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De-centralised power production using low-calorific value gas from renewable energy resources in gas turbines

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This report is a public version of the full, confidential report to NOVEM by ECN and OPRA. Chapter 5 of that report contained proprietary information and has been removed.

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ABSTRACT

The technical and economic feasibility has been studied of de-central installations that produce power by gasification of biomass and use of the fuel gas in a gas turbine at a scale between 1 MW_e and 10 MW_e. The study starts with a market analysis in the Netherlands and the European Community. Next, atmospheric gasification in a circulating fluid bed gasifier and the gas treatment are described. The gas quality is compared with gas turbine requirements. Modifications to an existing gas turbine have been considered but are not discussed in the present report.

The economy of the gas turbine installation is compared with that of a similar installation using a gas engine and of a combustion installation using a steam turbine. At 5000 operating hours per year and a fuel price of € 2.4/GJ, the electricity production costs for 1 MW_e installations vary from € 0.15/kWh for the gas engine and € 0.16/kWh for the gas turbine to € 0.18/kWh for the steam turbine. At 10 MW_e scale, the production costs decrease to € 0.09/kWh for the steam turbine and € 0.10/kWh for the gas engine and gas turbine. These costs are similar to the market value in the Netherlands and Germany. Production costs can drop by € 0.01/kWh for gas engines and nearly € 0.02/kWh for gas turbines if reject heat is sold at € 3.2/GJ. Sufficient heat demand, a larger number of operating hours or lower fuel price than assumed make installations smaller than 10 MW_e economically attractive.

Of the three options compared, the gas turbine is expected to yield the lowest NO_x and CO emissions. Given the small differences in electricity production costs, the gas turbine becomes the best choice if stringent emission limits are to be met.

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KEYWORDS

Biomass Gasification, Gas Engine, Gas Turbine, Low-calorific Gas, Combined Heat and Power

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CONTENTS

SUMMARY

Both in the Netherlands and in Europe the use of biomass as a source of energy is strongly promoted. The target is to double at least the fraction of primary energy supplied within the next 10 years. A similar target is set for the combined production of heat and power (CHP). To reach these goals, subsidies are made available to develop and implement de-central installations for the production of electricity and heat from biomass.

The present study analyses the feasibility of de-centralised power production by gasification of biomass and use of the fuel gas in a gas turbine. The study considers the market size, technical obstacles and competition from gas engines and steam turbines. The necessary modifications to the gas turbine are considered in detail for the OP16R engine produced by OPRA b.v.

Market
The market for biomass-fired CHP installations of 1 MW_e to 10 MW_e capacity is estimated at 5 MW_e per year for the Netherlands and 120 MW_e in the European Community. Most European countries support the production of electricity from biomass by subsidies on investments. Price guarantees or direct subsidies increase the value of electricity produced from biomass by about € 0.03/kWh when compared with electricity from conventional sources. In the Netherlands and Germany the margin is about twice as large.

Gas quality
An inventory of the gas quality that can be produced from biomass and the requirements posed by the gas turbine shows that there are no real obstacles. However, the concentrations of K, Na and Ca in the gas may reach values harmful to the gas turbine. Caution is advised in the design of the gas cleaning system to ensure sufficient removal of these elements.

Gas conditioning
The fuel gas must be pressurised for use in a gas turbine. The energy required for compression corresponds to 6% of the energy content of the gas. Several options have been considered to enhance the calorific value of the gas and thus reduce the energy for compression. Additional preheating of gasification air increases the system efficiency slightly. The net economic effect is negligible. The energy requirement for gas drying by cooling to 7°C approximately equals the energy saved in compression. The associated costs may be justified if corrosion problems are expected. Removal of CO_2 and O_2 enrichment of gasification air are energetically neutral too. However, removal of CO_2 is very expensive. The use of O_2 can be justified if tar is removed by thermal cracking, which is assumed not to be necessary.

Gas turbine modification
The effects of low-calorific gas on the operation of the gas turbine and the necessary modifications are discussed in the confidential version of the report.

Power output and efficiency
If the installation is operated mainly in winter, the average electricity production by the modified version of the OP16R gas turbine can be close to 1.9 MW_e and the efficiency 36% (from gas to electricity). After correction for power use and losses in the gasifier and gas compressor, the net power output decreases to 1.5 MW_e. The system efficiency from biomass to electricity is calculated to be 21.9%. In addition, exhaust heat can be used with 32% thermal efficiency at 120°C or 39% thermal efficiency at 70°C.

Competing options
At (nearly) the same thermal input, the steam turbine yields 1.0 MW_e at 16.0% efficiency and the gas engine 1.7 MW_e at 25.4% efficiency. The power required for gas compression causes the difference in electrical efficiency between the gas engine and the gas turbine. At a larger scale, the efficiency of installations with several gas engines or gas turbines in parallel increases by at most 0.5%. The efficiency of the steam turbine installation increases to 22% at 10 MW_e

scale. In case of the steam turbine, heat supply reduces the electrical efficiency and does not improve the economy of the installation. Exhaust heat of the gas engine yields a thermal efficiency of 20% at 120°C. If heat is required at 70°C, additional heat from the engine cooling system increases the thermal efficiency to 34%.

Economy: electricity only
An economic analysis shows that for 10 MW_e scale the steam turbine achieves the lowest electricity production costs at € 0.09/kWh, based on 5000 operating hours per year, 11.6% internal rate of return and € 2.4/GJ fuel price. The gas engine and the gas turbine achieve € 0.10/kWh. At 1 MW_e to 2 MW_e scale, the production costs increase to € 0.15/kWh for the gas engine, € 0.16/kWh for the gas turbine and € 0.18/kWh for the steam turbine. The gas turbine is less economic than the gas engine because of the power required for gas compression. Even if modification for low-calorific gas would not increase the price with respect to the standard recuperated version, the electricity production costs would remain higher than for the gas engine.

Economy: co-generation
The gas engine and gas turbine systems become more competitive if heat is supplied for e.g. central heating or process heat. At a heat price of € 3.2/GJ the income from heat reduces the electricity production costs by € 0.004/kWh to € 0.020/kWh depending on the required temperature and number of operating hours for heat supply.

Economy of scale
With all three options the electricity production price at 1 MW_e to 2 MW_e scale is substantially higher than the sale value, even if tax reduction and subsidy for energy from renewable sources are taken into account. At the larger scale, the electricity production costs are close to the sale value. If local conditions are more favourable than assumed here, installations between 1 MW_e and 10 MW_e can be realised on a commercial basis.

Emissions
The above economic analysis does not consider the costs related to emissions. Combustion of biomass may cause NO_x emission close to or above the European limit. In the Netherlands, the limit is even more stringent and measures have to be taken to reduce the NO_x emission. Part of the NO_x results from nitrogen bound in the fuel. During gasification most of the fuel nitrogen is converted to NH_3 that can be removed by wet scrubbing of the fuel gas. The formation of thermal NO_x can be limited by choosing the right combustion conditions in the gas engine or gas turbine. The gas turbine is expected to yield the lowest emissions.

Another emission problem with gas engines is the incomplete burn out of CO in the fuel gas. High values of CO in the exhaust gas are reported, but as yet there is no emission limit to be complied with. In this respect too, the gas turbine is expected to outperform the gas engine. However, at present that advantage does not suffice to warrant commercial success for a development program of a dedicated gas turbine.

1. INTRODUCTION

Energy from renewable sources is to cover an appreciable part of the energy demand in the EU within 10 years from now. In the Netherlands, where the potential of hydropower is small, biomass will be the main renewable source of energy. The use of biomass for the production of heat is already well established. Increasingly, biomass will also be used for the production of electricity. Either by co-firing in large coal-fired utilities or by firing in medium-scale dedicated facilities and small-scale facilities for co-production of electricity and heat.

The present report considers the feasibility of small-scale production of electricity and heat by gasification of biomass followed by combustion of the fuel gas produced in a gas turbine. The study is based on results of the ECN circulating fluid-bed gasifier BIVKIN and performance data of the OPRA 1.6 MW_e gas turbine. An analysis is made of technical problems and possible solutions. The expected performance is compared with similar installations for the production of electricity and heat where fuel gas from a gasifier is fed to a gas engine or where biomass is burned to produce steam for a steam turbine.

The analysis starts from the following choices and assumptions:

- The size is about 1 MW_e to several MW_e.
- The system operates in base load for 5000 hours/year.
- The fuel is clean wood (e.g. willow) with 20% moisture content.
- The fuel price is € 45 per tonne dry mass.
- Reject heat has zero net value.
- Gasification is performed at atmospheric pressure in a circulating fluid bed.
- Conventional, commercially available gas cleaning equipment is used.
- The gas turbine is a modified recuperated version of the OP-16 gas turbine developed by OPRA.

The assumption that reject heat has zero net value may seem strange where a system is considered that delivers both power and heat. The assumption results in an upper limit for the electricity price and simplifies the comparison with alternative systems. The effect of positive net value for heat will be considered as variant of the base case. The comparison with alternative systems will be limited to two options that are described in recent EWAB reports (*Van der Drift 2000*), (*De Vries 1999*):

- The use of a gas engine instead of a gas turbine in conjunction with the same gasifier and gas cleaning equipment.
- The use of a wood-fired boiler for steam production and a steam turbine to produce electricity.

Chapter 2 of the report presents an analysis of the market situation: the market size, emission regulations, government policy relating the use of biomass and co-generation of heat and power, and a description of the competing technologies considered. Chapter 3 describes the gas quality delivered and required. Chapter 4 discusses options available to improve the gas quality. Chapter 5 considers modifications to the gas turbine. Chapter 5 contains proprietary information on the OP16 gas turbine. Hence, in the present public report only a summary is given. The results of the previous chapters are used in chapter 6 to analyse the feasibility and competitiveness of a system to produce power and heat by gasification of biomass followed by combustion of the gas in a gas turbine. Finally, chapter 7 contains the conclusions.

2. MARKET ASPECTS

2.1 Market size

2.1.1 The Netherlands

Biomass availability
Energy from renewable sources and waste accounts for about 2.5% of the primary energy supply in the Netherlands. Biomass alone contributes about 1.5%, taking into account that 50% of the energy value of waste is credited to biomass. The government target for the contribution of renewable sources is 5% in 2010 and 10% in 2020. In 2020 biomass will remain the largest source with a contribution of 120 PJ/y. According to a recent inventory, currently available biomass sources in the Netherlands amount to 63 PJ/y, with only 34 PJ/y not yet claimed for other use (*Arts 1999*). Not included in these figures are large quantities of residues in the food industry and manure. These may become available if their present use is restricted by government measures in response to increasing concerns about food safety and water quality.

Government policy
The government prefers the adaptation of coal-fired power stations to the use of biomass as secondary fuel. This way, the highest electrical efficiency and largest CO_2 emission reduction are obtained. At a smaller scale, a similar reduction of CO_2 emission can be obtained if both electricity and useful heat are produced[1]. If biomass of local origin is used, small-scale application yields minimum transport emissions.

In the past, co-generation of electricity and heat (CHP) has been strongly promoted as a means to increase energy-efficiency. Liberalisation of the electricity market threatens the economic viability of CHP. The new tariff structure leads to high cost of back-up power. According to the "Nationale Energieverkenningen 1995-2000" (*Kroon 1998*) the share of CHP in the total installed capacity will continue to increase from about 25% in 1995 to about 50% in 2010. Active government support is required to realise the predicted growth.

Electricity generation capacity
Table 2.1 shows the subdivision of the total capacity in different categories in 1995 and the expected situation according to the "European Co-ordination" economic model in 2010 (*Kroon 1998*). Clearly, small co-generation facilities represent a substantial market share. At present most of the facilities have capacities smaller than 1 MW_e and use gas engines with natural gas for fuel. However, installations between 1 and 10 MW_e accounted for 35% of the total installed capacity of small co-generation units in 1997.

Table 2.1 Installed and expected electricity generation capacity (GW_e) in the Netherlands.

	1995	2010
Total capacity	17.7	25.3
Conventional	12.3	8.3
Combined Heat and Power	4.7	14.6
From which small-scale	0.8	3.3
Durable	0.7	2.4
from which biomass large-scale		0.3
and biomass small-scale		0.2

[1] The CO_2 emission reductions are equal for co-firing with 40% efficiency or CHP with 30% electrical and 40% thermal efficiency if in both cases the substitute fuel is coal for electricity and natural gas for heat production.

Conclusion
The predicted growth in small-scale co-generation between 1995 and 2010 corresponds to an average yearly market demand of 50 MW_e capacity in the size range from 1 to 10 MW_e, with a 10% share for biomass-fueled installations. The potential yearly market of 5 MW_e corresponds to three units each year with OPRA gas turbines modified for use of low-calorific gas produced from biomass. The market is largely determined by government policy.

2.1.2 Europe

Biomass availability
Energy from renewable sources and waste accounts for about 5% of the primary energy supply in the European Union. The most important renewable sources are biomass and waste (3.5%) and hydropower (1.3%). The relatively large contribution from biomass shows that in other European countries biomass is more readily available than in the Netherlands.

European policy
For the year 2010 the European union has set a target of 12% for energy from renewable sources. This represents a 7% increase, substantially higher than the target of 2.5% in the Netherlands. Co-generation of heat and electricity is less common in other European countries than in the Netherlands. In 1994, CHP accounted for 9% of the electricity generation in Europe. The European Commission recognises CHP as "one of the very few technologies which can offer a significant short or medium term contribution to the energy efficiency" (*EC 1997*) and aims at doubling the 9% share to 18% in 2010.

Electricity generation capacity
Table 2.2 presents data on the electricity market in the European union for the year 1994. The total installed CHP capacity amounts to 67 GW_e.

Table 2.2 *Electricity production and CHP market share in Europe in 1994 (data from EUROSTAT in EC 1997).*

	Total installed capacity [GW_e]	CHP share of installed capacity [%]	Total electricity generation [TWh]	CHP share of electricity generation [%]
Austria	16	20	55	21
Belgium	15	12	72	11
Denmark *	11	71	40	39
Finland	14	29	66	31
France	107	3	476	2
Germany *	115	23	528	9
Greece	10	2	39	2
Ireland	4	1	15	1
Italy	64	10	231	11
Netherlands	18	34	80	40
Portugal	9	10	31	10
Spain	44	3	162	5
Sweden	36	8	143	6
United Kingdom	69	4	325	4

* The large difference between shares of installed capacity and electricity generation is due to units that operate only part of the year in CHP mode.

Conclusion
The European target to double the CHP market share in 16 years corresponds to a yearly market of 4 GW_e capacity. If 3% of that market, i.e. 120 MW_e per year, would be small-scale biomass-fired, like expected in the Netherlands, the potential market corresponds to 70 units each year with OPRA gas turbines modified for use of low-calorific gas produced from biomass.

2.2 Emission regulations

In the Netherlands, the department VROM, which is responsible for the environment, has proposed in 1999 to tighten emission limits for biomass-fueled installations. In future, these installations should conform to the BLA directives for waste incineration. The BLA directives are more stringent than the BEES directives for energy production or the NER rules for wood combustion at a scale smaller than 5 MW_{th}. There is still discussion whether the NO_x limit may be multiplied by an efficiency correction factor. Table 2.3 compares the Dutch BLA and BEES emission limits with proposed European limits for clean biomass in Large Combustion Plants (LCP) and for waste incineration. Clearly, the Dutch limits for NO_x and particles are more stringent than the proposed European limits.

Table 2.3 *Emission limits in the Netherlands (BLA and BEES) and proposed European limits. All limits are given in mg/m_n^3 at 11% O_2.*

	BLA	BEES	LCP biomass	EU waste
SO_2	40	133	133	50
NO_x	70	133	233	200
Particles	5	13	33	10
Cd + Tl	0.05			0.05
Hg	0.05			0.05
Other heavy metals	0.5			0.5
Dioxines and furanes	0.1 10^{-6}			0.1 10^{-6}
HCl	10			10
HF	1			1
Volatile organics				10
CO				50

2.3 Government support for energy from renewable sources

2.3.1 The Netherlands

The government promotes the use of energy from renewable sources ("green" energy). The aim is to provide 5% of the primary energy supply from renewable sources in 2010 and 10% in 2020. In order to reach these goals the government supports the use of green energy by a number of fiscal and tariff measures. The fiscal measures are intended to reduce the production cost of green energy. The tariff measures are meant to make green energy more competitive to energy from conventional sources.

The VAMIL measure allows investors to depreciate their investment for the production of green energy over a short period of their choice. In practice, tax payment over profits can be postponed. The tax advantage depends on the interest rate and the commonly allowed depreciation period. At 6% interest and a depreciation period of 15 years, immediate depreciation yields an 11% advantage. The EIA measure gives companies an additional tax reduction proportional to their investments in durable energy. For investments larger than 0.5 Mfl and the present tax rate of 35% on profits, the net tax reduction corresponds to 14% of the investment. Subsidies on investments are given within the framework of the CO_2 reduction programme. Freedom of taxes is given to a certain level for individuals who obtain income from investments in or loans to "green" funds. These funds provide loans at reduced rates for investments in green energy.

Consumers pay a levy (REB) on their gas and electricity consumption. Electricity from green sources is exempt from this levy. Part of the REB fund goes directly to producers as subsidy on the production of green electricity. The sum of the REB levy and subsidy amounts to € 0.05/kWh. Recently, a similar subsidy has been introduced for the delivery of heat from renewable sources. A system of green labels has been agreed between producers of green electricity and energy distribution companies. The distribution companies buy these labels from suppliers to prove that a given share of the electricity they sell is from green sources. The system of green labels is voluntary and will be finished at the end of 2000. It will probably be followed by a similar but compulsory system of green certificates in 2001.

2.3.2 Europe

The European Union promotes the use of green energy, with emphasis on the production of electricity. Hydropower is usually considered a mature green technology that needs no further support. The actual use of energy from renewable sources depends on local, often geographical conditions. Traditionally, the use of wood for heating is important in Austria and the Scandinavian countries. In these countries and Germany the production of heat from biomass is also promoted, preferably in district heating and co-generation facilities.

Separate countries have taken different measures to increase the use of energy from renewable sources. In Germany, the Renewable Energy Sources Act guarantees a price of € 0.09/kWh for biomass installations with less than 5 MW_e capacity. Subsidies and special rates are common in other countries. Systems of green certificates are in various states of development in Belgium, Denmark, Italy, the Netherlands and the United Kingdom. The costs and benefits of a European system are being studied in the RECerT project[2] (Renewable Electricity Certificate Trading). Novem has gathered information on the measures taken by several countries in "The European financial guide for renewable energy, with a special focus on biomass". Table 2.4 presents a summary of data obtained from the Novem internet site (www.novem.org/biofinance). Further information on the strategy of the European Union and separate countries towards renewable energy sources can be found at an internet site of the European Union (www.agores.org).

Table 2.4 *Summary of subsidies and special tariffs for green energy in European countries.*

	Investment subsidy or tax profit	Low-interest loans	Special price or price guarantee	Price subsidy [€/kWh]
Austria	x	x		
Belgium	x		x	0.025
Denmark	x		x	0.035
Finland	x			0.007
France	x		x	
Germany	x	x	x	
Netherlands	x	x		0.015*
Sweden	x		x	0.015#
United Kingdom			x†	

* In addition to the subsidy, there is a tax reduction of 0.035 €/kWh for consumers of green electricity. This enables producers to charge higher rates.

\# This subsidy is not available for electricity from biomass.

† Contracts are awarded by the best-bidder principle within separate categories of renewable energy. The difference between the contract price and rates for electricity from fossil fuels is paid from a fund filled by a levy on the consumer price for electricity.

[2] Project manager Christopher Crookall-Fallon, chris@esd.co.uk

2.4 Competing technologies

The data in table 2.4 show that a direct comparison between the production price of electricity from renewable or conventional sources is irrelevant. At present, in most European countries a price difference of the order of 0.03 €/kWh seems to be considered an acceptable margin. In Germany and the United Kingdom the margin is higher for less mature technologies than for more mature technologies. Denmark too is considering price differentiation in order to secure the development of less competitive technologies that are needed to fulfil the long-term target for renewable energy. Similar measures may be expected in other countries in their attempt to reach a common policy. Hence, within the scope of the present report it is realistic to compare the prospects of a gas turbine coupled to a biomass gasifier only with its direct competitors, i.e. a gas engine coupled to a biomass gasifier and a steam turbine coupled to a biomass-fired steam boiler.

The comparison between the gas turbine and gas engine is made for an atmospheric circulating fluid bed gasifier. High-pressure operation of the gasifiers would remove the need of a separate fuel gas compressor in case of a gas turbine but increase the investment cost substantially (*EC 1998*). Fixed bed gasifiers are not considered here because they have more limited fuel flexibility than circulating fluid bed gasifiers and are less easily scaled to larger capacities.

2.4.1 Gas engine

Gas engines for operation on natural gas are commonly available from several suppliers. Usually, these engines can be adapted for operation on medium-calorific landfill gas which exist of nearly equal amounts of CH_4 and CO_2. With lean-burn engines, the air excess can be reduced to accommodate the inert gas in the fuel and the power output hardly changes. Gas produced by gasification of biomass has a much lower heating value, comparable to coke gas, and requires a modified engine. According to data from Jenbacher this reduces the power output to between 50% and 70% of the output on natural gas and increases the price by about 15%, i.e. the specific price per kW installed power approximately doubles.

With natural gas for fuel the mechanical efficiency of a gas engine varies from about 35% for 200 kW_e units to more then 40% for 2 MW_e units. The total efficiency (mechanical plus heat) is 80% to 85%, irrespective of size. Useful heat can be obtained from hot exhaust gases and from engine cooling. The exhaust gases contain about 60% of the heat at a maximum temperature of 450°C. Engine cooling delivers about 40% of the heat at a temperature of about 90°C.

Operation on low-calorific gas yields a reduced power output, but hardly changes the mechanical and thermal losses of the engine. Hence, the mechanical efficiency is lower by 1% to 2%. If the compression ratio is reduced to allow for the presence of H_2 in the fuel gas, the loss in efficiency is larger. It is assumed that the thermal efficiency does not change. Engine radiation loss and heat loss in the flue gas increase, but the loss in mechanical efficiency increases the available heat.

Gas engines that operate at stoichiometric conditions are usually equipped with a three-way catalytic converter to remove NO_x, CO and unburned fuel. Larger engines (typically from 0.5 MW) use excess air to prevent overheating the cylinders. Excess air reduces the combustion temperature and the formation of thermal NO_x, but increases the emission of CO and unburned fuel and prohibits the use of the efficient three-way catalytic converter. Operation on low-calorific gas with up to 20% CO aggravates the problem of CO emission. As shown in table 2.3, there is as yet no limit to the CO emission. However, the CO emission is considered a major problem to be solved if gas engines are to produce "green" electricity.

Maintenance costs of gas engines operated on natural gas are approximately 0.01 €/kWh. A significant part of these costs are for lube oil. Low-calorific gas produced by gasification of biomass contains dust, tar and acid components that reduce the oil quality. In order to prevent engine wear and corrosion the oil exchange time has to be reduced. This may increase oil consumption by as much as 40%.

Tar in the gas leads to clogging of fuel entrance ports and deposits on spark plugs, valves and shafts. More regular inspection of these engine components is advised to prevent irreparable damage. The severity of the problems depends of course on the level of harmful components in the gas left after gas cleaning. Here we assume that gas cleaning is efficient. If the total maintenance costs are comparable for operation on natural gas and low-calorific gas from biomass, the specific costs increase by 50% because of the de-rating of the engine. The useful life of the engine remains unaffected. Table 2.5 summarises the technical and economical data used for the gas engine in the comparison with a gas turbine.

Table 2.5 *Summary of technical and economical data for gas engines operating on low-calorific fuel gas.*

Investment cost	800	€/kW$_e$
Expected lifetime	80,000	hours
Electric efficiency	35	%
Thermal efficiency	45	%
Maintenance cost	0.015	€/kW$_e$

2.4.2 Steam turbine

System description

Steam turbines with a power output between 1 MW and 10 MW operate in a simple cycle: steam is raised in a boiler, expanded in the turbine, condensed and the water returned to the boiler. The stack exhaust temperature of the boiler is kept at 180°C to prevent acid condensation. As a result, 10% of the combustion heat is lost and 90% is available for steam raising. The optimum steam pressure for small turbines is 30 bar to 40 bar and the maximum temperature 400°C to 450°C. Higher pressures require a larger number of turbine stages, which increases costs and reduces internal efficiency.

For maximum power production steam turbines operate in condensing mode. The steam is expanded to approximately 0.1 bar, a pressure obtained by cooling to 40°C. The heat removed by cooling is not useful for heating purposes. In back-pressure operation mode, the steam is expanded to above atmospheric pressure. Power production decreases by 30% or more, but cooling and condensation of the low-pressure steam now delivers useful heat. Steam turbines in district heating facilities may operate in condensing mode during summer and (partly) in back-pressure mode during winter to match the heat demand.

System efficiency

The theoretical efficiency of a simple steam cycle with condensation is 32.5% (30 bar, 400°C) to 36% (40 bar, 450°C). If the steam is extracted at 3 bar, these values decrease to 18.5% and 21%. The net system efficiency is obtained after correction for the internal efficiency of the steam turbine, the boiler and generator efficiency and system power use. According to Perry's Chemical Engineers' Handbook (*Perry 1997*) the internal efficiency of steam turbines varies from 64% at 1 MW to 78% at 10 MW. We use slightly higher values for back-pressure operation. The boiler efficiency is 90%, the generator efficiency 97%. We estimate the system power use at 1.5% of thermal input plus 1.5% of reject heat in condensing mode.

In condensing mode the system delivers no useful heat. In back-pressure mode, the thermal output equals the difference between the boiler output and the sum of turbine mechanical output, steam and heat loss. We estimate the heat loss at 15% for 1 MW$_e$ and 10% for 10 MW$_e$.

Practical example: Schijndel

The demonstration project in Schijndel produces electricity from biomass using a condensing 1.3 MW steam turbine (*De Vries 1999*). The design inlet steam conditions are 28 bar and 420°C, the design condensor pressure is 0.15 bar. The steam turbine internal efficiency is 66% and the gross mechanical efficiency is 21%.

The generator efficiency is 97% and the power consumption of the installation 150 kW. The net nominal power is 1 MW_e and the design efficiency 16%. In practice, the net electrical efficiency is 14% in a situation where about 5% of the available heat is not used for steam raising but for heating purposes. The relatively low net efficiency is due to the high stack loss (13% instead of 10%) and off-design operation of the steam cycle, i.e. a 20°C lower maximum temperature and 0.05 bar higher condensor pressure.

Measurements by KEMA show that the emissions of the installation in Schijndel were within the limits required for small installations. However, the reported value of 260 mg/m_n^3 for NO_x is above the limits given in table 2.3. Addition of NO_x-reduction equipment will increase the investment and operational costs.

Economics
The installation in Schijndel required an investment of 3.1 10^6 €. An estimated 10^6 € are needed to bring the performance at the required level (*De Vries 1999)*. This brings the investment at 4,000 €/kW_e. For a similar system with condensing steam turbine of 5 MW_e we obtained a price indication from a manufacturer of 1,400 €/kW_e. The price of a system that delivers power and steam for process heat is given as 1,400 €/kW_e plus 230 €/kW_{th}. We increase the latter prices by 20% to account for the required building and storage facilities that are not included in the specification.

The maintenance and operational costs in Schijndel are estimated at 1.1 10^5 € per year or 0.014 €/kWh (8000 hours/year). Fuel and manpower are not included in these costs. The boiler performance is sensitive to the quality of the fuel, especially its water content. Because of varying fuel quality and operational problems the installation requires attention by two full-time staff members. This approximately doubles the operational costs. We assume that one full-time staff member suffices after the additional investment to solve the operational problems. In the first years of operation the availability of the installation amounted to 70% due to technical problems. The availability is expected to rise to 90%.

Table 2.6 summarises the technical and economical data used for a biomass-fired boiler and steam turbine with generator. These data should not be compared directly with the data in table 2.5 that refer just to the gas engine. In chapter 6 a comparison is made with complete systems containing a biomass gasifier and gas engine or gas turbine driving a generator.

Table 2.6 *Summary of technical and economical data for a biomass-fired boiler, steam turbine and generator with 1 MW_e and 10 MW_e capacity in condensing mode operating 8000 hours per year.*

Size: thermal input	6.3		45		MW
net output	1	0.6	10	5.8	MW_e
	-	3.8	-	28.0	MW_{th}
Steam pressure	30		40		bar
Steam temperature	400		450		°C
End pressure	0.1	3	0.1	3	bar
Net electrical efficiency	16	9	22	13	%
Thermal efficiency	-	60	-	62	%
Specific investment	4,000	4,000	1,700	1,700	€/kW_e
	-	+ 400		+ 280	€/kW_{th}
Total investment	4.0	3.9	17	17.7	M€
Maintenance cost	0.021	0.035	0.010	0.017	€/kW_e

3. SPECIFICATIONS LOW-CALORIFIC GAS

3.1 System description

The gasifier considered is an upscaled version of the ECN atmospheric circulating fluid bed (CFB) gasifier BIVKIN. The gas cleaning consists of components that have been tested or will be tested shortly in combination with BIVKIN in the GASREIP project (*Dinkelbach 2000*). It consists of a cyclone, a dust filter, a wet scrubber and a device to remove droplets of condensed tar after the scrubber. The fuel gas is compressed to the required pressure and fed to the gas turbine.

3.2 Gasifier performance

3.2.1 Gas composition

ECN has performed experiments with a variety of fuels in the 500 kW_{th} BIVKIN gasifier (*Vermeulen 1998*). Based on the results of these experiments, a computer simulation model has been developed that describes the operation of the gasifier. An important conclusion is that the gas composition is largely independent of the fuel source. The water content of the fuel does play a role, but for economic operation any fuel that contains too much moisture must be dried before gasification, preferably with use of waste heat.

The computer model is used to predict the performance of a 5 MW_{th} CFB gasifier. The relative heat loss will be smaller than for the experiments performed at 500 kW_{th} scale. The air to fuel ratio must be reduced to maintain the same temperature. As the change in relative heat loss becomes smaller at larger size, the results for a 5 MW_{th} gasifier are considered representative for the scope of the present study.

In order to predict the composition of the gas produced by the gasifier the following assumptions have been made:

- The fuel is fresh wood, e.g. willow, dried to 20% moisture content and containing 2% ash in dry matter. The organic material consists of 50% (by weight) C, 6.1% H, 43.5% O and 0.4% N. The mineral content is given in appendix A.
- The gasifier is operated at atmospheric pressure with air that contains 1% moisture and is preheated to 400°C.
- The temperature in the gasifier is 850°C.
- Heat loss of the gasifier equals 2%.
- The carbon conversion is 95%, i.e. 5% of the carbon in the fuel ends in the ash.
- Part of the fuel is converted to hydrocarbons with molecular weight larger than 100. These heavy hydrocarbons are removed from the gas and returned to the gasifier.
- The gas is cooled by the scrubber to 30°C. This reduces the water content to 4%.

Apart from the base case (A), three more cases have been defined:

B. Air temperature increased to 600°C.
C. Gasification with 400°C air and 20°C O_2 to obtain an O_2-concentration of 30%.
D. Gasification with oxygen-enriched air followed by removal of tar by thermal cracking at 1100°C. That temperature is reached by reaction of the gas with O_2.

It should be realised that these conditions fall outside the range for which the computer model has been validated by experiments. Hence, the predicted gas compositions given in table 3.1 should be considered indicative only. Table 3.2 shows the cold gas efficiency (CGE) of the gasifier and characteristics of the low-calorific gas. CGE is defined as the lower heating value (LHV) of the gas divided by the LHV of the fuel input (at 20% moisture content).

Table 3.1 *Gas composition in volume % for gasification of fresh wood with 20% moisture under different conditions.*

Component	Case A	Case B	Case C	Case D
CO	13.6	14.5	17.0	24.2
H_2	13.9	14.8	17.4	18.4
CH_4	4.0	4.2	4.9	2.0
C_2H_4	1.3	1.4	1.6	0.7
C_6H_6	0.3	0.3	0.4	0.0
CO_2	16.2	16.0	19.4	17.4
H_2O	4.0*	4.0*	4.0*	4.0*
N_2	46.2	44.3	34.9	32.9
Ar	0.5	0.5	0.4	0.4

*The water content corresponds to the water vapour pressure at 30°C.

Table 3.2 *Cold gas efficiency (CGE) of the gasifier and characteristics of the low-calorific gas.*

		Case A	Case B	Case C	Case D
CGE	%	76.3	78.5	77.5	68.5
Gas density	kg/m_n^3	1.174	1.161	1.154	1.134
LHV	MJ/m_n^3	5.89	6.23	7.35	6.18
Air requirement#	m^3/m^3	1.35	1.42	1.68	1.32
Flame temperature#	°C	1609	1645	1734	1715

For stoichiometric combustion

Differences similar to those between the cases A and B are obtained if the relative heat loss or carbon conversion are varied, e.g. during operation at part-load or at different temperature. Oxygen enrichment results in a higher content of combustible components. Thermal tar cracking increases the CO and H_2 content. It reduces the hydrocarbon content and the calorific value. The actual composition depends strongly on the temperature increase needed for tar reduction. In all cases, the air requirement for combustion is much lower than the 8.5 m^3/m^3 required for Groningen natural gas. The adiabatic flame temperature is much lower too. However, it should be remembered that in gas turbines combustion takes place with excess air that is preheated by compression.

3.2.2 Contaminants

The raw gas contains a number of contaminants that must be removed. Here, we consider tar, dust and gaseous components.

Tar

Tar consists of heavy hydrocarbons, that may condense below 300°C. Condensation will cause problems (clogging, sticking) in the fuel supply system. The tar content in the gas from a CFB gasifier is typically 7 g/m_n^3. Most applications require a tar content below 100 mg/m_n^3. In cases A, B and C it is assumed that tar is removed from the product gas and returned to the gasifier as part of the fuel input.

Recent results at ECN show that cooling of the gas to 30°C and filtering do not reduce the tar content sufficiently (*Dinkelbach 2000*). In the second phase of the GASREIP project an improved gas cleaning system with similar technology will be tested. Alternative methods for tar removal are catalytic or thermal cracking. The efficiency and cost of these methods are still subject to study and not part of the present project. Gas composition D reflects the expected effect of thermal cracking.

Dust
Most of the minerals in the biomass end in the ash. Dust consists of light ash particles and light particles of char (mainly carbon, not converted to gaseous components) that are carried along with the gas stream. Large particles can be removed by a cyclone, smaller particles by a dust filter. The dust content of the raw gas after the cyclone is about 4 g/m_n^3. We assume that the dust content is reduced to 4 mg/m_n^3 by the dust filter and scrubber, i.e. 99.9% of the dust is removed.

Gaseous components
Sulphur, nitrogen and halogens form volatile compounds. A dust filter operating at about 300°C removes part of the halogens as salts of Na and K. The remainder is removed by wet scrubbing together with H_2S and NH_3. Results at ECN show that wet scrubbing can remove at least 98% of NH_3. If the same applies to H_2S and HCl, the remaining concentrations in the gas will be less than 40 mg/m_n^3 for NH_3, 4 mg/m_n^3 for H_2S and 2 mg/m_n^3 for HCl. The contribution of other halogens is at least a factor 10 lower.

Some elements vaporise in the gasifier, but can be removed at least partly from the product gas by cooling and filtration. Of special interest are metals known to cause damage in the gas turbine (alkali metals and vanadium, see section 3.2) and toxic elements. In biomass, alkali metals are present in large concentrations. After gasification the concentration in hot gas is reported to be in the order of 1 ppm to 10 ppm. After cooling and filtration of the gas, the remaining concentration is less than 0.1 ppm. This corresponds to a removal efficiency of more than 99%.

Metals
According to (*Salo 1998*), of the other elements, only Cd and Pb are present in concentrations above the detection limit. We have calculated upper concentration limits for all metals in the gas from the average composition of clean wood (see Appendix A). The following assumptions have been made:

- Elements present in the fuel are fully transferred to the gas phase.
- The elements Hg, Se, As and Cd are volatile at 200°C and are not removed by the dust filter. The contribution of the scrubber in removal of these elements is neglected.
- The remaining elements are removed with 99.9% efficiency.

Table 3.3 contains a list of metals that might be present in concentrations above 0.001 mg/m_n^3. The element V is added because of its importance in hot corrosion. Values reported from experiments for Na, K and Cd are an order of magnitude lower than the estimated upper limits given in table 3.3. For Pb, measured values are similar to the estimated upper limit given in table 3.3. Measured values are invariably higher than consistent with the composition of biomass in case of Ni, Mn and Cr, probably due to wear of metal parts (*Salo 1998*).

Table 3.3 *Estimated upper concentration limits for metals in gas produced by gasification of clean wood. Contributions from the installation have been neglected (see text).*

Element	Concentration [mg/m_n^3]	Element	Concentration [mg/m_n^3]
Na	0.2	V	0.0001
K	0.8	Cr	0.005
Mg	0.3	Mn	0.09
Ca	6.0	Fe	0.06
Ba	0.07	Ni	0.01
Al	0.1	Cu	0.01
Si	0.4	Zn	0.03
As	0.5	Cd	0.2
Ti	0.002	Pb	0.004

Another contribution neglected in table 3.3 is the gasifier bed material. This consists of 95% SiO_2 and small fractions of oxides of Al, K, Na, Mg, Ca, Fe and Ti. The loss of bed material is comparable to the amount of ash in the fuel. However, bed material is relatively coarse and will be removed more efficiently by the dust filter.

3.3 Gas turbine requirements

3.3.1 Combustion characteristics

The combustion chamber of the gas turbine has been designed for diesel and natural gas fuel. If natural gas is substituted by low-calorific gas, the fuel gas volume increases by a factor 5 (or by a factor 4 when the standard OP16 engine without recuperator is compared with a modified version with recuperator)[3]. The fuel supply system must be enlarged accordingly. Further changes to the combustion chamber can be limited, if the combustion characteristics of low-calorific gas are similar to those of natural gas. Important aspects are the ignition behaviour, flame temperature and stability.

Ignition
Methane, the major component in natural gas is a relatively stable fuel that requires a high temperature or large spark energy for ignition. Hydrogen ignites easily and within a large window of fuel-air ratios. The hydrogen content in low-calorific gas should be sufficiently high to prevent ignition problems. The required content is difficult to quantify.

Flame temperature
The adiabatic flame temperature is lower for low-calorific gas than for natural gas. In practice, excess air is used to lower the flame temperature to about 1600°C and thus limit the formation of NO_x. As the air is heated in the compressor and recuperator, this temperature will easily be reached with low-calorific gas too. However, the distribution over combustion and dilution air will have to be adapted.

Flame stability
Conditions in the combustion chamber are close to the extinction limit. Easy ignition and a high flame speed increase the chance of re-ignition in case of local extinction and thus promote flame stability. The flame speed is a function of the turbulence and the laminar flame speed. Results of measurements show the laminar flame speed for methane and low-calorific gas to be similar at combustion chamber conditions.

3.3.2 Contaminants

The following paragraph describes the effect of contaminants on the operation of the gas turbine and gives limits for the acceptable concentrations in the fuel gas. Standard limits for natural gas are reduced by a factor 4 to allow for the increased gas volume.

Limits can also be derived from the emission limits imposed by Dutch or European regulations. Given the air requirement for combustion (c.f. table 3.2), the dry exhaust gas volume at 11% O_2 is roughly 4 times the volume of the fuel gas. Where applicable, a factor 4 is used to calculate the level of contaminants in the exhaust gas from the level in the fuel gas.

Tar
Possible problems, related to the presence of tar in the fuel gas, are condensation in the fuel supply system and incomplete combustion. The critical part for condensation is not the gas turbine itself, but the compressor needed to raise the fuel gas pressure to about 8 bar. This means that the gas must be kept at or above the temperature of the scrubber, where tar is removed. After compression condensation is unlikely. The gas warms during the compression

[3] The standard OP16 engine with recuperator is referred to as OP16R. The code OP16L will be used to indicate the version with recuperator and adapted to low-calorific gas.

and may be heated further in a heat exchanger if required[4]. Preheating of the fuel supply system at start-up and flushing after shutdown suffice to prevent condensation.

Incomplete combustion will result in the emission of soot, volatile organic substances and CO. Essentially, the situation is similar with other fuels. Hence, the level of emissions is not determined by the tar content of the fuel gas but by the quality of the combustion in general. The Dutch BLA and European LCP directives do not specify emission levels for volatile organic compounds and CO. The norm for particles limits the emission of soot.

Dust
The normal specification for particles in the fuel of the OP16 engine is based on the risk of fouling in the fuel pump and fuel metering system. The specification can be relaxed to a value sufficient to prevent blockage of the fuel nozzle and keep the level of erosion of engine components within acceptable limits. The allowable level depends on the particle size. Typical values are <0.1 ppm of particles >20 μm, <1 ppm of particles between 10 μm and 20 μm, and <10 ppm for particles between 4 μm and 10 μm. Smaller particles are assumed to pass through the turbine without damaging it (*Wright 2000*).

From the emission limit for dust follows a maximum content in the fuel gas of 20 mg/m_n^3 for the Netherlands if BLA is followed and 130 mg/m_n^3 in Europe if LCP biomass is considered. The limit becomes more stringent if soot is formed during combustion.

Sulphur compounds
Hydrogen sulphide and organic S cause corrosion in the fuel supply system. Proper materials have to be selected for the components of the fuel supply system to prevent excessive corrosion. Combustion of sulphur compounds produces SO_2 that causes acid corrosion of the engine components downstream of the combustion chamber. Especially, the recuperator requires proper material selection to prevent early failure due to corrosion. The hot section components of the OP16 engine are manufactured from Ni-base superalloys with high Cr content. These materials show excellent corrosion resistance. In standard applications the sulphur content of gaseous fuel is required to be less than 2% by volume. This corresponds to 30 g/m_n^3 and is reduced to 7 g/m_n^3 for low-calorific gas.

The BLA limit for SO_2 emission limits the S content in the low-calorific gas to 80 mg/m_n^3. Again, the European LCP limit allows a higher level, about 250 mg/m_n^3. Both values are far more stringent than the gas turbine requirement.

Chloride
The chloride salts of K and Na cause hot corrosion of turbine parts. The risk is reduced if the Cl content of the gas is at least a factor 4 lower than the S content. At an expected S concentration of 4 mg/m_n^3, the Cl concentration should be limited to 1 mg/m_n^3.

Ammonia
Ammonia can cause corrosion in the fuel supply system. Proper materials (with high Cr content) have to be selected for these components if there is a substantial amount of ammonia in the fuel gas. Stainless steel will be specified as the material to be used in the fuel supply system.

The "normal" lean pre-mixed combustion process produces about 150 mg/s of NO_x, which corresponds to 35 mg/m_n^3 at 11% O_2. Ammonia in the fuel produces additional NO_x during combustion. If all NH_3 is converted into NO_x, the BLA limit corresponds to a maximum allowable NH_3 concentration in the fuel gas of 50 mg/m_n^3. The European LCP biomass limit corresponds to a maximum allowable NH_3 concentration of 300 mg/m_n^3. These limits are probably more stringent than necessary, as full conversion of NH_3 into NO_x is not likely.

Alkali metals
The concentrations of Na and K must be restricted to very low levels in the fuel gas and in the combustion air. In the presence of S, these elements form alkali metal sulphates and cause

[4] In a gas turbine, heating of the gas decreases the fuel consumption without affecting the power output. In a gas engine, heating of the gas decreases both the fuel consumption and the power output.

corrosion of the hot turbine parts. If the S to Cl ratio is lower than 4, alkali chlorides are formed that are even more corrosive. As biomass contains relatively little S, the possibility of corrosion attack by chlorides must not be neglected. For the standard OP16 engine using liquid hydrocarbon fuels, the total amount of Na and K is limited to 1 ppm by mass. In low-calorific gas, the total concentration of Na and K must be limited to 0.2 mg/m_n^3.

Vanadium
Vanadium can form low melting compounds such as V_2O_5 that cause severe corrosive attack. If there is sufficient Mg in the fuel, it will combine with V to form compounds with higher melting points and thus reduce the corrosion rate to an acceptable level. The specification for liquid fuels recommends a Mg to V weight ratio of 3 to 1 to control corrosion, when V is present in more than 1 ppm by mass. In low-calorific gas, the limit for V must be lowered to 0.2 mg/m_n^3.

Calcium
Calcium is not harmful from a corrosion standpoint. In fact, it inhibits the corrosive action of V in a way similar to Mg. However, Ca can lead to hard-bonded deposits. For a standard OP16 engine the maximum Ca level in liquid fuel is specified as 1 ppm by mass. Again, in low-calorific gas, the limit must be reduced to 0.2 mg/m_n^3.

3.4 Comparison of gas quality and requirements

The previous sections discuss the quality of the gas produced by gasification of biomass and requirements by the gas turbine. It is immediately clear that the fuel supply and burner section of the gas turbine must be modified to accommodate the larger fuel mass flow as a result of the low calorific value. These modifications are discussed in chapter 5. Here, we compare only the levels of contaminants expected with the levels allowed for safe operation of the gas turbine or by restrictions on emissions.

Table 3.4 summarises the data given in the previous sections. It shows that the simple gas cleaning system considered suffices to meet most of the specifications. In the case of Ca, Na and K, the assumptions made (i.e. all metal present in the biomass is transferred to the gas and 99.9% is removed by gas cleaning) probably exaggerate the risk, but caution is advised.

Table 3.4 *Expected concentration levels of contaminants in low-calorific gas produced by gasification of biomass and limits derived from gas turbine requirements and emission restrictions. Compare §3.1.2 and §3.2.2 for details on assumptions made.*

Contaminant	Expected concentration [mg/m_n^3 fuel gas]	Gas turbine requirements [mg/m_n^3 fuel gas]	BLA / EU LCP biomass emission restrictions [mg/m_n^3 fuel gas]
Dust	4	10*	20 / 130
H_2S	4	7000	80 / 250
NH_3	40		50 / 300
HCl	2	1	40
Na + K	< 1	0.2	
V	< 0.0001	0.2	
Ca	< 6	0.2	
Cd	< 0.2		0.2
Heavy metals	< 1		2

* Particles between 4 μm and 10 μm.

4. GAS CONDITIONING

The previous chapter contains data on the composition and quality expected for gas obtained by gasification of biomass after cleaning with a system consisting of a cyclone, dust filter and wet scrubber. These data form the basis of the technological and economic assessment. The system performance is affected by the power needed for compression of the gas to the required pressure. The performance may be improved by different operating conditions, removal of inert gas or admixing of natural gas. Compression of the gas and several improvement options are discussed in the present chapter. The gas is assumed to be at atmospheric pressure and at a temperature of 30°C.

4.1 Gas compression

For use in the OP16 gas turbine, the gas pressure must be raised to 8 bar. Work performed during compression heats the gas. If hot gas is used in the gas turbine, the specific fuel consumption is reduced. If the gas is cooled before use (or between compression stages), this advantage is (partly) lost. However, cooling of the gas between compression stages reduces the power used.

Fuel gas compressors basically fall into two groups:

- Dynamic machines such as centrifugal and axial compressors, generally used for gas flows above 1.5 m^3/s and relatively low compression ratios.
- Positive displacement machines such as reciprocating and screw compressors, generally used for gas flows below 1.5 m_n^3/s and relatively high compression ratios.

Centrifugal compressors have a low compression ratio and require multiple compression stages. The efficiency can be 75% to 80%. Axial compressors require even more stages and are used for larger gas flows. The efficiency can be 80% to 85%. Both centrifugal and axial compressors are sensitive to variations in inlet conditions.

Reciprocating compressors are simple in principle and can accept wide variations in inlet and outlet conditions. However, they deliver a pulsating gas flow. A buffer vessel and regulating valve are required to dampen pressure and flow variations to a level that does not interfere with gas turbine operation. The adiabatic efficiency of a water-cooled two-stage reciprocating compressor can be 93%. Reciprocating compressors contain valves that generally require refurbishment at least every 8000 hours.

Screw compressors which are oil-injected are not suitable because of cross-contamination between the gas and the oil. Oil-free screw compressors could be used. Disadvantages are their lower efficiency and higher maintenance cost.

The above considerations lead to the conclusion that a reciprocating gas compressor is best suited to the present application. If gas of 30°C is compressed in two stages with intercooling to 50°C (to prevent condensation problems), the power requirement for compression is 340 kJ/m_n^3 at 85% efficiency. Part of the work delivered is recovered during expansion in the gas turbine. The price of the compressor is estimated at 200 k€.

4.2 Gas drying

In the scrubber, the gas is cooled to 30°C. The water partial pressure is reduced to the vapour pressure of 0.04 bar. If the gas is pressurised by a two-stage compressor with intercooling, condensation will occur if the gas is cooled below 50°C. If the gas is dried by cooling, both the lower mass and the lower temperature of the gas reduce the power required for compression. If the gas is cooled to 7°C, 86 kJ/m_n^3 of heat is removed and the water content reduced to 1%. As a result, the calorific value of the gas (in MJ/m_n^3) increases by 3%. Compression of the gas requires less power, which cancels the power spent in cooling. The additional cost for the cooler may be justified if drying is required to prevent corrosion or condensation problems.

4.3 Removal of CO_2

The gas produced by gasification of biomass contains 15% to 20% CO_2. Removal of the CO_2 would reduce the power requirement for compression and increase the calorific value of the gas substantially. Obviously, techniques that require high gas pressure need not be considered. This effectively limits the options to absorption in a solution of monoethanolamine (MEA) or diglycolamine (DGA). For the commercially applied Econamine FG process, the energy consumption for CO_2 removal equals 4 MJ/kg CO_2 (in the form of 150°C steam) plus 48 kWh of electricity per tonne of CO_2 (*Hendriks 1994*).

If residual heat is used to produce the required steam, only electricity has to be provided. A reduction of the CO_2 content from 16% to 1% requires 51 kJ/m_n^3 in the form of electricity. Again, the power saved in compression of the gas cancels the power spent in the gas treatment (i.e. CO_2 removal). The investment costs for a CO_2 removal installation are estimated at 1.1 M€ and the operation and maintenance costs at 60 k€ per year. These costs make CO_2 removal unattractive.

4.4 Preheating of gasifier air

In chapter 3 the gas compositions are given for gas obtained when the air is heated to 400°C (case A) or 600°C (case B). The higher air temperature increases the calorific value of the gas and the cold gas efficiency of the gasifier (cf. table 3.2). The air is heated by heat exchange with the hot gas leaving the gasifier. For case B, the wall temperature or the surface area must be increased. It is expected that the price of the heat exchanger will double from 150 k€ to 300 k€.

4.5 Gasification with O_2-enriched air

Gasification with O_2-enriched air increases the gasifier efficiency and the calorific value of the gas (cf. case C in table 3.2). If thermal cracking is used to remove tar, O_2-enriched air may be necessary to limit the loss in calorific value (cf. case D in table 3.2). VPSA (vacuum pressure swing absorption) is the cheapest commercially available method to produce O_2 at the scale under consideration. The electricity consumption is 0.45 kWh/m_n^3 of gas with 93% O_2.

Gasification with O_2-enriched air increases the gasifier cold-gas efficiency and reduces the fuel gas volume. Hence, the power use for O_2-production is compensated by a reduced power use in other parts of the system. The main components to be considered are the fuel feeding system, the air blower, the fuel gas cleaning and cooling system and the fuel gas compressor.

Table 4.1 *System power requirement for 5.2 MW_{th} output of fuel gas.*

		Case A	Case B	Case C	Case D
Thermal input (LHV)	MW	6.8	6.6	6.7	7.6
Power use for					
Fuel feeding	kW	34	33	34	38
Air blower	kW	17	15	10	11
Gas cleaning	kW	34	32	27	32
Gas compressor	kW	299	282	237	285
O_2 production	kW	-	-	68	168
System power use	kW	384	362	376	534

Table 4.1 compares the estimated power demand of these components for the cases A to D defined in chapter 3. Given the assumptions made, it can be concluded that O_2-enrichment has a negligible effect on the system power use. However, the power use increases substantially if a thermal tar cracker is installed that heats the gas by burning part of it with O_2.

4.6 Mixing with natural gas

Mixing of low-calorific gas from biomass with natural gas may be undesirable or not even permitted if green energy is to be produced. Here, the option is considered because of the following reasons

- It may be useful to start the gas turbine with natural gas, e.g. to improve cold ignition or to bring the system at operating temperature without risk of condensation.
- It may be necessary to switch from low-calorific gas to natural gas before stopping the gas turbine, e.g. to prevent condensation, or to prevent emission of unburned fuel gas with high CO-content.
- It may be useful to switch from fuel gas to natural gas in case of malfunctioning of the gasifier to prevent damage to the gas turbine.
- Admixing of natural gas offers an opportunity to stabilise the calorific value of the fuel gas.
- Admixing of natural gas increases the calorific value of the fuel gas. This may reduce the necessary modifications to the gas turbine and improve its efficiency.

Table 4.2 compares the combustion properties of low-calorific gas (case A), natural gas (NG) and mixtures that derive 5% or 10% of their energy content from natural gas. It shows that admixing of natural gas in these quantities has a minor effect on the fuel gas properties. Admixing of natural gas does not alter the need for modification of the gas turbine.

Table 4.2 *Combustion properties of low-calorific gas, natural gas and mixtures.*

		A	NG	5% NG	10% NG
Calorific value (LHV)	MJ/m_n^3	5.89	31.7	6.14	6.41
Air requirement#	m^3/m^3	1.35	8.52	1.42	1.49
Flame temperature#	°C	1609	2012*	1625	1641

For stoichiometric combustion.

* In practice, dissociation of CO_2 and H_2O reduces the flame temperature considerably.

5. GAS TURBINE MODIFICATIONS

Chapter 5 of the confidential report discusses the effects of low-calorific gas on the operation of and necessary modifications to the gas turbine. It shows that an OP16L gas turbine, suited for operation on fuel gas from a biomass gasifier, can be developed from the existing OP16R version at reasonable costs. The average electricity production can be close to 1900 kW_e and the efficiency 36% (from fuel gas to electricity, without correction for electricity use by the fuel gas compressor).

Because of the proprietary character of the information contained in Chapter 5, it is omitted from the present public version of the report.

6. SYSTEM ECONOMY

6.1 Cost contributions

Investment costs

Chapters 2 and 5 describe the main characteristics of three options to drive a generator producing electricity from biomass:

1. Combustion of biomass to produce steam for a steam turbine
2. Gasification of biomass and combustion of the fuel gas in a gas engine
3. Gasification of biomass and combustion of the fuel gas in a gas turbine

The second and third option both require a gasifier and gas cleaning equipment. To simplify the comparison, the fuel gas input is fixed at 5.2 MW_{th} in both cases. The gasifier thermal input equals 6.8 MW_{th}. In case of the combustion system 6.3 MW_{th} input is assumed, for which data are given in table 2.6. Based on confidential data used in a recent study (*Van der Drift 2000*) a 6.8 MW_{th} gasifier with control equipment, cleaning system and building requires an investment of 4.7 M€. This figure must be added to the costs of the gas engine (c.f. table 2.5) or to the costs of the gas compressor plus gas turbine to obtain the total investment. Table 6.1 summarises the essential data for the three options at 1 MW_e to 2 MW_e scale.

Table 6.1 *Technical data and investment costs for installations producing electricity from biomass at 1 MW_e to 2 MW_e scale.*

		Steam turbine	Gas engine	Gas turbine
Thermal input	[MW_{th}]	6.30	6.80	6.80
Net electrical output	[MW_e]	1.01	1.73	1.49
Net efficiency	[%]	16.0	25.4	21.9
Total investment	[M€]	4.04	6.20	6.10
EIA/VAMIL subsidy[#]	[M€]	0.84	1.29	1.27
Net investment	[M€]	3.20	4.91	4.83

[#] 25% of investments, excluding building costs.

If the scale is increased to about 10 MW_e, the specific investment costs of the steam turbine option decrease by 58% according to table 2.6. The efficiency increases from 16% to 22%. As gas engines are limited in size, at a larger scale several engines must be used. The same holds true for the gas turbine considered here. Hence, increasing the scale has a limited effect on the specific investment for those engines. The specific costs of the gasifier and associated systems decrease markedly. Overall, we expect a 45% reduction in the specific price of the total system. The efficiency increases by 0.5% because of lower heat loss of the gasifier and reduced system use of electricity. Table 6.2 summarises the data for the economic analysis at 10 MW_e scale.

Capital costs

The capital costs of electricity produced from biomass have been calculated from the net investment costs at an internal rate of return of 11.6% and 5000 operating hours per year. These values have also been used in a recent study comparing various options to produce electricity from biomass (*Van Hilten 2000*), but differ significantly from the 9% and 8000 hours used in the study on commercialisation of gasification technology (*Van der Drift 2000*).

Maintenance and operating costs

The maintenance costs of the steam turbine are given in table 2.6 for 8000 operating hours per year. These costs are corrected to 5000 operating hours per year. The maintenance costs of the

Table 6.2 *Technical data and investment costs for installations producing electricity from biomass at 10 MW_e scale.*

		Steam turbine	Gas engine	Gas turbine
Thermal input	[MW_{th}]	45.4	40.1	39.9
Net electrical output	[MW_e]	10.0	10.4	8.9
Net efficiency	[%]	22.0	25.9	22.4
Total investment	[M€]	17.0	20.6	19.5
EIA/VAMIL subsidy#	[M€]	3.5	4.3	4.1
Net investment	[M€]	13.5	16.3	15.4

25% of investments, excluding building costs.

gasifier and associated systems, the gas compressor and the gas turbine are estimated at 4% of the investment costs per year. Data for the gas engine are taken from table 2.5. Operating costs are assumed to be k€ 60 per year (one man-year) at 1 MW_e scale and k€ 90 per year at 10 MW_e scale.

Fuel and related costs
The biomass price is assumed to be € 45,= per tonne dry mass, i.e. € 2.4/GJ. Related costs (e.g. ash disposal, purge gas, ammonia etc. for gas cleaning) equal approximately 10% of the fuel costs (*Van der Drift 2000*).

6.2 Electricity production costs

Zero heat income
The electricity production costs are calculated first with zero value assigned to heat. The results are given in table 6.3 for installations at 1 MW_e to 2 MW_e scale and in table 6.4 for installations at 10 MW_e scale. Clearly, the differences between the three options are small. The steam turbine option is the most expensive at small scale and the cheapest at the larger scale. The gas turbine option is slightly more expensive than the gas engine option.

Table 6.3 *Electricity cost calculation for installations producing electricity from biomass at 1 MW_e to 2 MW_e scale without income from heat.*

		Steam turbine	Gas engine	Gas turbine
Capital	[€/kWh]	0.074	0.066	0.075
Fuel	[€/kWh]	0.054	0.034	0.039
Maintenance and operation	[€/kWh]	0.045	0.044	0.041
Ash disposal and consumables	[€/kWh]	0.005	0.003	0.004
Total	[€/kWh]	0.178	0.147	0.159

Table 6.4 *Electricity cost calculation for installations producing electricity from biomass at 10 MW_e scale without income from heat.*

		Steam turbine	Gas engine	Gas turbine
Capital	[€/kWh]	0.031	0.037	0.040
Fuel	[€/kWh]	0.039	0.033	0.039
Maintenance and operation	[€/kWh]	0.018	0.025	0.019
Ash disposal and consumables	[€/kWh]	0.004	0.003	0.004
Total	[€/kWh]	0.092	0.098	0.102

Sensitivity of results on assumptions

The calculated electricity costs depend on the assumptions made. Some of these are specific for each option, like the investment and maintenance costs. Other assumptions, like the number of operating hours and the fuel price, relate simultaneously to all three options, but the effects may vary. Table 6.5 shows the sensitivity of the results on variations in the main parameters, i.e. the relative change in electricity price divided by the relative change in a single parameter. It shows that effects do vary. However, a 20% change in one of the parameters for all three options simultaneously does not change the ranking. A 20% reduction of the investment costs for the gasifier and associated systems would make the gas engine and gas turbine competitive with the steam turbine at 10 MW_e scale.

Table 6.5 *Sensitivity of electricity production costs on variations in main parameters.*

	Steam turbine	Gas engine	Gas turbine
Operating hours	-0.62	-0.59	-0.68
Total investment	0.38	0.53	0.62
Internal rate of return	0.38	0.41	0.43
Fuel price	0.40	0.31	0.35
Maintenance	0.18	0.25	0.19
Manpower	0.05	0.04	0.04

If the normal electricity price for producers, the REB exemption and return value in 2000 were added, the maximum product value in the Netherlands would be € 0.085/kWh. In Germany, the value is € 0.09/kWh for installations up to 5 MW_e. Clearly, with the present assumptions, none of the options would be commercially attractive at 1 MW_e to 2 MW_e scale. The gas engine and gas turbine would reach electricity production costs of € 0.085/kWh, if simultaneously the number of operating hours is increased to 8000 hours per year, the fuel price halved and the internal rate of return reduced to 9%. At 10 MW_e scale all three options are close to economic viability. An increase of the number of operating hours to 6000 hours per year for the steam turbine or to 7000 hours per year for the gas engine and gas turbine would suffice.

Combined heat and power

The results change significantly if reject heat carries a positive net value. As explained in section 2.1, co-generation of heat and power is strongly promoted in Europe as a means to reduce CO_2 emissions. The fraction of useful heat depends on the application. With demand for process heat or hot tap water, the fraction can be 100%. It is assumed that heat will be required at 120°C for these applications. If hot water is supplied for central heating, the number of operating hours will be about 2000 hours per year. It is assumed that heat available down to 70°C can be used. In both cases, a back-up system is required to match peak demand or demand during shutdown of the biomass installation. The value of heat varies substantially between European countries and between industrial or household applications. A realistic price for heat is € 3.2/GJ (*Van der Drift 2000*).

Heat withdrawn from the steam turbine reduces the power output in a 1:7 ratio between power loss and heat withdrawn. At a heat price of € 3.2/GJ, the electricity value should be lower than € 0.08/kWh for heat supply to be economic. It may be concluded that heat supply need not be considered in the present analysis for the steam turbine option.

Both the gas engine and gas turbine can deliver heat without penalty to the electricity production. If the exhaust gases are cooled to 120°C, the gas engine delivers 20% of the thermal input to the gasifier as heat and the gas turbine 32%. If heat is used for central heating, the output can be increased to 34% for the gas engine and to 39% for the gas turbine. Even more heat can be supplied if latent heat of the fuel gas is used. That option is neglected because of the associated costs and risk of tar condensation at the heat exchanger. The income from heat supplied during 2000 hours per year corresponds to a decrease in electricity production price by € 0.004/kWh to € 0.008/kWh. If the number of operating hours for heat supply equals the total number of operating hours, the effect increases by a factor 2.5. Table 6.6 summarises the results.

Table 6.6 *Electricity production price in €/kWh for CHP applications.*

	Steam turbine	Gas engine	Gas turbine
No heat supply, 1 MW_e to 2 MW_e	0.178	0.147	0.159
Process heat 2000 hours/year	-	0.143	0.153
Process heat 5000 hours/year	-	0.138	0.143
Central heating 2000 hours/year	-	0.141	0.151
No heat supply, 10 MW_e	0.092	0.098	0.102
Process heat 2000 hours/year	-	0.094	0.095
Process heat 5000 hours/year	-	0.089	0.085
Central heating 2000 hours/year	-	0.092	0.094

The results in table 6.6 show that income from heat does improve the attractiveness of the gas engine and gas turbine. If the heat demand matches the supply continuously, 10 MW_e installations can produce electricity at a cost equal to the present market value in the Netherlands and Germany. Even lower electricity production cost will be reached if the investment costs decrease because of learning effects. Launching customers may be found who are willing to accept a lower internal rate of return or can achieve a larger number of operating hours than assumed in the present analysis.

7. CONCLUSIONS

Main conclusions

The present study considers the technical and economic feasibility of installations that produce power by gasification of biomass and use of the fuel gas in a gas turbine at a scale between 1 MW_e and 10 MW_e. These installations are not competitive to conventional installations without government support.

Both in the Netherlands and in Europe, ambitious targets are set both for energy from renewable sources and for the combined production of heat and power (CHP). Stimulating measures (subsidies, tax incentives, price guarantees) are taken to promote the development and implementation of installations for the production of electricity and heat from biomass and other renewable sources. The market for biomass-fired CHP installations of 1 MW_e to 10 MW_e capacity is estimated at 5 MW_e newly installed capacity per year for the Netherlands and 120 MW_e in the European Community.

An OP16L gas turbine, suited for operation on fuel gas from a biomass gasifier, can be developed from the existing OP16R version at reasonable costs. The average electricity production can be close to 1900 kW_e and the efficiency 36% (from fuel gas to electricity). After correction for power use and losses in the gasifier and gas compressor, the net power output decreases to 1.5 MW_e. The net efficiency from biomass to electricity equals 22%. The thermal efficiency for heat delivery varies from 32% for process heat at 120°C to 39% for heat at 70°C.

Alternatives to the system considered above are a similar system with a gas engine instead of the gas turbine, or the combustion of biomass to produce steam that drives a steam turbine coupled to a generator. The use of a gas engine improves the net electrical efficiency by about 3%. The difference is due to the energy required for compression of the gas for use in the gas turbine. The thermal efficiency varies from 20% at 120°C to 34% at 70°C. The steam turbine yields an electrical efficiency of 16% at 1 MW_e to 22% at 10 MW_e. Heat can be delivered only at the expense of a lower electrical efficiency.

At 5000 operating hours per year and a fuel price of € 2.4/GJ, the electricity production costs for 1 MW_e installations vary from € 0.15/kWh for the gas engine and € 0.16/kWh for the gas turbine to € 0.18/kWh for the steam turbine. At 10 MW_e scale, the production costs decrease to € 0.09/kWh for the steam turbine and € 0.10/kWh for the gas engine and gas turbine. These costs are similar to the market value of electricity from renewable sources in the Netherlands and Germany. Production costs can drop by € 0.01/kWh for gas engines and nearly € 0.02/kWh for gas turbines if reject heat is sold at € 3.2/GJ. Sufficient heat demand, a larger number of operating hours or lower fuel price than assumed make installations smaller than 10 MW_e economically attractive.

The gas turbine option is expected to show the best performance on emissions. However, at present that advantage does not suffice to warrant commercial success for a development program of a dedicated gas turbine.

Detailed technical conclusions

An inventory of the gas quality that can be produced from biomass and the requirements posed by the gas turbine shows that there are no real obstacles. However, the concentrations of K, Na and Ca in the gas may reach values harmful to the gas turbine. Caution is advised in the design of the gas cleaning system to ensure sufficient removal of these elements.

When biomass is converted in an atmospheric gasifier, the gas must be pressurised for use in a gas turbine. The energy required for compression corresponds to 6% of the energy content of the gas. Several options have been considered to enhance the calorific value of the gas and thus reduce the energy for compression. Additional preheating of gasification air increases the system efficiency slightly. The net economic effect is negligible. The energy requirement for gas drying by cooling to 7°C approximately equals the energy saved in compression. The associated costs may be justified if corrosion problems are expected. Removal of CO_2 and O_2 enrichment of gasification air are energetically neutral too. Removal of CO_2 is very expensive. The use of O_2 can be justified if tar is removed by thermal cracking, which is assumed not to be necessary.

When compared to the gas engine, the gas turbine is less economic because of the power required for gas compression. Even if modification for low-calorific gas would not increase the cost price of the gas turbine with respect to the standard recuperated version, the electricity production costs would remain higher than for the gas engine.

Combustion of biomass may cause NO_x emission close to or above the European limit. In the Netherlands, the limit is even more stringent and measures have to be taken to reduce the NO_x emission. Part of the NO_x results from nitrogen bound in the fuel. During gasification most of the fuel nitrogen is converted to NH_3 that can be removed by wet scrubbing of the fuel gas. The formation of thermal NO_x can be limited by choosing the right combustion conditions in the gas engine or gas turbine. The gas turbine is expected to yield the lowest emissions.

Another emission problem with gas engines is the incomplete burn out of CO in the fuel gas. High values of CO in the exhaust gas are reported, but as yet there is no emission limit to be complied with. In that respect too, the gas turbine is expected to outperform the gas engine. Given the small differences in electricity production costs, the gas turbine becomes the best choice if stringent emission limits are to be met.

APPENDIX A: MINERAL CONTENT OF WOOD

The average content of minerals in wood has been calculated from data contained in the ECN database Phyllis (*ECN 2000*). In principle, only data for clean wood have been used. The spread in reported values suggests that some samples were contaminated. In practice, contamination by sand, plastic or metal parts is difficult to exclude completely in bulk quantities of wood fuel. Hence, the values reported here may be higher than observed in carefully selected samples but are considered representative for nominally clean wood. Table A1 shows the average mineral content, the reported minimum and maximum values and the number of analyses available for the calculation of the average.

Table A1 *Mineral content of clean wood.*

Element	Average	Minimum	Maximum	Number of analyses	Element	Average	Minimum	Maximum	Number of analyses
	[mg / kg dry]					[mg / kg dry]			
S	500	0	9,000	121	Hg	0	0	0.1	5
Cl	270	40	2,000	78	K	1,800	90	4,000	17
F	10	0	10	6	Mg	750	160	3,800	52
Al	210	10	2,200	52	Mn	210	8	840	50
As	1.2	0	1.7	7	Na	375	17	3,500	17
B	7	5	12	7	Ni	22	1.3	65	8
Ba	150	1.3	540	43	P	500	120	1,100	42
Ca	14,0000	1,300	52,000	52	Pb	9	0.3	42	7
Cd	0.5	0	1.2	7	Si	850	18	6,600	50
Co	0.6	0.6	0.6	6	Ti	5	1.3	11	6
Cr	11	0.9	31	8	V	0.3	0.2	0.6	6
Cu	20	1.5	320	56	Zn	60	15	130	9
Fe	130	15	1,200	52					

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