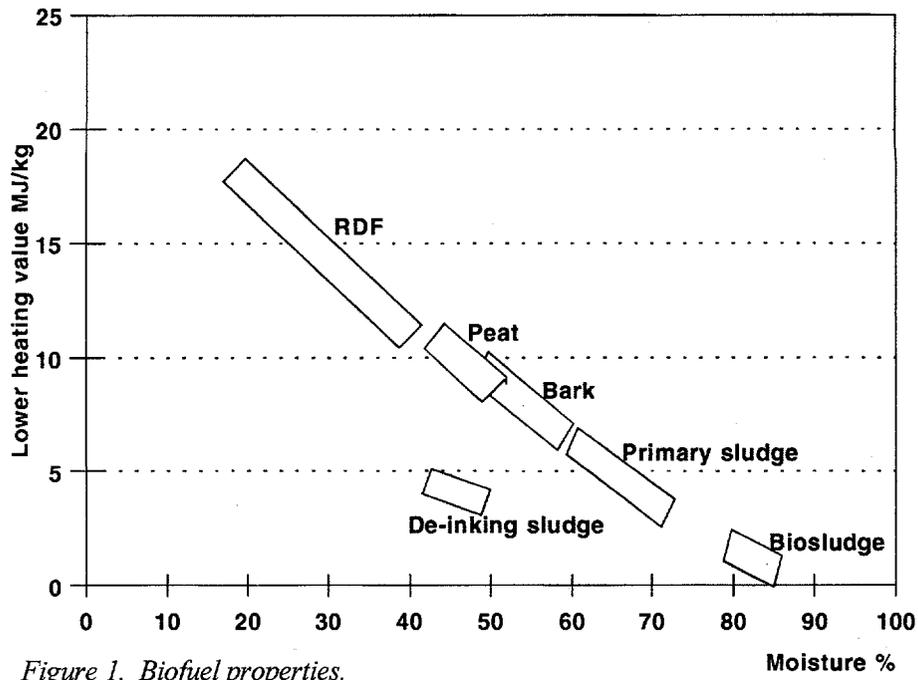


Figure 1. Biofuel properties.

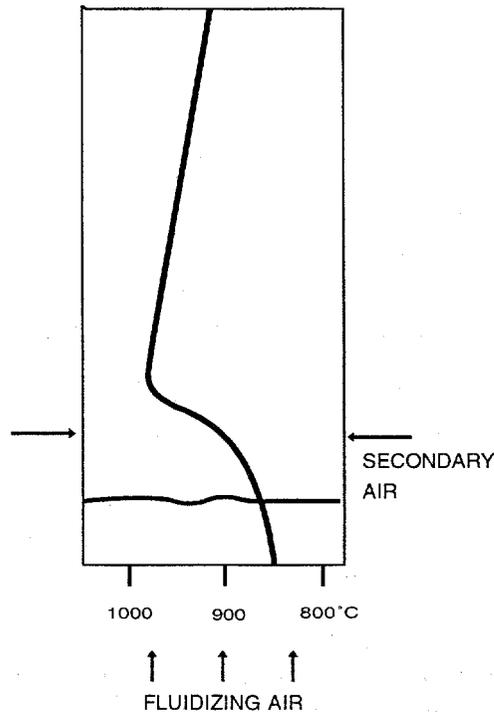


Figure 2. Typical bubbling fluidized-bed boiler furnace temperature profile for biofuel.

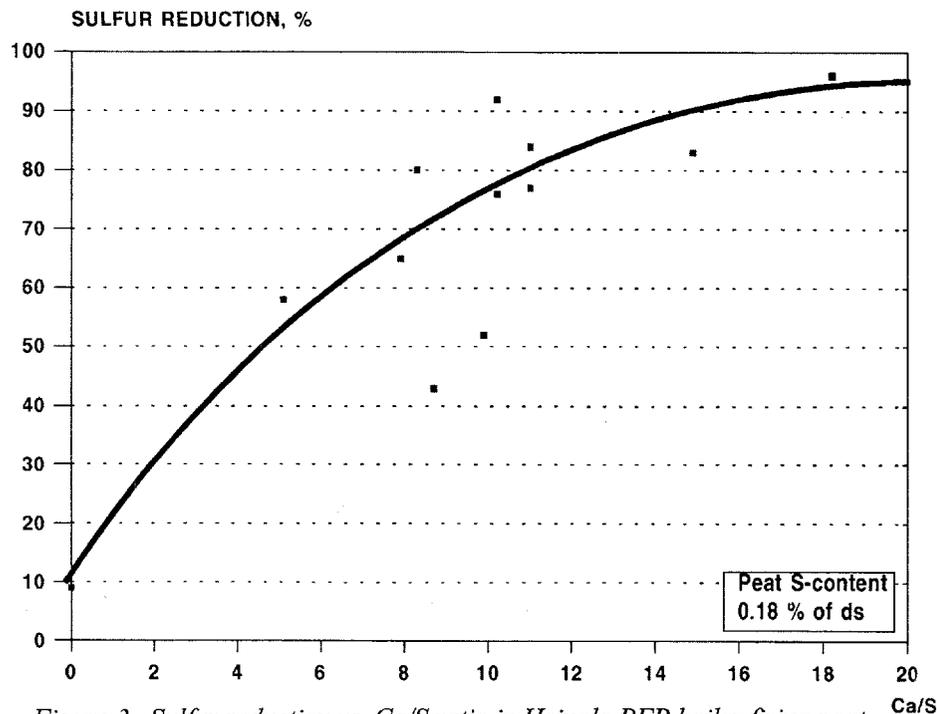


Figure 3. Sulfur reduction vs. Ca/S ratio in Heinola BFB boiler firing peat.

2 CONVERSION ACCOMPLISHMENT

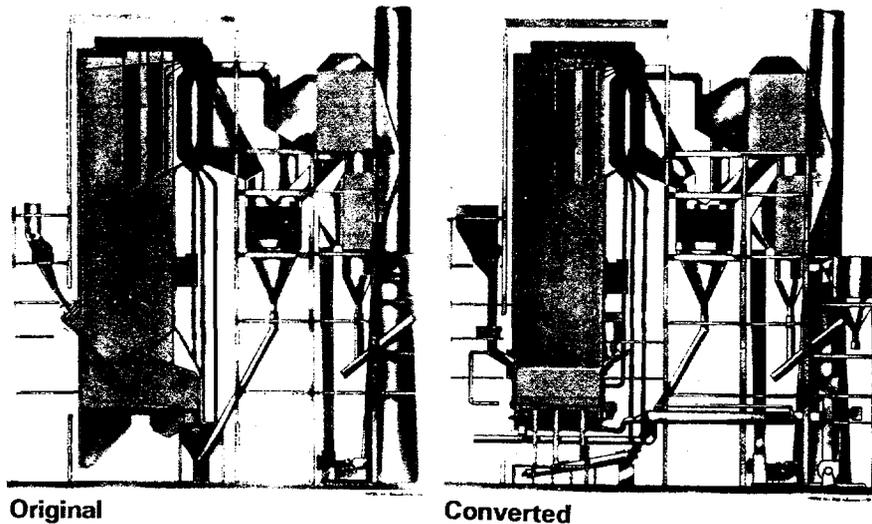
The actual scope of work to convert an old boiler to bubbling fluidized bed combustion consists of:

- replacing the lower part of the furnace with a fluidized bed bottom
- adding required new fuel feeding and ash removal equipment
- adding a primary air fan and ducts and overfire air nozzles and ducts.

The size of the fluidized bed bottom is based on the required capacity and fuel properties, and so it can be equal, smaller or larger than the original furnace size (Figure 4). In all cases, the bed section consists of a fluidized bed grate with air nozzles to introduce the fluidising air. The furnace walls are covered with refractory to prevent erosion in the bed area. The fluidized bed consists of about 50 cm sand, which expands to double height when fluidized.

With high volatile biofuels, stable feeding is essential. The boiler load and the emissions respond immediately to variations in the fuel feed rate. Normally at least the controlling part of the fuel feed system is replaced in the conversion and new feed chutes are added.

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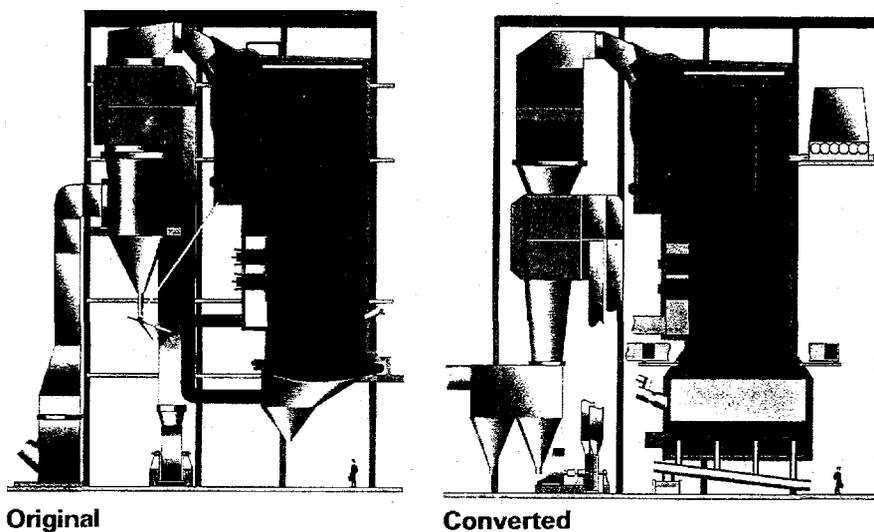


Figure 4. Examples of boiler conversions for biofuel.

Removal of the coarse incombustible material from the bed is also a key aspect of high availability. This is normally done by coarse removal chutes through the furnace bottom

Air is introduced as primary air to fluidise the bed and as overfire air to complete the combustion and to make the staging effect. For maximum NO_x reduction, the residence time for final combustion has shortened, and so the correct design of air distribution and air nozzles is of crucial importance to good emission and unburned carbon results.

3 CONVERSION EXPERIENCES

Tampella Power has made 17 boiler conversions for biomass ranging from 40 to 295 MW fuel capacity. With good results from the conversions, the bubbling fluidized bed combustion has also become a standard for new boilers firing biofuels in the Finnish pulp and paper industry.

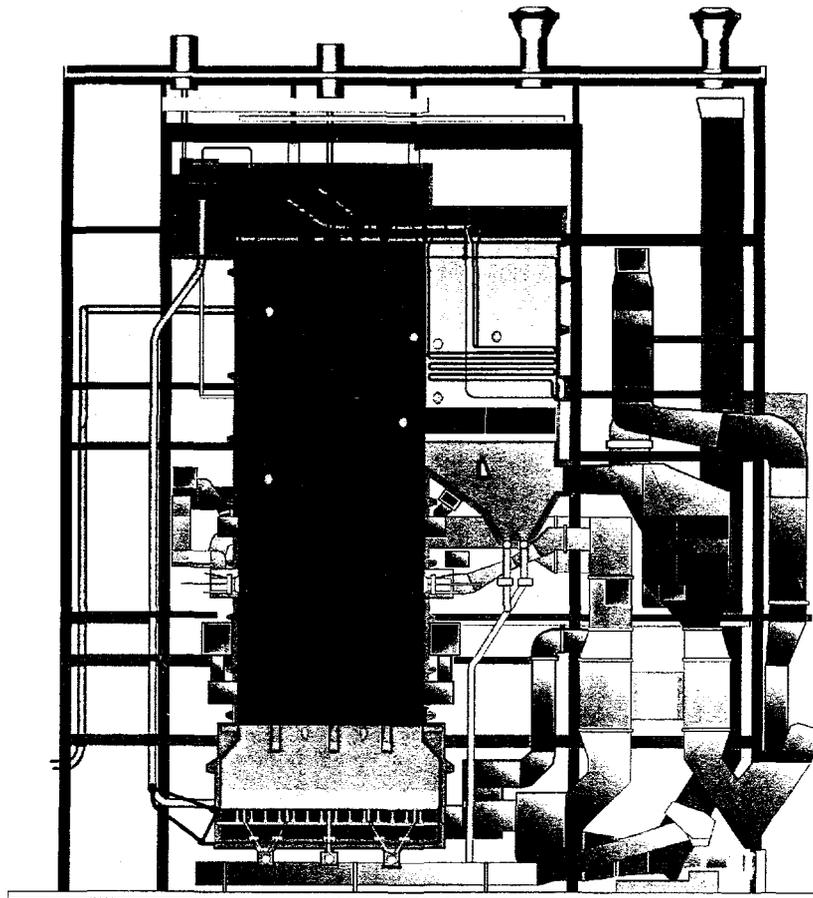
3.1 IVO, RAUHALAHTI

The largest conversion has been the Imatran Voima (IVO) Rauhalahki pulverised-peat-fired boiler conversion to fluidized bed firing in 1993 (Figure 5). As a result of the conversion, the NO_x emissions dropped by a good third to below 150 mg/MJ. The SO_2 emission dropped to a level corresponding peat sulphur, as the need for support oil and coal decreased close to zero. In the conversion, the boiler capacity was raised from 100 kg/s steam to 110 kg/s steam, which makes the Rauhalahki boiler the world's largest biofuel-fired bubbling fluidized bed boiler.

The new combustion technology also enables the utilisation of wood fuels, such as saw mill waste, chips and bark alongside peat. The use of these new fuel sources has increased steadily after the conversion.

The furnace of the boiler is 31 metres high and has a volume of 2 800 m³. The bottom of the furnace has a 122 m² fluidized bed. Peat and wood are fed into the boiler through six openings in the side walls. Steam is used to produce electricity with maximum 87 MW output and, after the turbine, as process steam for the nearby paper mill and for district heating.

The combustion results presented in Table 1 show that the process is stable and air mixing is efficient. The unburned carbon in fly ash, which is below 0.1 % of fuel heat input, is extremely low.



ORIGINAL		CONVERTED	
Steam:	100 kg/s 790,000 lb/h	Steam:	110 kg/s 871,000 lb/h
	135 bar 1960 psig		135 bar 1960 psig
	533 °C 991 °F		533 °C 991 °F
Fuels:	Peat, coal, oil	Fuels:	Peat, coal, oil, wood waste

Figure 5. Imatran Voima, Rauhalahki boiler after conversion.

Table 1. IVO, Rauhalahki emission results.

Fuel		Peat
Efficiency		
- O ₂ after furnace	%	2.7
- O ₂ after air heater	%	5.0 - 5.2
- unburned carbon in fly ash	%	1 - 2
- combustion efficiency	%	> 99.9
Emissions		
- NO _x	mg/MJ	120 - 150
- SO ₂	mg/MJ	190 - 200
- CO	ppm	60 - 70

The operational reliability after the conversion can be seen from the capacity curve for the first year operation, Figure 6. There have been no shutdowns caused by the fluidized bed combustion.

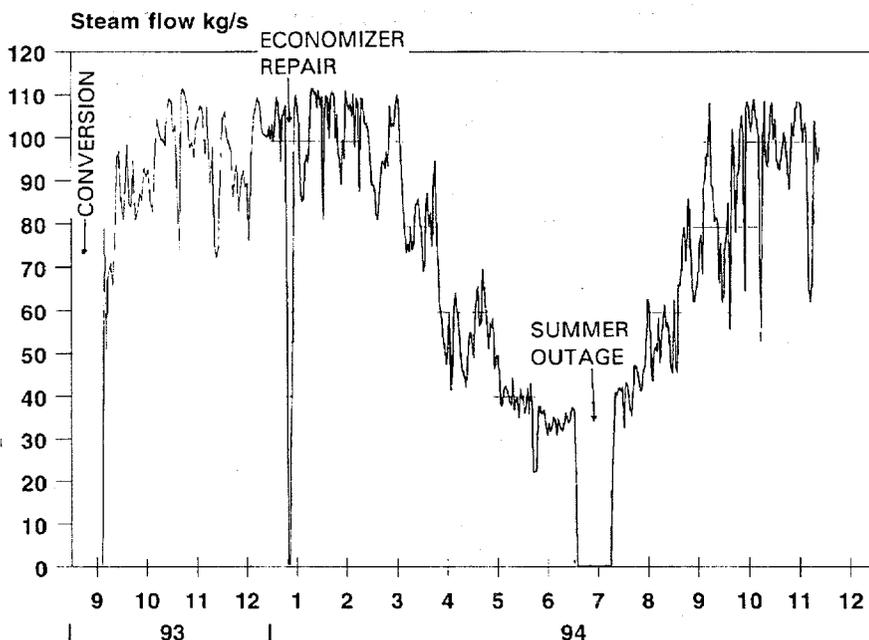


Figure 6. IVO, Rauhalhti steam capacity after conversion.

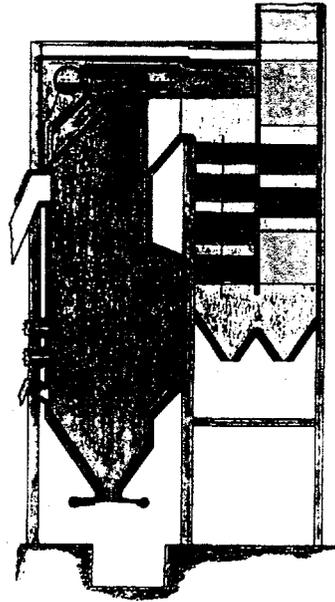
3.2 KYMMENE LTD., KUUSANKOSKI

An old sulphite recovery boiler in the Kymmene Kuusankoski mill was converted to bubbling fluidized bed firing in 1989 (Figure 7). Even before the fluidized bed conversion, the boiler had been used as a power boiler with pulverised-bark and peat burners. The requirement to burn bio-sludge was the main reason for the new conversion.

The fluidized bed cross-section is 50 m². The original design for sulphite with a precombustion chamber is the reason for the exceptionally large cross-section of the upper furnace. This design leads to long residence time in the furnace.

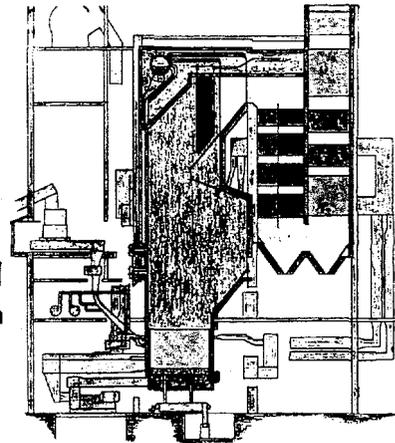
The biosludge from the pulp mill water treatment contains a large amount of chlorine. Dioxin formation has been the major fear for bio-sludge combustion. The emission tests performed show that the dioxin levels of below 0.1 ng/m³ I-TEF equivalent can be achieved (Table 2).

For decreasing the NO_x level, an air system modification was completed last summer. A further 50 to 60 % reduction in NO_x was achieved by adding air staging.



Original

Steam: 28 kg/s 220,000 lb/h
130 bar 1 885 psig
525 °C 977 °F
Fuels: Pulverized peat,
bark



Converted

Steam: 28 kg/s 220,000 lb/h
130 bar 1 885 psig
525 °C 977 °F
Fuels: Bark, peat, sludge

Figure 7. Kymmene Ltd., Kuusankoski boiler conversion.

Table 2. Emission results; Kymmene, Kuusankoski.

Fuel		bark	bark + sludge
- Cl	mg/kg	250	1340
Temperature			
- furnace	°C	877	830
- bed	°C	869	844
Flue gas			
- O ₂	%	8.7	8.8
- NO _x	ppm	143	162
- CO	ppm	23	33
- Dioxins, I-TEF	ng/m ³ n	0.02	0.07
Fly ash			
- unburned carbon	%	6.3	6.5

4 FUTURE TRENDS

The same trend to increase biofuel capacities and increase sludge and waste combustion can be seen in all major pulp and paper making countries. This applies to both boiler conversions to biofuel and to new units.

The emission limits are becoming tighter all the time. Levels required for new plants in Germany are 2 to 10 times as tight as the current state regulations. The boiler has to be designed to meet the emissions arising in incomplete combustion; CO, hydrocarbons and dioxins. Other components, e.g. NO_x and SO₂, can always be handled by flue gas treatment. Bubbling fluidised bed combustion with efficient mixing in a high temperature freeboard is suitable for these applications.

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SMALL SCALE POWER PRODUCTION

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1 GENERAL

IVO International is a major constructor of biomass power plants in Finland and abroad. As a subsidiary of Imatran Voima Oy, the largest power utility in Finland, it has designed and constructed ten power plants owned by IVO Group or others capable of burning biomasses. Sizes of the plants vary from the world's largest condensing peat-fired power plant of 155 MW_e to a 6 MW_e combined heat and power producing unit.

If the upper limit to a small-scale power plant is defined as 50 MW_e, three of these belong to the group of small-scale ones.

Table 1. Municipal combined heat and power plants constructed by IVO International (capable of burning biomass).

Name	Electric output MW _e	Heat output MW _{th}	Steam flow kg/s	Fuels	Type of boiler
Kuusamo	6	20	8	Wood chips, peat	BFB
Lieksa	8	22	10	Sawdust, bark, peat	CFB
Mikkeli	20	54	33	Peat, wood chips, coal	CFB

In addition to the above IVO International has constructed plants of this size for the pulp and paper industry. In Sachsen Papier, Germany, a versatile process combining cogeneration of heat and power by steam turbine, gas turbine with heat recovery steam generator and a bubbling fluidized-bed boiler burning solid waste from the paper mill has been commissioned.

IVO owns Kauttua power plant, which is equipped with one of the oldest circulating fluidized-bed boilers. This plant was commissioned in 1981. The plant uses paper waste from the neighbouring paper mill, together with peat. The plant is also used to conduct tests with different fuels and emission levels. Extensive RDF burning tests have only recently been concluded.

Kokkola is the latest of IVO's boiler plants using biomass as fuel. It was commissioned in late 1994. The boiler produces 33 kg/s steam and reheats

Table 2. Industrial plants constructed by IVO International or owned by IVO Group (capable of burning biomass).

Name	Electric output MW _e	Heat output MW _{th}	Steam flow kg/s	Fuels	Type of boiler
Sachsen Papier	44	100	11(+28)	Solid waste, natural gas	BFB+HRSG
Kokkola	(180)	(130)	33(+17)		CFB
Uimaharju	(105)	(230)	32	Peat, coal, process waste, wood waste	BFB
Kaattua	18	40	25	Bark, sludge Peat, wood waste, coal	CFB

Values in brackets indicate the total production of power by other means than just burning biomass

17 kg/s of steam from the nearby Outokumpu Zinc Factory. The boiler is of a new type of circulating fluidized bed, Ahlstrom Compact. This is the second of its kind in the world.

Mikkeli Power Plant was commissioned in 1990 as the first IVO International turnkey power plant delivery. The owner of the plant is Mikkeli Municipal Energy Board. Electricity is supplied into the national grid and district heat to the surrounding municipality. The plant was initially designed for peat and coal, but coal has not been used since. Instead use of wood waste has increased considerably. At the moment about 30 % of fuel is wood waste. Operation experiences from the plant for the four years passed have been very positive. Excluding the four-week annual maintenance period, the plant has been operating in full power since it was commissioned.

Kuusamo, Toranki Power Plant went on line at the beginning of 1994. The plant is owned by IVO Group. As an extra feature, the plant incorporates a new revolutionary drier. The bed-mixing dryer, as it is called, can increase the thermal efficiency of the plant by up to 15 % by utilising the latent heat of evaporation during fuel drying with the bubbling fluidized-bed boiler's hot sand. After about one year of extensive testing and minor modifications, the dryer is at present operating at 100 % loads. The plant is also used as a full-scale test plant for other biomass fuels as exotic as olive husk.

Liekka Power Plant delivers district heat to the town of Liekka close to Finland's eastern border. The plant is owned by the Finnish peat producer and distributor Vapo Oy. It was taken into commercial use at the beginning of 1995. The power plant was the first of its kind to be commissioned incorpo-

rating a new circulating fluidized-bed boiler CYMIC by Tampella Power. Another interesting feature in the plant is a steam-air combustion air pre-heater patented by IVO. The fuel of the plant is composed of 110 000 m³/a peat and 140 000 m³/a bark.

In addition to these, IVO has constructed larger biomass power plants. A list of all IVO references is attached.

2 AVAILABILITY

Availability figures for some of the plants are shown in Table 3. As is seen the reliability of the plants can be regarded excellent.

Table 3. Availability figures during 1994 for some biomass power plants constructed by IVO International or owned by IVO Group (capable of burning biomass).

	Toranki/ Kuusamo	Mikkeli	Kauttua	Rauhanlahti (large scale 87 MW _e)
tg _{dE}	96.5 %	98.1 %	99.9 %	98.8 %

tg_{dE} - operation time energy availability

3 ENVIRONMENTAL ISSUES

Emission levels of importance when burning biomass are NO₂, SO₂ and dust emissions. In all IVO plants electrostatic precipitators are used.

Table 4. Emission levels reached (and limits) in some power plants.

Level/Limits	Liekka	Toranki/ Kuusamo	Rauhanlahti (large scale 87 MW _e)
NO ₂ (mg/MJ)	150	180	150/180
SO ₂ (mg/MJ)	110	225	250
Dust (mg/MJ)	45/81	55/83.6	40

IVO's experience from operating FBC boilers is extensive. Burning biomass is one of the IVO R&D Department's key areas of research, which can be seen on the products developed. With the knowledge gained from its own and other power plants, IVO is one of the few world leaders in designing, constructing and operating biomass-fired FBC power plants.

BIOMASS EXPERIENCE OF IVO INTERNATIONAL LTD

PLANT	COUNTRY	TYPE OF BOILER	MANUFACTURER	YEAR OF COMMISSIONING	ELECTRIC OUTPUT MWe	HEAT OUTPUT MWth	STEAM FLOW kg/s	PRESSURE bar(a)	TEMPERATURE °C	FUELS
KAUTUA	FIN	CFB	Ahlstrom Pyroflow	1981	18	40	25	83	500	Coal, Peat, Wood waste
LOHJA	FIN	BFB	Ahlstrom Termoflow	1986	-	36	15	25	240	Coal, Wood waste, Paper waste
JOENSUU	FIN	PF	Ahlstrom (Flash Dryer)	1986	52	120	75	115	533	Peat
HAAPAVESI	FIN	PF	Tampella Power (Vapour Separation) ¹	1989	155	-	125	180	530	Peat
MIKKELI	FIN	CFB	Ahlstrom Pyroflow	1990	26	54	33	114	535	Peat, Coal
RAUHALAHTI	FIN	BFB	Tampella Power (*)	1993	87	205	110	136	533	Peat, Coal, Wood waste
UIMAHARJU	FIN	BFB	Tampella Power	1993	105	230	32	83	480	Bark, Sludge
KUUSAMO	FIN	BFB	Ahlstrom Termoflow	1993	6	20	8	60	510	Wood waste, Peat
LIEKSA	FIN	CFB	Tampella Power CYMIC ²	1994	8	22	10	60	510	Peat
KOKKOLA	FIN	CFB	Ahlstrom Compact ³	1994	180	130	33+17	60	510	Peat, Coal, Process waste
SACHSEN PAPIER	D	BFB+HRSG	Tampella Power	1994	44	100	11+28	84	490	Solid waste, Natural Gas
OULU	FIN	CFB	Ahlstrom Pyroflow	1995	140/113	170	103	156	540	Peat

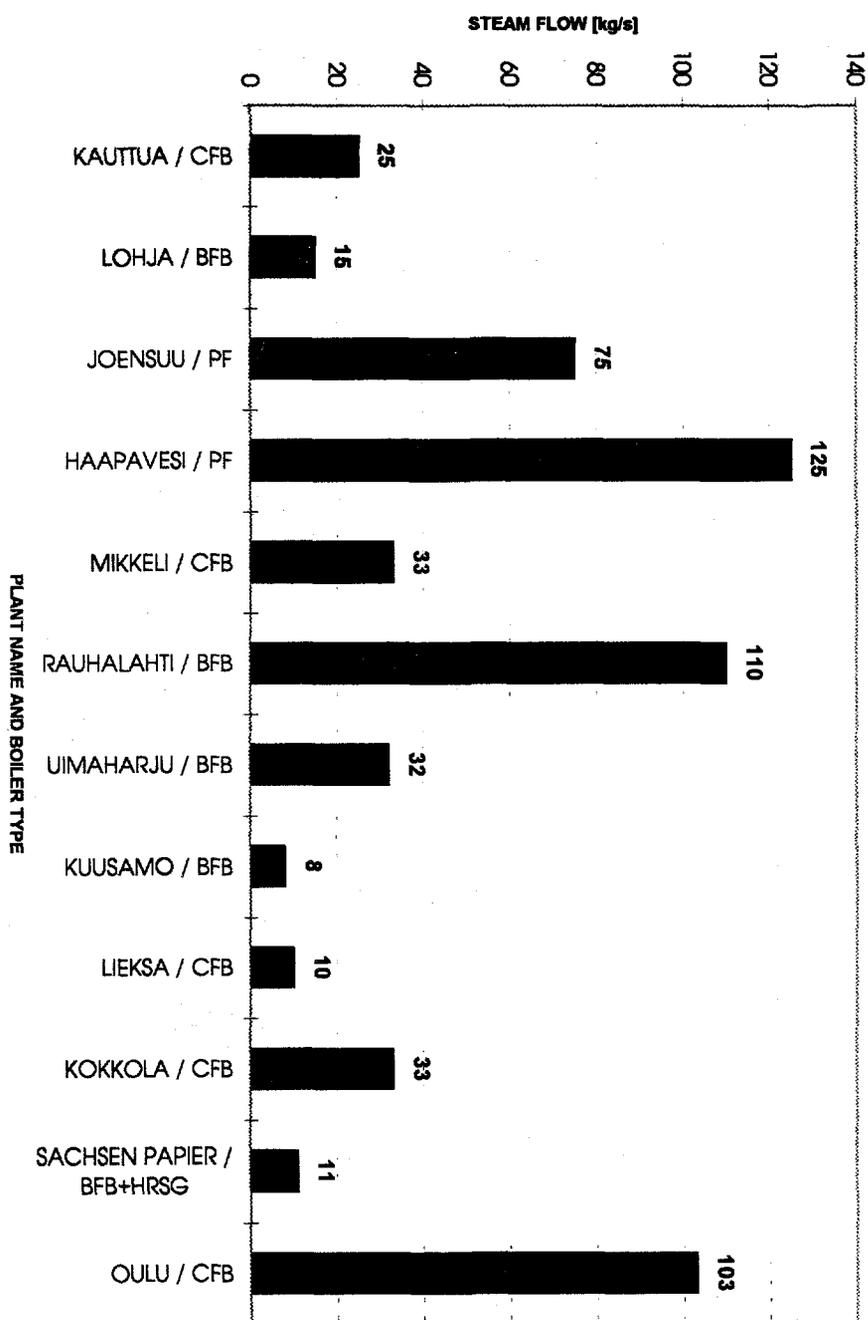
¹ condensing

² first installation of the type in the world

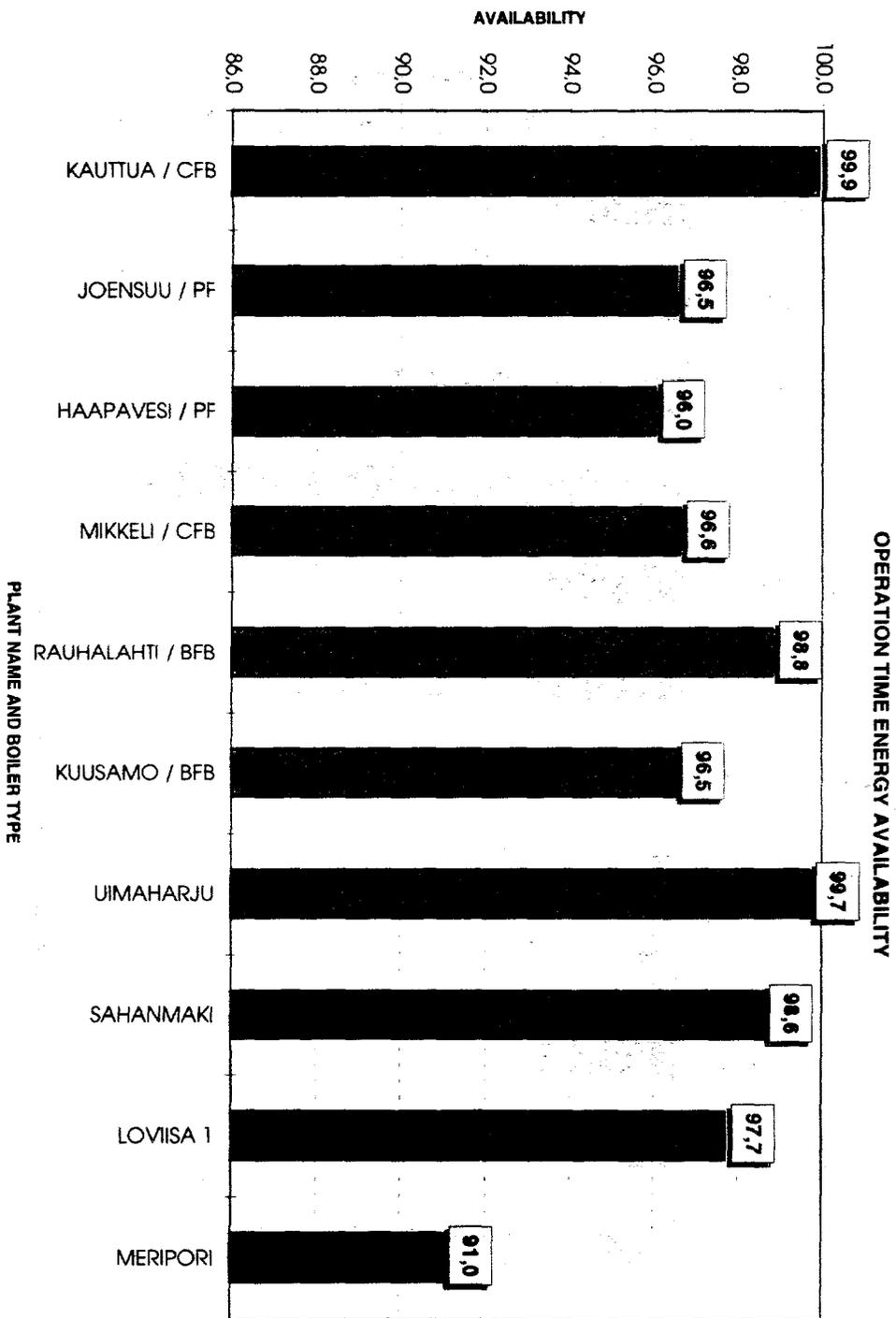
³ second installation of the type in the world

(*) converted from PF to BFB in 1993

ABBREVIATION:	DESCRIPTION OF BOILER TYPE
CFB	Circulating Fluidized Bed
BFB	Bubbling Fluidized Bed
PF	Pulverized Fuel
HRSG	Heat Recovery Steam Generator



IVO GROUP / BOILER SIZES AND TYPES



CO-COMBUSTION AND GASIFICATION OF VARIOUS BIOMASSES

Keijo Mutanen

A. Ahlstrom Corporation, Ahlstrom Pyropower, Varkaus, Finland

Abstract

During the last twenty years the development of fluidized bed combustion and gasification technology has made it possible to increase significantly utilization of various biomasses in power and heat generation. The forerunner was the pulp and paper industry that has an adequate biomass fuel supply and energy demand on site. Later on municipalities and even utilities have seen biomass as a potential fuel. The range of available biomasses includes wood-based fuels and wastes like bark, wood chips, and saw dust, agricultural wastes like straw, olive waste and rice husk, sludges from paper mills and de-inking plants, other wastes like municipal sludges, waste paper and RDF. Recently new environmental regulations and taxation of fossil fuels have further increased interest in the use of biomasses in energy generation.

However, in many cases available quantities and/or qualities of biomasses are not adequate for only biomass-based energy generation in an economic sense. On the other hand plant owners want to maintain a high level of fuel flexibility and fuel supply security. In some cases disposing by burning is the only feasible way to handle certain wastes. In many cases the only way to fulfill these targets and utilize the energy is to apply co-combustion or gasification of different fuels and wastes.

Due to the fact that fluidized bed combustion technology offers a very high fuel flexibility and high combustion efficiency with low emissions it has become the dominating technology in co-combustion applications. Fluidized bed gasification has not yet met solid commercial status but offers a technically feasible solution for some specific cases like in utilization of demolition waste for energy or in lime kilns. There are some technical issues in co-combustion of biomasses to be emphasized. Feeding of all selected fuels must be secured by appropriate design of the fuel handling and feeding systems. Some biomass fuels contain environmentally harmful impurities like heavy metals or chlorines. In addition, chlorine may cause corrosion risks. Ash of some biomasses melts at low temperatures leading to slagging and fouling problems. Depending on the fuel mix desired these is-

sues must be emphasized in the design of the co-combustion or gasification system.

This paper will present Ahlstrom's experiences in co-combustion of biomasses in bubbling beds and Ahlstrom Pyroflow circulating fluidized beds based on about 200 operating references worldwide. CFB gasification will also be discussed.

1 INTRODUCTION

During the last twenty years the development of fluidized bed combustion and gasification (FBC/G) technology has made it possible to increase significantly utilization of various biomasses in power and heat generation. The forerunner was the pulp and paper industry that has an adequate biomass fuel supply and energy demand on site. Later on municipalities and even utilities have seen biomass as a potential fuel. The range of available biomasses includes wood-based fuels and wastes like bark, wood chips, and saw dust, agricultural wastes like straw, olive waste, and rice husk, sludges from paper mills and de-inking plants, other wastes like municipal sludges, waste paper and RDF. Recently new environmental regulations and taxation of fossil fuels have further increased interest in use of biomasses in energy generation.

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Due to the fact that fluidized bed combustion (FBC) technology offers a very high fuel flexibility and high combustion efficiency with low emissions it has become the dominating technology in co-combustion applications. Fluidized bed gasification has not yet met a solid commercial status but offers a technically feasible solution for some specific cases like in utilization of demolition waste for energy or for supply of energy to a pulping process.

A. Ahlstrom Corporation initiated the development of fluidized bed combustion technology in the late 1960s. The first concepts were based on bubbling fluidized beds (BFB), but since the beginning of the 1970s Ahlstrom has been the world leader in the development of circulating fluidized

bed technology (CFB). Ahlstrom Pyropower is now the market leader with its Pyroflow CFB technology and also a significant supplier of BFBs. In 1995 there are over 100 Pyroflow CFBs in operation and almost 30 under construction worldwide using about 70 different fuels, in many cases in a co-combustion mode. The number of BFB references is close to 80, most of them using biomass or other low-grade fuels.

Ahlstrom has supplied for commercial CFB gasifiers for biomass, supplying the gas to a lime reburning kiln in a pulp mill. Ahlstrom has also a fixed bed gasifier with the product name, Bioneer, but there is no active marketing for this product. The first plant based on Ahlstrom's pressurized CFB gasification technology was built for biomass in 1992 in Värnamo, Sweden, in cooperation with a Swedish utility company, Sydkraft AB. The plant is at commissioning stage.

Fluidized bed technology has demonstrated its commercial maturity and the vendors are scaling-up their designs and confidence. E.g., Ahlstrom offers now CFB units up to 400 - 500 MW_e with full commercial guarantees. On the other hand, new designs allow even higher fuel flexibility with enhanced efficiency in power generation and with lower emission levels combined to lower investment and operating costs. Ahlstrom's new CFB design Pyroflow Compact satisfies these customer requirements. High fuel flexibility, low emissions, higher efficiencies, need to refurbish old power plants and need to utilize various wastes and biomasses for energy will be the major driving forces behind the development of fluidized bed technologies in the future too.

2 FLUIDIZED BED TECHNOLOGIES

2.1 BASIC TECHNOLOGIES

Fluidized bed combustors or gasifiers are usually classified as either bubbling (BFB) or circulating beds (CFB). The distinctive depends on gas velocity (Figure 1). In a fluidized bed system, the solid bed materials are normally made of fuel (such as wood chips or coal), an inert material (such as sand, stone and/or ash) and if needed a sorbent (such limestone). The bed lays on a distribution plate. When a stream of air or other gas passes through the plate nozzles it lifts the solid particles. The air velocity must be great enough to counteract the gravitational forces of the particles. In a BFB system the air velocity is lower, i.e., 1.0 - 3.5 m/s and the particles behave like a boiling fluid but stay in the bed (Figure 2). In a CFB system the air velocity is higher, i.e., 3 - 6 m/s and part of the bed material actually leaves

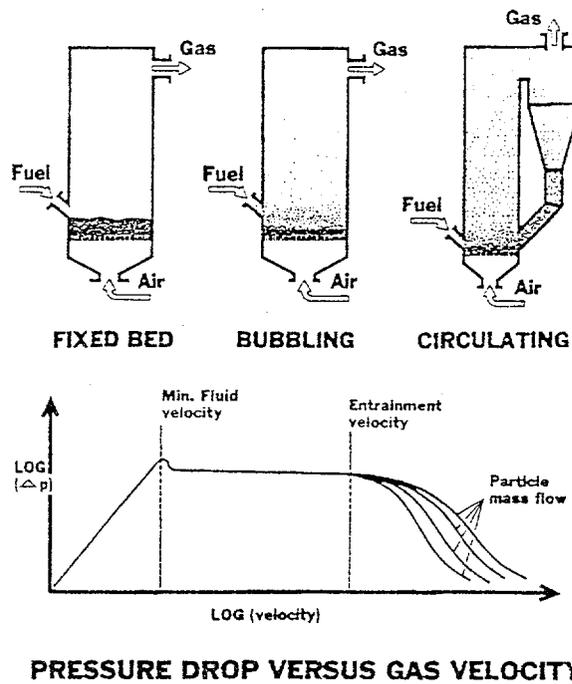


Figure 1. Classification of fluidized bed combustion systems.

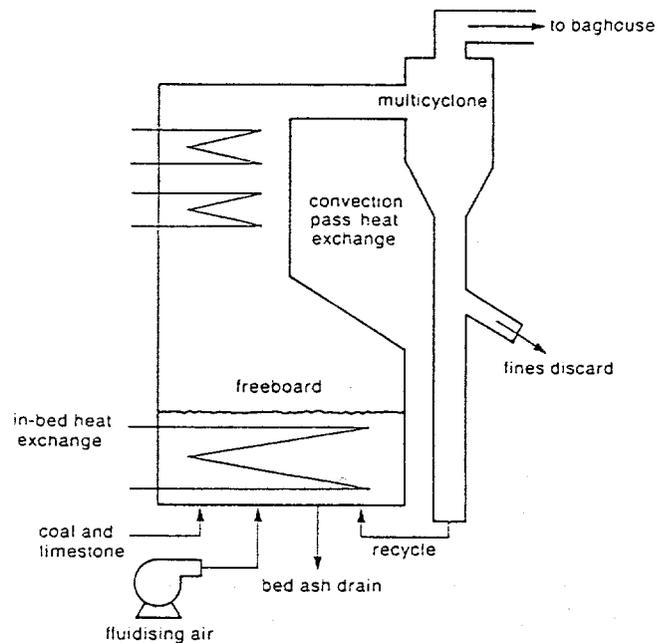


Figure 2. Principle of bubbling fluidized bed combustion system.

the bed and is collected by cyclone separators before being recirculated to the bed (Figure 3). both concepts are operated at low temperatures, 800 - 950 °C, primarily to avoid formation of thermal NO_x, to avoid melting of the bed material and with sulfur containing fuels to make efficient use of the calcium-oxide-sulfur dioxide reaction for SO₂ control. Despite the low bed temperature the efficiency of combustion is high due to very high rates of heat and mass transfer between the gas and the particles and due to staging the feeding of combustion air.

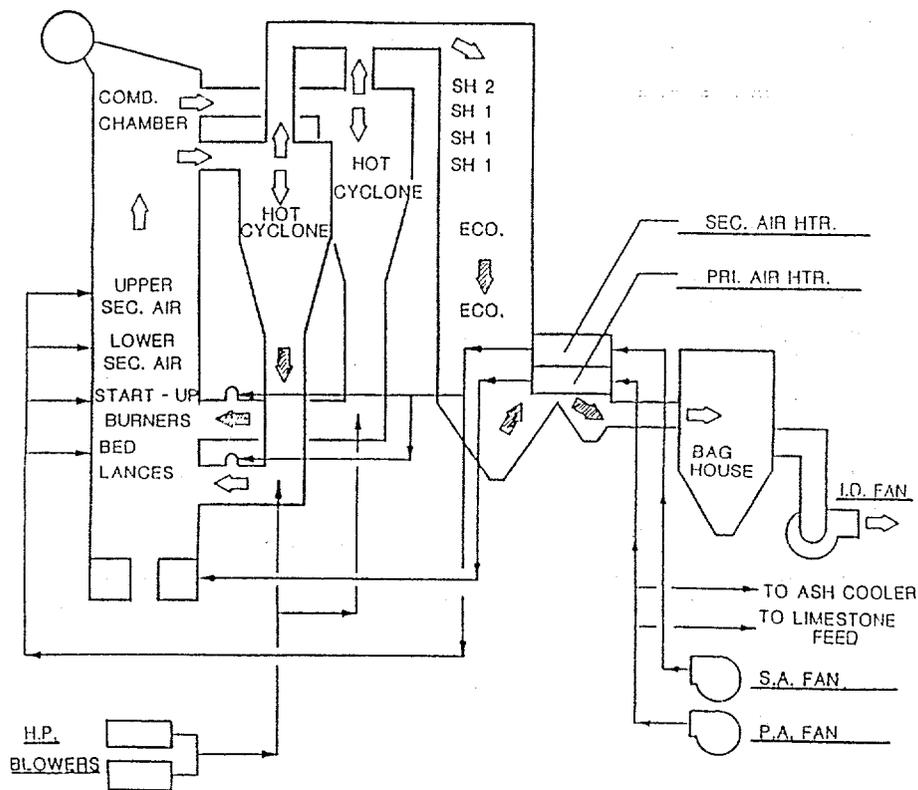


Figure 3. Principle of circulating fluidized bed combustion system.

2.2 DEVELOPMENT TRENDS

Both BFB and CFB can be pressurized and/or applied to gasification mode. Atmospheric BFB combustion is considered commercial up to 150 MW_e and CFB up to 400 - 600 MW_e. CFB is favored in fossil fuel and in co-combustion applications due to a higher combustion efficiency, lower NO_x emissions, efficient sulfur removal, better heat transfer, higher fuel flexibility and fewer feeding points compared to BFB. BFBs are favored when only biomass or similar low-grade fuels are used due to simpler design and lower investment and maintenance costs compared to CFB. Plants that use biomass are typically smaller in size. As an example, almost all small-scale cogeneration district heating power plants in operation or under construction in Finland using various biomasses apply Ahlstrom's BFB technology. Recently new CFB designs like Ahlstrom Pyroflow Compact have increased CFBs competitiveness also in smaller biomass-fired plants. However, the choice between CFB and BFB must be based on the fuels preferred, on existing and future emission requirements, and on technical and economic feasibility.

Atmospheric fluidized bed gasification of various biomasses has been developed since the 1970s. The first commercial applications were all based on Ahlstrom's Pyroflow technology and applied to firing low-grade gas in a pulping process (Figure 4). There are four units in operation: one in Finland, two in Sweden, and one in Portugal. There is some development going on related to the application of CFB gasification for demolition waste and for other dry biomass fuels. The product gas can be burned in a separate boiler, in an industrial process or as an additional fuel in a large utility or industrial boiler (Figure 5). These applications seem to be quite economic. If the fuel contains impurities like heavy metal there might be a need to clean the gas before burning. When fuel drying is needed the competitiveness of atmospheric CFB gasification of biomasses is poorer at present oil and gas prices.

3 AHLSTROM'S EXPERIENCES FROM CO-COMBUSTION

3.1 TECHNICAL REQUIREMENTS IN CO-COMBUSTION

Fluidized bed combustion was developed in the 1970s especially for biomass and other low-grade fuels which typically have large variations in fuel properties. A benefit of FBC when using these fuels is the large amount of bed material compared to the mass of the fuels (98 % versus 2 %) and thus the large heat capacity of the bed material that stabilizes the energy output

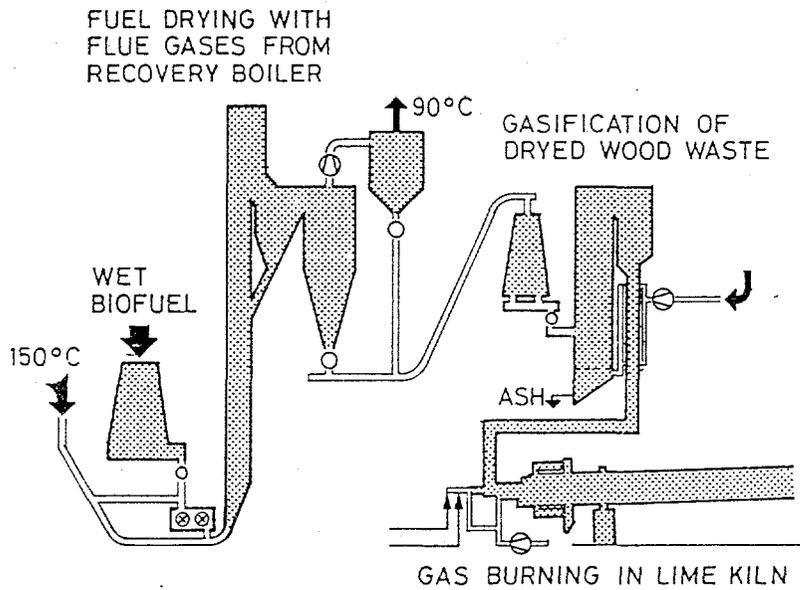


Figure 4. Principle of a CFB biomass gasification system for a lime kiln.

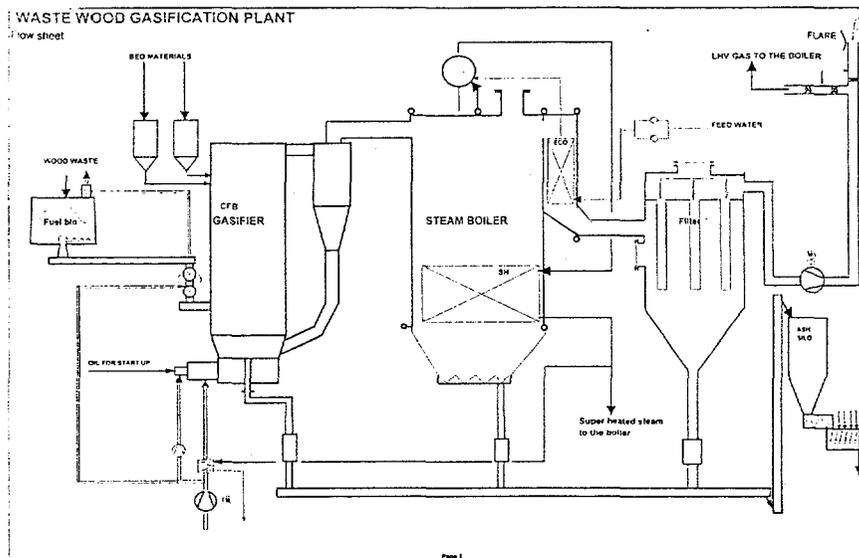


Figure 5. Principle of a clean gas production system based on atmospheric CFB gasification of biomass.

caused by variations in fuel properties. The other advantages of FBC like sulfur removal with limestone or dolomite and low NO_x emissions became important in parallel with the new environmental requirements of the 1980s. Although FBCs and especially CFBs are being scaled up to utility sizes the dominating markets for FBCs in the 1990s and at the beginning of the 2000s will be in industrial and district heating co-combustion and low-grade applications. Development of FBC for new difficult fuels like sludges, RDF and coals that contain chlorine and for fuels with high alkaline contents like straw and some other biomasses is a challenge for Ahlstrom and other companies because of high temperature corrosion risks of the superheater tubes and/or fouling and slagging risks in the furnace. On the other hand, these fuels offer an interesting new market too.

In the design of a boiler for co-combustion the following requirements must be taken into account:

- combustion temperature control when firing fuels having different heating values and contents
- steam temperature control when having different flue gas flows from high and low-grade fuels
- dimensioning auxiliary equipment for different fuels (e.g., fuel handling, ash removal)
- design of fuel feeding system for different fuel types
- meeting of emission requirements with all the fuels selected for use.
- Fluidized bed combustion technology can meet these requirements in the following way:
 - flexible air distribution system for different fuels to control combustion temperature and emissions
 - use of flue gas recycling when firing high-grade fuels like coal to control combustion temperatures, steam pressure and emissions
 - allowing sufficiently large margins when dimensioning auxiliary equipment to meet the requirements of different fuels
 - use of double feeding system if needed to ensure a high availability in fuel feeding
 - use of a heat exchanger in bed material return to control combustion temperature and emissions (CFB).

3.2 CO-COMBUSTION IN AN AHLSTROM PYROFLOW BOILER

There are about 70 different fuels burned in over 100 operating Ahlstrom Pyroflow boilers. The experience from over 300 operating years of these boilers covers several types of industrial waste, oil refining waste, peat, lignite, bark and other moist fuels as well as some high-ash fuels like oil

shale up to 80 % ash content (Table 1). As an example the CFB boiler supplied to Kemira Company's plant in Oulu, Finland, utilizes more than ten different fuels.

In addition to the fuels listed in Table 1, successful pilot tests have been carried out with such fuels as crushed tires, shredded cars and cow dung. Refuse derived fuel (RDF) and packaging wastes (PDF) have been burned with peat and coal in a commercial Pyroflow boiler in Kauttua, Finland, over one-year period in 1993 - 1994 with very successful results. When the amount of waste did not exceed 30 % and the chlorine content of the waste was less than 0.15, no signs of high-temperature corrosion were detected in RDF combustion tests in another commercial boiler in France. The only technical issue that must be considered in co-combustion seems to be feeding of different types of fuel. When designing the fuel handling and feeding systems the physical characteristics of different fuels must be taken into account.

Table 1. Examples of fuels used in commercial Ahlstrom Pyroflow boilers.

Fuel	Unit size MW _{th}	LHV MJ/kg	Moisture %	Ash content % in d.s.	Sulfur content % in d.s.
Brown coal	55 - 313	10 - 24	17 - 51	15 - 55	0.9 - 7.8
Coal	25 - 409	14 - 27	4 - 30	6 - 45	0.4 - 6.2
Petroleum	28 - 160	25 - 32	2 - 10	1 - 10	2.8 - 6.6
Coal refuse	72 - 120	8 - 21	6 - 39	31 - 65	0.3 - 11.0
Oil shale	40 - 156	3 - 6	8 - 12	62 - 67	2.7 - 3.1
Wood waste	15 - 150	6.5	61	2.9	0.08
Bark	43 - 150	6	61	2.3	0.05
Sludge	14 - 240	2.6 - 4.1	50 - 60	10.1 - 47	0.0 - 0.5
Peat	7 - 299	8 - 10	36 - 52	2 - 10	0.2 - 0.9

Based on Ahlstrom's experiences the following conclusions can be drawn from the feasibility of CFB for co-combustion:

- high heat capacity of the bed and good mixing (fuel, air, bed material, sorbent)
- high combustion efficiency based on good turbulent mixing and long residence time in the circulating bed
- optimal system for in furnace sulfur retention at 830 - 900 °C with limestone or dolomite
- low NO_x emissions caused by low combustion temperature and staged combustion
- low CO and C_xH_y emissions due to turbulent conditions, long residence time and mixing in the cyclone

- stable combustion process because of efficient heat and mass transfer between the fuel and the bed material
- good turn-down ratio and boiler response
- no need for in-bed boiler tubes, which are subject to erosion
- smaller amount of fuel feeding points, e.g., compared to BFB, due to good mixing.

BFB has more limitations in multifuel applications than CFB. It is common that BFBs are designed for only a certain type of fuels like biomasses with 30 to 60 % moisture content. BFB can be used for co-combustion of fuels with physical and chemical characteristics close to those of the design fuels. Coal use in a BFB is limited due to the low sulfur removal efficiency with limestone or dolomite compared to CFB and to the need of in-bed boiler tubes for bed temperature control. Therefore, BFBs are feasible for biomass fuels when co-combustion with other types of fuel is not considered.

3.3 CONTROL OF EMISSIONS IN FLUIDIZED BED COMBUSTION

The most important environmental benefits of FBCs and especially CFBs are low NO_x emissions and an opportunity to capture sulfur with limestone or dolomite in the furnace. Ahlstrom Pyroflow CFB boilers have met even the emission limits of California, which are the most stringent in the world. The following describes Ahlstrom's experiences in emission control of Ahlstrom Pyroflow CFB boilers:

SO₂ emissions

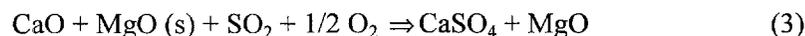
SO₂ emissions are controlled simply by feeding sorbent, i.e., limestone or dolomite into the furnace. In the furnace, limestone is calcinated rapidly to reactive CaO according to reaction (1):



Calcium oxide reacts with the SO₂ released in combustion and forms gypsum, which is removed with fuel ash from the furnace:



When dolomite is used the reaction is as follows:



In CFB combustion, 90 % sulfur capture is normally met at 1.5 - 2 Ca/S ratio. As a comparison, in BFB combustion 90 % sulfur removal requires in Ca/S ratio 3 in minimum (Figure 6). The amount of limestone needed is dependent on the required emission levels, fuel sulfur content, properties of fuel ash, limestone reactivity and particle size distribution. The most important process conditions are temperature, SO₂ concentration in flue gas, flue gas residence time, primary/secondary air split, excess air and bed inventory. Fly ash recycling also decreases the limestone consumption. Optimal temperature for the sulfur capture reaction is between 850 and 880 °C.

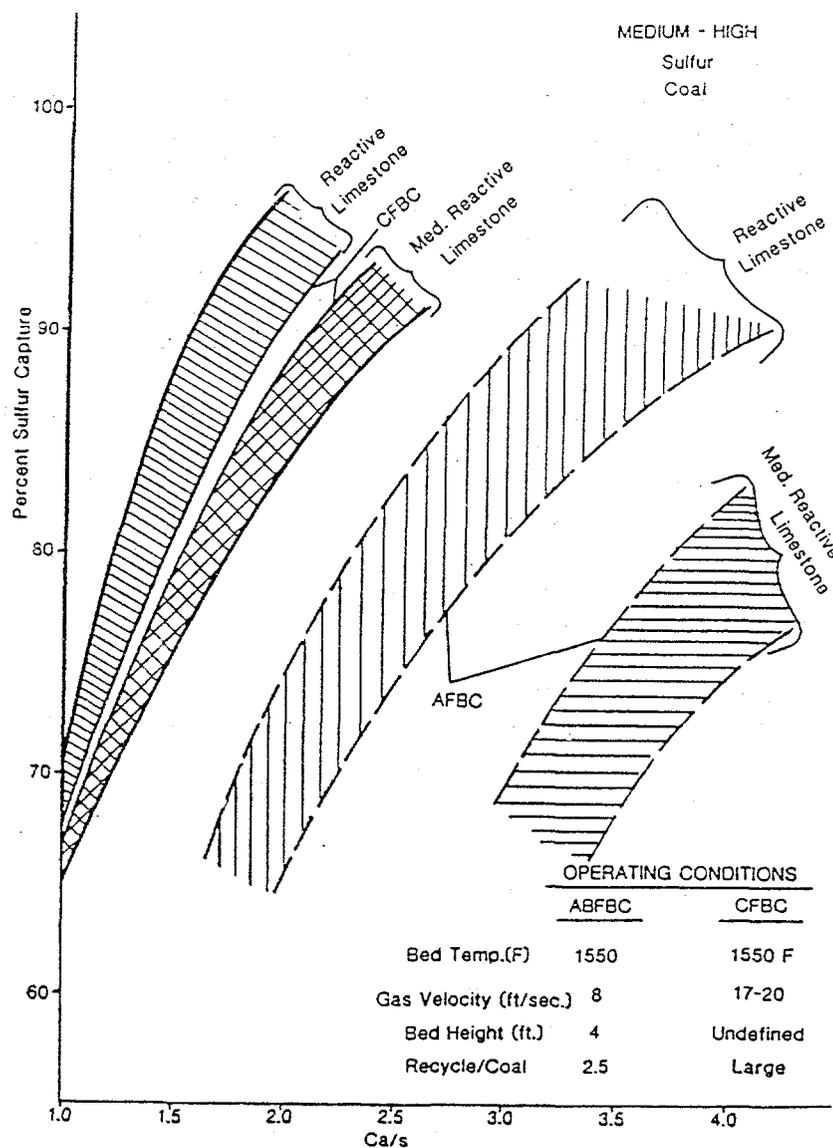


Figure 6. Sulphur retention as a function of limestone types for bubbling bed and circulating fluidized bed combustors [5].

NO_x and N₂O emissions

NO_x emissions of CFBs are low compared to other, more conventional combustion methods due to minimized formation of thermal NO_x caused by low combustion temperature. The NO_x species formed in the CFB combustion originate mostly from fuel nitrogen. In the Pyroflow units in commercial operation, in which the combustion temperature varies 800 - 930 °C, NO_x emissions are lower in CFBs than in BFBs due to a more uniform temperature profile in the CFB furnace.

There are two basic methods to lower NO_x emissions further in CFB combustion. In the furnace, minimization of NO_x formation can be met by staged combustion and by operation at low temperatures. In coal combustion NO_x emissions can be reduced by about 50 % with flue gas recycling that lowers combustion temperature. If even lower NO_x levels are required the SNCR method can be used, i.e. injection of ammonia or urea into the flue gas stream. In extreme cases like in Sweden where environmental taxes are in use, economically optimal and very low NO_x levels are met by installing a thin catalytic layer in the backpass of the boiler for NO_x reduction.

Concerning the N₂O formation, the latest investigations have confirmed that the formation of N₂O is more intensive in low-temperature processes than in combustion processes at higher temperatures. The temperature dependence is strong and at temperatures exceeding 900 °C minor amounts of N₂O are formed. Fuel quality is another important process variable. The emissions are lower when the nitrogen content of the fuel is low and the geological age of the fuel is younger.

The measured N₂O emissions in the cFBs have been from 20 to 130 ppm for coal and from 5 to 30 ppm for biomass fuels. Emissions can be reduced from these levels by staged combustion and combustion temperature control. Catalytic methods can also be applied.

CO and C_xH_y emissions

CO and gaseous hydrocarbon emissions are controlled in CFBs by excess air and combustion temperature. Typically, in operating boilers the CO emission has been 20 - 100 ppm at combustion temperatures of 850 - 900 °C. The total gaseous hydrocarbon emission also correlates with the combustion temperature and has been in the range of a few ppm as methane equivalent. Table 2 presents typical emission values of a commercial-scale Pyroflow boiler.

Table 2. Mt. Poso 163 MW_{th} Pyroflow boiler emission data. The plant is equipped with limestone injection for SO₂ retention and ammonia injection for NO_x control.

Emission	Unit	Guarantee	Performance test	Normal operation
CO	mg/m ³ n	96	74	23
C _x H _y	mg/m ³ n	12	ND	ND
NO _x	mg/m ³ n	113	74	74
SO ₂	mg/m ³ n	84	38	28
Particulates	mg/m ³ n	15	11	Not measured
Ammonia	mg/m ³ n	11	0.9	3.7

ND = not detected

Halogen emissions

Some low-grade fuels contain relatively high amounts of chlorine and some fluorine. Typically chlorine exists as alkaline salts (NaCl, KCl) like in coal, but organic chlorine is abundant in wastes and sludges. During combustion, chlorine and fluorine are released as HCl and HF, which are highly corrosive and environmentally harmful.

In CFB boilers limestone can be used also for halogens control. However, there are significant differences in the behavior of fluorine and chlorine containing compounds under CFB conditions. The fluorine compounds are captured almost entirely in hot conditions inside the furnace, while HCl is mainly captured after the furnace in cooled sections of the boiler and in the backhouse. For high-chlorine fuels, such as PVC-containing plastics, when recovery and recycling of chlorine is needed, a standard scrubber can be used for emission control instead of limestone feeding.

Dioxin and furan emissions

As regards dioxins and furans (PCDD/F) with fuels containing chlorine, the correlation between the formation rate and the combustion conditions has been demonstrated in several studies: the more stable and controlled the combustion conditions the smaller amount of PCDD/Fs is formed. Although the combustion of different types of fuel is well controlled in CFB boilers and hence, the amounts of PCDD/Fs are very low, there is some formation of PCDD/F in the post-combustion area. Meeting the emission limit of 0.1 ng/m³n also requires an efficient flue gas dust removal system, because the measurements have proven that a significant portion of PCDD/F compounds are bound on surfaces of fly ash particles. Table 3 introduces measured PCDD/F emissions of Pyroflow CFB boilers for some chlorine-containing fuels and fuel mixtures.

Table 3. Measured PCDD/F emissions from Pyroflow boilers. The results are corrected to dry gas with 11 % O₂ content. The measurements were carried out during the years 1990 - 1992.

Unit size MW	Fuel	Dust removal	PCDD + PCDF ng/m ³ n
65	coal peat mixed plastics	ESP	0.001 (I-TEQ)
65	coal peat RDF	ESP	0.012 (I-TEQ)
76	coal bark	ESP	0.06 (I-TEQ)
150	coal bark	ESP	0.007 (I-TEQ)
1	wood waste sludge natural gas	bag filter	0.06 (Eadon 86)
1	bark sludge natural gas	bag filter	0.06 (Eadon 86)

Emissions of heavy metals

Volatile metals, such as Hg, As, Pb, Cd, Ni, V and Zn, are vaporized at combustion temperatures. Some of them leave the furnace mainly as vapor (Hg) but some others are condensed and enriched on the surfaces of small ash particles. Due to lower combustion temperature in the CFB, compared to other combustion methods, smaller amounts of heavy metals are vaporized leading to lower levels of emissions, e.g., compared to those of pulverized coal combustion.

It is also possible to use absorbents for some heavy metals. It has been demonstrated that limestone and coal ash capture over 70 % of the fuel Hg into fly ash. As an example, vaporized mercury in RDF combustion is bound into CFB ash containing some amount of free lime. The pH of ash leachates is high, 10 - 12. In these conditions the solubility of heavy metal compounds is minimized and the ash is considered stable and safe.

4 AHLSTROM PYROFLOW COMPACT - THE NEXT GENERATION CFB

The challenge of the 1980s was to develop, from the customer's point of view, a simpler, more reliable and less space-requiring CFB meaning also lower investment and operation costs. On the other hand, in the 1990s there

is a need to develop CFB's competitiveness against large pulverized coal-fired boilers and to increase the efficiency of the CFB system in power generation. The key issue was the uncooled cyclone that requires quite a lot of space, increases maintenance costs, causes some energy losses and is rather expensive. Many customers also felt that a boiler with a large cyclone or several cyclones did not look like a real boiler.

In the 1980s some CFB manufacturers developed a cooled cyclone to be located outside the furnace but it lowered neither the need of space nor investment costs. As a result of Ahlstrom's intensive development efforts the new enhanced CFB, Ahlstrom Pyroflow Compact (C) was introduced in 1992. Pyroflow C is not of new CFB combustion technology. It is an enhanced version of the Pyroflow CFB with square solids separators that are constructed of water-cooled membrane walls (Figure 7). The benefits of Pyroflow C are small space requirement due to compact design, lighter structure, cooled cyclone and lower maintenance and investment costs. The amount of refractories in Pyroflow C is about 70 % smaller than that in conventional CFB, leading to shorter start-up and shut-down periods.

What is a Pyroflow Compact?

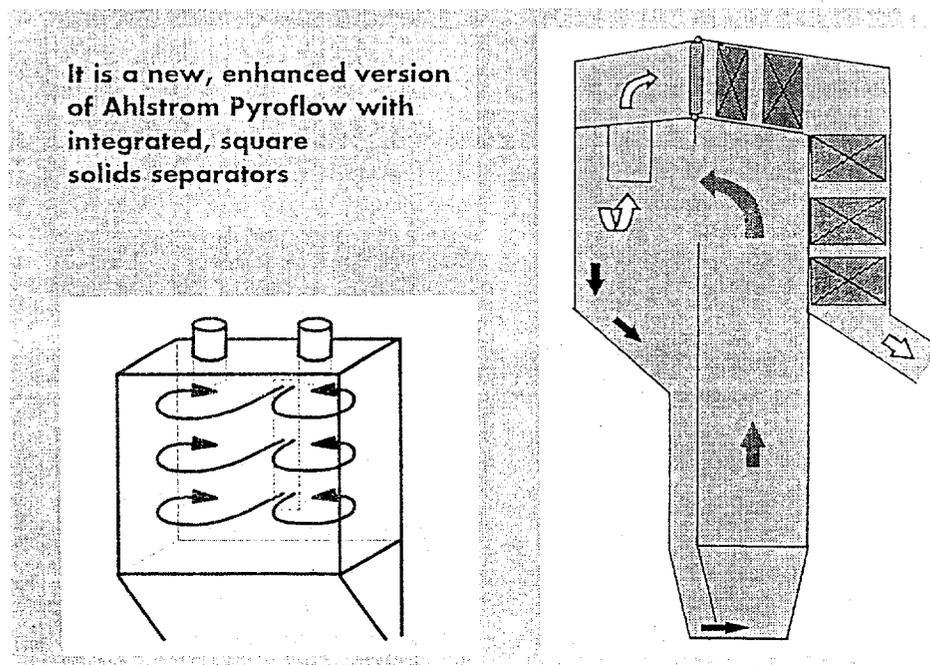


Figure 7. Principle of PYROFLOW Compact Circulating Fluidized Bed system [8].

The first Pyroflow C started operation in Kuhmo, Finland, in 1992 for combined heat and power generation. The electric output of the plant is 5 MW and district heat output 13 MW. The plant uses wood waste and peat as fuels (Table 4). Pyroflow C has been accepted by customers very quickly and in total seven other units have been commissioned to Finland, Sweden, and Thailand. During the next few years Ahlstrom's plan is to replace the conventional Pyroflow with the C model on all markets and in all size classes. In addition, our target is to scale Pyroflow C up to 400 - 600 MW_e applying also supercritical steam conditions.

As a nephew for Pyroflow C Ahlstrom developed a fluid-bed heat exchanger that is placed in the solids return part of the Compact separator (C-HEX, Compact Heat Exchanger). Replacement of any heat exchangers with C-HEX(s) increases flexibility in heating surface arrangements, gives a much higher heat exchange efficiency (5 times higher than in gas pass), provides a new means to control the temperature in the furnace and also a new means for superheat/reheat temperature

Table 4. Technical and emission data of Kuhmo Pyroflow compact plant [8]. Kuhmon Lämpö Oy, Kuhmo, Finland. Ahlstrom Corporation.

Cogeneration Power Plant			
Power output max		4.8 MW _e	
District heat output max		12.9 MW _t	
Ahlstrom Pyroflow Compact CFB boiler, design data			
Thermal output		MW	18
Stem flow		kg/s	6.3
Steam pressure		bar	81
Steam temperature		°C	490
Fuels		Peat	Wood waste
		100 % MCR	100 % MCR
Sulfur	%	0.2	0
Ash	%	5.6	2
Moisture	%	55	55
Lower heating value	MJ/kg	7.7	7.3
Emission guarantees		Guarantee	
NO _x	mg/MJ	150	
Dust	mg/MJ	66	

control as well as a new means for higher steam conditions and power generation efficiency. C-HEX also provides a very promising solution to deal with high-temperature corrosion that strikes the tube bundles in the gas pass when using high-chlorine fuels and/or various biomasses. The final stages of superheat/reheat can be realized as C-HEX surfaces in a chlorine-free environment while chlorine in the gas pass does is not causing corrosion in the lower metal temperature conditions.

The C-HEX has been tested by Ahlstrom's laboratory in Karhula since 1992 and a C-HEX was retrofitted to a commercial coal-fired Pyroflow CFB boiler in 1993. In all these tests C-HEX has operated precisely as expected. Pyroflow C with C-HEX under full commercial guarantees has been proposed and the first contracts are expected in the near future.

5 CONCLUSIONS

Fluidized-bed technology has proven commercially its superiority in efficient, economic and environmentally sound combustion of a large variety of fuels starting from very high-ash fuels like oil shale, from very moist fuels like bark and sludges up to high-grade fuels like low-sulfur bituminous coals. Especially CFBs are real multifuel boilers with a very small amount of limitations in chemical or physical fuel characteristics. There are about 130 Ahlstrom Pyroflow CFB boilers in operation or under construction and about 80 bubbling bed boilers, respectively. Pyroflow boilers have proven feasibility to burn about 70 different fuels alone or in co-combustion mode. BFB boilers have proven their feasibility for biomass and other fuels with similar characteristics especially in smaller sizes.

The new enhanced CFB technology, Pyroflow Compact (C) offers an even more competitive solution for combustion and co-combustion of various fuels in industrial and district heating scale as well as for scaling-up CFB technology up to 400 - 600 MW_e plants for coal or lignite. New developments connected to Pyroflow C such as C-HEX heat exchanger increase fuel flexibility further and allow higher efficiencies in the power generation process.

Atmospheric circulating fluidized-bed gasification will have niche market opportunities in gasification of dry wood wastes or some other dry biomasses. There are some development activities going on related to burning the gas in a large utility or industrial boiler as an additional fuel. Application of atmospheric or pressurized CFB gasification of various biomasses in combined-cycle processes (IGCC) is under development as well.

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USE AND CO-COMBUSTION OF STRAW IN DENMARK

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Abstract

Coal has in more decades been the backbone of the Danish energy production. As a consequence of a political wish to utilise domestic fuel and reduce the massive use of coal and the CO₂ emission, straw has since 1989 been used in Denmark at small-scale combined heat and power plants.

All straw-fired combined heat and power plants in Denmark are owned by the power stations. Furthermore some district heating plants owned by the municipalities, consumers or privately owned, also use straw as a fuel, as in the middle of the eighties it was prohibited to use coal as fuel in district heating plants. Different rules of subsidies and duties made natural gas or biomass the most competitive fuel for the district heating plants. For various other reasons there are also some oil-fired district heating plants in operation. Today five straw-fired combined heat and power plants in Denmark are in commercial operation. Three of these plants exclusively use straw as a fuel, one uses both straw, wood chips and natural gas, and one straw and coal. These five combined heat and power plants, having a total annual consumption of straw of approx. 200 000 tonnes, supply district heating to five medium-sized towns.

On 14 June 1993 an agreement was made in the Danish Parliament ordering the power stations to reach an annual volume input of 1.2 mill. tonnes of straw and 0.2 mill. tonnes of wood chips in year 2000.

Therefore two new plants are under construction and co-combustion with straw is being installed at an existing coal-fired power station. In addition, two large plants are under consideration.

With the two plants under construction and with the co-combustion plant, the straw consumption is expected to increase to 430 000 tons of straw per year. These two plants will start operations in 1995 and 1997 respectively.

All the operating straw-fired combined heat and power stations show an economic loss. Besides the price of fuel, this is due to the efficiency of the

plants, which with a steam temperature of approx. 430 °C is not sufficiently high. In order to make the straw-fired combined heat and power stations profitable the efficiency and the steam temperature must be increased.

The low steam temperature is due to the fact that straw is a particularly corrosive fuel. Straw contains very little sulphur, but in return so much chlorine that it is one of the most aggressive fuels. At straw firing, steam temperatures above approx. 450 °C have so far given unverifiable corrosion damage to the superheaters.

In the two plants under construction the steam temperature is increased in two principally different ways. One plant is described in details.

1 INTRODUCTION

ELKRAFT is co-operative owned by the power producers on Zealand. ELKRAFT represents the total power supply in the Danish region east of the Great Belt. The power producers west of the Great Belt are correspondingly associated in the organisation ELSAM. SK Power is the biggest power producer in Denmark covering 33 % of the electricity supply. The newest decentralised CHP plant of SK Power fuelled by straw is Masnedøværket.

2 DANISH ENERGY POLICY

During the 1950s, the energy supply was changed from coal to oil due to the ever falling oil prices. Consequently oil grew to an almost entirely predominant position among the fuels. This left Denmark particularly vulnerable to external geopolitical events at the end of the 1960s being more than 90 % dependent on oil imports. During this period energy consumption grew very fast. When the first oil crisis came, Denmark established its first de facto energy policy, and a number of measures were introduced.

Between 1973 and 1988 security of supply, domestic energy production and energy savings were given the highest priorities. The most important measures were:

- Increased energy efficiency in district heating (DH) and combined heat and power (CHP). Overall efficiency in the power/heat supply rose from 45 % to 56 % during this period, making Denmark one of the most energy efficient countries in the world today.

- Savings in room heating were stimulated by grants for insulation etc. During this period, energy consumption per square meter heated area decreased by app. 50 %.
- Oil was substituted with coal, in particular in the power production sector, where imported coal today constitutes 93 % of the fuel supply. The dependency on oil was reduced from 93 % to less than 50 %.
- Domestic oil and gas production from the North Sea was increased, and today, Denmark's own energy production outbalances its total energy consumption.
- Renewable energy production tripled, and the use of biomass in the heat supply was expanded through energy taxes. Biomass today supplies 6 % of gross energy consumption.

The development is illustrated in Figure 1.

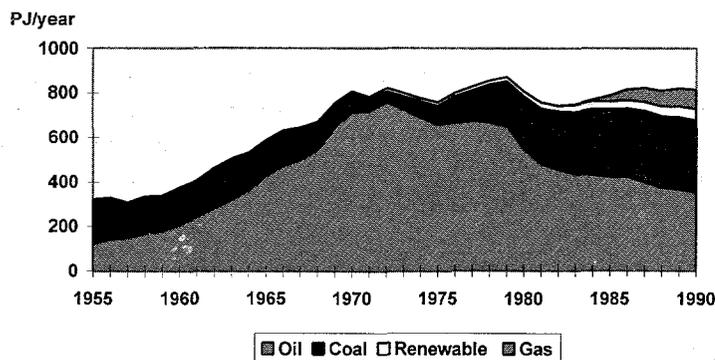


Figure 1. Danish energy consumption 1950-1990.

Following the World commission's recommendations, the Danish government in 1988 decided upon a comprehensive strategy to create a sustainable development, and a national goal for reducing CO₂ emissions was set, committing Denmark to

- reduce emissions by 20 % of the 1988-level by year 2005
- reduce NO_x and SO₂ emissions by 50 % and 60 % respectively
- and further reduce CO₂ emissions by 50 % by the year 2030.

The elements in this plan include:

- Enhanced energy efficiency through attachment of more consumers to existing district heating and gradual conversion to CHP of more than 330 district heating plants.
- Savings
- A CO₂ tax on fossil fuel

- Increased use of cleaner fuels to substitute coal. To stimulate this, a subsidy of DKK 0.27 to electricity production from renewable sources is given.

On 14 June 1993 an agreement was made in the Danish Parliament ordering the power stations to reach an annual volume input of 1.2 mill. tons of straw and 0.2 mill. tons of wood chips in year 2000.

3 BIOMASS RESOURCES IN DENMARK

The quantities of biomass in Denmark available for energy production correspond to 127 PJ. This amounts to a potential of 15 % of the total Danish gross energy consumption. Today biomass supplies 6 % of energy consumption.

75 % of the available amount of wood and municipal solid waste is used for energy purpose today. A surplus of 2,5 mill. tons of straw is available for energy purposes, but only 1 mill. tons is actually used, as can be seen in Figure 2. Likewise, only 1 % of animal manure is today processed in biogas plant.

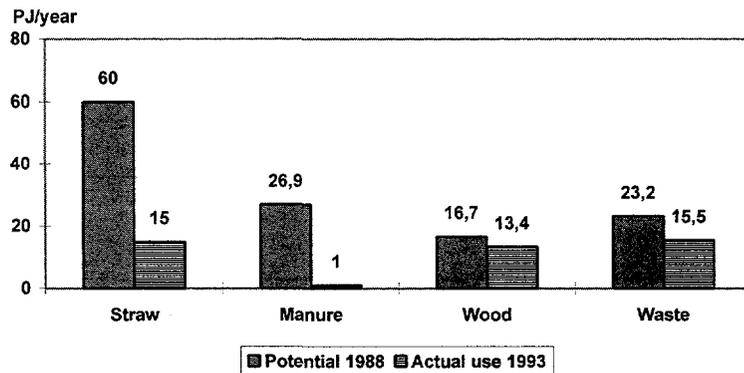


Figure 2. Energy potential and actual use of biomass.

The burning of straw in the fields has been prohibited since 1990. The main focus of attention consequently rests with straw.

The energy potential of biomass is significant. Compared to coal biomass is a more complicated energy resource, which poses a number of problems. Future production patterns in agriculture may have large effects on the long term supply and the general costs of recovery from the fields are too high today. The combustion characteristics are very different from those of coal.

4 BIOMASS AND POWER PLANTS

Since 1985, the utilities have spent more than DKK 2.2 bn (USD 034 bn) on research and development of efficient electricity production from biomass in order to use biofuels in a vary large scale.

The biomass related activities till today have been focused on the following areas:

- Development and demonstration of full-scale decentralised CHP plants fuelled with straw, biogas, wood and waste.
- Use of biomass in central coal fired power plants
- Improved straw production, handling and transportation.

5 BIOMASS IN DECENTRALISED CHP PLANTS

In 1986 an agreement was made between the Danish parliament and the utilities, under which a total of 450 MW of small-scale CHP plants should be established all fuelled with domestic energy sources i.e. natural gas, biomass and municipal solid waste.

In March 1990 a detailed plan to convert all 330 Danish district heating plants to small-scale CHP-plants was agreed on.

In Table 1 an overview is given of 6 plants that include straw in their fuel supply. The straw fired plants in Haslev, Rudkøbing, Slagelse, Måbjerg and the new Masnedø are based on conventional grate-fired boiler, while the plant in Grenå is based on a circulating fluid bed boiler.

Table 1. Utility built CHP-plants fuelled with straw.

Plant	Commissioned	MW	MJ/s	Straw %	Waste %	Other
Haslev	1989-08	5	13	100		
Slagelse	1990-04	11.7	28	47	53	
Rudkøbing	1990-08	2.3	7.8	100		
g	1990-12	3	9	16	71	13 % wood chips
Vejen	1990-01	18.6	60	60		40 % coal
Grenå	1993-01	28	68	20	61	19 % woodchips
Måbjerg						/gas
Total		68.6	186			

5.1 OPERATIONAL EXPERIENCES

A number of important conclusions can be drawn from the operation of the straw-fired plants:

- Low power-to-heat ratio
- The average power-to-heat ratio has been lower than expected due to running-in problems caused by slag and clinker formation in the furnace, which has meant more closing downs for maintenance and repair than originally anticipated. Due to this, the sale of electricity has been lower than budgeted.
- Slag formation
The many starts and stops have caused the furnace walls to be alternately cooled and heated, resulting in increased slag-formation and corrosion. The automatic slag removing systems has proven not able to handle problem.
- Combustion
Because straw is such an inhomogeneous fuel all kinds of problems have been experienced. Certain straw types were found not suitable for combustion, except if mixed with other straw types. The experience with straw shredders up to now has shown, that the capacity of the shredders is rapidly going to zero, when the moisture content in the straw exceeds 22 %.
- Personnel
The need for repairs and modifications in the prolonged running-in period, has required more personnel as expected.

To increase the economic profitability at straw fuelled CHP plants it is urgent to increase the energy efficiency and the ratio between electric and heat production. That means that steam-pressure and -temperature must be increased. The steam data for the straw fuelled CHP plants up to now are approx. 70 bar and 430 °C.

The steam data are due to, that straw is a very aggressive fuel, because of the very high contents of chlorine (2 %). When steam temperatures do not exceed approx. 450 °C the corrosion of the superheaters is controllable. When steam temperatures exceeds approx. 450 °C the corrosion of the superheaters has up to now not been controllable.

There are two principles to increase steam temperatures and reduce high-temperature corrosion in straw-fuelled plants:

- Use of other kinds of steels types than the types used until now, and a better design of furnace and superheaters to reduce fluegas-velocity and slag-building between the superheater tubes.

- Use straw to superheat steam to 450°C and then use another fuel such as wood chips or natural gas to superheat the steam from 450°C to the desired end steam temperature.

The next generation of straw-fuelled CPH plants, following the first principle, is commissioned in October 1995 at Masnedø and will be described later in this paper.

6 BIOMASS IN CENTRAL POWER STATIONS

The utilities have carried out a great amount of research and development including several test trials, firing biomass in a mix with coal on central power stations. In Table 2 an overview of trials carried out is given.

Table 2. Utility test trials using biomass co-fired with coal.

Power Station	MW	Biomass fuel		Period	Spending (mill. DKK)	Spending (mill. \$)
Masnedø	75	Straw	15700 tons	1985-1987	5	
Århus	43	Straw	10-30% 2000 tons	1992	2.5	
Århus MFCB	20 (heat)	Straw	0-80% 10000 tons	1988-1991	87.6	
Århus MFCB	20 (heat)	Wood	50 tons	1991	-	-
Studstrup	152	Woodpills	40 tons	1992	-	-
Vestkraft	153	Straw	1500 tons	1992	2.5	0.4
Østkraft	26	Straw pills	500 tons	1992	2.5	0.4
Vestkraft	153	Straw	36000 tons	1993-1994	-	-
Vestkraft	153	Woodpills	1400 tons	1994	-	-
Amager	250	Straw	2500 tons	1994	5	0.8

Straw is much more expensive than coal per GJ, with current market prices ranging from 350 to 600 DKK/ton corresponding to DKK 23 - 40 /GJ. Coal prices are DKK 12 /GJ. The costs of supplying straw to a central power plant can be divided into the following elements, see Table 3.

Table 3. Straw recovery costs.

Handling and recovering	190 DKK/ton	29 \$/ton
Storage	30-130DKK/ton	4.6-19.8 \$/ton
Insurance	10 DKK/ton	1.5 \$/ton
Transportation	70 DKK/ton	10.7 \$/ton
Total	300-400 DKK/ton (20-27 DKK/GJ)	45-61 \$/ton (3-4.1 \$/GJ)

Primarily baling and storage of straw add to the high present costs. New storage and baling systems are being investigated, and it appears, that a cost of 220 - 300 DKK/ton is not unrealistic.

Besides the problems known from decentralised CHP plants investigations in the following areas are necessary:

- A coal/straw burner concept must be developed.
- Co-firing of coal and straw together, or mixing fluegas from coal and straw may influence the operation of de-NO_x and de-SO_x cleaners and may render the mixed ash and residue quality impossible to use for industrial purposes.

Adding the amount of straw and wood, that is available for energy production to any randomly selected central power station does not per se result in the desired CO₂ reduction. On the contrary, it can result in increased emissions as can be seen from Figure 3.

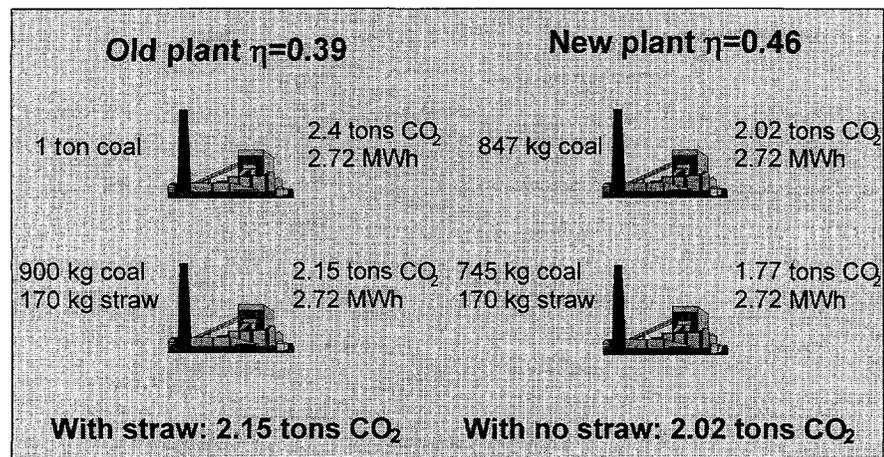


Figure 3. Different combinations with different CO₂ impact.

From the figure two important conclusions can be drawn:

1. In order to maximise the CO₂ effect, it is necessary to use straw in the plants with the highest available efficiency. In some cases, it can from a CO₂ point of view be even more profitable to build new efficient coal plants, to substitute old inefficient ones.
2. When straw is used in plants with low efficiency, that would not otherwise have been in operation, the 90 % coal with which it is co-fired is tied up with the straw, thus constantly substituting electricity that could otherwise have been produced with much less CO₂ emission at another coal plant - and as such erode the CO₂ benefits.

The plants with the highest efficiency are the most important plants in the power system, and also the ones where reduced availability, for instance due to the risk of superheater corrosion because of co-firing, are least acceptable. Hence plants with separate coal and straw boilers are most probable in the future in spite of the higher investment costs.

In the ELSAM area a new project has been decided to replace steam from an existing boiler with steam from a new biomass fuelled plant. Steam data are 210 bar and 543 °C and the steam flow is 33 kg/s. The project includes a straw fired boiler, which superheats the steam to 470 °C, and a wood chips fired boiler, which heats the steam from 470 °C to 543 °C. The new boilers will be commissioned in July 1997.

7 DESCRIPTION OF MASNEDØVÆRKET CHP

7.1 GENERAL DESCRIPTION OF MAV12

The board of directors of SK Power decided in March 1993 to establish the straw fuelled combined heat and power plant Masnedøværket 12. The plant will be commissioned October 1995 and the total costs will be DKK 220 mill. (USD 36.7 mill.). The plant has the following main data (Table 4):

Table 4. Main data of MAV12.

MAV12		
Electric output (gross)	9,5	MW
Electric output (net)	8,3	MW
Heat output	20,8	MJ/s
Heat sold	386	TJ/year
Fuel input	33,2	MW
Straw consumption	62079	tons/year
Electric output / heat output	0,40	
Total efficiency	87,5%	
Steam flow	12,01	kg/s
Steam pressure	90	bar
Steam temperature	520	°C
District heating supply temperature	95	°C
District heating return flow temperature	60	°C

The plant shall primarily ensure the power and heat supply of the city of Vordingborg. The heat production of 337 TJ will cover 90 % of the heat consumption of Vordingborg. The plant is automated so, that it is only manned in the daytime in workdays. The plant will be operated by 10 men.

7.2 FUEL

The plant will be fuelled by Heston-bales of straw. It is also possible to use bales with straw and grain. Yearly straw consumption will be 62 000 tons. In addition it is also possible to fuel the plant by up to 30 % wood chips. The straw is stored in a straw storage of 2 500 m². The straw storage is capable of holding straw for the consumption of 3 days.

7.3 PROCESS

From the straw storage the straw is transported to the boiler by an automated crane-system. Immediately before the boiler the strings around the bales are teared off by 2 straw shredders and the straw is pushed into the furnace by 4 screw-conveyers. In the furnace the straw is falling down on a water-cooled grate.

The boiler is a grate-fuelled drum-boiler with furnace, 2 superheater-passes and a pass with economiser and air-preheaters. The fluegas is cleaned in an electrostatic precipitator (Figure 4).

To increase the energy efficiency of the plant the turbine is equipped with steam bleeds for the two district heating heat exchangers, condensate preheater, feed water tank and feedwater preheater. The district heating heat exchangers and the condensate preheater are equipped with titanium tubes.

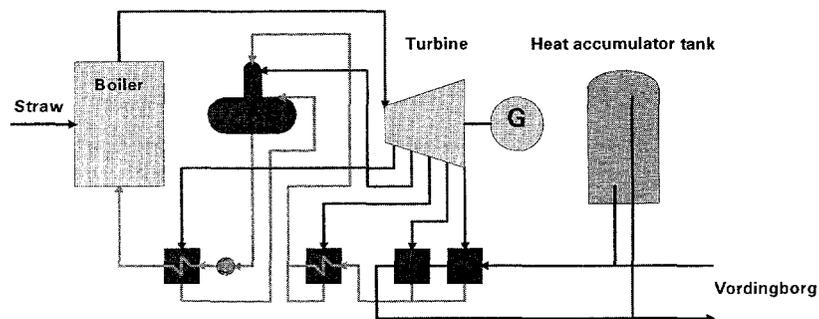


Figure 4. MAV12 CHP.

The plant includes a heat accumulator tank with a capacity of 5 000 m³ district heating water. The tank has a height of 33 metres and can store heat corresponding to 9 hours of full load production.

7.4 IMPROVEMENTS IN RELATION TO PREVIOUS PLANTS

The experience with straw shredders has up to now shown, that the capacity of the shredders is rapidly going to zero, when the moisture content in the straw exceeds 22 %. Therefore a new and very simple type of straw shredders are introduced, so that it is possible to burn straw with a higher moisture contents, because the straw price can thereby be reduced.

The steam data for the existing straw fuelled CHP plants are approx. 70 bar and 430 °C. Steam data for MAV12 are 90 bar and 520 °C. It is attempted to reach the high steam data for MAV12 by implementing the superheaters in TP347 H FG, by designing the superheaters with a big distance between the superheater tubes and by designing the superheaters with a very large area, so that the flue gas velocity is very low.

As a test 10 pieces of different steel types are welded in into the superheaters and a test program is planned to monitor the corrosion. If an appropriate lifetime of the superheaters is not reached, it is possible to implement a natural gas fuelled superheater.

As mentioned above the energy efficiency is increased by implementing a high pressure feedwater heater.

To keep the dust-emission below the required value, it is necessary to lower the fluegas temperature in the electrostatic precipitator. Hence a fluegas-cooler is implemented between the boiler and the electrostatic precipitator.

New technologies, pyrolysis

THERMOCHEMISTRY: THE KEY TO MINERALS SEPARATION FROM BIOMASS FOR FUEL USE IN HIGH PERFORMANCE SYSTEMS

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Abstract

Biomass use in high efficiency thermal electricity generation is limited not by the properties of the organic component of biomass, but by the behavior of the associated mineral matter at high temperatures. On a moisture and ash free basis biomass, which has an average formula of $\text{CH}_{1.4}\text{O}_{0.6}\text{N}_{0.1}$, has a relatively low heating value of 18.6 GJ/t. However, this would not limit its use in high efficiency combustion systems because adequate high temperatures could be reached to achieve high carnot cycle efficiencies.

These high temperatures cannot be reached because of the fouling and slagging propensities of the minerals in biomass. The mineral composition is a function of soils and the growth habit of the biomass, however, the most important element is potassium, which either alone or in combination with silica forms the basis of fouling and slagging behaviors.

Growing plants selectively concentrate potassium in their cells, which along with nitrogen and phosphorus are the key macronutrients for plant growth. Annual plants tend to have very high potassium contents, although wood biomass exclusive of the living cambial layer (i.e. minus the bark, small branches, and leaves) has minimal potassium content and other nutrients. Under combustion conditions the potassium is mobilized, especially in the presence of chlorine, at relative low temperatures and fouls heat transfer surfaces and corrodes high performance metals used, for example, in the high temperature sections of burners and gas turbines.

Recent work has demonstrated the phenomenology of ash fouling, mainly by the potassium component of biomass, as well as identifying the key species such as KOH, KCl, and sulphates that are involved in potassium transport at temperatures <800 °C. Techniques that separate the mineral matter from the fuel components (carbon and hydrogen) at low temperatures reduce or limit the alkali metal transport phenomena and result in very high efficiency combustion applications in combustors, gas turbines, and diesel engines. Gasification and various types of clean up systems as well as pyro-

lysis techniques are able to separate the minerals from the fuel component. The performance of these systems under investigation will be discussed.

1 INTRODUCTION

Until the early 1970s, the industrialized world thought that biomass was likely to be replaced by much cleaner and more convenient fossil fuels, or even intermittent renewables such as wind and photovoltaics as the century progressed. The term biomass was almost synonymous with forest derived materials or wood fuel, and by-products of the major wood processing industries such as sawmills and pulping operations. In context of developing countries, biomass use was seen as necessary, but once again would slide out of the picture as the industrialization process continued in the Less Developed Countries (LDCs). Many factors, including energy security from imported oil, the need to address the disposal of industrial and domestic residues, and the need to pay attention to the accumulation of greenhouse gases in the atmosphere, have changed this to the point that biomass is no longer seen as going away, rather it will be one component of the fuel and energy mix for the next 50 years.

As a renewable source of energy, biomass has some entirely different characteristics to the other intermittent sources - for one thing it is stored solar energy. Unfortunately the collector size is limited to that portion of the land surface that will support forests and arable land operations. Biomass potential also has to be seen in the context of the supply of wood, fodder and feed for animals, and the production of materials such as lumber and paper. Thus, any student of the use of biomass knows that growing plants for energy only is likely to be a small part of the total supply because dedicating land for such purposes requires there to be land surplus for food, feed, and fiber requirements - something that is very limited in China, but available within the ECU and USA at the present time.

It is much more likely that bioenergy resources will be associated with harvesting, processing and recycling activities in the agriculture, food, fiber and urban sectors. I have proposed a hierarchy of bioenergy resources that is given in Appendix I to illustrate this fact. However, the important bottom line to be drawn from this discussion is that bioenergy opportunities are likely be a mix of feedstocks that vary in quantity and quality with time or season.

Nowhere is this better illustrated than in the independent power industry of California where power plants routinely accept a wide and variable range of resources as shown in Figure 1.

Even under conditions in which some of the biomass will come from a dedicated feedstock supply system such as a short rotation woody crop, e.g. willow, some portion of the feedstock supply will be residues and other materials that will vary in quantity, quality, and availability by season.

2 BIOMASS. THE QUALITY ISSUE

All biomass on moisture and ash free basis has essentially the same composition - an average formula $CH_{1.4}O_{0.6}N_{0.1}$ and thus almost all biomass has very similar heating values. There are tremendous variations in the nature of the natural polymers: cellulose, hemicellulose, lignin and organic extractives.

The unique feature of biomass is that it is composed of recent plant matter, material that in fact was living, respiring carbon dioxide and oxygen only days, weeks or months before utilization. Life is conducted at a cellular level; the well-known components of the cell include proteins, and electrolytes, which by using energy in the form of ATP (the fuel prepared from photosynthesis), maintain the cells functions of growth and respiration. In particular, potassium is the chief cation in plant vacuoles, causing water to

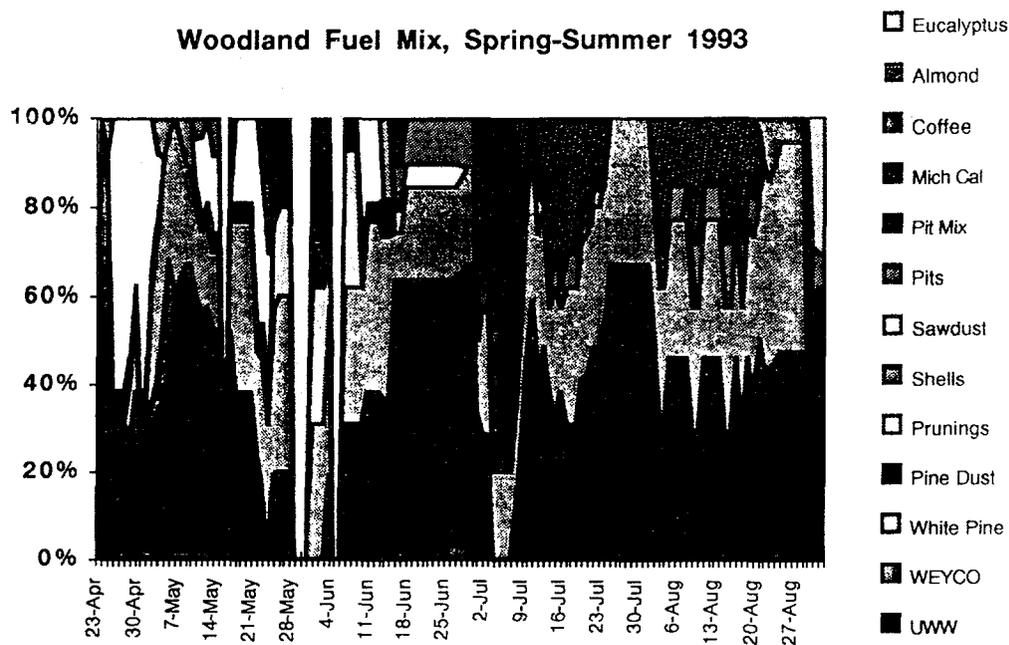


Figure 1. Biomass use at a California site [15].

be retained osmotically, thus generating turgor to support the plant, as well as being the principal electrolyte of the cytoplasm (where sodium is in fact toxic). The plasma membrane of the cytoplasm is an ion pump that uses ATP to drive the potassium ions against the electric gradient between the cell and the surroundings [1]. Harvesting biomass then captures all of the cell constituents, which as the cell dries out, are incorporated by absorption and other mechanisms into the matrix of the cell wall.

Thus biomass has inorganic constituents that include as major components: nitrogen, phosphorus, potassium, calcium, magnesium, sodium, chlorine, sulphur, silica, alumina, and carbonates. Harvesting biomass removes these materials from the soil along with the fiber or seedcrop, and as a result, farmers use chemical fertilizers that contain N, P, and K levels appropriate to the status of the soil and the crop requirements. It should also be noted that plants contain a variety of heavy metals including iron, zinc, copper, and manganese that are constituents of essential enzymes that take part in cellular synthesis - or processes - one of the most obvious is the magnesium that is at the photosynthetic center - in the heme molecules of photosynthesis.

3 POTASSIUM - OK OR A KO (KNOCK OUT) FOR THE COMBUSTION OF BIOMASS?

Potassium (along with N, S, Si and Cl) is one of the major non-organic components of biomass and is the root cause of most of the known fouling problems in direct combustion. Despite potassium being similar in abundance to sodium in igneous rocks - because of the biochemical role it plays in cellular activity - it is concentrated relative to sodium in plant biomass by a factor of 10 to 1 000 in biomass, and is thus the major alkali metal to be dealt with.

In combustion systems using fuels with high potassium contents a major problem is the deposition of potassium in conjunction with other inorganic species including silicates on heat transfer surfaces. Recent studies [15] have correlated this behavior for a range of biomass fuels to predict fouling potential in high intensity combustion boilers such as those used by non-utility generators in the USA (Figure 2).

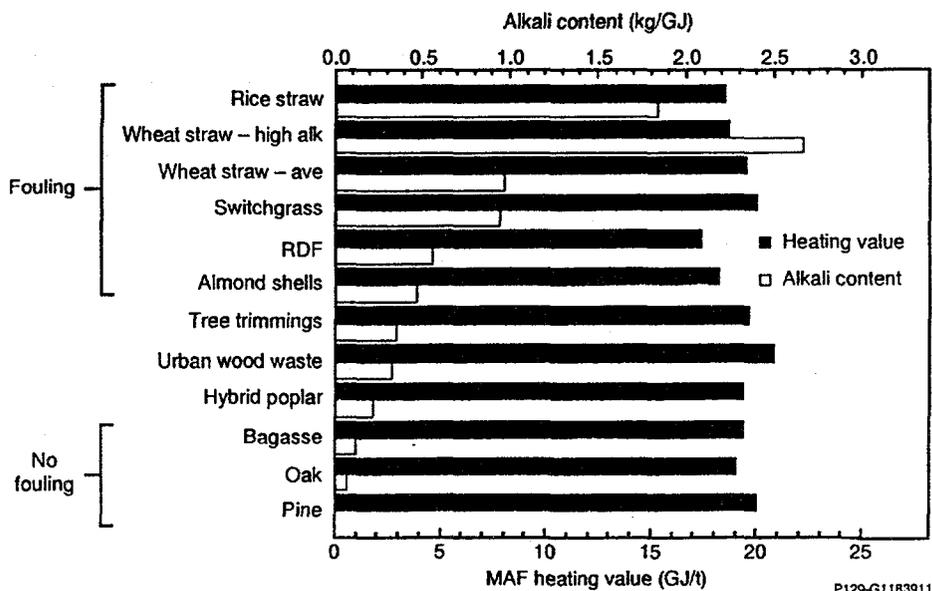


Figure 2. Fouling behavior of biomass [15].

Because high temperature processes produce higher efficiencies of electricity generation, there is much interest in the use of high efficiency (and thus high temperature gas turbines) in either open cycle or in combined cycles. Gas turbine designers Because high temperature processes produce higher efficiencies of electricity are very concerned about the consequences of ash in fuels which can affect the performance of the hot section in three ways [2]: 1. Deposition, 2. Erosion, 3. Corrosion.

1. Deposition of alkali metal salts can block the narrow hot section passageways of gas turbines very rapidly. The particles reach the surfaces by inertial impact, turbulent eddy diffusion, brownian diffusion, and thermophoresis. Typically first of these factors is only important for particles larger than
2. μm , a size that can be effectively removed by high efficiency cyclones [3]. Turbulent eddy diffusion occurs on the suction side of airfoils and is generally a phenomenon for particles that range in size from $3\ \mu\text{m}$ and smaller, particle sizes that require filtration techniques to remove them from gas streams [4]. Brownian diffusion is important for particles less than $50\ \text{nm}$ in diameter, while thermophoresis can occur on a molecular scale as well as for larger particles in very large temperature gradients. Studies of the performance of direct biomass fired turbine systems have demonstrated that the first two of these mechanisms are in fact very important [5, 6]. Deposition decreases the performance of

turbines by increasing surface roughness, and increases in the trailing edge thickness and reducing flow areas.

3. Erosion is the literal removal of material by the action of moving particles. This can even be observed in the relatively high speed passes between boiler superheater tubes, however, in a turbine impact erosion can remove protective oxide coatings from blades, and destroy the mechanical integrity of blades by thinning their trailing edges. Particles of less than 1 μm in diameter are more likely to follow stream lines, therefore, using cyclones and filtration should minimize these effects.
4. There are two types of hot corrosion: high temperature or type I corrosion, occurs at metal temperatures of about 815 - 950 $^{\circ}\text{C}$ when sulfur is present with either potassium or sodium. These sulfates condense on the surface of the high temperature alloy and dissolve the protective oxide surface allowing further oxidation and corrosion to occur. Lower temperature corrosion, type II corrosion, is also caused by sulphates, usually under a high partial pressure of sulfur trioxide, a condition that is relatively rare for biomass.

4 POTASSIUM IS EASILY TRANSPORTED OUT OF BIOMASS INTO THE GAS STREAM

The studies by Professor Ragland's group in Madison, Wisconsin [7] have demonstrated that when low temperature ashes of different wood species and components are heated in the range of 500 - 900 $^{\circ}\text{C}$ there is a significant mass loss. Ragland's detailed analysis shows that potassium, zinc, sulfur, boron, sodium, and copper were lost, whereas calcium, magnesium, phosphorus, manganese, aluminum, iron and silicon did not decrease in the temperature range of 600 - 1 300 $^{\circ}\text{C}$.

At the National Renewable Energy Laboratory, work by David Dayton and Thomas Milne [8] has demonstrated that the mineral and other non-CHO elements are mainly retained in the char phase after combustion of biomass volatile materials (Figure 3). Char combustion then liberates a wide range of species. Of particular interest is the extensive range of potassium compounds that are volatilized from potassium-rich materials such as wheat straw char (Figure 4).

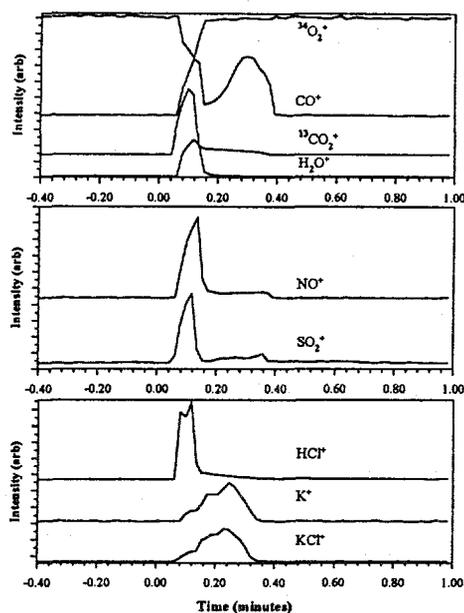


Figure 3. Time sequence of alkali evolution in switchgrass combustion.

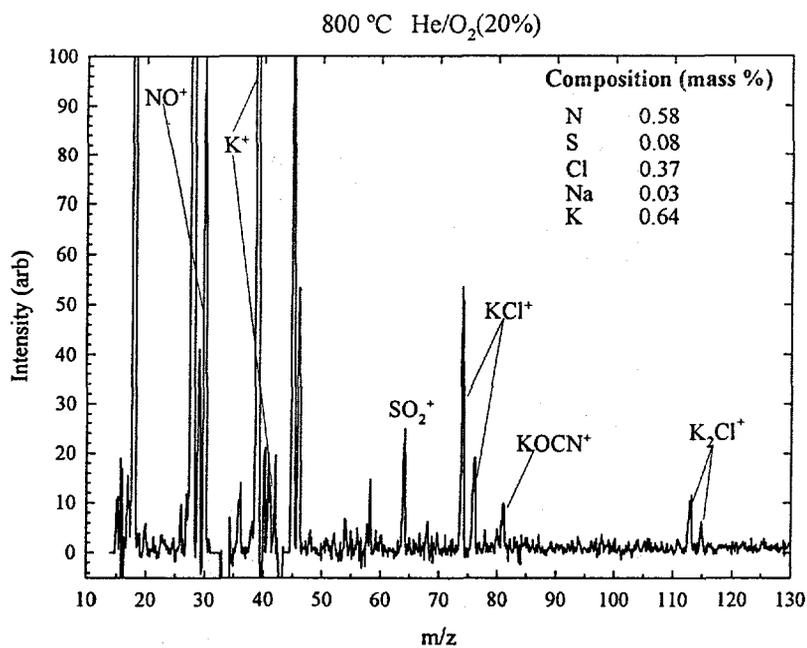


Figure 4. Species evolved during the combustion of wheat straw char (Haslev) at 800 °C in a synthetic air atmosphere (20 % oxygen in helium).

5 WHY BOTHER WITH ALL OF THESE CONTAMINANTS? WHY NOT SEPARATE THEM FROM THE BIOMASS IN THE FIRST PLACE?

Because the contaminants in biomass are dispersed at the cellular scale, physically removing alkali metals or any other inorganic component is extremely difficult.

Even sugar cane, which is estimated to have, like all grasses, an ash content of about 6 - 10 %, is only reduced to an ash content of between 1 and 3 % in the bagasse (which is the fiber portion that remains after extensive crushing and water extraction of the sugars) (Figure 5), and about two-thirds of the mineral matter "harvested" along with the sugar cane which is found in the molasses produced in the sugar process.

Thermochemical processes conducted at low temperatures have the unique capability of concentrating the ash materials, and to some extent the chlorides and sulfur in char, while liberating the majority of the CHO as volatile material. Some very elegant demonstrations of this are given in a paper by Zanzi et al. [9], where despite the difficulties of performing a mass balance on the ash in drop tube pyrolysis experiments, they arrived at a recovery of

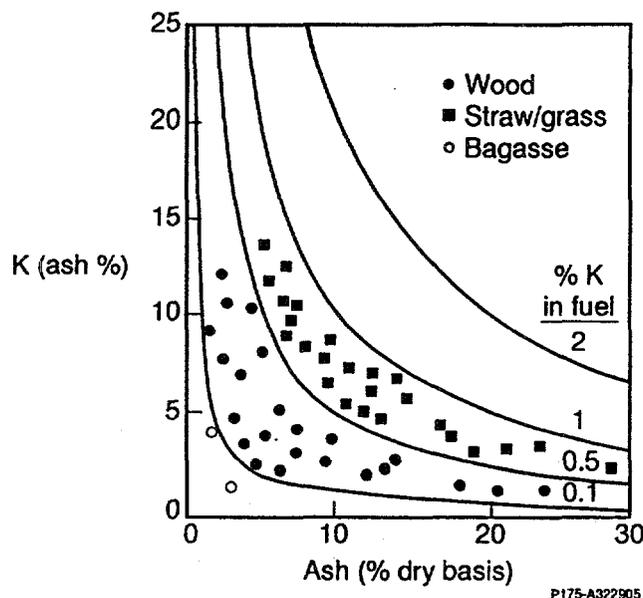


Figure 5. Potassium and ash in biomass.

between 90 - 115 % of the initial biomass ash content in the chars obtained at very high temperatures of 700 - 900 °C in rapid heat up experiments. Similar results for a hardwood and a softwood were obtained by W. F. De-Groot and F. Shafidazah [10]. Lower temperature slow carbonization maintains the cellular structure of the biomass and will probably retain all of the non-CHO components [11].

The principle of separating the contaminating materials by pyrolysis has in fact been demonstrated in the case of straw by Hummelshoj, who introduced the concept of a screw-fed coking reactor to separate the straw into a fuel gas (50 % of the input energy) and a coke (also 50 %) [12]. The coke is burned along with its burden of alkali and chlorine in a relatively low temperature combustor to raise low temperature and pressure steam, which is then passed to the pyrolysis gas-fired steam superheater. The total fly ash production was reduced to less than 20 mg/Nm³, and the hydrochloric acid gas production was reduced to <4 mg/Nm³, at a coking temperature of 600 °C. The potassium content of the flue gas was also at a similar level.

Pyrolysis to produce liquids demonstrates a very similar performance in separating the alkali materials from the fuel product [13]. Figure 6 demonstrates a high correlation between char and ash content in the bio-fuel oil produced in fast pyrolysis. Fast pyrolysis gives a high yield of liquid, a gas

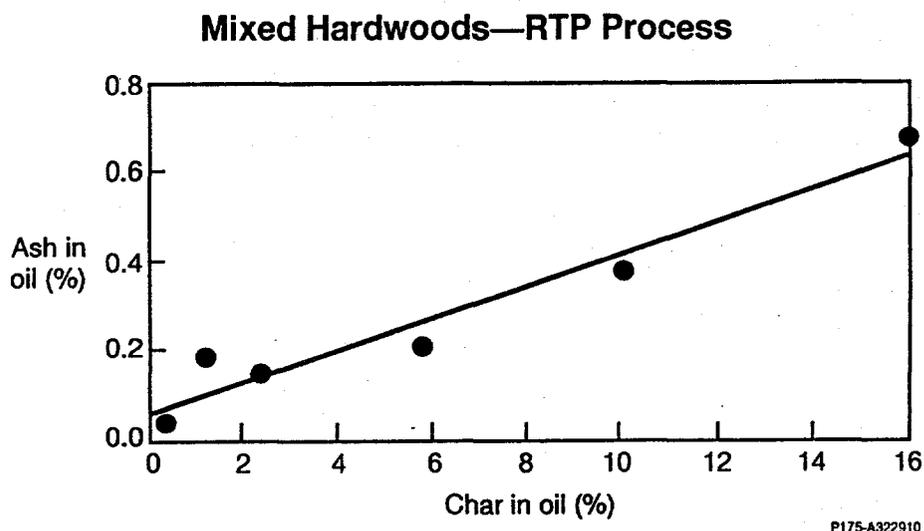


Figure 6. Biofuel oil - ash and char content (mixed hardwoods RTP power) systems approaches to alkali metal salt mitigation in biomass conversion.

and char fraction in the approximate proportions of 70(75): 15(10); 15(20) on a mass (energy) basis. Using the gas stream as an energy source for the pyrolysis will leave the char as a product for further upgrading as an absorbent (assuming relatively low ash content) or as a fuel in briquetted form recognizing that the char will need specialized combustion facilities. High temperature filtration of the pyrolysis gases prior to condensing the biofuel oil has been demonstrated to produce an oil with essentially zero char and alkali levels of less than 10 ppm. Recent unpublished work at the National Renewable Energy Laboratory has demonstrated through electron microprobe analysis that the char remaining after fast pyrolysis has potassium and other metals embodied in the carbonized cell wall fragments, often with a silica cell around the char particle. Somewhat similar results of the buildup of ash around peat (partially fossilized biomass) particles in gasification have been observed by Moilanen and co-workers [14].

6 COMBUSTION SYSTEMS

Combustion systems were the first conversion systems to reveal the extent of alkali metal-promoted ash fouling and slagging behavior [15]. Because the alkali will be mobilized into the gas phase at reasonable combustion temperatures (i.e., $>900\text{ }^{\circ}\text{C}$), the problem can be minimized by reducing the temperature of the gases to less than $760\text{ }^{\circ}\text{C}$ before they reach the superheater bank to enable the alkali compounds to condense onto inert particles rather than the superheater tube. Alkali vapors in the combustion gases produced in the special case of fluidized beds can be reduced by adding reactive intermediates to the bed that moves the eutectic melting point above the fluidized bed operating temperature, and by reducing the alkali loadings per unit heat input the system moves into a non-fouling regime.

The latter can be obtained by means of either feedstock selection or appropriate biomass fuel blending strategies if in fact high alkali fuels such as cereal straws and other residues are required fuels. The Danish experience reported in the Miles report [15] takes the first strategy by having very large heat exchange areas as water walls in the combustor and reducing the furnace exit gas temperature to $760\text{ }^{\circ}\text{C}$ thus restricting the unit to generating low temperature steam with a concomitant reduction in thermal efficiency for electricity generation. Some degree of fouling of the water walls is acceptable under such conditions. A number of fluidized beds operate with dolomite or adding calcium oxide, initially proposed for sulfur dioxide mitigation *in situ*. Because alkali metals form eutectics with higher melting points than the mean temperature of combustion in the fluid bed, this can minimize the deposit problem.

7 GASIFICATION SYSTEMS

There are a wide number of gasification systems that are either available or under development today. For the purposes of this discussion they can be divided into two classes: 1) autothermal units in which the heat for gasification is supplied within the gasifier by combustion under substoichiometric conditions using either oxygen or air; and, 2) allothermal units in which the heat is supplied externally to the gasification unit.

8 AUTOTHERMAL GASIFICATION

There are several configurations of gasifiers ranging from fixed bed (actually moving bed) down draft, cross draft and up-draft units, to fluidized bed units. The down and cross draft units are very sensitive to slagging behavior and are well known as being unsuitable for high alkali materials [16], and as a result require essentially clean wood as the specified fuels. Specialized grates that are designed to cope with the slagging behavior in down draft gasifiers have been developed in the past as described by Rambush [17], and more recently by Liinanki et al. [18].

Experiments conducted recently in the United States with wood chips demonstrated that up draft gasification with wood chips resulted in greater than 95 % of the input potassium leaving the gasifier in the bottom ash, with the remainder mainly in the particulate material that was trapped by the gas cleaning cyclones. The cyclone exit gas temperature was 580 °C and it is presumed that the alkali condensed on particulates that were captured in the cyclones could also be in the fly ash. The residual potassium in the gas stream would have resulted in a concentration of 90 ppb in the turbine hot section (post combustion). This is still too high for advanced, high temperature turbine operation, compared to the General Electric standard of 20 ppb [19].

Fluidized bed units have been developed and operated on high alkali feedstocks, however, the temperature must be kept below 800 °C (thus minimizing the rate of gasification) to avoid agglomeration [20]. The root cause of the agglomeration is the formation of a $K_2O:4SiO_2$ eutectic on the surface of the silica particles with a melting point of 760 °C.

9 ALLOTHERMAL OPERATION

In the United States, two systems that have addressed the alkali issue are the Battelle Columbus dual fluidized bed system [21], and the in-bed heat exchanger system of MTCI [22].

In the Battelle gasifier, the biomass is gasified at temperatures close to 760 °C under pyrolytic conditions. The resulting char that contains the majority of the ash and alkali is then circulated to an external fluidized bed combustor that operates at about 1 050 °C to provide hot sand for heat transfer in the first fluidized bed. This arrangement minimizes the transfer of alkali to the gas stream, however, it also results in a high potential for agglomeration during char combustion since the char is enriched in alkali. This is mitigated by using magnesium oxide in the combustor to shift the eutectic to a non-sticky state. Both hybrid poplar and switchgrass, which are dedicated feedstocks for energy production in the United States, have been successfully gasified in this system.

In the MTCI gasifier, the heat is provided by burning a portion of the output fuel gas in an in-bed tubular heat exchanger. The bed, which is fluidized with steam at a temperature of 790 - 800 °C, achieves 95 % char conversion in situ, and apparently accumulated potassium over time in experiments that involved the gasification of a high alkali content wheat straw. A full mass balance on the potassium is not yet available.

10 FAST PYROLYSIS

Fast pyrolysis generally operates at temperatures of less than 650 °C and produces a char which has been demonstrated to contain essentially 100 % of the ash and alkali content (see above). Efficient separation technologies have demonstrated how to reduce the alkali content to the ppm level in the biofuel oils. These technologies that include hot gas filtration or liquid phase filtration are ready for scale up according to NREL and Ensyn.

11 CONCLUSIONS

Alkali, especially potassium, is an essential constituent of growing biomass where relative to other metals such as sodium and calcium it is concentrated ten to a hundred fold in living cells. Some of the biomass resources such as heart wood of mature trees have very low concentrations of ash and alkali as a result of recycling within the growing plant. Nevertheless, even in mature trees, the living skin in the form of the branches and the bark does contain significant quantities of ash and alkali materials. Annual plants and short rotation tree species, however, contain appreciable quantities of ash and alkali materials distributed throughout their structure.

Lower cost and abundant biomass supplies for energy tend not to be the clear and clean fiber of trees which finds higher value applications than energy in fiber applications, but rather it is the bark and branch components that have higher alkali contents. In the United States, the expansion of the bioenergy industries will result in them having to use either agricultural residues, urban wood wastes, residues from pulp and paper and wood product industries, forest clearings, or dedicated feedstocks, all of which have very high alkali contents (even up to 2 % by weight in potassium).

High efficiency conversion systems require high temperature cycles for high thermodynamic efficiency, whether it is in the direct steam cycle or in gas turbine systems. In the case of steam generation systems, the role of potassium and alkali in fouling heat transfer surfaces and causing reduced heat transfer and superheater corrosion is well characterized. Reducing operating temperatures is effective in mitigating the fouling, however, this is at the expense of thermodynamic efficiency.

In high temperature turbines, alkali and ash result in deposition on high temperature stationary and rotating components which reduce efficiency. Larger particles also cause erosion in high speed passages in the hot sections of the turbine, and finally the high temperature alloys used in the hot sections are very susceptible to corrosion. Current hot section limits on the concentrations of alkali are about 20 ppb for the 1 450 - 1 500 °C state-of-the-art turbines. For a biomass that has more than 2 % potassium content, these are very stringent criteria to attain.

One mechanism for alkali ash mitigation is to recognize that the majority of the inorganic material will remain with the char component if the biomass is thermochemically converted to either a fuel gas or a biofuel oil at relatively low temperatures. Technologies that are based on the production of char are already at the process development scale, with throughputs of 10 - 25 t/day of dry biomass, and could be developed for the high efficiency electricity generation market relatively rapidly.

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APPENDIX

BIOMASS CLASSIFICATION FOR THE NORTHEASTERN UNITED STATES REGION

Forest based biomass

Forest harvesting for energy

 Fuel wood harvesting

 Silvicultural practices

 Stand conversion

 Stand improvement

 Thinning

Co-harvest for other products (e.g. associated with pulp and paper or solid products)

 Forest residues

 Slash (tops and branches) from harvesting

 Slash at landings (tops, branches and bark)

 Slash at mill site from whole tree harvest

In mill process residues

 Sawdust/sander dust

 Fuel chips

 Bark

 Black liquors

 Paper fines and sludges (ex primary clarifiers)

Agriculture based biomass resources

Perennials

 Short rotation wood crops (willow, poplar, etc.)

 Herbaceous energy crops (grasses, alfalfa, etc.)

Perennial crop residues

 Orchard prunings

 Vines/pomace, etc. from wine industry

Annual crops

 Corn (e.g. for ethanol)

 Sorghum

 Potato

 Oil seeds (soybean and rape)

Annual Crop residues

 Straw (wheat, barley, oats)

 Corn stover

 Potato storage clearings

Animal husbandry

- Swine manure
- Cattle manure
- Chicken litter/bedding (a mix of wood chips/paper/chicken droppings)
- Food processing residues
 - Diary operations
 - Milk washings
 - Cheese whey
- Fats from frying operations - e.g. from potato chip preparation
- Sugar/protein streams (often seasonal at freezing and canning plants)
 - e.g. Potato peelings and starch waters
 - wheat an other grain chaff
- Maritime
 - Crustacean shells/meat
 - Fish processing offal
- Abattoirs
 - Blood/paunch contents

Urban and Industrial Generated Biomass and Residues

- Wood
 - Right-of-way clearances
 - Land clearance for urban development
 - Pallets
 - Furniture plant residues (includes glued wood, e.g. plywood)
 - Construction and demolition wood
 - Normal urban renewal
 - Results of a disaster (e.g. hurricanes, earthquakes)
 - So-called green or yard waste
- Paper
 - "Waste paper", i.e. not capable of entering the recycling stream
 - Sludges from recycled paper plants
- Sewage sludges from municipal treatment plants
- Landfill gas
- Lipid residues
 - Tallow (from animal fat rendering)
 - Cooking oils (e.g. from restaurants)

June 14, 1994

COMMERCIAL ASPECTS OF RAPID THERMAL PROCESSING (RTP)

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1 INTRODUCTION

In its broadest sense, Rapid Thermal Processing (RTPTM) covers the conversion of all types of carbonaceous materials to liquid fuels, high quality fuel gases, and chemicals. Scientifically, it is based on the general premise that products which result from the extremely rapid application of heat to a given feedstock are inherently more valuable than those which are produced when heat is applied much more slowly over longer periods of processing time.

Commercial RTPTM activities (including the actual implementation in the market as well as the short-term R&D initiatives) are much narrower in scope, and are focussed on the production of high yields of light, non-tarry *liquids* (i.e. "bio-crude") from *biomass* for fuel and chemical markets. Chemicals are of significant interest from an economical point of view since they typically have a higher value than fuel products. Liquid fuels are of interest for many reasons:

1. Liquid fuels do not have to be used immediately after production, such as is the case with hot combustion gases or combustible gases produced via gasification. This allows the decoupling of fuel production from the end-use (i.e. the conversion of fuel to energy).
2. The higher energy density of liquid fuels vs. that of fuel gases and solid biomass results in a large reduction in the costs associated with storage and transportation.
3. The costs to retrofit an existing gas or oil fired combustion system are much lower than replacement with a solid fuel combustor.
4. In general, liquid fuel combustion is much more efficient, controllable, and cleaner than the combustion of solid fuels.
5. The production of liquid bio-crude permits the removal of ash from the biomass prior to combustion or other end-use applications.
6. Gas or liquid fuel-fired diesel or turbine engines cannot operate commercially on solid fuels.

Although wood represents the biomass which is of principal commercial interest (including a vast array of wood residues), bagasse, various straws,

non-recyclable paper and other cellulosic materials are also of significant interest.

RTP™ is not an incineration process. In commercial applications, it is simply the liquification of biomass by the addition of heat at atmospheric pressure in the absence of air or oxygen. There is no direct combustion in the conversion unit. In effect, wood is converted to liquid wood, bagasse to liquid bagasse, straw to liquid straw, etc. The liquid is pourable and pumpable at room temperature, and has approximately the same heating value as the feedstock entering the conversion unit.

The typical liquid yield from a representative hardwood at 10 - 15 % moisture content is about 73 % by mass in industrial operations. In general, the yield increases slightly with an increase in feedstock cellulose composition and slightly decreases with an increase in feedstock lignin composition.

However, the energy yield remains approximately constant since lignin-derived liquids have a higher energy content than cellulose-derived liquids. These liquids are produced as a single phase and are not to be confused (either in appearance or chemical behaviour), with the heavy tars produced via conventional pyrolysis or as a gasification by-product.

RTP™ was commercialized in 1989 after about 10 years of research, development and demonstration. Current product applications include boiler fuel and food chemicals (flavourings, natural colourings, etc.). It is important to note that the primary liquid product or "bio-crude" is essentially the same whether it is destined for the fuel or the food chemicals markets. However, if intended for fuel use, the downstream RTP™ equipment can be operated in a manner to reduce the moisture content, increase the heating value and decrease the char/ash content.

Other product applications which are expected to be realized over the short-term are "bio-diesel" fuel, "bio-turbine" fuel, wood preservatives, polymers/resins and activated carbon. These products are being developed both independently by Ensyn and in cooperation with strategic partners throughout Europe and North America.

2 RTP™ TECHNOLOGY STATUS

RTP™ is truly commercial in terms of hardware, financing and operations/production. It has not merely been "demonstrated" on a large-scale, but operates continuously with production contracts in place. Capital has been raised through many of the financial market options including private

funding, commercial banking and the bond market (Industrial Development Bonds, for example).

There are currently two RTPTM plants in commercial production which supply liquids for the food chemicals and boiler fuel markets. The largest, a 50 green tonne per day (25 dried tonnes/day) facility in Wisconsin, operates under contract 5 days per week and 24 hours per day. Operation is scheduled to increase to 6 days per week in mid-1995. The operating contract is structured such that Ensyn must meet production quotas or pay penalties for under-production. "Availability" approaches 100%, but this is clearly meaningless since Ensyn currently has two days per week which are not under contract. During the non-contract periods, bio-crude product is produced for combustion, diesel and turbine testing, and for chemical product development. In the Wisconsin facility, one portion of the bio-crude is used for food chemicals production while the remaining portion is used to fuel a commercial combustion system which operates 24 hours per day.

The second commercial RTPTM plant is located in Ottawa and has a nominal capacity of 2 tonnes per day. It operates at 93 % availability 7 days per week and 24 hours per day, and its full production is allocated to the food chemicals market.

Contracts have been signed for 5 additional plants producing both fuels and chemicals, and ranging from 0.5 to 110 green tonnes per day (60 dried tonnes/day). Three of these are commercial facilities, one is a demonstration plant for a power utility, and the fifth is a process development unit for a strategic partner in Europe. These units are being engineered and assembled in Ensyn's Ottawa (Greely) facility, which was expanded from 50 to 300 M² in 1993 for this purpose. Other commercial RTPTM projects dedicated to fuel production and ranging from 150 to 350 tonnes per day are in various stages of progression and are beyond the scope of this discussion.

3 SHORT-TERM PRODUCT DEVELOPMENT

In addition to the current boiler fuel and food chemical applications, products are rapidly being developed for power, non-food chemicals and other value-added applications. Based on the successful bio-crude combustion and emissions experience in Wisconsin, Massachusetts and Ottawa, permission has been granted by a Wisconsin public utility to co-fire RTPTM bio-crude with coal and coke in a 20 Mwe stoker-fired boiler. The bio-crude will provide about 5% of the input fuel demand and will therefore account for about 1 Mwe of the power output. The bio-crude storage, handling and delivery system has been designed, assembled and tested. Actual hot-firing

is expected to occur in mid-1995, when the state environmental permits are granted. It is believed that this will be the first commercial production of bio-electricity via thermochemical conversion (ie. not-direct biomass combustion) in either North America or Europe.

A European/Canadian consortium, (including Wartsila, Vapo Oy, VTT, NRCan and Ensyn) is developing a stationary diesel engine to operate on RTP™ bio-crude. The objectives of this \$8 million project are twofold:

1. Develop a fully-warranted bio-diesel engine for power production or cogeneration.
2. Investigate RTP process and product refinements to fully optimize for bio-diesel applications.

In the early stages, successful combustion in a medium-speed Wartsila 32 diesel engine has been demonstrated, and critical areas for long-term operation have been identified. As a result, injection system re-design has occurred and a long-term test program, to investigate the effect of bio-crude combustion on engine wear and performance, are in progress.

For gas turbine bio-fuel applications, Ensyn has developed a strategic partnership with Hawker-Siddeley Canada, Orenda Division. Orenda has a license for the Mashproekt stationary gas turbine, originally developed for marine propulsion and power generation in the former Soviet Union.

Designed for operation on lower spec fuel oil rather than jet fuel, and for operation under particularly rugged and remote conditions, the Mashproekt engine is particularly robust and well suited for bio-crude operation. Work is in progress to test the injection and combustion systems and to observe the effect on key components when exposed to RTP™ bio-crude combustion in the flame tunnel test facility at Canmet in Ottawa. A 2.5 MW_e turbine is being prepared by Orenda for actual hot tests.

Ensyn is cooperating with other strategic partners in North America and Europe to produce effective and economical wood preservatives, road surfaces and pre-polymers/resins directly from the RTP™ bio-crude. Extensive testing has been done to investigate the production of activated carbon from the RTP™ char by-product. Activation results have proceeded quite well to date and economic analyses suggest that the char by-product, with a yield of about 12 %, could provide a product with an economic value greatly exceeding that of the bio-crude fuel oil.

Other short-term R&D is focused on simple inexpensive methods for physical upgrading of the bio-oil, particularly bio-crude recovery enhancement, liquid filtration and hot vapour filtration. This work is being conducted in support of the commercial bio-diesel and bio-turbine initiatives. The alkali

content of both bio-crudes and gasification products is of particular concern in diesel and turbine firing, and the National Renewable Energy Laboratory (NREL) has clearly demonstrated that removal of the char and ash (i.e. by liquid or vapour filtration) will effectively lower the bio-crude alkali content.

Recent product recovery tests carried out by manipulating the vapour condenser operating conditions have shown that the bio-crude specifications can be tailored for boiler fuel, diesel and turbine fuel, and chemicals applications, without altering the RTP™ conversion process itself. An example is given in Table 1, where it can be seen that the bio-crude produced for diesel tests has a higher energy content, lower moisture content and lower solids/ash content than bio-crude produced for fuel oil applications even though both liquids were produced in the same RTP™ equipment under similar process conditions.

Table 1. A comparison of recent fuel oil and diesel bio-crude properties.

RTP™ bio-crude property	Fuel oil bio-crude	Diesel bio-crude
Moisture content (%)	23	19
Higher heating value (MJ/kg)	17.5	20
Lower heating value (MJ/kg)	16.0	17.5
Solids content (%)	2.6	0.7
Ash content (%)	0.14	0.04
Viscosity (cSt @ 25 °C)	128	1 150

4 COMBUSTION AND EMISSIONS EXPERIENCE

Since 1989, RTP™ bio-crude has been fired both commercially and for demonstration and testing purposes in at least 9 combustion systems. These are listed with system capacities in Table 2.

The West Waste Fuel Burner (WWFB) located at the Red Arrow Products facility in Wisconsin was the first commercial combustion system to use RTP bio-crude for an industrial energy demand. This system, supplied by Energy Control Engineering of Minnesota, has been fuelled with charcoal and slow pyrolysis tars since 1987, and with RTP bio-crude since 1989. It has a thermal capacity of about 6 MWth (20 MBTU/h), operates continuously (the availability is greater than 90 %), and employs a stainless steel Ripco nozzle for the injection of fuel into the combustion zone. Environmental approvals have been granted by the State of Wisconsin, and the emissions meet or exceed all of the State regulations. CO emissions were 17 % of the permitted rate, NO_x only 1.2 % of the permitted rate and formaldehyde emissions were not detected. A summary of the WWFB test data

Table 2. RTPTM bio-crude combustion/emissions experience.

Combustion system	Facility location	Status	Rated thermal capacity	
			MW _{th}	MBTU/h
West waste fuel burner (WWFB)	Red Arrow (USA)	Commercial	6	20
Danstoker	Neste Oy (Finland)	Demo/Emissions	2.5	8.5
CRF flame tunnel	MIT (USA)	Demo/Emissions	1	3.4
Modified Robert Bell boiler (flame tunnel)	Canmet (Canada)	Demo/Emissions	0.7	2.5
Kewanee boiler	Ensyn (Canada)	Demo	0.6	2.0
	RA (USA)			
Multi-purpose test rig (MPTR)	ENEL (Italy)	Demo/Emissions	0.5	1.7
Gas turbine combustion test rig (GT CTR)	ENEL (Italy)	Demo/Emissions	0.05	0.2
Brock LO-1M (household furnace)	Canmet (Canada)	Demo/Emissions	0.03	0.1
Maxon household burner	Ensyn (Canada)	Demo	0.03	0.1
Multifuel combustor (MFC)	NREL/Sandia (USA)	Demo/Emissions	-	-

is given in Table 3. Also reported in Table 3 are the emissions data from combustion tests conducted at MIT, Canmet and Ensyn, including a comparison of the RTP bio-crude and petroleum fuel oil data.

Table 3. A summary of emission data for various combustion systems using RTPTM bio-crude and petroleum fuel oil.

Combustion system	Fuel*	Emission levels			
		Particulate mg/Nm ³	CO ppm _v	SO _x ppm _v	NO _x ppm _v
WWFB (USA)	RTP TM	0.7*	44	-	<50
Canmet (Canada)	RTP TM	34	26	4	164
	HFO	76	37	952	268
MIT (USA)	LFO	5	43	118	89
	RTP TM	<5	38	-	108
Brock (Canada)	LFO	<1	15	-	80
	RTP TM	-	40	-	88
	LFO	-	2	-	69

*Notes: - RTP, HFO and LFO fuels refer to RTP Bio-crude, Heavy Fuel Oil (No. 6) and Light Fuel Oil (No. 2), respectively

- The particulate emission levels reported for the WWFB are after the existing baghouse.

In general, the RTPTM bio-crude was relatively easy to handle and deliver to the various combustion systems. The MIT report stated that the Ensyn fuel "performed comparably to No. 2 fuel oil, producing slightly higher NO_x and CO emissions". It concludes:

"The Ensyn oil required more frequent filter changes, but otherwise could be used with the same fuel delivery system and operating procedure as No. 2 fuel oil. Soot concentration did not differ measurably for the two fuel types ... The detailed flame maps indicate no fundamental differences in the combustion behaviour of the wood pyrolysis oil that would act as a barrier to utilizing the [RTP™] oil in industrial scale furnaces."

The most recent Canmet tests were of particular significance since they were set up in accordance with certified test protocols in order to satisfy New Jersey environmental permitting regulations.

These tests were commissioned in direct support of a specific commercial RTP fuel project in that State. However, since New Jersey regulations are among the most stringent in the USA, compliance in this State will ensure compliance in most other states.

The New Jersey tests were conducted in Canmet's 0.7 MWth (2 MBTU/h) Combustion Research Facility flame tunnel in Ottawa (Canmet is a division of Natural Resources Canada). The Canmet combustion system utilizes a Robert Bell boiler with a modified, refractory-lined combustion zone.

During the New Jersey tests, Canmet personnel operated the flame tunnel continuously on wood-derived bio-crude at steady-state conditions for about 9 hours. The sampling, analyses and data processing were conducted by CSP Environmental Consultants Ltd. of Amherstburg, Ontario. Using sampling methods recommended by the United States Environmental Protection Agency (USEPA), Environment Canada (EPS) and The Ontario Ministry of the Environment and Energy (MOEE), emission rates were determined for the following:

- combustion gases (CO, CO₂, O₂, NO_x, SO_x and H₂O_v)
- particulate matter
- metals
- PCDD's and PCDF's (dioxins and furans)
- PCB's (polychlorinated biphenyls)
- POH's (polycyclic organic hydrocarbons)
- VOC's (volatile organics)
- CB's (chlorobenzenes)
- CP's (chlorophenols).

Representative emission data for selected components are given in Table 4.

Table 4. RTPTM bio-crude combustion emission data: New Jersey Protocol.

Emissions	Emission levels			
	Parts per ¹	mg/Nm ^{3 2}	Fuel energy basis	
			g/GJ	lb/MBTU
Particulates	34 ppm _w	48	23	0.053
CO	26 ppm _v	33	16	0.036
SO _x ³	3.8 ppm _v	11	5.2	0.012
NO _x ⁴	164 ppm _v	220	162	0.38
VOC's	70 ppb _v	0.20	0.098	2.3 x 10 ⁻⁴
POC's	1.0 ppb _v	0.0072	0.0035	8.1 x 10 ⁻⁶
Dioxins/Furans (TEF) ⁵	0.01 ppt _w	1.3 x 10 ⁻⁸	6.5 x 10 ⁻⁹	1.5 x 10 ⁻¹¹
Lead	106 ppm _w	0.14	0.069	1.6 x 10 ⁻⁴
Total metals	44 ppm _w	60	29	0.067

- 1 The "w" subscript following parts per million (and billion or trillion) signifies weight basis. The "v" signifies volume basis.
- 2 The flue gas density is 1.39 kg/Nm³ (ie. at 273 K and 1 atm)
- 3 The concentration levels of SO_x (ppmv and mg/Nm³) are expressed on an SO₂ basis
- 4 The concentration levels of NO_x (ppmv and mg/Nm³) are expressed on an NO basis. However, the fuel energy basis emissions (g/GJ and lb/MBTU) are assumed to be for NO₂, consistent with New Jersey guidelines.
- 5 Total dioxin and furan emissions are expressed as a toxic equivalency factor (TEF) which averages individual dioxins and furans in terms of the toxicity of 2,3,7,8 - TCDD (the most toxic species).

The primary data in Table 4 can be extrapolated to more practical terms in order to determine the level of compliance, with New Jersey regulations, for several boiler sizes. The data in Table 5 represents such an extrapolation of the primary emissions data.

The test results, including those reported in Table 5 and others which are not reported, clearly indicate that the RTPTM bio-crude combustion emissions are in full compliance, with the exception of NO_x. However, particularly for the low end of the range of industrial boiler sizes, the NO_x emissions are only moderately above the regulated levels. Furthermore, because of special considerations for small boilers in New Jersey, these levels will not prevent the issuance of permits sizes which typically correspond to RTPTM bio-crude applications. For example, the current NO_x levels are permissible for boilers whose rated capacity is less than 6 MWth (20 MBTU/h). Boilers in the range of 6 to 29 MWth (20 to 100 MBTU/h) are subject to "RACT" or reasonable available control technology. Even in larger New Jersey installations (ie. those typically beyond the scope of bio-crude applications), low-NO_x burners are expected to reduce NO_x emissions to acceptable levels (all new boiler installations in New Jersey require these burners regardless of the fuel). By way of illustration to show the effectiveness of such burners, the NO_x levels produced during the combustion of RTPTM bio-crude in the MIT low NO_x burner were about 35 % lower than levels produced in the standard Canmet burner (Table 3).

Table 5. Calculated emissions for various boiler sizes and compliance with New Jersey Regulations.

Emissions	Emissions for various boiler sizes tons per year			Allowable NJ emission levels tons per year
	6 MW _{th} (20 MBTU/h)	15 MW _{th} (50 MBTU/h)	29 MW _{th} (100 MBTU/h)	
Particulate	4.6	12	23	100
CO	3.2	7.9	16	100
NO _x	33	82	165	25
SO _x	1.1	2.6	5.3	100
VOC's	0.020	0.050	0.10	25
Lead	0.014	0.035	0.071	10

5 ECONOMICS

The detailed economics of the RTPTM process for bio-fuel production can be greatly simplified according to the following model. If the wood or other biomass feedstock is available at zero cost, an RTPTM fuel oil price of about USD 17 per MWh_{TH} (ie. approx. USD 5/MBTU) is required to render a 100 tonne per day RTP plant economically viable. This price covers all fixed and variable operating costs, the annual capital costs to finance the debt (75 % of total capital) and an acceptable rate of return on the equity investment (25 % of the total capital). The model assumes that the wood is in the form of wet chips, and that drying and grinding equipment, as well as the basic RTP conversion equipment, are included in the capital cost estimates. Expressed in other terms, the economic model estimates a cost of about USD 60 to convert one (1) tonne of wood or other biomass feedstock to bio-crude in a 100 tonne per day RTPTM plant. This means that the price of bio-crude will double to USD 34/MWh_{TH} (or USD 10/MBTU) if the cost of the biomass feedstock is USD 60.00 per dried tonne. Alternatively, a tipping fee or credit in the amount of USD 60 per dried tonne of biomass feedstock would result in a zero cost fuel oil product.

In practical terms, there is an abundance of zero cost feedstock in North America and the bio-crude product is competitive with light fuel oil. Several commercial RTP fuel projects are therefore proceeding on this basis. In Europe, low cost biomass is only available from forest operations, typically in the Nordic countries. However, heavy fuel oil is typically in the range of USD 14 to USD 17/MW_{th} (and light fuel oil is double this price, or more, depending on the tax structure), and commercial RTPTM projects are therefore possible in certain locations.

Where high-cost or purpose-grown biomass is available specifically for energy applications, RTPTM can only be economically viable where the environmental advantages of bio-crude (ie. CO₂ neutrality and negligible sulphur content) are internalized in the economics via tax or other incentives. Such is the case in Sweden, the U.K. (NFFO), Italy (Bioelectricity Souvention) and other EU countries.

In any event, it is clear that RTPTM is viable where there is an environmental driving force - ie. either in North America where forest industry residues represent a serious disposal problem resulting in zero or negative cost feedstocks, or in Europe where environmental penalties such as CO₂ and sulphur taxes add significantly to the prices of fossil fuels.

PYROLYSIS OIL AS DIESEL FUEL

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Abstract

Wood waste pyrolysis oil is an attractive fuel alternative for diesel engine operation. The main benefit is the sustainability of the fuel. No fossil reserves are consumed. The fact that wood waste pyrolysis oil does not contribute to CO₂ emissions is of utmost importance. This means that power plants utilising pyrolysis oil do not cause additional global warming. Equally important is the reduced sulphur emissions that this fuel alternative implies. The sulphur content of pyrolysis oil is extremely low. The high water content and low heating value are also expected to result in very low NO_x emissions.

Utilisation of wood waste pyrolysis oil in diesel engines, however, involves a lot of challenges and problems to be solved. The low heating value requires a new injection system with high capacity. The corrosive characteristics of the fluid also underline the need for new injection equipment materials. Wood waste pyrolysis oil contains solid particles which can clog filters and cause abrasive wear. Wood waste pyrolysis oil has proven to have extremely bad ignition properties.

The development of a reliable injection system which is able to cope with such a fuel involves a lot of optimisation tests, redesign and innovative solutions. Successful single-cylinder tests have already been performed and they have verified that diesel operation on wood pyrolysis oil is technically possible.

1 INTRODUCTION

The sustainability aspect in power generation concepts has received a lot of attention lately. This is a consequence of the growing energy demand, which is especially noticeable in the developing world. Equally important is the environmental impact of power generation. Wood pyrolysis oil (WPO) as a diesel fuel is a concept where a renewable fuel source is combined with low exhaust gas emission levels. Development work is presently at an early stage, but the concept has considerable potential, especially with the increased focus on CO₂ emissions.

2 DIESEL POWER GENERATION

One decade ago the diesel engine had a quite modest role in power generation. This has changed dramatically during the last five years as can be seen from the diesel engine and the gas turbine order statistics shown in Figure 1. Gas turbine power plants had for many years dominated newbuilding in power generation. From being below 15 % of annual gas turbine orders in 1990 the diesel engine concept had grown to more than 30 % of turbine orders in 1994. This positive development has many reasons including:

- short delivery times; 12 months for 100 MW_{el}.
- high electrical efficiency; $\eta_{el} = 45\%$
- fuel versatility; HFO, GO, gas LPG, crude oil
- low emissions; CO₂, CO, HC, PM; NO_x and SO_x emissions are low with appropriate fuel choice or abatement technique.

The short delivery time and the simple way the diesel power plant can be enlarged by gradual addition of engines has made the diesel concept very attractive in developing countries. The fuel versatility and the possibility to retrofit the power plant for natural gas utilisation make the customer less sensitive to fluctuations in fuel prices.

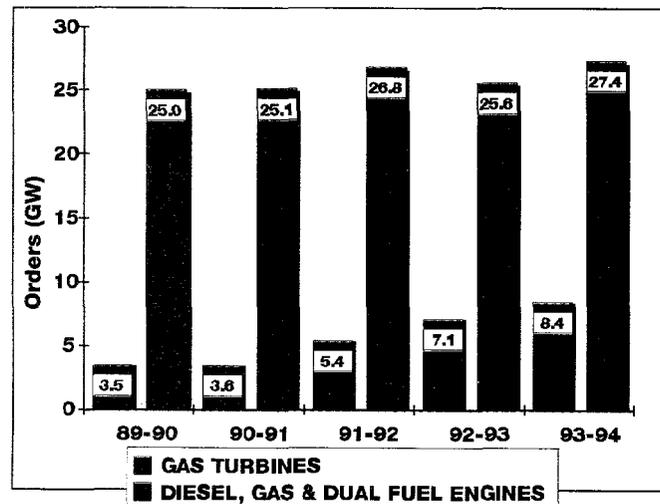


Figure 1. Diesel engine and gas turbine orders.

3 ENVIRONMENTAL CONSIDERATIONS

The greenhouse effect caused by water, carbon dioxide and other gases is a condition of life on earth. A change in the balance towards more heat absorbance by the atmosphere may, however, have severe consequences such as:

- less areas suitable for agricultural activities
- higher sea level
- more tropical storms
- changes in groundwater reserve.

A pyrolysis oil concept utilising renewable resources will result in CO_2 emissions which are part of the global carbon cycle and thus cause no additional greenhouse effect (Figure 2).

SO_x emissions causing acidification are also completely avoided by the pyrolysis diesel concept because the fuel does not contain sulphur.

CO and hydrocarbon emissions from a diesel engine are traditionally at a very low level thanks to high temperatures and pressures resulting in a high degree of complete combustion. The extreme properties of the wood pyrolysis oil may, however, lead to a different combustion pattern, which may

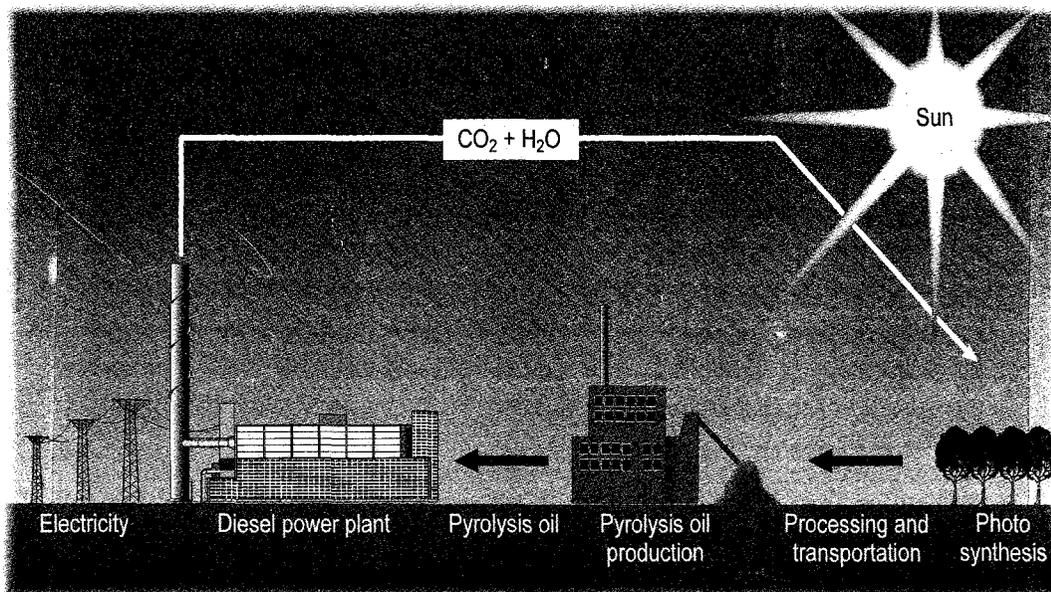


Figure 2. Wood pyrolysis oil as fuel makes the CO_2 emissions part of the global carbon cycle.

increase these emissions. This is an aspect which must be carefully optimised.

NO_x emissions contribute to acidification and are also involved in the ozone forming mechanism at ground level. If not controlled, the diesel engine emits fairly high concentrations of NO_x as a consequence of high combustion temperatures and pressures. Efficient primary and secondary reduction techniques exist for NO_x emissions. In this respect the pyrolysis oil has an advantage; the low heating value in combination with high water content will suppress the formation of hot combustion zones and thus suppress NO_x formation.

4 PYROLYSIS FUEL PROPERTIES

Table 1 shows a comparison of important fuel properties between wood pyrolysis oil, heavy fuel oil (HFO) and marine diesel fuel (MDF). It should be noted that the properties of WPO can vary considerably depending on the quality of the wood and the way the pyrolysis unit is operated, and naturally HFO and MDF properties may also vary a lot with crude oil source and refinery configuration.

Table 1. A comparison of important fuel properties between wood pyrolysis oil (WPO), heavy fuel oil (HFO) and marine diesel fuel (MDF).

Fuel property		WPO	HFO	MDF
Density	kg/m ³ at 15°C	1220	963	854
Viscosity	cSt at 50°C	13	351	2.5
Flash point	°C	66	100	70
Pour point	°C	-27	+21	-20
Conradson carb.	wt-%	17.8	9.0	<0.1
Ash	wt-%	0.13	0.03	<0.01
Vanadium	ppm	0.5	100	<1
Sodium	"	38	20	<1
Calcium	"	100	1	<1
Potassium	"	330	1	<1
Chloride	"	80	3	<1
Sulphur	wt-%	0.0	2.5	0.15
Water	wt-%	20.5	0.1	0.1
LHV	MJ/kg	17.5	40.7	42.9
Acidity	pH	3.0	-	-

The WPO contains particles originating from incomplete pyrolysis reaction of the wood raw material. These particles may cause erosion and other difficulties in the injection equipment. Therefore appropriate filtration is required.

A comparison shows that WPO tends to be fairly high in terms of ash content. A typical heavy fuel oil contains 0.03 - 0.04 wt% ash and in extreme cases 0.1 wt%. The WPO ash content of 0.13 wt% is well above these values and if the increased fuel consumption, as a consequence of low heating value, is taken into account it is obvious that the diesel engine will see a great deal of ash. Ash in HFO may cause hot corrosion, burned valves and deposit formation. However, a major difficulty with HFO ash is the vanadium related reactions. Because WPO does not contain vanadium and sulphur to any great extent it is possible that the detrimental effects of WPO ash are in fact quite negligible. This must be established by endurance tests when the development work has proceeded further.

Another property worth attention is the lower heating value. The heating value and the density define the capacity of the fuel injection system. The fairly low heating value of WPO, partly because of the high water content, requires an injection system with higher capacity than for normal HFO or MDF operation. If water is evaporated from the WPO, for instance, the viscosity will increase substantially, requiring a high preheating level of the fuel. This may on the other hand cause instability problems with the fuel. These are questions which will be subject to further optimisation.

The very high acidity of WPO makes it corrosive and requires special attention. Thus the fuel properties of WPO involve a lot of challenges before it can be successfully used in a diesel engine.

5 WPO FILTER TESTS

To evaluate filtering and separation techniques a test rig was built in the Diesel Laboratory at the Wärtsilä Diesel site in Vaasa. The test rig made it possible to test combinations of separation and filtration under very controlled conditions (Figure 3). The results showed that most filters were completely blocked within a few seconds (Figure 4). Even after four hours of separation the clogging of the filters was unacceptably fast (Figure 5). The filter tests clearly showed that hot filtration at the pyrolysis production plant or more sophisticated cold filtering techniques are required.

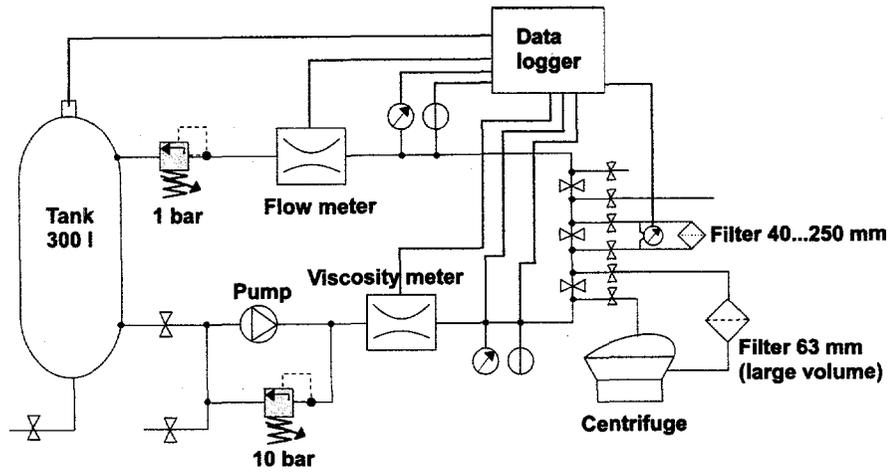
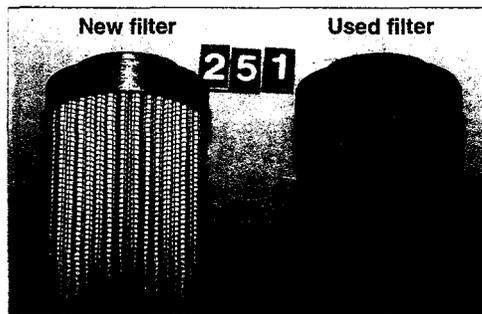


Figure 3. A test rig for evaluation of WPO filtering and separation requirements.



The filters were blocked within some seconds

Figure 4. Trying to filter a WPO batch containing a high level of particles was impossible

Performance after 4 hours separation in centrifuges

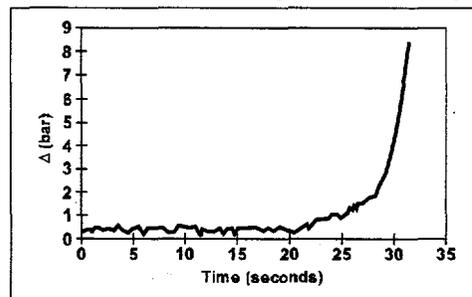


Figure 5. Even at thorough separation did not prevent the filter clogging.

6 CORROSION TESTS

To get more detailed information on the corrosive nature of WPO, ordinary HFO injection equipment parts were put into a WPO bath. This test clearly showed that the corrosion rates were unacceptable (Table 2 and Figure 6).

To find an appropriate material at test matrix with injection valves with different materials was tested in an injection test rig (Figure 7). Materials with acceptable wear and corrosion behaviour in test rig conditions were found.

Table 2. The corrosion rates of ordinary HFO injection equipment parts were unacceptably fast.

Denox components	Test duration	Measurement
Needle high speed steel	1/2 week 1 week 2 weeks 7 weeks	Diameter decreasing 2.1 μm 8.9 μm 50 μm 220 μm
Spring	7 weeks	Wire diameter decreasing 0.2 mm
Spring spacer	7 weeks	Plate thickness decreasing 90 μm
Push rod	7 weeks	Diameter decreasing 34 μm
Insert	7 weeks	Inside diameter no changes

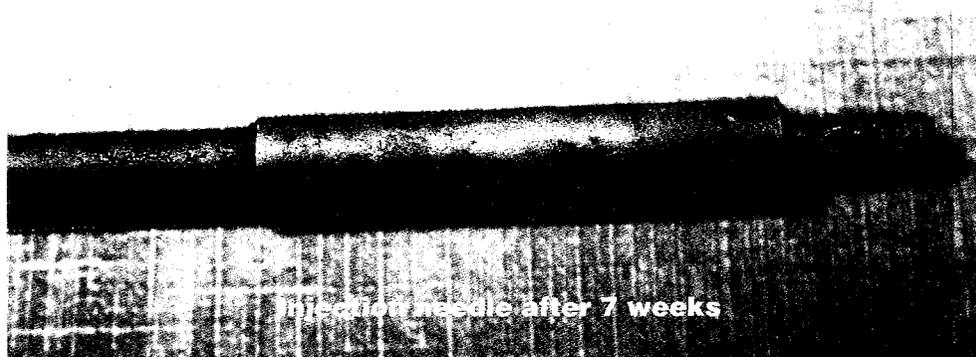


Figure 6. The air-sealed pyrolysis oil material test caused severe corrosion on ordinary injection needles.

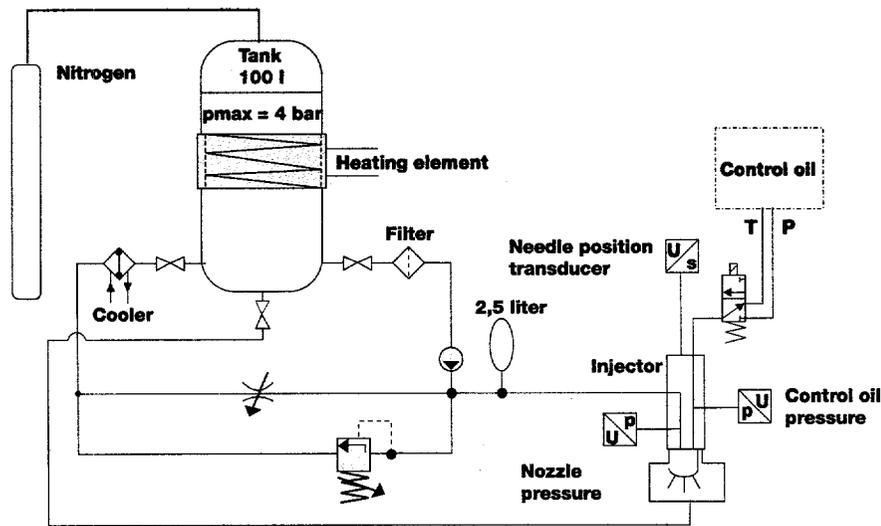


Figure 7. Injection test rig. This has been used for testing corrosion resistant materials as well as investigation of mechanical and hydraulic performance.

7 DESIGN AND DEVELOPMENT OF THE INJECTION EQUIPMENT

Ignition tests in combustion bombs clearly show that pyrolysis oil is very difficult in terms of ignition quality. This implies that a pilot injection with gas oil or heavy fuel oil is required to ensure proper ignition. This technique has been used by Wärtsilä Diesel in various gas diesel concepts and in the Wärtsilä 46 engine for HFO operation.

As described earlier the lower heating value of WPO requires a higher volumetric capacity of the injection equipment. A high injection pressure is most likely to give the best performance because of better fuel atomisation, which is an advantage with poor ignition quality fuels. A high volumetric capacity in combination with high pressures would create very high torsional vibrations on the camshaft, even to such an extent that a redesign of the engine and the camshaft would be difficult. To avoid this problem and minimise high-pressure pipes and fittings a pressure amplifier system will be tested. An example of a pressure amplifier is shown in Figure 8.

The optimisation of the injection system includes various static and dynamic simulations where the appropriate injection duration and response

times can be achieved by modifying accumulator volumes, opening pressures, nozzle hole configuration, orifice diameters, etc. Figure 9 shows typical simulation results.

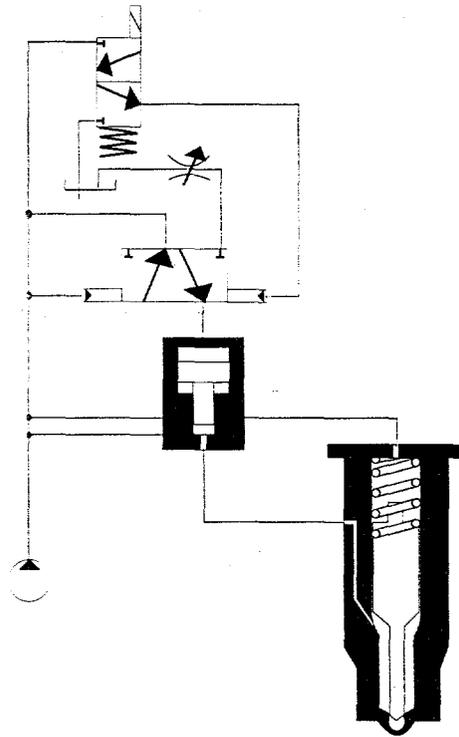


Figure 8. An example of a pressure amplifier system.

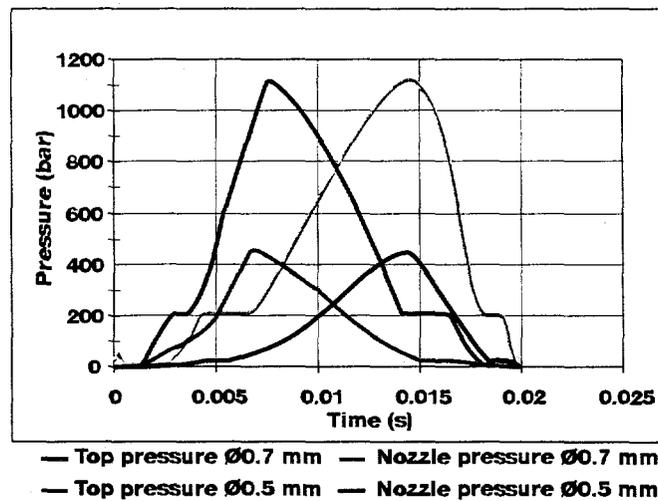


Figure 9. By simulation optimisations the correct response time of the injection system can be achieved which makes the design process faster.

8 SINGLE-CYLINDER TESTS

Ignition bomb tests clearly verified that wood pyrolysis oil has very poor ignition properties. It is therefore obvious that the WPO concept requires a pilot injection system. To get more information about the ignition and combustion process a single-cylinder test with a pilot system was performed. Important parameters to clarify by this test were:

- required pilot amount
- optimum timing for pilot
- combustion rate for WPO
- emission levels.

The injection system used is shown in Figure 10, the test engine and the pyrolysis rig in Figure 11, and the wood pyrolysis feed system in Figure 12.

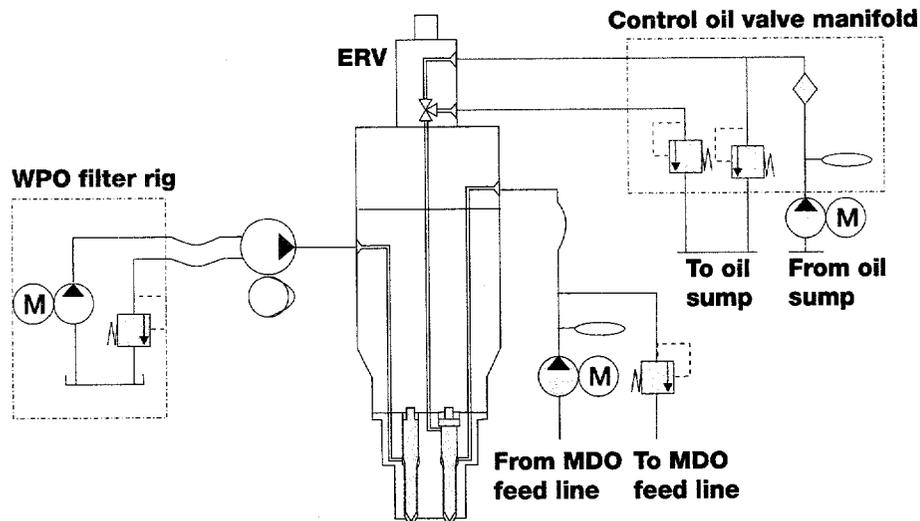


Figure 10. Single-cylinder test configuration to map ignition and combustion with various timing and flow rates for the pilot injection.

The actual combine pilot and pyrolysis oil injection valve used during the single-cylinder tests is shown in Figure 13.

When analysing the test results about 150 different measurements were recorded, mainly pressures, temperatures and flows. Figure 14 shows three important parameters: pilot injection pressure, pyrolysis injection pressure as a function of the crank angles. Using the measured parameters the cumu-

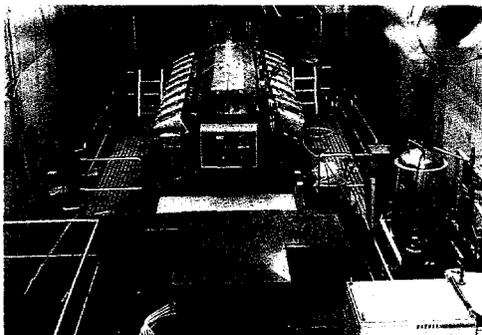


Figure 11. The wood pyrolysis oil single-cylinder test was performed with a Vasa 18V32 engine in the Vaasa test laboratory.

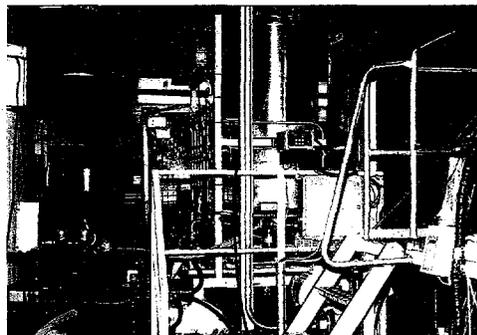


Figure 12. Wood pyrolysis oil feed system.



Figure 13. Injection valve after the single-cylinder pyrolysis oil test. Both the pilot nozzle and the main injection nozzle can be seen in the photograph.

lative and the momentary heat release profiles can be calculated. A comparison of marine diesel operation and pyrolysis oil with pilot assistance is shown in Figures 15 and 16. The loads are not completely identical but still the main conclusion can be drawn:

- Wood pyrolysis oil burns very fast once it is ignited.

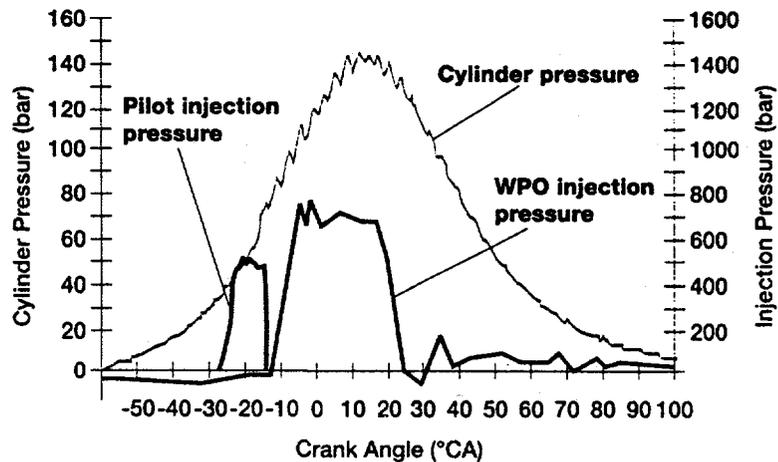


Figure 14. Pilot injection pressure, pyrolysis oil injection pressure, and cylinder pressure in a single-cylinder, full-load test.

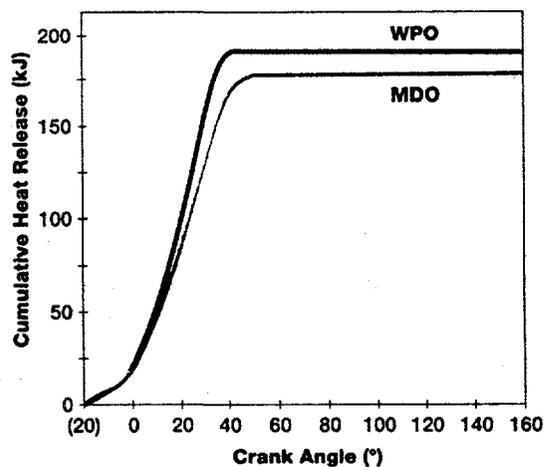


Figure 15. The cumulative heat release at full-load operation for WPO and MDO.

Naturally the pilot injection and slightly different injection durations make it difficult to precisely compare the combustion rates of the two liquids.

The initial peak in the momentary heat release curve for WPO operation in Figure 16 represents the pilot combustion. Figure 17 illustrates the rate of

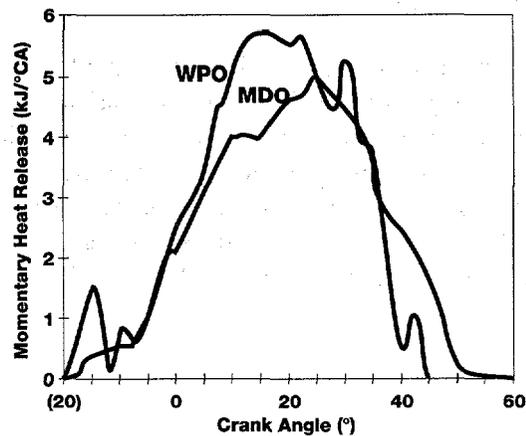


Figure 16. The momentary heat release comparison between WPO and MDO illustrates the fast combustion process for the pyrolysis oil.

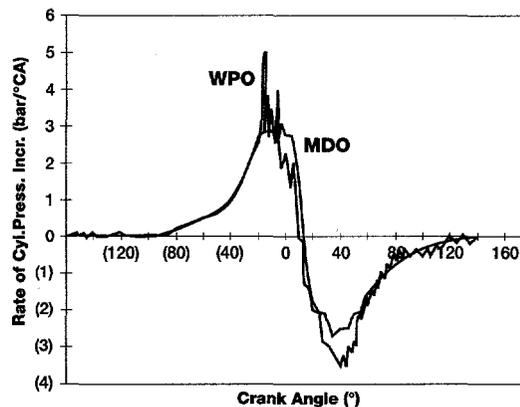


Figure 17. The pyrolysis oil operation implies an increased mechanical load compared with MDO. However, this load is acceptable and very similar to HFO operation.

cylinder pressure increase. This parameter indicates if the combustion creates fast pressure rises which increase the mechanical load on important engine components such as piston rings, bearings, etc. It can be seen that the pyrolysis oil is not as smooth as marine diesel in this respect. However, the

measured values, around 5 bar⁰ CA are not critical, and are in fact typical values for heavy fuel oil operation.

The emission measurements during the single-cylinder tests are not very reliable because of the difficulties with pressure pulsations from other cylinders. Also unburned pyrolysis oil got into the equipment during the start procedure. The preliminary results indicated, however, low NO_x and CO emissions. The hydrocarbon emissions were higher than during normal MDO operation. Whether this was a result of measurement difficulties or incomplete combustion has not been fully established.

9 SUMMARY

The wood pyrolysis diesel concept has successfully been tested in a single-cylinder configuration in a Vasa 18V32 engine. The test clearly demonstrated the need for pilot injection. The fast burning rate of WPO was also recognised. The preliminary emission measurements also showed that the concept has an environmental-friendly profile.

ASSESSMENT OF ADVANCED SMALL-SCALE COMBINED HEAT AND POWER PRODUCTION

Dr. Josef Spitzer
Joanneum Research, Austria

To increase the share of renewable energy sources, bioenergy has to be used for electricity generation, preferably in combined heat and power (CHP) production systems, besides its traditional use in space heating.

The need for small-scale, i.e. below 5 MW_{el}, CHP production arises from the fact that a considerable portion of the available solid biofuels may not be transported over long distances for economic reasons and that in many cases the heat demand is below 10 MW_{th}, e.g. in district heating schemes in communities with less than 10 000 inhabitants.

The available technical options have to be assessed with respect to performance, reliability and economy. Such an assessment has been performed in a study where the following options have been compared:

- Gasification - combustion engine or gas turbine
- Combustion - steam turbine/engine
- Combustion - hot air turbine
- Combustion - Stirling engine

While conventional steam cycle systems are available and reliable they are generally not economical in the power range under consideration. Among the other systems, which are not yet commercially available, the Stirling engine system seems to be attractive in the power range below 500 kW_{el} and the hot air system could close the gap to the steam cycle systems, i.e. cover the power range between 0.5 and 5.0 MW_{el}. Gasification schemes seem less suitable: the power generation part (combustion engine and gas turbine) is well established for natural gas, with the combustion engine in the lower (<5 MW_{el}) and the gas turbine in the higher (>5MW_{el}) power range. However, the gas quality needed for the operation of a combustion engine requires expensive pre-treatment of the gas from wood gasification so that this scheme is less attractive for the power range under consideration.

These conclusions lead to R&D efforts in Austria in two directions:

- Hot air turbine: A utility demonstration plant is under construction with a power of 1 600 kW_{el}.
- Stirling engine: An R&D project is under way with the goal of developing a CHP plant in the power range below 500 kW_{el} to be operated with a conventional wood chip boiler.

The hot air turbine plant is expected to be in operation by the end of 1996. First results of an experimental Stirling plant will be available by mid-1995.

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JOANNEUM RESEARCH
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Assessment of advanced small-scale combined heat and power production

Josef Spitzer
JOANNEUM RESEARCH, Graz - Austria

- Goals
- Technical options
- Economy
- Development examples

2

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Assessment of advanced small-scale combined heat and power production

Goals

- Increase share of biofuels
- Competitive use of solid biofuels
- Cover district heat demand < 10 MW_{th}
- Cover plant electricity demand

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Assessment of advanced small-scale combined heat and power production

Technical options

- Gasification - combustion engine or gas turbine
- Combustion - Steam turbine / engine
- Combustion - hot air turbine
- Combustion - Stirling engine

4

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Assessment of advanced small-scale combined heat and power production

Technical options

Gasification	Fuel upgrading	Gasifier	Gas treatment	Combustion engine or gas turbine				
Combustion ▶ steam cycle	<table border="1" style="width: 100%; border-collapse: collapse;"> <tr> <td style="padding: 5px; text-align: center;">Furnace</td> <td style="padding: 5px; text-align: center;">Boiler Condenser</td> <td style="padding: 5px; text-align: center;">Steam turbine / engine</td> </tr> </table>				Furnace	Boiler Condenser	Steam turbine / engine	
Furnace	Boiler Condenser	Steam turbine / engine						
Combustion ▶ hot air cycle	<table border="1" style="width: 100%; border-collapse: collapse;"> <tr> <td style="padding: 5px; text-align: center;">Furnace</td> <td style="padding: 5px; text-align: center;">High temperature heat exchanger</td> <td style="padding: 5px; text-align: center;">Turbo charger Air turbine</td> </tr> </table>				Furnace	High temperature heat exchanger	Turbo charger Air turbine	
Furnace	High temperature heat exchanger	Turbo charger Air turbine						
Combustion ▶ Stirling	<table border="1" style="width: 100%; border-collapse: collapse;"> <tr> <td style="padding: 5px; text-align: center;">Furnace</td> <td colspan="2" style="padding: 5px;"></td> <td style="padding: 5px; text-align: center;">Stirling engine</td> </tr> </table>				Furnace			Stirling engine
Furnace			Stirling engine					

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Assessment of advanced small-scale combined heat and power production



Economy (Example)

- Thermal power > 1 MW_{th}
- Electric Power 100 kW_{el}
- Full power operation 4,000 h/a
- Cost of electricity
 - ▷ Steam cycle 0.24 – 0.36 ECU/kWh_{el}
 - ▷ Hot air turbine (future) - 0.20 ECU/kWh_{el}
 - ▷ Stirling engine (future) - 0.16 ECU/kWh_{el}

(Source: E. Podesser 1993)

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Assessment of advanced small-scale combined heat and power production



Development examples

- Hot air turbine
- Stirling engine

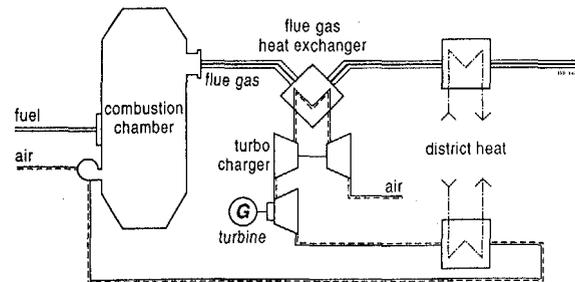
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Assessment of advanced small-scale combined heat and power production



Biomass CHP with hot air turbine



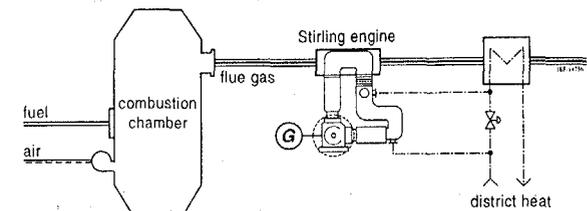
(Source: ABB und F. Legerer)

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Assessment of advanced small-scale combined heat and power production



Biomass CHP with Stirling engine



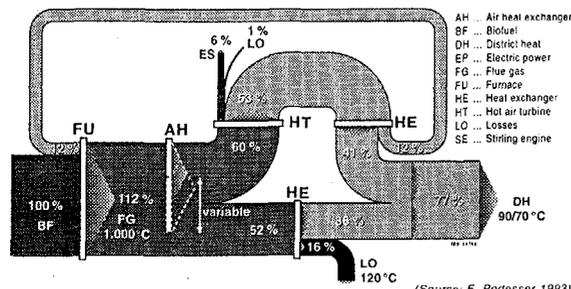
(Source: E. Podesser 1993)

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Assessment of advanced small-scale combined heat and power production



Sankey diagram: Hot air turbine

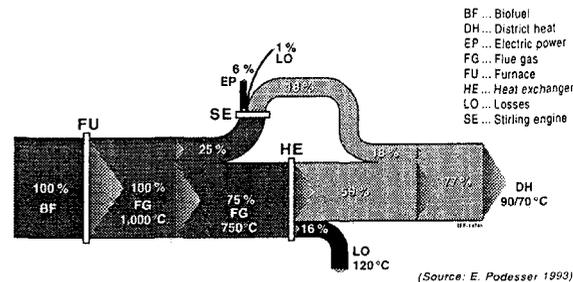


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Assessment of advanced small-scale combined heat and power production



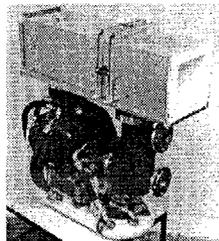
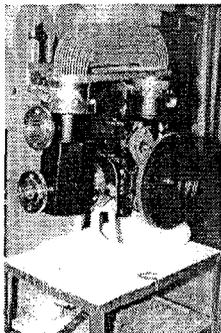
Sankey diagram: Stirling engine



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Assessment of advanced small-scale combined heat and power production



Stirling engine for a Small Biomass CHP-Plant

EC-ASEAN COGEN Programme

THE EC-ASEAN COGEN PROGRAMME

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Abstract

The EC-ASEAN COGEN Programme is a co-operation programme between the European Commission (EC) and the Association of South East Asian Nations (ASEAN) co-ordinated by the Asian Institute of Technology (AIT), Bangkok, Thailand. Its aim is to accelerate the implementation of proven technologies generating heat and/or power from wood and agro-industrial residues through partnerships between European and ASEAN companies.

RATIONALE

ASEAN countries are currently enjoying some of the most rapid economic growth rates in the world, resulting in an ever increasing demand for energy. In order to limit the demand for fossil fuels, ASEAN countries are promoting efficient energy strategies such as cogeneration (the combined production of heat and power). In order to limit the public sector capital requirements for infrastructure, ASEAN countries are encouraging the private sector contribution to power generation.

The economies of most ASEAN countries are still mainly based on agriculture and the agro-industrial sector. All these wood and agroindustries generate huge quantities of biomass residues. Apart from the obvious environmental benefits associated with utilising CO₂ neutral fuels, the economic incentives to install biomass fuelled energy plants (with the increased access of auto-produced electricity to national grids) will become increasingly attractive. Efficient, high-quality and proven technologies for the processing and combustion of biomass residues are available in Europe.

OBJECTIVES

The EC-ASEAN COGEN Programme attempts to promote technology transfer by increasing ASEAN awareness of European technologies and

know-how. As one of the fastest growing markets in the world today, ASEAN offers a huge potential for European energy technologies. Biomass residues are increasingly considered to be a valuable energy source, as both energy prices and energy demand continue to rise. Therefore, another important objective is to increase European awareness of ASEAN opportunities and capabilities.

TARGET GROUPS

Since the primary objective is to transfer technology from Europe to ASEAN, the overall approach has, on the European side, been to identify relevant and interested equipment suppliers, and on the ASEAN side to identify potential equipment end-users and business partners, and to investigate overall market potential. The EC-ASEAN COGEN Programme is thus designed to be a support for European companies producing biomass energy technology, who are interested in expanding their markets in ASEAN, but do not have sufficient capacity to cultivate the market alone.

The Programme focuses on proven technologies only. Research projects, pilot plants or prototypes are not considered. Sources of biomass that need to be harvested, pre-treated or transported, are not considered by the Programme because of the costs of such operations. The main focus has consequently been on waste products generated by four important agro-industrial sectors in ASEAN (rice, sugar, palm oil and coconut) and the wood sector. Such waste is generally centralised at industrial sites, and available free of charge or at a minimal cost. Wood and agro-industries producing waste thus constitute the main target group in ASEAN. Local manufacturers of biomass energy technology wishing to form partnerships with European equipment suppliers are also a target group for the Programme.

Finally, EC-ASEAN COGEN Programme is directed towards policy makers. Based on a systematic technical and socio-economic approach, the Programme attempts to provide policy makers with an accurate assessment of the environmental and economic benefits associated with an expanded use of biomass in the ASEAN energy supply.

FULL SCALE DEMONSTRATION PROJECTS (FSDPS)

During the last 3 years the EC-ASEAN COGEN Programme has identified significant potential for technology transfer of proven technologies generating heat and/or power from wood and agro-industrial residues. In order to

accelerate the implementation of these technologies, the COGEN Programme has made available funds for investing in Full Scale Demonstration Projects. New funds will be made available during early 1995.

The EC-ASEAN COGEN Programme 1995-1996 will consist of the three following components:

1. Implementation of full scale demonstration projects (FSDPs).

Some technologies are technically and economically viable but are not yet implemented in ASEAN. To overcome this obstacle, the EC-ASEAN COGEN Programme will bring technical and financial assistance to implement FSDPs. An FSDP can be defined as the implementation of a proven technology on a full scale basis in order to demonstrate its technical reliability and economic viability. Therefore, an FSDP constitutes a shop window in ASEAN, aiming to convince other potential end-users to select the technology.

What are the criteria of a project?

The technology must already be proven elsewhere and must use biomass (wood or agro-residues) as a fuel. The project must offer scope for a Euro-ASEAN partnership, it must not have a negative impact on the environment and finally it must be replicable.

What can the EC-ASEAN COGEN Programme support?

- Investment assistance.
- The investment assistance for the selected projects consists of a grant covering up to 15 % of the total European or Euro-ASEAN tax free equipment cost, with a ceiling at 400,000 ECU per project.
- Training in EUROPE and ASEAN.
- In order to ensure the successful implementation and operation of the equipment, the EC-ASEAN COGEN Programme will provide support to the training in ASEAN and/or in Europe of the End-User personnel assigned to the operation and maintenance of the project, and/or personnel of the local equipment manufacturer.
- Monitoring by an independent organisation.
- In order to evaluate the technical reliability and the economic viability of the technology, a monitoring campaign will be supported and performed according to procedures jointly defined by the EC-ASEAN COGEN Programme, the European Equipment Supplier and the End-User. The monitoring campaign will be carried out by an organisation independent from and jointly agreed by the European Equipment Supplier and the End-User.

What are the requirements?

The end-users must allow both technical and economic monitoring, diffusion of the technical and economic results of the project, and visits to the installation from interested parties throughout ASEAN.

2. Promotion of full scale demonstration projects in ASEAN

To ensure the maximum replication of the demonstration projects, independent technical and economic monitoring of the equipment will be performed. The project results, including economic benefits for the end-users, will be widely advertised in the region, through media, printed material, as well as visits of the plants by public and private sector representatives from all ASEAN countries.

3. Supporting measures

In parallel to the demonstration projects, a series of activities have been planned to ensure that cogeneration using biomass will flourish, on a sustainable basis, on completion of Phase II. These activities include:

- Sectoral market studies
- Information dissemination
- Industrial tours in ASEAN and in Europe
- Seminars/Conferences
- Training workshops.

THE 1995 CALL FOR FULL SCALE DEMONSTRATION PROJECT

Within the current call for Full Scale Demonstration Projects a total fund of 2.25 Million ECU is available. Project proposals must be received by the EC-ASEAN COGEN Programme Secretariat in Bangkok by 31 May 1995. A further call for the project proposals will be announced if any funds are not allocated from the first call.

EXPECTED RESULTS

In the short term, the Programme will establish:

- References of European and Euro-ASEAN equipment in selected wood and agro-industries of relevant ASEAN countries.
- Promotion of the reference projects and their monitored performance.

- Closer links between European suppliers and ASEAN customers and partners.
- Publications and databases on biomass resources, ASEAN customers, industrial partners, public agencies, and European suppliers.

In the long term, the Programme will bring significant implementation of these technologies, and the creation of Euro-ASEAN partnerships to produce the appropriate equipment and promote business development.

Further information concerning the EC-ASEAN COGEN Programme can be obtained from:

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Posters

FINNISH BIOENERGY RESEARCH PROGRAMME

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1 INTRODUCTION

Finland is a leading country in the use of biofuels and has excellent opportunities to increase the use of biofuels by up to 25 - 30 %. The Finnish Government has set an objective for the promotion of bioenergy. The aim is to increase the use of bioenergy by about 25 % from the present level by 2005, and the increment corresponds to 1.5 million tonnes of oil equivalent (toe) per year. The R&D work has been considered as an important factor to achieve this ambitious goal. Energy research was organised into a series of research programmes in 1988 in accordance with the proposal of Finnish Energy Research Committee. The object of the research programmes is to enhance research activities and to bundle individual projects together into larger research packages. The common target of the Finnish energy research programmes is to proceed from basic and applied research to product development and pilot operation, and after that to the first commercial applications, e.g. demonstrations. For example in 1988, ten five-year research programmes were started, including two programmes of fuel peat production. One of these programmes was Optimiturve - Peat production based on solar energy. Within the Optimiturve new and more efficient methods and machinery for peat production were successfully developed. The programme has provided in-depth knowledge on different stages of peat production. This basic information has led to the development of new methods of producing milled and sod peat. As the organisation of energy research to programmes has led to good results, the Finnish Ministry of Trade and Industry decided to go on with this practice by launching new six-year programmes in 1993.

2 FINLAND HAS ABUNDANT BIOENERGY RESOURCES

The total annual primary energy consumption in Finland is 30 million toe. In 1993 the share of wood-derived fuels of the total primary energy consumption was about 14 % (ca. 4.3 million toe) and peat about 5 % (1.5 million toe). Finland's forests contain ample quantities of wood, and at least 10 million m³ (2 million toe) more wood could be harvested annually for en-

ergy purposes. Areas suitable for the production of peat fuel amount to about 0.6 million hectares, with a total energy potential of around 550 million toe. At current rates of use there is peat to last for hundreds of years. In the next few years it is estimated that 0.5 - 1 million hectares of arable land will cease to be used for traditional cultivation. One possibility is to use these fields to produce biofuels. The useful potential of energy crops is probably about 1 - 2 million toe. The exploitation of solid wastes and sludges in energy production could also be increased.

It has been estimated that the use of bioenergy could be increased by 3 million toe till the year 2010, i.e. to 8.5 million toe (Figure 1). Today high harvesting costs are an obstacle to profitable use of wood fuels in Finland. The major part of this increase could be in pulp and paper industry by developing new harvesting methods and using the fuel for power production.

3 BIOENERGY RESEARCH PROGRAMME

The Finnish Ministry of Trade and Industry started eight new energy technology research programmes for the years 1993 - 1998. One of these programmes is the Bioenergy Research Programme. The programme is supported by the Technology Development Centre, the Ministry of Trade and Industry, the Ministry of Agriculture and Forestry and Finnish companies.

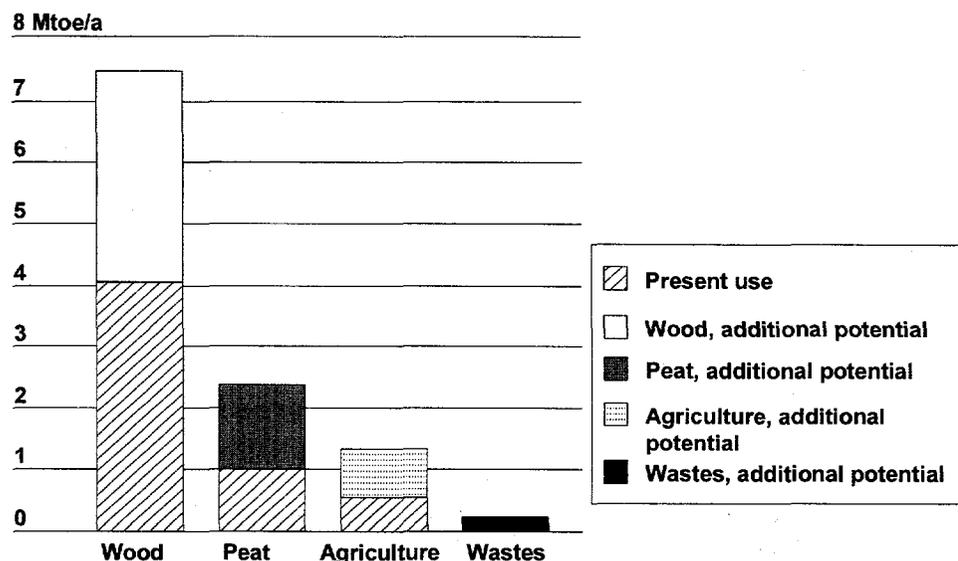


Figure 1. Potential for the additional use of biofuels in Finland in 2025.

The co-ordination of the research programme is carried out by VTT Energy. Public funding for the research programme during 1993 - 1998 is suggested to amount to FIM 138 million and the funding from mainly industrial sources to FIM 72 million (1 ECU = 6.3 FIM).

The total funding of the Programme would be FIM 210 million. The funding in 1994 was FIM 50 million and about 60 projects were going on in 1994. Nearly half of the funds were channelled to the area of production of wood fuels. VTT Energy, the Finnish Forest Research Institute, Work Efficiency Institute, Metsäteho, University of Joensuu and several companies are participating in the programme.

The main research areas include

- production of wood fuels,
- peat production,
- use of bioenergy,
- conversion of biomass.

In addition to the above, the programme would also include special projects for producing biofuels from energy crops and for exploiting the energy content of sludges and solid wastes. The Bioenergy Research Programme includes research projects connected with the handling of biofuels and with pressurised drying as well as utilisation of bioenergy. The programme will also involve schemes linked with development of equipment and plant technology for small-scale combustion and small-scale power plants. Schemes related to the gasification and combustion of biofuels, as well as new power plant technology for larger plants form part of the Combustion and Gasification Technology Research Programme - LIEKKI 2.

4 OPERATIONAL PRINCIPLE

The aim of the research programme is to increase the use of economically profitable and environmentally sound bioenergy by improving the competitiveness of present peat and wood fuels. Research and development projects will also develop new economically competitive biofuels, new equipment and methods for production, handling and use of biofuels.

Increasing the use of bioenergy will make it possible to limit carbon dioxide emissions in energy production, improve the silvicultural state of forests, raise the level of self-sufficiency in energy production and the productive value of forests, and also create favourable conditions for entrepreneurial and business activity, and increased employment. Finland has a tradition of exporting equipment for the forest industry and energy production. The

development projects and demonstrations involved with bioenergy promote the development of new equipment especially for exports.

5 MAIN GOALS

The main goals of the programme are as follows:

- to develop new production methods for wood fuels in order to decrease the production costs to the level of imported fuels. The total potential of the wood fuel use should be at least 1 million toe per year;
- to increase the competitiveness of peat fuels by decreasing the production costs by 20 % as compared with 1992 prices, and also to reduce environmental load;
- to develop and demonstrate at least 3 - 4 new equipment or methods for handling and use of biofuels. The equipment and/or methods should provide economically competitive and environmentally sound energy production;
- to demonstrate at least 3 - 4 large-scale biofuel end-use technologies. Each of these should have a potential of 0.2 - 0.3 million toe per year till the year 2000;
- to produce basic information on biomass conversion, to evaluate the quality of products, their usability, environmental effects of use as well as the total economy of the production. The objective of biomass conversion is to develop 2 - 3 new methods, which could be demonstrated, for the production and utilisation of liquefied, gasified and other converted biofuels. The production target of biomass "refineries" is 0.2 - 0.3 million toe per year by 2005 at a competitive price level.

The most important area of research on *wood fuel production* is the development of various methods, machines and systems connected to this area, in order to produce economically competitive fuel. In the area of integrated harvesting new methods as well as processing methods for small-sized trees are being developed. The target is to find out new production methods for pulp chips that allow harvesting of undelimited trees or tree sections with acceptable total economy. In harvesting of logging waste, research and development work is focused on forwarding and rational means to combine transport and comminution of residues.

The research in *peat production* focuses on the use of all the available in a bog and the development of peat production methods and machines. Development work in this area aims at decreasing production costs and also at decreasing the waste water and other elements in environmental load around the peat production sites.

The *use of bioenergy* research will be concentrated on the small scale (20 MW_{th}); in the long term, the increase of bioenergy in the space heating of small houses and farms, as well as in the production of heat and power.

This research into the *conversion of biomass* is focused on the production of biomass-based liquid fuels.

6 PRELIMINARY RESULTS

Two projects aim to increase the productivity of harvesting small-sized trees, and at the same time, to produce more biomass for energy production. The modification of a conventional felling head makes it possible to collect several trees and delimb and cross-cut them together. This increases productivity of felling by 20 - 30 % in the first thinning. A combi-machine for felling and forwarding of undelimbbed trees and tree sections is also being developed. The machine is capable of multi-tree harvesting and it has load compressing devices. It has been estimated that a productivity of 5 - 7 solid m³/ha can be achieved even in the first thinning. If it is possible to manufacture the machine at a reasonable price, e.g., by using a second-hand base machine, harvesting costs may be at the level of FIM 50 - 60/solid m³ at a roadside inventory.

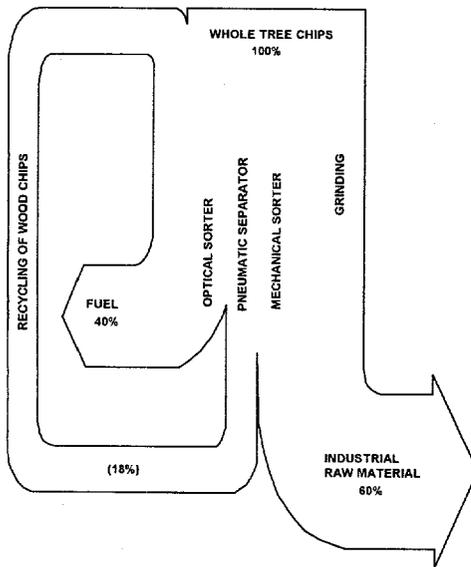
A wood chip harvester that operates on strip roads could be one alternative to rationalise logging. The Chipset harvester being developed by Logset Company with some Swedish participants is also included in this research programme. The chip harvester fells small trees or picks up slash and tops from the ground, and feeds the trees into a front-mounted drum chipper, from where the chips are conveyed into a rear-mounted 6 m³ container. The contents of the full container are side-tipped into a trailer or container at the roadside or landing site. The project received EUREKA status at the Ministerial Conference in Paris in June 1993. The first prototype was built in 1991, and a new prototype was demonstrated this year in full scale in Finland.

The integrated harvesting methods, which would produce both wood raw material for pulp mills and wood fuel for energy production, have been developed further and partly demonstrated. The chain delimiting-debarking of small-diameter wood has showed technical possibilities, and economical calculations show that the method will have economical profits. Also the MASSAHAKE method, based on several different successive separation phases of whole-tree chips, has showed a debarking result for birch and bark content below 1 %, and economical calculations show that the method can be profitable. The Ministry of Trade and Industry made a decision in 1993

about an investment subsidy on a full-scale MASSA-HAKE demonstration plant, flail delimiting-debarking machinery of Hooli Company and flail delimiting-debarking chipper and grinder for Pertti Szepaniak Company. Large-scale wood fuel production is demonstrated in Central Finland and in Mikkeli district. Figure 2 shows a biomass flow chart of MASSAHAKE method and flail delimiting-debarking chipping.

The mechanical final cutting yields annually some 1 million toe of logging residues (6 million solid m³). Satisfactory efficiency in fuel wood harvesting can be achieved only by year-a-round logging and transport. This is only possible, if the fuel wood harvesting is combined with regular supply and forwarding of pulpwood and sawlogs. Chipping and transport of the fuel is carried out with a combined chipping and transporting lorry utilising a sea container as cargo carrier. If the use of bioenergy is centralised, the long-distance transport of energy will be carried out using sea-containers and trains. The cost level reached in the study is based on utilising two-shift operations in pulpwood and sawlogs harvesting and combining fuel harvest with the main operation. This combination benefits both operations and makes the initial harvesting of biofuels feasible in all mechanised final cutting of spruce-dominated stands. Combining roadside chipping and transport of biochips in the same vehicle minimised the "mobilisation" costs

MASSAHAKE-METHOD



DELIMITING-DEBARKING-CHIPPING TECHNIQUE

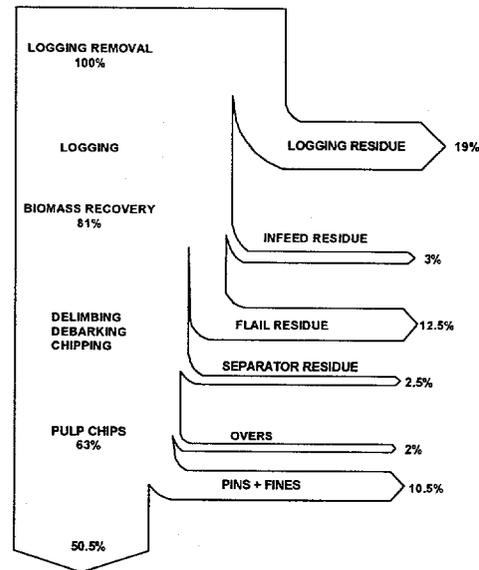


Figure 2. Biomass flow of MASSAHAKE method and flail delimiting-debarking chipping method.

related to small operations typical of Finland. This equipment can also be used in roadside chipping and transporting biomass from thinnings and other harvesting operations.

In small-scale combustion research a 200 kW prototype burner was designed for an automatic combustion system fueled by wood chips and sod peat. The combustion system includes a fuel feeder, a burner, a new-type boiler and a control system to the fuel feeder and the burner. The aim was to achieve the total efficiency of at least 85 % at full load and that the carbon monoxide content of the fuel gas should be lower than 0.1 % (1 000 ppm). 200 kW heat output was achieved both by wood chips and sod peat as a fuel provided that the moisture of fuel was not too high. The total efficiency when burning wood chips at the full load was 85 % according to the standard DIN 1942 and 80 % at the 50 % load. Usually the carbon monoxide (CO) content was lower than 1 000 ppm. For example, when burning birch wood chips, the average CO content was 530 ppm at the 12.7 % CO₂ content. During the project, the burner was developed to the stage where the commercialisation can be started. Burning of wet fuels needs further development work. The full-scale demonstration project has been started by Högfors Lämpö (output of the boiler 500 kW).

Thermochemical conversion of biomass has in the Bioenergy programme focused mainly on processing of spent cooking liquors and crude soap to liquid fuels, flash pyrolysis including wood oil production and use in boilers and engines. The main application in Finland is expected to grow in chemical and mechanical wood industry where low-price biomass is available in large quantities and the reference option is conventional CHP boilers and chemical recovery boilers. If in the future additional biomass will be available based on integrated harvesting methods, the base scenario will be replacement of coal in multifuel boilers with additional condensing mode in power production. The challenge for R&D is, if several types of biomass can be converted to liquid (gaseous) fuel with higher efficiency than in condensing power production. The biofuel market will be in decentralised diesel power plants in CHP production (Figure 3), in oil boilers and possible also on long-term in transport sector. At the moment 8 % of total research funding is spent on thermochemical conversion in the Bioenergy research programme. Together with several joint projects by key companies they form a well focused activity to most interesting topics in Finland. Possibilities to use tall oil or tall oil fatty acid fraction of spent liquors is of interest for diesel fuel oil or as a component in diesel oil. The other key area is flash pyrolysis of biomass, where significant co-operation with EC and Canadian partners is taking place. This is also a key area in starting the 4. framework programme JOULE-THERMIE. The aim is to use wood oil heating boilers in size class of 100 - 700 kW or in diesel power plants in 2 - 20 MW_e. For.

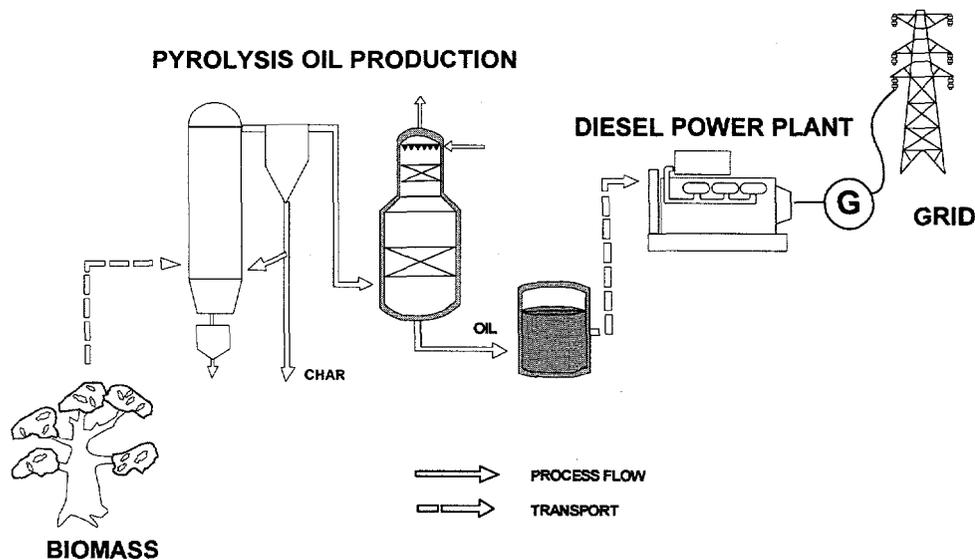


Figure 3. Flash pyrolysis and diesel plant.

utilisation of agrobiomass in various forms of energy, a system study is introduced where special attention is how to use rapeseed oil unprocessed in heating boilers and diesel engines. Energy crops like reed canary grass is investigated as a solid fuel to fluid-bed boilers, gasifiers and flash pyrolysis. The overall economy is compared to conventional ethanol/ETBE, methanol/MTBE and rapeseed RME option. For biotechnical conversion of biomass, there are unfortunately no activities at the moment

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TESTING OF DOWNSTREAM CATALYSTS FOR TAR DESTRUCTION WITH A GUARD BED IN A FLUIDISED BED BIOMASS GASIFIER AT PILOT PLANT SCALE

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Abstract

A new pilot plant for advanced gasification of biomass in a fast fluidised bed is now fully operative at University of Saragossa, Spain. It is a "3rd generation" pilot plant. It has been built up after having used two previous pilot plants for biomass gasification.

The main characteristic of this pilot plant is that it has two catalytic reactors connected in series, downstream the biomass gasifier. Such reactors, of 4 cm i.d., are placed in a slip stream in a by-pass from the main gasifier exit gas. The gasification is made at atmospheric pressure, with flow rates of 3 - 50 kg/h, using steam + O₂ mixtures as the gasifying agent. Several commercial Ni steam-reforming catalyst are being tested under a realistic raw gas composition. Tar eliminations or destructions higher than 99 % are easily achieved.

INTRODUCTION

After having started to study the fluidisation technology in 1965, Corella and co-workers started to study the gasification of biomass at laboratory scale in 1982. In 1985 - 1986 they started the gasification in fluidised bed at a pilot plant and built up the first pilot plant (Figure 1) for such purpose. The pilot plant was based on a bubbling fluidised bed of 15 cm i.d. The gasifying agent was steam and different types of biomass were gasified in it. Some results of research have been presented by Herguido et al. [1]. Very important was the experience gained with the feeding system which used two screw feeders. The height of the fluidised bed was small. So, to avoid a big carry over of char, ash, fines..., the superficial gas velocity was low. Once fixed the steam/biomass feeding ratio, the throughput of biomass had also to be low.

The endothermicity of the gasification with steam, our knowledge on the FCC process and similar circulating systems, and some data published by the Battelle Columbus Laboratory (Ohio, USA) made us deeply modify that first pilot plant.

So, in 1989 the multisolid, catalytic and circulating fluidised-bed gasification (MSCCFBG) pilot plant (Figure 2) was built up. It was like the Battelle Columbus one, but due to the fact that we wanted and needed to work out the field of application of the Battelle Columbus's patent we introduced further modifications like using inside (in-bed) an 'in equilibrium' (already used by Oil Refineries) FCC catalyst which had a remaining activity for tar cracking and circulated between the two main vessels (gasifier and char combustor). Some data and results obtained with that 2nd pilot plant were published by Herguido et al. [2].

Our 2nd pilot plant had high throughputs and solved the problems derived from the endothermicity of gasification with steam. Nevertheless, the overall process was too complex and the tar content in the exit gas was still high. Simultaneously we operated another gasification facility with downstream catalytic reactors. It gave excellent results for tar destruction. As a conclusion, in 1993 we decided to thoughtfully modify the existing MSCCFB gasification plant and to build up another new one. This is the main objective of this communication.

3RD PILOT PLANT FOR ADVANCED GASIFICATION OF BIO-MASS IN FLUIDISED BED

Our actual pilot plant for biomass gasification was recently presented at the last EC Conference on Biomass in Vienna, Austria, October 1994 (Figure 3). The modifications made from the previous one (Figure 2) lasted near two years. That means that the revamping has been deep and the concept of our gasification process has changed a lot. The detailed description of the modifications made are out the scope of this communication.

As a brief summary, our pilot plant is based on a fast fluidised-bed gasifier of 15 cm i.d. and 3 m high, operating at slightly above atmospheric pressure. Its throughput is 3 - 50 kg biomass/h. Our main problem has been perhaps the flame or torch produced at burning the main exit gas. It was 2 - 3 m high and since our pilot is located in the Faculty of Sciences of the U.Z., in the centre of the city of Saragossa (700 000 inhabitants), such a 'nice, big and spectacular' flame made some people to protest. We had to reduce the exit flow of gas (to decrease the size of the flame), reducing thus the feeding of biomass till flow rates of only 5 - 10 kg/h. Simultaneously we had to

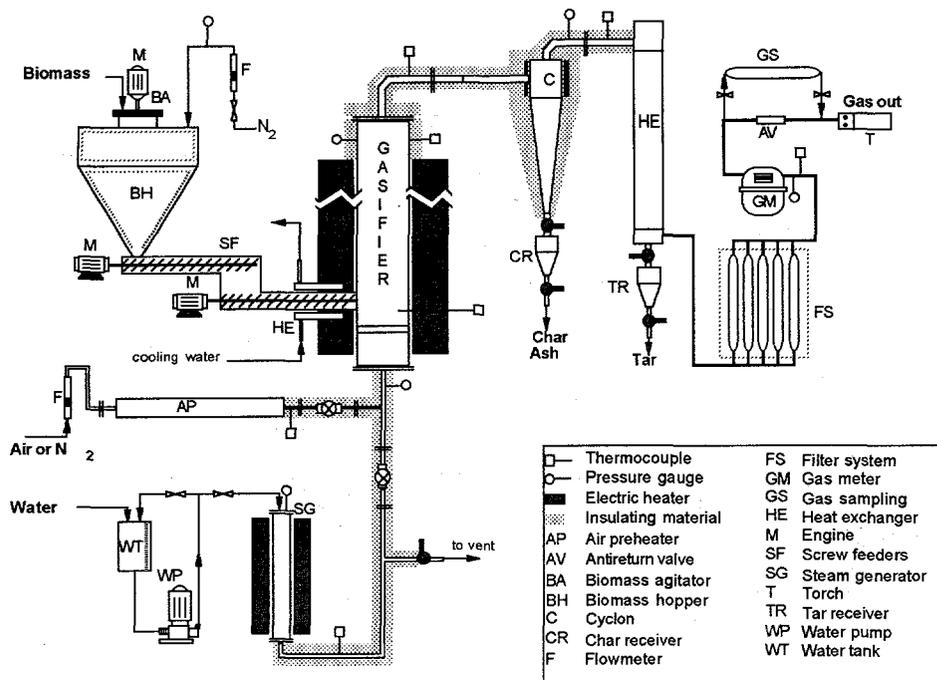


Figure 1. First pilot plant used by Corella et al. for gasification of biomass-based in a bubbling fluidized bed.

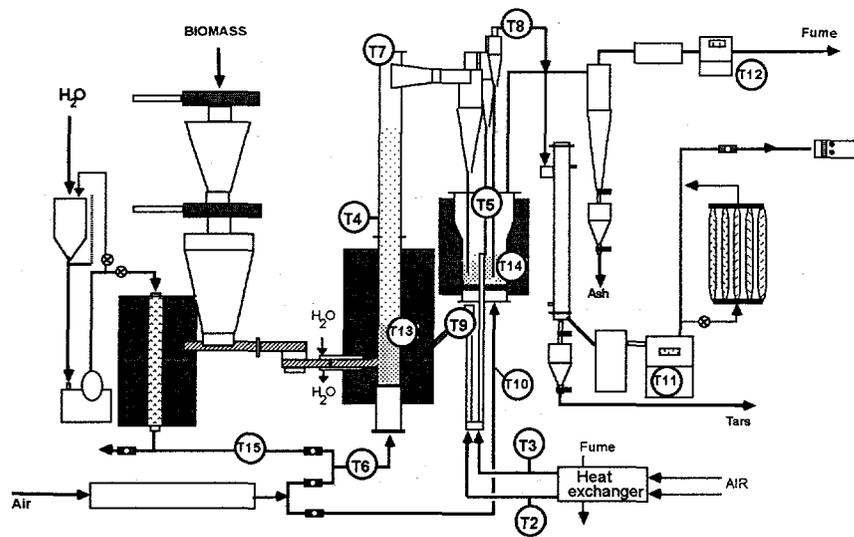


Figure 2. Second pilot plant of Corella et al. for gasification of biomass based on a MSCCFB gasifier.

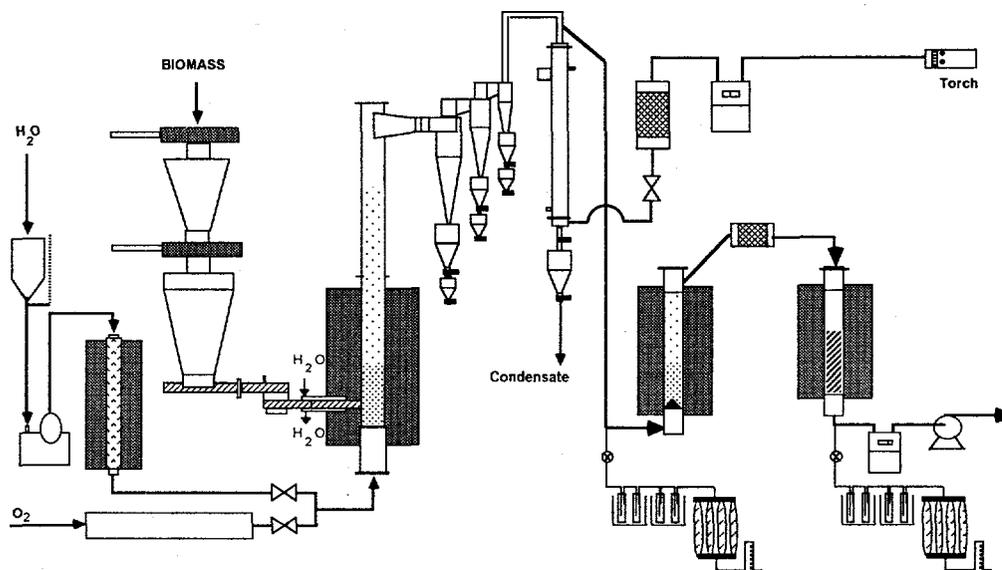


Figure 3. Our actual 3rd generation biomass gasification pilot plant with downstream catalytic reactors.

install a new and bigger stack and a new good burner for the exit gas. Curiously, these have been the main problems of our gasification facility.

The main characteristic of our facility is that it has two catalytic reactors connected in series and located in a slip stream, downstream the gasifier. The 2nd one is for commercial steam reforming catalysts. They are used to 'destroy' the tar present in the flue gas. The 1st bed is used as a guard bed for the catalytic one. It eliminates some tars and sulphur present in the flue gas using calcinated dolomites (OCa-OMg) or OZn, respectively, or both.

SOME RESULTS IN PILOT PLANT

The main operation conditions in our facility are shown in Table 1. Some results of the gas composition and tar content before and after the test (guard + catalytic) reactors in experiment number 4 are shown in Table 2.

Table 2. Some results for experiment no. 4.

Component, vol%	Raw gas	Clean gas
H ₂	19.8	41.2
CO	45.2	37.2
CO ₂	13.6	8.2
CH ₄	5.6	0.08
C ₂ H ₄	2.0	0.00
C ₂ H ₂	0.50	0.00
C ₂ H ₆	0.25	0.00
Tars, g/Nm ³	21.2	0.33

ACKNOWLEDGEMENT

The financial support of the EC project/contract no. JOU2-CT93-0399 and the help of Mr. J.A. Borque is acknowledged.

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FRESH TAR (FROM BIOMASS GASIFICATION) DESTRUCTION WITH DOWNSTREAM CATALYSTS: COMPARISON OF THEIR INTRINSIC ACTIVITY WITH A REALISTIC KINETIC MODEL

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Abstract

A model for fresh tar destruction over catalysts placed downstream a biomass gasifier is presented. It includes the stoichiometry and the calculation of the kinetic constants for the tar destruction. Catalysts studied include commercial Ni steam reforming catalysts and calcinated dolomites. Kinetic constants for tar destruction are calculated for several particle sizes, times-on-stream and temperatures of the catalyst and equivalence ratios in the gasifier. Such intrinsic kinetic constants allow a rigorous or scientific comparison of solids and conditions to be used in an advanced gasification process.

INTRODUCTION

Mudge, Baker et al. at PNL (Richland, WA, USA), Corella et al. at Universities of Saragossa and Madrid (Spain), K. Pedersen at DTI (Aarhus, Denmark) and P. Simell and E. Kurkela at VTT (Espoo, Finland), besides the MINO Swedish process, have published data on the high activity and efficiency of commercial catalysts placed downstream a biomass gasifier for the undesirable tar (present in the flue gas) destruction.

Most of such commercial catalysts used till now are for steam reforming (Ni based) or for hydrocracking (Co-Mo based). They are quite active but some problems still remain to be solved. One of them seems to be its deactivation by coke and by sulphur. Another problem is that such commercial catalysts are being designed to be used in fixed beds. So, their size is high enough to have very low effectiveness factors (as it will be demonstrated here for tar destruction) and their softness makes problematic (if not impossible) their fluidisation. Even more, the small work made (or, at least, published) on

this subject makes very difficult till date to compare and to select a good catalyst to clean the exit raw gas or to modify and to tailor its composition. With a lack of space, we present here a kinetic model for tar destruction with downstream catalysts, the calculation of the kinetic constants for such tar destruction and the comparison of several types of solids (catalysts) based on their intrinsic kinetic activity for tar destruction.

EXPERIMENTAL FACILITY USED

Previously, Corella et al [1, 2] published data on biomass gasification using a downstream catalytic reactor with several types of commercial steam reforming catalysts. Their tar destruction efficiencies or conversions were till 99.9 % but the life of the catalysts seemed not to be very high due to a large amount of tar ($10 - 50 \text{ g/Nm}^3$) coming from the gasifier. This fact made us to modify our process and facility and to set up/install a new guard bed before the catalytic one. This guard bed uses (mainly, but not exclusively) calcinated stones like dolomites, calcites and magnesites. There are now three different beds: gasifier, guard and catalytic. The process is now more complex and expensive but the results obtained now are much better. A good economic evaluation remains to be done for such purpose.

We are working on three different gasification facilities. Two of them are bench scale (1 kg biomass/h) and the 3rd one is a pilot plant (5 - 50 kg/h). In the two first ones all the raw gas produced in the gasifier is passed through the guard and catalytic beds. In the pilot plant only a slip stream is sent towards the guard and catalytic beds. The detailed description of such facilities have been published elsewhere [3, 4].

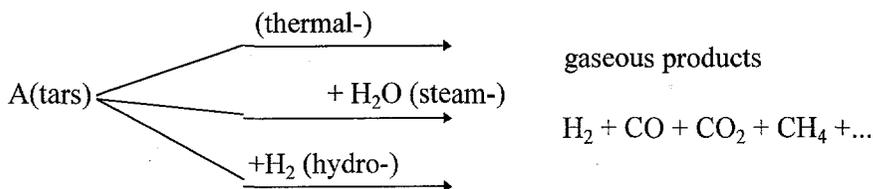
Tars produced in the gasification of biomass with steam are different from those produced in gasification of biomass with air or with (steam +O₂) mixtures. The results given here come from gasification with air (only). Similar results for gasification with steam or with (steam + O₂) will be presented in the future.

STOICHIOMETRY AND KINETIC MODEL FOR TAR DESTRUCTION

Tars present in the flue gas from biomass gasifiers can be destroyed (not only cracked, so this word is not correct and should not be used in the future) by different and simultaneous reactions and mechanisms of

- thermal-, steam-, hydro-cracking
- steam-, CO₂-, ... reforming
- hydro-reforming
- etc.

The overall reaction for this tar (A) destruction or elimination can be written as:



The proposed kinetic equation for this model is:

$$\begin{aligned}
 -r_A &= k C_A + k' y_{\text{H}_2\text{O}} C_A + k'' y_{\text{H}_2} C_A = (k + k' y_{\text{H}_2\text{O}} + k'' y_{\text{H}_2} + \dots) C_A = \\
 &= k_{\text{overall}} C_A
 \end{aligned}$$

For the (2nd) bed, of calcinated dolomite (CaO-MgO) or guard bed, we will define and use for k_{overall} : k_2

For the (3rd) bed, of commercial catalyst (of steam reforming, Ni-MgO/Al₂O₃, for instance), we will define and use for k_{overall} : k_3

The rate for tar destruction can be calculated by:

$$(-r_A) = dC_A / d(W_j / Q_{j,0}) = (C_{A,\text{inlet}} - C_{A,\text{out}}) / (W_j / Q_{j,0})$$

where $C_{A,\text{inlet}}$ and $C_{A,\text{out}}$ mean the tar concentration in the flue gas at the bed inlet and outlet, respectively, W_j the amount (kg) of catalyst in the j-th (2nd or 3rd) bed and $Q_{j,0}$ the volumetric flow rate (Nm³/h) at inlet of the j-th bed.

The tar sampling and analysis methods for the calculation of $C_{A,\text{inlet}}$ and $C_{A,\text{outlet}}$ are absolutely important for the usefulness of the kinetic constants. We have used a complex tar sampling method very similar to that used by VTT which will be published elsewhere.

SOME KINETIC RESULTS

The value of the k_2 and k_3 have been calculated in each experiment at different times-on-stream. The obtained values of k_3 for the steam reforming

catalyst from BASF ref. no. G1-25-S are shown in FIGURE 1. One can see in it, for instance, the different values of k_3 (or tar destruction efficiency) for different experiments (at different operation conditions).

The very important effect of the particle diameter of the commercial steam reforming catalyst is shown in Figure 2. Results are shown for three different temperatures. With particle diameters of the catalyst above 0.5 mm there is a clear control of the internal diffusion (effectiveness factor <1.0).

The effect of the Equivalence Ratio (E.R.) and of the temperature on k_3 for the BASF G1-25-S catalyst is presented in Figure 3.

For the calcinated dolomites (used in the 2nd reactor), the kinetic constants for tar destruction obtained in the different experiments are shown in Figure 4. The space-time (τ), value close to the mean residence time for the gas in the bed used is also here indicated. Notice that different temperatures, particle diameters and types of dolomites have been used in these experiments. A very important conclusion is deduced when the values in the ordinate of this Figure 4 are compared with the values given in the ordinates of Figures 1, 2 and 3.

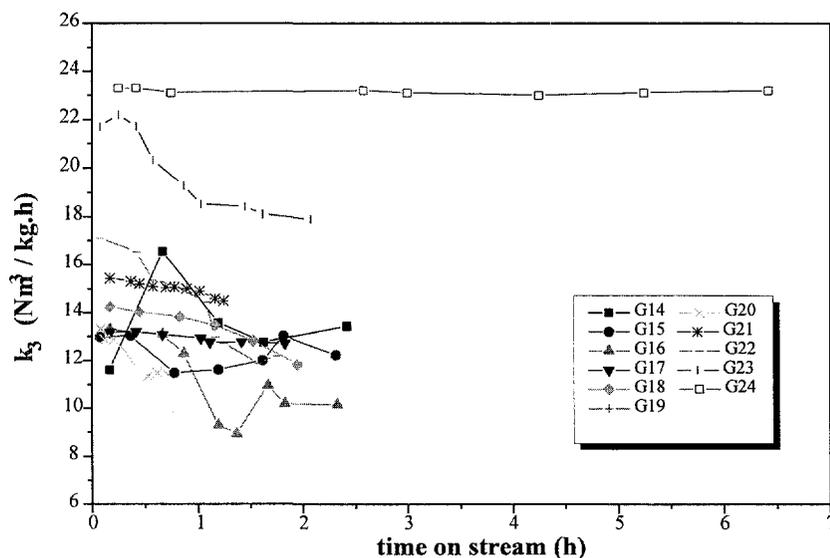


Figure 1. Kinetic constant for tar elimination vs time on stream, for some experiments. Catalyst BASF G1-25-S.

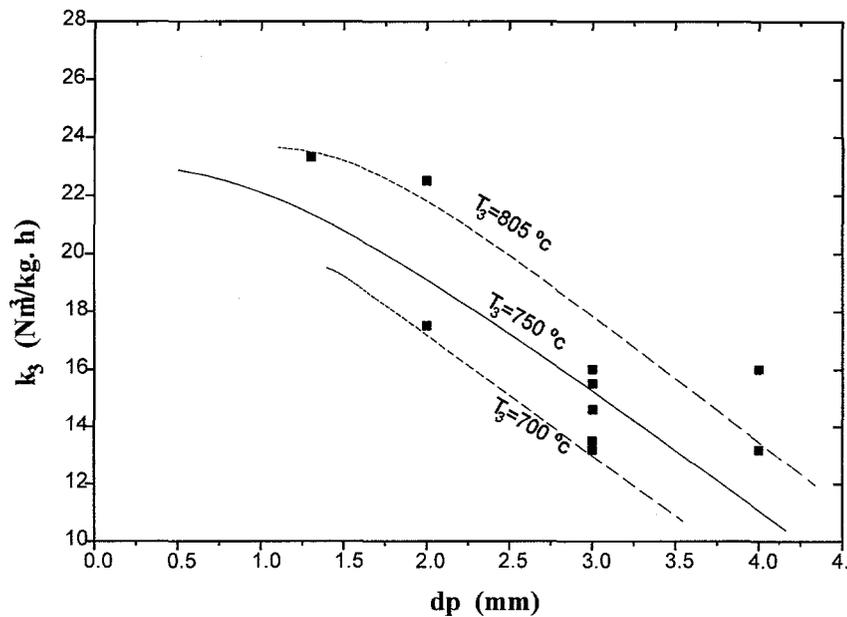


Figure 2. Kinetic constant for tar elimination vs time on stream, for some experiments. Catalyst BASF G1-25-S.

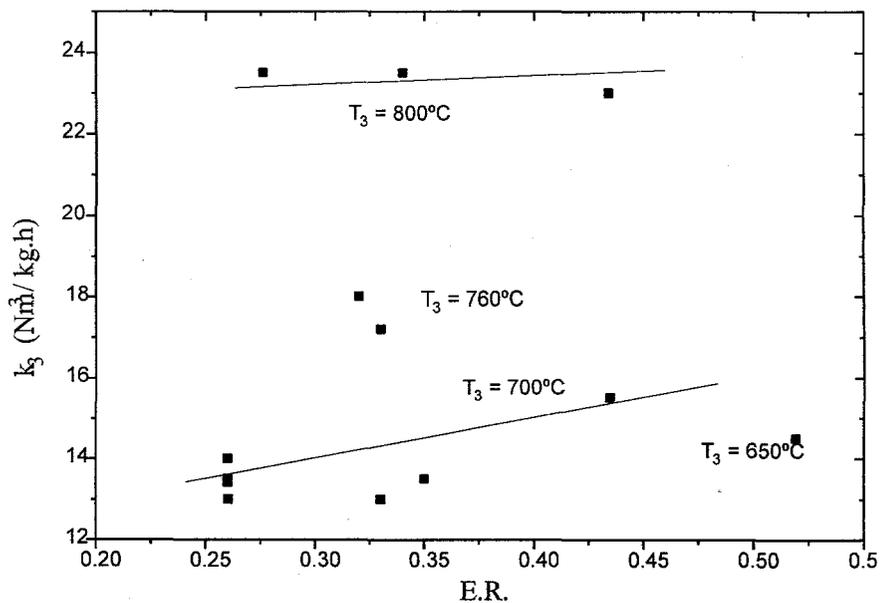


Figure 3. Effect of the E.R. on the kinetic constant for tar conversion.

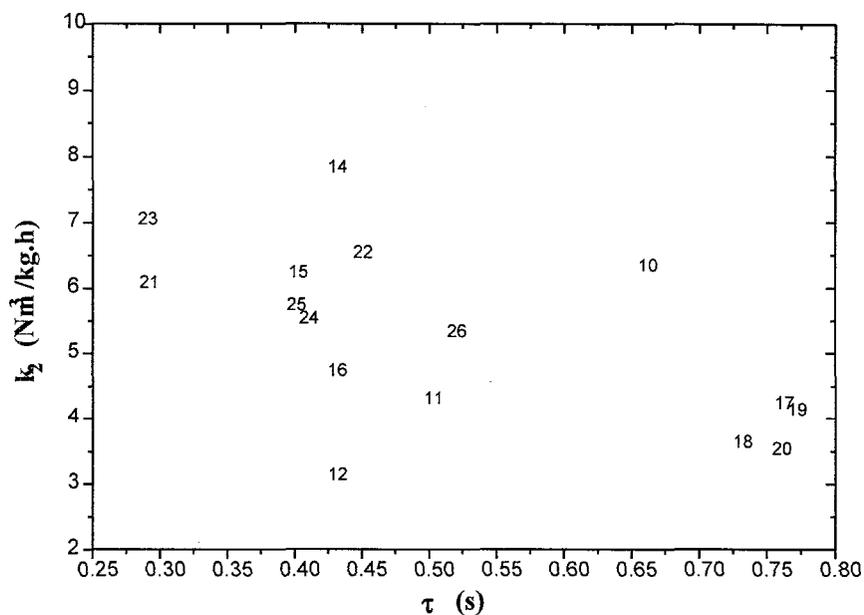


Figure 4. Kinetic constant for tar destruction over dolomites vs residence time.

For the same particle size the activity (k_3) of the steam reforming (Ni) catalysts is (2215.5) about 4 times higher than the activity (k_2) of the calcinated dolomites.

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BIOFLUID PROCESS: FLUIDISED-BED GASIFICATION OF BIOMASS

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Abstract

Fluidised-bed gasification of biomass was developed by ATEKO by using long-term experience from coal gasification. An experimental unit was built and a number of tests, first with sawdust gasification, were carried out. A gas combustion engine combined with a power generator was installed and operated in power production.

1 INTRODUCTION

The aim of the development of the BIOFLUID process was energy utilisation of biomass gasification in a fluidised-bed reactor to gain energy gas either as a fuel for gas combustion engines or turbines for co-generation of heat and power or for replacing conventional fuels. There are different wastes and residues available from agriculture, vegetable production and wood processing industry, i.e. from farms, sawmills, pulp mills, and forest residues. In Czech Republic, the quantity of wood waste only exceeds 10^6 t/a. These residues that contain a great energy potential are utilised to a small extent only and limited mostly to combustion, in many cases resulting in non-effective heat utilisation.

Biomass, especially wood waste, can be gasified, and the product gas is utilised either for replacing conventional fuels (natural gas, fuel oil, etc.) or as a fuel in gas combustion engines or turbines for heat and power co-generation. In this way, possibilities of biomass utilisation for energy are more economical. Replacing conventional fuels is applicable in brick kilns, lime kilns at glass or ceramic works, etc., due to operating cost (in case of natural gas) or environmental aspects (fuel oil with sulphur content). Heat and power production from wood waste is required, for example, by sawmills to produce energy for own use.

2 DEVELOPMENT OF THE BIOFLUID PROCESS

ATEKO has been interested in the gasification process, especially in lignite gasification, since 1949. It participated in research and development of fixed-bed generators for coal gasification using a steam-oxygen mixture as gasification agent at pressures up to 3.0 mPa. More than 60 such generators were manufactured. With regard to environmental aspects, ATEKO has been engaged in fluidised-bed technology since 1980. A pilot plant with a capacity of 12 t/day was built for coal gasification and it was operated for three years.

The fluidised-bed gasification process was modified for gasification of sawdust, wood residues and bark at the end of 1993. An experimental pilot plant was built in 1994 and it has been tested since September 1994.

2.1 MATHEMATICAL MODEL

A mathematical model for gasification based on chemical equilibrium was prepared and tested on wood waste. Composition of combustible matter and gasification agent, temperature and pressure of gasification, moisture and ash content of fuel, and equilibrium were determined. Gas composition, specific consumption of fuel and gasification agent, and residue from the gasification reactor were calculated.

A good congruence with experimental values (except for CH₄ content in gas) was obtained. Some calculation results for air gasification at 850 °C and atmospheric pressure are given in Table 1.

Table 1. Calculated results for air gasification at 850 °C and atmospheric pressure.

Fuel composition, wt%		Gas composition, vol%		Specific consumption, raw gas	
C	41.7	H ₂	13.4	air	0.59 Nm ³ /Nm ³
H	5.0	CO	16.5		
O	36.3	CO ₂	10.8		
N	0.4	CH ₄	0.8	fuel	0.36 kg/Nm ³
Water	15.0	N ₂	46.7		
Ash	1.6	H ₂ O	11.9		

2.2 COLD MODEL

The aim of tests with a cold model was to find out the optimal fluidisation velocity in the reactor. Sawdust with 3 - 5 mm particle size was fluidised by air to determine the threshold velocity of fluidisation. Test results for various heights of the still sawdust bed are given in Figure 1. The threshold velocity of fluidisation was about 0.3 m/s and the operating velocity in the fluidised-bed reactor was chosen 0.7 m/s.

2.3 EXPERIMENTAL UNIT

An experimental unit was designed on the basis of model testing (Figure 2). Sawdust of about 3 mm particle size is fed into a hopper, 3, equipped with a vault breaker. Wood waste is fed by a screw feeder, 4, into the lower part of the gasifier, 5. Gasification air is heated up to 300 °C in an electric heater, 2, and fed into the reactor in some levels to gain optimal temperatures in the whole volume of the reactor to suppress tar formation. Pressure of gasification air is controlled by a valve, 1. The product gas leaves the reactor from the upper part into a cyclone separator, 6. Dust is removed from the bottom of the cyclone. Gas continues through a water cooler, 7, and a water seal, 8, at about 30 °C temperature either into a gas burner, 9, or into a gas combustion engine combined with an electric generator, 10.

3 RESULTS OF TESTS WITH THE EXPERIMENTAL UNIT

Parameters of the experimental unit are given in Table 2. The tar content of the raw gas (before the water cooler) was in the range of 0.394 - 1.967 g/m³, its content being closely dependent on temperature distribution in the reactor and on the start-up procedure. At the stabilised operation state at about 850 °C in the upper part of the gasification reactor, the tar content was about 0.5 g/m³. The ash content of the residue from the cyclone separator was 15 - 10 wt%, with the combustible fraction 85 - 90 wt%. Comparison of operating parameters for the gas combustion engine with natural gas (NG) and wood gas (WG) is given in Table 3.

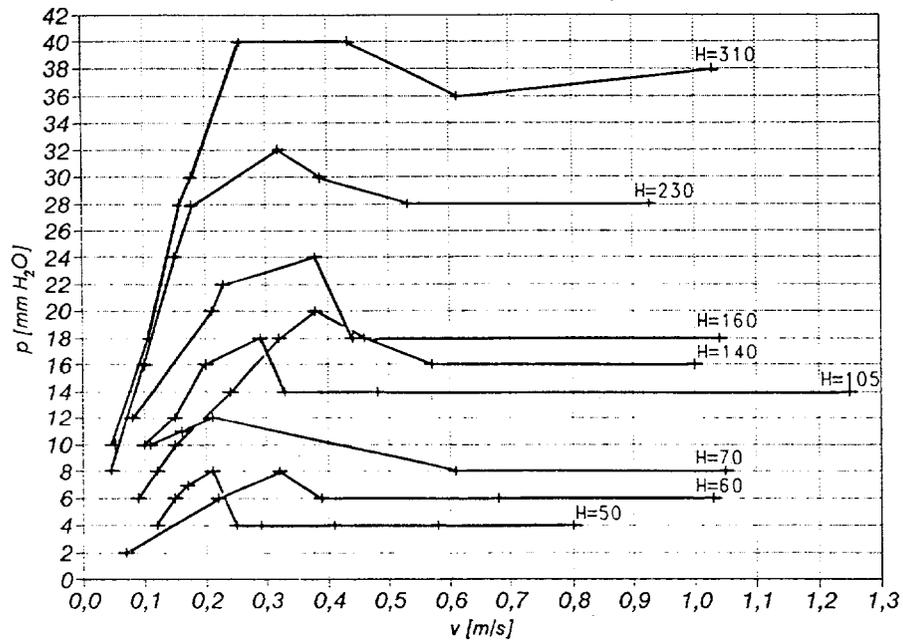


Figure 1. Pressure drop versus flow velocity relationship.

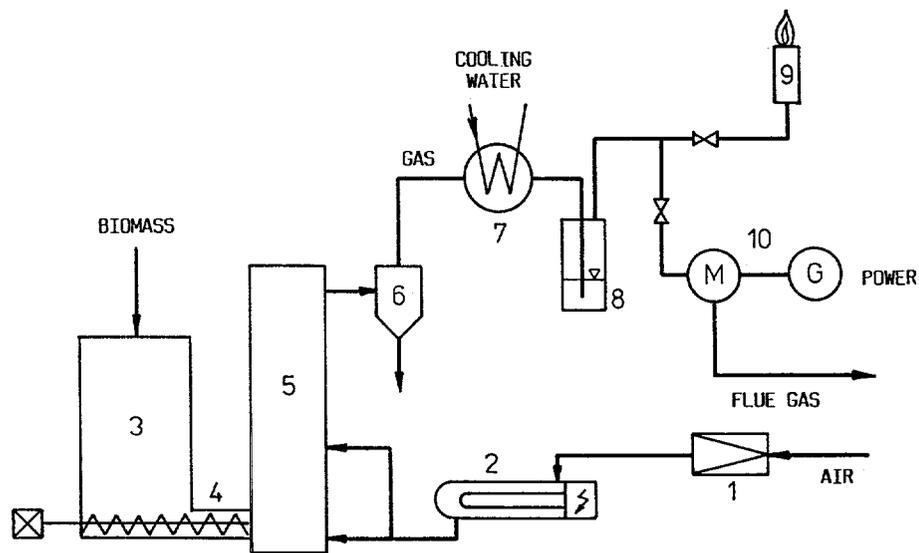


Figure 2. Biofluid experimental plant. 1. Check valve. 2. Electric heater. 3. Feed hopper. 4. Screw feeder. 5. Gasification generator. 6. Cyclone. 7. Gas cooler. 8. Water seal. 9. Burner. 10. Gas combustion engine with electric generator.

Table 2. Parameters of the experimental unit.

Fuel (sawdust) (wt = 15 %, LHV = 15.4 MJ/kg)		27 kg/h
Gasification agent: air		35 Nm ³ /h
Operating pressure		50 - 70 mbar (g)
Operating temperature		820 - 950 °C
Produced gas		51 Nm ³ /h
Composition, vol%	CO	16.8 - 18.0
	CO ₂	13.6 - 14.8
	CH ₄	7.2 - 8.0
	H ₂	6.1 - 7.3
	O ₂	0.2 - 0.4
	N ₂	53.2 - 55.8
LHV		5.1 - 5.4 MJ/Nm ³
Power production		16.5 - 17.5 kW _e

Table 3. Operating parameters for the gas combustion engine with natural gas (NG) and wood gas (WG).

	LHV, MJ/Nm ³	Flow rate, NM ³ /h	Gas input, kW	El. output, kW _e
NG	34.0	8.6	81.1	22.0
WG	5.1	51.0	72.2	16.5
	Efficiency, η_{el} , %		Specific consumption of energy, MJ/kW _e	
NG	27.0		13.3	
WG	22.8		15.8	

4 CONCLUSIONS

The tests with the experimental unit were divided into three stages. The aim of the first stage of the tests was to verify the heat and material balance, to stabilise operating parameters and to determine the optimal procedure for starting and stopping the gasification reactor. In this stage, operation with wood waste only was used. Installation of the gas combustion engine combined with an electric generator for combustion of wood gas and production power was proposed in the second stage. The optimal operation of gas combustion engines combined with the gasifier is being studied presently. Various operating states with regard to the optimal mixing ratio, regulation of

the unit and emission reduction are being tested. Gasification of other types of biomass such as straw, residues from rapeseed oil production and other biomasses, is planned for the third stage of the tests.

Application of the fluidised-bed gasification reactor with a multilevel input of gasification agent is distinguished for the production of clean gas with a very low content of higher hydrocarbons. Temperature of the gasification reactor has a great influence on the quality of the product gas. It is of significance to keep the gasification temperature above 800 °C in the whole volume of the reactor. This temperature is sufficiently high to suppress tar formation.

Presently two projects on energy utilisation of wood waste are underway for Czech clients. The first one concerns combined heat and power production with 60 kW_e and 85 kW_t output. The expected term of delivery is the end of 1995. The other one concerns replacement of heavy fuel oil in a brick kiln with 2.2 MW thermal output (according to LHV of energy gas). The term of starting the construction is expected to be in February 1996.

UTILISATION OF ESTONIAN ENERGY WOOD RESOURCES

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In the end of the Soviet period in the 1980s, a long-term energy programme for Estonia was worked out. The energy system was planned to be based on nuclear power and the share of domestic alternative sources of energy was low. The situation has greatly changed after the re-establishment of the Estonian independence, and now wood and peat fuels play an important role in the energy system. Energy consumption in Estonia decreased during the period 1970 - 1993 (Figure 1), but this process has less influenced the consumption of domestic renewable fuels - peat and wood. It means that the share of these fuels has grown. The investment on substitution of imported fossil fuels and on conversion of boiler plants from fossil fuels to domestic fuels has reached the level of USD100 million.

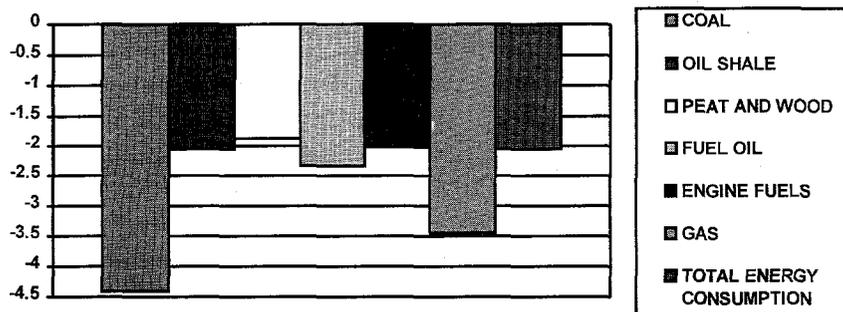


Figure 1. Decrease of consumption of fuels during 1970 - 1993.

The perspectives of the wood energy depend mainly on two factors: the resources and the price of wood energy compared with other fuels. The situation in wood market influences both the possible quantities and the price. The basic data characterising the biomass and energy wood production is given in Tables 1 and 2.

Table 1. Biomass production in Estonian forests.

PRODUCTIVE FOREST LAND	2.02	Mha
AVERAGE SITE PRODUCTIVITY	4.8	m³sob/ha/a
Production of productive forest land		
• Stemwood, excl. tops	8.8	Mm ³ sob/a
• Tops and branches	2.7	Mm ³ sob/a
Production on other land		
• Stemwood, excl. tops	0.8	Mm ³ sob/a
• Tops and branches	0.3	Mm ³ sob/a
TOTAL BIOMASS PRODUCTION	12.6	Mm³sob/a
Biomass volumes not available for environmental reasons, % of total productive forest area	4	
• Total biomass	0.03	Mm ³ sob/a

Table 2. Estimated availability of tree biomass as fuel.

	ALT. A Mm ³ s/a	ALT. B Mm ³ s/a
ASSUMED CUT OF COMMERCIAL WOOD ON PRODUCTIVE FOREST LAND	3.3	6.3
Volumes of tops and branches	1.0	1.9
ASSUMED CUT ON NON-FOREST LAND	1.1	1.1
Volumes of tops and branches	0.3	0.3
Assumed consumption of sawlogs	1.6	3.0
Assumed consumption of small-dimension wood in pulp and board industry and for exports	1.0	2.0
Stemwood and other biomass not used by the industry (available for fuel)		
• Stemwood	2.1	
• Tops and branches	1.3	2.2
Reductions		
• For technical and economical reasons	0.4	0.7
• (30 % of tops and branches)		
POTENTIALLY AVAILABLE VOLUMES OF TREE BIOMASS FOR FUEL	2.4	3.6

ALT. A: Consumption of sawlogs on the level of 1988 - 1991

ALT. B: Consumption when the sawmill sector has developed

It is typical that the quickly growing cost of labour power in Estonia is greatly affecting the price of energy wood. Though the price level of fuel peat and wood chips is lower than the world market price today, the conditions for using biofuels could be more favourable, if higher environmental fees were introduced.

In conjunction with increasing utilisation of biofuels it is important to evaluate possible emissions or removal of greenhouse gases from Estonian forests.

Forests, which cover 47.7 % of the Estonian land, are an important terrestrial sink for carbon dioxide (CO₂). Because approximately half of the dry mass of wood is carbon, as trees add mass to their stems, branches and roots, more carbon is accumulated and stored in the trees than is released to the atmosphere through respiration and decay. Soils and vegetative cover in forest also provide a potential sink for carbon emissions. When man's use alter the functions of the forest ecosystem through land use change and forest management activities, the natural balance of CO₂ and other GHG-s emissions and uptake may be disbalanced and their atmospheric concentrations adjust.

The area of forest stands has more than doubled during the past half-century (in 1935 - 20.2 %; in 1993 - 47.7 %) and will be increasing in the nearest future in Estonia. As a result of biological process (e.g. growth, mortality) and man's activities (harvesting, thinning, etc.) the carbon balance in the forest ecosystem has already changed if compared with the situation in the past and will change due to alterations in the Estonian forestry in the future. The Estonian forest carbon flux was presented in inventory estimates for 1990 (± 2 years) and is based on total accounting of biomass carbon stored in aboveground biomass of trees, soil carbon, as well as carbon in product pools.

The annual carbon flux from Estonian forests is estimated to have been a net sequestration of carbon from the atmosphere to the biosphere. The total removal of carbon to forest was accounted to be 3094.57 Gg, including 2476.63 Gg removal by trees and 617.94 Gg by soils.

Commercial harvest and management of various kinds make up a large majority of total forests biomass losses. Depending on the level of that, the annual rate of removals and emissions may be changed. The annual rate of carbon emission from Estonian forests is estimated to be 962.27 Gg. The harvested timber and fuelwood effectively results in immediate carbon emission to about 769.64 Gg. Additional carbon flux from forests, from on-site burning of branches, bark and other wood wastes, has been estimated at

9.51 Gg. In forest logging some biomass remains on the ground (stumps), where it decays slowly and 9.22 Gg carbon is released to the atmosphere due to the decay. A rather high amount of carbon is released to the atmosphere from the forest soil.

The basic calculations focus primarily on forest logging processes and abandonment of managed lands. In the calculation processes of CO₂ removals or emissions from forests, alterations of areas and aboveground biomass changes due to management of forest have been taking into account. So, the annual removal of CO₂ to Estonian forests was during the inventory year 11346.75 Gg. This figure includes 743.27 Gg CO₂ due to accumulation by the total growth increment of managed forests and 3908.48 Gg CO₂ due to accumulation by abandonment of managed lands over previous 20 years.

In the processes of forest management part of wood may be removed from the logging site and used as fuelwood or for products. This results in 2791.03 Gg of CO₂ emission annually to the atmosphere. Part may be burned on site or converted to slash and decayed to carbon dioxide step by step. The annual rate of soil CO₂ emission from forest conversions was estimated at 508.75 Gg CO₂. The total CO₂ emission from forest ecosystem is 3396.32 Gg CO₂.

Taking into account emissions and removals of CO₂ in the forest ecosystem the net CO₂ uptake by the forest ecosystem in Estonia is estimated at 7950.43 Gg per year (Figure 2).

Forest management activities may also result in fluxes of other greenhouse and radiatively important gases balance in the atmosphere. Open burning associated with forest clearing or other land use change may be a cause to disbalance in the normal situation of non-CO₂ trace gases in the atmosphere. The effects of forestry activities on fluxes of these gases are not finally understood and highly uncertain. Data calculated for Estonia by using the methods recommended in IPCC Guidelines (1977) are presented in Table 3.

As a conclusion we can say, that both the biomass resources of Estonian forests and the calculation of greenhouse gases show that the share of wood energy could be higher. Utilisation of wood for energy production is safe from the ecological point of view, reduces dependence of imported fuel and improves employment opportunities.

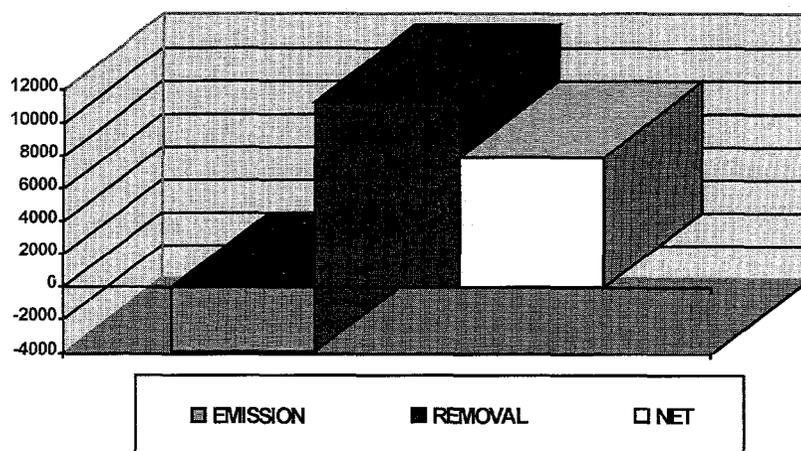


Figure 2. CO₂ emissions and removal.

Table 3. Results of estimation of emissions (Gg) of non-CO₂ trace gases in Estonian forests.

CH ₄	CO	N ₂ O	NO _x
0.1521	1.3307	0.0010	0.0378

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GASIFICATION OF SAWDUST IN PRESSURISED INTERNALLY CIRCULATING FLUIDIZED BED

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Abstract

A test plant for pressurised gasification of biofuels in a internally circulating fluidized bed has been built at the department of Chemical Engineering II at the University of Lund. The design performance is set to maximum 20 bar and 1 050°C at a thermal input of 100 kW or a maximum fuel input of 18 kg/h. The primary task is to study pressurised gasification of biofuels in relation to process requirements of the IGCC concept (integrated gasification combined cycle processes), which includes studies in different areas of hot gas clean-up in reducing atmosphere for gas turbine applications.

1 INTRODUCTION

A test plant for pressurised gasification of biofuels in a internally circulating fluidized bed has been built at the department of Chemical Engineering II at the University of Lund. The design performance is set to maximum 20 bar and 1050°C at a thermal input of 100 kW or a maximum fuel input of 18 kg/h. The primary task is to study pressurised gasification of biofuels in relation to process requirements of the IGCC concept (integrated gasification combined cycle processes), which includes studies in different areas of hot gas clean-up in reducing atmosphere for gas turbine applications. The plant is also described in Figure 1.

The PFBG plant in Lund consists of four main parts:

- the pressurised feeding system
- the fluidized bed gasifier
- the hot gas filtration unit
- the catalytic conversion unit.

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The feeding system consists of a pressurised chamber and a hydraulic compression unit. Biomass fuel is fed into the compression unit and is compressed by a hydraulic piston before pressurising with nitrogen. In this manner nitrogen consumption and dilution of the fuel gas are kept to a minimum. The fuel is introduced into the pressurised chamber from which it is fed by screws into the gasification reactor.

The gasification reactor, the hot gas filter unit, and the catalytic conversion unit are placed inside of three cylindrical pressure vessels of 0.5 m inner diameter. These cylindrical vessels are connected to each other and so are the inner units. Insulation and electrical heating coils are placed between the inner units and the pressure vessel. In this way thermal losses are prevented and fast start-up procedure is possible. Inside the pressure vessel nitrogen will balance the gas pressure of the inner parts.

The gasifier reactor is of internally circulating fluidized bed type(ICFB) and consists of a 102 mm inner diameter tube with a 40.6 mm inner diameter tube placed inside the larger tube. The annular space in between the larger tube and the inside placed tube forms the downcomer. The inside placed tube is named riser. Fluidising agent is fed into the bottom of the riser and at the top, a static impeller separates the solids from the gas. The solids will then be recycled falling down through the downcomer.

The filtration unit consists of a cooler and a SiC candle filter. The cooler is placed ahead of the filter and will cool the gas to an appropriate filtration temperature. The catalytic conversion unit, placed after the filtration unit, is simply a 102 mm inner diameter tube filled with catalytically active material. There is a gas cooler consisting of tube coils, in the bottom of the catalytic conversion unit. This cooler lowers the temperature of the gas before exiting the pressure vessel. The pressure vessel is constructed for withstanding pressures up to 25 bars and the inner parts for temperatures up to 1 050 °C.

The plant is displayed in Figure 1 and technical data for the gasifier reactor are listed in Table 1.

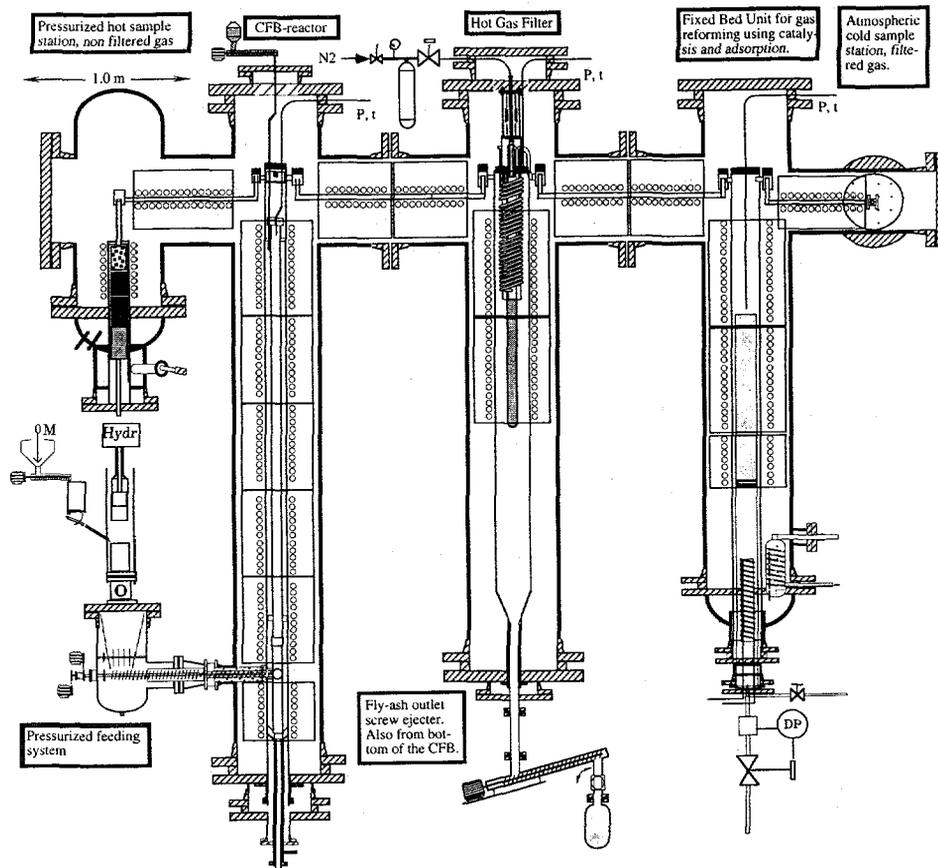


Figure 1. Overview of PFBG pilot plant built at the Department of Chemical Engineering II at the Institute of Technology in Lund.

Table 1. Pressurised internally circulating fluid bed reactor, technical data.

Riser, inner diameter, (mm)	40.6
Downcomer(annular space)	
inner diameter, (mm)	48.0
outer diameter, (mm)	102.0
Reactor height, (m)	3.30
Process pressure, bar(a)	6 - 20
Average riser temperature, (°C)	800 - 1 000
Gasification fluid	air or O ₂ in N ₂
Fluidising velocity, (m/s)	1.5 - 2.5
Feedstock	sawdust
Fuel feed rate, (kg/h)	4.2 - 18.0
Bed material	quartz sand

2 WORK PROGRAM

The purpose of the project is to establish realistic conditions for the gasification of biofuel, as well as for gas cleaning. It is also to determine the basic properties, and the performance, of the plant at different pressures, temperatures, and loads. The intention is to study formation of the most important gasification byproducts and to report the material balance of the equipment at different performance rates. The basic test program is planned to study the influence from the following parameters on gas composition, tar content, and gas production among others:

- Process pressure in the range of 0.5 to 2.0 MPa(a).
- Fuel to air ratio (ER) in the range of 0.2 to 0.35.
- Particle size distribution of the bed material in the range of 0.10 to 0.20 mm of average particle diameter.

The hot gas clean up study will emphasise on detection, identification, quantification and development of reduction methods for the following impurities:

- Fuel bound nitrogen and its conversion to ammonia, hydrogen cyanide and nitrogen containing tars.
- High temperature condensable hydrocarbons e.g. biotars.
- Fuel and bed material bound alkali components and their conversion to high temperature condensable salts of mainly sodium and potassium.

3 PRELIMINARY RESULTS

3.1 FUEL MATERIAL

Sawdust from the southern part of Sweden was used as feedstock in the initial gasification experiments. The bed material used in the first runs was a quartz sand quality from Baskarp in Sweden. Chemical composition and physical properties of the sawdust feedstock and the quartz sand bed material are listed in Table 2.

3.2 EXPERIMENTAL PROCEDURE

A couple of gasification runs has been made so far and initial test and sampling results from two of those are presented here. A total amount of typical 8 - 9 kg of sawdust was fed continuously into the riser of the ICFB reactor during a run which typically lasted between one to three hours. A typical average temperature along the riser of the reactor has been about

620 °C at the beginning of fuel feed. The average feed of sawdust were about 180 g TS/min. In order to smoothly rise the temperature in the reactor from the starting temperature of 620 °C to the set point for gasification around 850 °C has the air to fuel ratio (ER) successively been lowered as the temperature has risen.

Table 2. Chemical composition and physical properties of sawdust feedstock and quartz sand bed material.

Sawdust feedstock		Quartz sand bed material	
<i>Proximate, wt%</i>		<i>Composition, wt%</i>	
Volatile matter	81.4	Fe ₂ O ₃	0.51
Fixed carbon	11.2	SiO ₂	87.7
Ash	1.6	Al ₂ O ₃	6.0
Moisture	5.8	CaO	0.51
		MgO	0.11
		Na ₂ O	1.32
		K ₂ O	2.48
<i>Ultimate, wt%</i>			
C	48.6	Dp _{average} (μ m)	150
H	6.0		
N	<0.2		
S	0.01		
O	44.0		
Na, ppm-wt	11		
K	115		
Dp _{average} (μ m)	786		

This has been achieved by successively lowering of the air feed at a constant fuel feed. Operational parameters and preliminary results from the gasification runs presented here are listed in Table 3.

All the process data together with gas sample analyses from the atmospheric sample station situated down stream of the catalytic reactor has been continuously registered by computer. Additionally, continuous sampling of condensate components as tar, moisture and ammonia has also been undertaken. The fluidisation condition of the ICFB has continuously been controlled by measuring the material density of the riser. Also the temperature profile along the riser has been continuously measured. This in order to consolidate that the fluidisation conditions are acceptable and above all to consolidate that the circulating of the bed is maintained at a stable level.

Table 3. Gasification runs - preliminary results.

Experiment no	601	609
Feedstock	sawdust	sawdust
Bed material	quartz sand	quartz sand
Bed material, $D_{p\text{average}}$ (μm)	150	150
Pressure, bar(a)	12.0	15.2
Equivalence ratio(ER)	0.29	0.28
Average riser temperature, ($^{\circ}\text{C}$)	850 \pm 15	832 \pm 19
Feedstock moisture, (w% of TS fuel)	5.8	5.8
Fuel feed rate, (kg TS/h)	10.8	11.1
Primary air, (Nm^3/h)	14.0	13.9
Nitrogen feed, (Nm^3/h)	2.2	2.2
Product gas flow rate, (Nm^3/h)	25.6	
Maximum gas velocity riser, (m/s)	1.9	
Dry gas composition, (vol%)		
CO	13.3	13.6
CO ₂	11.7	
CH ₄	4.2	5.8
H ₂	3.6	
N ₂	55.6	
H ₂ O, wet	11.7	
Lower heating value, (kJ/Nm^3)	4.2	
Total condensate content, (g/Nm^3)	117	149
Condensate Tar content, (g/Nm^3)	21	
Condensate moisture, (g/Nm^3)	96	

3.3 SAMPLING PROCEDURE AND ANALYSIS

At the first experimental test runs has only the sampling equipment for atmospheric sampling of particulate filtered gas before the catalytic reactor and at the product gas outlet been tested. The sampling procedure has included sampling of condensate components, tar and water, and dry gas for on-line analysis by mass spectrometry and IR-spectrometer. The pressurised sampling station has so far not been used since the atmospheric sample stations still are being continuously modified.

PYROLYSIS OF BIOMASS WASTE TO PRODUCE SORBENTS WITH SPECIFIC PROPERTIES

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Abstract

Variants of introducing iron salts into wood, cellulose and kraft lignin (impregnation, pH 1.5, pH 5.5, and ion exchange) have been investigated by the ESR method. Iron forms in the products of thermal treatment of samples were identified by the X-ray diffraction method, using ASTM-based data bank. The highest values of sorption activity and magnetizability were achieved for carbonized Fe^{+3} wood samples prepared by the ion exchange method.

1 INTRODUCTION

Sorption methods are the most effective means of waste water treatment and gas exhaust cleaning in various industries from the viewpoint of environment protection. Among the materials used, carbon sorbents provide the highest efficiency of cleaning. High-quality carbon sorbents can be produced by the pyrolysis of lignocellulosic materials. Additives of metal compounds with varying valency, for example, iron salts, allow to extend the application sphere of the carbon materials obtained, due to their new attractive properties - magnetisability.

Additives of the salt mentioned were studied extensively in the gasification processes and used for the production of specific catalysts.

The aim of this work was to study the effect of differences in wood, cellulose and lignin structures and methods of introducing iron ions in them on the characteristics of the iron - lignocellulose system formed, on its chemical transformation and on the properties of the carbonized products.

2 RESEARCH METHODS

The wood sample was prepared by grinding on a ball mill, selecting the fraction of < 0.5 mm. The samples of sulfate cellulose and kraft lignin were obtained during industrial wood processing.

To determine the behaviour of lignin and cellulose component of the wood complex in thermal treatment with the ion Fe^{+3} introduced, a model system of sulphate cellulose + Fe^{3+} and sulphate lignin + Fe^{3+} were used. Thermal treatment was performed in the isothermal regime in the temperature range of 400 - 900 °C in 60 min. Iron ions (in the form of $\text{Fe}_2(\text{SO}_4)_3$ salts) were introduced by ion exchange and impregnation (pH 5.5 and 1.5) methods. The iron content of the wood and lignin samples (in terms of Fe_2O_3) was 10, 15, 20, and 30 %. X-ray and magnetisability measurements were used to characterise the structure.

3 RESULTS AND DISCUSSION

The interaction of lignin or wood powder with iron ions depends on the polymer structure and the method of salt introduction. From the data presented in Table 1 it follows that the *impregnation* of kraft lignin *in neutral medium* is accompanied by a decrease in the intensity of the narrow signlet signal characteristic for lignin.

In this case, the degree of decrease in the concentration of paramagnetic centres (PMC) does not depend on the amount of the iron introduced. The broad signal with the g-factor 4.2, characteristic of Fe^{3+} appears in the kraft-lignin spectrum during impregnation at pH = 5.5.

In the case of wood powder, the signlet signal in the ESR spectra is completely depressed after the treatment in the same conditions (*impregnation at pH = 5.5*). This is obviously due to the death of free radicals and the corresponding change of the active centres of the matrix. The iron line is represented by the parameters characteristic of iron hydroxides ($\Delta H > 100$ mT, g-factor 2).

When samples were treated with iron sulphate salts without additional neutralisation, the *impregnation* solution had the *acid reaction* (*pH = 1.5*) due to the hydrolysis of the salt. The characteristics of the ESR spectra of the kraft lignin treated in these conditions completely differ from those obtained in neutral medium: the concentration of paramagnetic centres increases, the form and width of the line (ΔH) being preserved. This is characteristic of

Table 1. Change of parameters of ESR spectra with the methods of iron ions introduction.

Method of introduction	Quantity of Fe ₂ O ₃ wt%	Concentration of PMC * ¹⁰⁻¹⁶ spin/g	Width of ESR line, mT, Δ H
KRAFT LIGNIN			
Initial		90.70	5.89
Impregnation pH = 5.5	10	63.88	7.07
	20	59.90	7.62
	30	55.99	7.62
Impregnation pH = 1.5	10	146.57	5.44
	20	220.01	5.71
	30	333.31	4.90
Ion exchange	10	92.65	6.52
	20	128.30	7.07
	30	132.22	7.07
WOOD POWDER			
Initial	-	91.77	8.70
Impregnation pH = 5.5	10	-	-
	20	-	-
	30	-	-
Impregnation pH = 1.5	10	9.33	5.44
	20	39.02	5.44
	30	75.56	5.71
Ion exchange	10	37.25	9.79
	20	36.25	9.52
	30	29.43	9.95

doped organic semiconductors. The increase of the iron introduced is accompanied by the increase in the concentration of PMC.

In the wood samples (*impregnation at pH = 1.5*), the lignin signal was decreased, which was expressed most prominently when 10 % of Fe₂O₃ was introduced. The iron signal is not very broad (≈ 10 mT) and was not practically changed when different amounts of iron were introduced (Table 1).

The introduction of iron ions by the *ion exchange* method into the lignin was accompanied by an increase in the PMC concentration and a considerable increase in the line width. Such changes are obviously connected with the course of oxidative-reduction reactions with electrons transition and participation of both stable and unstable lignin radicals in these reactions.

In the case of wood powder, the PMC concentration was decreased three times and did not depend on the amount of the iron introduced. A wide line (ΔH 1 000 mT, g-factor 2) appeared, which was probably caused by the presence of an iron component in the form of hydroxide as a separate phase. However, in the case of kraft lignin, the iron component signal was absent.

Thermal treatment of the cellulose sample + 15 % Fe^{3+} in the temperature range of 400 - 700 °C was accompanied by reduction reactions as a result of which the Fe component in carbonisation products was represented actually only by Fe_3O_4 . The variation on the X-ray pattern of the line with index 521, having the highest peak in the magnetite spectrum, indicates that the accumulation of Fe_3O_4 in the pyrolysis products reached the maximum when the treatment temperature was raised to 600 °C. Further increase in the pyrolysis temperature was accompanied by a decrease in the magnetite content of the products, which was obviously connected with further stages of the iron process according to reaction $\text{Fe}_3\text{O}_4 \Rightarrow \text{FeO} + \text{Fe}^0$. In the pyrolysis product of the cellulose sample + 15 % Fe^{3+} at 800 and 900 °C, the presence of all the three compounds was observed.

From the intensity of the reflexes on the X-ray patterns it followed that, when the amount of the iron oxide introduced was increased from 10 to 20 %, the Fe_3O_4 content of the cellulose carbonisation products obtained at 900 °C doubled. However, at the same time the FeO amount was increased 1.5-fold at a constant share of Fe^0 . In this case, obviously, a shortfall of the carbohydrate component for the magnetite reduction process manifested itself.

As a result of the thermal treatment of the lignin sample + 25 % Fe^{3+} , raising the treatment temperature to 600 °C, as in cellulose carbonisation, an increase in the magnetite content of the carbon material took place. However, magnetite was reduced already at 700 °C, and the Fe component was represented exclusively by FeO oxide. A rise in the pyrolysis temperature to 900 °C resulted in further reduction of iron to Fe^0 (identified in the form of martensite). In contrast to the cubic form of the iron formed during the carbonisation of the cellulose systems, in the case of lignin carbonisation metallic iron represented the unsaturated solution of α -iron-carbon in the tetragonal form, which indicates the specificity of the lignin behaviour during carbonisation and the formation of crystalline structures of iron.

Pyrolysis of the kraft lignin and wood powder prepartes treated with iron sulphate led to the reduction of metallic iron. The products acquire magnetizability properties, which can be regulated by pyrolysis conditions.

Comparison of the X-ray analysis of the kraft lignin and wood powder samples treated at 760 °C, obtained by *ion-exchange* technique, indicated that at this temperature the metallic Fe⁰ phase began to form in the carbonised kraft lignin samples, while the wood powder samples contained a considerable amount of reduced Fe⁰ already. These data do not contradict the results obtained when measuring the magnetic susceptibility of the samples. The carbonised Fe⁺³ wood samples prepared by the ion exchange method showed the highest sorption activity to iodine (623 mg/g) and the highest sorption of methylene blue (321.2 mg/g). The best sorbents exhibited the highest magnetisability (40.6 A*m²/kg).

During *impregnation in neutral medium* (pH = 5.5) two crystalline structures are present, i.e. mixed oxide Fe₃O₄ (with predominance of magnetite) and reduced iron, in both the wood powder and kraft lignin samples.

Impregnation in acid medium (pH = 1.5) resulted in the fact that during the carbonisation process at 760 °C the iron component was represented by magnetite Fe₃O₄ in both samples. It means that up to this temperature no reduction of iron to the metallic form takes place.

In all the samples, the intensity of the peak corresponding to Fe⁰ is indicative of the rise in the temperature of carbonisation to 800 °C, which results in an increase in the amount of the reduced-form iron.

4 CONCLUSIONS

It was shown that the characteristics of the Fe⁺³ lignocellulosic system depend on the structure and properties of the organic matrix, media acidity and the presence of residual ion.

The highest characteristics of sorption activity and magnetisability were achieved for carbonised Fe⁺³ wood samples prepared by the ion exchange method.

CHARACTERISTICS AND UTILISATION OF HIGH-TEMPERATURE (HTHP) FILTER DUSTS FROM PFB GASIFICATION OF BIOMASS

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Abstract

The aim of the study was to survey characteristics, utilisation and possible environmental impacts of solid wastes, i.e., in case of biomass, mainly high-temperature filter ash (HTHP) from pressurised fluidised-bed gasification (PFBG). The aim is to utilise solid wastes (slag, filter dust, additives) from biomass gasification instead of dumping. One alternative is recycling to the soil as liming material or fertiliser. It is expected that the ash recycled to forest soils changes the environment less than non-recycled ash.

SAMPLES UNDER STUDY

Solids emissions from the PDU gasifier rig of VTT Energy (0.4 MW) from several gasification test runs were studied. Coal, peat, chips (whole-tree, pine and spruce), sawdust, straw and mixtures of straw and coal were included in the study. Major part (30 - 80 %) of the residue of fluidised-bed gasification consists of so-called hot-filter dust (HTHP), which is removed from the gas by a ceramic filter. In total 15 samples from pressurised gasification in the test rig of VTT Energy were studied. The samples comprised mainly hot-filter dusts collected from the product gas at about 450 °C.

RESULTS

Basic characteristics were first determined for the samples: ash, calorific value, elemental analysis, and bulk density. The amount of unreacted carbon was very high in the hot-filter dust. The pore structure of unreacted carbon was observed to be well developed and the specific surface area large.

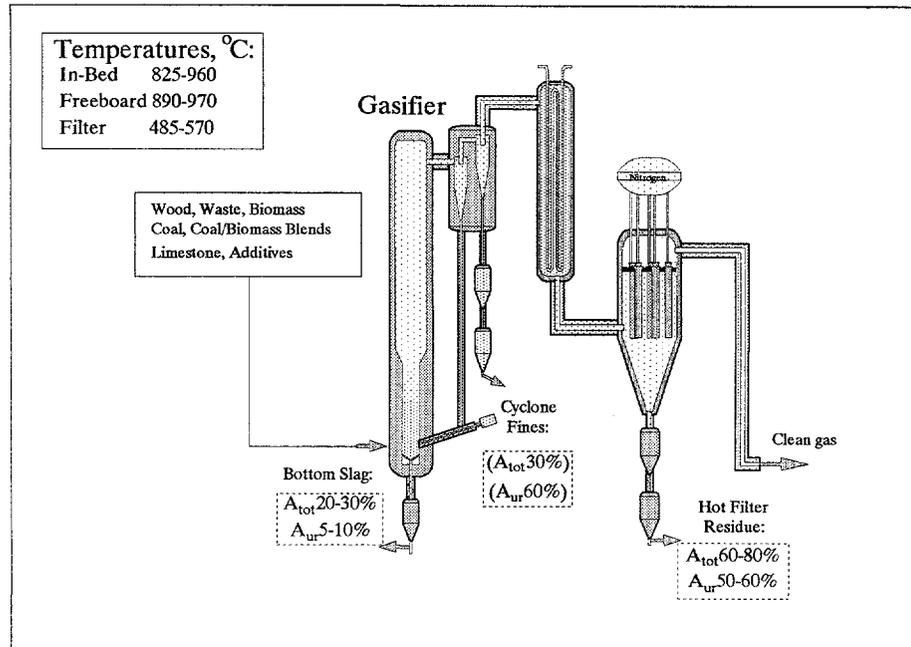


Figure 1. PFB gasifier PD unit (0.4 MW), solid flows.

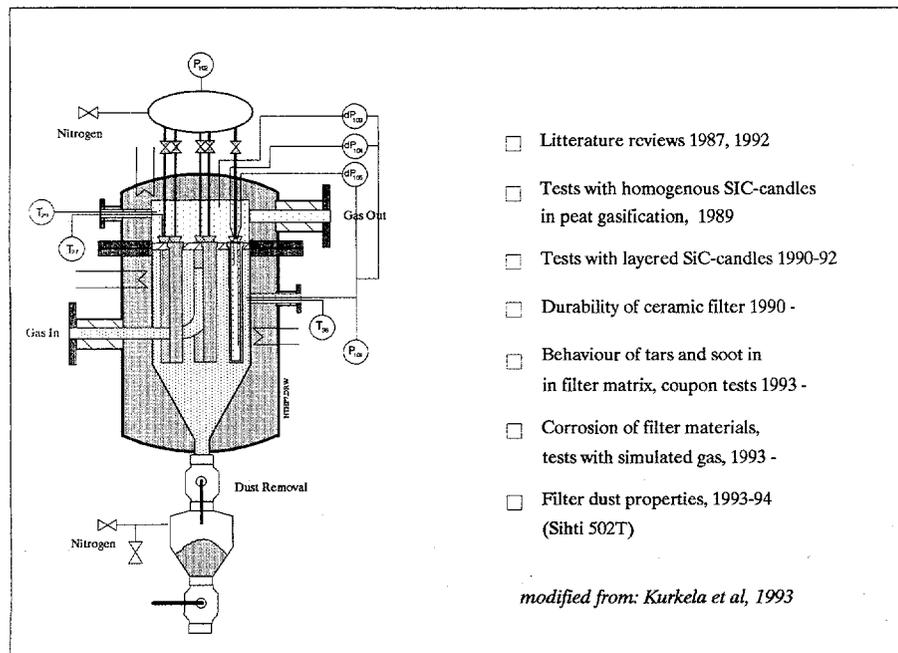


Figure 2. HTHP filter and related research at VTT.

THE AMOUNT OF RESIDUE

The total amount of residue (reactor bottom ash, cyclone ash, filter ash and possible residues from additives) was in case of peat 8.5 wt%, coal 20.3 %, whole three 7.7 - 9.5 % and wood 1.7 %. In some cases the values are relatively high compared to the ash contents of the raw materials. This was due to high amounts of additives (e.g. limestone) and unreacted char in certain samples.

UNREACTED CHAR

A very essential characteristic of hot filter ashes was a very high amount of unreacted char, typically close to 50 % w/w or more. Thus the residues had a relatively high calorific value, which makes it possible to utilise them as such in a suitable burning device. A high carbon content, including PAH's and other organics, would in fact restrict the conventional disposal of residues. By adding water some self-hardening was observed but this was negatively affected by the high carbon content, too. Dusting of the samples is also a problem and could be avoided by adding water.

BULK DENSITY

The volume weight or bulk density of the dust varied in wide limits (depending mainly on the amount of additives) being, however, in some cases as low as 150 kg/m^3 . This type of ash should be handled in a closed inertified system. By agglomerative systems the bulk density could be increased and handling facilitated but due to the high carbon content self-hardening is limited. It is thus reasonable to utilise the char before agglomeration.

SPECIFIC SURFACE AREA

In the second stage the pore structure of the samples was investigated by N_2 adsorption/desorption measurements at 77 K. As the pore structure was well developed (specific surface areas 30 - 600 m^2/g , the tarry (and some others) compounds were expected to be adsorbed on the carbon phase. Therefore, extraction/baking studies were carried out to preliminary survey the behaviour of particles/tar. The results indicated that the active surface area of "young" dusts was larger and that the dusts were regenerated by baking at least partly (Ranta & Nieminen 1995).

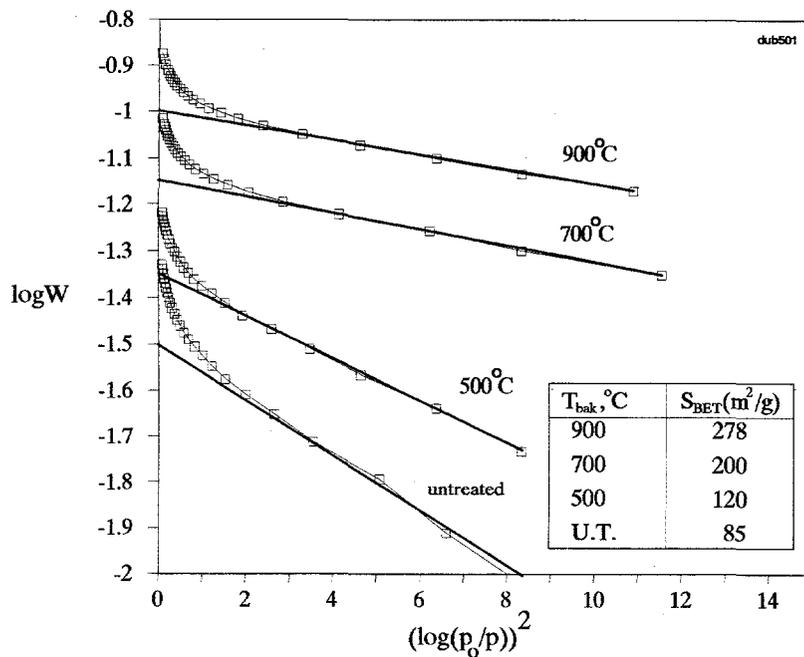


Figure 3. Effect of baking on the microporosity and specific surface area of hot-filter dusts.

ORGANICS

Extraction of the samples by methylene chloride showed that in some cases the filter dust contained a notable amount of organics including PAH's. The concentration of components like phenanthrene, fluoranthene and pyrene were particularly high.

REACTIVITY

As the proportion of unburned char in the residue was very high, the reduction of carbon content is necessary with regard to the utilisation of the waste. Therefore, reactivity measurements using TGA were carried out in air and in gasification gas (first H_2O , 5 bar) to assess the behaviour of filter dusts in different reactor types. The results indicated that in the gasification environment the hot-filter dust of some samples was clearly inertified compared with inherent char (Ranta & Moilanen 1995). This may indicate that circulating the dust into the gasifier may in some cases be problematic.

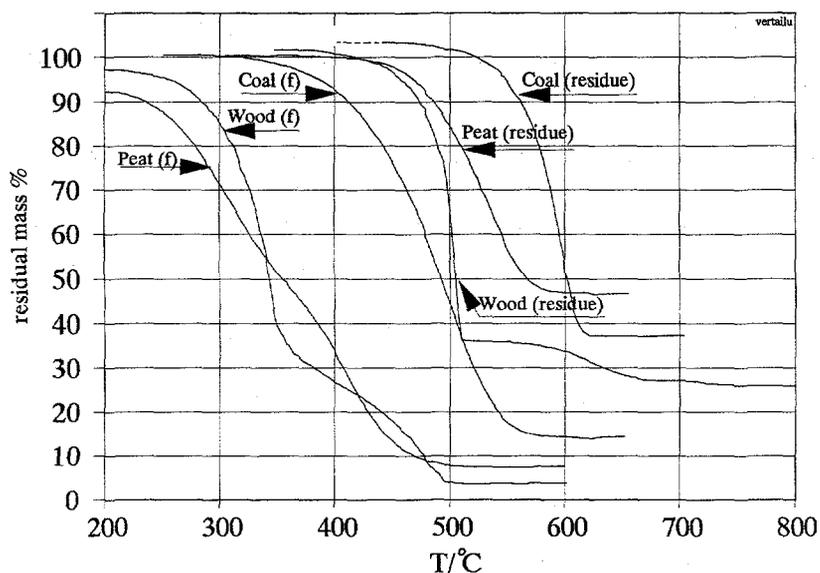


Figure 4. Comparison of burning profiles of HTHP (High Temperature High Pressure) filter dusts and precursory fuels (wood, peat and coal) by non-isothermal TGA (Thermogravimetric Analysis). Heating rate 10 deg/min, synthetic air (16 % O₂/100 ml/min).

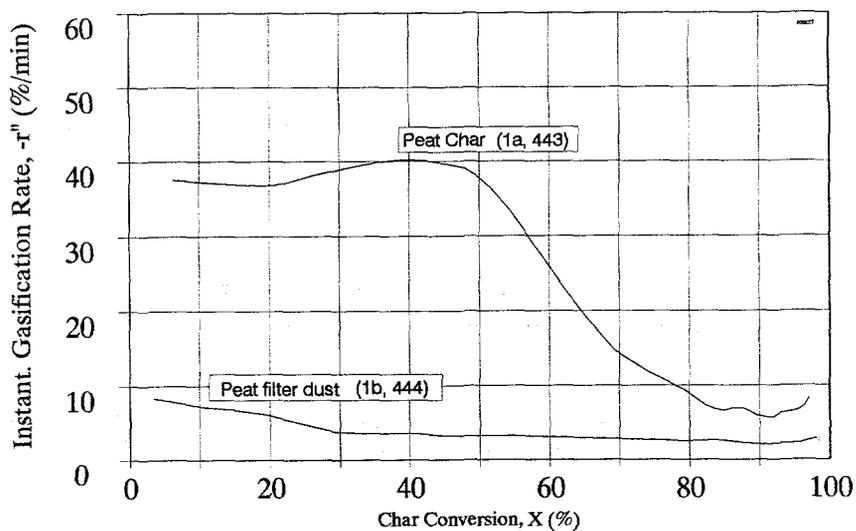


Figure 5. Gasification reactivity (%/min) of peat gasification filter dust and inherent char of pyrolysed peat at 5 bar H₂O, 800 °C.

CONCLUSIONS

The solid residue from pressurised fluidised-bed gasification of biomass comprises mainly dust deposited on the hot filter. The amount of dust is typically 30 - 80 % of the total amount of solids.

The dust contains an abundance of unreacted char, in which i.e. tarry components have possibly been adsorbed. The residual char is active having a large specific surface area and its reactivity is typical of the raw material used. Active particulates may be of significance to the adsorption of impurities and to gas phase chemistry (activity nests). The residual char or filter dust has a lower reactivity than inherent fuel char in certain cases.

The ashed final product is a mixture of biomass ash and additives. It has in principle the properties of liming agent. However, the utilisation potential is limited by small amounts produced (low ash content of biomass, small plant size) or, if not treated, by a too high amount of unreacted char.

As regards agricultural biomasses, variations in ash quality may be problematic. If biomass is gasified together with coal, the lowering quality of ash may restrict its conventional use (quality standards for the use of coal fly ash in concrete and cement industry).

If it is not feasible to reduce the proportion of unburned material in the gasifier, it is likely that the ashes have to be oxidised in a separate reactor prior to utilisation or disposal.

Concerning recycling to the gasifier the use potential of char in the process should be studied more profoundly. The aim is to focus further research on the utilisation of active particle mass within the process.

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TECHNICAL AND ECONOMIC PERFORMANCE OF INTEGRATED BIOENERGY SYSTEMS

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Abstract

A comprehensive study of biomass production, conversion and utilisation systems has been carried out to examine complete bioenergy systems from biomass in the forest to electricity delivered to the grid. Spreadsheet models have been derived for all of the key steps in an integrated process and these have been compiled into an overall BioEnergy Assessment Model (BEAM). The model has also been used to investigate both the performance of different technologies and the effect of different configurations of the same basic system by manipulating the interfaces between feed production, feed conversion and electricity generation. Some of the results of these analyses are presented here.

1 INTRODUCTION

The relationships between biomass production, conversion and generation of electricity have been examined by two IEA Bioenergy Agreement Activities (Task IX - Technoeconomic assessment of wood fuel; Task X - Interfacing). The main purpose of the work was to provide a technoeconomic assessment of biomass to energy and to investigate the interrelationships between the stages in the supply chain and identify those stages or interfaces between stages which were strongly influential in terms of the technical and financial feasibility of the project. This paper will concentrate on the generation of electricity from short rotation coppice. More feedstocks, products and conversion routes are available and a more comprehensive and detailed review of results is available in [1].

2 METHODOLOGY AND SCOPE

Spreadsheet models of system components have been supplied by various participants according to their expertise. An executive program has been written to provide a user interface and to transfer data between the component spreadsheets. The executive program and the component spreadsheets make up the BioEnergy Assessment Model (BEAM), which offers the system configurations shown in Figure 1. The spreadsheet format also makes the model inherently expandable: new modules can easily be included by adding new spreadsheets and making minor adjustments to the executive program that links the spreadsheets together.

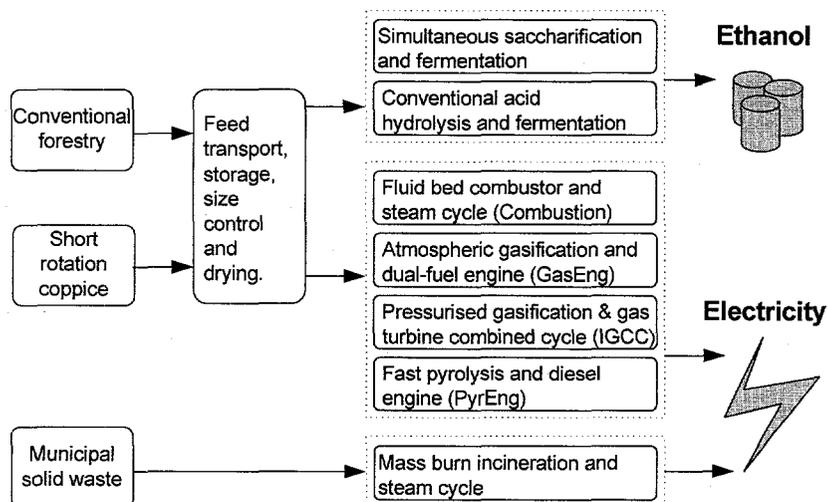


Figure 1. Bioenergy systems available in BEAM.

3 SYSTEMS ANALYSES

One of the objectives of this work was to investigate which technologies were most appropriate over a range of generating capacities. The systems were analysed by first defining a set of base cases, each generating 20 MWe and each using the same financial and operating parameters (listed in [1]). BEAM was used to study a range of capacities as shown: the interactions between feedstock costs (Figure 2), feed requirements (Figure 3) and capital costs (Figure 4) give different technologies overall advantage in terms of electricity production cost as system capacity changes (Figure 5).

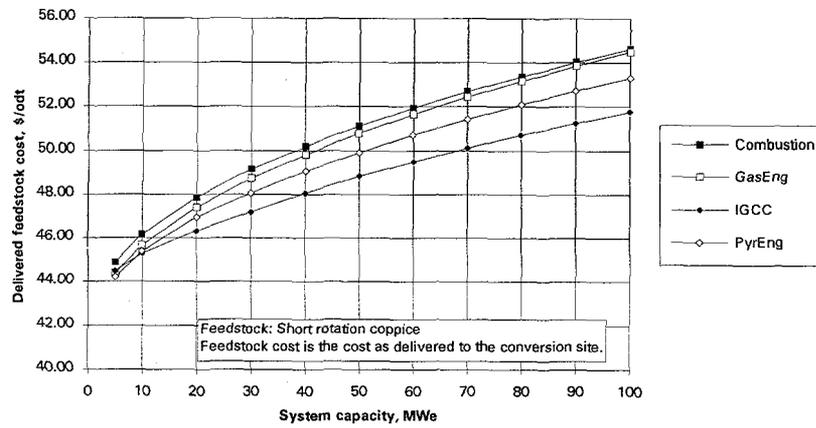


Figure 2. System delivered feedstock costs.

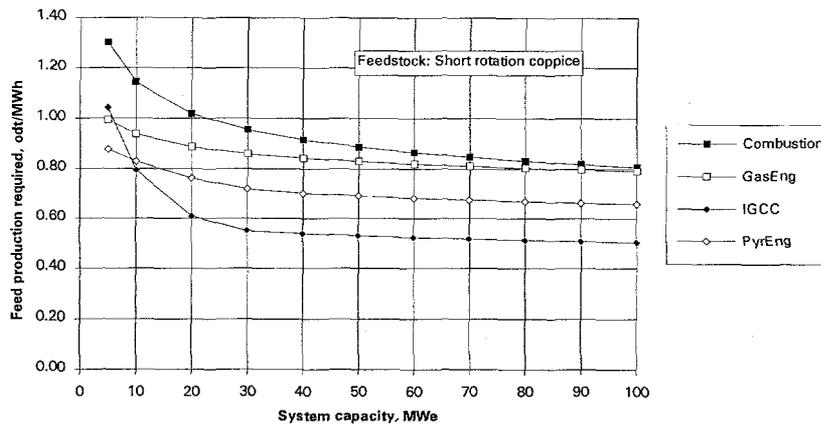


Figure 3. System feed production requirements.

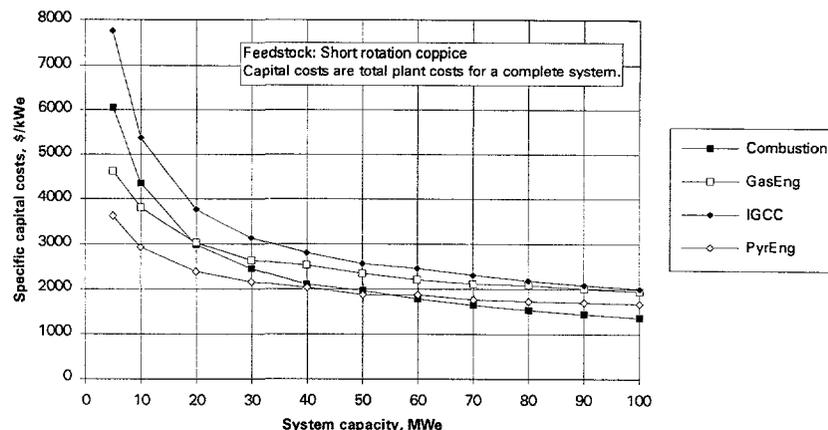


Figure 4. System specific capital costs.

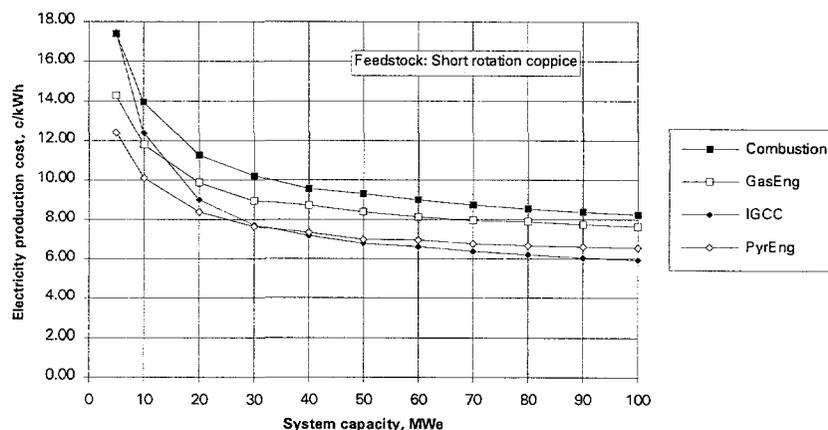


Figure 5. System feed production requirements.

4 INTERFACE ANALYSIS 1

This analysis evaluates the effects of different feed harvesting and storage strategies on overall production costs. It is an example of how BEAM may be used to investigate the impact of system interfaces on overall performance.

If the SRC is harvested as shoots then there are potential cost advantages relating to lower dry matter losses during storage although these may be outweighed by the increased costs of harvesting with subsequent chipping. The location of long term storage is also relevant: storage at the plantation

should be more cost-effective than storage at the conversion facility because dry matter losses are incurred before transport.

Results of the interfacing analyses are shown in Figure 6, for four configurations of a fast pyrolysis and diesel engine system:

- Base Case Harvest as chips, store chips at plantation, transport.
- Strategy 1 Harvest as chips, transport, store at conversion site.
- Strategy 2 Harvest as shoots, store at plantation, chip, transport.
- Strategy 3 Harvest as shoots, chip, transport, store at conversion site.

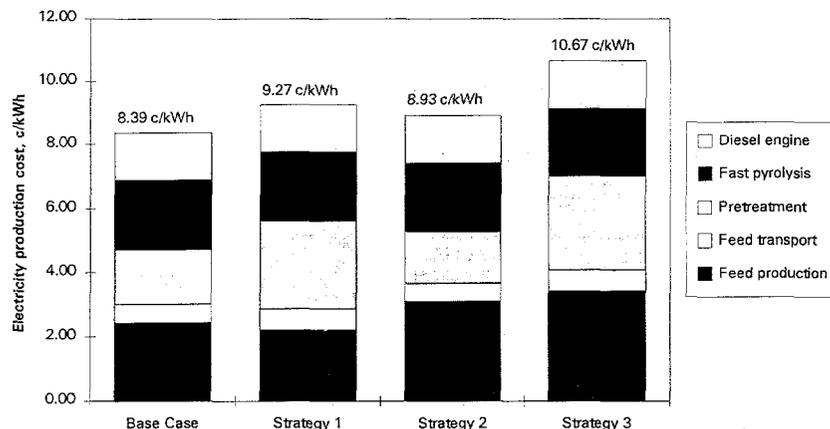


Figure 6. Electricity production cost variations with supply strategy.

5 INTERFACE ANALYSIS 2

Conversion of the solid biomass feedstock into a liquid fuel via fast pyrolysis brings new flexibility into the system since the liquid fuel can be stored and transported before use in a generating cycle. One opportunity that this offers is the use of multiple conversion facilities and a central generating plant, reducing the cost of feed transport at the expense of increased capital costs of multiple conversion sites. Figure 7 shows that multiple conversion sites are not a viable option over any of the capacities shown because economies of scale savings outweigh the reduced feed transport costs i.e., it is better to transport feed than to build multiple small plants. The results for a 100 MW_e system show an almost constant electricity production cost, so that a modest reduction in future capital costs could make a multiconversion site system attractive.

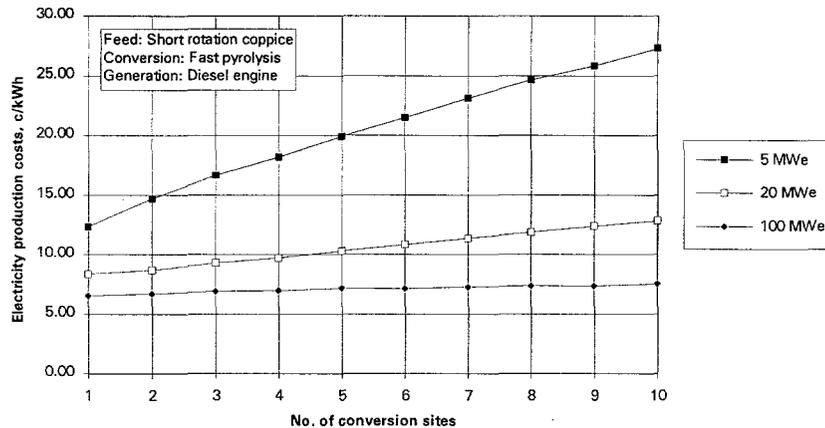


Figure 7. Electricity production costs with multiple conversion sites.

6 CONCLUSIONS

BEAM has been used to determine the costs of generating bio-electricity from short rotation coppice over a range of power outputs and for several conversion technologies. Alternative feedstock supply strategies and system configurations have been examined to evaluate the impact of system interfaces. The following conclusions can be drawn.

- Under base case conditions pyrolysis and diesel engine is the lowest cost option up to about 30 MWe. Above 30 MWe, an IGCC system shows small cost advantages.
- The lowest cost feed supply strategy is to harvest as chips, store at or near the production site and then transport them to the conversion facility.
- It is preferable to transport biomass feed material than build multiple small conversion plants to reduce feed transport costs.

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GROUND TESTS OF 120 KW(HEAT) BIOMASS FIRED GASIFIER DIESEL INSTALLATION

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Abstract

For the 1 MW and less power range diesel gasifier power plants could be considered as one of the main energy sources. The brief information about works carried out in Russia according to this direction is presented. Data of preliminary tests for gas diesel installations are presented.

1 THE PROBLEM OF BIOMASS POWER UTILIZATION IN RUSSIA

The task of power utilization of biomass has three aspects of equal importance: economical, environmental and technical ones.

The economical aspect of the problem of biomass as power source is connected in Russia, first of all, with the fact that more than 40 % of our territory has unstable power supply from the central sources, or use brought fuel. At the same time, a big part of these regions has a lot of vegetable biomass and waste. In whole Russia, the yearly quantity of unused vegetable biomass is 200 million tons of equivalent fuel, as our economists estimated. These resources were not used until the recent time. But the growing fuel prices had led to the fact that now on the big territories the expenditures on the gathering and fuel utilization of local stocks of biomass are found to be economically effective.

The environmental aspect of the problem is universally recognized. It is called forth by the fact that biomass is renewable energy source and its burning does not lead to any increase of carbon dioxide contents in the atmosphere, well then to the "hotbed-like"-effect. At the same time the use of biomass gives the reduction in use of environmentally more harmful fuels: coal, petroleum refining product, etc.

Considering technical aspects of power utilization of biomass, it must be pointed out that it is a quite effective kind of fuel. As it is known, when biomass is burning out, the sulfur emission is 20 - 30 times lower and

production of ash is 3 - 5 times lower as compared with coal burning. The high output of volatile components and the absence of sulphur allows to provide good combustion in simple furnaces at fuel moisture of 40 - 50 %. However, biomass direct combustion invokes a number of difficulties. The cause of these difficulties is the unstable burning with small surplus of the air, polyfractional, variable structure of the fuel, and its extra humidity.

In this connection, gasification as an alternative to direct combustion attracts permanent interest of researchers. The choice of biomass processing method depends significantly on power installation purpose, power range and kind of fuel.

For power range below 1 MW, diesel engines may be considered as basic mechanical work sources. Analysis shows that most of Russian village consumers need 500 kW (and less) of electric power. We do not see any alternative to biomass gasification in this case.

Currently, non-traditional power engineering problems are arousing considerable interest. Several long-term programs for the most important scientific and technological problems are active now at Russian national level. The 'environmentally pure power engineering' program is one of them. Two projects are within the frames of this program. Technology perfection and assimilation for production of thermochemical gasifiers, processing vegetable biomass and waste into gas fuel are carrying out in the context of the program.

The thermogasification project provides creation of downdraft process gasifiers as the first stage. Downdraft fixed-bed gasifiers process wood waste (chips, bark, sawdust), hydrolytic lignin, peat, agricultural, technological and municipal waste. Together with gasifiers, the whole complex of power equipment for generator gas utilization is being created, including burners, furnaces, diesel generators and turbogenerators. The final purpose of the development program is creation and manufacturing of complete equipment for processing and utilization of vegetable biomass and waste as power and technological fuel. Installations of power range from several kilowatts up to 5 MW are to be used for independent power supply of decentralized heat and electricity consumers. The total demand in Russia is about tens of thousands of these installations now.

During the program realization, the following works based on existing data were fulfilled in the last 10 years:

- several stationery downdraft biomass-fired gasifiers were designed. 120, 600, 1000 and 1600 kW installations are built and tested or are being tested. For example, Table 1 shows test results for two of these gasifiers.

- burners and furnaces for P-gas were designed and certified.
- 10, 120 and 600 kW gasifier power plants were designed. Heat schemes of these plants provide maximal heat utilizing and combined production of heat and electricity.
- works for diesel conversion to gasdiesel are being carried.

We shall discuss some aspects of the last listed direction.

Table 1. Experimental results for 0.6 MW and 1 MW gasifiers.

Parameters	0.6 MW gasifier		1.0 MW gasifier	
	Lignin briquettes	Wood waste	Softwood bark	Veneer production waste
Relative humidity, %	10	50	52 - 58	28 - 41
Average fuel size, mm	60x20x60	70x30x20	32x12x2.5	42x9x2
Ashes (by work mass), %	10	5	2.5	0.6
Temperature in the gasification zone, °C	950	930	850	960
Output gas temperature, °C	185	180	165	195
Minimal caloric ability of output gas, MJ/nm ³	5.2	4.6	4.3	5.9
Overpressure in the well, kPa	0.7	1.0	5.5	5.5
Gasifier efficiency, %	88	85	83	86

2 FORMULATION OF INVESTIGATION TASKS

The grounds for choice of gasifier power plant engine are important. One of two possible variants may be chosen.

The first one provides engine operation on two fuel kinds at a time: P-gas and diesel oil. The fuel flow rate is 80 % gas and 20 % diesel oil (by heat). The necessity of diesel oil feeding stems from the fact that producer gas has higher ignition temperature. Under the present pressure ratio it will not be ignited. The engine realizing this process is called *gas diesel*.

The second method allows a engine operation on producer gas only. They apply the sparking ignition for producer gas firing. The such engine is called *gas*.

The gas diesel engine advantages are:

- low expenses for engine conversion to bi-fuel firing; possibility for standard devices maintenance;
- pressure ratio retention, high indicated efficiency (36 - 45 %) (gas engine efficiency is 26 - 30 %);
- lower power losses as against original diesel engine (not more 25 %);
- on retention of standard fuel equipment it is possible to vary ignition fuel fraction from 15 - 20 % to 100 % at same (full) power.

The gas diesel disadvantages are:

- the necessity of diesel fuel feed in all operation modes;
- rather complex bi-fuel control system.

As for now, we have stopped at the gas diesel option. In so doing the following primary factors were taken to account: net-independent starting possibility and existing engines conversion possibility. Industrial gas diesel creation takes the number of problems studying. The main of them are:

- Engine operation process investigation when operating on P-gas with lightning fuel;
- Evaluation of cylinders and piston group working ability at gasdiesel cycle operation.
- Perfection of control system for two kinds of fuel.

For the noticed problems decision the ground tests are necessary. The tests were carried out on small-series equipment.

3 TEST INSTALLATION

Tests on atmosphere dried chocks (15..40 % humidity) were made on the installation shown on Figure 1. This installation includes the following parts:

- 120 kWh gasifier Г-50 (2) with blower (1);
- gas cooling and cleaning system, including cyclone unit (3), gas-water heat exchanger (4) and scrubber (5);
- gas-air mixer (6);
- 1×18/20 gasdiesel (7);
- hydro-brakes (8);
- gas burner (9).

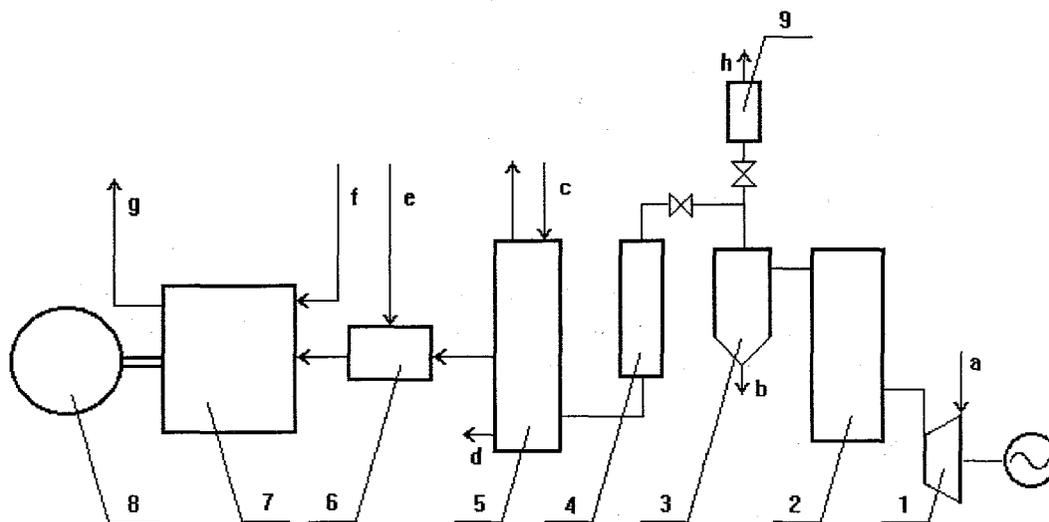


Figure 1. Experimental installation scheme. a - air feed into gasifier, b - ash-removal, c - cooling water feed and removal, d - water and tar water removal, e - air feed into diesel engine, f - diesel oil feed, g - diesel exhaust gas removal, h - combustion products removal.

4 TEST RESULTS AND DISCUSSION

In 1994, several comparative tests were done. In these tests the engine worked both as gasdiesel and diesel. Tests were headed by Eng. W. Danschikov. Table 2 shows the essence of results obtained at 1 000 rpm.

Complete analysis of whole results brings us to the following conclusions:

1. The Г-50 gasifier supports gasdiesel mode of $1 \times 18/20$ diesel at $70 \text{ m}^3/\text{h}$ gas expenditure. Average gas composition was: 14.6% H_2 , 15.5% CO , 1.1% CH_4 , <1% O_2 , <1% CO_2 , $57 \text{ mg}/\text{m}^3$ ash, $83 \text{ mg}/\text{m}^3$ tars.
2. The inspection of cylinders, pistons and valves did not show any differences in coking and wear.
3. Gas-diesel mode using P-gas provides the same maximal power as diesel (25.7 kW at 1000 rpm; 31 kW at 1 200 rpm).
4. The comparison of cycle parameters of diesel and gasdiesel modes shows practically the same compression rate, air surplus rate, maximal pressure and outlet gas temperature.
5. High-moisture wood (over 30%) brings to degradation of combustion process (delayed combustion at expansion phase), and limits engine power at 13 - 15 kW at 1 200 rpm.

6. The comparison of environmental parameters for gasdiesel and diesel modes (Table 2) shows for the gas diesel mode:

- 1.5 - 3 times decrease of outlet smoke;
- 30 % decrease of NO_x contents;
- 2 - 3 times increase of CO contents.

In case of high-moisture gas, NO_x decreases by 8 - 10 times but CO increases by 6 - 8 times.

The marked changes of environmental parameters are explained by delayed expansion phase combustion and water steam presence. Both factors brings to lower maximal cycle temperature.

CONCLUSION

Present scientific and technical state-of-art allows to predict parameters of diesel engines after P-gas gas diesel conversion. P-gas mode provides 30 % NO_x emission decrease.

It is feasible to carry the further investigations for P-gas combustion in diesel power plants:

- cycle optimization (valve phases, compression rate, injection phases);
- general optimization of the gasifier installation (gas cleaning system, fuel loading process, etc.)
- perfecting automatic control systems that could be used both for diesel and gasdiesel modes of standard engines;
- comparative lifetime tests.

It is planned to solve these tasks both on the existing test installation and on special 10 - 500 kW gas diesel engines being under design now.

Table 2. The results of comparative tests for 1 x 180 (w/o supercharge) fired by producer gas and diesel oil.

Effective power	Effective diesel parameters						Environmental parameters					
	Diesel oil consumption kg/h		Exhaust temperature °C		Maximal combustion pressure kg/cm ²		Smoke in exhaust 'Bosch' units		Carbon monoxide %		Nitrogen oxides %	
29	8.88	1.74	620	530	65	63	6.4	1.4	0.80	1.00	0.062	0.040
26	7.72	1.69	540	480	63	62	4.6	0.9	0.42	0.35	0.085	0.075
22	5.90	1.62	450	430	62	60	2.0	0.8	0.12	0.38	0.087	0.070
18	4.92	1.65	390	380	60	58	1.0	0.6	0.09	0.40	0.083	0.062
15	4.14	1.66	325	320	56	54	0.8	0.5	0.07	0.42	0.080	0.055



Authors Ed. by Sipilä, Kai Korhonen, Maija	Name of project	
Title Power production from biomass II with special emphasis on gasification and pyrolysis R&DD	Commissioned by VTT Energy, EC DGXII, IEA Bioenergy agreement, Technology Development Centre (TEKES)	
Abstract <p>The Seminar on Power Production from Biomass II with special emphasis on gasification and pyrolysis R&DD, was organized by VTT Energy on 27–28 March 1995 in Espoo, Finland. All seminar speakers were invited in order to give a high-level overview of the achievements of biomass combustion, gasification and flash pyrolysis technologies. The sessions included presentations by all key industrial entrepreneurs in the field. The poster session was open to all groups interested.</p> <p>Globally bioenergy covers about 3 % of the primary energy consumption. Locally it has a significant role in many countries like in Finland, where bioenergy covers almost 15 % and peat 5 % of primary energy consumption. Today's cost-effective heat and power production is based on industrial wood residues and spent cooking liquors in relatively large industrial units or municipal heating and power stations. Agricultural residues like straw and especially energy crops are becoming more interesting in co-utilization with other biomasses or fossil fuels.</p> <p>The seminar successfully displayed the status of present technologies as well as development targets for new gasification and flash pyrolysis technologies in the coming years. The many industrial participants showed that there are growing business possibilities in many countries all over the world.</p> <p>The proceedings include the most oral presentations given at the Seminar and also abstracts of poster presentations.</p>		
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