

Swedish Energy Agency Report

Small Scale Gasification: Gas Engine CHP for Biofuels

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Preface

This has been a joint project between the Linnaeus University in Växjö and the Faculty of Technology at Lund University (LTH), both in Sweden. The project was initialized by the former professor Rolf Egnell at the department of combustion engines, LTH.

We are grateful for the time allocated, the opinions and advices given, during our work, by the steering committee.

Members of the steering committee:

Owe Jönsson, E.on.

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Summary

In a joint project, Linnaeus University in Växjö (LNU) and the Faculty of Engineering at Lund University (LTH) were commissioned by the Swedish Energy Agency to make an inventory of the techniques and systems for small scale gasifier-gas engine combined heat and power (CHP) production and to evaluate the technology. Small scale is defined here as plants up to 10 MW_{th}, and the fuel used in the gasifier is some kind of biofuel, usually woody biofuel in the form of chips, pellets, or sawdust. The study is presented in this report.

The report has been compiled by searching the literature, participating in seminars, visiting plants, interviewing contact people, and following up contacts by e-mail and phone.

The first, descriptive part of the report, examines the state-of-the-art technology for gasification, gas cleaning, and gas engines. The second part presents case studies of the selected plants:

- Meva Innovation's VIPP-VORTEX CHP plant
- DTU's VIKING CHP plant
- Güssing bio-power station
- Harboøre CHP plant
- Skive CHP plant

The case studies examine the features of the plants and the included unit operations, the kinds of fuels used and the net electricity and overall efficiencies obtained. The investment and operating costs are presented when available as are figures on plant availability. In addition we survey the international situation, mainly covering developing countries.

Generally, the technology is sufficiently mature for commercialization, though some unit operations, for example catalytic tar reforming, still needs further development. Further development and optimization will probably streamline the performance of the various plants so that their biofuel-to-electricity efficiency reaches 30-40 % and overall performance efficiency in the range of 90 %.

The Harboøre, Skive, and Güssing plant types are considered appropriate for municipal CHP systems, while the Viking and VIPP-VORTEX plants are smaller and considered appropriate for replacing hot water plants in district heating network. The Danish Technical University (DTU) Biomass Gasification Group and Meva International have identified a potentially large market in the developing countries of Asia.

Areas for suggested further research and development include:

- Gas cleaning/upgrading
- Utilization of produced heat
- System integration/optimization
- Small scale oxygen production
- Gas engine developments

1. Introduction

1.1 Project description

In a joint project, Linnaeus University in Växjö (LNU) and the Faculty of Engineering at Lund University (LTH) were commissioned by the Swedish Energy Agency to make an inventory of the techniques and systems for small scale gasifier- gas engine CHP production and to evaluate the technology. The study is presented in this report.

”Small scale”, is defined here as plants up to 10 MW_{th}, and the fuel used in the gasifier is some kind of biofuel, usually woody biofuel in the form of chips, pellets, or sawdust. Figure 1.1, shows the general layout of a small-scale gasification gas engine CHP plant. The gasification unit, gas cleaning devices, and the gas engine can be of any type, and are described later in this report. A system boundary is drawn, and the area within this boundary coincides, more or less, with the scope of this report.

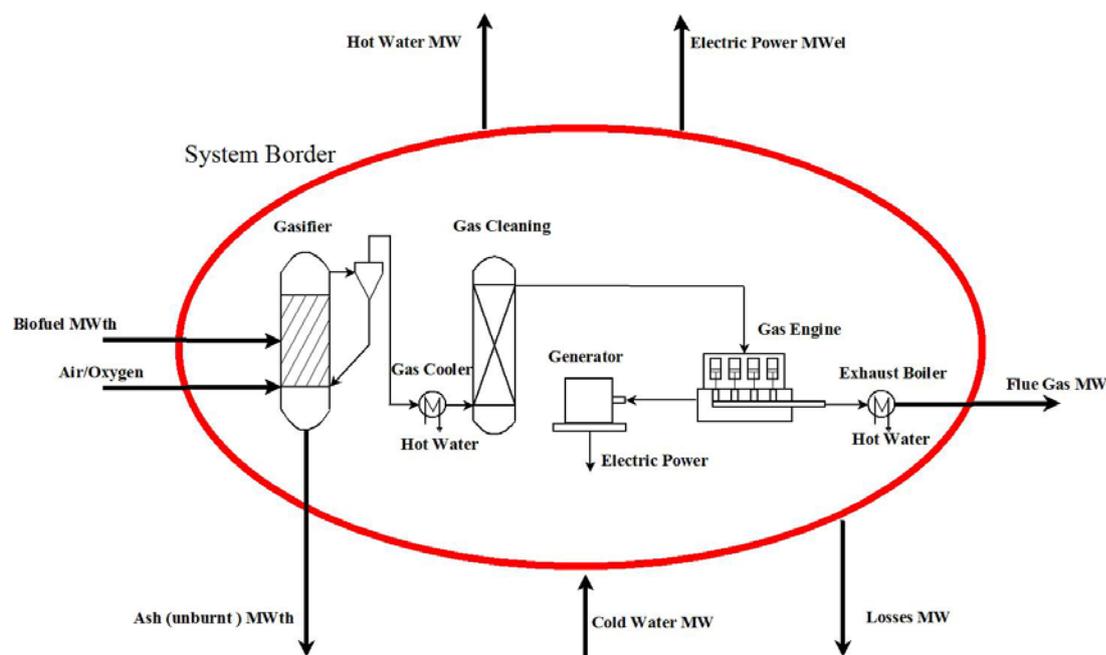


Figure 1.1 System boundary of a small-scale CHP plant based on a biomass gasification-gas engine.

Only gas engines are considered in the study, because steam turbines must be larger than 2 MW_{el} [1] to be sufficiently efficient. Although small gas turbines can be constructed for high efficiency, both gas and steam turbines lose efficiency on partial or varying load (Table 1.1). In Table 1.1, the highest efficiency presented is 28 % and is for the gas engine system. This system has also a number of advantages such as high electrical efficiency even at small sizes, low cost, and reliability; it also works well even at low loads. According to Arena et al. [2] the major drawbacks of the system are that the gas engine is exposed to corrosive combustion products resulting in short and expensive maintenance intervals.

Table 1.1 Advantages and disadvantages of various energy conversion devices for syngas from biomass gasification, 100 -600 kW_{el}. [2]

Energy conversion device	Net electrical efficiency of gasification plant	Main advantages	Main disadvantages
Steam turbine	10-20 %	Turbine components isolated from combustion products Long maintenance intervals, high availability High specific work	Expensive Electrical yield is low at small sizes Partial load decreases efficiency significantly Plants are extremely large due to space requirements for condenser and boiler
Gas turbine	15-25 %	Electrical efficiency is good even at small sizes Compact assembly Long maintenance intervals, high availability Ideal for cogeneration plants (CHP) due to high exhaust temperatures	Turbine components are exposed to combustion products Partial load reduces efficiency significantly Moderately expensive
Externally fired gas turbine	10-20 %	Turbine components isolated from combustion products Electrical efficiency is acceptable even at small sizes Long maintenance intervals and high availability Ideal for cogeneration plants (CHP) due to high exhaust temperatures	Expensive Heat exchanger is exposed to high temperature and aggressive combustion gases Partial load reduces efficiency
Gas engine	13-28 %	High electrical efficiency even at small sizes Relatively inexpensive Durable and reliable Partial load affects efficiency only marginally	Engine components are exposed to combustion products Short and expensive maintenance intervals, low availability

The rationale of CHP is that both the electric power and the heat produced should be used. The produced heat is often fed to the district heating network or used by industry. The efficiency of the plant then increases from 25-35 % if only electric power is produced to an overall efficiency of 70-90 %.

Above 8-10 MW_{th} (2-3 MW_{el}) is an area in which gas engines and turbines have similar efficiencies. However, plants equipped with gas engines have better flexibility to run at partial loads than do turbine-based ones.

Various indexes are used when discussing performance. Based on the streams crossing the system boundary in Figure 1.1, we can define some of the system efficiencies often used:

- Net Electrical Efficiency = Electric power (MW)/Biofuel thermal power (MW_{th})
- Net Heat Efficiency = (Hot Water-Cold Water) (MW_{th})/ Biofuel thermal power (MW_{th})
- Overall Efficiency = (Electric Power + (Hot Water-Cold Water) (MW_{th}))/Biofuel thermal power (MW_{th})
- Electric power-to-heat ratio = electric power (MW_{el})/hot water power (MW_{th})

1.2 References to chapter 1

1. I. Oberberger and G. Thek, "Combustion and Gasification of Solid Biomass for Heat and Power Production in Europe - State of the Art and Relevant Future Development", *Proc. of the 8th European Conference on Industrial Furnace and Boilers, GENERTEC, Ed. April 2008, Vilamoura, Portugal, ISBN-978-972-99309-3-5*.
2. U. Arena, F. Di Gregorio, and M. Santonastasi, "A techno-economic comparison between two design configurations for a small scale, biomass-to-energy gasification based system", *Chem. Eng. J.*, 162 (2010) 580-590.

2. Biomass

2.1 Use of biomass for energy production in Sweden

In energy technology, the term biomass refers to any material, dead or alive, produced by living organisms, normally plants, which can be used for heat and/or other energy production. According to the Swedish Standardization Institute (SIS,) biofuels are: fuels sourced from biomass. These fuels can have been biologically or chemically converted, processed, or passed through another user.

Biofuels can originate from the following [1]:

Forest or forest residue

woody biomass that has not been chemically processed:
wood, branches and roots, bark, sawdust, pellets, etc.

Agricultural or agricultural residue

energy crops, straw, grain etc.

Residues from pulp and paper production

black liquor and other by-products

Miscellaneous waste

organics from waste handling, municipal sludge, manure, etc.

Peat

SVEBIO [2] has calculated the total energy consumption in Sweden to have been 364 TWh in 2009. This is the total of all energy consumption in Swedish society, including electric power as well as energy for heating and transport in the industrial, transport, service, and domestic sectors. This is a low figure as, over the past 40 years, total energy consumption has ranged from 370 to 400 TWh. According to SVEBIO, the long-term trend is that energy consumption has started to decline in Sweden.

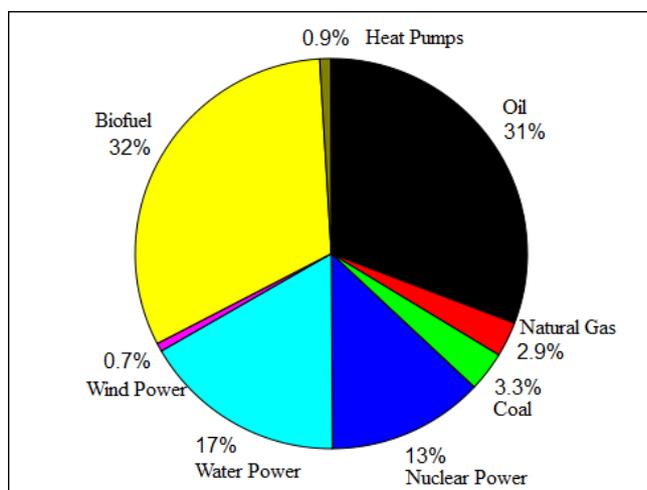


Figure 2.1. Total energy consumption in Sweden (% of 364 TWh) distributed on different sources [2].

Table 2.1 Total energy consumption in Sweden 2009 [2].

Source	Energy consumption (TWh)
Biofuel	115.6
Oil	112.2
Water power	61.3
Nuclear power	47.3
Coal	12.0
Natural Gas	10.5
Heat Pumps	3.4
Wind power	2.4
Total	364.3

The major use of the biofuel is in the industrial and district heating sectors for heating purposes (85.2 TWh). Those sectors also co-produce the 10.1 TWh of electric power that have been used (Figure 2.2).

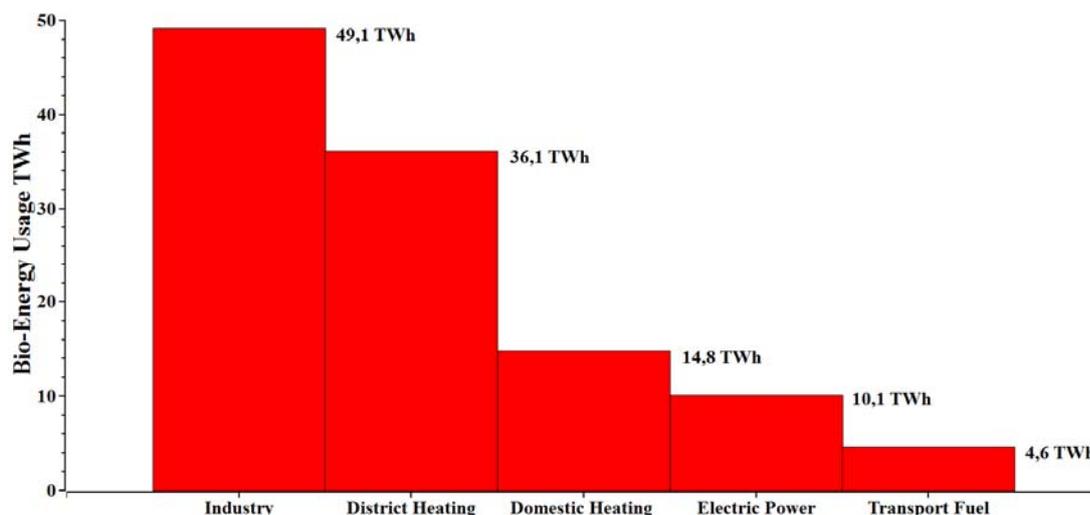


Figure 2.2. The Bioenergy uses in Sweden 2009 [2].

In 2006 the pulp, paper and sawmill industry accounted for 95% (55.7 TWh totally) of the use in the industrial sector [2]. The distribution of use is shown in Table 2.2.

Table 2.2 Use of biofuel in the Swedish industry in 2006 (totally 55.7 TWh) [3].

Industry	Energy (TWh)	Share (%)
Pulp & Paper		
Black liquor	38.1	70
Other by-products	8.3	15
Sawmills		
By-products	5.1	9
Other branches	3.5	6

The pulp and paper industries are completely dominant in biofuel use, also using their own black liquor and by-products to supply their energy needs. In Sweden, 36.1 TWh of district heating, from biomass, was used in 2009, up from 34.4 TWh in 2006. The source distribution of the energy used for district heating is shown in Table 2.3.

Table 2.3 Sources of biofuel for district heating 2006 in Sweden [3].

Source	Energy (TWh)	Share (%)
Wood (pellets, chips etc.)	19.9	58
Waste	8.3	24
Tall oil	0.7	2
Peat	2.0	6
Other	3.6	10

The waste lot in Table 2.3 contains organic waste from municipal waste plants, sludge etc., but not forest residue. The forest residue is included in the wood lot.

The 14.8 TWh of biofuel used for domestic heating (Figure 2.2), mainly wood pellets and wood, does not include the district heating.

In the transport sector, 4.6 TWh of biofuel were used in 2009 in the form of:

- alcohol added to gasoline
- FAME
- biogas

In the transport sector, dependency on petroleum is overwhelming. In 2006, 100.9 TWh of energy were used for transport, 94 % originating from oil.

2.2 Total potential for biofuel in Sweden

The total potential of biofuel in Sweden was projected by SVEBIO [2] in 2008, both for up to 2020 and in the long term. By referring to “potential” use, SVEBIO is referring to the maximum *available* amount of biofuel, and is not implying that there are plans to use this amount.

Table 2.4 Total potential for biofuel use in Sweden [3].

Source	Until 2020 (TWh)	On long term (TWh)
Wood fuel	129	190
Black liquor	45	50
Agriculture	39	70
Waste	23	20
Peat	12	64
Sum	248	394

The wood fuel portion comes from various sources. A somewhat older (2006) breakdown, totalling 119 TWh, is shown in Figure 2.3 [3].

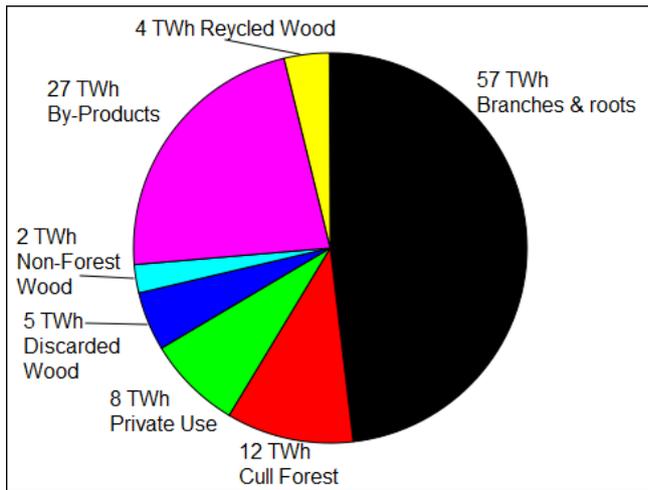


Figure 2.3 Sources of wood biofuel (totally 119 TWh) [3].

In the above breakdown, the forest industry by-products comprise chips, sawdust, and bark.

The potential for biogas production from waste (e.g., forest waste, municipal waste and sludge, and manure) was estimated in 2008 by Linné et al. [4], including no dedicated agricultural production (e.g., energy forests or grain) or dedicated forest harvest. Biogas is an energy gas with a high methane content that can be used as transportation fuel or for heat and power production. The gas can be produced by either fermentation (e.g., of sludge or manure) or gasification. The idea expressed in the report [4] is that the biogas should be used for transportation fuel. Biogas is upgraded producer gas – the gas formed in the gasifier – used in combustion engines for small-scale heat and power generation. Even gas produced by fermentation can be used for this purpose.

Table 2.5 Potential for biogas production in Sweden [4].

	Biogas (TWh)	Electric Power Potential* (TWh)	Heat Production Potential** (TWh)
Fermentation	10 (15)	3 (4.5)	6 (9)
Gasification	60	18	38

*With 30% efficiency in the conversion of biogas to electricity

**From the engine flue gas with 90% thermal efficiency.

The figure in the fermentation row (10 TWh) is the conditional value. The conditions imposed are, for example, that cattle are outdoors part of the year, making the manure difficult to collect then. The figure within parentheses (15 TWh) is the figure without conditions. The electric power and heat production potentials have been calculated; the heat content of the biogas can be converted into electric power at 30 % efficiency, while the combustion heat can be recovered at 90 % efficiency. However, the gasification step will also produce recoverable heat not included in the table.

2.3 Summary biofuel use in Sweden

Biofuels account for a considerable proportion of Sweden's energy supply and offer considerable potential for expansion. The types of biofuels available for expansion seem mainly to be forest residue and other types of waste. These types of biofuel are very suitable for CPH production from small-scale gasification–gas engine plants. However, the high stated efficiency depends on using the produced heat in district heating networks. Producing electric power only would result in efficiency in the range of 30 %. Figure 2.4 shows the district heating used in 2009 according to energy source. The most obvious action would be to eliminate the fossil fuel used in district heating, but this amounts to only 5 TWh. Another possibility would be to replace older central hot-water plants producing only heat from biofuel with new co-production plants producing both heat and electric power. In established district heating networks in Sweden, energy consumption has decreased due to increased insulation and energy savings. This has reduced the profitability of district heating plants, and switching to CHP would reverse this trend. However, at the time of writing it is unclear what capacity this would correspond to. Another possibility would be to find new uses for the produced heat, eliminating the need to waste it.

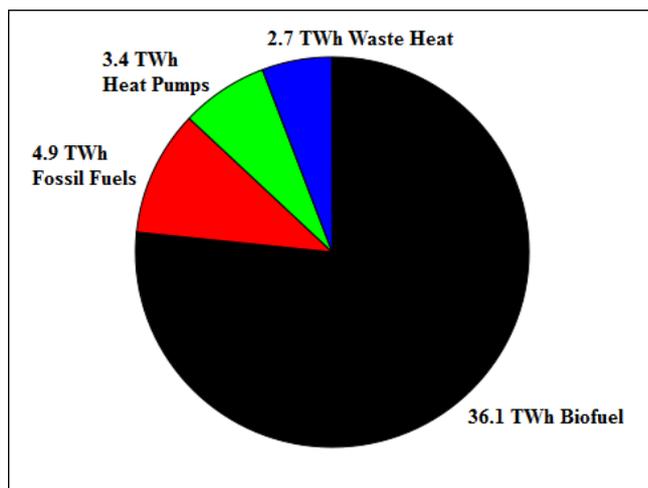


Figure 2.4. Energy sources used in district heating in Sweden in 2009 [2].

2.4 Pretreatment of biomass

2.4.1 Introduction

Before gasification, it is necessary to pretreat the biomass. Feedstock preparation is required for almost all types of biomass materials, because of their large range of physical, chemical, and morphological characteristics. Depending on the type of biomass, various pretreatment methods can be used. Figure 2.5 shows the main biomass sources in Sweden, as well as their intermediate and final products [5].

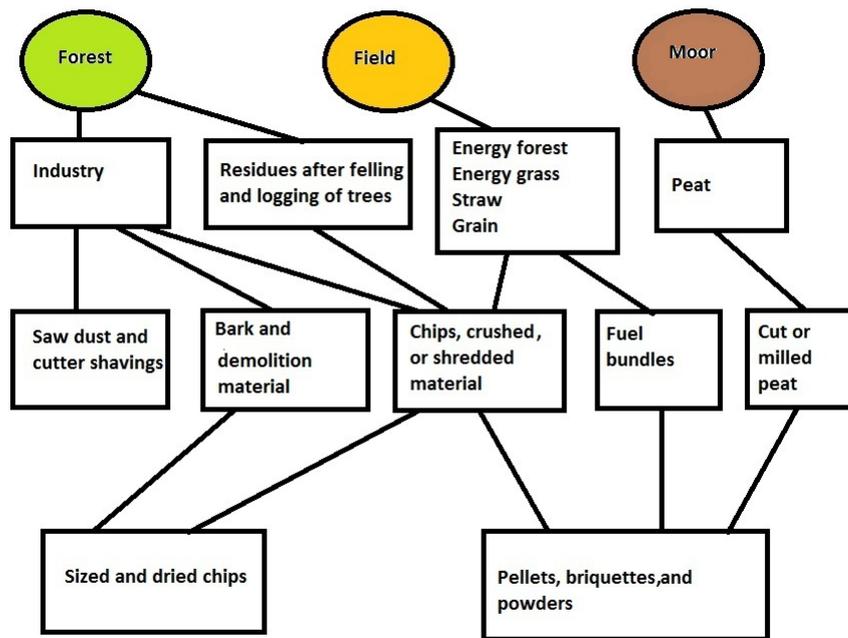


Figure 2.5. Typical types of biomass used in Sweden and their origins as well as their intermediate and final forms [5].

A portion of the trees growing in a forest are used in industry. Sawdust and cutter shavings produced in sawmills can be transformed into pellets, briquettes, and powder. The forest industry also produces bark. Building demolition also yields biofuel material that can be used in the form of sized and dried wood chips. Another and very important source of biomass from the forest is the residues left after felling trees; these materials are turned into either pellets or chips.

The biomass from agricultural fields can be energy grass, straw, and grain. These materials can be transformed into chips, crushed, or shredded material that end up as sized and dried chips, pellets, briquettes, and powders. Grass or cultivated small trees can be stored in fuel bundles and later be transformed into pellets, briquettes, and powders. The biofuel material obtained from moors is peat, which is cut into large pieces or milled; later on, this material is transformed into pellets, briquettes, and powders.

2.4.2 Growth of biomass

In Canada, for example, the total carbon stock is 15,835 million tons [6]. Forest biomass can come from natural forests or from plantations. Trees grown in natural forests take 40–100 years to produce a crop, while in plantations the time to harvest is only 3–15 years. Plantations also have the advantage of enabling production of biofuel near where it is needed. Silver maple and several varieties of fast-growing poplar, willow, and alder have been tested for suitability for energy plantations in Canada.

2.4.3 Harvesting

The first pretreatment step is harvesting, for which modified agricultural equipment is used [5].



Figure 2.6 Tractor used for handling biomass. (photo reproduced by courtesy of Johan Andersson)

2.4.4 Storage and pre-drying

Storage is needed after harvesting. Moist material is usually stored outdoors in large stacks. Microorganisms degrade biomass with time, faster in the case of finely divided material. Therefore, the drying biomass should be stored in large pieces and be divided just before use [5]. Material for storage should preferably be collected in spring to take advantage of the naturally efficient drying process in summer. Drying takes six months to one year, when the water content is 30–40 %.



Figure 2.7. Storage of tree branches, roots, and tops for pre-drying (photo reproduced courtesy of Johan Andersson).

2.4.5 Transportation

Before the material is transported, it is usually chipped in the forest and loaded on the truck. Material is usually transported by truck, but the mode of transport used depends greatly on the development level of the country where the material is used. A transport distance of 50–80 km is economically feasible.



Figure 2.8 Chipping machine emptying its load into the tractor for transportation to large containers. (photo reproduced by courtesy of Johan Andersson)

2.4.6 Conventional pelletization

Biomass can be compressed and turned into fuel pellets [7]. Pellets are preferred because they have a uniform structure and composition allowing storage in a smaller space. The pelletizer machine is a self-contained low cost system being used to create pellets from a wide variety of biomass.

Table 2.6 Examples on Swedish suppliers of equipment for small-scale pelletization [7].

Supplier	Type of supplier	Brand/model	Capacity (kg/h)
Sweden Powers Chippers AB (SPC)	Manufacturer	SPC	100-500
Biopress AB	Manufacturer	Biopress	100-800
PM Bioenergi och Smide	Reseller	BT-press	150
SvenskEkoDiesel	Reseller	Ekopell	200-1000
Morums Mekaniska	Manufacturer	Morumspressen	50
Mared AB	Reseller	Munch	150-5000
Roland Carlberg processystem AB	Reseller	KAHL	300-8000
UNY Konsult	Reseller	Salmatec	450-950

Table 2.6 presents examples of suppliers of pelletization equipment and their capacity to produce pellets. Many of them are local Swedish manufacturers.

2.4.7 Torrefaction and compacting

Densification for pellet production is a proven technology for improving the properties of biomass for conversion into heat and power. The current worldwide production volumes exceed 5 Mton/a, indicating that the biopellet (including wood pellets) market is fairly mature. However, biopellets are expensive and cannot be produced from a wide variety of biomass feedstock. ECN, in Holland, has introduced an alternative process for biopellet production. This process, based on a combination of torrefaction and pelletization, is called the TOP process [8].

TOP pellets have a bulk density of 750–850 kg/m³ and a net calorific value of 19–22 MJ/kg, resulting in an energy density of 14–18.5 GJ/m³. This energy density is significantly higher than that of conventional biopellets, for example, sawdust biopellets have an energy density of 7.8–10.5 GJ/m³. TOP pellets can be produced from a wide variety of materials, such as sawdust, willow, larch, verge grass, demolition wood, and straw, yielding similar physical properties from all feedstocks. TOP pellets have a greatly improved durability compared to ordinary pellets.

It is expected that the TOP production process can be operated at a typical thermal efficiency of 96% or a net efficiency of 92% on a lower heating value (LHV) basis. The TOP process requires a higher total capital investment than does conventional pelletization, EUR 5.6 million versus EUR 3.9, respectively, for a capacity of 170 kton/annum of sawdust feedstock with 57% moisture content.

However, the total production costs of the TOP process are expected to be lower, EUR 2.2/GJ versus EUR 2.6/GJ for conventional pelletization. The cost advantages of TOP pellets amount to approximately 30 % in logistics operations using the same infrastructure as used for conventional biopellets. This results from the higher bulk density of TOP pellets and the lower tonnage that needs to be transported (per GJ).

At a market price of EUR 7.3/GJ of biopellets, the internal rate of return of the TOP process is 30 % versus 13 % for conventional pelletization, and under these conditions the payout periods are three and six years, respectively.

Table 2.7 Comparison of costs for combined torrefaction and pelletization and conventional pelletization (in EURO/kWh). [8]

Units for combined torrefaction and pelletization			
Raw material (saw dust)	Torrefaction and compacting	Transport/Logistics	Final use
0.00260	0.00759	<0.00759	<0.0181
Units for conventional pelletization			
0.00260	0.00883	0.01110	0.0226

Table 2.7 presents the costs of various stages of pellet production. The figure shows that the transportation cost is approximately 32 % lower for torrefacted than conventional pellets. The total cost is 20 % lower for the torrefacted material.

2.4.8 Drying

Fuel drying is advisable if fresh wet materials (moisture content of 50–60 % on a wet basis) are to be gasified [9]. Drying can be performed inside or outside the gasifier system. Using the exhaust gases from an internal combustion engine is a very efficient way to dry wet materials, the sensible heat in exhaust being sufficient to dry biomass from 70 % to 10 % moisture content. Rotary kilns are the most commonly used biomass dryers.

2.5 References to chapter 2

(weblinks April 2011)

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10. www3.ivl.se/rapporter/pdf/B1825.pdf

3. Gasification

3.1 Gasification chemistry

In the gasifier the solid biomass is converted into gas. This is done by a network of sequential and parallel physical processes and chemical reactions.

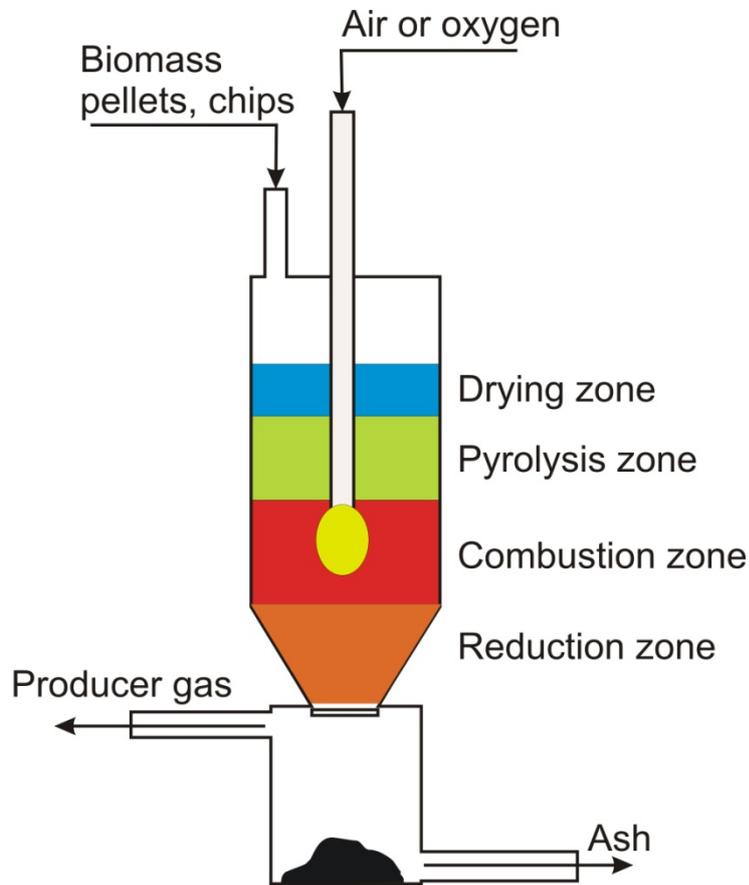
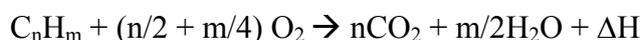
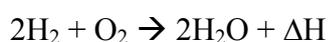
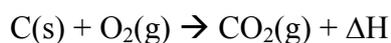
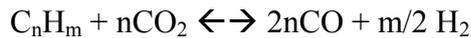
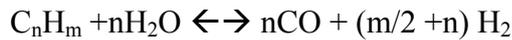
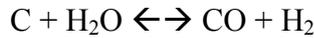
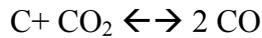


Figure 3.1. Schematic of a downdraft gasifier and the zones inside it.

When biomass is fed into the gasifier, the constituent particles (e.g., chips and pellets) are dried by the heat in the gasifier, releasing steam into the gas phase. Further heating the dry biomass causes pyrolysis, i.e., breakdown by heat. First, volatile compounds desorb from the particles; then larger molecules, such as cellulose, hemicellulose, and lignin, start to decompose, emitting fragments into the gas phase. Finally, a carbon-rich porous structure remains, i.e., charcoal. If an oxidizer is used, such as air or oxygen (the gasifier can also be heated indirectly), the released hydrocarbons and charcoal are partly combusted, forming CO_2 , CO , and water and releasing heat.



This released heat (or transferred if it is an indirect gasifier) is the driving force to all of the processes taking place in the gasifier. When the oxygen is consumed, reduction reactions take place in the hot environment. Those reactions are endothermic and bind heat from the environment. This means that the temperature drops in the gasifier due to the reactions.



Those reactions produce a gas mixture, producer gas, consisting of CO₂, CO, H₂, H₂O, lower hydrocarbons (mainly CH₄ and some C₂ compounds) and tars as the main components. The exact composition depends on the type of gasifier and the mode it is operated. Table 3.1 presents the composition of gas from 3 different sources (compiled from [1]).

Table 3.1. Comparison of the composition of gas from three plants [1].

Component	Viking	Värnamo	Harboøre
H ₂	30.5	9.5-12	19.0
CO	19.6	16-19	22.8
CH ₄	1.2	5.8-7.5	5.3
N ₂	33.3	48-52	40.7
Tar (mg/Nm ³)	>1	No data	Tar free
LHV (MJ/Nm ³)	5.6	5.0-6.3	5,6

A detailed breakdown of the composition of gas from various plants can be found in Hulteberg and Hansson [2].

3.2 Tars

Tars are polyaromatic compounds formed when heating the biomass and during the breakdown of its main constituents, i.e., cellulose, hemicelluloses, and lignin. Evans et al. [3] classify the formed tars in four groups:

Primary products: mixed oxygenates (e.g., organic acids, aldehydes, and ketones) formed at low temperature, approximately 400 °C

Secondary products: phenolic compounds formed at approximately 600 °C

Tertiary products: methyl derivatives of polynucleous aromatics (alkyl-PNA) (e.g., methyl acenaphthylene, methyl naphthalene, toluene, and indene) formed at approximately 800 °C

Quaternary products: at higher temperatures, the tertiary products (alkyl-PNA) are stripped of their substituents and benzene, naphthalene, acenaphthylene, and pyrene are formed, at approximately 900 °C

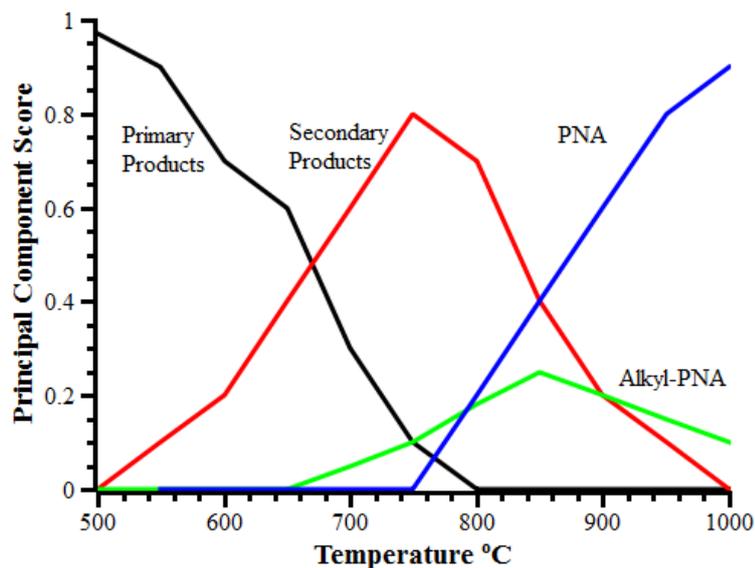


Figure 3.2. Distribution of the four tar component classes as a function of temperature at 300 ms [4].

Figure 3.2 shows the distribution of the four tar component classes as a function of temperature at a residence time of 300 ms [3]. The composition of tars is highly dependent on process parameters such as temperature, pressure, and residence time. Eliot [5] broke down the composition of tars produced by various processes, as shown in Table 3.2.

Table 3.2 Composition of tars from biomass [5].

Conventional Flash Pyrolysis (450-500 °C)	High Temperature Flash Pyrolysis (600-650 °C)	Conventional Steam Gasification (700-800 °C)	High Temperature Steam Gasification (900-1000 °C)
Acids Aldehydes Ketones Furans Alcohols Complex Oxygenates Phenols Guaiacols Syringols Complex Phenols	Benzenes Phenols Catechols Naphthalenes Biphenyls Phenanthrenes Benzofurans Benzaldehyde	Naphthalenes Acenaphthylenes Fluorenes Phenanthrenes Benzaldehydes Naphthofurans Benzanthraenes	Naphthalene Acenaphthylene Phenanthrene Fluoranthene Pyrene Acephenathrylene Benzanthracenes Benzopyrenes 226 MW* PAHs 276 MW* PAHs

*MW = Molar Weight

The structural formulas of some of the tars are shown in Figure 3.3.

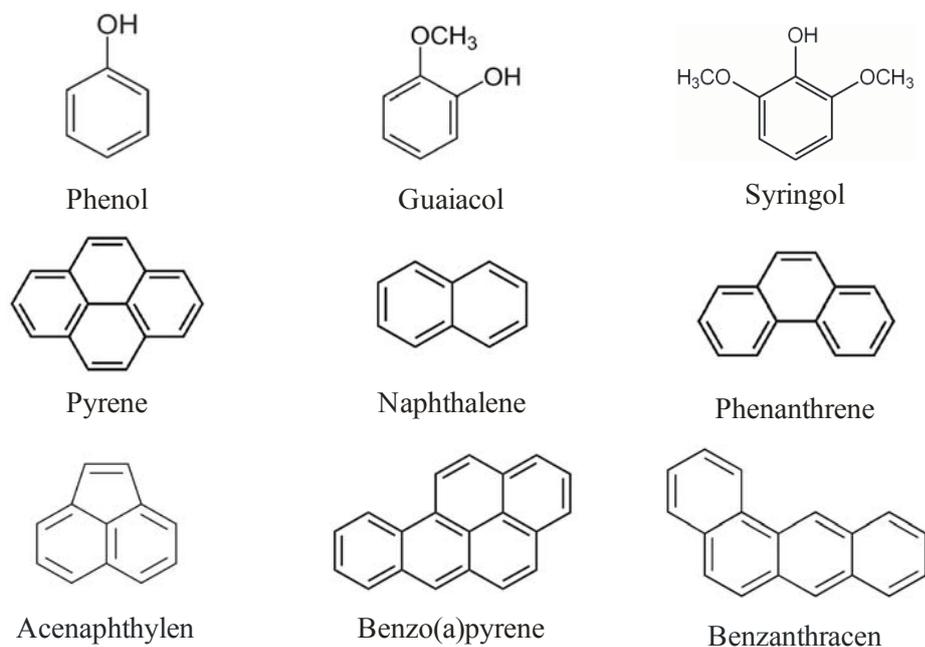


Figure 3.3. Examples of tar molecules.

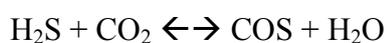
Naphthalene is the simplest polyaromatic compound, having a molecular weight of 128 g/mol and a boiling point of 218 °C. The polyaromatic tars generally have high molecular weights and high boiling points. This can cause clogging problems in filters, heat exchangers, pipes, etc., necessitating preventative action. Considerable research has been published over the last century on the issue of removing, destroying, or using tars formed during biomass gasification.

3.3 Minor contaminants: H₂S, NH₃, COS, and HCN

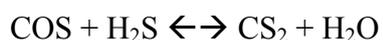
The sulphur content of biomass is generally low, but varies with the type of biomass. During ordinary combustion, the sulphur is mainly released as SO₂, but in the reducing environment present during gasification, the sulphur is instead released as hydrogen sulphide, H₂S. The hydrogen sulphide level in the producer gas is approximately 30–150 vppm when woody biomass is used, but can be higher, for example, reaching 500 vppm in the case of peat.

During gasification, the nitrogen content of the biomass is released as ammonia; NH₃. The levels of ammonia in the producer gas can reach fairly high levels. Ammonia levels of 3,000 vppm after the gasifier were expected in the Värnamo plant.

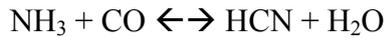
The hydrogen sulphide and ammonia in the producer gas participate in various gas phase reactions. Hydrogen sulphide reacts with carbon dioxide in the gas phase, forming carbonyl sulphide:



The formed COS can react further with H₂S, forming carbon disulphide CS₂:



Similarly, ammonia reacts with carbon monoxide CO:



There might be other reaction pathways by which COS and HCN are formed from the solid biomass during gasification and from tar decomposition, but the above reactions describe the composition of the gas phase. Common to the above reactions is that they are all equilibrium reactions: depending on the composition of the gas and the temperature, they might go in either direction. They are also equimolar reactions, indicating that the equilibrium state for each is independent of the pressure.

If one cools down the producer gas, for example, to perform a cleaning operation, one could find that the concentrations of those components deviate considerably from the equilibrium values determined by the equilibrium at the actual gas state. This is because the gas freezes when the temperature decreases, caused by the slowing rate of reaction as the temperature decreases. In other words, the gas strives to reach equilibrium, but the reaction rate is so low that this cannot be detected.

3.4 References to chapter 3

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4. Gasifiers

There are many types of gasifiers [13] and they can be classified according to:

- oxidation agent: air, oxygen or steam
- heating: direct (autothermal) or indirect (allothermal)
- pressure at gasification: atmospheric or pressurized
- reactor: fixed bed, fluidized bed, entrained flow, twin-bed

4.1 Fixed-bed gasifiers

Fixed-bed gasifiers are simple in design and operation, making them suitable for small-scale applications in the range of a few hundred kW_{th}. Fixed-bed gasifiers can be operated in either batch or continuous mode. The generator gas units fuelling cars in Europe during the Second World War were small-scale fixed-bed gasifiers.

4.1.1 Updraft gasifiers

According to [13], the simplest type of gasifier is the fixed-bed updraft gasifier.

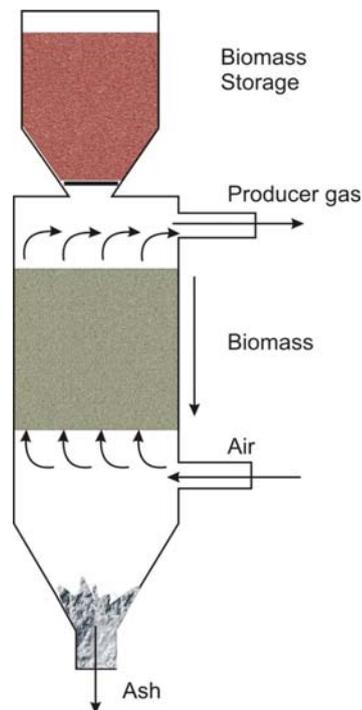


Figure 4.1. Schematic of a small-scale updraft gasifier.

The air enters at the bottom of the bed and moves up through the bed of biomass. The biomass moves in the opposite direction from top to bottom. The gasifier can be operated in batch mode, in such a way that the biomass is loaded once into the gasifier, which is operated until the biomass is consumed. In continuous operation, biomass is continuously fed into the top of the gasifier while the formed ash is removed from the bottom. The advantage of this gasifier is the good heat exchange in the reactor: the outgoing hot gas is cooled down while heating the incoming fresh biomass. In the bottom, the hot charcoal meets the incoming fresh air, ensuring the good burnout of carbon in the ash. However, since the pyrolysis gas does not come in contact with the entering air, the outgoing gas contains high amounts of tars.

4.1.2 Downdraft Gasifiers

In a downdraft gasifier, the biomass is also fed from the top while the air is introduced into the bed from either the top or the side. Both the biomass and the gas move downward during the gasification process[13].

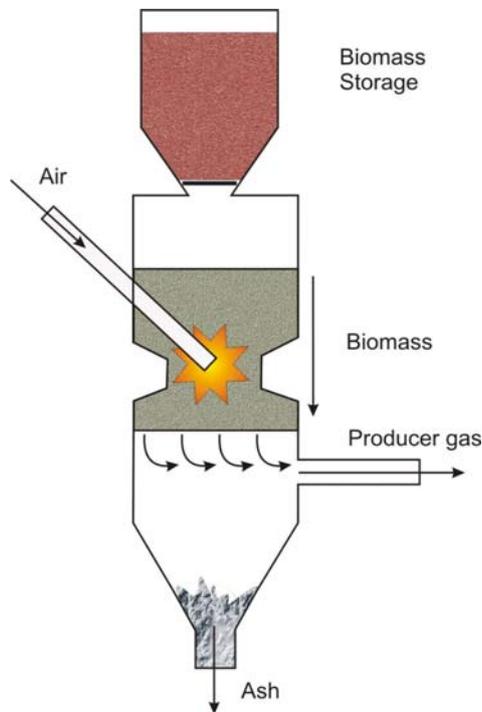


Figure 4.2. Schematic of a downdraft gasifier.

Because the pyrolysis gases pass through the oxidation and charcoal reduction zones, the tar in the gas is effectively reduced ($<100 \text{ mg/Nm}^3$) [13]. At high loads, the temperature in the gasifier is higher than at low loads, meaning that tar reduction works better at high than at low loads. Since it is important to maintain constant temperature in the oxidation zone, downdraft gasifiers usually have a throat, i.e., a narrow passage just below the air injection point. It is easier to obtain a constant temperature in this arrangement and all gas is forced to pass through the narrowed throat. The disadvantages of downdraft gasifiers are that the produced gas is very hot, since it leaves the bed from a very hot zone, and internal heat recovery is less effective than in an updraft gasifier. The ash contains a higher proportion of unburned charcoal and the ash and dust content of the produced gas is much higher than in gas from an updraft gasifier.

4.1.3 Crossdraft gasifier

In a crossdraft gasifier [13], the biomass passes from top to bottom in the same manner as in other fixed-bed gasifiers. However, the gas passes from one side to the other, perpendicularly

to the biomass flow. This type of gasifier is intended for gasifying charcoal, i.e., a fuel low in volatiles and tars. The produced gas requires little cleaning and the gasifier is suitable for very small-scale applications (<10 kW). However, if one puts fuel rich in volatiles and tars in this type of gasifier, this will result in very large amounts of tars and hydrocarbons in the produced gas.

Table 4.1. Characteristics of fixed-bed gasifiers [13].

Fuel (wood)	Downdraft	Updraft	Crossdraft (charcoal)
Moisture content (% water)	12 (max. 25)	43 (max. 60)	10–20
Ash (% dry)	0.5 (max. 6)	1.4 (max. 25)	0.5–1.0
Fuel size (mm)	20–100	5–100	5–20
Gas exit temp. (°C)	700	200–400	1250
Tars (g/Nm ³)	0.015–0.5	30–150	0.01–0.1
Turndown ratio	3–4	5–10	2–3
LHV (MJ/Nm ³)	4.5–5.0	5.0–6.0	4.0–4.5
Power MW _{th}	< 5	< 20	Small (~10 kW)

4.2 Fluidized beds

In a fluidized bed, solid particulate material is suspended in moving liquid or gaseous fluid. Figure 4.3 shows the fluidization process and its dependence on the velocity of the fluid flow. At low flow velocities, the solid particulate bed is unaffected, and the bed acts as an ordinary stationary bed. At increasing applied flows, the bed expands, increasing the void in the bed. At a certain flow, corresponding to the minimum fluidization velocity, the particles float free, collectively acting as a liquid. At still higher flows, bubbles appear in the bed. At a sufficiently high flow velocity, the particulate material will be blown out of the reactor in a two-phase flow.

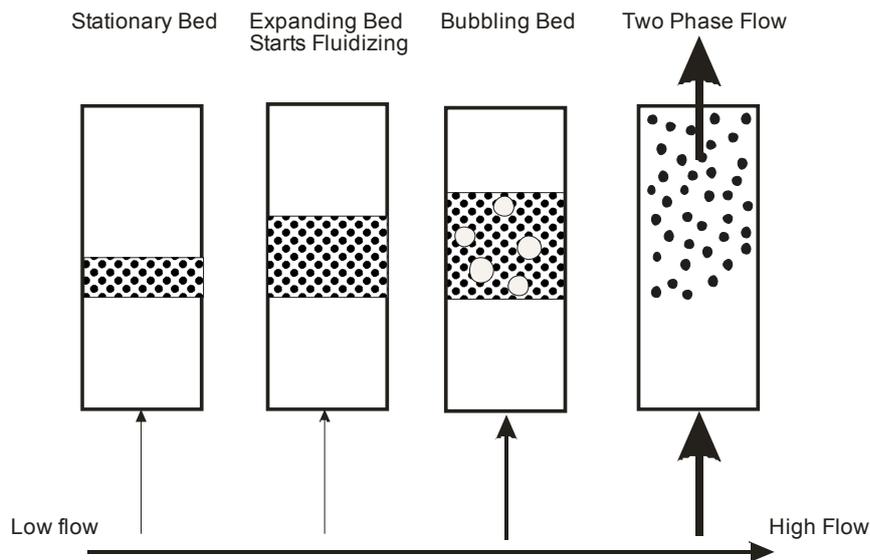


Figure 4.3. Effect of gas flow on the characteristics of the gasification bed.

4.2.1 Bubbling Fluidized bed (BFB)

The use of bubbling fluidized-bed (BFB) gasifiers, originally developed for coal gasification, solves a series of problems connected with fixed-bed gasifiers[13]. Since the BFB gasifier operates in a manner similar to a continuously stirred tank reactor (CSTR), the temperature is constant and low throughout the bed, and no hot spots are possible. The fuel is evenly distributed throughout the bed and cannot become stuck or cause channelling. Due to the automatic density separation in the bed, dense particles sink while light particles leave the bed with the gas. CFB gasifiers can handle high-ash-content fuels. They are well suited for continuous operation and scalable to a wide range of sizes, allowing for large-scale industrial plants.

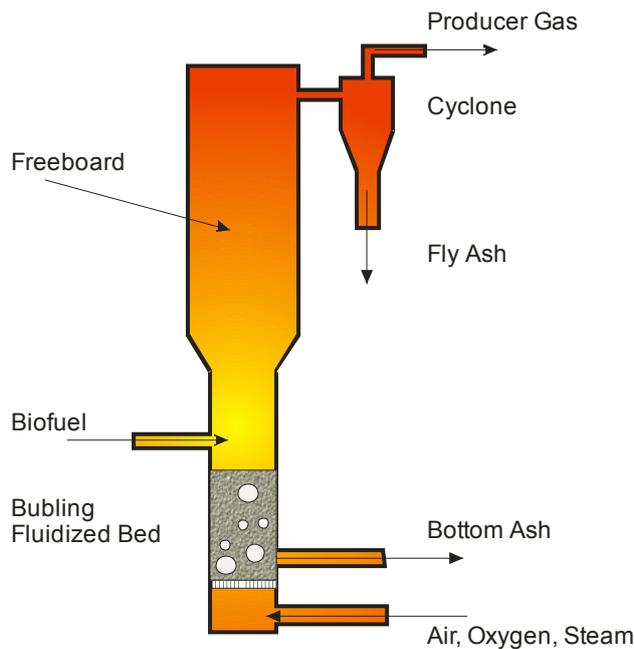


Figure 4.4. Schematic of a bubbling fluidized-bed gasifier.

In normal operation, the bed material is usually some sort of sand, SiO_2 . However, the biomass contains fairly high levels of alkali, mainly salts of potassium, K. At high temperatures, the alkalis attack the SiO_2 , forming alkali-silicates with low melting points. This might cause problems due to agglomeration of the bed material. To prevent this problem, the bed material can consist of non-silicates such as magnesite, MgCO_3 , or dolomite, $\text{CaMg}(\text{CO}_3)_2$. The choice of bed material can also affect the chemical reactions in the bed. Since the BFB gasifier resembles a CSTR, a fairly high amount of tars and unburned char leaves the bed even if gas phase reactions occur in the freeboard area.

4.2.2 Circulating fluidized bed (CFB)

In a circulating fluidized-bed (CFB) gasifier [13], there is no freeboard where the gas velocity decreases and entrained particles fall back to the fluidized bed. Instead, some of the bed and char particles that are sufficiently small become entrained with the produced gas and leave the gasifier. Those particles are separated from the gas in a cyclone and returned to the bottom of the bed. In CFB gasifiers, the burnout of the char is higher and the tar levels are lower than in BFB gasifiers. CFB gasifiers are also somewhat cheaper to construct than are BFB gasifiers of corresponding capacity. The Värnamo gasifier, 18 MW_{th}, is an example of a pressurized, air-blown, CFB.

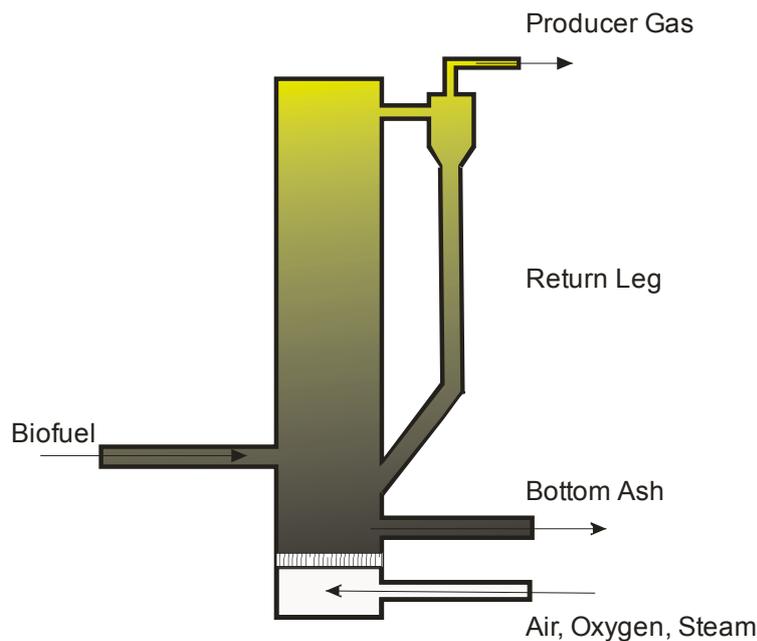


Figure 4.5. Circulating fluidized-bed gasifier.

4.3 Entrained-flow gasifier (EF)

The entrained-flow (EF) gasifier was originally developed for coal gasification, and there are many variants of the EF gasifier design. Well-known EF processes have been developed by Koppers-Toptzek, Texaco, Shell, Pernflo, and GSP. The fuel must be ground very finely and can be mixed with water to form slurry sprayed into the gasifier, although some variants inject the fuel powder and water separately. Oxygen or air is mixed into the fuel-water aerosol and

the mixture is lit by a pilot flame. The EF gasifier operates at a very high temperature, approximately 1450 °C, and works by a combination of partially oxidizing and gasifying the fine fuel particles. Due to the high operating temperature, most of the tars and lower hydrocarbons are converted, and the produced gas requires little cleaning.

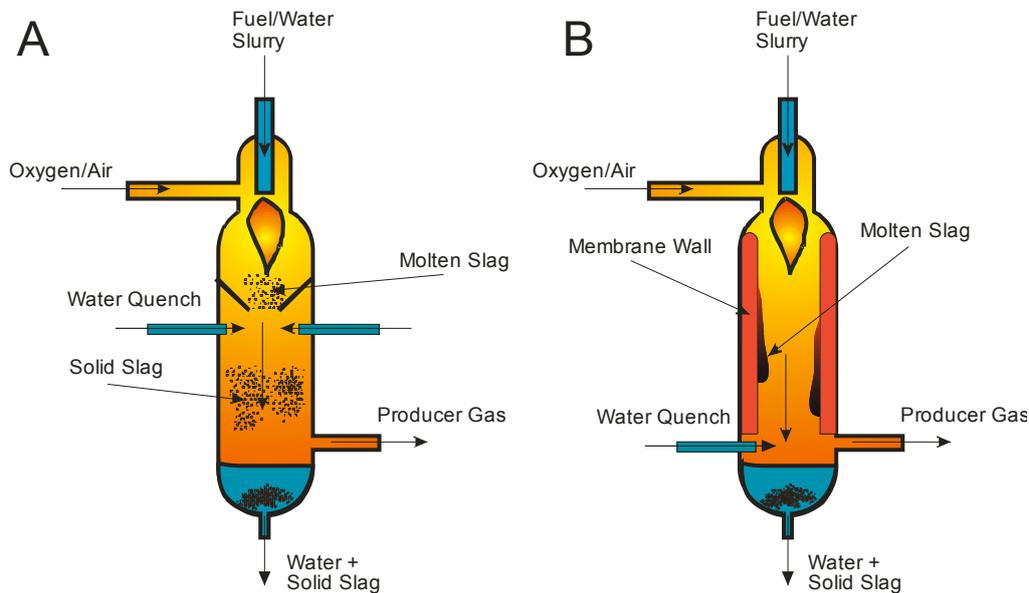


Figure 4.6. Schematics of two entrained-flow gasifiers operating under slagging conditions.

Due to the high operation temperature, the ash melts and forms slag. Depending on the ash content of the fuel, EF gasifiers may operate under non-slagging or slagging conditions. The high operation temperature requires materials or constructions that can withstand the harsh conditions. Under slagging conditions, membrane walls are used. Membrane walls are built by metal tubes cooled by steam flowing inside. These tube walls become resistant to the molten slag, since a layer of solid slag forms on their cool surfaces.

Figure 4.6 shows two EF designs for use under slagging conditions. In the gasifier shown in Figure 4.6A, gasification is performed in a separate chamber and the slag occurs in gaseous or droplet form. When the gas enters the second chamber, it is cooled by water and the slag is solidified in the form of grains that fall to the bottom and are removed together with the water.

In Figure 4.6B, the slag condenses on the cooler membrane walls and flows down to the bottom of the gasifier where it is cooled down with water, cracking into pieces due to the thermal shock.

Chemrec's black liquor gasifier in Piteå, Sweden, is an example of an entrained-flow gasifier. When the black liquor is gasified, the slag contains the inorganic salts (mainly sodium sulphide, sodium carbonate, and sodium sulphate). Together with the quenching water, they form green liquor in the bottom of the gasifier. The green liquor is recycled to the causticizing plant of the pulp mill for sodium hydroxide (NaOH) recovery.

Table 4.2 presents a compilation of data on BFB, CFB, and EF gasifiers. As can be seen, those processes are useful for large-scale industrial processes. BFB and CFB should eventually be useful for smaller processes in the 10–20 MW range.

Table 4.2. Operating conditions for fluidized-bed and entrained-flow gasifiers [13].

	BFB	CFB	EF
Temperature (°C)	< 900	< 900	~ 1450
Tars	Moderate	Moderate	Very low
Control	Moderate	Moderate	Complex
Scale (MW _{th})	10-100	20- ??	>100
Feedstock	Less critical	Less critical	Only fines

4.4 Multi-bed Gasifiers

Various tasks can be conducted separately using multiple beds, which can solve the indirect heating problem and reduce tar production.

4.4.1 Indirect heating

Figure 4.7 shows an example of the use of multiple beds for indirectly heating the gasifier.

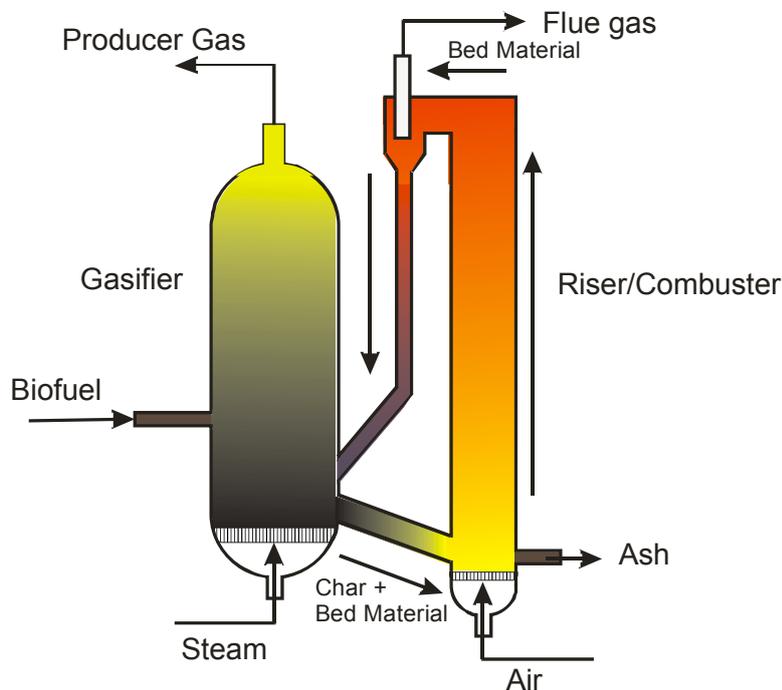


Figure 4.7. Schematic of use of multiple beds for indirect heating of the gasifier.

The unit is a steam-blown CFB gasifier equipped with a riser in the return leg. The bed is tapped at the bottom instead of the top. When the drawn-off bed material, char, and ash enter the riser, they are mixed with air that burns the char. The combustion heat heats the bed

material, which is separated in a cyclone on top of the riser and returned to the gasifier. The combustion flue gas is vented separately, while the hot bed material supplies the gasifier with the required heat. The advantage is that the producer gas is nitrogen free, having a higher energy density than gas that contains nitrogen.

This is the type of gasifier used in the BKW Güssing plant; however, others, for example, the Battelle Memorial Institute [4] in the USA, have developed similar gasifiers.

4.4.2 Separate pyrolysis and char gasification solutions

Several designs for smaller gasifiers are based on separate pyrolysis and char gasification steps. The expected advantage is cleaner gas that requires little or no cleaning. Figure 4.8 shows one such gasifier design encountered in this project; however, other similar types of gasifier also exist.

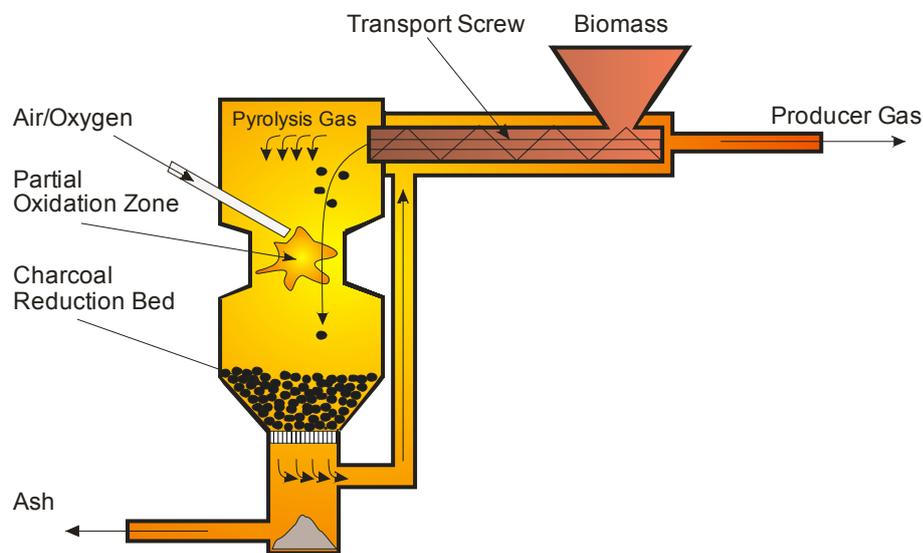


Figure 4.8. Viking gasifier with separate pyrolysis and char gasification beds.

Figure 4.8 shows a twin-bed gasifier with separate pyrolysis and char gasification beds. This is the type of gasifier developed at DTU in Denmark, the Viking gasifier. The biomass is fed into the gasifier by a transport screw in a double-jacketed casing. The casing is heated by the hot outgoing producer gas. During the transport through the gasifier, the biomass is first dried and then pyrolysed. By the time the biomass feed has reached the reactor entrance, the solid material has been converted to charcoal. This falls through the reactor down to the bottom, where it forms a charcoal bed. Injecting air/oxygen into the reactor subjects the pyrolysis gas to partial oxidation above the charcoal bed. The remaining hydrocarbons are reduced when passing through the charcoal bed, which is itself concurrently gasified by steam. The arrangement reduces the tar content from 50,000 mg/Nm³ in the gas leaving the screw to 500 mg/Nm³ after the partial oxidation step, and further down to 25 mg/Nm³ after the charcoal bed.

Figure 4.9 shows a schematic of the fairly recently developed [5] Woodroll gasifier of Cortus AB, Sweden. The name probably refers to the fact that the biofuel drying and pyrolysis occur in rotating drums heated by the flue gases from the combustion of the pyrolysis gas in

recuperative Kanthal-type burners (Figure 4.10). When the biofuel leaves the pyrolysis drum, it has been converted into char.

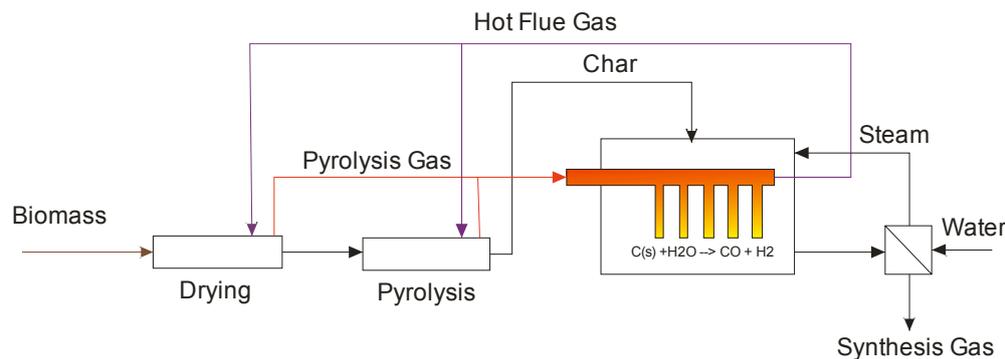


Figure 4.9. Woodroll gasifier with separated pyrolysis, combustion of pyrolysis gas, and char gasification.

The char is transported to the gasification reactor/chamber heated by the heat radiation from the recuperative burners. The char is gasified by steam generated by the outgoing producer gas (in this case, actually synthesis gas). The major advantage of the Woodroll gasifier is the purity of the gas, which is produced by the steam gasification of charcoal. Purification will probably be needed to remove, for example, sulphur, from the gas, depending on its intended use. Cortus AB says that there are three uses for the Woodroll: industrial use for heating and chemical reduction purposes, production of synthesis gas for synthesis processes, and for small-scale CPH applications. The Woodroll has been demonstrated at a 150 kW scale and a 500 kW plant is under construction; a 5 MW plant is planned in the future.

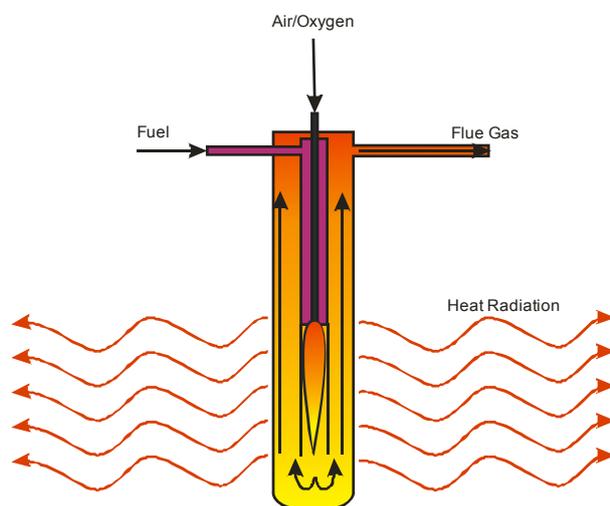


Figure 4.10. Recuperative Kanthal burner.

Kanthal's recuperative heater [6], Ecothal, is used for high-temperature heating by radiation, for example, in the metallurgical industry [7, 8].

4.5 The Cyclone Gasifier

Cyclone gasifiers have been developed in several places [9–12]. The cyclone gasifier is a kind of entrained-flow gasifier in which small biofuel particles, such as sawdust, are gasified and

partially oxidized in the swirling flow inside a cyclone. The temperature inside the cyclone is 900–1000°C.

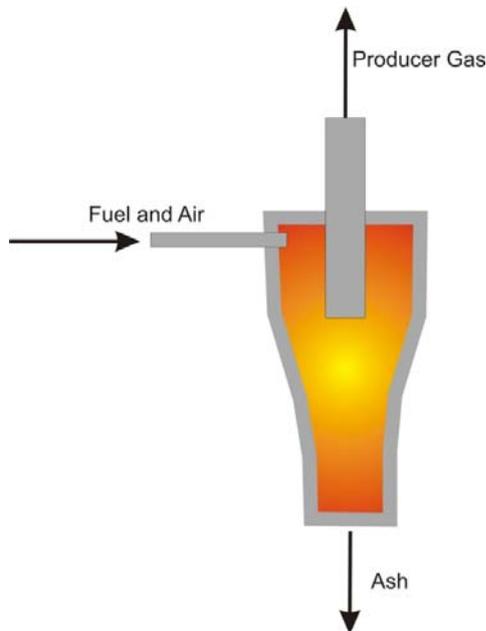


Figure 4.11. Schematic of a cyclone gasifier.

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5. Gas cleaning

The gas leaving the gasifier normally contains dust, ash, tars, and other contaminants and needs to be cleaned before use.

5.1 Dust and ash

Cyclones are standard equipment in producer gas treatment. Cyclones generally remove particles from 1 mm down to 5 μm [1] in size and work with dry particulates. Cyclones can operate at actual gas temperatures (up to 900–1000 $^{\circ}\text{C}$) to avoid chilling the gas. Cyclones can be used in series, in a multi-cyclone installation, to remove successively smaller particles.

Candle filters consist of a porous metallic or ceramic filter material that allows gases to pass but not the particulate matter (Figure 5.1). Candle filters can be operated at temperatures up to 500 $^{\circ}\text{C}$ and can effectively remove particles in the 0.5–100 μm range [2]. The filter is regenerated, either by removing the filter cake or by back flushing with steam or nitrogen.

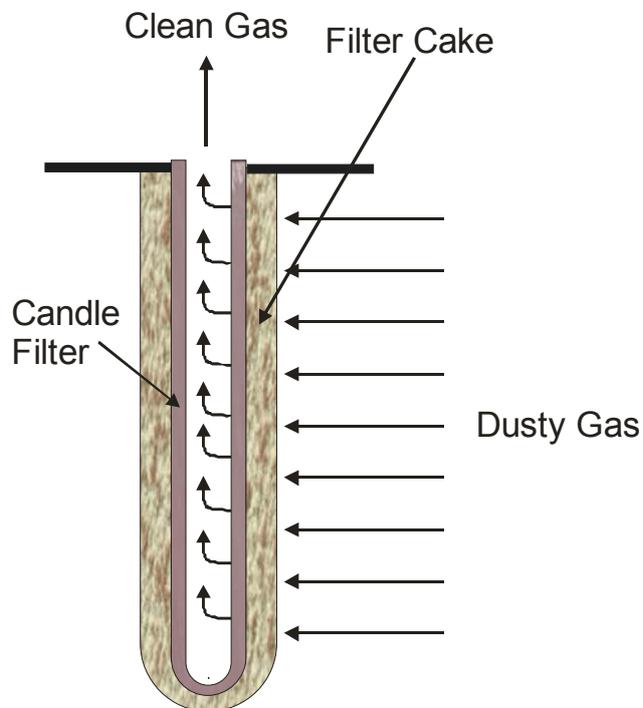


Figure 5.1. Schematic of a candle filter.

Bag filters consist of woven bags of polymeric, ceramic, or natural fibres. They operate in a similar manner to the candle filter and are regularly vibrated or back-flushed to remove the built-up filter cake. The maximum operation temperature of a bag filter is approximately 350 $^{\circ}\text{C}$. In an electrostatic precipitator (ESP), ash and dust particles receive a negative electric charge when they pass an electrode connected to a high voltage source (10–100 kV DC). The charged particles will then be attracted to, precipitated out, and collected on a positively charged collector electrode (Figure 5.2).

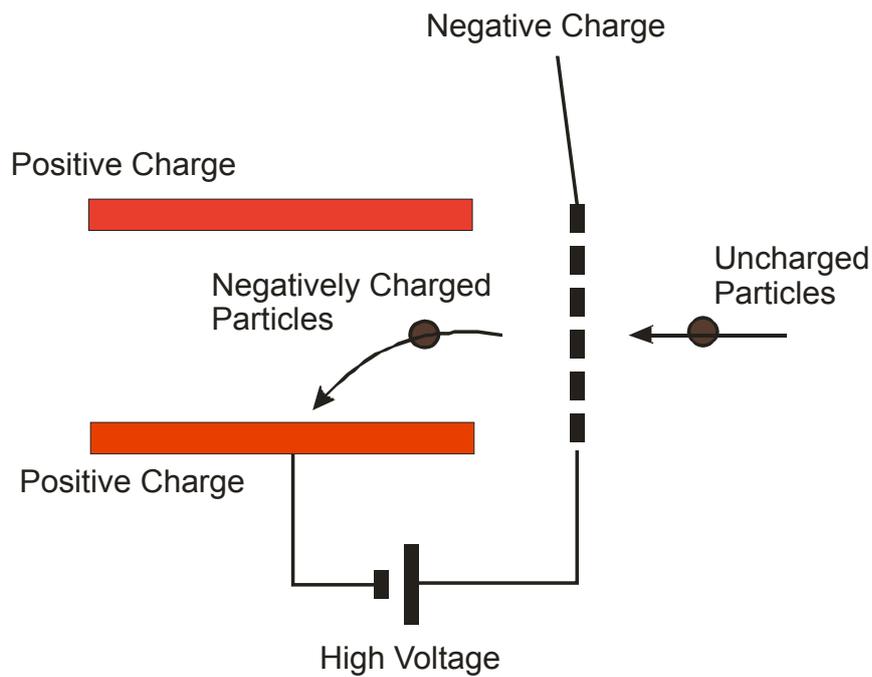


Figure 5.2. Schematic of an electrostatic precipitator.

Electrostatic precipitators can be operated at temperatures up to approximately 400 °C. The collected dust must regularly be removed by vibration or brushing. Wet electrostatic precipitators (WESP) also exist. They can operate at high humidity and are used, for example, to remove sulphuric acid mist. WESP are also used to remove oil droplets (actually fatty acid methyl esters, FAME) released by oil scrubbers, used for tar removal. In a WESP, the liquid phase can drain off the collector electrodes, which consequently do not require cleaning to the same extent as do electrodes in dry electrostatic precipitators.

5.2 Tar cleaning

The occurrence of tars in producer gas is the single largest problem that has had to be overcome in striving to commercialize gasification processes for various purposes. Much work has been performed over the last century to alleviate this problem, and many processes have been developed, many patents filed, and many papers published on the subject. One could, of course, choose a gasifier that eliminates or greatly reduces the amount of tar in the gas, such as an entrained-flow (EF) gasifier. However, due to the high-temperature operation of the EF process, more of the chemically bonded energy in the fuel must be released as heat to increase the temperature than in other types of gasifiers that operate at lower temperatures. EF gasifiers are suited for large industrial-scale operation (~100 Mw), and not for small–medium-sized operation.

There are two main strategies for dealing with the tar once it is present in the producer gas: removal and use, and in situ conversion.

5.2.1 Removal and use

5.2.1.1 OLGA: Oil Scrubber

OLGA – the Dutch acronym for “oil gas scrubber” – has been developed by the Energy Research Centre of the Netherlands (ECN). It operates in the temperature range in which tars condense, but above the dew point of water [3]. The washing and absorption media are usually referred to as “oil”, though they are in fact fatty acid methyl esters (FAME) produced by the transesterification of triglycerides from plants, also known as bio-diesel.

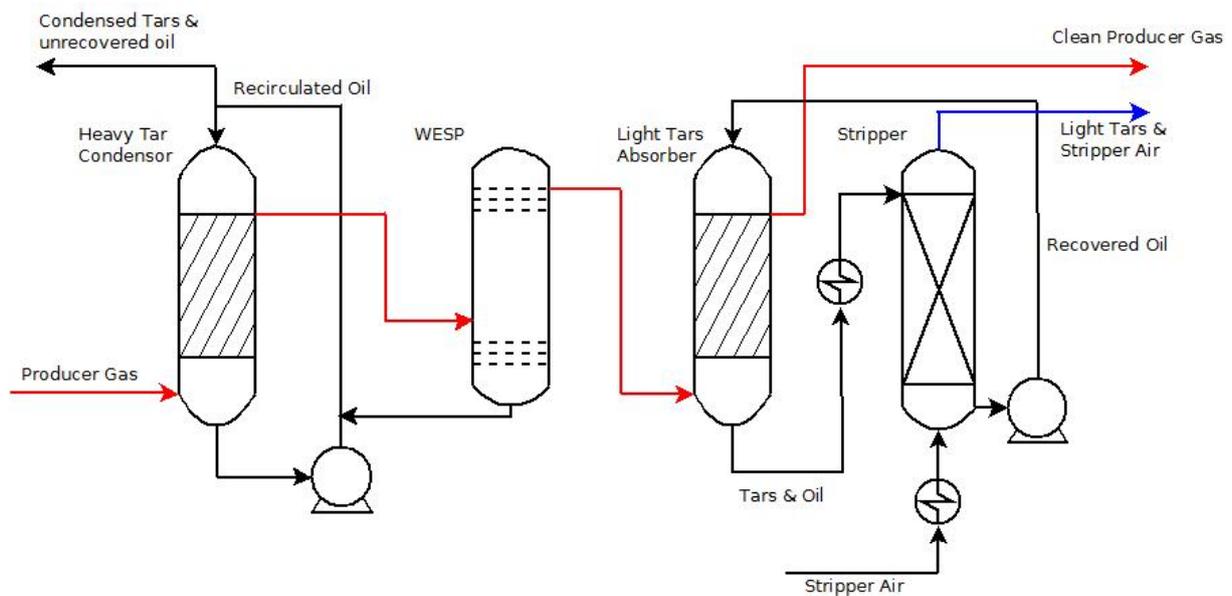


Figure 5.3. Schematic of the OLGA process.

In the OLGA process, the dust-cleaned raw producer gas first enters a condensation step: the inlet temperature of the gas can be up to 350 °C, but the gas is cooled down by the recirculating oil, which washes out the condensed heavy tars. Part of the oil/tar mixture is bled off and may be returned to the gasifier, while make-up oil is added. A WESP is used to remove droplets of tars and oil from the gas, and returns the drainage to the condenser. The producer gas now contains only the light tars, which are separated in a light-tar absorber. In the absorber, the temperature is just above the water dew point. The absorbed tars and absorbent oil are fed into a stripper where the light tars are stripped off by hot air, regenerating the oil that is fed back to the absorber. The tar/air mixture can then, for example, be fed back to the gasifier.

Variants of the design have been developed; for example, the BKW Güssing and the MEVA unit are both equipped with oil scrubbers.

5.2.1.2 TARWATC

At the Harboøre plant in Denmark, the original plan was to use catalytic tar cracking to clean the producer gas. Instead, Babcock & Wilcox Vølund developed the TARWATC process [4] for removing tar from the producer gas by condensing the tar and water in the gas. The tar–water mixture separates into two phases:

- One tar phase consisting of heavy tars (100 kg/h) having a calorific value of 27 MJ/kg: This tar is stored in heated tanks and is used for district heating during peak loads.
- A second “tar water” phase, i.e., water contaminated with lighter tars to form an emulsion (approx. 1100 kg/h): This phase contains approximately 10 g/dm³ of phenols and a total organic carbon (TOC) content of 45 g/dm³ with a pH of 2.

It is this tar–water phase that is treated using the TARWATC process. Hot water from the engine’s exhaust boiler evaporates the contaminated water, separating the light tars, with a heat value of 14 MJ/kg. The contaminated steam is further heated by heat exchange with the outgoing gas from the TARWATC reactor. The light tars are burned inside the TARWAC reactor, cleaning the contaminated steam.

The condensate from the TARWATC fulfils environmental standards for discharge into municipal systems. Phenols should be below 0.15 mg/ dm³, TOC below 15 mg/dm³, and pH in the 6.9–7.0 range.

5.2.2 In situ conversion

In situ conversion means that the tars are converted within the producer gas by some kind of thermal and catalytic process.

5.2.2.1 Partial oxidation

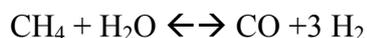
Partial oxidation is a thermal process in which an oxidizer, usually air or oxygen, is injected into the producer gas. The amount of added gas is only sufficient to combust part of the combustibles in the gas, but increases the temperature of the gas. The higher the temperature required, the more oxidizer gas must be added. However, since the added oxidizer releases the chemically bonded heat in the fuel gas, a larger addition means that the calorific heating value of the gas decreases. However, it is possible to reduce the tar content of the gas by increasing the temperature, and gasifiers operating at high temperatures, such as EF gasifiers, produce little or no tar. Reducing the tars content of the producer gas by partial oxidation depends on the nature of the existing tars. According to Elliot [5], it is possible to remove primary tars by partial oxidation. However, tertiary tars are precursors of soot, and high-temperature treatment will not eliminate them; instead, soot formation will take place. The developer of the Viking gasifier has demonstrated a good understanding of this connection by combining fairly low-temperature pyrolysis with partial oxidation of the formed pyrolysis gas.

5.2.2.2 Catalytic tar cracking.

The term catalytic tar cracking was probably originally connected to the destruction of tars over basic oxides, such as dolomite or magnesite, though nickel-based catalysts are now also referred to as tar cracking catalysts. The functions of these two types of catalysts must be fundamentally different. The nickel-based catalysts used for tar cracking are of the same type that are used for reforming of hydrocarbons in steam reforming or autothermal reforming. The basic catalysts, such as dolomite, magnesite, and olivine, are initially carbonates and must be calcinated into oxides to become active. They are also sensitive to pressure: if the pressure (actually the partial pressure of CO₂) becomes too high, carbonate is formed and, at the operation temperature, the catalyst loses its activity. This means that the catalyst must operate below the stability limit of the carbonate (e.g., Ca and Mg carbonate), which might reveal something about the catalytic mechanism, meaning that the operating temperature must be high (>700°C) and the pressure low (<10 bars). Various contaminants, such as iron (Fe), might be present in the catalyst, since it is usually of natural origin and not synthesized, and can affect the results. The catalyst can be used in the gasifier as bed material, but dolomite is brittle and easily breaks apart. However, downstream reactors are also possible, such as packed-bed or fluidized-bed reactors. The active surfaces of these catalysts are generally small, several m²/g, and they deactivate quickly. This makes the fluidized-bed concept a good choice, as the particle erosion during fluidization exposes fresh surfaces, resulting in longer-lasting catalytic material. The catalysts used are denoted tar-cracking catalysts because they convert tars into synthesis gas (i.e., CO, CO₂, and H₂) but not into the lower hydrocarbons (e.g., ethyn, ethene, ethane, and C₃) and especially not into methane (CH₄).

5.2.2.3 Catalytic steam reforming and autothermal reforming

Catalytic steam reforming is a process used for approximately 100 years to convert (fossil) hydrocarbons into synthesis gas. It uses a catalyst of metallic nickel (Ni) on a thermostable carrier, such as α -alumina or spinel. The hydrocarbon conversion is endothermic and the reaction binds heat, so the reactor temperature will drop unless heat is supplied. As the name implies, water is consumed during the reaction and is added in a steam/carbon ratio of between 2 and 3. Methane and the formed synthesis gas exist in equilibrium:



This makes it impossible to convert all hydrocarbons despite reforming temperatures of ~850 °C and steam/carbon ratios of approximately 3.

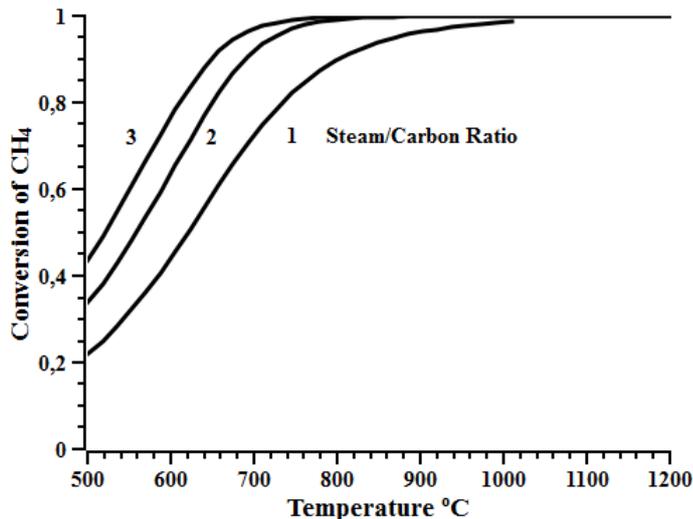


Figure 5.4. Calculated equilibrium conversion of methane reforming at various steam-to-carbon ratios at 1 bar pressure; calculated using HSC Chemistry 6.1[10].

Adding steam costs heat and increases the volumetric flow in the reactor, so the amount added must be limited. To reduce the volumetric flow rate, the process can be pressurized. However, due to the equilibrium described above, the methane conversion decreases with increased pressure.

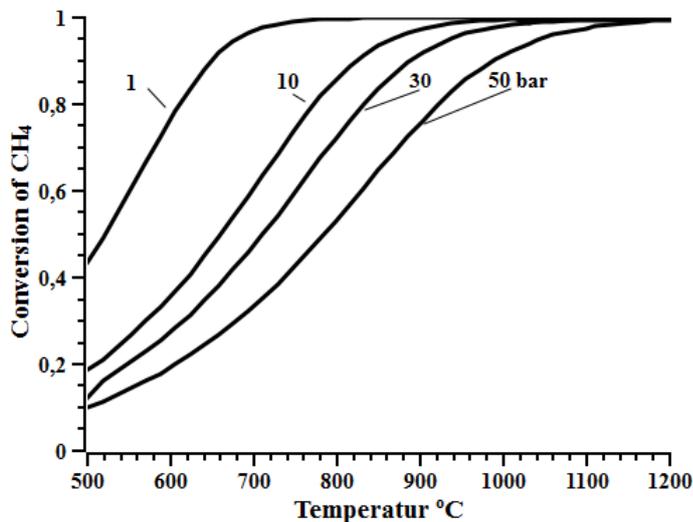


Figure 5.5. Calculated equilibrium conversion of methane at various pressures (i.e., 1, 10, 30, and 50 bars) at a steam to carbon ratio of 3; calculated using HSC Chemistry 6.1[10].

To obtain high methane conversion, a secondary reformer step can be used. In such a unit, part of the gas is combusted inside the reactor to increase the temperature to $\sim 1000^{\circ}\text{C}$, as in partial oxidation. However, a catalyst bed is used in the secondary reformer unit. The catalyst is of the same sort used in steam reforming, but with a lower nickel load. The concept of the secondary reformer unit has evolved into a standalone process, autothermal reforming (ATR), primary for natural gas conversion. Haldor Topsoe A/S in Denmark has developed this process and the special burner required (Figure 5.7) [6–8].

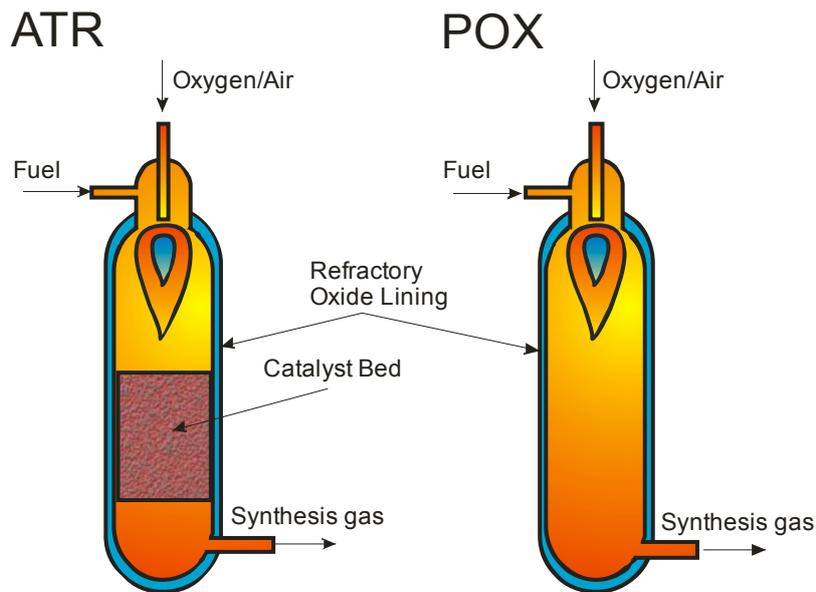


Figure 5.6. Comparison of the ATR and POX reactors.



Figure 5.7. The Topsoe CTS burner for ATR (courtesy of Haldor Topsoe A/S, DK).

The problem with catalytic reforming regarding gasified biomass is that the nickel-based catalyst is very sensitive to contaminants, especially sulphur, in the gas (Figure 5.8)

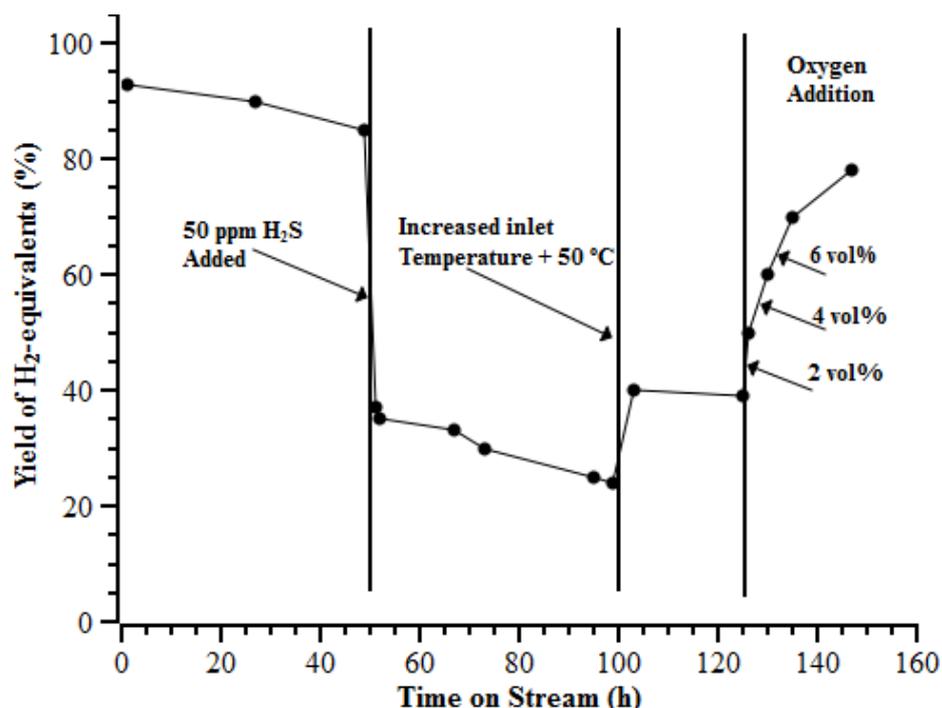


Figure 5.8. Effect of adding 50 vppm of H₂S on steam reforming of methane on a nickel-based catalyst; inlet temperature 800°C, steam/carbon ratio 3 [8].

In the figure, one can see the rapid drop in the activity when 50 vppm of H₂S is added to the gas. However, the loss in activity can be compensated for by increasing the temperature, first by increasing the oven temperature by 50°C, and then by injecting oxygen before the catalytic bed. However, a consequence of increasing the temperature is that the catalyst sinters faster, resulting in a short lifetime.

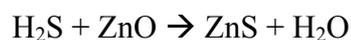
The loss of activity is predominately connected to methane, since this compound is the most difficult to convert and requires high catalytic activity; higher hydrocarbons can still be reformed. The plant at Skive, Denmark, is equipped with a monolithic catalyst developed by Haldor Topsoe A/S. This unit initially had a conversion efficiency of approximately 90% of the hydrocarbons (tars), but according to Kari Salo [9], the conversion had declined to 70% by October 2010.

5.3 Minor contaminants

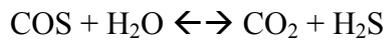
5.3.1. Sulphur

Depending on the biomass source, the gas will have a hydrogen sulphide content of 50–200 vppm. Unless an active method is used to remove this sulphur, it will remain in the gas until the gas is burned. When the gas is burned in the engine, the hydrogen sulphide will be oxidized into sulphur dioxide and leave with the flue gas.

In industrial use, the sulphur is removed by adsorption in either a dry or wet process. ZnO is often used in dry absorption, but other absorbents are also possible, for example, CuO. The hydrogen sulphide reacts with the ZnO, forming ZnS and water:

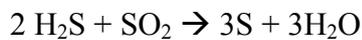


The ZnO only removes H₂S. If sulphur is present in the form of carbonyl sulphide (COS), it is necessary to hydrolyse it to H₂S over an acidic catalyst, such as γ -alumina, before it can be removed:



The ZnO is consumed during the absorption process and will finally be replaced; it is normally not regenerated on site.

An example of a wet absorption process is the Lurgi Rectisol process. It is primarily a process for CO₂ removal, but will also remove H₂S and COS, without the need for a hydrolysis step, by absorption in methanol. The absorbed CO₂ is released in a flash step and vented to the atmosphere, while the absorbed sulphur is released in a separate step, in which it can be fed into a Claus step. In the Claus process, hydrogen sulphide and sulphur dioxide react to form elemental sulphur:



This can be done by oxidizing part of the hydrogen sulphide content of the gas, giving the overall reaction:



The recovered sulphur can then be used for technical applications, for example, for sulphuric acid manufacture.

5.3.2 Ammonia

Fairly high levels of ammonia can be found in the producer gas; for example, 3000 vppm were expected in the VVBGC Värnamo plant. If the producer gas is upgraded by catalytic reforming, the ammonia is expected to be decomposed in the catalytic bed, in the process of ammonia cracking. However, if the process is based on a non-catalytic principle of tar elimination or if the catalytic activity is hampered by catalytic poisoning, for example, by sulphur, the ammonia will then not be, or maybe only partly, removed from the producer gas.

If the product gas is cooled down and the water is condensed, most of the ammonia will dissolve in the water. This will of course clean the gas, but will shift the problem into the condensate. Kari Salo [9] claims that the ammonia content of the condensate is a major problem, given emission regulation at the municipal water treatment plant at the Skive plant, despite the catalytic reforming step for the tars.

5.3.3 Alkali

Biomass is rich in potassium. Due to the usually high temperatures during gasification, potassium salts, mainly chloride and hydroxide, are volatilized. However, when the temperature decreases to approximately 600 °C, the salts precipitate and form dust and aerosols particles that can be removed by filters.

5.4 References to chapter 5

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6 Combustion engine

6.1 Gas engines: an introduction

Gas engines are increasingly part of modern society, mainly due to their benefits in terms of emissions. A short introduction to the use of modern gas engines is presented here.

Most current gas engines have been developed for natural gas operation, but are often used with methane-rich biogas or propane as well. For producer gas operation, natural gas engines are often employed. But since such operation is quite unusual, very few of the engine manufacturers warrant such use.

According to the International Association of Natural Gas Vehicles [1], as of October 2010 more than 12 million gas engine vehicles were in use. These are mostly private cars or city buses, but gas engines are also used in, for example, locomotives, ships, and stationary energy production facilities such as gensets and combined heat and power plants (CHP). Most of these operate on natural gas, but biogas, coal gas, hydrogen, and producer gas is also used. In Europe, gas engine cars and buses are relatively common, and in mobile applications the gas is typically compressed or liquefied. The gas used can be, for example, compressed natural gas (CNG), compressed biogas (CBG), liquefied natural gas (LNG), liquefied petroleum gas (LPG or propane), and liquefied biogas (LBG).

Private cars are often using converted gasoline engines of approximately 2 litres displacement that can run on either gasoline or a gaseous fuel – hence the “bi-fuel” or “flexi-fuel” designation (Figure 6.1). According to the Swedish Environmental Protection Agency, operating on biogas reduces CO₂ emissions by 70–85% compared with running on gasoline [2].



Figure 6.1. The Volvo V70 AFV BI-FUEL is a typical gas fuelled car (courtesy of AFV) [3].

For the vehicle owner, there is almost no difference in performance when the vehicle is operating on gas, for example, one can shift between gas and gasoline operation “on the run”. These engines typically employ regular spark ignition (SI) and stoichiometric operation so that a three-way catalytic converter can be used to reduce the engine-out emissions. The efficiency of these engines is usually similar to that of regular gasoline engines, seldom exceeding 35%. Gas operation is, however, slightly cheaper than running on gasoline or diesel due to lower taxation.

It is popular to use natural gas or biogas in city buses. Hydrogen has been tested as well, but only in small scale. The engines used are usually converted diesel truck engines of approximately 10 litres displacement (Figure 6.2). The conversion consists of removing the in-cylinder fuel injector, replacing that with a spark plug, and adding gas injectors at the intake port. One or several throttles need to be installed as well. The combustion principle is thus of the SI type and can be either lean-burn or stoichiometric. The latter is required if a three-way catalytic converter is to be used. Supercharging is often employed to increase the power density and efficiency. Power may reach 250 kW and brake efficiency 40%.



Figure 6.2. Biogas-fuelled city bus. The gas tanks are placed on the roof (courtesy of Volvo).

According to COGEN Europe, 11% of all electricity in Europe is produced through cogeneration CHP [4]. These CHP plants employ various technologies (Table 6.1), but a respectable part of the production uses gas-fuelled internal combustion engines. As reported in Table 6.1, internal combustion engines are a competitive option in terms of efficiency and capital costs, though maintenance costs are slightly higher [5].

Table 6.1. Cogeneration technology characteristics [5].

Technology	Fuel	Size (MWe)	Electrical efficiency (%)	Overall efficiency (%)	Average capital cost (\$/kWe)	Average maintenance (\$/kWe)
Steam Turbine	Any	0.5-500	7-20	60-80	900-1800	0.0027
Gas Turbine	Gaseous and liquid fuels	0.25-50+	25-42	65-87	400-850	0.004-0.009
Combined Cycle	Gaseous and liquid fuels	3-300+	35-55	73-90	400-850	0.004-0.009
Diesel and Otto engines	Gaseous and liquid fuels	0.003-20	25-45	65-92	300-1450	0.007-0.014
Micro turbines	Gaseous and liquid fuels		15-30	60-85	600-850	<0.006-0.01
Fuel cells	Gaseous and liquid fuels	0.003-3+	App. 37-50	App. 85-90	?	?
Stirling engines	Gaseous and liquid fuels	0.003-1.5	App. 40	65-85	?	?

Increasingly, gas engines are also used in micro CHP. One example is the Vaillant (Honda) Ecomax 1.0 [6]. Honda has substantial experience using combustion engines in micro CHP to meet the heat and power demands of single homes. The system has been used in Japan and the USA (100,000 units) since 2003 and has now been launched worldwide. It has a rating of 1 kW electric and 2.5 kW thermal power; the electrical efficiency is 26.3% and total efficiency 92%. The engine is a four-stroke SI engine of 163 cc displacement.



Figure 6.3. The Vaillant ecomax 1.0 Micro-CHP (courtesy of Honda) [7].

At the other end of the size range we find the Wärtsilä 18V50GS engine that, according to Wärtsilä, is the world's largest gas engine genset [7]. The engine is intended to be installed in genset parks of ten or more engines. Natural gas is the main intended fuel, but associated gas, biogas, and coal bed gas are also possible. The rated power is 18 MW and electrical efficiency is 48.6%. The engine is a lean-burn spark-ignited engine with a pre-chamber. For installation where the gas supply is unstable, dual-fuel engines that can operate on liquid fuel as well are offered (Figure 6.4).



Figure 6.4. The Humboldt power plant in California consists of ten Wärtsilä dual-fuel gas engines with a total output of 162 MW. To meet the strict Californian emission requirements, SCRs are employed (courtesy of Wärtsilä) [7].

In shipping, it is especially beneficial to use gas engines on LPG carriers that can run on the boil-off gas (BOG). One such example is the MAN two-stroke dual-fuel engine, which is offered in sizes up to 26 MW [8]. Not only is the fuel essentially free in this situation, but emissions of CO₂, NO_x, and particulate matter are generally reduced by 5–10% and of SO_x, by more than 90% compared with those from operation on heavy fuel oil (HFO). The engine can operate on HFO only or on LPG with a minimum of 5–8% pilot oil. The LPG is injected using an unusual high-pressure gas direct injection system. Brake efficiency is not revealed, but should be slightly over 50% (Figure 6.5).

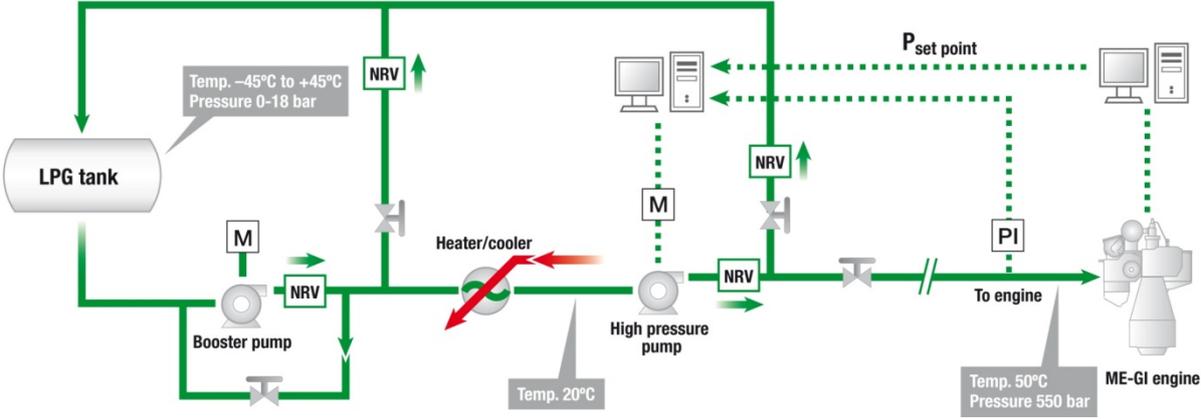


Figure 6.5. LPG treatment in MAN engines used in LPG carriers (courtesy of MAN) [8].

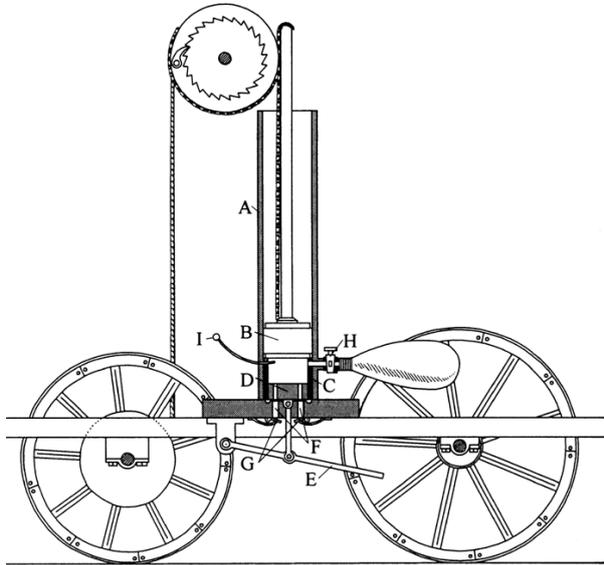
Finally, gas engines are not exclusively used for energy production. One lesser-known application is in the greenhouse industry where, in addition to heat and electricity, they produce CO₂ for the enhanced production of vegetables and flowers, for instance roses.

6.2 History of gas engines

The early history of internal combustion engines is actually that of gas engines [9]. With the emergence of coal gas (or town gas) for lighting, around the end of the eighteenth century, ideas for internal combustion engines started to materialize. Steam engines were already widespread but depended on external combustion of mostly solid fuels, which meant hard and laborious work to fuel the engine due to the low engine efficiency. The idea of using the already distributed town gas directly to propel an engine seemed practical and attractive. Liquid fuels such as gasoline and diesel oil, the most commonly used fuels in internal combustion engines today, did not exist and were almost a century away in practical terms. Gasoline and diesel were eventually developed for use in combustion engines but depended on the discovery of the huge oil deposits we still exploit.

One of the first to actually build a working internal combustion engine was the Swiss engineer Isaac de Rivaz. Not only did he build the engine, he patented it 1807 and also installed it in a vehicle he had previously designed but run with a steam engine. The engine worked without compression and did not have a regular crank mechanism. The piston, attached to a cog beam, was raised by the electrically ignited combustion pressure. After reaching the top position, the cog beam drove the vehicle via an attached cog wheel. The cooling of the cylinder created a partial vacuum that, together with the piston weight pressure, pulled down the cog beam thus

propelling the vehicle forward. The engine did not have a flywheel, which meant that the vehicle came to a halt between each combustion event during up-hill operation. The fuel was coal gas supplied from a 0.4 m³ leather bag. As Rivaz foresaw a need for a mobile fuel network, he proposed placing coal gas generators every three kilometres to serve as fuelling stations.



*Figure 6.6. The Rivaz vehicle from 1805. To the right of H is the leather bag holding the coal gas. The bag had a volume of 0.4 m³, sufficient for three km of travel. One pound of coal was required to refill the bag (From *Internal Fire* by Lyle Cummins with permission) [9].*

For energy production for industry, Samuel Brown, the “father of the gas engine”, devised several novel solutions. He patented, built, and demonstrated a 1.5 hp pumping engine that could raise 300 gallons of water 15 feet for each cubic foot of coal gas consumed. Brown continued to develop his engine designs for boats and carriages as well. A company set up in 1825 to build “gas vacuum engines” was in the end unsuccessful, although several of Brown’s engines were reported to be in use years later. The principle of Brown’s gas engines was similar to that of Rivaz. Work was extracted through the partial vacuum created by cooling after combustion and expansion. In Brown’s designs, the cooling was improved with water. At about the same time, in 1824, Samuel Morey in the United States patented an engine using a combustion principle similar to that of Brown’s engine. Morey realized that it could be problematic to carry large quantities of gas in mobile applications, and developed a device to produce the combustible gas as the engine consumed it. This device was the first practical carburettor, and paved the way for the use of liquid fuels in the combustion engine. Morey put his engine in a boat, fed it with turpentine, and successfully travelled at speeds up to eight miles per hour. Although this was the first internal combustion engine in America and contained other novelties, such as poppet valves, a base-mounted crankshaft, and back-fire gauze, Morey could never find a buyer for it. Morey himself was ingenious in several fields and was involved in discovering a new process for producing town gas. Although several important improvements and new designs had been presented, internal combustion engines were still far from common. Not until 1859, when Etienne Lenoir

presented a design using opposing pistons, did the internal combustion engine begin to sell in larger numbers. The Lenoir engines were built under license and approximately 500 were sold. The engines saw use in several applications in factories, print shops, and hotels (to power elevators) as long as there was a supply of illumination gas. The Lenoir engine was still non-compressing, but used double-acting pistons in steam engine style that, with internal combustion, proved difficult to cool.

Within a few years, the Lenoir engine was outcompeted by the Otto-Langen engine, 2649 examples of which came to be built by the newly formed Gasmotoren-Fabrik Deutz AG and almost as many by other companies. The Otto-Langen engine was still an atmospheric engine with limited power, but had slightly higher efficiency than a high-pressure steam engine (Deutz AG still exists, and one of the investigated gasifiers uses a Deutz-MWM engine). The real breakthrough, however, came just a few years later with the Otto four-stroke engine. By having fewer combustion events, the engine could suddenly produce both much higher efficiency and much more power. In one innovative leap, the power-to-weight ratio improved four-fold and the efficiency 50%. The Otto engine was patented and thus protected, so for others to be able to compete on the market, several other new and important engine designs saw the light. These were the Brayton engine (USA), which was effectively the ancestor of the gas turbine, the two-stroke engine, and the hot-bulb engine. Town gas was still the most important fuel, but petroleum products had by now emerged and were increasingly being used as engine fuels. By the end of the nineteenth century, gasoline and oil were important fuels.

224 American Gas Light Journal. Oct. 16, 1885.

THE "OTTO" GAS ENGINE.

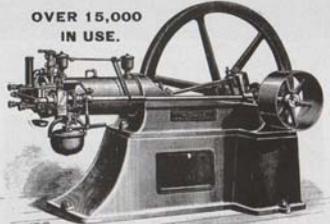
Guaranteed to Consume 25 to 75 ANY OTHER GAS ENGINE
Per Cent. LESS GAS than PER BRAKE HORSE POWER.

TWIN ENGINES Impulse every revolution.
THE STEADIEST RUNNING GAS ENGINE YET MADE

ENCINES AND PUMPS COMBINED,
For Hydraulic Elevators, Town Water Supply, or Railway Service.

Special Engines for Electric Light Work.

OVER 15,000
IN USE.



The Otto Gas Engine is now consuming, at a moderate computation, 2000 millions cubic feet of gas per year, nearly all of which is furnished during day time only.

THE ONLY HIGHEST AWARD, ONLY GOLD MEDAL.
AT ELECTRICAL EXHIBITION, PARIS, 1881.

MADE IN SIZES FROM 1 TO 25 HP. INDICATED.

FOR PARTICULARS, PRICES, ETC., APPLY TO

SCHLEICHER, SCHUMM & CO.,

Works: Branch Office:
N. E. Cor. 32d & Walnut Sts., Phila., Pa. 214 Randolph Street, Chicago, Ill.

Figure 6.7. Advertisement for the "Otto" gas engine, 1885 [9]. Note the proposed use for electricity production. With the typical use of CO-rich gas at the time, the fundamental engine-generator for a small-scale gasifier-gas engine system suitable for producer gas was already available (From *Internal Fire* by Lyle Cummins with permission).

In the decades following 1880, the ever-increasing numbers of larger and larger gas engines posed new challenges for the cheap and efficient production of gaseous fuels. The Dowson gas producer, in sizes small enough to efficiently supply even single engines and fuelled with coke, became the most used gasifier in the late 1800s. Joseph Emerson Dawson also incorporated gas coolers and purification equipment to make engine operation more sustainable. In addition, in this period generator sets started to appear for the production of electricity from gas engines. By the end of the nineteenth century, the fundamental technology for small-scale CHP production using gasification and gas engines was in place. The diesel engine, invented by Rudolf Diesel 1893, had little to do with gaseous fuels and was originally designed to be used with the direct injection of a liquid fuel, initially gasoline. The diesel engine, however, has become important for the development of modern and highly efficient gas engines for both mobile and stationary applications. During the Second World War, there was renewed interest in gasifier engines due to the extreme shortage of gasoline and diesel fuel [10]. It became common to equip vehicles with a wood gasifier and to run the engine on the produced wood gas [11]. At least one million vehicle gasifiers were built. Operation was fairly cumbersome, though, requiring continuous attention and maintenance, and with the end of the war and the building of new infrastructure for the distribution and use of fossil fuels, wood gasification was largely abandoned.



Figure 6.8. Private car wood gasifier. To operate the system, the driver periodically had to feed the gasifier with wood pieces. This particular car belonged to the Swedish King (Copyright Scanpix Sweden).

More recently, environmental concerns have meant renewed interest in producer gas and in producer gas-driven engines. Throughout the 1900s, the gas engine as such evolved through successive refinement, although the fundamental engine concepts remained fundamentally the same. Resources of natural gas, and more recently of biogas from fermentation, have provided the basis for the modern and efficient gas engine for mobile and stationary use. Combined with the advent of the modern computer, the ability to operate and control gas engines for high efficiency and low emissions has improved substantially.

6.3 Fundamental definitions

This section describes the key parameters and operating principles of internal combustion engines in general and gas engines in particular. The basic engine operating principles are very briefly described while the combustion principles are described in greater detail, due to their importance in gas engine systems. Further details can be found, for example, in Stone [12].

6.3.1 Basic engine operating principles

Internal combustion engines are based on a piston and cylinder system that can exchange the working fluids, contain the combustion, and convert the in-cylinder pressure into rotational work. Combustion engines work according to either the two- or four-stroke principle. Either case involves five fundamental processes: filling the cylinder with fuel and air, compression, combustion, expansion, and emptying the cylinder of combustion gases.

6.3.1.1 The two-stroke engine

In the two-stroke engine, the above five processes occur more or less simultaneously. Early in the compression stroke, part of the cylinder filling and emptying is ongoing. The actual compression starts once the piston passes and closes the intake and exhaust ports in the cylinder walls. Close to the top dead centre, the combustion occurs. The expansion takes place once the piston starts to move down, and when the ports are open, the gas exchange process starts over. The combustion is not infinitely fast and occurs partly during the expansion. Two-stroke engines depend on supercharging to realize the gas exchange. In smaller two-stroke engines, as in mopeds, the crankcase is exploited as a supercharger, while in larger two-stroke engines (e.g., stationary and ship engines), an external supercharger is used.

6.3.1.2 The four-stroke engine

In four-stroke engines, the five processes, i.e., filling, compression, combustion, expansion, and emptying, are more easily controlled and the need for supercharging is made redundant. The first stroke is used for cylinder filling, the second for compression, the third for expansion, and the fourth for emptying. Combustion occurs, just as in two-stroke engines, at the end of the compression and the beginning of the expansion process (Figure 6.1).

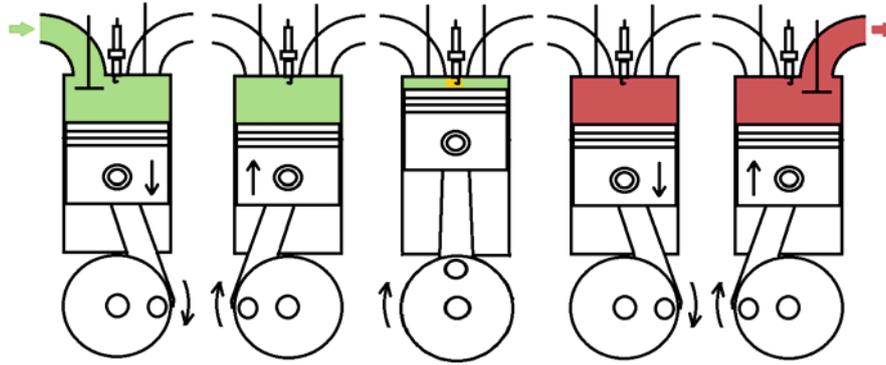


Figure 6.9. Four-stroke engine. Left to right: induction stroke (1), compression stroke (2), combustion and expansion stroke (3), and exhaust stroke (4).

6.3.1.3 Supercharging

To increase the load of an engine, supercharging may be employed. Through supercharging, the in-cylinder mass of air and fuel can be increased and thus more work produced from each cycle. Supercharging can be achieved using a mechanically driven compressor, but it is more efficient to use a turbocharger that exploits the otherwise-wasted exhaust energy. For low-calorific fuels, such as producer gas, supercharging is very useful for increasing the power output and thus the mechanical and total efficiency of the engine.

6.3.1.4 Engine performance targets

Engines used in mobile applications, for example, cars, trucks, ships, and airplanes, are designed to produce as much work as practically possible from a given amount of fuel. The target is thus maximum brake efficiency and the losses are divided between combustion losses, heat losses to exhaust gas and as heat transfer, pumping losses, and friction losses. In CHP production, the targets differ slightly, since the desired product is not only work but also heat. Thus what is regarded as a loss in a mobile application is an asset in a CHP system. However, high brake efficiency is also a priority for CHP applications since there is not always a demand for heat when producing electricity.

6.3.1.5 Engine efficiency

The energy flow through an internal combustion engine can roughly be divided into four parts according to the losses and efficiencies (Figure 6.10).

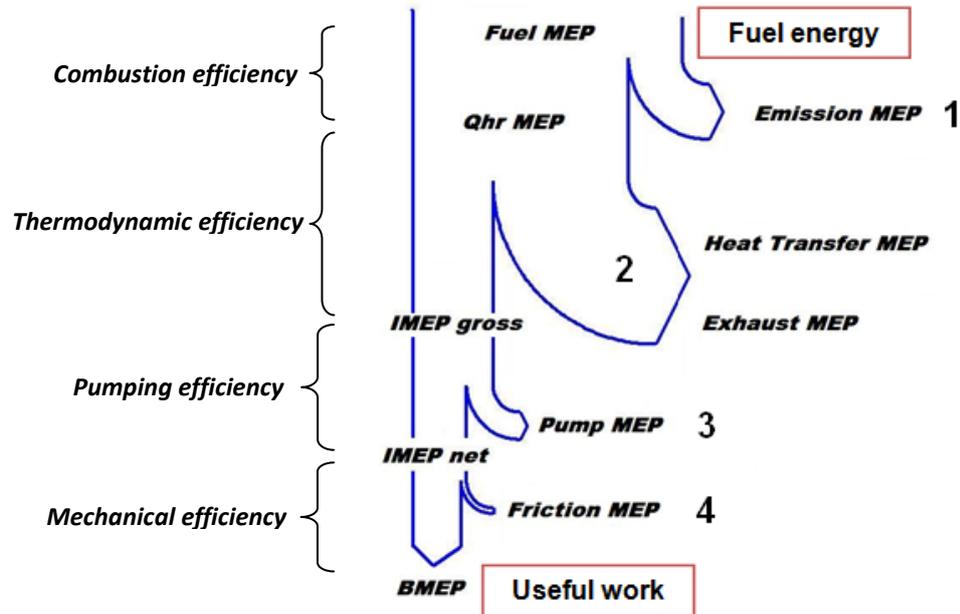


Figure 6.10. Sankey sheet representing the energy flow through an internal combustion engine. Mean effective pressure (MEP), in bars, provides a convenient means to compare engines of various sizes.

1. *Combustion efficiency*: Chemically bound fuel energy is converted through combustion into heat. If the combustion is incomplete, the exhaust will contain products that still have energy content. Combustion efficiency is usually higher than 99% in a diesel (CI) engine, while a spark ignition (SI) engine can have combustion efficiency as low as 90–95%.

2. *Thermodynamic efficiency*: Heat is converted through a thermodynamic cycle into mechanical work. The theoretical maximum thermodynamic efficiency is approximately 85%, but in reality it is approximately 35–40% for stoichiometric SI and 50% for CI. The main difficulty in converting heat to work is that of limiting the associated heat loss to the expelled exhaust gases and the heat transfer through the cylinder walls. In stationary CHP applications, these losses can be used for district heating, while in some gasification/engine systems, the wasted heat can be used in the gasification process. In either case, the system efficiency is increased by using the waste heat.

3. *Gas exchange efficiency*: The burned gas needs to be replaced with fresh air (in an SI engine, with air/fuel mixture). The gas exchange efficiency indicates whether this can be done with low losses or whether high pumping work is needed. Under high loads, the pumping work is limited, but the loss can be significant in SI engines operating under lower loads due to throttling. Gas exchange efficiency is often in the order of 85–95%.

4. *Mechanical efficiency*: Internal friction of the engine parts consumes some of the power, as do all the auxiliaries, such as the water pump, oil pump, and generator. The mechanical efficiency relates these losses to the power produced. At full load operation, mechanical efficiency may reach 95%, but at lower loads it drops to 0% at idle (no practical work produced).

Brake (total) efficiency is the product of the four efficiencies listed above, the weakest of which is clearly thermodynamic efficiency. The main losses in the thermodynamic cycle occur during the conversion of heat into work, when heat is lost to the combustion chamber walls and into the atmosphere with the expelled exhaust gases.

There are a number of other measures of efficiencies that are relevant to understand in the presented work. In engine-related work, *gross indicated efficiency* and *net indicated efficiency* are commonly used. These efficiencies have historical significance, since they could be calculated from the indicator diagrams traditionally produced from simultaneous pressure and volume measurements. Gross indicated efficiency is the product of combustion efficiency and thermodynamic efficiency, while net indicated efficiency is defined as the product of gross indicated efficiency and gas exchange efficiency. In gasifier–gas engine CHP systems, another set of efficiencies is relevant as well. *Engine electrical efficiency* is the product of engine brake efficiency (sometimes referred to as shaft efficiency) and generator efficiency. The *total electrical efficiency* of a gasifier CHP system is the total efficiency of the system from the solid fuel to the electrical output. This is typically defined as the product of the cold gas efficiency of the gasifier and the engine electrical efficiency.

For engines in the relevant size for small-scale gasification (<3 MW), standard truck diesel engines of today have brake efficiencies in the order of 42%. Before year 2000, the engine brake efficiency was actually higher, but the introduction of EURO III emissions after-treatment systems entailed a reduction in engine efficiency. State-of-the-art truck engine-sized diesel engines operating in homogenous charge compression ignition (HCCI) mode were able to reach thermal efficiencies in the order of 54%, according to experiments performed at Lund University [13]. The downside of the HCCI engine is the difficulty associated with controlling it and the fairly limited operating load range that limits brake efficiency (in this case, to approximately 45%). Another engine combustion concept, partially premixed combustion (PPC), has been steadily improved at the Competence Centre for Combustion Processes (KCFP) at Lund University [14]. Recent results have demonstrated brake efficiencies of 50% combined with excellent controllability, high-load operation, and ultra-low emissions. Otherwise, few truck engines in the world display the efficiencies achieved in Lund. The University of Wisconsin–Madison has presented the concept of a truck engine with 59% gross indicated thermal efficiency that uses two liquid fuels separately injected in particular proportions to control the rate of combustion and thus the efficiency [15]. There are no data on the brake efficiency of this engine, but it should be close to or slightly above 50%. The most efficient production engines are the big two-stroke ship engines (see introduction). These engines can operate at brake efficiencies of 50–55%, although it should be noted that some of the heat losses are used in the ship systems. If waste heat recovery through a Rankine cycle and turbo compounding is added, the efficiency of these engine systems can reach 55–60%. One extremely specialized research marine engine reportedly achieved 68.6% thermal efficiency in year 2000 [16]. This engine basically used all known technologies for managing heat and effectively using it to produce work. Ceramic coatings were applied to create an essentially adiabatic engine, while the remaining heat in the exhaust was captured by turbocharging, turbo compounding, and fuel reforming.

For dedicated genset gas engines operating on natural gas, engine electrical efficiencies are typically reported to be in the order of 43–45% for engine sizes above 1 MW electric. Both lean-burn Otto engines and dual-fuel engines are similar in efficiency. For smaller truck engines used in stationary applications (<0.5 MW), the electrical efficiencies are typically 3–5 percentage points lower.

6.3.2 Combustion principles

The combustion principle used exerts the most profound influence on the performance of an internal combustion engine and its applicability to various fuels. To realize a certain combustion principle, other parts of the engine system must usually be adapted as well. The most common systems for gas engines are described, while a novel one, the HCCI, is discussed.

6.3.2.1 SI – The Otto engine

As mentioned in the history chapter, the Otto or spark ignition (SI) engine started life as a gas engine, but once gasoline was produced and distributed in quantity, it became commonly used and known as the gasoline engine. Today, the most common engine is still the gasoline engine. Nevertheless, the SI engine is an excellent gas engine and in vehicle applications the most common type of gas engine.

The SI engine works according to the following fundamental principles. Fuel and air are mixed before entering the cylinder. The compressed in-cylinder charge is ignited at a controlled time by an electrical spark. After a short delay, the homogeneous charge of fuel and air burns from the spark plug out to the cylinder walls through flame propagation. Engine load is controlled by a throttle in the induction channel, thus controlling the total amount of fuel and air that enters the cylinder. There are two main drawbacks to the SI engine. The first is the throttle that limits part load efficiency by increasing the pumping losses. The second is that, with a premixed charge, the compression ratio has to be limited (which means lower efficiency) and a high-octane fuel must be employed to avoid pre-ignition and knock. The SI engine has several advantages. It is easy to control. It can be run very cleanly by using stoichiometric operation and a three-way catalytic converter aftertreatment system. It lends itself very well to gas operation, with either lean-burn or stoichiometric operation, since natural gas and producer gas generally have very high octane ratings and, besides, are easily provided to the engine through cheap low-pressure central injection systems.

6.3.2.2 CI – The diesel engine

In the diesel or compression ignition (CI) engine, only air is drawn through the induction system into the engine. The air is compressed, and shortly before the top dead centre (TDC) is reached, the fuel is injected directly into the cylinder and ignited by the high temperature and pressure of the compressed air. The CI has several advantages over the SI engine. The load is controlled by the amount of fuel injected rather than by using a throttle that increases the pumping losses. The combustion efficiency is usually very high, since little fuel will reach and quench against the cylinder wall and crevice volumes, becoming unburned hydrocarbon

and carbon monoxide emissions. Furthermore, the compression ratio can be comparatively high, since there is no risk of pre-ignition or knock.

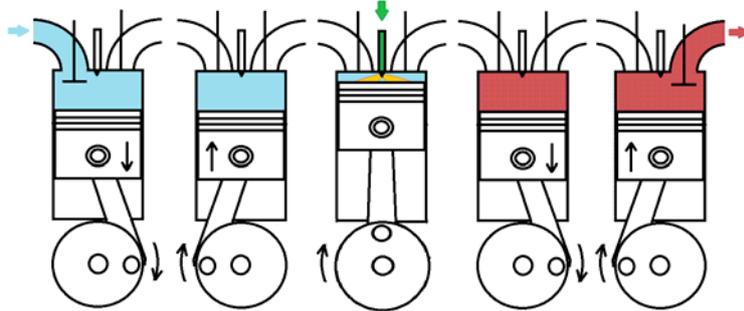


Figure 6.11. CI engine. Left to right: Air (blue) induced during the induction stroke is compressed; fuel (green) is injected directly into the cylinder and ignited by the hot and pressurized air; the exhaust gases (red) expand and are finally expelled.

One major disadvantage of the CI engine is its comparatively complex and expensive high-pressure fuel injection system. Another important problem is the great amount of NO_x and soot produced by CI combustion. This is explained by the local fuel-rich zones and high local combustion temperatures that give rise to soot and NO_x , respectively. Fuel properties are also important for the likelihood of soot production. Unfortunately, exhaust aftertreatment is not as elegantly handled in the CI engine as in the SI engine, and it might require several separate catalytic converters and particulate filters for the CI engine to comply with the more stringent emissions regulations. Nevertheless, the CI engine is, thanks to its very high efficiency, the most common type of engine for commercial vehicles and marine applications. For stationary gas engine applications in which higher power outputs are required, CI engine gensets converted to SI-operation are quite often used.

6.3.2.3 CI - Dual fuel engines

For larger stationary engines, lean-burn dual-fuel is often the combustion principle of choice for installations where gas delivery can be uneven. Total efficiency is usually very high and can be even higher than in a comparably sized CI engine due to fast combustion leading to high thermodynamic efficiency. Due to combustion close to the combustion chamber walls, the combustion efficiency is usually a bit lower, though. Gas and air are mixed and provided to the engine as in the SI engine, but instead of a spark igniting the mixture, a high-cetane (i.e., easily ignited) fuel is direct-injected and ignited by the high pressure and temperature from the compression, which in turn ignites the main gas and air charge. The ensuing combustion occurs mainly through flame propagation.

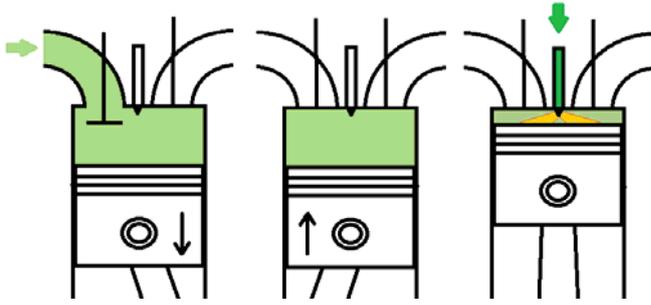


Figure 6.12. Dual-fuel engine. Left to right: Premixed gas and air (green) are induced during the induction stroke; the charge is compressed, an easily ignitable liquid fuel (dark green) is injected directly into the cylinder and ignited by the hot and pressurized gas and air mixture, which in turn is ignited. The exhaust gases expand and are finally expelled, as in Figure 6.11.

Dual-fuel engines depend on a direct injection system for the liquid ignition fuel. Load is regulated by controlling the amount of gas in the inlet and the liquid fuel in the injection system. The benefits of dual-fuel engines are that they can run on liquid fuel alone, if gas is unavailable, and that varying gas quality can be compensated for by liquid fuel injection. This is a particularly interesting property for operation on gasifier gas, which can be susceptible to variations in energy content and gas composition. Another advantage of lean-burn dual-fuel operation is the lower NO_x emissions compared with regular CI operation. The diluted mixture leads to lower combustion temperature and thus lower NO_x production: the smaller the amount of liquid fuel, the greater the advantage in terms of NO_x reduction. Extremely small amounts of liquid fuel injection, representing 1–2% of total energy, are sometimes referred to as micro-injection.

A development of the dual-fuel engine is to directly inject the gas in a similar fashion as the ignition fuel. See the LPG engine in section 6.1 and comments on research engines, section 6.5.

6.3.2.4 SI – Lean-burn pre-chamber engines

Lean-burn pre-chamber SI engines are possibly the most common type of engine for larger stationary applications (>1 MW) in which the gas supply is stable. These engines do not require any additional fuel for ignition and have very high efficiencies. During induction, gas is also fed separately to a small pre-chamber where the gas mixture is richer than in the cylinder (Figure 6.13). At the end of the compression, the rich mixture in the pre-chamber is ignited by a spark and the flames from the nozzles of the pre-chamber in turn ignite the lean mixture in the cylinder. The lean gas charge is consumed by a flame front combustion. The reason for using a pre-chamber is that it can be difficult to ignite lean mixtures with a spark alone. Such difficulties can lead to slow combustion, misfiring, and thus high emissions and low efficiency. The advantages and disadvantages of lean-burn pre-chamber SI engines are basically the same as those of lean-burn dual-fuel engines, except for the single-fuel requirement. Emissions can be very low and efficiencies very high if the pre-chamber is carefully designed.

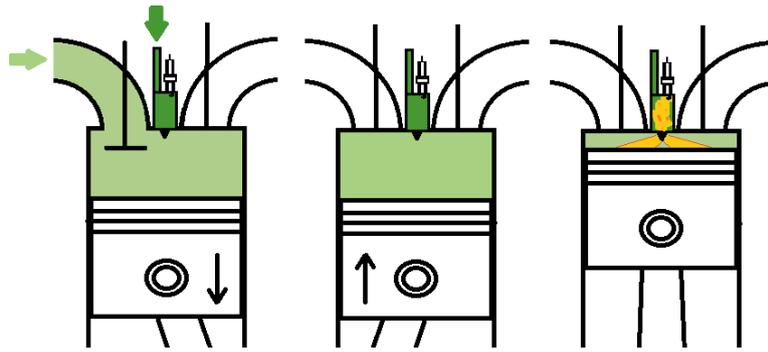


Figure 6.13. SI pre-chamber lean-burn engine. Left to right: Premixed gas and air (green) are induced during the induction stroke, into both the main combustion chamber (lean = light green) and the pre-chamber (rich = dark green). The charge is compressed, and the fuel-rich mixture in the pre-chamber is ignited by a spark plug. The leaner gas and air mixture in the main combustion chamber is in turn ignited by the propagating hot gases from the pre-chamber. The exhaust gases expand and are finally expelled, as in Figure 6.11.

6.3.2.5 HCCI

The homogenous charge compression ignition (HCCI) engine is a comparatively new concept that has yet to find commercial success. The working principle is similar to that of the SI engine, in that the fuel and air are mixed before being induced into the cylinder. The HCCI engine does not use any specific device to ignite the in-cylinder charge. Combustion starts simultaneously throughout the cylinder through auto-ignition by compressing the charge to sufficiently high pressures and temperatures (Figure 6.14). The HCCI has some interesting properties well suited for producer gas operation. In regular operation, the HCCI engine needs dilution of the intake charge to limit the pressure rise rate during combustion. This leads to a low combustion temperature that is beneficial for efficiency and for low NO_x emissions. Producer gas often has a very low calorific value, which suits HCCI operation very well.

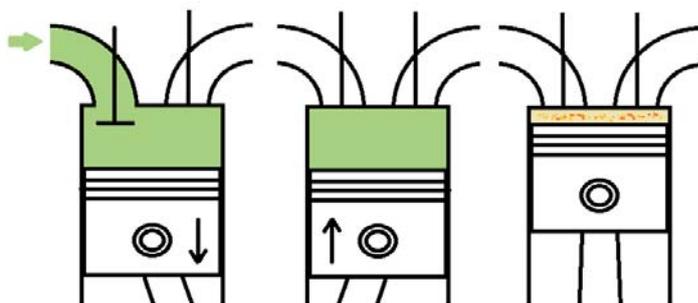


Figure 6.14. HCCI engine. Left to right: Premixed gas and air (green) are induced during the induction stroke; the charge is compressed and then ignited by the simultaneous high temperature and pressure throughout the cylinder. The exhaust gases expand and are finally expelled, as in Figure 6.11.

6.3.3 Engine out emissions and aftertreatment

Unfortunately, most engine operation is associated with negative aspects, such as emissions. Typical engine-out emissions that have been regulated due to negative health effects are: carbon monoxide (CO), hydrocarbons (HC), nitrous oxides (NO_x), and particulate matter

(PM), which is usually soot. In addition, carbon dioxide (CO₂) is increasingly being considered and regulated due to its impact on global warming. The engine-out emissions are very dependent on the fuel used, and while natural gas (and biogas), gasoline, and diesel are hydrocarbon fuels, producer gas is usually mainly based on CO and hydrogen (H₂) and may contain very low levels of HC. Since CO is lethal, colourless, and odourless, this entails direct safety concerns regarding both CO fuel leaks and CO engine-out emissions during producer gas operation.

In addition to CO₂, the gases CO, CH₄, and N₂O all act as greenhouse gases (GHG) as well [17]. CH₄ is a strong GHG with a global warming potential of 100 years (GWP-100), that is, 23 times higher than that of CO₂. Obviously, from a GHG perspective, it is much better to burn CH₄ than to allow it into the atmosphere. Much more potent is the N₂O that is also formed during combustion in engines, although in much lower quantities than NO_x. The GWP-100 of N₂O is 298. CO does not directly act as a GHG; instead, CO indirectly acts as one by reacting with OH, which would otherwise react with and reduce the levels of methane and tropospheric ozone.

An obvious advantage of producer gas as an engine fuel is the very low levels of CO₂ and CH₄ emitted. Actually, CO₂ is emitted, but with the short carbon cycle of biomass-based operation, these CO₂ emissions are regarded as contributing much less in GHG terms than do fossil fuels. Compared with natural gas, the amounts of CH₄ in both fuel and emissions are usually very low in producer gas.

6.3.3.1 Emission standards

Sweden has no national regulations applicable to small-scale gasification gas engines, but instead adheres to those of the European Union. For the European Union, the Stage I-IV emission standards for nonroad engines apply (Tables 6.2–6.4) [18]

Table 6.2. Summary of EU Stage IIIA emission standards [18].

Net Power	Date*	CO	NO _x +HC	PM
<i>kW</i>		<i>g/kWh</i>		
130-560	2006 (2011)	3.5	4.0	0.2
75-130	2007 (2011)	5.0	4.0	0.3
37-75	2008 (2011)	5.0	4.7	0.4
19-37	2007 (2012)	5.0	7.5	0.6

*Later dates are for constant speed engines

Table 6.3. Summary of EU Stage IIIB emission standards [18].

Net Power	Date	CO	HC	NO _x	PM
<i>kW</i>		<i>g/kWh</i>			
130-560	2011	3.5	0.19	2.0	0.025
56-130	2012	5.0	0.19	3.3	0.025
37-55	2013	5.0	0.47 NO _x +HC		0.025

Table 6.4. Summary of EU Stage IV emission standards [18].

Net Power	Date	CO	HC	NO _x	PM
<i>kW</i>		<i>g/kWh</i>			
130-560	2014	3.5	0.19	0.4	0.025
56-130	2014.10	5.0	0.19	0.4	0.025

In Europe, national rules may be applied, such as the German TA Luft (2002) (see Table 6.5).

Table 6.5. Summary of German TA Luft emission standards [18].

Type (>3 MW / <3 MW)	CO	HC	NO _x	PM
	<i>g/Nm³@5%O₂</i>			
CI, liquid fueled	0.3		0.5 / 1.0	0.02
CI, fossil gas fueled	0.3		0.5	No limit
CI, biogas	0.65 / 2.0		0.5 / 1.0	No limit
SI, fossil gas	0.3*		0.5	No limit
SI, biogas	0.65 / 1.0		0.5	No limit
Other 4-stroke Otto (SI)	0.3		0.25	-
2-stroke engines	0.3		0.8	-

* 0.65 for mine gas

In the USA, the emission limits are regulated in the EPA's New Source Performance Standards (NSPS) 40 CFR, Parts 60,85 et al., in force from July 2006. These rules are generally modelled after the EPA's emission standards for nonroad/marine engines, Tiers 1–4. This can be slightly confusing, since in the text of EPA Tiers 1–4, stationary engines are not considered nonroad engines.

The following tables summarize the most relevant Tier 3 and 4 regulations for engines with single cylinder displacements of less than 10 L. Those of larger volumes adhere to the rules for marine engines. For existing stationary engines before 2006 (>500 hp, 2002), the EPA-NESHAP standards may under certain conditions apply. The observant reader will notice the similarity between the “tiers” of the EPA rules and the “stages” of the EU rules. A useful harmonization of the rules has been realized.

Table 6.6. Summary of EPA-NSPS Tier 3 emission standards [18].

Net Power	Date	CO	NO _x +HC	PM
<i>kW</i>				
>560 (Tier 2)	2006	3.5	6.4	0.2
130-560	2006	3.5	4.0	0.2
75-130	2007	5.0	4.0	0.3
37-75	2008	5.0	4.7	0.4

Table 6.7. Summary of EPA-NSPS Tier 4 emission standards [18].

Net Power	Date	CO	HC	NO _x	PM
<i>kW</i>					
130-560	2011	3.5	0.19	0.4	0.02
56-130	2012	5.0	0.19	0.4	0.02
37-56	2008 / 2013	5.0	4.7		0.3 / 0.03
19-37	2008 / 2013	5.5	7.5 / 4.7		0.3 / 0.03
8-19	2008	6.6	7.5		0.4
<8	2008	8.0	7.5		0.4

Table 6.8 Summary of EPA-NSPS Tier 4 emission standards for engines > 560 kW [18].

Net Power	Date	CO	HC	NO _x	PM
<i>kW</i>					
Gensets >900	2011	3.5	0.4	0.67	0.10
Other >900	2011	3.5	0.4	3.5	0.10
Gensets >560	2015	3.5	0.19	0.67	0.03
Other >560	2015	3.5	0.19	3.5	0.04

China and India are countries where gasification and producer gas engines have attracted substantial interest and achieved relatively widespread use. In these two countries, the emission standards essentially follow those of EU Stages II–III and US Tiers 2–3, but with a few years' delay (Table 6.9).

Table 6.9. Summary of Chinese Nonroad diesel engine emission standards [18].

Net Power	Date	CO	HC	NO _x	PM
<i>kW</i>					
130-560	2009	3.5	1.0	6.0	0.2
75-130	2009	5.0	1.0	6.0	0.3
37-75	2009	5.0	1.3	7.0	0.4
18-37	2009	5.5	1.5	8.0	0.8
8-18	2009	6.6	9.5		0.8
<8	2009	8.0	10.5		1.0

In countries that do not have their own specific emission regulations, the World Bank Group guidelines from 1998 are often used as a minimum standard for engine-driven power plants. The guidelines are primarily intended for fossil-fuel thermal power plants of >50 MW_{el} and provide limits for particulate matters, sulphur dioxide, and nitrogen oxides (Table 6.10).

Table 6.10. Summary of World Bank Group emission standards [18].

PM	50 mg/Nm ³	
SO ₂	2000 mg/Nm ³	20 metric tons per day / MWe
NO _x	400 mg/Nm ³ dry at 15% O ₂	2000 mg/Nm ³ (if ambient < 150µg/Nm ³)

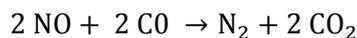
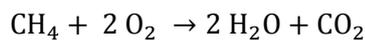
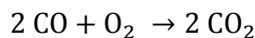
The Gothenburg Protocol from 1999 (in force 2005) has been signed by several European countries, one Asian country, Armenia, Canada, and the USA. For most pollutants, however, Canada and the USA have different emission reduction provisions from those of the Gothenburg Protocol. NO_x is limited according to Table 6.11.

Table 6.11. Summary of Gothenburg protocol emission standards [18].

Spark ignition (Otto) engines, 4-stroke, > 1 MW	NO _x Limit, mg/Nm ³ 5% O ₂
Lean-burn engines	250
All other engines	500
Compression ignition (Diesel) engines, > 5 MW	
Natural gas, dual-fuel engine	500
HFO and diesel	600 and 500

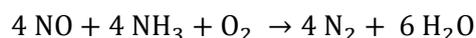
6.3.3.2 Emission aftertreatment systems

To counter the engine-out emissions, Aftertreatment systems may be employed. For engines operating at stoichiometric conditions, the three-way catalytic converter (TWC) is excellent at simultaneously reducing CO, HC, and NO_x emissions. CO and HC are oxidized with available oxygen (O₂), while NO_x is reduced with CO and HC through catalytic reactions [12].



Gas engines are often operated in lean-burn mode, leading to lower combustion temperatures and thus reduced NO_x emissions. How lean is a key question here since, under insufficiently lean conditions and with good combustion efficiency, NO_x could in fact be difficult to counter since there is air excess and almost no CO or HC in the exhaust. In this case, a TWC cannot reduce NO_x, so a separate reducing catalyst is needed together with a reducing agent, typically ammonia (NH₃). NO_x in the exhaust gases normally contain about 90-95 % NO and 5-10 % NO₂.

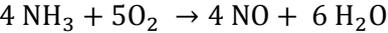
The SCR reaction for NO is:



There is also a fast SCR reaction according to:



Modern catalyst systems utilize this fast reaction and usually contain an oxidation catalyst to convert part of the NO to NO₂ before it enters the SCR catalyst. Since it is difficult to achieve perfect conversion of NO_x to N₂ there is likely to be a small ammonia slip after the catalytic converter. This ammonia slip can be converted back to NO by an oxidation catalyst by:



With very lean operation, however, NO_x is more seldom a problem but due to less efficient combustion CO and HC could pose a more serious problem.

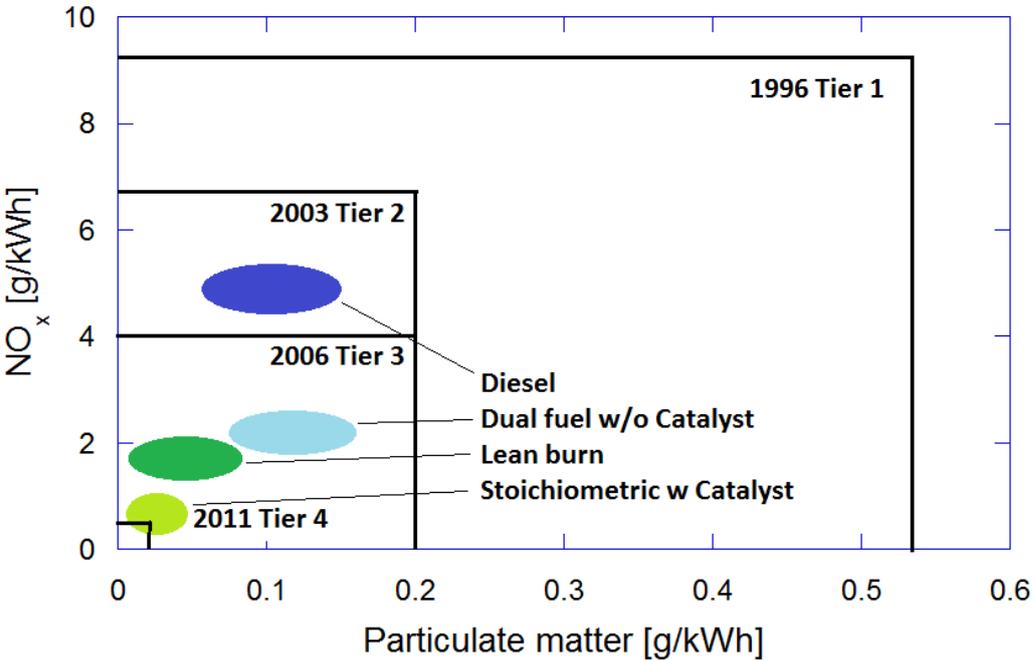


Figure 6.15. NO_x versus particulate matter for EPA Tiers 1–4 and various engine concepts.

Particle traps may be employed to capture particulate matter, exploiting the mass inertia of the particulates. These traps need to be regenerated at intervals, usually by running the engine rich, to let CO and HC reach the trap and burn out the PM. This is of course detrimental to efficiency.

6.4 Producer gas quality versus engine performance

Depending on the gasification process, producer gas contains various proportions of combustibles and inert species as well as of contaminants, such as tars, dust, and particulates. This section discusses the various properties of gaseous fuels and their implications for engine operation, performance, and maintenance. Figure 6.16 indicates some typical areas of concern for engine operation on producer gas [19].

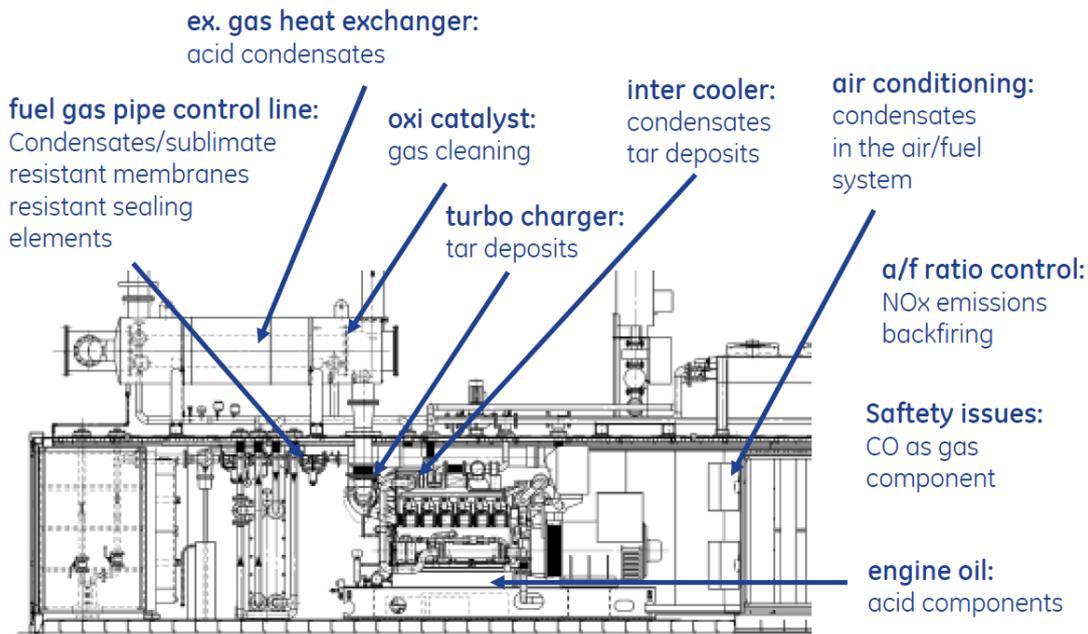
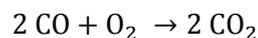


Figure 6.16. Typical areas of concern for engines using gasifier gas (courtesy of GE's Jenbacher gas engine business) [19].

6.4.1 Typical components of producer gas

Producer gas is usually a mixture of mainly carbon monoxide (CO), hydrogen (H₂), methane (CH₄), and the inert species carbon dioxide (CO₂), nitrogen (N₂), water steam (H₂O), and small amounts of Argon (Ar) [20]. Apart from the main species, the gas contains various minor species, tars, and particulates depending on the feedstock and the production method.

CO is seldom produced or used as a fuel on its own. It is typically used together with H₂ in what is known as synthesis gas or syngas produced by the steam reforming of coal. Syngas can be used, for example, in producing synthetic diesel or gasoline through the Fisher-Tropsch process. CO, in itself, has a high resistance to auto-ignition, meaning that the engine can run with a high compression ratio, which is good for efficiency. Using CO will usually lead to very low HC emissions, but naturally to CO and CO₂ emissions. CO is oxidized with O₂ from the air to form CO₂.



As CO is highly toxic, unburned CO must be prevented from passing through the combustion process or leaking from the gasifier. Therefore, the combustion temperature and oxygen content of the air/fuel mixture must be high enough to achieve a nearly 100% conversion of CO to CO₂. If the combustion of the producer gas is carried out under lean conditions to avoid NO_x production, the temperature will decrease and CO emissions will increase due to incomplete combustion throughout the combustion chamber.

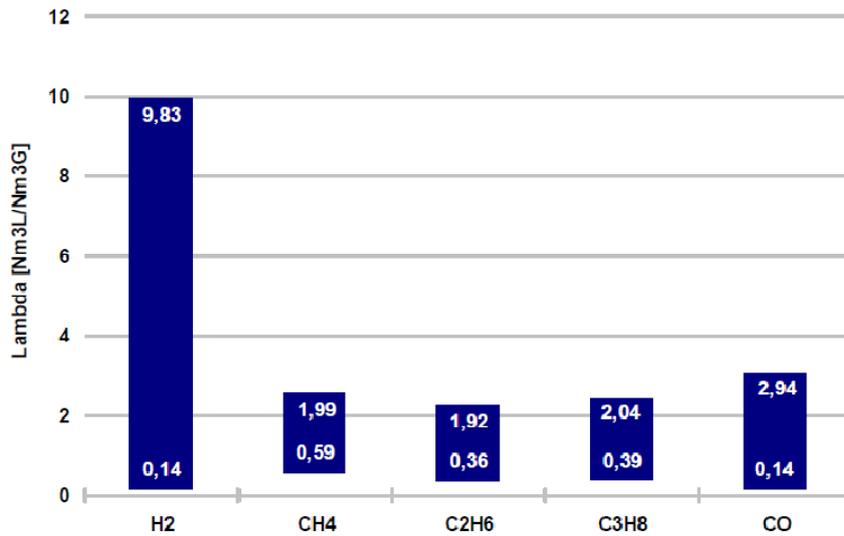


Figure 6.17. Lambda limits for ignition for several gaseous fuels (courtesy of GE's Jenbacher gas engine business) [19].

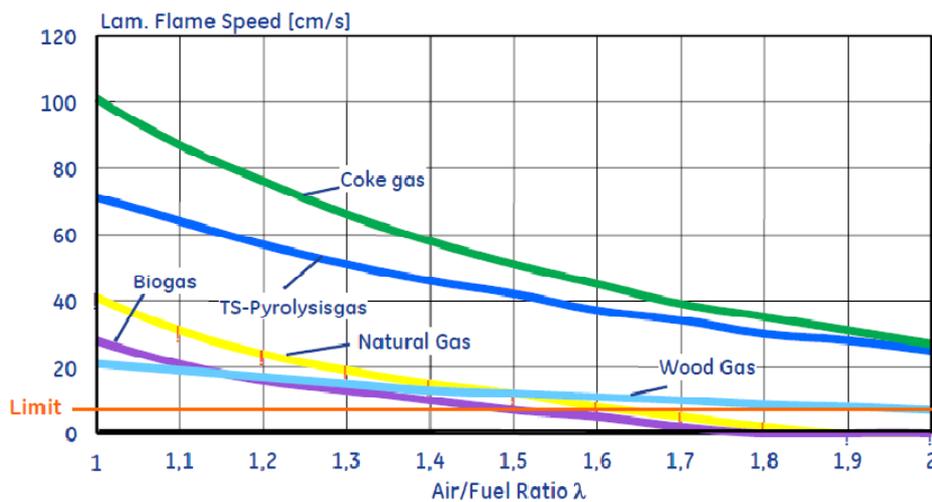
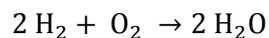


Figure 6.18. Laminar flame speeds versus lambda for several gaseous fuels (courtesy of GE's Jenbacher gas engine business) [19].

H₂ is considered an excellent engine fuel, especially in SI engines, and has the obvious advantage of not yielding CO, CO₂, and HC emissions. It has not become more widely used due to the difficulty of economic distribution and production. The energy content in relation to volume is very small for this, the smallest known molecule, making storage and transportation expensive. Hydrogen does not exist naturally in useful concentrations, but has to be produced. From this perspective, CHP from biomass gasification is excellent, since hydrogen is produced while electricity and heat are distributed.

Hydrogen has fairly unusual and sometimes contradictory properties. For example, its research octane rating (RON) is very high while its motor octane rating (MON) is low. This

indicates that hydrogen has a very low resistance to knock, which can be explained by its low ignition energy and extremely high flame speed. In a mixture, however, hydrogen acts in the opposite way by increasing the overall knock resistance. This is explained by the trade-off that the mixture's ignitability is less improved by the hydrogen addition than are the flame speed and thermal diffusivity. Improved flame speed limits the time for knock to occur, while



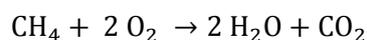
the high thermal diffusivity of hydrogen limits the risk of high-temperature gas pockets in the combustion chamber that could initiate knock or pre-ignition. The reduced risk of knock and pre-ignition means that the compression ratio of the engine can be increased, which increases thermal efficiency.

The improved ignitability due to hydrogen addition is very beneficial as well, since this enables very lean engine operation. Under these conditions, combustion temperatures can be decreased, which results in extremely low NO_x emissions.

The combustion of hydrogen with oxygen produces water and forms no hazardous emissions. It should be remembered that variations of the hydrogen content of the producer gas exert a significant influence on combustion phasing, meaning that the engine controls need to be designed to respond so as to avoid load changes, increased emissions, or even engine damage.

Furthermore, pure H_2 has some challenging properties regarding, for example, diffusivity, that need to be addressed if in high concentrations. Hydrogen is thus incompatible with many steels, nickel and its alloys, titanium alloys (pure titanium works well, though), and cobalt and its alloys, which can be susceptible to hydrogen brittleness or that are permeable to hydrogen, permitting it to diffuse (leak) through. Hydrogen's extreme flammability makes it important to avoid static spark discharges by properly grounding materials in contact with hydrogen. In mixtures, such as producer gas, in which the hydrogen content seldom exceeds 30%, the problems are not as extreme as in pure hydrogen.

CH₄ is a good engine fuel as well, as attested by the wealth of engines operating on natural gas, which consists mainly of methane. Methane combustion in air naturally causes HC, CO, and CO₂ emissions, but, on the positive side, its high octane rating leads to high engine efficiency and its high H to C ratio leads to comparatively low CO₂ emissions. The exothermic chemical reaction of CH₄ with O₂ leads to the following reaction equation:



Under lean combustion conditions, the temperature at the end of the combustion cycle can become so low that CH₄ is not completely converted to CO₂, but only to CO, resulting in

higher CO emissions. Previous studies have demonstrated that the CH₄ content influences burning velocity: higher methane contents lead to slower combustion, while higher hydrogen contents, in contrast, favour rapid combustion.

CO₂ and N₂ are considered inert species and as such do not directly take part in combustion, but instead act as thermal buffers that lower the combustion temperature [22]. These species are excellent choices for diluting the in-cylinder charge to limit peak cylinder temperatures, for example, to reduce NO_x formation and suppress knock and pre-ignition. In this case, the carbon dioxide content has the same diluting effect on the fuel/air charge as does exhaust gas recirculation (EGR), whereas EGR usually leads to higher temperatures than does fresh charge [23]. H₂O is important, especially for the autoignition of CO through the so-called wet kinetics mechanism.

Table 6.12. Properties for a number of combustible gases. Producer gas properties varies considerably depending on gasifier and feed-stock. Data is compiled from several sources, for instance [20,24,33].

	H2	CO	CH4	PG	NG	Propane
RON	>130	-	120	-	130	112
MON	Very low	-	120	-	130	97
Wobbe index MJ/Sm ³	40-48	13	48-53	23-30 *	48-54	74-81
Maximum laminar flame speed in air m/s	2.83	0.52	0.45	0.26-0.50	0.30	0.46
Flamability limits % fuel gas by volume	4-74	13-74	5-15	17-74	4-15	2-10
LHV MJ/Nm ³	11	13	37	2-12	33-42	97
Ignition Temperature °C	572	609	632	-	900	466
Molecular mass g/mol	2.016	28.01	16.042	-	19.5	44.094
Specific gravity air=1	0.07	0.97	0.55	-	0.67	1.56

* Syngas.

The properties of the biomass feedstock typically vary over time. From one batch to another, wood chips may vary, for example, in moisture content, heating value, and alkali compound content, and, combined with the gasification process dynamics, the producer gas composition will vary as well [20, 25]. Depending on the type of engine, this may call for more or less advanced automatic engine controls to adapt engine operation to maintain load and avoid excessive amounts of hazardous emissions. One way to limit too swift changes in engine operation due to temporary variations in the producer gas is to use sufficiently large buffer tanks.

6.4.2 Contaminants

Particles, alkali compounds, tars, and nitrogen-containing substances in producer gas can lead to combustion process and emission problems as well as to engine oil contamination, deposit formations in engine induction and combustion systems, and corrosion. As mentioned, the properties of the specific feedstock and the gasification process will greatly influence the severity of such problems and the approach needed to counter them. The gas can be treated

using various filters, scrubbers, or condensers to achieve trouble-free engine operation. Well-developed modern gasifiers deliver clean producer gas, in which the above-mentioned contaminants are almost nonexistent, meaning unproblematic engine operation [20, 25, 26].



Figure 6.19. Tars condensed on a compressor wheel (courtesy of GE's Jenbacher gas engine business) [19].

6.4.3 Heating value and air/fuel ratio

Producer gas has much lower energy content than do more conventional fuels, such as gasoline, diesel, alcohols, and natural gas. The actual energy content of the producer gas varies depending on the gasifier. For example, the Viking gasifier yields a producer gas with an LHV of 6 MJ/Nm^3 , while producer gas from the Güssing gasifier has almost twice the energy content, with an LHV of up to 12 MJ/Nm^3 [20, 25].

Considering that natural gas typically has an LHV of 39 MJ/Nm^3 and that gasoline has an LHV of up to 228 MJ/Nm^3 , it is easy to assume that producer gas is an inferior fuel, leading to very low engine power. In reality, producer gas is an excellent engine fuel with a very low engine output penalty compared with natural gas or gasoline [28, 29]. This is due to the very low stoichiometric air/fuel ratio of producer gas of only $1.3 \text{ Nm}^3/\text{Nm}^3$ (Viking gas), meaning that, for “ideal” engine operation, only 1.3 portions of air are required to completely combust one portion of producer gas. For comparison, natural gas has a stoichiometric air/fuel ratio of $10.6 \text{ Nm}^3/\text{Nm}^3$. In practical terms, this means that during stoichiometric operation the energy content of the intake charge will differ by only 23% ($\text{LHV}_{\text{mixture}} 2.6$ versus 3.4 MJ/Nm^3), since almost six times more producer gas than natural gas is allowed to enter the combustion chamber. Gasoline has a stoichiometric air/fuel ratio of approximately $49 \text{ Nm}^3/\text{Nm}^3$ and an $\text{LHV}_{\text{mixture}}$ of 3.75 MJ/Nm^3 .

Furthermore, the leaner the operation mode, the greater the benefit of using producer gas. Figure 6.20 shows the $\text{LHV}_{\text{mixture}}$ as a function of lambda for producer gases from Güssing, Harboøre, and Viking and for natural gas [20]. Under conditions leaner than $\lambda = 2.5$, the energy content of the Viking gas charge is higher than that of natural gas. The situation is even better for the Güssing gas: the gas has to start with a higher energy content, and even at $\lambda = 1.2$ there is a benefit compared with natural gas. The Harboøre gas has a performance similar to the Viking gas.

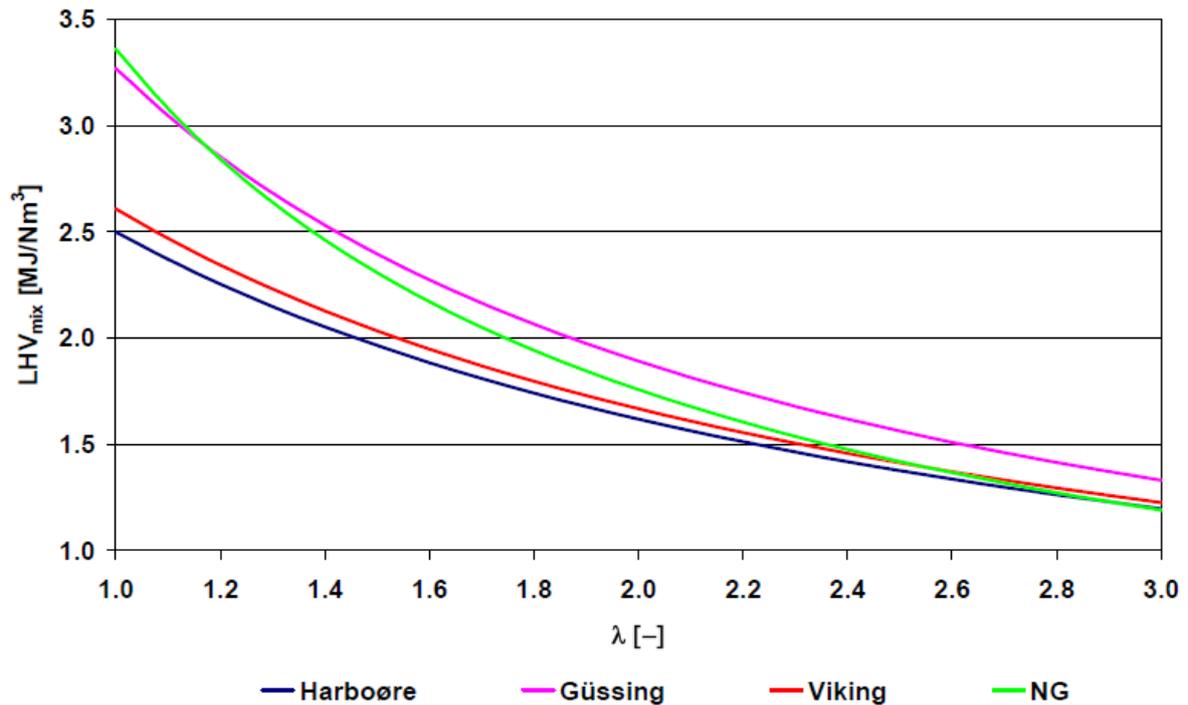


Figure 6.20. LHV values for air/fuel mixtures of several producer gases and natural gas. This figure shows the significance and relevance of producer gas as a lean-burn fuel (courtesy of J. Ahrenfeldt) [20].

6.5 Commercial engines

Engine manufacturers commonly offer either bespoke gas engines or gas engine conversions of their regular engines. Engines destined for markets with stringent emission regulations are typically of very high technical standard and offer very high efficiency and dependability. Where emission standards are less strict and investment costs are an issue, older/simplified technology may be preferred.

CHP systems with producer gas gasifiers typically use gas engine gensets from producers such as Jenbacher, Cummins, and Caterpillar. Jenbacher has solid documentation of the operation of its engines on producer gas (some data can be found in chapter 7). In developing countries, converted diesel gensets or even converted natural gas vehicle engines are common. In India and China, where there is considerable biomass gasification activity, gensets are offered by companies such as Cummins-India and Weichai. Other common international brand names are Lovol, MTU, Perkins, Deutz, MWM, Waukesha, Kubota, Yanmar, Isuzu, Daewoo, Hyundai, and Mitsubishi.

The Swedish manufacturers Volvo and Scania offer heavy-duty engines that are regarded as of high technical standard. The Volvo group is one of the largest engine producers in the world in the heavy-duty segment up to 700 kW, and includes brands such as Volvo, Renault, and Mack. Gas engines are currently available in Volvo's truck and bus programmes and will shortly be available in its industrial engine and genset programmes as well. These

programmes include dual-fuel, SI lean-burn, and SI stoichiometric engines, depending on the application. Volvo's current genset programme ranges from 75 to 644 kW.

Scania has an industrial and genset programme as well, with a range from 225 to 610 kW. Its current gas engines are for trucks and buses and are mainly of the lean-burn SI configuration. A Scania gas engine was recently used with producer gas at Lund University. Indicated gross efficiency reached an impressive 49%, considering that the setup was not optimized; the results are presented in section 6.6.2.

For power levels above 700 kW, one must search outside Sweden. In the Nordic countries, Wärtsilä and MAN Diesel & Turbo companies of Finland and Denmark, respectively, have developed first-rate large gas engines.

Wärtsilä offers power plant gas engines ranging in capacity from 1 MW to 18 MW. Gas engines are available as lean-burn pre-chamber SI or dual-fuel CI engines (see section 6.1). Total CHP efficiency may exceed 90%, and these power plant engines can be delivered with a number of additional technologies, for example, to use waste heat more efficiently.

MAN Diesel & Turbo has a similar power plant engine programme, offering four-stroke engines of 450 kW–21.6 MW and two-stroke engines of 3.6–80 MW. Gas engines of lean-burn pre-chamber SI and dual-fuel CI types are offered in capacities up to 18 MW. For marine applications, direct injection gas engines (see section 6.1) are available.

6.6 Research on producer gas engines

6.6.1 Overview of research in the last decade

There is not a wealth of scientific work on producer gas engines reported. Earlier international reports were quite often based on Swedish experiences from WWII and the renewed efforts during the oil crises of the 1970s [10].

Regarding international research performed over the past 10 years, G. Sridhar in India stands out with several publications on the practical integration of gas engines in gasifier applications [e.g., 30–33]. One of these publications, from 2003, reports investigations of three engines of different types to establish ignition settings and the optimal compression ratio to limit engine derating [33]. The studied engines are of an interesting range of types and sizes, including two natural gas engines and one modified diesel engine. One NG engine was turbocharged while the other NG engine and the modified diesel engine were naturally aspirated. An open-top re-burn gasifier fuelled with Casuarina wood and coconut shells produced a gas of 19% H₂, 19% CO, 2% CH₄, and 12% CO₂, the balance consisting of N₂, with an LHV of 4.5 MJ/kg. Apart from the lower hydrogen content, this producer gas is relatively similar to that produced by the Viking gasifier. A specific carburettor developed by Sridhar to feed the producer gas to an engine was used for all three engines. The engine specifications are shown in Table 6.13.

Table 6.13. Engine parameters for the three tested engines [33].

Parameter	Engine 1 (E1)	Engine 2 (E2)	Engine 3 (E3)
Make and Model	Kirloskar, RB-33	Greaves, TBDV12	Cummins, G743G
Engine Type	In-Line, 3 Cylinder, Naturally Aspirated Diesel Engine	V 12 Cylinder, Turbo-Charged / After Cooler Gas Engine	In-line, 6 cylinder, Naturally Aspirated Gas Engine
Net Output - @ Bangalore ~ 1000m above sea level	24 kW, with diesel fuel	240 - 258kW, with diluted natural gas	84 kW, with natural gas
Bore x Stroke, mm	110 x 116	128 x 140	130 x 152
Total Displacement, L	3.3	21.6	12.1
Specific Power, kW/L	8.5 (diesel)	13.4 – 14.4 (diesel)	7.0 (with NG)
Compression Ratio (CR)	17 (Variable)	12	10

Some of the results, for example, CR and optimal timings, are reported in Table 6.14. Although this was not discussed in the paper, the turbocharged engine (E2) – by far the largest – delivered strikingly poor performance (BMEP was 6.7 bar). Although not all performance details are available, one would expect much higher efficiency when supercharging is an option. The results likely indicate a problem with turbo matching, which is crucial for efficient producer gas engines. Apart from this interesting aspect, Sridhar’s papers confirm much of the reported experience with and performance of producer gas-operated engines.

Regarding the importance of optimizing turbo-charging for gas engine CHP, Klaus Payrhuber and Christian Trapp at GE’s Jenbacher presented results in 2011 indicating that total efficiency could be raised from 87.0% to 89.5% by introducing two-stage turbocharging combined with lean Miller cycle operation for the GE’s Jenbacher J624 [34]. The gain in total efficiency came by allowing a higher charge temperature, thus providing more useful heat for CHP from the charge cooler, while maintaining the charge density and engine electrical efficiency through the improved charging approach. Alternatively, the improved charging can be used for an increase of the engine electric efficiency from 45.4% to 46.3%.

Table 6.14. Results for the three tested engines [33].

Engine	CR	IGN, BTC	Φ	Net Elec. Power, kW _{el}	Net Brake Power (BPNet) kW	Mixture Energy Density, MJ/kg	Efficiency : Gas-to-Shaft, (%)
E1	17.0	06	1.10	17.5	20.0	2.20	30.7
	14.5	10	1.10	16.4	18.8	2.20	29.0
	13.5	14	1.06	16.2	18.6	2.10	29.3
	11.5	15, 17	1.07	15.3	17.6	2.20	27.5
E2	12	12, 14	0.94	165	182	1.90	28.3
E3	10	22, 24	1.01	55	60	2.15	27.4

Jesper Ahrenfeldt and Ulrik Birk Henriksen at Risø DTU have published substantial amount of research on producer gas engines and are prominent sources of experience in the field of both biomass gasification and producer gas. Some of their most relevant papers are cited in

the reference list at the end of this chapter [see 20, 35–38]. Research has been performed on modified SI engines and natural gas engines, both supercharged and naturally aspirated and with both stoichiometric and lean-burn operation. Tests have been performed using different combustion chamber shapes to optimize power and efficiency, but also potential problems, such as combustion chamber deposits and emissions from long-term operation with the Viking gasifier, have been studied. Much of the fundamental knowledge presented here on the use of producer gas in engines comes from collaboration and the exchange of information between the present authors and Jesper Ahrenfeldt and Ulrik Birk Henriksen. The focus of research at Risø DTU has been on small-scale engines of less than 100 kW. Neither dual-fuel nor pre-chamber SI engines have been investigated experimentally. The results for the Viking gasifier/gas engine are presented in greater detail in chapter 7.

Papers on the Güssing facility focus more strongly on the gasification than on the commercial Jenbacher gas engine [25]. The importance of gasification parameters for total electrical efficiency was examined by Rauch et al. [26]. Depending on the parameters, total electrical efficiency could range from 18 to 25%. How much of this variance was contributed by changes in wood-to-gas efficiency versus changes in engine efficiency was not revealed. Further data and experiences on the Güssing facility can be found in chapter 7.

HCCI has been investigated as a potential engine concept for use with producer gas by both Yamasaki et al. [22] and Haggith et al. [39]. Yamasaki et al. investigated HCCI operation with simulated producer gas by varying the proportions of the gas constituents, and demonstrated an evident relationship between H_2 and CO_2 , described as the hydrogen/carbon dioxide ratio, depending on the ignition timing and combustion duration. CO apparently had little effect on these parameters in HCCI combustion. Yamasaki et al. [40] reached the same conclusions for SI combustion.

Roubaud et al. from Swiss federal Institute of technology investigated the performance of an unscavenged pre-chamber engine on simulated biogas instead of direct ignition on a turbocharged 6 cylinder 150 kW gas engine [44]. This prechamber is used for operation with a simulated biogas (40 % CO_2 in natural gas). The results show that, compared to natural gas operation for the same rated power output of 150 kW and the same NO_x emissions, the CO emissions are reduced by 15 % and the HC emissions at least by 8 %. Efficiencies higher than 36 % are achieved which is very promising and the lower CO emissions give a margin to consider an increase of compression ratio

6.6.2 Recent research at Lund University

In conjunction with this project, the division of Combustion Engines at Lund University instigated an experimental investigation. Contact was made with the Biomass Gasification Group at Risø-DTU and cooperation started. The aim of the cooperation was to examine the potential efficiency and emissions when using a modern truck engine running on producer gas in both SI and HCCI combustion modes. As reported, the engine at the Viking facility was older, so the potential performance of a more modern unit was interesting to verify. Funding the experimental work was outside the scope of the present study, so funding was applied for and received from Lund University Combustion Centre (LUCC) Transnational Access within

the European Research Infrastructure. DTU supported the work by supplying equipment and supervision, while Scania supplied a natural gas engine that was modified in Lund. Work was mainly performed by M.Sc. students Matthias Achilles and Jonas Ulfvik, and the results were reported at the SAE World Congress (April 2011 in Detroit, MI), Scania (Södertälje, Sweden), and the Competence Centre for Combustion Processes (KCFP) (Lund, Sweden) [28, 29, and 45].

Focusing on in-cylinder performance, efficiency, and emissions, the research can be divided into three parts: comparison between SI operation on natural gas and producer gas, comparison between HCCI operation on natural gas and producer gas, and comparison between SI and HCCI operation on producer gas.

The investigations were performed on a Scania five-cylinder, 9.6-litre, natural gas SI engine. Table 6.15 presents general data on the engine, which is depicted in Figure 6.1. The engine is designed for use in city buses and is based on the diesel engines produced at Scania, but with modified cylinder heads and pistons for SI operation. The engine was further modified in Lund for single-cylinder operation by drilling holes in the other four pistons and blocking the coolant for the decoupled cylinders. A port injection system with four injectors and an annular injector block was installed; for SI operation, a high-swirl configuration with a quartet piston was used, while a flat piston was used for HCCI operation. The compression ratio was the original 12.6 for SI operation and 22.5 for HCCI (Figures 6.21–6.25). The engine was instrumented with, for example, a cylinder pressure transducer, a high-resolution angle encoder, lambda sensors, and emission measurement systems. Air was provided to the engine by an external compressor, providing the means for supercharged operation. To simulate the energy loss associated with turbocharging, a back-pressure valve was installed and set to a slightly higher pressure than that of the supercharger. The engine also featured an EGR circuit that was not, however, used in this work. For HCCI operation, a heater was installed to raise the temperature of the incoming air. The engine was monitored and controlled using an in-house designed Lab-View system that also logged important data.

Table 6.15. General engine data for the Scania engine.

Bore	130mm
Stroke	140mm
Cylinders	1
Displaced volume	1.858 cm ³
Connection rod length	255mm
Compression ratio	12.6 / 22.5
Number of valves	4
Exhaust valve diameter	41mm
Inlet valve diameter	44mm
Coolant temperature	63 °C ± 2 °C
Oil temperature	73 °C ± 2 °C
EGR	0%
Engine speed	1050 rpm

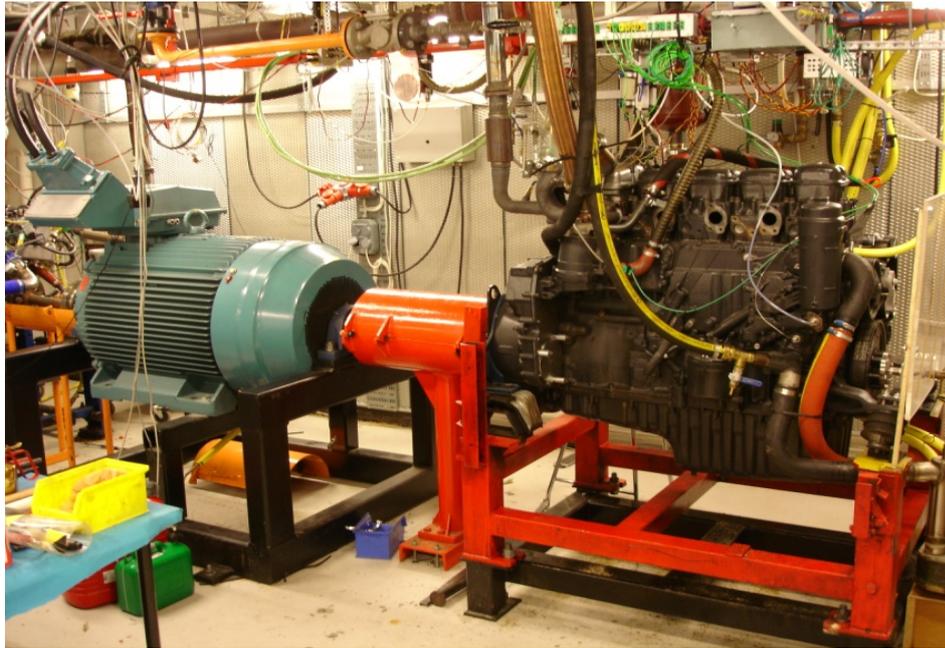


Figure 6.21. The Scania gas engine in the laboratory in Lund.

Natural gas was obtained from the city of Lund network, while the producer gas was provided by a gas mixer from bottles of the individual gas components. The producer gas was thus simulated and had to be monitored using a separate gas analyzer to ensure that its composition matched that of the Viking gasifier gas. The engine was always warmed up running on natural gas, and using a solenoid, the shift to producer gas operation could be made without shutting down the engine. All equipment related to the simulated producer gas was provided by BGG Risø-DTU [20]. A schematic of the experimental setup can be found in Figure 6.24.



Figure 6.22. Left: the original piston shallow bowl combustion chamber, quite typical of gas engines. Centre: the high-swirl piston “Quartette” combustion chamber developed in Lund. Right: the typical flat combustion chamber used in HCCI.

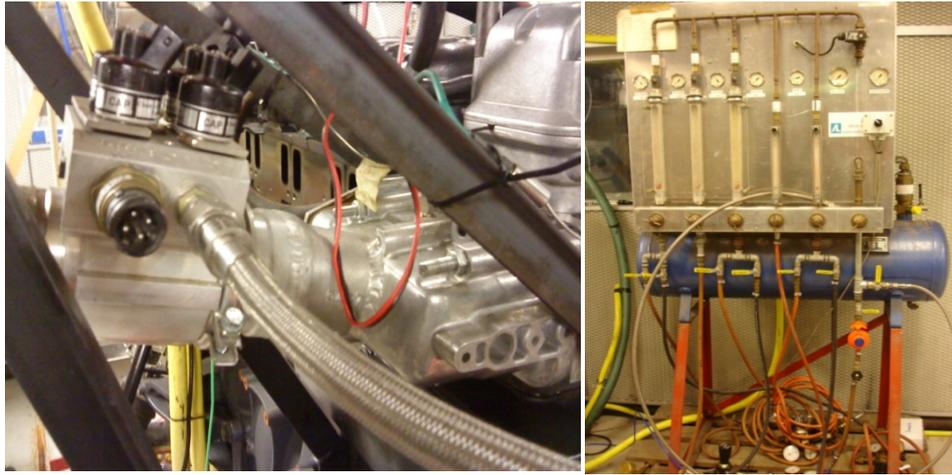


Figure 6.23. Left: the annular gas injector block with four gas injectors on top. Right: the DTU producer gas mixer.

The main limitations of the experimental setup were as follows:

1. The engine operated using an external compressor and an exhaust back-pressure valve, so gross indicated values are presented.
2. The producer gas flow was not measured due to pulsations, but was instead calculated in several steps based on lambda estimation, slightly lowering the accuracy of the indicated results.
3. SI operation on producer gas was load limited, since the gas supply equipment could not provide enough gas.

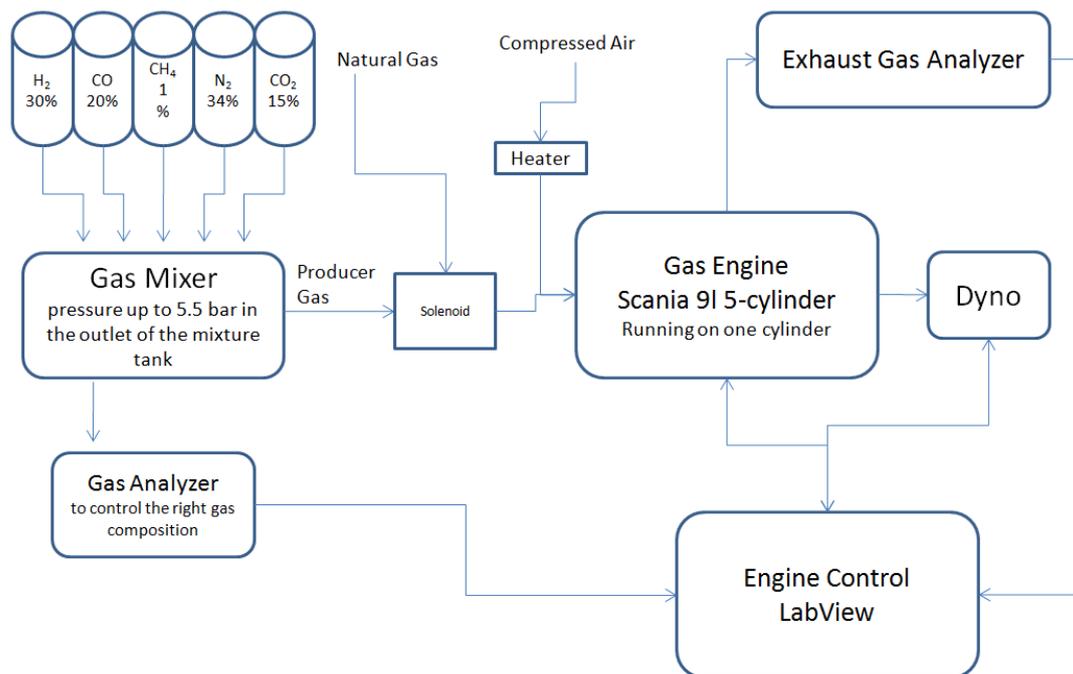


Figure 6.24. Schematic of the experimental setup.

Some of the results of this investigation are presented here because, in several ways, they summarize and confirm the results of previous research and experience with commercial producer gas engines. These results also clarify and reinforce the theory presented in previous sections.

6.6.2.1 Results of comparison between SI operation on natural gas (NG) and producer gas (PG)

Figure 6.26 shows several interesting properties of engine operation using producer gas. Under richer conditions, NG is advantageous, while under conditions leaner than λ 2.4, PG offers a clear advantage. With NG, rich operation was limited by knock and lean operation by misfire and uneven running. On the other hand, with PG, rich operation was limited by the inability of the gas supply system to provide enough producer gas. Although the coefficient of variation (COV) of IMEP is high at the point of leanest PG operation, this is slightly misleading, as the engine ran much more smoothly on PG than on NG.

Regarding combustion speed, PG burns much faster than does NG, which can be clearly seen in Figure 6.27. Combustion duration is shorter and spark timing much less advanced. This is generally good for efficiency and is a consequence of the hydrogen content of the producer gas.

NO_x emissions are generally much lower in PG operation, but only with $\lambda > 1.9$. NO_x emissions are below 30 ppm for both fuels, demonstrating the previously discussed advantages of lean-burn SI operation (Figure 6.28). On the other hand, CO emissions are fairly high with both fuels, especially in the case of PG, since CO is one of the main components of the fuel. With very lean operation, quenching becomes a problem, CO and THC emissions increase, and efficiency starts to decline (Figure 6.29).

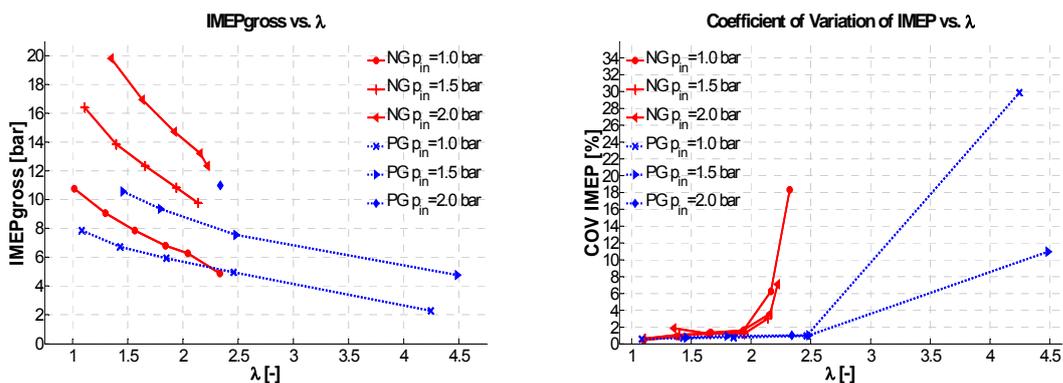


Figure 6.26. Load (left) and coefficient of load variation (right) versus λ at three boost levels for NG and PG operation, respectively.

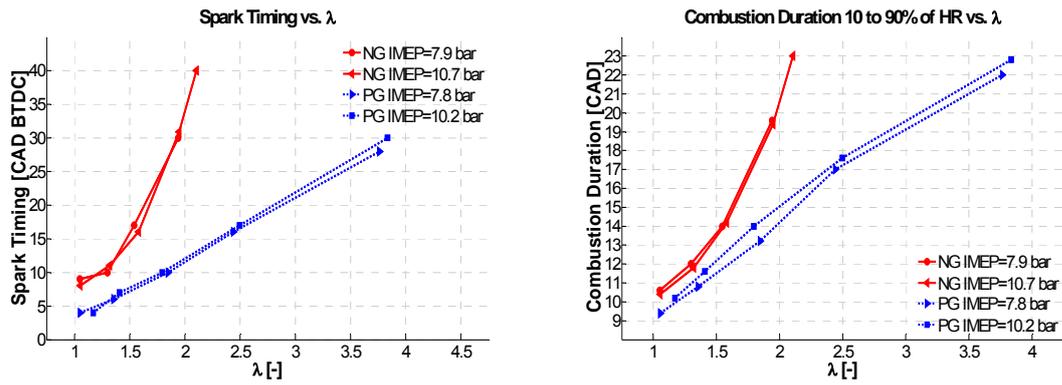


Figure 6.27. Spark timing (left) and combustion duration (right) versus λ at two load levels for NG and PG operation, respectively.

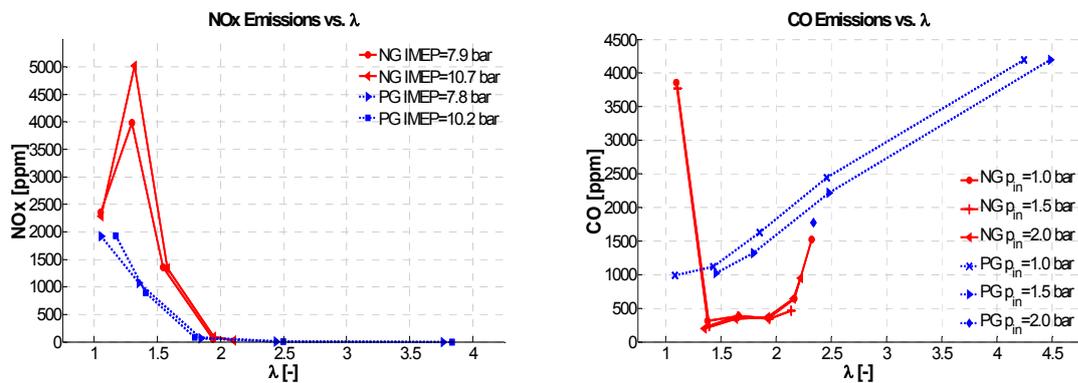


Figure 6.28. Emissions of NO_x (left) and CO (right) versus λ at three boost levels for NG and PG operation, respectively.

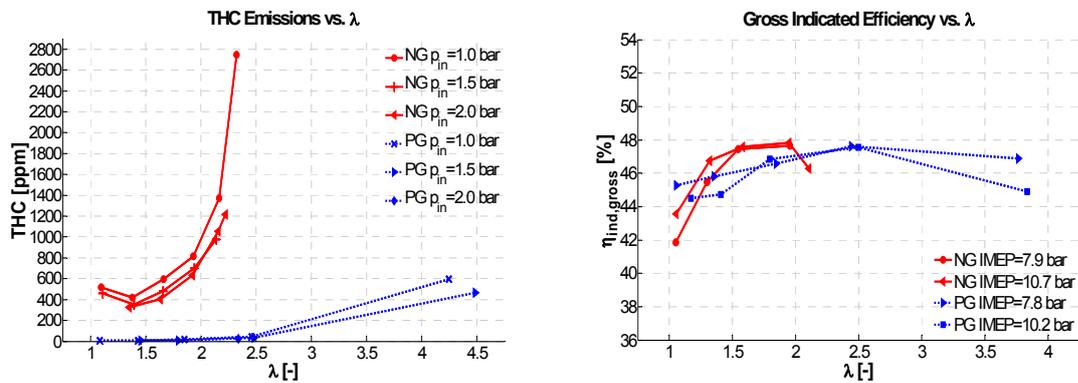


Figure 6.29. THC emissions versus λ at three boost levels (left) and gross indicated efficiency at two load levels (right) for NG and PG operation, respectively.

THC is much lower for PG since it contains only 1-2 % HC in the fuel to start with. In very lean operation the CH₄ start to show in the emissions even for PG. The same peak efficiency was reached with both fuels, almost 48 % gross indicated efficiency. What is interesting is how high the efficiency continues to be with very lean PG operation, 47 % at $\lambda=3.8$. PG is definitely a very good lean burn fuel.

6.6.2.2 Results of comparison between HCCI operation on natural gas (NG) and producer gas (PG)

With $\lambda > 2.4$, the energy content of the air/fuel mixture is higher for PG than for NG. This is largely reflected in Figure 6.30, where the load is higher for PG than NG. The rich limit was limited by knock and pre-ignition, while misfire limits the lean range. It is difficult to control HCCI combustion at the limits, and with the higher hydrogen content of PG, knocking occurred earlier than with NG, which could run slightly richer and thus provide higher load. For NG, 9.6 bar IMEP was possible, while 8.3 bar IMEP was possible for PG. To achieve HCCI auto ignition, the charge often needs to be heated; PG displayed lower resistance to auto ignition than did NG, which required a much higher temperature and thus heating.

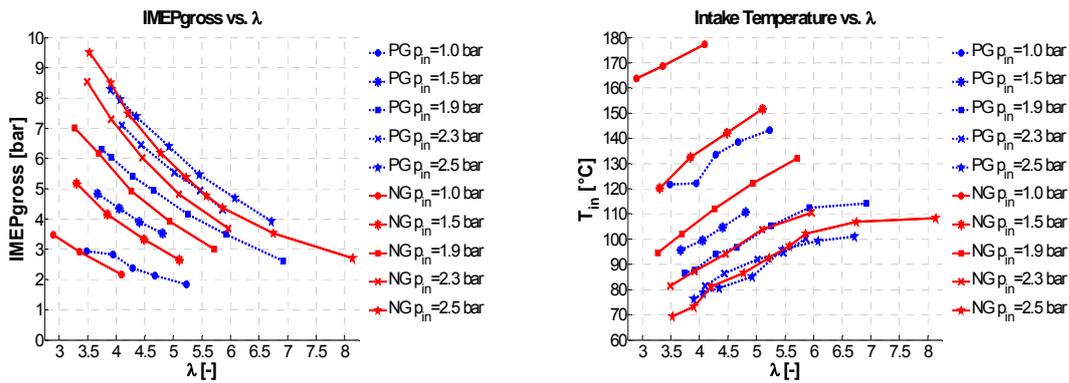


Figure 6.30. Load (left) and air inlet temperature (right) versus λ at five boost levels for NG and PG operation, respectively.

Due to faster combustion, PG generally runs more smoothly and more stably than does NG, but at higher peak pressure rates that could pose a problem for engine durability (Figures 6.31–6.32). The charge pre-heating thus had to be adjusted to achieve a combustion timing allowing a 50% burn, as a compromise between stability and peak pressure rise, usually around 6 crank angle degrees after top dead centre (CAD ATDC) for both gases.

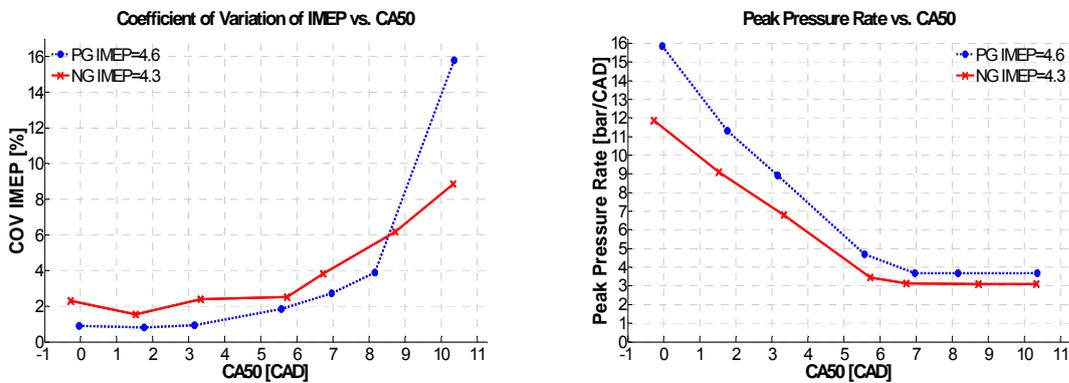


Figure 6.31. Coefficient of variation (left) peak pressure rise (right) versus 50% burned timing at two load levels for NG and PG operation, respectively.

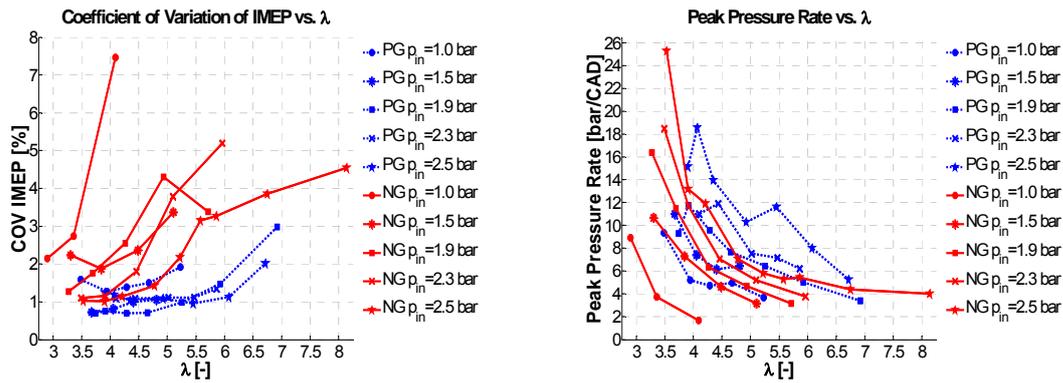


Figure 6.32. Coefficient of variation (left) peak pressure rise (right) versus λ at five boost levels for NG and PG operation, respectively.

CO emissions are much higher in PG operation when $\lambda < 4.2$. Under leaner conditions, CO emissions are surprisingly similar, given that CO is a main constituent of PG (see Figure 6.33). In NG operation, THC emissions are more than 10 times higher than in PG operation over the complete λ range. With PG, THC emissions remain around 30–50 ppm.

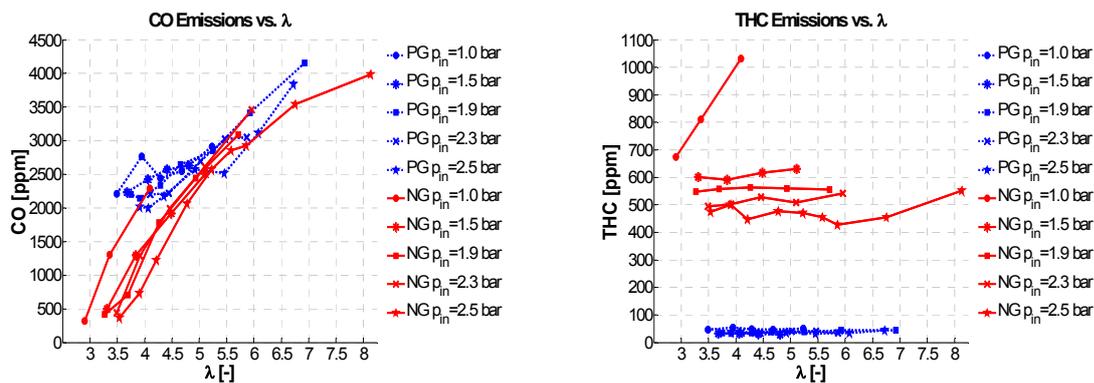


Figure 6.33. Coefficient of variation (left) peak pressure rise (right) versus λ at five boost levels for NG and PG operation, respectively.

The advantage of HCCI low-temperature combustion in terms of NO_x emissions is obvious in Figure 6.34: for both fuels, NO_x emissions are below 2 ppm most of the time. Regarding gross indicated efficiency, NG performs slightly better below $\lambda = 4.5$, while PG performs better under leaner conditions. In both cases, one needs to consider that gross indicated efficiency does not take into account the energy needed for heating the charge.

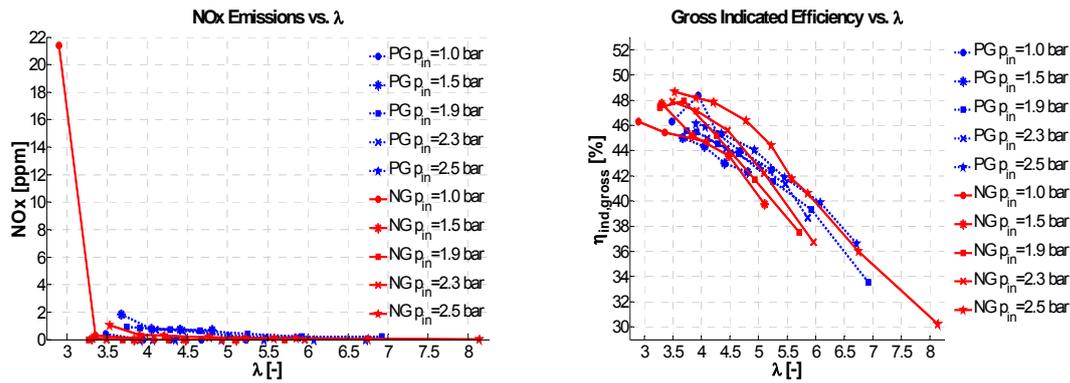


Figure 6.34. Coefficient of variation (left) peak pressure rise (right) versus λ at five boost levels for NG and PG operation, respectively.

6.6.2.3 Results of comparison between SI and HCCI operation on producer gas (PG)

Figure 6.35 shows that HCCI can expand the lean operating range substantially compared with SI, while SI is advantageous in the richer range. One issue of concern regarding HCCI operation is the very low exhaust temperatures. Providing high boost pressures with such a low amount of energy in the exhaust would likely be a problem when using turbocharging. Even in lean SI operation, exhaust energy is low and could be challenging for turbo matching. Indeed, the findings of Sridhar and Payrhuber (Jenbacher) indicate the importance of turbocharging strategies and turbine-compressor dimensioning for efficient producer gas operation.

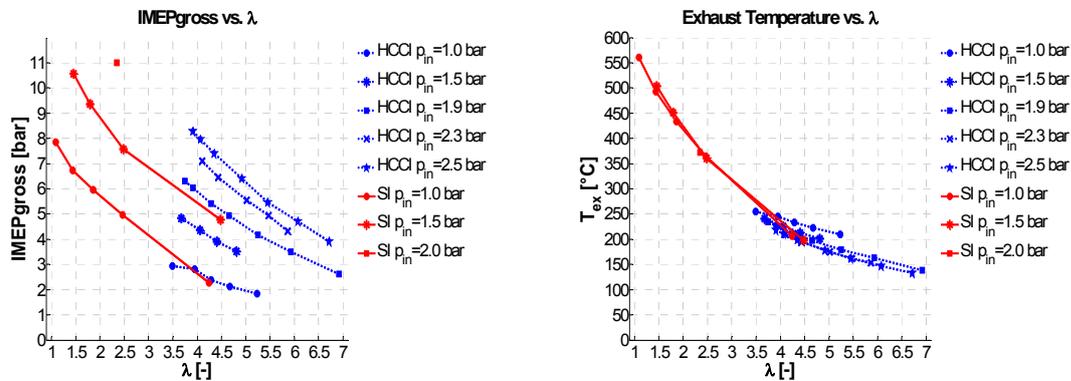


Figure 6.35. Load (left) and exhaust temperature (right) versus λ at various boost levels for SI and HCCI operation, respectively.

HCCI usually puts more stress on mechanical components than does SI operation, and HCCI operation with PG is no exception. With high boosting, both peak pressures and peak pressure rates are high with HCCI (Figure 6.36). With more traditional fuels, it is possible to slow the combustion rate using exhaust gas recirculation, increasing the amount of inert species. How this would work with PG that already contains substantial amounts of inert species and has a very low energy content besides, remains for further research to answer.

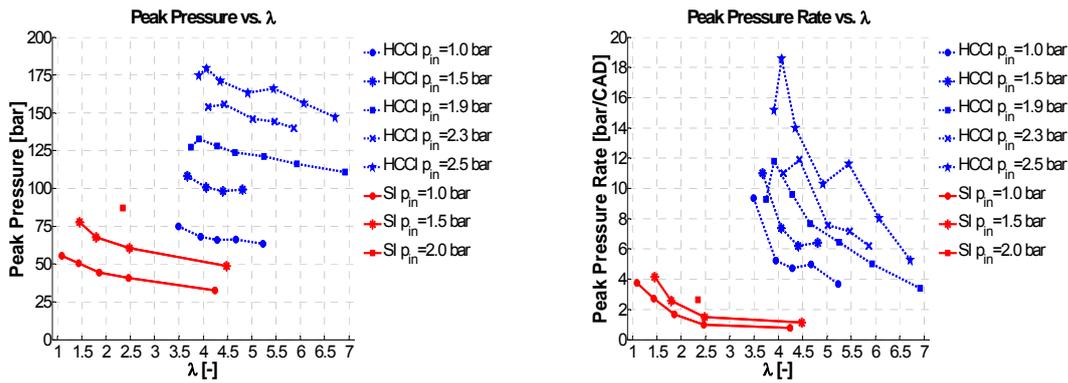


Figure 6.36. Peak cylinder pressure (left) and peak pressure rate (right) versus λ at various boost levels for SI and HCCI operation, respectively.

The NO_x , THC, and CO emission trends are similar for HCCI and SI, although they shift slightly, depending on the λ range. High boost, lean-burn SI operation at $\lambda = 2.0$ – 2.5 seems to be the most beneficial in terms of emissions and efficiency (Figures 6.37–6.38), while NO_x and THC are very low and CO emissions lower than under any HCCI conditions. Considering that HCCI poses control, mechanical stress, and load challenges, the only obvious benefit of HCCI over lean-burn SI operation, both with PG, identified by this limited study is the increased lean range. The usefulness of the capability to run extremely lean is not obvious either, as matching the gasifier to engine size essentially deals with that. Nevertheless, the efficiency trend shown in Figure 6.38 increases fairly steeply at lower λ values. What would happen to efficiency and emissions if it were possible to run HCCI at $\lambda = 2.5$? Obviously, research still has many questions to answer. Finally, it would be useful to assess the brake efficiency of the Lund engine, to identify the potential electrical and total efficiencies of the Viking gasifier. Considering the engine speed and assuming reasonable turbo matching and typical friction losses for the engine size, brake efficiency could be slightly above 40%, conservatively estimated. This would correspond to an engine electrical efficiency of approximately 38% and, considering the Viking unit's cold gas efficiency of 93%, a total electrical efficiency of 35%. Compared with the efficiency of the older Deutz-MWM engine, this represents an improvement of 40%.

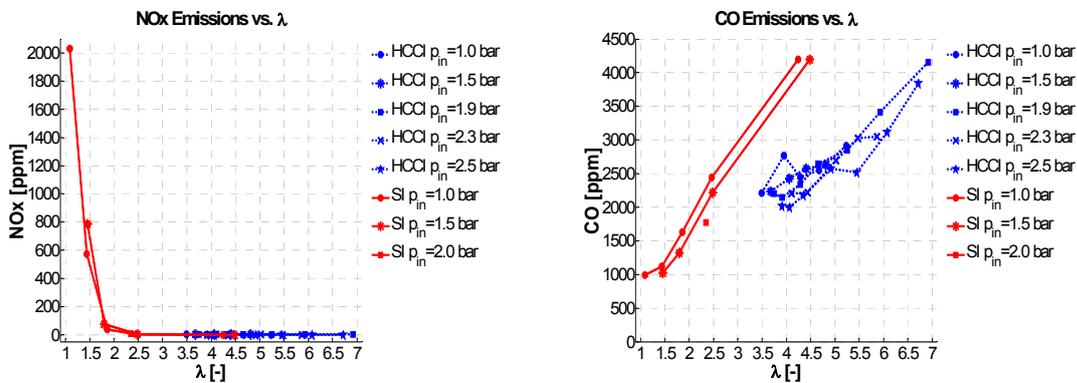


Figure 6.37. Emissions of NO_x (left) and CO (right) versus λ at various boost levels for SI and HCCI operation, respectively.

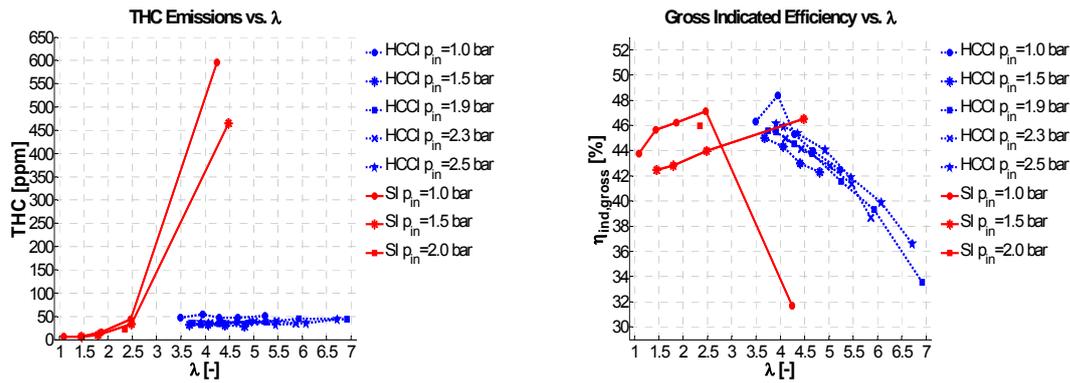


Figure 6.38. THC emissions (left) and gross indicated efficiency (right) versus λ at various boost levels for SI and HCCI operation, respectively.

6.6.3 Research on engines directly fuelled with wood powder

Instead of gasifying the solid fuel into an engine suitable gaseous fuel, it has been proposed that by grinding the solid fuel into fine particles it should be possible to use it directly as an engine fuel. For instance have tests been performed with coal powder in diesel engines. The potential benefit is that the complex and expensive gasifier can be omitted, but this has to be balanced against the costs for the production of the wood powder, increased fuel costs if the electrical and total efficiencies are reduced and increased costs if more engine maintenance is required.

Regarding wood powder as engine fuel, two paths of research have been performed in Sweden. The first one involves direct injection of wood powder in a diesel engine [46-47] and the second one involves wood powder combustion in an external combustor for a Stirling engine [48].

6.6.3.1 Results on direct injection of wood powder in a diesel engine

A six cylinder Volvo Penta TWD1631G engine had one cylinder converted to burn wood powder [46]. The conversion consisted of the removal of the diesel injector and the installing of a high pressure (200 bar) air/wood powder injection system. The engine was operated with Asp-wood powder with a average diameter of 16 μm at 1500 rpm and two different injection timings were tested; 10 and 20 CAD bTDC with an indicated torque of 270 and 130 Nm respectively. Indicated efficiency was in the range of 35-41% for the later injection case and 25-27% for the early injection case. The 41% indicated efficiency case differed from the others, which did not reach above 37%, and had precariously high exhaust temperature of 890°C. The high exhaust temperature can possibly be explained by that it was noted during the experiments that heat was released yet once more late during expansion. For the best setup indicated emissions were below; 3g/kWh NO_x, 2 g/kWh HC and 48 g/kWh CO. Particulate matter emissions were not measured. A previous theoretical study, from 1993, concluded that wood powder as engine fuel was economically beneficial in comparison to ethanol [47].

The results indicate that it is possible to run an engine on wood powder with reasonable efficiency and emissions. But the small number of experiments performed makes a proper evaluation difficult. Issues related to load range, control, emissions and wear would require

further studies. According to the Swedish Farmers' Foundation for Agricultural Research, that has partly financed the research; repeated engine break-downs have stopped progress. The importance of efficient processes to economically produce the fine-grinded wood powder is also a challenge. To evaluate whether wood powder engine CHP is economically competitive, in comparison to gasification-gas engine CHP, a new financial evaluation would be required. The data from the 1993 investigation is not relevant any longer.

6.6.3.2 Results on wood powder combustion in an Stirling engine

The Stirling engines depend on an external heat source, thus possibly posing a smaller challenge than directly combust wood powder within the working cylinder. In [48] a SM3D Stirling engine from Stirling Denmark with a rating of 35 kW was adapted to wood powder operation. A bespoke burner and combustion chamber had to be designed and build at Lund University. Operation worked well, but measured electrical efficiency was fairly low at approximately 15%. The main reason for the low efficiency could be found in insufficient insulation of the burner, leading to excessive heat losses. The authors claim that with improved insulation and reduced transport and primary air the electrical efficiency would increase to 20-25%.

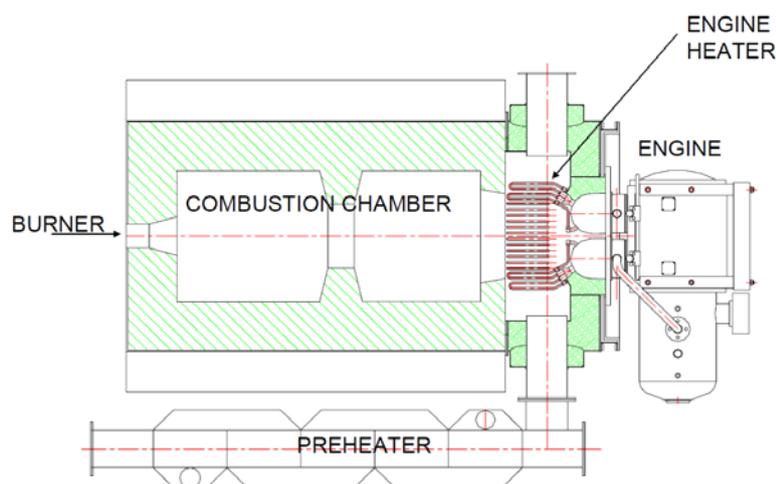


Figure 6.39. System drawing of the wood powder fuelled Stirling engine.

As for the wood powder engine in the previous section, processing costs of the fuel and system efficiencies are important parameters to determine whether a wood powder Stirling engine CHP can compete with a gasifier-gas engine CHP. To improve on its current configuration further research is required.

6.6.4 Future research

Existing research on producer gas operation in engines is limited. Most producer gas engines are in fact natural gas engines, so trends in natural gas engine research are relevant and interesting. Research on natural gas engines is much more widespread due to the many applications of such engines.

What is likely to affect producer gas engines in the future is probably high-pressure gas direct injection systems. These systems can work either in conjunction with pilot injection, as in the

MAN engine described in section 6.1, or with a single fuel, as in some Westport systems [8,49]. The main benefit of each engine is that, before combustion, there is no fuel in the cylinder, which would otherwise be susceptible to knock, meaning that the compression ratio and thus the efficiency can be increased. Recent research at IFP has also demonstrated that power density can also be substantially increased through gas direct injection, another interesting option for producer gas operation, which often suffers from power derating [50]. However, there is a cost in energy for compressing the gas that must be considered with respect to the total efficiency. Potential problems with, for instance, condensation of tars in the high pressurized gas also needs to be investigated. Power derating is countered with increased engine size, which usually means a more expensive engine. To increase the power density from producer gas operation is thus also an important challenge for future research.

It should be remembered that producer gas is not natural gas; specific research is needed into producer gas operation if we are to better understand the requirements for achieving higher efficiency and power density and lower emissions. The number of engines produced for producer gas operation is still so low that funding for specific producer gas engine research is fairly limited. What could help expand research into producer gas engines is the renewed interest in engines running on reformed methanol gas (RMG) [43]. CH₃OH and water can be reformed in a catalytic endothermic process to form a mixture of CO and H₂ that has a 20% higher LHV than does the methanol itself. This process has attracted interest in the engine community as a means of waste heat recovery. The composition of RMG is thus similar to that of producer gas, making future research on either valid for both applications.

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7 Case studies

7.1 Introduction

In this section we present some working plants that we have examined. The Viking, MEVA, and Bio-Kraftwerk Güssing (BKG) plants have been visited and their staff interviewed. We had planned to visit the Skive and Harboøre plants on the same trip, since they are located near each other. However, Carbona (Fi), which is responsible for the Skive plant, could not arrange a site visit, so this had to be cancelled. Instead, the study of these two plants is based on literature findings. In addition to the plant visits and literature research, information was also gathered in meetings, such as the “SGC-International Seminar on Biomass Gasification” in Gothenburg and the GREENSYNGAS workshop at Güssing, and by phone calls and e-mails to the actors involved.

7.2 The Viking gasifier

The Viking gasifier was developed by the Biomass Gasification Group at the Danish Technical University (DTU) in the 1990s, and the pilot unit (now at the Risø facility) was completed in 2002. In its first year, the plant operated for 2200 hours, producing 37 MWh of electricity. The unit has a thermal input of 80 kW and is fed with wood chips approximately 5 × 3 cm in size.



Figure 7.1. The Viking 80 kW_{th} gasifier (today located at the Risø facility) (courtesy of the Biomass Gasification Group, DTU)

7.2.1 The Viking gasification unit

The gasification unit is based on a double-bed approach. The fuel is moved from storage into the gasifier by a heated transport screw. The screw is heated indirectly by the outgoing gases from the gasifier and gas engine. The biomass is transported into an area of successively

higher temperatures. Since no oxygen is present in the gas, the biofuel pyrolyses and forms a gas phase with volatile hydrocarbons and a non-volatile residue – the char. When the char reaches the end of the transport screw (inside the reactor), the char falls to the bottom of the reactor, where it forms a stationary char bed. The pyrolysis gases, consisting mainly of primary and secondary tars, are partially oxidized above the char bed by means of air injection. The hot gases (1100 °C) pass through the char bed and gasify it. When passing through the bed, the remaining tars are also reduced. Figure 7.2 shows the principal reduction of the tars. The tar level, which is 50 g/Nm³ immediately after the transport screw, is reduced by 99 %, to 500 mg/Nm³, by the partial oxidation step. The tar level drops further, to 25 mg/Nm³, during passage through the char bed.

When the producer gas leaves the reactor, it cools by passing through several heat exchangers for heat recovery. When the gas is sufficiently cool, it is filtered to remove dust particles, after which the tar level is down to 5 mg/Nm³. The water contained in the gas is condensed out to improve the heating value of the gas, leaving a condensate that is sufficiently clean to be processed by municipal sewage plants. The LHV of the producer gas is 4–5 MJ/Nm³.

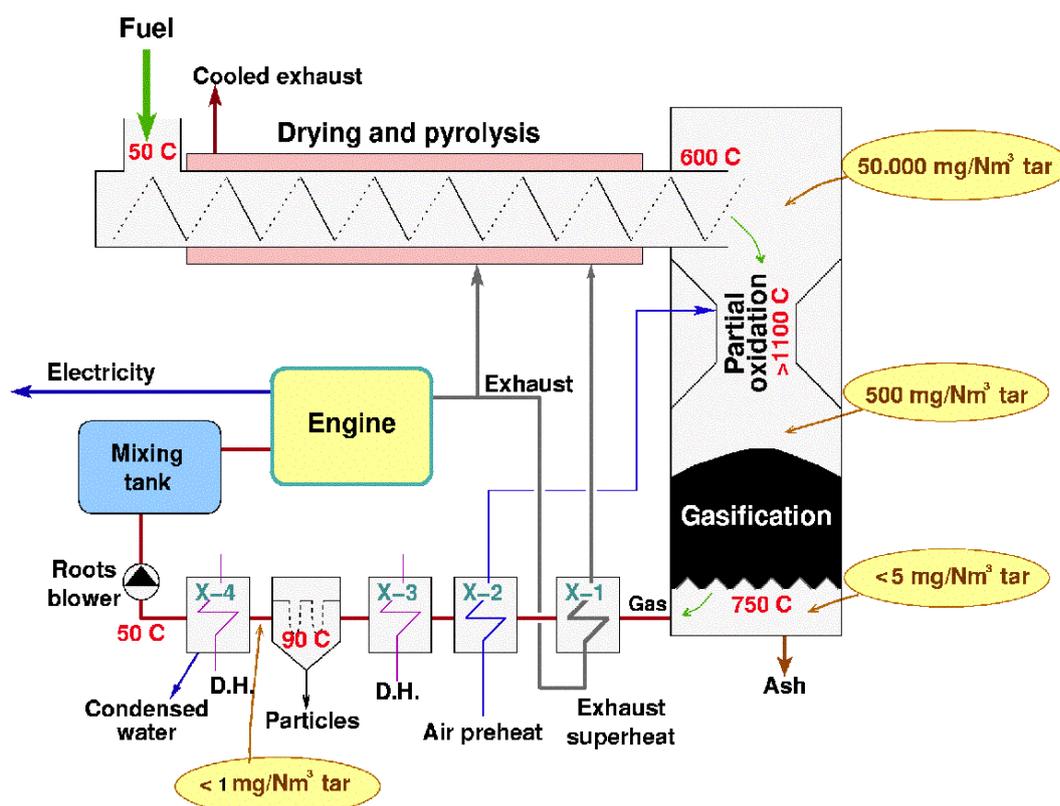


Figure 7.2. Schematic of the Viking gasifier system (courtesy of the Biomass Gasification Group, DTU).

The efficiency in the gasifier is 93 % and the biomass-to-electricity efficiency is 25 % in the pilot plant. The overall efficiency is approximately 80 % when producing 65 kW of heat and

20 kW of electricity. The pilot plant uses a diesel (truck) engine, converted into a lean-burn Otto engine, for power production.

7.2.2 Commercialization

The Viking gasification system has been commercialized by Weiss A/S, in three unit sizes, i.e., 200, 500, and 1000 kW_{el}. This has resulted in two commercial units, one 200 kW_{el} in Hadsund (η_{el} 30%) and one 500 kW unit in Hillerød (η_{el} 33%).

7.2.3 Applicability of the technique

According to DTU's Biomass Gasification Group, the main application of the system in Nordic countries is to replace central hot water plants in district heating networks, improving the electricity production balance from biomass. In developing countries, with their poor infrastructure, the main application of the system will be to produce local electricity from agricultural waste. To this end, the Biomass Gasification Group is participating in development projects in India.

7.2.4 Operation and investment

The plant is fully automated and is remotely supervised, requiring only 1–2 person hours per day of supervision. The cost of a plant is claimed to be “the same as for an equal sized biomass boiler plus the cost of the engine and the generator”.

7.2.5 Engine parameters of the gasifier at Risø DTU, Roskilde, Denmark

The Risø DTU, Technical University of Denmark, Biomass Gasification Group has for several years performed research on small-scale CHP through gasification. This has led to the development of the Viking gasifier test plant, a two-stage wood gasifier. In 2010, the research facilities and all equipment were moved from Copenhagen to the Risø DTU facilities at Roskilde. The gasifier had not yet been set up in its new facility and hence was not operational at the time of our visit. However, this made it more convenient to inspect both the gasifier and the engine setup. The Viking gasifier uses an older three-cylinder, 3.1-litre Deutz-MWM gas engine genset. The engine operates as a lean-burn SI engine with a power rating of approximately 20 kW. The combustion chamber is of typical bowl-in-piston design without pre-chamber. The engine is operated naturally aspirated and the producer gas is fed into the engine induction system from the gasifier through a Roots blower.

The Viking gasifier process is designed for wood chips and yields a producer gas that is comparably clean of tars and other contaminants that could harm the engine. The downside of this gasification process is, of course, that it is inefficient when used with sources of biomass other than wood chips.

The exhaust heat from the engine is used to support the gasification process. The heat used for district heating from the Viking comes from cooling the producer gas after the gasification steps and from the engine cooling circuit. Thus, the engine exhaust heat is used indirectly for district heating. For the Viking test plant, district heating was simulated using an external cooler; the temperature out was 75°C while the return temperature was approximately 35°C.

Engine electrical efficiency has been calculated to be 29% and total electrical efficiency at 25%. Although the engine electrical efficiency is not particularly impressive, the total electrical efficiency is high, thanks to the very high, i.e., 93%, cold gas efficiency of the gasifier. The difference between the electrical engine and total efficiency measures takes account of the power consumed by the electrical equipment needed to operate the gasifier. Such equipment includes fuel feeders, roots blower, and the PLC system.

Table 7.1. Main engine parameters of the gasifier/engine system.

Engine Year model	-
Configuration	In line 3 cylinder
Valves/cylinder	2
Miller-cycle	no
Bore (mm)	105
Stroke (mm)	120
Displacement (liter)	3.1
CR (compression ratio)	-
Speed (rpm)	1500
Electrical output Max	-
Electrical output	17.5 kW
Combustion system	Lean burn Otto
Supercharging	No

Table 7.2. Data on fuel for the gasifier/engine system.

Fuel	Wood chips
Fueling	Port feed through a roots blower
Fuel pressure (bar)	-
LHV (MJ/Nm ³)	6
A/F stoichiometry (Nm ³ /Nm ³)	1.3
LHV stoichiometric (MJ/Nm ³)	2.5
N ₂ (%)	32-37
CH ₄ (%)	1
CO ₂ (%)	15-16
H ₂ (%)	30-32
CO (%)	18-20
Tar raw gas (mg/Nm ³) clean gas (mg/Nm ³)	< 0.1 Below detection
Particles raw gas (mg/Nm ³) clean gas (mg/Nm ³)	- < 5
Ammonia raw gas (ppm) clean gas (ppm)	522-545 mg/Nm ³ 64-141
H ₂ S (ppm) COS (ppm) Cl (mg/Nm ³)	<2 0.93 - (6.7 raw gas)

Since 2002, the gasifier and engine have operated for more than 10,000 hours, and experience indicates very few problems and low maintenance requirements. Early tests revealed misfire problems due to the poor ionization of the producer gas, a problem solved by improving the

isolation of the engine ignition system. Wear is claimed to be lower than in liquid-fuelled engines and oil degrading has been limited as well. The oil exchange interval has been set by BGG at 600–800 hours of operation.

Fuel contamination problems, such as tar condensation in the induction system, have been nearly nonexistent. The engine components have displayed no signs of tar build-up when dismantled. It should be mentioned that the high chlorine content of the producer gas may shorten the oil lifetime and cause corrosion problems in the gas conditioning system, although these effects are marginal.

Table 7.3. Engine exhaust aftertreatment.

Exhaust aftertreatment	No
CO (mg/Nm ³)	
Before cat	1900
After cat	No cat
HC (mg/Nm ³) at 5 % O ₂	40
NO _x (mg/Nm ³)	200
Dust (mg/Nm ³)	
PAH	< 1.95

Table 7.4. Engine and system performance.

Operation hours	>10000
Engine electrical efficiency (%)	29.0
Total Electrical efficiency (%)	25.0
Gasifier efficiency (%)	93
Water temperature to district heating (°C)	70

7.3 MEVA Innovation: VIPP-VORTEX

7.3.1 The cyclone gasifier

Development of the cyclone gasification technique began in the Department of Energy Technology at Luleå Technical University (LTU) in the 1990s, and the first prototype was constructed by the Energy Technology Centre (ETC) in Piteå, Sweden. The technology was thereupon acquired by MEVA Innovation (MI), which has continued the development work in collaboration with ETC. MEVA was visited in February 2011 and both the pilot system and the first commercial CHP system in Hortlax, Piteå, were inspected. At the time of the visit, the commercial CHP system was still under construction, so no actual operational data could be gathered. The engine was installed, however, and could be inspected. Since there are as yet no operational data on the Hortlax CHP system, data from the pilot system are used here.

The biofuel must be ground into sawdust and is pneumatically fed into the gasifier. The air is used for both sawdust transport and partial combustion in the upper part of the cyclone. The sawdust is combusted/gasified while swirling around in the cyclone, and the entrained flow ensures a good heat and mass transport between the gas and the solid. Except for the size of the particles, the fuel is considered flexible, for example, branches, roots, bark, straw, and rice husks all being usable. According to MI, the advantages of the cyclone gasifier over other

gasifiers are that construction is simple and cheap, operation is robust and can handle rapid load changes, and concept should be scalable up to 10 MWth.



Figure 7.3. Schematic of a cyclone gasifier (reproduced courtesy of MEVA Innovation).

7.3.2 The VIPP-VORTEX gasification unit

The pilot plant at ETC in Piteå, Sweden, has a power of 500 kWth with a claimed biomass-to-electric power efficiency of 30%, meaning that 150 kW of electric power could be produced. However, the pilot plant is equipped with only a rebuilt diesel engine, converted into a lean-burn Otto engine, of 50 kW. This means that the excess gas is flared.



Figure 7.4. MEVA Innovation's 500 kW VIPP-VORTEX pilot plant at ETC in Piteå, Sweden.

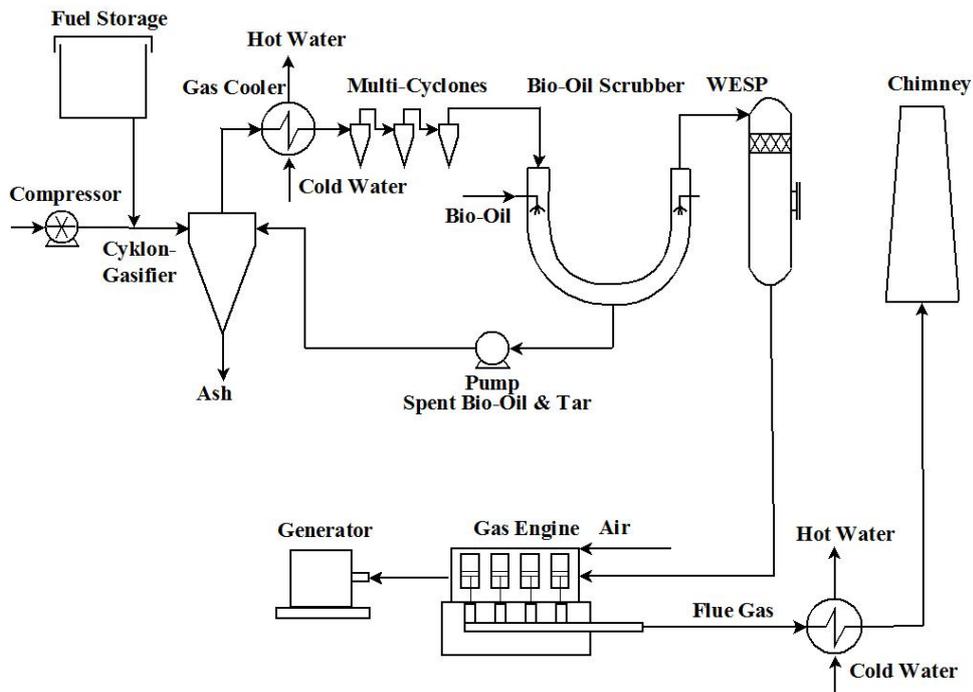


Figure 7.5. Schematic of MEVA Innovation's VIPP-VORTEX gasification unit.

The core of the system is the cyclone gasifier, with the fuel injection system. The gasification occurs at $\lambda = 0.2\text{--}0.4$. After the gasifier, the gas cools down in a gas cooler. Cooling occurs at several places in the system (not shown in the figure) where hot water for district heating is produced. A multi-cyclone package reduces the dust content of the gas before it enters a bio-oil scrubber that makes use of FAME (also called bio-diesel). The bio-oil cools down the producer gas, condensing and absorbing the tars. After the scrubber, the gas passes through a wet electrostatic precipitator (WESP) that removes oil droplets and tar aerosols. The cleaned gas has a temperature of approximately $70\text{ }^{\circ}\text{C}$, a particle density of $5\text{ mg}/\text{Nm}^3$, and an LHV of $4\text{--}5\text{ MJ}/\text{Nm}^3$. The cleaned producer gas is then combusted in a gas engine connected to a generator, producing electric power. However, in the pilot unit at ETC, no electricity is produced; instead, part of the gas is consumed in a rebuilt diesel engine equipped with a water break, while the surplus gas is flared.

7.3.3 Commercialization

MEVA Innovation has sold its first commercial unit, a $3.5\text{ MW}_{\text{th}}$ plant, to PiteEnergi in Piteå, Sweden. The plant is under construction in the village of Hortlax, near Piteå, and completion is planned for May–June 2011. The plant uses the same design as the pilot unit, but scaled up by a factor of 7.

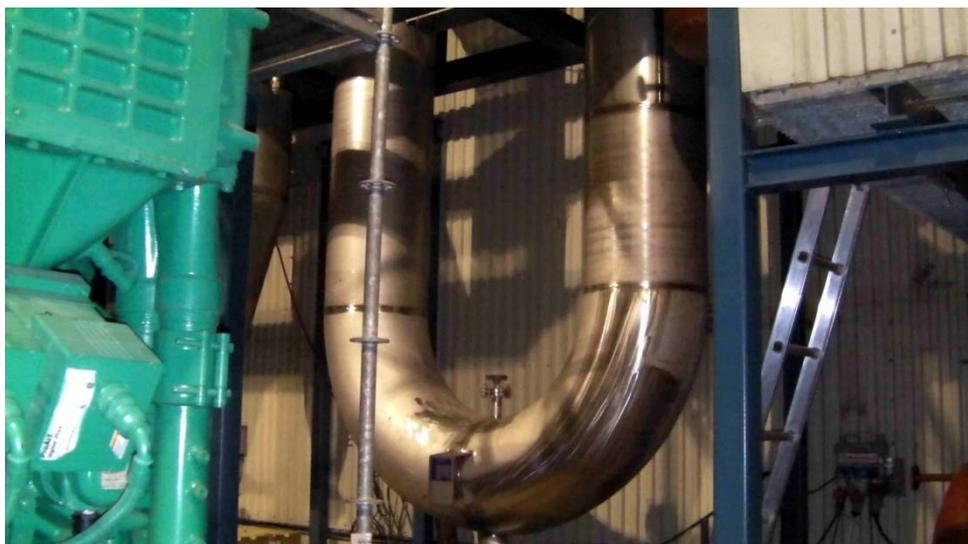


Figure 7.6. Unassembled parts of the Hortlax plant. The bio-oil scrubber is shown in the centre and the gas engine to the left in green.

The Hortlax plant is equipped with a Cummins V18 gas engine, operating as a lean-burn Otto engine, with 90 dm³ cylinder volume and a maximum power of 1.2 MW operating on producer gas.



Figure 7.7 The Cummins V18, 1.2 MW gas engine at Hortlax.

7.3.4 Applicability of the technique

7.3.4.1 Sweden, Nordic Countries, Europe, and industrialized countries with good infrastructure

The main application, according to MI, is in central hot water plants for district heating. As secondary uses, the units can be used as power packs, delivering both heat (or steam) and electric power for industrial facilities (e.g., sawmills and pulp and paper mills) with their own biofuel, such as sawdust and bark.

7.3.4.2 Industrialized countries with some poor infrastructure

In Canada, for example, some municipalities and settlements are in very isolated locations and are surrounded by forest. Application of small-scale CHP technology could produce local and independent district heating and electric power, fuelled with abundant native biofuel.

7.3.4.3 Developing countries with poor infrastructure

In developing countries with poor infrastructure, the technique can be used for local electric power production from agriculture waste, such as rice husks. MI is participating in such projects sponsored by the Swedish International Development Cooperation Agency (SIDA) in India. In warm climates, the produced heat is of limited use, though it might be directly usable in some local industries, such as laundry, fabric dyeing, and silkworm farming. It might also be possible to use the heat for cooling purposes, for example, by means of adsorption cooling. This might be usable for industrial or corporate refrigeration or freezing applications in food production.

7.3.5 Operation and investment

The units are completely automated and supervised remotely. According to MI, only 1–2 person hours per week are needed to supervise operation. MI is reluctant to put a price tag on their units, but claim that the payoff time for a plant of Hortlax size is 3–5 years.

7.3.6 The engine parameters of the gasifier in Piteå, Sweden

The Hortlax facility will use a modern 92-litre, 18-cylinder engine gas engine genset from Cummins (commissioned 2010). The rated electrical power is 1.75 MW, but 1.2 MW is the expected electrical output. The engine uses a lean-burn Otto pre-chamber design with turbocharger and intercooler, the producer gas being introduced before the turbocharger. The installation is prepared for an oxidizing catalytic converter, if such would be required in the future.

The MEVA pilot plant uses an older in-house converted diesel genset, also from Cummins. The conversion consisted of replacing the high-pressure diesel-fuel direct injector with a spark plug and ignition system, making the engine an SI engine. There is no information on whether the combustion chamber shape within the pistons was changed from the original diesel bowl-in-piston design to the more open bowl-in-piston design typical of gas engines. There is no pre-chamber and the engine does not have any supercharging and is thus naturally aspirated. Fuel is fed into the induction system in a fashion similar to that of the Viking engine.

Engine operation using the pilot gasifier gas was reported to be without problems, except for the over-simplified engine control that made speed control cumbersome. MEVA expects no specific problems with the commercial engine installation.

Table 7.5. Main engine parameters of the gasifier/engine system.

	MEVA-Pilot	MEVA-Hortlax
Engine	Cummins 4BTA3.9-G Diesel genset converted to gas	Cummins QSV91
Engine Year model	Nd	2010
Configuration	I4	V18
Valves/cylinder	2	4
Miller-cycle	No	No data
Bore (mm)	102	180
Stroke (mm)	120	200
Displacement (liter)	3.9	91.6
CR	12:1	12:1
Speed (rpm)	1500	1500 rpm
Electrical output Max	50 kW	1.75 MW
Electrical output	50 kW	1.2 MW
Combustion system	Lean burn Otto	Lean burn Otto
Supercharging	No	Turbo intercooler

Table 7.6. Fuel gas data.

	MEVA-Pilot	MEVA-Hortlax
Fuel	Wood pellets	Wood pellets
Fueling	Blower	Blower
Fuel pressure (bar)	-	0.3-0.6
LHV (MJ/Nm ³)	4.6	-
N ₂ (%)	57	-
CH ₄ (%)	2.4	-
CO ₂ (%)	12.5	-
H ₂ (%)	8.1	-
CO (%)	15.9	-
Tar		
raw gas (mg/Nm ³)	-	-
clean gas (mg/Nm ³)	<50	-
Particles		
raw gas (mg/Nm ³)	-	-
clean gas (mg/Nm ³)	0.06	-
Alkali (mg/Nm ³)	<0.06	-
Sulphur (mg/Nm ³)	4.4	-

No measurements of the concentration of ammonia and chlorine were performed by MEVA. However, since the chlorine content in the fuel is low, the concentration in the syngas is also expected to be low (according to MEVA).

Table 7.7. Engine and system performance.

	MEVA-Pilot	MEVA-Hortlax
Gasifier efficiency (%)	-	85
Investment genset	11320 €	679 000 – 905600 €
Service h/oh	-	750h oil + filter + spark plugs 15000h inspection, gasket change 30000h main service
Service cost/ oh	-	15.3 €/h

7.4 Güssing bio-power station (BKG)

7.4.1 Introduction

Güssing is located in a depopulated region of Austria without any noted industries or other larger workplaces. The only abundant resource is forests, which cover 40 % of the district's area. As early as 1991, it was decided that all energy requirements should be met by renewable sources, so a biodiesel plant and district heating system fuelled with biomass was installed. In the last years before the new millennium, an initiative was taken to implement technologies developed at the Technical University of Vienna at this location. The construction took place between 2000 and 2001 and was funded by European and national funds and private investors. The plant is a commercial operation producing electricity and district heating for the surrounding area. The plant is also the core of an energy research centre focusing on gasification techniques with an array of related pilot projects, for example, SNG and methanol production, FT processing, and the use of solid oxide fuel cells (SOFC). At the end of 2004, the plant had run for 11,500 hours producing 21,000 MWh of electricity. The Güssing community has developed into a research centre testing “green” energy for a sustainable society. We visited Güssing in March 2011 and inspected the gasifier.

The plant uses steam gasification and is indirectly heated by hot bed material from an external riser. The gasifier can be described as of BFB design with an internally circulating bed (Figure 4.7). Part of the main BFB, containing unconverted char, is moved over to the raiser where it meets air as the raiser medium. The char is combusted during transport to the top of the raiser, heating the entrained bed material in the process. At the top of the raiser, the hot solid bed material is separated in a cyclone and returned to the BFB, while the flue gas goes to the stack. The plant has a thermal input of 8 MW and uses wood chips as biofuel, as can be seen in the foreground to the right in Figure 7.8.



Figure 7.8. Güssing bio-power station (photo by Jan Brandin).

The plant has a total thermal input of 8 MW_{th} , and produces 2 MW_{el} of electric power and $4.5 \text{ MW}_{\text{th}}$ of district heating. The biomass-to-electricity efficiency is 25% and the overall efficiency is 81%.

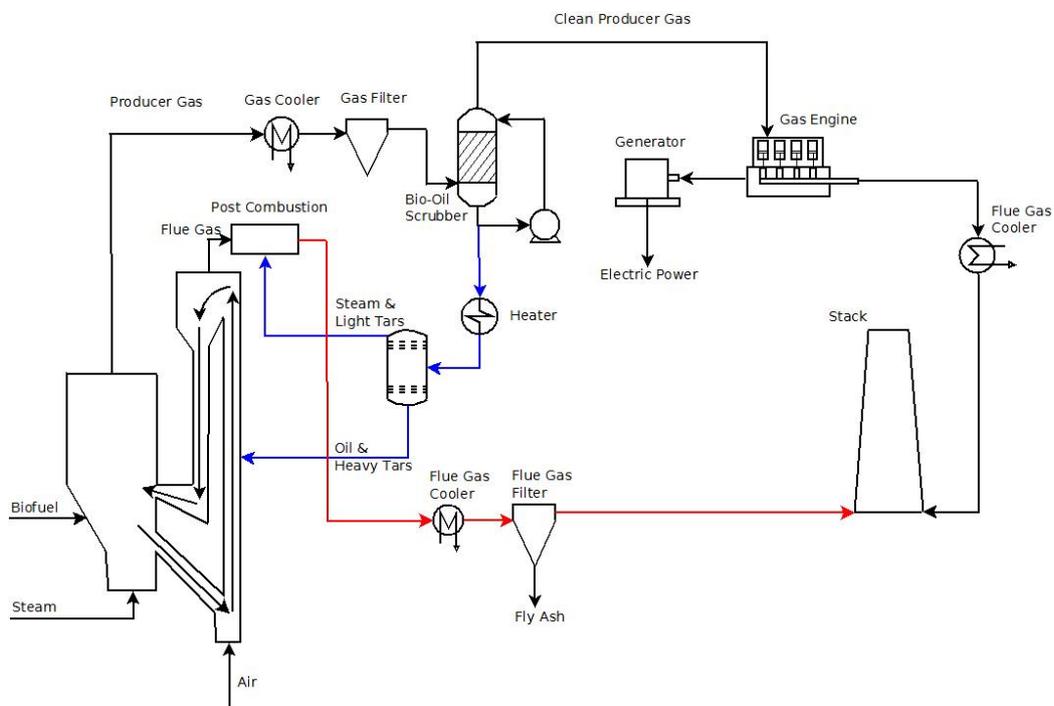


Figure 7.9. Schematic of the Güssing bio-power station.

The biofuel, wood chips, is fed into the gasifier by a transport screw and steam is added to the gasifier as both the fluidization medium and – since the process is steam gasification – also

the gasification medium. When the biofuel enters the 800–900 °C BFB, it pyrolyses, leaving char in the bed. Part of the bed, comprising bed material and char, floats through a transport leg to the riser. Air is injected into the riser, entraining the char and bed material. The char is combusted by the oxygen in the air during transport upward, and the heat of char combustion heats the entrained bed material. At the top of the riser, the hot bed material is separated in a cyclone and returned to the BFB while the flue gas is separated.

The producer gas leaving the BFB gasifier is first cooled in a gas cooler to 160–180 °C, after which it passes through a fabric bag filter to remove dust. The dust-free gas is then scrubbed with FAME. In this step, all the tars are condensed and absorbed and, since the temperature decreases to 40 °C, most of the water condenses as well. The clean dry producer gas is then fed into a Jenbacher gas engine. If the engine is offline, the gas can be burned in a boiler to produce heat. Heat is retrieved at several points in the system to produce hot water for the district heating network.

The spent bio-oil, saturated with tars and condensate, is heated in a steam generator. The light tars and water are vaporized and fed into a post-combustion chamber where they are mixed with the hot flue gases from the riser and combusted. The liquid remains, i.e., the spent bio-oil and heavy tars, are fed into the combustion zone in the riser. This treatment of the tars and the condensate recalls the TARWATC process of Babcock-Wilcox Vølund.

7.4.2 Commercialization

Austrian Energy and Environment, now owned by Andritz, holds the patents to the technology in Austria. Two companies, Ortner Anlangenbau and Repotec, have built commercial plants of this type under licence in Austria (the patents only apply in Austria).

Table 7.8. Commercial plants.

Location	Thermal input (MW _{th})	Electricity output (MW _{el})	Operation
Austria			
Güssing	8	2	2002
Oberwart	8.5	2.8*	2008
Villach	15	3.7	2010
Klagenfurt	25	5.5	Planned for 2011
Germany			
Ulm	15	5.3*	2010

* Gas engine/ORC

Table 7.8 shows the actual and planned installations of this system. Two installations use both gas engines and the organic Rankine cycle (ORC). ORC is a process for producing electric power from lower-value heat by vaporizing an organic compound with a lower boiling point than that of water, as in the usual steam power cycle (i.e., the Rankine cycle). ORC works by boiling the liquid organic compound with external heat, generating pressure to run a turbine,

then condensing the organic vapour in an externally cooled condenser, and returning the liquid to the boiler in a closed loop. Depending on the choice of organic compound, the boiling and condensing temperatures can be adapted to fit various heat/cooling systems. For example, the heat for the boiler can come from the hot engine exhaust gases, while the chilling for the condenser can come from the cooled water returning through the district heating network to the central steam plant. Applying OCR to a CHP process can convert 10–15% of the produced heat into electric power. Since, approximately, twice the amount of heat is produced, compared with the amount of electric power produced, it means that the electric power production can be increased by 20-30 %.

7.4.3 Applicability of the technique

The plants are considered appropriate for municipal heat and power plants.

7.4.4 Operation and investment

The Güssing plant is a demonstration and research facility. For this reason, the operation of the plant is handled manually. However, ensuing plants should be fully automated and unmanned, considerably reducing the operational costs. The investment cost as of 2001–2002 was EUR 10 million and the manned operational cost/year represents 10–15 % of the investment cost.

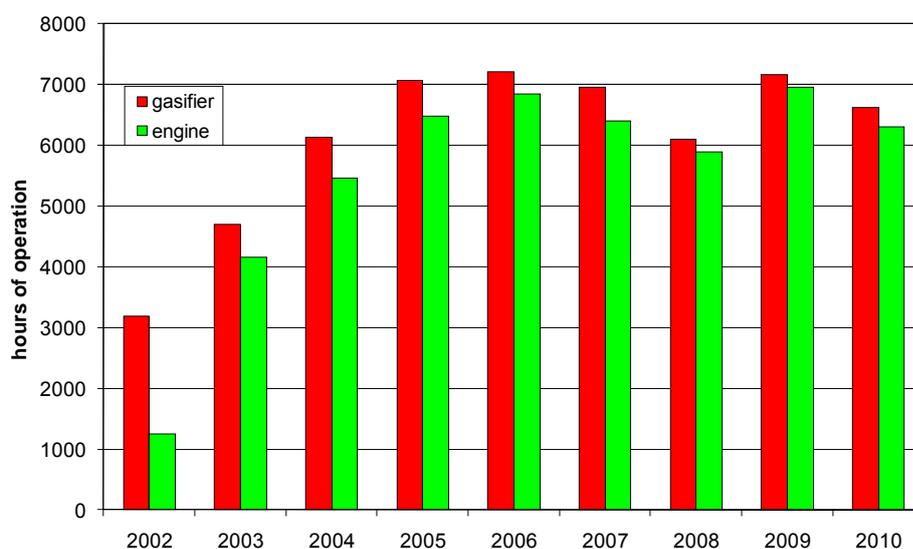


Figure 7.10. Availability of the Güssing bio-power station, 2002–2010 (courtesy of TU Wien, AT).

7.4.5 The engine parameters at Güssing, Austria

At the time of the visit, the CHP plant was in full operation so examining the engine was impossible. The gasifier was built and the engine commissioned in 2002. The 125-litre, 20-cylinder engine is a bespoke producer gas engine genset designed and built by GE's Jenbacher gas engine business. The rated electrical power is 2.0 MW and electrical efficiency 39%. It is

of a lean-burn Otto pre-chamber design, equipped with turbocharger and intercooler, and the producer gas is introduced before the turbocharger. The intake charge is not extensively cooled, but is kept above 50°C to avoid tar condensation in the turbocharger and induction systems.

Table 7.9. Main engine parameters.

Engine	GE's Jenbacher J620 GS
Engine Year model	2001
Configuration	V20
Valves/cylinder	4
Miller-cycle	No data
Bore (mm)	190
Stroke (mm)	220
Displacement (liter)	124.8
CR	12.0
Speed (rpm)	1500
Electrical output Max (MW)	2.0
Electrical output (MW)	1.5
Combustion system	Pre-chamber, Lean-burn Otto
Supercharging	Turbo, intercooler

Table 7.10. Fuel gas data.

Fuel	
Fueling	Central injection prior to compressor Intake charge kept above 50 °C to avoid condensation of tars in compressor
Fuel pressure (bar)	-
LHV (MJ/Nm ³)	10-12
A/F _{stoich} (Nm ³ /Nm ³)	2.7
LHV _{stoich} (MJ/Nm ³)	3.2
N ₂ (%)	3-5
CH ₄ (%)	8-12
C ₂ H ₆ (%)	2
CO ₂ (%)	15-25
H ₂ (%)	35-45
CO (%)	20-30
Tar	
raw gas (mg/Nm ³)	1500-4500
clean gas (mg/Nm ³)	10-40
Particles	
raw gas (mg/Nm ³)	5000-10000
clean gas (mg/Nm ³)	< 5
Ammonia	
raw gas (ppm)	1000-2000
clean gas (ppm)	<400
H ₂ S (ppm)	20-40
COS (ppm)	
Cl (mg/Nm ³)	

Compared with the PG from the other gasifiers examined here, the Güssing PG contains very little nitrogen and more hydrogen, giving it a higher total energy content (Table 7.10). The low nitrogen and high hydrogen content should likely lead to higher combustion rates and could cause knock problems. The comparatively high LHV of the mixture would likely be beneficial for engine-out power and efficiency.

To reduce CO emissions from 3000–4500 ppm to below the required 650 ppm, an oxidizing catalytic converter is used to good effect. The conversion efficiency of this converter is very high, reducing CO to less than 400 ppm. However, problems were encountered with condensation on the catalyst gradually reducing its performance (Figure 7.11). After changing the catalyst and the position of the catalytic converter, conversion has remained above 85% for more than 15,000 hours of operation.

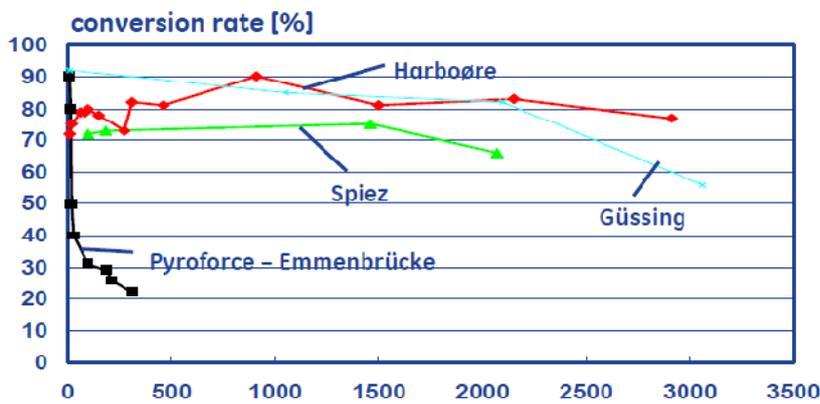


Figure 7.11. Conversion rate of the oxidizing catalytic converters at Güssing and other facilities. The figure shows the degrading of the first catalyst at Güssing due to condensates (courtesy of GE's Jenbacher gas engine business) [19].

Table 7.11. Engine exhaust aftertreatment.

Exhaust aftertreatment	Oxidizing catalytic converter for CO and HC
CO (mg/Nm ³)	
Before cat	900-1500
After cat	100-150
HC (mg/Nm ³) at 5 % O ₂	-
NO _x (mg/Nm ³)	300-350
Dust (mg/Nm ³)	< 20

Table 7.12. Engine and system performance.

Operation hours	>100000
Engine electrical efficiency (%)	39.0
Total Electrical efficiency (%)	25.0
Gasifier efficiency (%)	81.3
Water to district heating (°C)	80

7.5 Harboøre

7.5.1 Introduction

The Harboøre plant is a reference plant for Babcock-Wilcox Vølund. It is based on a 5.2 MW_{th} fixed-bed updraft gasifier design and began operating in 1993. It was originally intended to operate with a catalytic tar cracking or reforming step; however, this was abandoned in 1997. Finally, a process step based on condensing the tar and water was developed and successfully tested in 2001. The condensate separates into two phases, tar and tar–water. The tar fraction consists of the heavy tars, non-polar in nature and insoluble in water. This fraction has an LHV of 25 MJ/kg and, after separation, can be burned in a boiler to produce heat for district heating.

The tar–water phase consists of the water and the lighter oxygenated tars (e.g., acids, alcohols, and aldehydes) that partly dissolve and partly emulgate in water. This tar–water mixture is destroyed in a thermal process, TARWATC, described in section 5.2.1.2.

The wood chip biofuel is fed into the top of the gasifier, while the air is fed into the bottom and the producer gas leaves at the top. The producer gas is fed into the condenser, producing 1100 kg/h of tar–water mixture and 100 kg/h of tar. The heat recovered by the condenser is fed into the district heating network. After the condenser, the gas passes a WESP for the removal of droplets and aerosols.

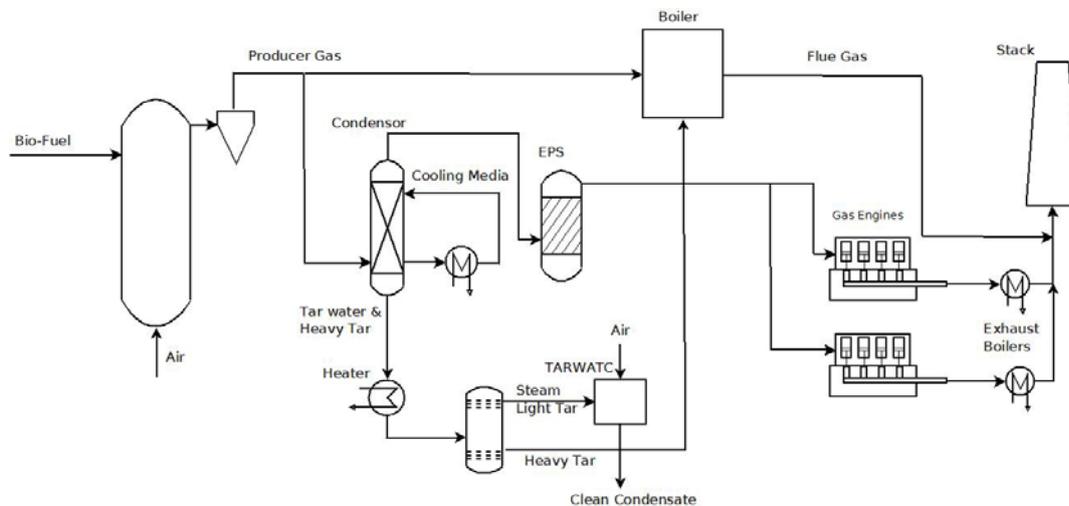


Figure 7.12. Schematic of the Harboøre plant.

The clean producer gas is combusted in two Jenbacher gas engines together producing 1.4 MW of electricity. The thermal output of 3.4 MW_{th} is used in the district heating network. This gives a biofuel-to-electricity efficiency of 28% and an overall efficiency of 93%. It is also possible to burn all the producer gas in the boiler for district heating peak loads, producing 4.2 MW_{th}.

7.5.2 Applicability of the technique

The standard Babcock-Wilcox Vølund module is available with a nominal power of 2 MW_{el} (7 MW_{th}). It should be possible to drive units producing 1–7 MW_{el} (3–23 MW_{th}) with one

gasifier, but such units are not available yet. The plants are considered appropriate for municipal heat and power stations.

7.5.3 Operation and investment

The plant is fully automated and designed for unattended operation. On average, it has operated for 8000 hours per year, for a total of more than 100,000 hours since 1993. As a demonstration plant, the investment cost was approximately EUR 9 million; a commercial plant should cost approximately EUR 6 million (2005).

7.5.4 The engine parameters at Harboøre, Denmark

Two Jenbacher gas engine gensets are used at the Harboøre facility. These engines are older (commissioned 2000) and of different, smaller design from those at Güssing and Skive. When installed, the engines were derated from the original 1000 kWel (under natural gas operation) to 643 kWel, but they were later uprated to 760 kWel (corresponding to 13 BMEP). Each 49-litre, 20-cylinder engine is equipped with turbocharging and intercooling. Combustion is according to a lean-burn Otto pre-chamber design, and the producer gas is introduced before the turbocharger. The engines have been in operation for more than 80,000 hours and no particular problems have been reported to the authors. It was impossible to visit the Harboøre facility within the time allocated for preparing this report.

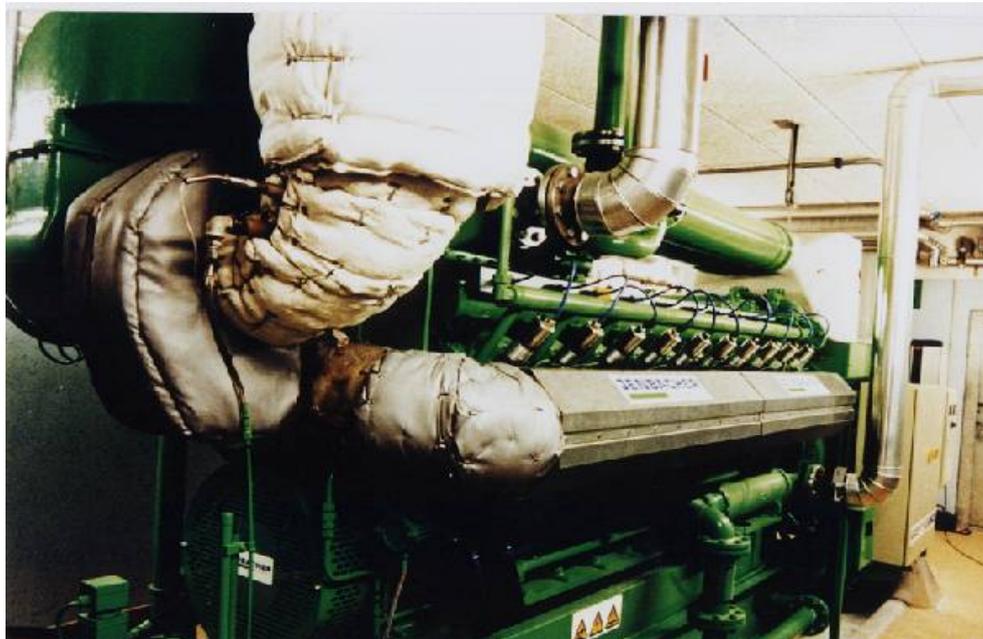


Figure 7.13. Jenbacher engine at the Harboøre plant (courtesy of GE's Jenbacher gas engine business) [19].

Table 7.13. Main engine parameters.

Engine	2 * Jenbacher 320 GS
Engine Year model	2000
Configuration	V20 70°
Valves/cylinder	
Miller-cycle	No data
Bore (mm)	130
Stroke (mm)	170
Displacement (liter)	48.7
Electrical output (kW)	2 * 760
Combustion system	Pre-chamber. Lean-burn Otto
Supercharging	Turbo, intercooler

Table 7.14. Fuel gas.

Fuel	Wood
Fueling	Port injection prior to compressor
LHV (MJ/Nm ³)	5.6
A/F _{stoich} (Nm ³ /Nm ³)	1.2
LHV _{stoich} (MJ/Nm ³)	2.6
N ₂ (%)	41
CH ₄ (%)	5
CO ₂ (%)	12
H ₂ (%)	19
CO (%)	23
Tar raw gas (mg/Nm ³) clean gas (mg/Nm ³ dry)	80000 < 2
Particles raw gas (mg/Nm ³) clean gas (mg/Nm ³)	- 6
Ammonia raw gas (ppm) clean gas (ppm)	0.01 mg/Nm ³

Table 7.15. Engine exhaust aftertreatment.

Exhaust aftertreatment	No data
CO (mg/Nm ³) Before cat After cat	1500
HC (mg/Nm ³) at 5 % O ₂	6
NO _x (mg/Nm ³)	400

Table 7.16. Engine and system performance.

Operation hours	>80,000
Engine electrical efficiency (%)	40
Total electrical efficiency (%)	28

7.6 Skive

7.6.1 Introduction

The Skive plant is used as a research and development facility in cooperation with Skive Fjernvarme and the builder Carbona/Andritz. The plant has a nominal thermal output of 19.5 MW (maximum 28 MW), making it too large to be included in this study. However, the plant was examined because of its interesting use of catalytic tar reforming. The plant's three Jenbacher gas engines produce 6 MW of electric power and 11.5 MW of heat in CHP mode, but all the gas can, alternatively, be burned in the two gas boilers. The biofuel-to-electric power efficiency is 31 % and the overall efficiency is 90 %.

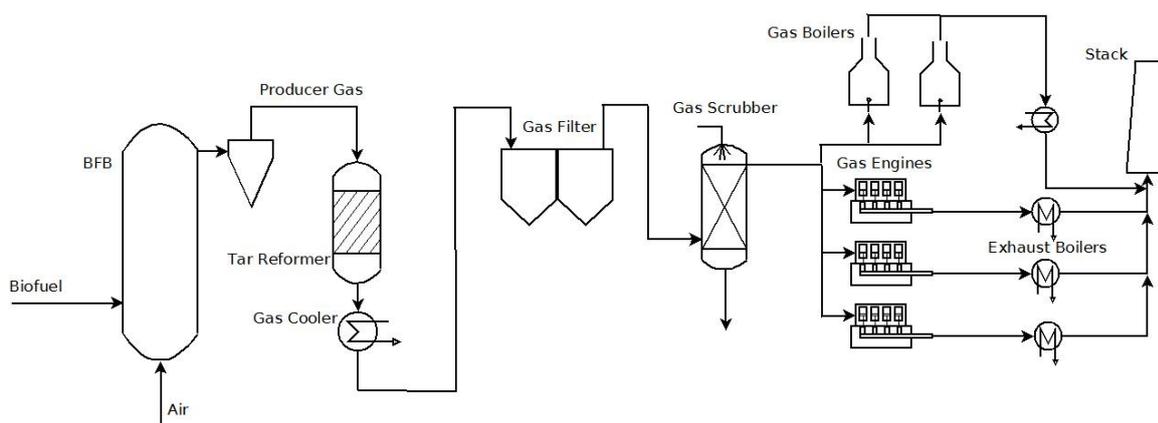
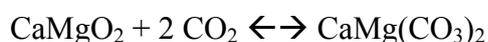


Figure 7.14. Schematic of the Skive plant (Carbona/Andritz).

The gasifier is of air-blown BFB design, fed with wood pellets and chips and operated at a pressure of 0.5–2 bars. The bed material is dolomite, giving the gasifier some tar cracking capability, and the tar level after the gasifier is claimed to be low. Dolomite is a naturally mixed calcium–magnesium carbonate; when used for tar cracking, it is decomposed by heating into calcium–magnesium oxide, which is the active component. However, if the CO₂ partial pressure becomes too high, the oxide reverts to carbonate at the gasification temperature, and other bed material has been or is being tested to find a way to avoid this.



The producer gas enters the reformer, which operates at a temperature of 950–850 °C. Since the reforming reaction is endothermic, this might mean that the producer gas enters at 950 °C and leaves at 850 °C, but this is not specified. The monolithic catalyst is provided by Haldor Topsø A/S and is probably based on Ni/spinel; however, the catalyst composition was not specified. According to Carbona/Andritz, no soot forms and the pressure drop is stable, but steam/nitrogen pulsing is used to clean the catalyst bed. A new catalyst was installed in the summer of 2009. At the SGC international seminar in Gothenburg in October 2010, Kari Salo (Carbona) stated that the initial tar conversion over the catalyst was 90 % but had decreased to 70 % by October 2010. However, no heavy tars were found after the reformer completed 7500 hours of operation.

The ammonia in the gas should be decomposed by ammonia cracking over the reforming catalyst; however, the ammonia conversion over the catalyst has been low, and a maximum of 60 % has been obtained. Since the ammonia is very water soluble, it follows the condensate and ends up in the scrubber water and finally the wastewater. The nitrogen level in the wastewater has been too high to be accepted at municipal wastewater plants. An active carbon filter is needed to treat the wastewater to reduce its organic content.

7.6.2 Applicability of the technique

The plant is considered appropriate for a municipal heat and power plant.

7.6.3 Operation and investment

The plant is fully automated. No information on investment costs was available.

7.6.4 The engine parameters at Skive, Denmark

The Skive plant could not be visited but uses three Jenbacher wood gas engines with the same designation as the one at BKG Güssing. The engines at Skive are, however, six years newer and their design should likely have benefited from the experiences in Güssing, possibly with higher efficiency. Each engine has a 125 liter displacement, 20 cylinders, turbocharging and intercooling. Combustion principle is lean-burn Otto pre-chamber design and the producer gas is introduced before the turbocharger.



Figure 7.15. The three Jenbacher gas engines at the Skive plant (courtesy of GE's Jenbacher gas engine business) [19].

Table 7.17. Main engine parameters.

Engine	3 * GE's Jenbacher J620 GS
Engine Year model	2008
Configuration	V20
Valves/cylinder	4
Miller-cycle	Nd
Bore (mm)	190
Stroke (mm)	220
Displacement (liter)	124.8
CR	12.0
Speed (rpm)	1500
Electrical output Max (MW)	3 * 1.97
Combustion system	Pre-chamber, Lean-burn Otto
Supercharging	Turbo, intercooler

Table 7.18. Fuel gas data.

Fuel	Wood
Fueling	Blower before TC
Fuel pressure (bar)	-
LHV (MJ/kg)	4.8-5.2
A/F _{stoich} (Nm ³ /Nm ³)	-
LHV _{stoich} (MJ/Nm ³)	-
N ₂ (%)	42
CH ₄ (%)	4
CO ₂ (%)	12
H ₂ (%)	20
CO (%)	22
NH ₃ +HCN (%)	0.005 design basis
H ₂ S + COS (%)	0.008 design basis
HCl (%)	0.003 design basis

Table 7.19. Engine and system performance.

Operation hours	>10.000
Engine electrical efficiency (%)	Estimated 41%
Total Electrical efficiency (%)	30

7.7 International outlook

The material presented in this section comes mainly from literature published in 2009 and 2010. The material concerning China is from 2002.

7.7.1 Developing projects in various countries

BTG biomass technology group BV, earlier known as the Biomass Gasification Group at the University of Twente, The Netherlands, started activity in 1979. This group has worked on small- to medium-scale biomass-fuelled power and heat gasifiers in many countries [1], including Tanzania, Sri Lanka, Indonesia, Brazil, Ivory Coast, Seychelles, Fiji, Solomon Islands, Vanuatu, Uruguay, Paraguay, and Ecuador. The following are some examples of implementation projects:

Netherlands (Schiedam)

- responsible for equipment purchasing and for supervising the construction of two 150 kWe grid-connected fixed-bed down-draft gasification systems for ONS, a power utility based in Schiedam

Netherlands (Bladel)

- responsible for the design, engineering, and implementation of a 60 kWe farm-scale gasifier CHP system
- the system uses chicken manure from the poultry farm of Duis VOF in Bladel

Fiji, Vanuatu, Solomon Islands, Papua New Guinea, and Western Samoa (South Pacific)

For ten biomass gasification projects, BTG provided one or more of the following: project identification, site selection, technical and economic feasibility studies, resource assessments, project monitoring and evaluation, training for operation and maintenance, and commissioning. The locations were: Batuna sawmill (Vangunu island, Solomon Islands), Onesua High School (Efate island, Vanuatu), Menvuvu (West New Britain, Papua New Guinea), Electric Power Corporation (Apoa, Samoa), and various sites in Fiji. This work was undertaken for SPEC, in 1985–1993.

Ghana

- feasibility study and demonstration project for decentralized electrification, handling the identification, evaluation, and selection of potential biomass project sites for Shell International Renewables, 1999

Indonesia

- study of the feasibility of setting up an Indonesian–Dutch entity to produce and market biomass gasifiers for stand-alone energy generation and rural electrification
- preparation of a pilot project on biomass gasification for Senter, 1999

Indonesia

- technical and financial assessment of the performance of existing gasifiers in Indonesia
- helped the government of Indonesia determine the technical, financial, and economic performance of gasifier installations, including social, institutional, and environmental aspects
- transferred knowledge to Bandung Institute of Technology (ITB)
- work undertaken for UNDP/World Bank, 1987–1989

Indonesia

- performed a feasibility study of the application of biomass gasification in Indonesia before investment decisions were made
- work undertaken for ESMAP, 1989

Indonesia, Sri Lanka, and Tanzania

- co-ordination of the biomass gasification programmes of the Netherlands Ministry of Foreign Affairs in three countries (Indonesia, Sri Lanka, and Tanzania); work undertaken for DGIS, early 1980s
- made recommendations concerning a demonstration project in Ouled M'lik for village electrification using biomass gasification; work undertaken for Shell International Renewables, 1998

Nicaragua/Guatemala

- pre-feasibility assessment for electrification by biomass gasification in rural areas in Nicaragua (Puerto Cabezas) and Guatemala (Santa Elena)
- work undertaken for Shell International Renewables, 1998

Solomon Islands

- performed a feasibility study for power generation at Batuna Sawmill; study included project identification, equipment commissioning, testing at manufacturers, and operator training
- studied a 15 kW_e BTG/BECE charcoal gasifier generating plant for electricity generation
- work undertaken for South Pacific Bureau for Economic Cooperation (SPEC) and European Commission (DG VIII), 1986–1988

Thailand

- supervised the monitoring of the ferrocement gasifier at the Asian Institute of Technology (AIT) Bangkok, Thailand
- project later transferred to the Bandung Institute of Technology (ITB) in Indonesia
- work undertaken for UNDP/World Bank, 1990

Vanuatu

- biomass gasification for power generation project started for Onesua High School
- feasibility studies, equipment commissioning, testing at manufacturers, and operator training
- project involved the supply, installation, and commissioning of a 35 kW_e wood gasifier generating plant
- work undertaken for South Pacific Bureau for Economic Co-operation (SPEC) and European Commission (DG VIII), 1985–1986
- after plant was used for at least ten years, the power plant was refurbished; work undertaken for Shell International Renewables, 1998–1999
- since 2007, BTG has increasingly worked with private energy producers

7.7.2 Projects in Nova Scotia, Canada

The province of Nova Scotia in Canada has large biomass resources. This prompted a study of how decentralized power generation could improve Nova Scotia's renewable energy strategy, and how this would affect a range of social and economic factors in rural areas of the province [2].

The recommendations of the project were as follows:

- Establish a province-wide feed-in-tariff to help promote investment
Encourage communities to get finance for initial start-up costs
- Ensure that the combined (i.e., electrical and thermal) efficiencies exceed 80%

Though energy production from forest biomass could be an opportunity for rural Nova Scotia, the unsustainable use of these fuel resources could be a problem. Therefore, public policy must be developed to prevent unsustainable use from occurring.

7.7.2.1 Scaling technologies to various uses

Some technologies are better suited for smaller scales of energy production. For example, a combustion furnace or wood stove is appropriate for space heating at the household scale.

Combined heat and power (CHP) biomass plants can yield high efficiencies only by capturing low-quality heat for uses such as space and water heating. Biomass facilities without heat capture waste energy resources. Therefore, it is very important that heat production from CHP biomass facilities be combined with use of the low-quality heat produced.

7.7.2.2 Transportation

Transportation costs can constitute a large portion of the cost of feedstock used in power plants. A Wisconsin study of the use of switchgrass as fuel in a CHP system determined that energy production costs increased 10% for every 48 km the fuel was transported. The transportation distance limitations are probably the same for wood. The existence of many small-scale biomass facilities, instead of a single large one of the same total capacity, can result in shorter transportation distances and thus reduce stress on biomass resources. It is recommended that fuel sources and biomass energy facilities be situated under 80 km from each other.

7.7.2.3 Small-scale biomass facilities: established projects

The paper [2] cites examples from two biomass energy facilities using the combination of gasifier and gas engine that could be used as models for small-scale, decentralized biomass energy development in Nova Scotia.

7.7.2.3.1 Community Power Corporation (CPC), BioMax25, USA

CPC developed a 12.5 kW_{el} modular system to produce energy for a remote community in the Philippines using coconut shell husks as fuel. The company had previously produced 5 and 15 kW_{el} systems; CPC nowadays markets a modular 25 kW_{el} CHP unit. This unit is completely self-contained and offers fully-automated, turnkey start-up/shut-down.

The BioMax 25 contains a downdraft gasifier yielding a clean gas. After filtration and cooling, the gas is injected into an internal combustion engine that drives an alternator to produce electricity.

Excess heat energy is collected throughout the process and is used for fuel drying and other thermal applications. Fuels include wood residues, shells or husks, agricultural residues, waste paper, and commercial pellets.

Customers have been furniture makers, walnut farms, and the US military. Customers usually have their own cheap fuel source, such as wood wastes or walnut shells.

7.7.2.3.2 Tervola, 470 kW_e, Finland

The Tervola system, built by Finnish company Entimos Oy, uses a combined counter-flow/forward-flow process that separates and burns the dirtier gasses in a separate gas boiler while the clean fuel is fed into a gas engine. Ninety percent and 10% of municipal thermal and electrical energy needs, respectively, are met by this plant. Tervola municipality has approximately 4000 inhabitants, and local sawmills provide the feedstock.

This system has a relatively high power-to-heat ratio of 0.42. In 1999, EUR 1,300,000 was invested in the plant, with the state government contributing 27 % of the total funds. The payback time was estimated to be 6–7 years.

7.7.3 India

SIDA and the Swedish Energy Board financed a trip to India in 2007, the aim of which was to study the development of Indian gasification technology [3].

The report states that small-scale gasification for heat and power production is based on fixed-bed gasifiers in India. Most of these gasifiers are downdraft while some are updraft. There are many actors in the area, ranging from small family companies to large, well-established ones. The Indian government supports development efforts by buying plants or granting money to those who install additional capacity in current sites.

The sizes of these biofuel gasification plants normally range between 10 and 500 kW_{el}, though there is a trend toward bigger electrical capacities. The plants can be found both at industrial sites and in rural areas. Smaller plants (10 kW_{el}) are used in villages, for example, for water pumping and lighting.

Diesel engines converted to dual-fuel engines were used at first, resulting in a 50–80% reduction in fossil fuel consumption. In recent years, more suppliers have started delivering 100% producer gas plants using dedicated gas engines. Cummins gas engines are the most common engines used.

The gasification plants seem to work well when qualified labour is available. Plants in rural areas suffer from some operation problems, both political and technical. Technical problems are mostly caused by the manual operation of the plants. The main reasons for such difficulties are:

1. shortage of fuel supplies
2. biofuel specifications are not met
3. shortage of labour, both skilled and unskilled
4. unstable national electricity grid

The gas cleaning system is based on water scrubbing. Water used in the scrubbing is replaced several times annually and disposed in the fields. The producer gas contains tars, phenols, and other harmful components. The disposed water can become mixed with groundwater and other water sources, which will cause environmental damage and possibly health problems.

All actors are aware of the problem but are convinced that the main task now is to meet the need for electricity and reduce CO₂ emissions; other considerations will be dealt with later.

The main conclusions from this trip were as follows:

1. Indian biomass gasification technology functions well when operated by skilled labour
2. The plants are mainly manually operated, which would be costly in a developed country
3. The plants must maintain operating data to enable identification of problems associated with plant operation
4. Water scrubbing causes environmental damage; there is need to develop a better cleaning system

Another study [4] demonstrated the potential of gasification projects in India. Preliminary estimates based on this study indicate a very large theoretical potential for CO₂ mitigation by means of biomass gasification projects in India.

In India, approximately 74 million tons of agricultural residues can be used for energy applications every year. The total capacity of biomass gasification could reach 31 GW, which could generate more than 67 TWh of electricity annually.

Projections based on past trends indicate that the practical use of biomass gasification plants is unlikely to peak for another 50 years in India.

Yet another paper [5] describes the technical and economic problems related to decentralized power generation in India using biomass gasification. Biomass-based energy has several advantages, such as wide availability and uniform distribution of biomass throughout the country. The estimated power generation potential of renewable energy sources in India is 85 GW, with biomass power contributing approximately 20 GW. Particularly in remote and hilly areas of India, biomass gasification-based power generation offers a very attractive way to meet the energy demands of small villages. This will not only make them independent but will also reduce the burden on the state electricity board.

7.7.4 Uganda

7.7.4.1 The Kasenge farm in Mukono

The potential of distributed wood-based power systems to meet basic electricity needs in rural Uganda has been investigated [6], and a case study of a 10 kW_{e1} project in the Kasenge farm in Mukono was presented.



Figure 7.16. Gasifier (left) and gas engine (right) at Mukono, Uganda (photo courtesy of T. Buchholz).

Table 7.20. Calculation of costs and revenues

Category	Unit	Amount
Installed capacity	kW	25
Capital cost	EURO/kW installed	1,659
Project lifetime	Years	10
Grid connection costs	EURO	-
House connection	EURO/house	43.3
Maintenance	EURO/year	2,524
Fuel	EURO/year	2,202
Electricity production cost	EURO/kWh	0.079
Cost per household	EURO/year	33.9
Project turnover	EURO	63,288
Financial flows	EURO	29,223

The effects of the gasification/gas engine power system were to:

- create opportunities for increased income
- raise living standards by improving, for example, lighting, health, communication, entertainment, and education
- keep money in the community, furthering wealth creation
- stop deforestation

7.7.4.2 The Muzizi Tea Estate

7.7.4.2.1 Description of the facilities

Another study examines the Muzizi Tea Estate in Uganda [7]. This estate is located outside the reach of the national electricity grid, but needs electricity and thermal power for drying the tea at 80 °C. Diesel generators have been used, one of which was replaced with a bioenergy system. The pre-feasibility study, system design, and selection of manufacturer for the gasifier system were carried out in 2005. The gasifier system was installed and commissioned in May 2006 and has been running consistently since August 2006.

The fuelwood demand is met from a 99 ha eucalyptus plantation. The wood is dried outdoors for six months to a moisture content of 15 %.

The power conversion system is the GAS 250 system from Ankur Scientific, India. It is rated at 200 kW net electricity output and is installed in a shed. The system includes the following parts:

- a downdraft gasifier reactor of 400 kW_{th} with automated fuelwood feeder and ash and charcoal removal
- a cyclone filter to separate ash from the hot gas
- a gas cooling and scrubbing unit using water
- two parallel filter units each consisting of a coarse filter (wood chips) and two fine filters (sawdust, not shown in the figure) to allow constant operation even when cleaning the filters
- one cloth bag filter (not shown in the figure)
- a blower to move the syngas to the engine
- a 250 kW Cummins India syngas engine
- heat recovery units on the exhaust pipes and in the water cooling cycle of the engine



Figure 7.17. The filter line and the WBG 400 gasifier (photo courtesy of T. Buchholz).

7.7.4.2.2 System startup

The gasifier system is started by a generator set delivering at least 30 kW to run the critical electrical devices in the system (e.g., pumps, blower, fuel wood feeder, and control units). Startup time is about seven minutes when the system is cold but considerably less when there is hot material in the reactor. The system provides three-phase electricity.

7.7.4.2.3 Consumption of fuel wood/efficiency

Fuel wood consumption was 1.6 tons of air-dried wood per MWh of electricity produced. Considering an energy content of 5 MWh per ton of eucalyptus wood, this equals an electrical conversion efficiency of 15%. The total annual electricity output equals 381 MWh.

The gasifier system does not operate at all one day per week for maintenance. The current average power output is 87 kW, far below the system's 200 kW peak rated capacity.

The heat recovery unit is located at the exhaust and cooling cycle of the syngas engine. Maximum heat recovery is assumed to be 80% of the heat produced. However, actual heat recovery data were not obtainable due to missing control units. They operators expect to save 15% of fuel wood at the boiler due to the heat recovery unit at the syngas engine.

7.7.4.2.4 Job creation

A minimum of 11.5 full-time jobs are created by this system. The bioenergy system requires two skilled (one engineer with a B.Sc. degree and one assistant) and four unskilled employees (two shifts for two employees) to run the gasifier system. On the date of visit, the gasifier system occupied more than 50% of the time of the estate engineer. Another six employees split wood.

The fuel wood feeder had to be filled about every 20 minutes with approximately 60 kg of wood. Other work included charcoal and sludge removal, filter cleaning, and monitoring of the controls.

7.7.4.2.5 Sustainable feedstock needed

An economically viable gasification system for electricity production requires a sustainable feedstock supply system. If the gasifier system is running 50% of the time, assuming low fuel wood stand production (5 odt/ha/yr) and low electrical efficiency (15%), the gasifier would require approximately 1.9 ha/kW. In the best-case scenario with high plantation yields (15 odt/ha/yr) and high gasifier efficiency (24%), the system would only require 0.3 ha/kW.

Assuming that the gasifier runs at full capacity of 200 kW 50% of the time at 24% electrical efficiency, an additional 60 ha of fuel wood plantation would be needed.

7.7.4.2.6 Atmospheric emissions

The gasifier system's emissions contain little if any sulphur because it is not present in wood, and the CO₂ produced can be seen as cycling in a closed loop when the fuel wood plantations are managed sustainably. Other air emissions from the system have not been monitored.

Preliminary analysis indicates that the system – as it is currently running – replaces approximately 120,000 litres of diesel per year, which is equivalent to offsetting 314 tons of CO₂ per year.

7.7.4.2.7 Wastewater

The wastewater discharged once per month contains ash and charcoal from the gasification. The charcoal is recovered and burned in the boiler; the ash can be partly skimmed off the water as sludge. Sludge and wastewater are discharged once per month and pumped to the tea plantations where they are used as fertilizer.



Figure 7.18. The 250 kW syngas engine with heat exchanger (photo courtesy of T. Buchholz).

7.7.4.2.8 Financial analysis

The total electricity production cost is EUR 0.159/kWh. Capital costs are EUR 1505/kW installed. For the gasifier system at Muzizi Tea Estate at 87 kW production (current scenario), assuming a project and equipment lifetime of 13 years, the cost shares are as follows: capital, 43 %; fuel wood and operations (running costs), 29 %; and labour, 28 %. The gasifier system is barely economically viable when competing with an electricity price of EUR 0.18/kWh from subsidized diesel generators at an internal rate of return (IRR) of 6 %. In this case, the payback period is 9.5 years. For a gasifier system at 150 kW production (future scenario), competing against unsubsidized electricity derived from diesel generators (EUR 0.238/kWh of which EUR 0.231 is for fuel), the IRR would increase to 18 % and the payback period would be reduced to 4.5 years.

7.7.4.2.9 Wastewater treatment

Currently, the wastewater in the cooling pond is emptied once a month. The water is pumped into the tea fields where it serves as fertilizer.

7.7.4.2.10 Implications for rural electrification

Gasification can be an economically attractive alternative to diesel-generated electricity for rural areas under certain conditions. In addition, the case study identified three main components to be focused on to ensure the successful implementation of a similar system in a wider range of areas.

Although running on a potentially inexpensive fuel (woody biomass at EUR 0.022/kWh), gasification systems are characterized by high capital costs (EUR 1505/kW at Muzizi Tea Estate). Such high upfront costs and long payback periods are a bottleneck for rural electrification efforts beyond those of large agroindustrial operations unless supportive credit schemes are in place.

7.7.4.2.11 Viable business models

The case study at Muzizi Tea Estate clearly indicates the need for well-designed business models to manage the feedstock supply, conversion technology, and energy allocation components of a gasification system. The creation and support of energy service companies could serve this end. These do not exist yet in Uganda. Without reliable business models, investors will not risk investing in gasification systems. Therefore, both public and private research and capacity building are required to develop and promote business opportunities and to overcome existing barriers.

Part of a viable business model is to match the system capacity to the power demand. High peak loads and abrupt power demand changes can be avoided or buffered already in the planning stage of such electricity systems.

7.7.4.2.12 Sustainable fuel wood supply

Business models for a complete gasification system have to provide incentives for farmers and entrepreneurs to provide biomass year round from sustainable sources. This can be achieved either by having the electricity provider directly manage fuel wood sources or by means of out grower schemes that encourage local farmers to grow fuel wood and sell it to the

plant, accompanied by extension services covering training, quality monitoring, and material provision. Issues such as competition with food production, biodiversity, site protection, or forest health would have to be addressed. A degree of local control over all components of the system – fuel wood supply, conversion technology, and power distribution – would make a gasification system more likely to succeed in rural electrification projects.

7.7.5 China

A paper from 2002 [8] provides an economic analysis of biomass gasification in China. China has large biomass resources and appears to have suitable conditions to develop biomass use technologies. Biomass gasification and power generation (BGPG), an important decentralized power technology, has a potential market in making use of biomass wastes. Even though the cost of cleaning wastewater is high, BGPG is economically feasible and can yield a financial return owing to the low price of biomass wastes and insufficient current power supply in some regions of China. The paper analysed experimental data from a 1 MW circulating fluidized-bed (CFB) BGPG plant constructed recently in China. The paper found that the capital cost of BGPG is only 60–70% of that of a coal power station and that the BGPG operation cost is much lower than that of conventional power plants. Due to the relatively low efficiency of small-scale plants, current BGPG technology is not economically attractive if its capacity is smaller than 160 kW or the price of biomass is higher than 200 Yuan RMB/ton.

Medium-scale BGPG plants, with capacities of 1000–5000 kW, are recommended. It is also recommended that BGPG technology be demonstrated at suitable sites in developing countries that have large amounts of biomass waste (e.g., rice and timber mills). Such siting means that biomass collection and transportation costs can be avoided and operation cost can be kept low.

7.7.5.1 General situation of the development

R&D activity concerning BGPG started in the 1960s. The most common systems are based on a 60 kW rice hull gasification unit. As of 2002, dozens of small 160 and 200 kW rice husk gasifier/power generator sets were in use.

In recent years, a MW-scale BGPG system was studied, aiming at the mid-scale application of biomass technology. The table below compares data on the two size ranges. It should be noted that the efficiency of the medium-scale unit is approximately 5% higher than that of the small one.

Table 7.21. Data on small- and medium-scale units.

Category	Small-scale unit	Medium-scale unit
Electrical capacity (kW)	200	1000
Gasifier type	Down-draft	Circulating fluidized bed
Gas cleaning system	Water scrubber	Water scrubber
Application	Gas engine for power generation	Gas engine for power generation
Water consumption (ton/h)	20	20
Overall efficiency (%)	12.5	17
Capital cost (EUR/kW)	238	265
Electricity cost (EUR/kWh)	0.030	0.023
Number of sites in use	approx. 30	2

7.7.5.2 Investment

The investment in BGPB systems mainly comprises three parts: gasification and gas cleaning, the power generation device, and civil work.

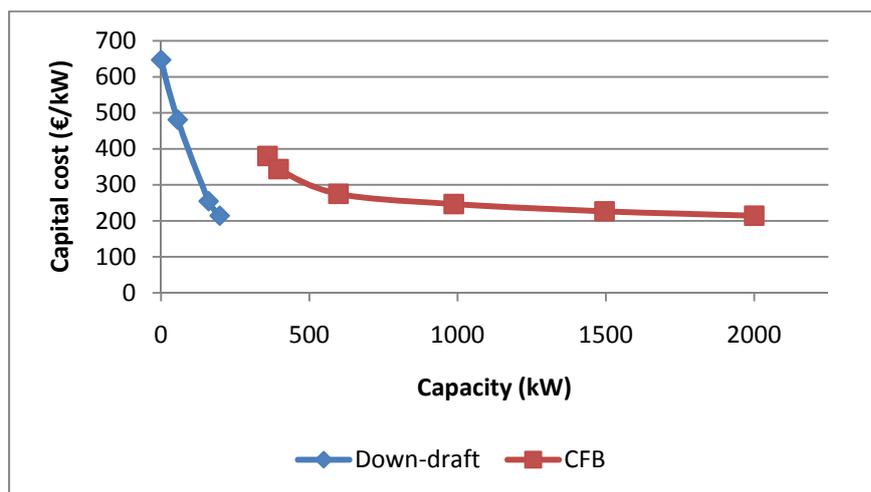


Figure 7.19. Capital cost of BGPB in China varies with capacity.

Figure 7.19 shows how the capital cost decreases rapidly from approximately EUR 685/kW for very-low-capacity down-draft gasifiers, stabilizing at approximately EUR 231/kW at

capacities above 1000 kW for CFB gasifiers. The same low values can be achieved with down-draft gasifiers at a capacity of 200 kW.

7.7.5.3 Price of biomass

Under 2002 conditions, when the radius of biomass collection exceeds 50 km, the electricity cost will exceed the electric network price (approximately EUR 0.0476/kWh), so the competitive advantage of BGPG will be lost. As shown in Figure 7.20, the prices of various types of biomass start at approximately EUR 4.33/ton for sawdust that is not transported, and reach EUR 13.7/ton for rice straw transported 50 km.

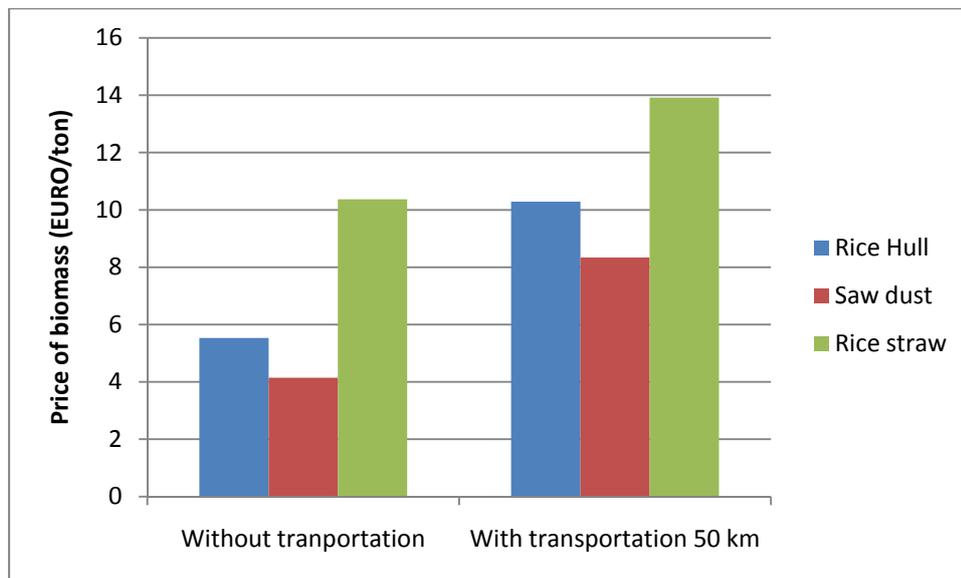


Figure 7.20. Price of various types of biomass in China as of 2002.

There are several Chinese producers of biomass gasification–gas engine generators. One is Chongqing Welluck Trading Co. [8], one of the leading suppliers in China of complete biomass gasification gas engine and generator units. It produces fixed-bed and fluidized-bed gasifiers that use biomass such as rice husks, wood chips, and corn stalks. The power of a single biomass power plant may be 70, 100, 200, 400, and 800–2000 kW. Since 1998, its biomass equipment has been exported to foreign countries such as Thailand, Malaysia, and Italy. At present, the company is testing biomass generating equipment conforming to European market standards.

7.7.6 Other parts of Asia

Renewable Cogen Asia, a company specializing in energy and environment systems, has 20 years of experience in more than 30 countries [9]. Its services cover Asia, Africa, and other regions and the company has strategic partners in several countries.

The customers include the private sector, UN/international organizations, international funding agencies, and government organizations

The company's services are categorized in the following areas:

- consulting/advisory services
- project development
- carbon credits (CDM, voluntary market, carbon foot print, and climate change)
- training/capacity building

Renewable Cogen offers various types of gasifiers, the choice of which depends mainly on the fuel used. In coming years, this technology will be a big boon for industries with low power demand in the 100 kW–1 MW range, where steam thermal technology is not feasible.

Proven gasification technology with good reliability and availability is ideal for rural electrification.



Figure 7.21. A 250 kW rice husk gasifier from Renewable Cogen Asia (photo courtesy of Renewable Cogen Asia).

7.7.7 Italy

A paper from Italy focuses on biomass gasification. In this process, synthesis gas is used to produce electricity [9]. The following table presents a comparison of the two energy conversion techniques examined in the paper. The industrial application of gasification-based, biomass-to-energy cogenerators in the 100–600 kW_{el} range was investigated.

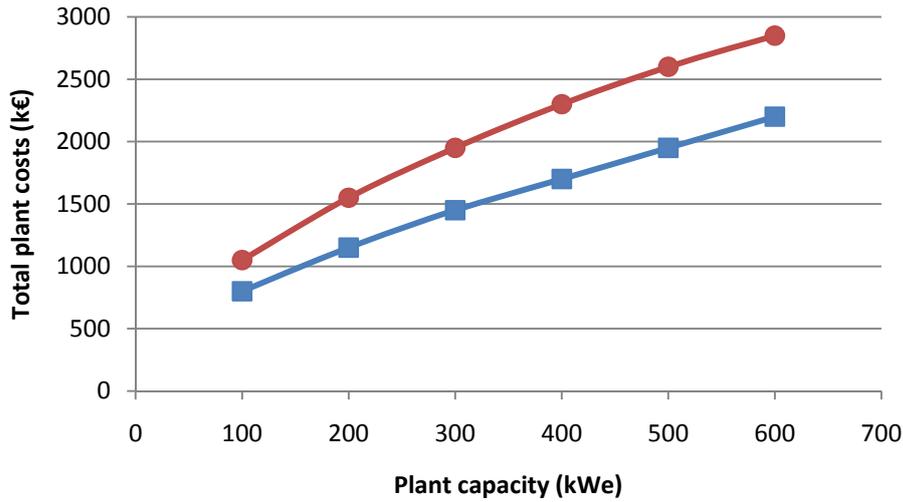
The highest efficiency of 28 % is for the gas engine system. This system offers a number of additional advantages, such as high electrical efficiency even at small sizes, relatively low cost, reliability, and good functioning even at low loads. The major drawbacks are that the engine is exposed to corrosive combustion products, entailing short and expensive maintenance intervals and likely leading to low availability.

Table 7.22 presents comparisons of the economic performance of gas engine and externally-fired gas turbine systems for biomass-to-energy conversion.

Table 7.22. Technical and economic performance of two biomass-to-energy configurations, with reference to a nominal plant capacity of 200 kW_{el}.

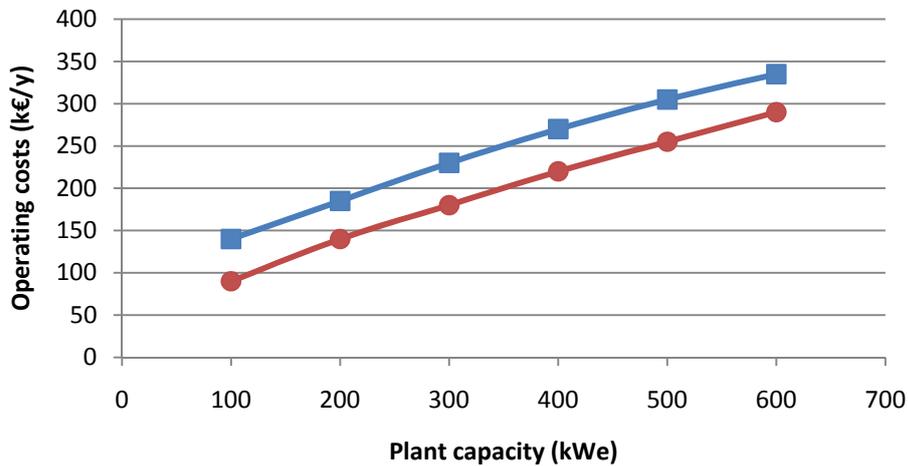
Category	Gas engine	Externally-fired gas turbine
Total energy conversion efficiency (%)	27.1	23.0
Specific biomass conversion rate (kWh _{el} /kg _{fuel})	1.20	1.02
Waste export (kg/kg _{fuel})	Gas: 6.64 Liquid: 0.11 Solid: -	Gas: 32.25 Liquid: - Solid: 0.01
Exhaust gas temperature (°C)	145	313
Total plant cost (EUR/kW _{el})	6000	7600
Operating costs ((EUR/y)/kW _{el})	940	690
Initial rate of return (%)	13.2	13.0

Again, a high efficiency (27.1 %) is reported for the gas engine system – almost 18 % higher than for the gas turbine. The total plant cost is EUR 6000/kW_e for the gas engine versus EUR 7600/kW_e for the turbine. Operating costs are higher for the gas engine, though, leading to about the same initial rate of return on the investment for the two systems.



A

■ Engine ● Turbine



B

■ Engine ● Turbine

Figure 7.22. Comparison of total plant and operating costs of the two biomass-to-energy design configurations, at a biomass fuel cost of EUR 20/ton. Squares: gas engines, Circles: externally fired gas turbines.

The two alternatives, which are based on identical gasification sections, do differ in energetic and environmental performance. The gas engine offers higher global efficiency (approximately 27 %) and lower capital costs (Figure 7.22A), but has lower availability (7680 h/y) and higher maintenance costs (Figure 7.22B). It also requires a suitable treatment unit for the wastewater, which is contaminated with tars, particulates, and inorganics.

The externally-fired gas turbine (EFGT) has a less efficient process (approximately 23 %) due to thermodynamic limitations. It also has higher initial investment costs (Figure 7.22A). The EFGT has higher annual availability (7920 h/y), lower maintenance costs, and must dispose of

a solid instead of a liquid waste stream. Moreover, the EFGT is more affected by the biomass cost due to its lower biomass conversion rate (Table 7.22).

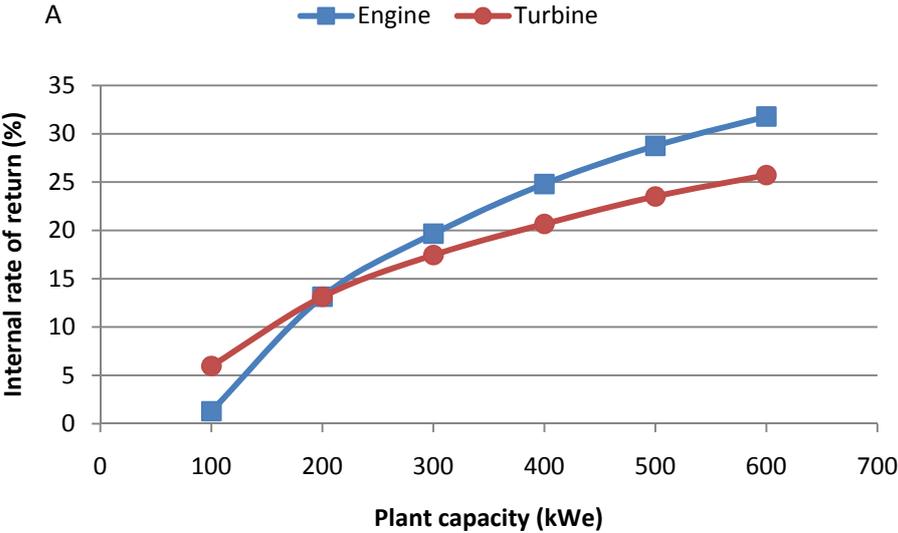
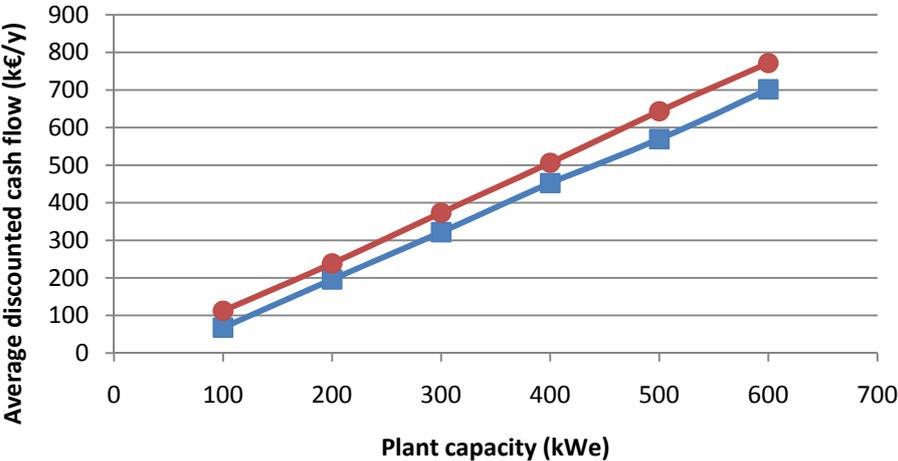


Figure 7.23. Comparison of the financial performance indexes of the two biomass-to-energy design configurations, at a biomass fuel cost of EUR 20/ton. Squares: gas engines, Circles: externally-fired gas turbines.

The EFGT’s lower operating cost cannot compensate for its higher capital costs and Figure 7.23B shows that the IRR always favours the gas engine at capacities over 200 kW_{el}. The results indicate that the internal combustion engine layout is the solution that currently offers the higher reliability and higher IRR of the two investigated electrical generation systems.

7.8 References to chapter 7

7.8.1 Relevant literature and Links on the Case studies

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8 Summary and discussion

8.1 The Case Study

In this study, we have studied five solutions for applying gasification–gas engine CHP technology. The performance of the five types of plants is quite similar.

- They all have biomass-to-electricity efficiency in the range of 25–31% and overall performance of 80–92%.
- Fuel flexibility is limited: some plants can use both wood chips and pellets, but none of them can combine, for example, sawdust and chips.
- The availability of the operating plants is high: The Harboøre and Güssing plants have operated commercially in the 70,000–100,000 hour range, while the Skive plant has run for approximately 10,000–20,000 h. The Viking gasifier has run in pilot tests, but for several thousand hours. The first commercial VIPP-VORTEX gasifier plant has not been commissioned yet and no data are available, but there is no reason to doubt its reliability at this point.
- All the plants are fully automated and are meant to be run under remote supervision, at least in the commercial versions.

But there are also some marked differences between the plants:

- The capability to rapidly change the load when the unit is running is emphasized in the VIPP-VORTEX gasifier, while the other gasifiers are probably more sluggish.
- The VIPP-VORTEX gasifier requires fuel in the form of small particles, such as sawdust, while the other gasifiers use pellets or chips. The sawdust used for the VIPP-VORTEX pilot is produced by milling wood pellets on site.
- The Viking gasifier is claimed to be able to standby for up to 24 hours, during which time it can be started immediately.
- The Güssing plant produces a nitrogen-free producer gas with a high heating value, while the other plants produce gas with low to medium heat content. This gas is also suitable for other applications, for example, SNG or methanol production and Fischer-Tropsch processing.
- The Harboøre and Güssing plants are below 10 MW_{th} and within the scope of this study; however, those plants and the Skive plant can be scaled up far above this range for commercial operation. The Viking and VIPP-VORTEX gasifiers have a maximum scalable size below or equal to 10 MW_{th}.

Generally, the technology is sufficiently mature for commercialization, however, some unit operations, for example, catalytic tar reforming, still need further development. Further development and optimization will probably streamline the performance of the various plants so that their biofuel-to-electricity efficiency reaches 30–40% and overall performance efficiency approaches 90%.

8.2 Market application of gasification–gas engine CHP plant technology

8.2.1 Harboøre, Skive, and Güssing plants

The gasification–gas engine CHP concept is valid up to 10–20 MW_{th}. Above this size, gasifiers or boilers with gas or steam turbines are more efficient. The Harboøre, Skive, and Güssing plants probably fill this niche, meaning that the field of application for such plants is municipal CHP production.

Table 8.1 Comparison of CHP economics

Plant	Investment Cost	Investment cost EURO/kW	Commercial Plant size
Viking			0.6- 3 MW _{th}
VIPP		2000-3000	0.5-10 MW _{th}
Güssing	10 Mio. EURO (2002)	1250 (2002)	8-20 MW _{th}
Harboøre	9 Mio.EURO (2001)	1730 (2001)	3-23 MW _{th}
Skive			20-30 MW _{th}

8.2.2 The Viking and VIPP-VORTEX plants

The Viking (maximum 3 MW_{th}) and the VIPP-VORTEX (maximum 10 MW_{th}) units are smaller plants. In interview, company representatives gave almost identical answers regarding the field of application of their plants.

8.2.2.1 In Sweden, Nordic countries, and similar developed countries

In these countries, the units should be used as local central hot water plants for district heating. The consumption of district heating (in the established networks in Sweden) has decreased due to improved building insulation and other energy savings. This means that the current heat-only production of such central hot water plants limits their profitability. If replaced with CHP plants, the extra production of electric power would improve the economic performance of district heating systems. Another use would be in industries with their own biofuel supplies, such as pulp and paper mills and sawmills, which currently use their biofuel solely for heat and steam production.

8.2.2.2 In developing countries

The Viking and VIPP-VORTEX plants seem to have the potential for use in developing countries. Both MI and BGG/DTU see developing countries as a potentially huge market and are involved in development projects, for example, in India. The Viking gasifier covers an output range from approximately 30 kW_{el} to 1 MW_{el}, while the VIPP-VORTEX gasifier is

somewhat larger, ranging in output from 150 kW_{el} to 3 MW_{el}. Both plants have integrated tar elimination and leave no waste products other than ash and engine flue gas.

8.2.3 Summary of the situation in Sweden

Figure 2.2 presents the use of biofuel as of 2009 in Sweden in industry (15 TWh excluding black liquor), for district heating (36.1 TWh), and for electric power production (10.1 TWh). This totals 61.1 TWh, giving a net electric power ratio of 16 %. As demonstrated above, the potential efficiency of small-scale gasification–gas engine CHP technology is approximately 30 % in terms of net electric power efficiency. This means that a large portion of the biofuel is used for purely heating purposes and that there is significant potential (additional 8 TWh) for electric power production by changing technology. Figure 2.4 shows that a further 5 TWh of fossil fuel used in district heating could eventually be replaced with biofuel. Both measures would require increased biofuel use for increased electric power production, and comparing Tables 2.3 and 2.4 indicates that this increased need for biofuel can be met by the increased use of woody biofuel suitable for gasification. There is thus a not insignificant market for this technology today and in the future, probably for all studied plant sizes and eventually even larger ones. The timing seems right for introduction of this kind of technology.

8.2.3.1 Further use of district heating in Sweden

To further increase the use of biofuel in CHP production in Sweden, the use of district heating must be increased. One emerging energy use in Sweden and Europe is for comfort cooling. Comfort cooling has traditionally been generated by electric-powered compressor machines operating at the site of consumption, but some energy companies have begun to distribute district cooling in the same fashion as district heating. However, comfort cooling can also be generated by distributed district heating on site using heat-driven heat pumps, for example, by means of adsorption cooling. According to Rydstrand et al. [1], producing cooling with heat-driven heat pumps (Heat → Cooling) represents a thermodynamic shortcut compared with producing cooling with electric power (Heat → Electric power → Cooling), the former route offering approximately 50 % greater efficiency. This is due to the conversion losses in each step. The season for comfort cooling in Sweden is short. However, heat pumps produce both heating and cooling and, if correctly constructed, should be able to deliver cooling in summer and heating in winter. According to the estimates of Rydstrand et al. [1], in 2004, Sweden could have saved 2 TWh_{el} in winter, but only 0.5 TWh_{el} in summer, by switching from electric-powered to heat-driven heat pumps. These figures are based on deliveries in the district heating and cooling networks and do not include domestic heating/cooling by means of private heat pumps.

8.2.4 Summary of the situation in developing countries

Lack of infrastructure in developing countries means a huge need for local power production. A variety of production scales is needed, ranging from single households and farms to cooperatives, industries, and villages, mainly in the range of 10–500 kW_{el}, but the demand for larger plants is reported to be increasing. These local power plants are usually fuelled with agricultural waste biofuels, such as coconut shells and rice husks. It is necessary for the

biofuel collection to be monitored to ensure it is done sustainably and does not, for example, contribute to deforestation.

Many local actors produce fixed-bed gasifier units or plants in this size range. These plants are usually manually operated, because labour is cheap and job opportunities are greatly needed. For smooth operation, it is essential to have access to skilled labour and this can be a problem.

It is common to purify the producer gas by water scrubbing, and the spent scrubbing liquid is often used as fertilizer for crop cultivation. Considering the common knowledge of tars, this must be considered a health and environmental issue.

In warm countries, there are limited uses for the produced heat, so the primary product is the electric power. Wasting the produced heat is considered, at least in industrialized countries, bad energy management. If there is little or no external use for the produced heat, it is important to integrate the released heat into process to increase its efficiency, for example, by eliminating the produced tars. However, in some cases the warm water produced can be used, for example, for drying local industrial biomass, fabric dyeing, silkworm farming, and laundry. There is potential to use the heat for cooling purposes, for example, by means of adsorption or desiccation cooling, but due to lack of infrastructure and low living standards, most developing countries are not ready for district cooling. It might be possible to use heat-generated cooling in industrial or corporate applications, for example, in local food industries or community buildings such as hospitals. The market for new and innovative uses of the produced excess heat is large.

8.3 Areas of development

8.3.1 Gas cleaning

8.3.1.1 Tars

The various existing techniques for removing the tars from the gas stream and using them in the process work well, and will probably continue to be developed. Regarding catalytic tar cracking in the gasifier bed and the catalytic reforming of tars, more research and development will be needed.

8.3.1.2 Sulphur

Over the past 20 years, sulphur emissions in Sweden have decreased by 74 % [2] and have now stabilized at approximately 30,000 tonnes per annum. Sulphur emissions from biomass use are usually regarded as low. However, any sulphur the biofuel does contain will be released to the atmosphere as sulphur dioxide after combustion if no cleaning is applied. The sulphur dioxide emission shares of the transport and energy sectors are approximately equal at 16,000 tonnes per annum. Biofuels are dominant in the energy sector (if hydropower, nuclear power, and wind power are excluded) and are its major source of sulphur emissions. A switch of technology from heat generation to combined heat & power generation might affect the sulphur emissions to the atmosphere, if the water in the gas is condensed before combustion. Depending on the condensation temperature, pH in the condensate and pressure the hydrogen sulphide will solve in the water. This means that the majority of sulphur emission will probably be moved to the condensate and the further treatment of the

waste water will determine the faith of the sulphur. However, at least the gas-liquid phase equilibrium amount of hydrogen sulphide will remain in the gas. This means that the gas engine flue gas will contain sulphur.

The only studied plant that is claimed to remove sulphur from the producer gas is the Viking plant, which is said to trap sulphur in an alkaline carbon filter created from the wood ash. If sulphur emissions can indeed be reduced so simply, the technique should be widely applied. A reason for this is that the catalyst needed for after treatment of the gas engine flue gas is seriously affected even by small amounts of sulphur.

8.3.1.3 Ammonia

Ammonia can occur at fairly high levels, up to 3000 vppm, in the producer gas. A catalytic reforming step should decompose this ammonia, though results from the Skive plant indicate that this step might not work as smoothly as planned. However, a non-catalytic process, oil scrubbing, does not remove the ammonia either. The producer gas is normally cooled down to condense its water content and increase the energy density of the gas before it enters the engine. Ammonia is highly soluble in water, and most of it will end up in the condensate. This might cause problems if the condensate/wastewater flows to municipal wastewater plants, as reported from Skive. The seriousness of the problem is probably directly connected to the size of the plant. The problem could be solved by a biological water cleaning step at the plant site. However, it might be possible to develop new catalysts or catalytic processes for eliminating the ammonia directly in the producer gas.

8.3.2 Use of the produced heat

By integrating the produced heat into the process, higher net electric power efficiency could be achieved in most cases. This is especially important if there is limited use for the produced heat, for example, in warm countries, but might also apply to Sweden, since there are not unlimited uses for hot water. For example, if all the electric power from Swedish nuclear plants was replaced with biofuel-powered generation from large-, medium-, and small-scale, combustion and gasification CHP plants, we would not have sufficient uses for all the produced heat.

If the produced heat could be used for other purposes than district heating, more gasification–gas engine CHP could be used in the near future in Sweden and other developed countries, or in warm developing countries, for electric power production. Examples cited here are the ORC, and eventually also the Stirling process, for additional electric power production and heat-driven heat pumps for heating and cooling purposes. Uses of these techniques are in their infancy, though commercial installations do exist. Considerable R&D work is likely needed before the techniques can come into common use. In addition, other new and innovative uses of produced heat/district heating should be promoted. For example, household appliances using electric power for heating, such as tumble driers, washing machines, and dishwashers, could be adapted to use the district heat supply. However, such equipment is not yet being commercially produced.

8.3.3 Small-scale oxygen production

To improve the heating value of the gas, the nitrogen must be removed. In the Güssing plant, this is solved by indirect heating, and the heating value of the produced gas is twice that of gas from other air-blown gasification plants. New and better concepts to solve this problem would be welcome. However, development of small-scale oxygen production plants and chemical looping concepts should also be considered.

8.3.4 Engines

Heat is not always a desired output of a CHP plant. If the total electrical efficiency could be increased, this would likely lead to a larger market for small-scale gasifier CHP plants. To increase the total electrical efficiency, it is necessary both to reduce the electrical consumption of the plant itself and to increase the efficiency of the generator and the combustion engine as well as the efficiency of converting the biomass to producer gas. Generator efficiency is usually very high, so there is limited potential for improvement in this area. Some of the presented gasifiers exhibit very high wood-to-gas efficiency, >90%, so engine efficiency may offer the greatest potential for improvement in the CHP system. As has been reported, several gasifiers with commercial gas engine gensets have efficiencies in the order of 40%.

The largest and most efficient gensets of today have electrical efficiencies in the order of 48%. The challenge is to make smaller engines perform as efficiently as larger ones and further to realize more of the practical maximum potential efficiency of up to 60%. To reach these targets, the thermodynamic cycle of the engine needs to be improved, i.e., more heat needs to be converted to work rather than being lost through the cylinder walls or expelled with the exhaust gases. From this perspective, HCCI is an interesting possibility, being a low-temperature combustion concept with high thermodynamic efficiency. Direct injection of gas is another interesting emerging technology that can be employed to avoid knocking problems and combustion near the cylinder walls, with attendant losses in combustion efficiency, excessive heat transfer, and mechanical losses. Direct injection of gas also has the potential to increase the engine power density thus reducing the engine size and cost.

System integration needs to be further investigated and improved as well. The Viking gasifier has a reported cold gas efficiency of 93% but only a total electrical efficiency of 25-27%. Clearly the engine efficiency is not the best, and the engine not optimally integrated with the gasifier. With a supercharged and more modern engine design total electrical efficiency has the potential of reaching at least 38% if the engine is properly integrated with the gasifier and can provide the required heat for the gasification process.

Fundamental research into wall heat transfer and thermal coatings is also important, as is supercharging technology. Ultimately, however, the proposed technologies need to be applied during producer gas operation, with its particular challenges of gas composition, energy content and tars, if we are really to understand the intricate interaction in the processes in order to optimize and develop the next generation of efficient producer gas engines. Fortunately, producer gas is generally an excellent engine fuel and, combined with the

simplifications afforded by stationary engine operation, the potential is very good for the future high-efficiency producer gas engine.

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