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Evaluations of biomass CHP technologies in a Norwegian context

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RESULT (summary)

CHP plants based on biomass are complex and challenging plants compared to most other CHP technologies, mainly due to the influence of the fuel on plant performance and economy. However, biomass also has several advantages compared to e.g. fossil fuels, being potentially CO_2 neutral and a widely distributed energy source. This report presents and discusses a number of aspects connected to biomass CHP, regarding technologies, cost-efficiency considerations, Norwegian framework conditions and research challenges connected to the relevant biomass CHP technologies. Depending on the framework conditions several scenarios can be envisioned with respect to the future of biomass CHP in Norway. The selection of the small-scale CHP technology or sub-system technology to be studied in detail in the last two years of the KRAV project should be based on one or more of the following criteria:

1) Established technologies with significant potential for improvements or **retrofit solutions** (e.g. biogas fired superheaters)
2) **Technology combinations** with focus on increased electric efficiency (e.g. system analysis of such combinations)
3) General **fuel aspects directly influencing the cost-efficiency** of biomass CHP plants (e.g. corrosion and fouling)
4) General **fuel aspects influencing emissions** from biomass CHP plants (e.g. NOx)
5) Technology aspects directly influencing cost-efficiency and emissions from biomass CHP plants (e.g. grate design)
6) New CHP technologies that have the potential to become of significant importance in Norway within 2020 (e.g. gasification based)

KEYWORDS

SELECTED BY AUTHOR(S)	biomass	small-scale
	CHP	cost-efficiency

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1 INTRODUCTION

The KRAV project focuses on small-scale CHP plants running on biomass, as one of the potentially important future contributors to the Norwegian energy system. Small-scale in this context meant initially plants with a capacity below 10 MWth based on the lower heating value (LHV) of the fuel. However, for reasons discussed later in this report **the recommendation is to also include medium-scale plants** (up to 30 MWth) in the KRAV project. CHP plants based on biomass are complex and challenging plants compared to most other CHP technologies, mainly due to the influence of the fuel on plant performance and economy. However, biomass also has several advantages compared to e.g. fossil fuels, being potentially CO_2 neutral and a widely distributed energy source. As such biomass is and will be an important contributor to the abatement of climate effects caused by excessive CO_2 emissions due to fossil fuel combustion and an important contributor to the renewable energy mix needed to cover the world's future energy demands in a sustainable manner.

Several biomass CHP technologies exist, and they can be divided into steam, or inert medium, based or gas based, or combined solutions of these. In the steam, or inert medium, based systems heat is transferred to a medium which then expands in a turbine or an engine to provide mechanical work and generate electricity. This includes steam turbines and steam engines, organic Rankine cycles (ORC) (evaporated organic oil as working medium), Stirling engines (helium, or possibly hydrogen, as working medium) and hot air turbines. The gas based systems generates a combustible gas from the solid biomass (e.g. through gasification or anaerobic digestion), which then is combusted and expanded in a turbine or combusted directly in an engine to provide mechanical work and electricity or electrochemically converted in a fuel cell to generate electricity. Combined systems are systems where excess heat (or fuel) from a primary cycle is utilised in a bottoming cycle, in more or less complex system configurations, to further increase the overall electric efficiency (e.g. a gas turbine followed by a steam turbine).

A substantial amount of biomass CHP is now operating around the world, providing the world with valuable electricity from a renewable energy source. However, experiences with such plants, and especially small-scale plants are various, and is connected both to technical and economical aspects. "Big is beautiful" is an expression which can be regarded as suitable, meaning that bigger plants in general show better performance. However, many aspects must be considered when sizing a biomass CHP plant, and the largest plant is therefore not necessarily the overall optimum solution.

The availability of biomass in a relatively close proximity of a plant and the amount of heat that can be utilised locally limits the CHP plant size. The heterogeneity of biomass fuels creates challenges both directly connected to the fuel properties and to secondary effects of the fuel downstream in the plant. This has contributed to a large amount of fuel conversion technologies, for different types of biomass fuels, and for different use. The clue then becomes to select a combination of the optimum conversion technology for a specific fuel and the optimum electricity generation technology, based on an optimum overall cost-efficiency. This is indeed a challenging task.

The fuel properties and composition has an important influence on the conversion process in a plant[1], and most of the technical challenges connected to biomass CHP plants are directly connected to the fuel properties and composition. Especially minor species in the fuel causes challenges connected to sintering, slagging, corrosion, fouling and emissions. Hence, fuel quality becomes a key issue in any biomass CHP plant. An improved fuel quality may significantly

[1] Handbook of biomass combustion and co-firing, (ed.: Sjaak van Loo and Jaap Koppejan), Earthscan, 2008

increase the plant performance, i.e. fuel quality engineering through pre-treatment, optimum fuel mixing or additives use then becomes very interesting.

THE RENEWABLES DIRECTIVE – OPPORTUNITIES FOR THE FUTURE

Norwegian authorities have recently decided that Norway will have to implement the EU Renewables Directive[2]. Presently Norway has a renewables percentage of 60 %, but it is expected that the new directive will require this percentage to increase to more than 70 % by 2020. This may imply more than ***20 TWh of new renewable energy*** in Norway over the next decade. It remains to be seen how large a portion domestically produced bioenergy is going to capture of this increase, but given the present low level of utilization of bioenergy resources in Norway, it is fair to assume that the bioenergy percentage will be significant. Such an assumption is also backed by the recent national Bioenergy strategy[3], targeting a 14 TWh increase in the use of bioenergy by 2020, including the use of biofuels.

According to the Renewables Directive, biofuels must constitute at least 10 % of the total energy consumption in the transport sector by 2020. Import is considered acceptable as long as sustainability is documented for the production of the imported biofuels. **For Norwegian conditions the 10% biofuels requirement will represent about 6 TWh**. StatoilHydro, the dominant player in the market for fuels for the transport sector in Norway, has however recently backed out of all domestic production of bioenergy, and presently their emphasis is on trade and import from the Baltic states and from Brazil.

It is important to be aware that in the last and final version of the Renewables Directive, “biofuels” may have CHP implications: The electric powering of electric and plug-in hybrid cars is included in the 10 % biofuels requirement in the final version of the Directive, and the high energy efficiency of electricity in the transport sector will be accounted for as follows: The actual electric energy input to the car should be multiplied by 2.5, in order to be comparable to the limited (approx. 40%) efficiency of car engines. This has the interesting implication that instead of using zero electricity and 6 TWh “real” biofuels in the transport sector, one might end up using 2.4 TWh electricity and zero “real” biofuels on the other extreme, and still be inside the limits stated by the Directive. The most likely situation is probably somewhere in between, but it should be expected that the present price advantage of electric power over highly taxed gasoline might be a strong incentive for electrification of the Norwegian car pool.

The BioWood Norway AS[4] pellet plant in Averøy on the west coast of Norway represents another source of bioenergy import. The production capacity of this plant, which will start production in early 2011, will be 450 000 tons per year, which is equivalent to 2 TWh. The biomass will be imported in the form of wood chips from USA, Canada and other countries around the Atlantic Ocean.

CHP TECHNOLOGIES AND COST – GENERAL BACKGROUND

Several studies have presented comparisons of biomass conversion technologies and of efficiencies and costs versus scale for different biomass CHP technologies recent years, as well advantages and disadvantages of the different technologies. There are a multitude of feedstock and conversion technology combinations to produce heat and power, albeit at different stages of development and deployment.

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[2] http://ec.europa.eu/energy/climate_actions/doc/2008_res_directive_en.pdf
[3] Bioenergistrategien, http://www.regjeringen.no/nb/dep/oed/tema/fornybar-energi/bioenergistrategien.html
[4] http://www.biowood.no/index.php?page_id=4

Figure 1 shows the development status of different routes[5]. The preferred route will depend on many considerations, including technology readiness, feedstock type and volumes available, as well as energy service required (heat and/or power); different actors may favour different technologies. While project developers will be interested in maximizing financial return, governments will also be concerned by considerations such as carbon saving potential, energy security and nation-wide economic return. For biomass to heat, combustion is the only fully commercial option. Steam cycles are the only fully commercial steam based biomass CHP technology. For some of the technologies it can be discussed whether the development status has come farther than indicated in the figure. This can be the case for torrefaction[6] and ORC[7].

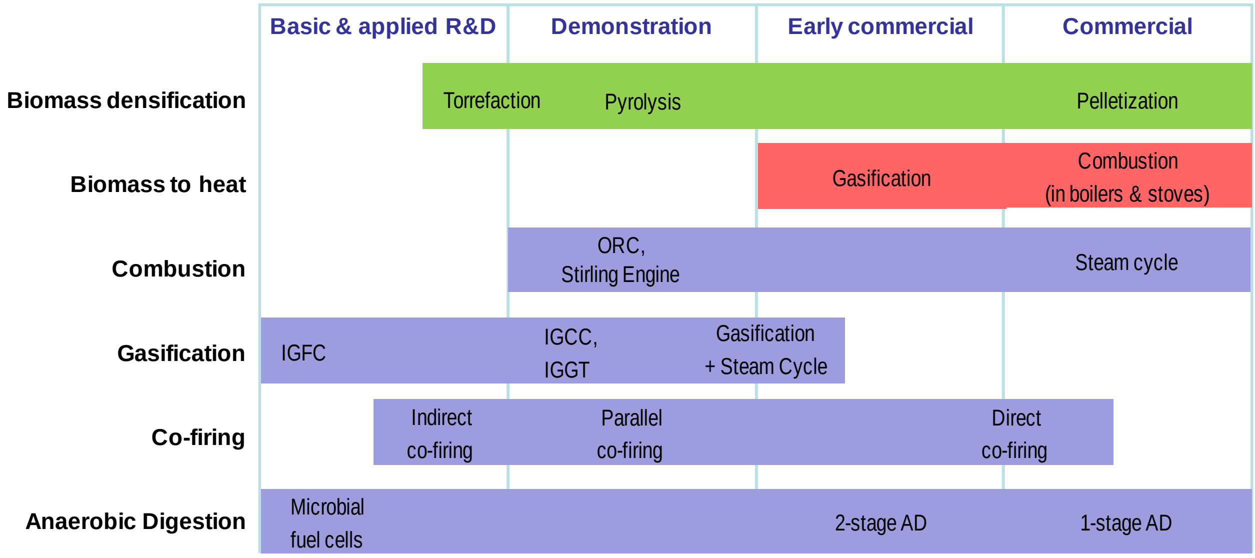


Figure 1 Development status of the main upgrading technologies (green), biomass to heat technologies (red) and biomass to power & CHP technologies (blue).[5]

Figure 2 shows capital cost for available biomass-fuelled technologies to power and CHP[5]. Direct co-firing of biomass with coal is the least capital intensive option.

[5] IEA Bioenergy Review , draft report, 3 October 2008
[6] http://www.topell.nl/
[7] http://www.turboden.it/public/09Z00180_e.pdf

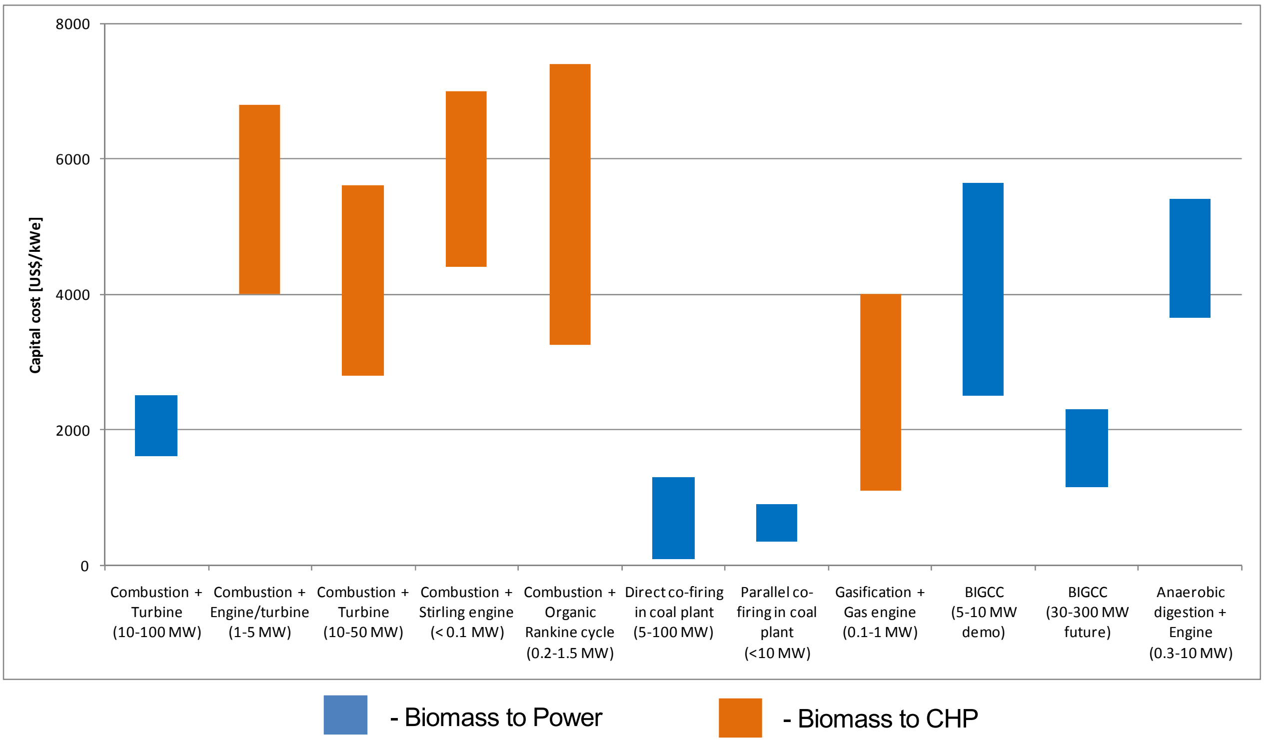


Figure 2 Capital cost for available biomass-fuelled technologies to power and CHP. Note 1: Anaerobic digestion is also found to be run in CHP mode.[5]

Figure 3 shows production cost for available biomass-fuelled technologies to power and CHP[5]. Again the direct co-firing with coal option is the least costly one. Such a comparison will always be sensitive to the relative importance of fuel cost and the price of electricity versus heat, which will be influenced by national framework conditions. In the figure fuel costs and heat prices are about half of what is seen in Norway today. The capital costs are less influenced by national framework conditions, but different national investment support schemes will also here to some extent influence the net capital cost.

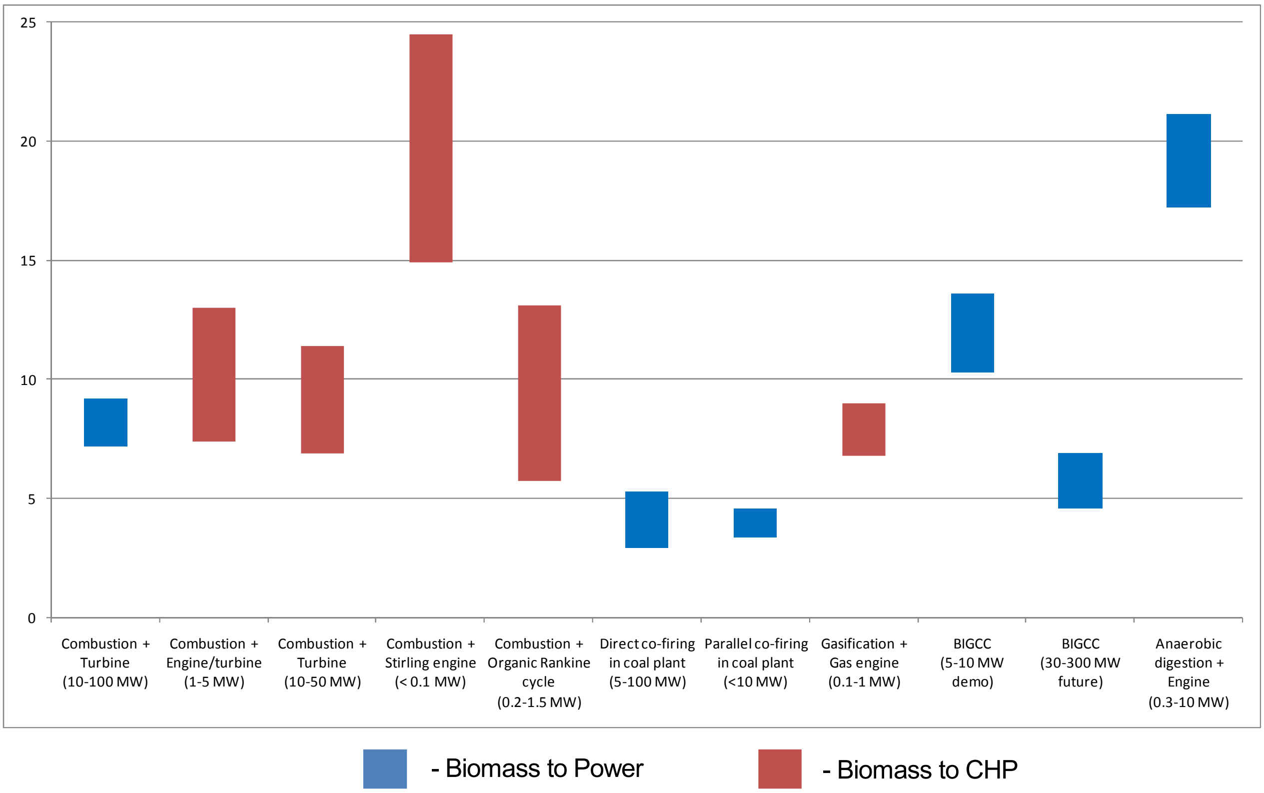


Figure 3 Production cost for available biomass-fuelled technologies to power and CHP. For the sake of making comparison possible, the production costs are based on the following assumptions for each of the technologies considered: (1) Plant lifetime=20 years, (2) Discount rate = 10%, (3) Heat value=5US$/GJ (for CHP applications only), (4) Biomass cost=3 US$/GJ. Note 1: Anaerobic digestion is also found to be run in CHP mode. Note 2: production cost can be reduced by 60-80% (depending on technology and plant size) if free biomass feedstock is used, such as e.g. MSW, manure, waste water, etc.

Obviously, negative cost, free and low-cost biomass has a great production cost advantage. Many places there are a demand to handle e.g. animal manure in a way that prevents negative environmental effects, e.g. emissions. This is a political demand. A gate fee will have to be paid to the plant treating the manure. Hence, biogas production cost considerations are sensitive to several factors, including also support schemes.

Figure 4 shows the world's share of the biomass sources in the primary bioenergy mix[5]. Clearly fuelwood is most commonly used, but residues and wastes are also important, and are beneficial with respect to fuel costs.

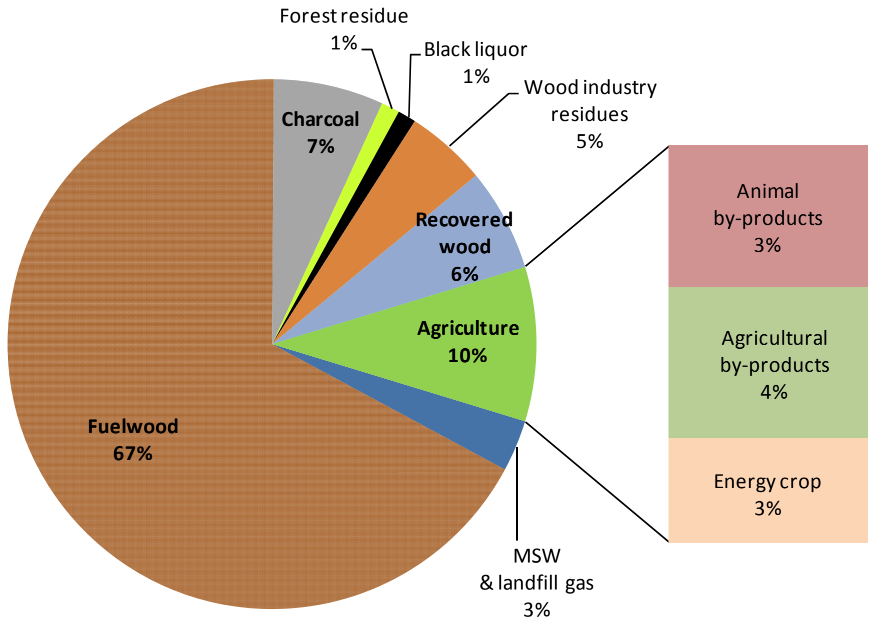
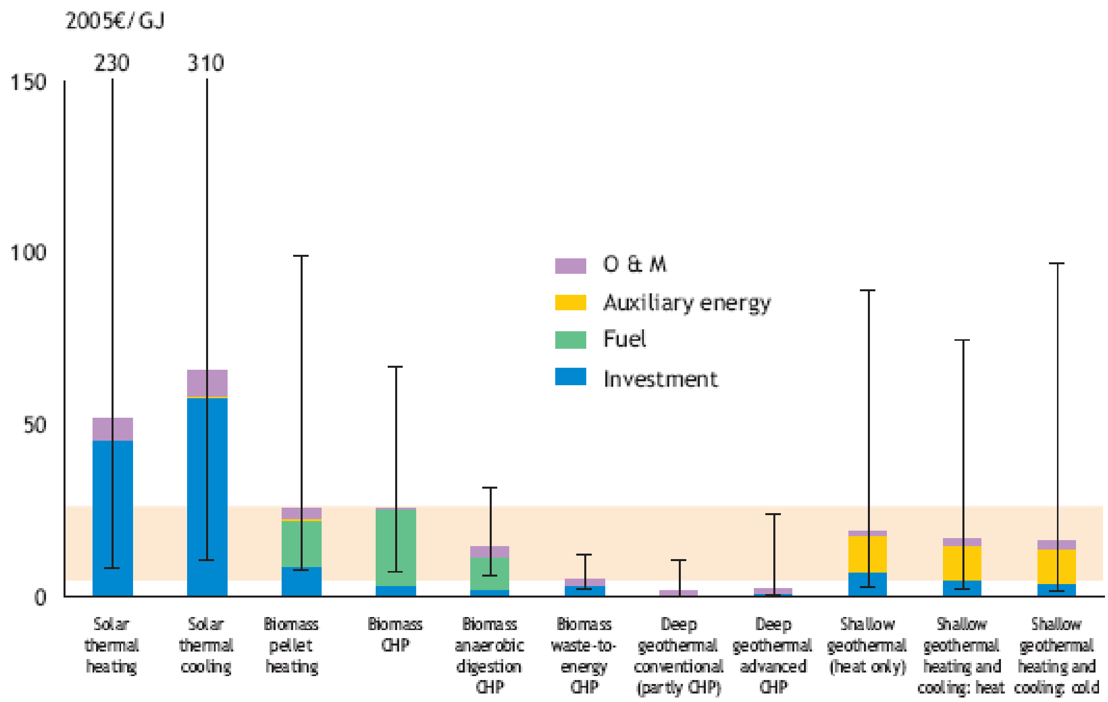


Figure 4 Share of the biomass sources in the primary bioenergy mix.[5]

Figure 5 shows cost breakdown and ranges (excluding VAT) in 2005 for a selection of renewable heating & cooling technologies compared with the reference energy price range[5]. Clearly biomass waste-to-energy CHP is the least costly option, however, gate fee for animal manure in connection with biogas production will make this option more favourable.



Notes: The conventional energy carrier costs are only based on fuel costs and conversion losses because investment and depreciation costs of appliances per GJ of heat are relatively small. Neither reference system nor avoided costs due to fuel savings are incorporated. Installation costs are included but heat distribution costs and costs allocated to electricity generation for CHP technologies are not. Details on cost assumptions are given in Annex A.

Figure 5 Cost breakdown and ranges (excluding VAT) in 2005 for a selection of renewable heating & cooling technologies compared with the reference energy price range (shaded horizontal bar) for gas, fuel oil and electricity heat energy carriers for the domestic (top of range bar) and industrial (bottom) sectors.[5]

The FME Bioenergy Innovation Centre (CenBio), running from 2009, has received substantial funding from the Research Council of Norway and industry.

Figure 6 shows the CenBio **vision** for future bioenergy utilisation in Norway in 2020[8]. As can be seen, it is expected that 4 TWh of bioenergy will be utilised in CHP applications and 1 TWh in standalone power applications within 2020. Additionally, 2 TWh of biogas is expected to be utilised, partly for CHP/power. This represents a substantially increased focus on biomass CHP and power in Norway, where today bioelectricity is generated to a very limited extent; one waste wood plant, one forest residues plant connected to a paper mill factory, a few MSW plants and some landfill gas plants. Hence, bioelectricity in Norway is solely connected to the utilisation of negative cost, free or very low cost biomass residues. However, several more (medium-scale) biomass CHP plants are currently planned in Norway, for different types of residues like paper mill residues and reject, and tree branches and treetops (GROT in Norwegian).

CenBio Vision 2020

	TWh - Today:			TWh - 2020:		
	Input	Efficiency	Output	Input	Efficiency	Output
Wood / pellet stoves	7	0,6	4,2	12	0,85	10,2
District heat	2,7	0,85	2,3	6	0,9	5,4
Wood industry	4,4	0,85	3,7	5	0,9	4,5
CHP - heat	~ 0	0,6	~ 0	4	0,65	2,6
CHP - power		0,2			0,3	1,2
Power	~ 0	0,4	~ 0	1	0,5	0,5
Biogas	~ 0	0,5	~ 0	2	0,7	1,4
SUM	**14,1**		**10,2**	**30**		**25,8**

Documented overall sustainability

Figure 6 CenBio Vision 2020 for Norway.[8]

Table 1 shows a summary of CHP technologies, including advantages, disadvantages and available sizes[9].

[8] FME application "CenBio", 2008

Table 1 Summary of CHP technologies.[9]

Table II: Summary of CHP Technologies			
CHP system	Advantages	Disadvantages	Available sizes
Gas turbine	High reliability. Low emissions. High grade heat available. No cooling required.	Require high pressure gas or in-house gas compressor. Poor efficiency at low loading. Output falls as ambient temperature rises.	500 kW to 250 MW
Microturbine	Small number of moving parts. Compact size and light weight. Low emissions. No cooling required.	High costs. Relatively low mechanical efficiency. Limited to lower temperature cogeneration applications.	30 kW to 250 kW
Spark ignition (SI) reciprocating engine	High power efficiency with part-load operational flexibility. Fast start-up. Relatively low investment cost. Can be used in island mode and have good load following capability. Can be overhauled on site with normal operators. Operate on low-pressure gas.	High maintenance costs. Limited to lower temperature cogeneration applications. Relatively high air emissions. Must be cooled even if recovered heat is not used. High levels of low frequency noise.	< 5 MW in DG applications
Compression ignition (CI) reciprocating engine (dual fuel pilot ignition)			High speed (1,200 RPM) ≤4MW
			Low speed (102-514 RPM) 4-75 MW
Steam turbine	High overall efficiency. Any type of fuel may be used. Ability to meet more than one site heat grade requirement. Long working life and high reliability. Power to heat ratio can be varied.	Slow start up. Low power to heat ratio.	50 kW to 250 MW
Fuel Cells	Low emissions and low noise. High efficiency over load range. Modular design.	High costs. Low durability and power density. Fuels requiring processing unless pure hydrogen is used.	5 kW to 2 MW

[9] Catalog of CHP technologies, U.S. EPA CHP Partnership, 2008, http://www.epa.gov/chp/documents/catalog_chptech_full.pdf

Table 2 shows a summary of typical cost and performance characteristics by CHP technology[9].

Table 2 Summary of Typical Cost and Performance Characteristics by CHP Technology.[9]

Table III: Summary Table of Typical Cost and Performance Characteristics by CHP Technology*					
Technology	**Steam Turbine[1]**	**Recip. Engine**	**Gas Turbine**	**Microturbine**	**Fuel Cell**
Power efficiency (HHV)	15-38%	22-40%	22-36%	18-27%	30-63%
Overall efficiency (HHV)	80%	70-80%	70-75%	65-75%	55-80%
Effective electrical efficiency	75%	70-80%	50-70%	50-70%	55-80%
Typical capacity (MW_e)	0.5-250	0..01-5	0.5-250	0.03-0.25	0.005-2
Typical power to heat ratio	0.1-0.3	0.5-1	0.5-2	0.4-0.7	1-2
Part-load	ok	ok	poor	ok	good
CHP Installed costs ($/kW$_e$)	430-1,100	1,100-2,200	970-1,300 (5-40 MW)	2,400-3,000	5,000-6,500
O&M costs ($/kWh$_e$)	<0.005	0.009-0.022	0.004-0.011	0.012-0.025	0.032-0.038
Availability	near 100%	92-97%	90-98%	90-98%	>95%
Hours to overhauls	>50,000	25,000-50,000	25,000-50,000	20,000-40,000	32,000-64,000
Start-up time	1 hr - 1 day	10 sec	10 min - 1 hr	60 sec	3 hrs - 2 days
Fuel pressure (psig)	n/a	1-45	100-500 (compressor)	50-80 (compressor)	0.5-45
Fuels	all	natural gas, biogas, propane, landfill gas	natural gas, biogas, propane, oil	natural gas, biogas, propane, oil	hydrogen, natural gas, propane, methanol
Noise	high	high	moderate	moderate	low
Uses for thermal output	LP-HP steam	hot water, LP steam	heat, hot water, LP-HP steam	heat, hot water, LP steam	hot water, LP-HP steam
Power Density (kW/m^2)	>100	35-50	20-500	5-70	5-20
NO_x (lb/MMBtu) (not including SCR)	Gas 0.1-.2 Wood 0.2-.5 Coal 0.3-1.2	0.013 rich burn 3-way cat. 0.17 lean burn	0.036-0.05	0.015-0.036	0.0025-.0040
$lb/MWh_{TotalOutput}$ (not including SCR)	Gas 0.4-0.8 Wood 0.9-1.4 Coal 1.2-5.0.	0.06 rich burn 3-way cat. 0.8 lean burn	0.17-0.25	0.08-0.20	0.011-0.016

* Data are illustrative values for typically available systems; All costs are in 2007$

[1]For steam turbine, not entire boiler package

Table 3 shows the commercialization status of biomass conversion systems for power and heat generation[10].

Table 3 Commercialization status of biomass conversion systems for power and heat generation[10]

Energy Conversion Technology	Conversion Technology Commercialization Status	Integrated CHP Technology (Prime Mover)	Prime Mover Commercialization Status
Anaerobic Digestion			
Anaerobic digester (from animal feeding operations or wastewater treatment facilities)	Commercial technology	Internal combustion engine	Commercial technology
		Microturbine	Commercial technology
		Gas turbine	Commercial technology
		Fuel cell	Commercial introduction
		Stirling engine	Emerging
Direct Combustion—Boilers			
Fixed bed boilers (stoker)	Commercial technology – Stoker boilers have long been a standard technology for biomass as well as coal, and are offered by a number of manufacturers.	Steam turbine	Commercial technology
Fluidized bed boilers	Commercial technology – Until recently fluidized bed boiler use has been more widespread in Europe than the United States. Fluidized bed boilers are a newer technology, but are commercially available through a number of manufacturers, many of whom are European-based.		
Cofiring	Commercial technology – Cofiring biomass with coal has been successful in a wide range of boiler types including cyclone, stoker, pulverized coal, and bubbling and circulating fluidized bed boilers.		
Modular* direct combustion technology	Commercial technology – Small boiler systems commercially available for space heating. A small number of demonstration projects in CHP configuration.	Small steam turbine	Commercial technology
		Organic Rankine cycle	Emerging technology – Some "commercial" products available.
		"Entropic" cycle	Research and development (R&D) status
		Hot air turbine	R&D status

*Small, packaged, pre-engineered systems (smaller than 5 MW).

Energy Conversion Technology	Conversion Technology Commercialization Status	Integrated CHP Technology (Prime Mover)	Prime Mover Commercialization Status
Gasification			
Fixed bed gasifiers	Emerging technology – The actual number of biomass gasification systems in operation worldwide is unknown, but is estimated to be below 25. A review of gasifier manufacturers in Europe, USA, and Canada identified 50 manufacturers offering commercial gasification plants from which 75 percent of the designs were fixed bed; 20 percent of the designs were fluidized bed systems.	Gas turbines – simple cycle	Prime movers have been commercially proven with natural gas and some medium heating value biogas. Operation on low heating value biogas and the effects of impurities on prime mover reliability and longevity need to be demonstrated.
Fluidized bed gasifiers		Gas turbines – combined cycle	
		Large internal combustion (IC) engines	
Modular* gasification technology	Emerging technology – A small number of demonstration projects supported with research, design, and development funding.	IC engine	Commercial technology – But operation on very low heating value biogas needs to be demonstrated.
		Microturbine	
		Fuel cell	Commercial introduction
		Stirling engine	Emerging technology
Modular* hybrid gasification/combustion	Emerging technology – Limited commercial demonstration.	Small steam turbine	Commercial technology – But integrated system emerging.

*Small, packaged, pre-engineered systems (smaller than 5 MW).

[10] Biomass Combined Heat and Power Catalog of Technologies, U.S EPA CHP Partnership, 2007, http://www.epa.gov/chp/documents/biomass_chp_catalog.pdf

Table 4 shows a comparison of prime mover technologies applicable to biomass[10].

Table 4 Comparison of prime mover technologies applicable to biomass[10]

Characteristic	Prime Mover: Steam Turbine	Gas/ Combustion Turbine	Micro-turbine	Reciprocating IC Engine	Fuel Cell	Stirling Engine
Size	50 kW to 250 MW	500 kW to 40 MW	30 kW to 250 kW	Smaller than 5 MW	Smaller than 1 MW	Smaller than 200 kW
Fuels	Biomass/ Biogas-fueled boiler for steam	Biogas	Biogas	Biogas	Biogas	Biomass or Biogas
Fuel preparation	None	PM filter needed	PM filter needed	PM filter needed	Sulfur, CO, methane can be issues	None
Sensitivity to fuel moisture	N/A	Yes	Yes	Yes	Yes	No
Electric efficiency (electric, HHV)*	5 to 30%	22 to 36%	22 to 30%	22 to 45%	30 to 63%	5 to 45%
Turn-down ratio	Fair, responds within minutes	Good, responds within a minute	Good, responds quickly	Wide range, responds within seconds	Wide range, slow to respond (minutes)	Wide range, responds within a minute
Operating issues	High reliability, slow start-up, long life, maintenance infrastructure readily available,	High reliability, high-grade heat available, no cooling required, requires gas compressor, maintenance infrastructure readily available	Fast start-up, requires fuel gas compressor	Fast start-up, good load-following, must be cooled when CHP heat is not used, maintenance infrastructure readily available, noisy	Low durability, low noise	Low noise
Field experience	Extensive	Extensive	Extensive	Extensive	Some	Limited
Commercializatio n status	Numerous models available	Numerous models available	Limited models available	Numerous models available	Commer-cial introduction and demonstr-ation	Commercial introduction and demonstr-ation
Installed cost (as CHP system)	$350 to $750/kW (without boiler)	~ $700 to $2,000/kW	$1,100 to $2,000/kW	$800 to $1,500/kW	$3,000 to $5,000 /kW	Variable $1,000 to $10,000 /kW
Operations and maintenance (O&M) costs	Less than 0.4 ¢/kWh	0.6 to 1.1 ¢/kWh	0.8 to 2.0 ¢/kWh	0.8 to 2.5 ¢/kWh	1 to 4 ¢/kWh	Around 1 ¢/kWh

* Efficiency calculations are based on the higher heating value (HHV) of the fuel, which includes the heat of vaporization of the water in the reaction products.

CHP IN EUROPE - BACKGROUND

Combined Heat and Power (CHP) has been promoted actively in Europe since the early 1980s, motivated by the fact that power is produced more efficiently in terms of cost and fuel consumption in CHP plants than in traditional large centralized thermal, typically coal-based, power plants. Initially, CHP was motivated by energy security issues, but during the 90ies the greenhouse gas emission issues grew even more important. A substantial portion of the CHP capacity in Europe that was established during the -80ies and -90ies was further based on natural gas, and not on coal. The development of natural gas distribution networks and the establishment of smaller distributed gas-based CHP plants were thus viewed to be both cost-effective and environmentally sound infrastructure projects. From a greenhouse gas emission perspective distributed gas-based CHP would thus give a triple benefit during this period:

1. The gas demand of CHP plants would promote a more widespread ***development of natural gas distribution*** networks.
2. This would enable a ***fuel shift*** from carbon-intensive fossil fuels such as coal and oil to the less carbon intensive natural gas.
3. The establishment of CHP based decentralized power plants would allow the development of ***more widespread district heating***, and at the same time ***save infrastructure costs*** compared to the further development of district heating based on a smaller number of large centralized coal-fired plants.

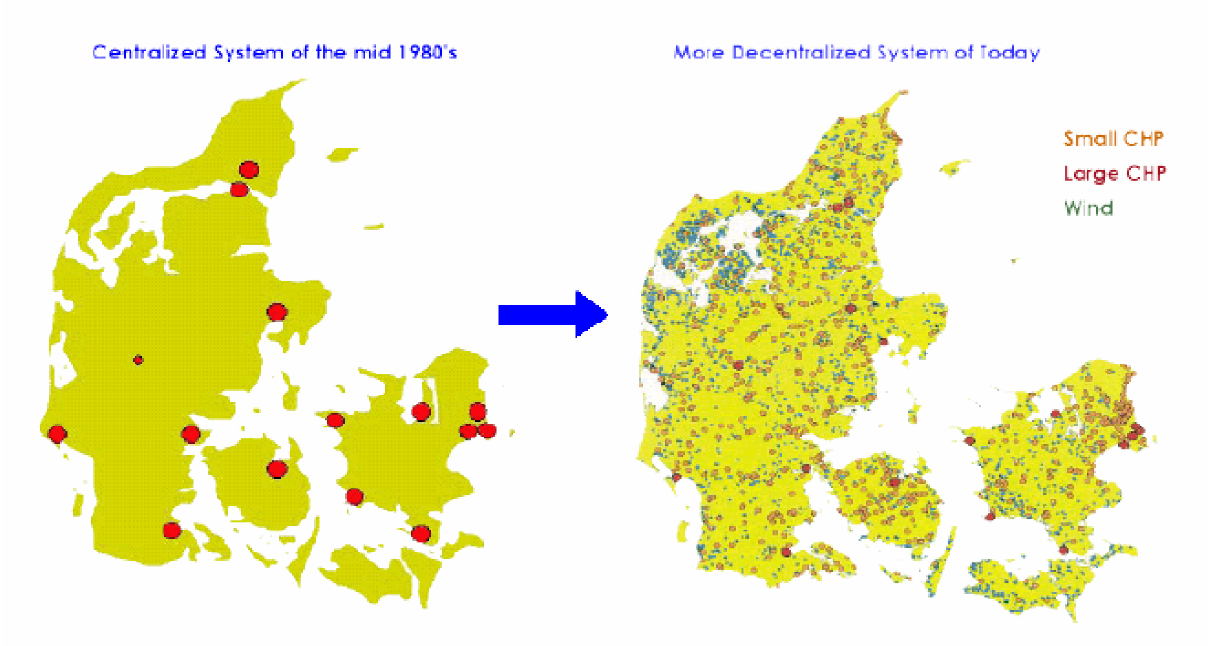


Figure 7 The Danish CHP plant transition.[11]

Figure 7 illustrates this transition for Denmark, where a large number of gas-based CHP plants have been established over the last 25 years. This has enabled a substantial improvement of the fuel efficiency in the Danish power sector, and it has been an important part of Denmark's strategy to achieve their Kyoto targets. The UK, the Netherlands, Spain, Italy, Portugal and France have adopted similar natural gas based CHP strategies, while Sweden, Austria and Finland are examples of countries that have instead promoted biomass based CHP.

Looking ahead into a future that most likely will require greenhouse gas emission reductions far beyond the Kyoto targets, it should be questioned whether the promotion of natural gas based CHP represents a sound long-term infrastructure. If Carbon Capture and Storage (CCS) turns out to be a viable alternative for the future, it would clearly be a handicap to have to deal with a large number of small emission points than a few large ones. The only reasonable long-term way forward in such a setting would be to ensure that the fuel used in a distributed CHP network is renewable, and instead of large-scale investments in the distribution of fossil fuels, infrastructure spending should be channelled into infrastructures for renewables.

[11] http://www.cogen-europe.eu/Downloadables/Events/EUSEW%202008/EUSEW_jan_30_5_Kees.pdf

HEATING IN A NORWEGIAN CONTEXT – PRESENT MARKET CONDITIONS

The Norwegian situation is very different from the typical European situation in many ways:

1. Heating is to a large extent provided by the direct use of electricity. Although the use of heat pumps has increased the last few years, the potential for profitable power consumption reduction by conversion from direct use of electricity to use of heat pumps and bioenergy is still large.
2. Electric power production is essentially hydro-power based – it is produced from non-greenhouse-gas-emitting sources. The effect of efficiency improvements in our use of electric power on our national Kyoto obligations are thus essentially zero.
3. Norway has no urgent security of energy supply issues to deal with. We are a major energy exporter and one of the major energy suppliers to the European oil and gas markets. (There are however regions in the country where the security of ***electricity*** supply is presently unsatisfactory.)
4. The price of electricity is low compared to other European countries, and heat from district heating networks is essentially priced to be on the same level as electric power.

A recent Enova study[12] concludes that there are two major obstacles to profitable development of heating based on renewables in Norway: First, the present ***heat distribution infrastructure is very limited***, ***and substantial infrastructure investments will be required*** to develop this market. This includes heat distribution pipeline networks from new heating plants to the premises of potential heat customers, but even more important, it includes the infrastructure in the customers' buildings, since this presently to a large extent is based on the direct use of electricity. Second, the ***small price difference between heat and power gives few incentives for rapid development***, viewed both from the supplier side and from the customer side.

Since CHP is dependent on a market for the heat produced, these market obstacles will also be highly relevant for the development of CHP in Norway.

The existence of a common Nordic market for electric power might mislead one to assume that the competitive situation for electricity vs. bioenergy is the same all over this region, but that is far from being true. As **Figure 8** and **Figure 9** illustrates, the taxation of the primary competitors to bioenergy varies substantially among the Nordic countries. As a result, bioenergy is in a much weaker competitive position in Norway than in our neighbour countries.

[12] "10 år med røde tall. Barrierer for økt utbygging av lokale varmesentraler og nærvarmeanlegg", ENOVA, 2007, http://www.enova.no/minas27/publicationdetails.aspx?publicationID=257

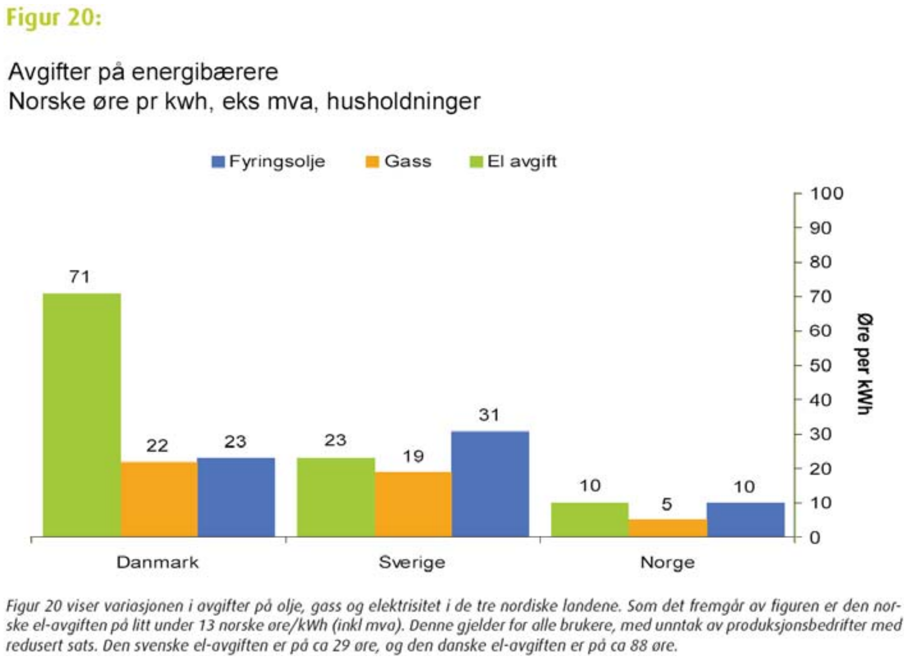


Figure 8 Variation in the taxation (in Norwegian øre per kWh excluding value added tax) of oil, gas and electricity for use in households in the Nordic countries.[12]
(Fyringsolje=Heating oil, Gass=Gas, El avgift=Electricity tax, Danmark=Denmark, Sverige=Sweden, Norge=Norway)

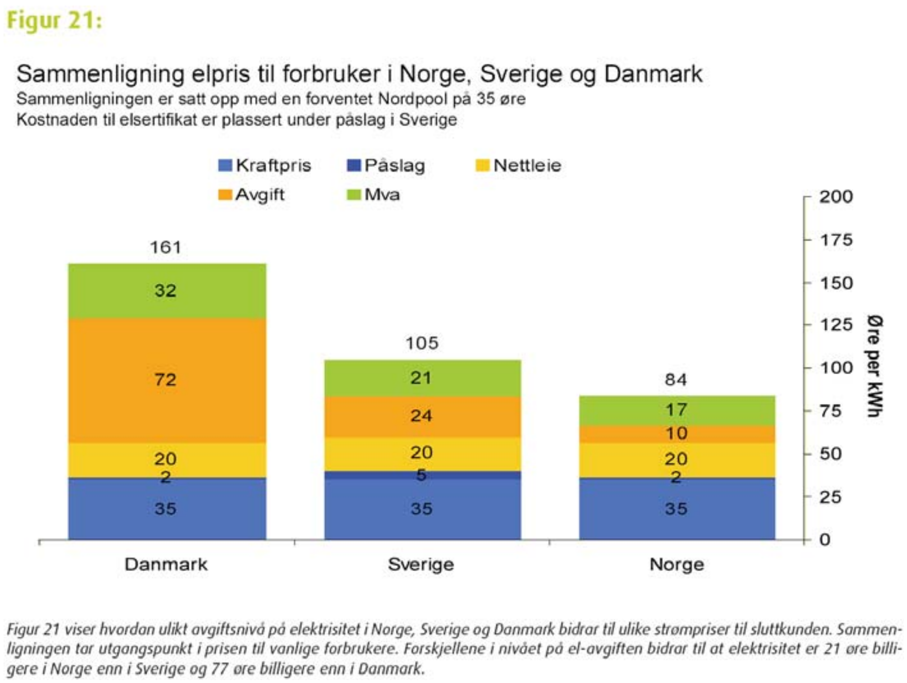


Figure 9 Comparison of the price and taxation of electricity in the Nordic countries.[12]
The comparison is based on an expected Nordpool price of 35 Norwegian øre per kWh. The cost of green certificates (Sweden) is included in Påslag=Additional cost. (Kraftpris=Electricity price, Nettleie=Transmission price, Avgift=Tax; Mva=value added tax)

The Østlandet region (Telemark, Vestfold, Buskerud, Oppland, Hedmark, Oslo, Akershus and Østfold) is the most mature of the Norwegian bioenergy regions, and it is also here that the majority of heating plants have been established. Typical raw material prices[12] are presented in **Table 5**. In the Midt-Norge region (Trøndelag and Møre og Romsdal) the price of woodchips is high due to the demand from metal smelting industries, but the price of pellets is low due to the lack of demand from heating customers. Existing district heating infrastructure is limited, except in Trondheim, where most of the capacity is based on waste. In the Vestlandet region (along the coast) there is substantial competition with natural gas, and the present use of bioenergy is very limited. In the Sørlandet region the market is also rather undeveloped, and there is only one major supplier. In the Nord-Norge region the population density is low, the market is not developed to any extent, and woodchips and pellets are available only in a few locations.

Table 5 Bioenergy prices to customers in Norway.[12]

Bioenergy prices to customers in Norway, excl. VAT			
(in øre / kWh)	**Woodchips**	**Pellets**	**Briquettes**
Østlandet	17-20	25-30	17-20
Midt-Norge	25	30	17-20
Sørlandet	17-20	24-27	18-22
Vestlandet	20 - 22	30	18
Nord-Norge	20 - 30	> 40	n.a.

As a result of its weak competitive position, Norwegian district heating at present does not produce more than a total of about 3 TWh, compared to the about 50 TWh of district heating in Sweden. As **Figure 10** shows, about 1 TWh of this is based on Waste-to-Energy, and another modest 0.5 TWh is based on other biomass.

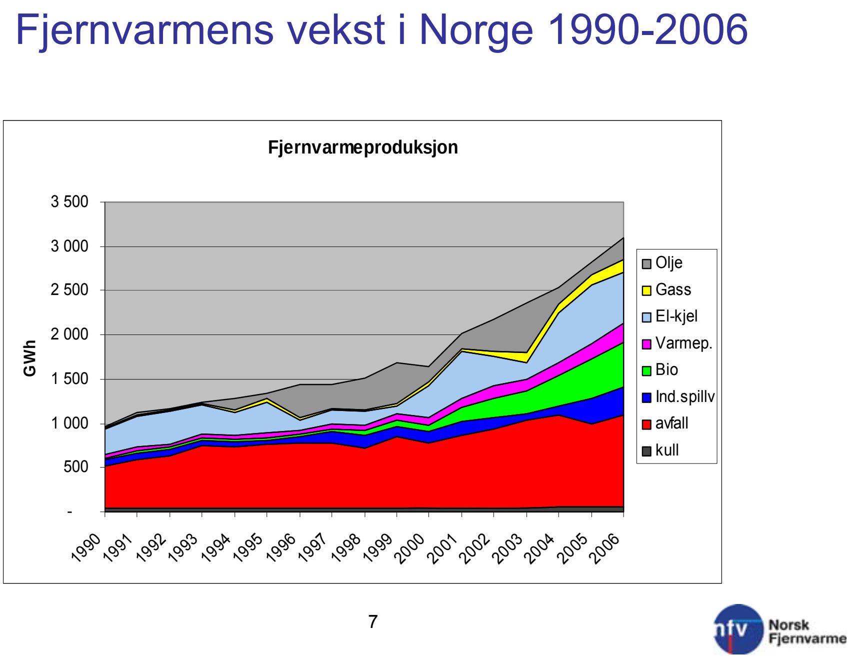


Figure 10 The growth of district heating in Norway from 1990 to 2006.[13]
(Fjernvarmeproduksjon=District heating production, Olje=Oil, Gass=Gas, El-kjel=Electric boiler, Varmep.=heat pumps, Bio=Biomass, Ind.spillv=Industrial waste heat, avfall=waste, kull=coal)

Figure 10 even demonstrates that under present and past market conditions, it has periodically been profitable to produce heat in district heating systems directly from electricity. This is a clear indication that present market conditions need to change before any large-scale power production from biomass becomes a profitable option. Nonetheless, the last few years there has been a substantial increase of activity in the Norwegian biomass heating market, indicating that the present market actors anticipate substantial improvements in the market conditions for renewable heating in the future.

[13] http://www.energi.no/filestore/NorskFjernvarmeJuhlerHeidiPotensialeforfjernvarme.pdf

Figure 11 The established and planned district heating networks as of April 2007.[3]
(Fjernvarme=District heating, Etablert=Established, Utbygging/utvidelse=Erection/expansion, Planlagt=Planned, Biobrensel=Biofuel, foredling=refining)

Figure 11 illustrates the established and planned district heating networks as of April 2007. Around 50 district heating plants were in operation in 2007. Presently more than 70 plants are under construction (including expansions), and more than 30 new plants are being planned. The heat distribution infrastructure of these new and extended heating plants may prove to be a determining factor for the establishment of future profitable CHP in Norway.

2 STEAM BASED BIOMASS CHP TECHNOLOGIES

Steam based biomass CHP technologies are the most commonly used biomass CHP technologies, mainly in steam turbines. Steam engines also have a long history and are a mature technology, but cannot compete with steam turbines in the upper half of the small-scale size range and in the medium- to large-scale size range, but are an alternative in the lower half of the small-scale size range. In addition to steam, other inert gases can be used, as evaporated organic oil in an ORC, helium, or possibly hydrogen, in a Stirling engine or air in a hot air turbine. However, ORC, Stirling engine or hot air turbine cannot today be regarded as serious competitors to steam turbines in the medium- to large-scale size range, but are candidates for the future in the lower half of the small-scale size range. The reader is referred to literature for the basic working principles of the different CHP technology options (e.g. [9]).

2.1 Technology options and status

Production of power by expansion of steam is as old as the industrial revolution. While the first steam engines exhibited an energy efficiency of merely 3-4 %, present supercritical steam cycles may achieve efficiencies of more than 50 %.

The theoretical efficiency of steam cycles is limited by the Carnot efficiency: $\eta = (T_h - T_c) / T_h$, where T_h is the high pressure inlet temperature of the steam before expansion and T_c is the low pressure outlet temperature after expansion. **Figure 14** illustrates the difference in Carnot efficiency between a case where the steam is expanded as far as possible and then condensed at 320 K, and a case where the steam is expanded only to 400 K, where the remaining heat is still on a useful temperature level to be used for heating.

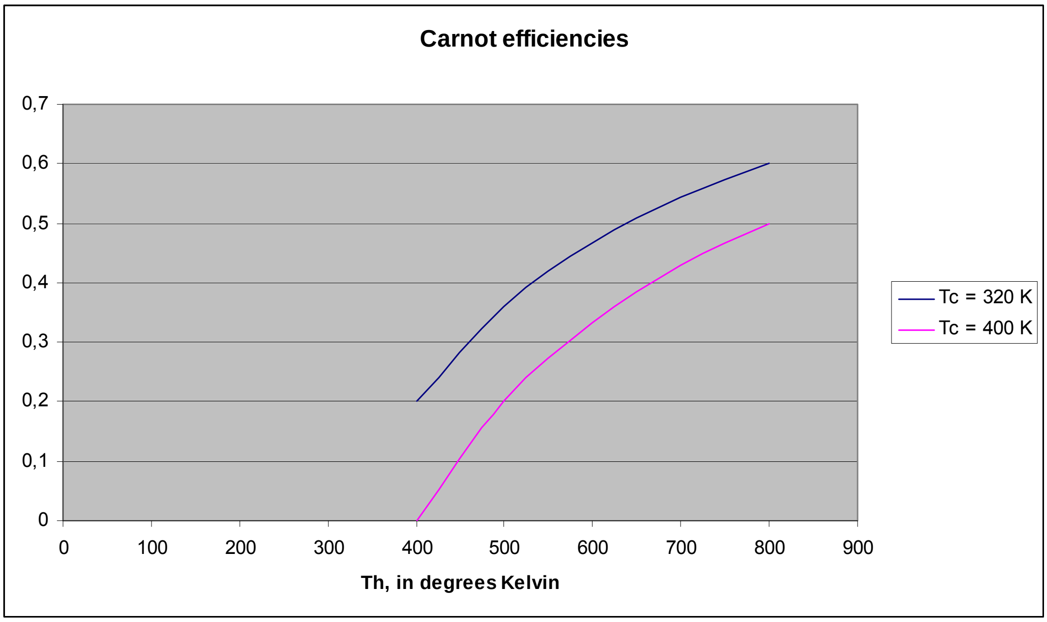


Figure 12 The difference in Carnot efficiency depending on degree of expansion (Tc).

Carnot efficiencies are not attainable in practice due to thermodynamic losses in the expansion process (friction, leakage, etc.), and the deviation between the ideal Carnot cycle and the real world is characterized by the ***isentropic*** or ***thermodynamic efficiency***. While large steam turbines (> 50 MW_e) may have thermodynamic efficiencies approaching 90 %, small steam turbines (< 1 MW_e) may be expected to be in the range of 50%. In addition, there will be additional losses in the rest of the system, e.g. friction losses in gears and generators, and the efficiency of the boiler producing the steam will typically be in the range of 85-90 %.

In any given CHP application, the lower temperature level is fixed by the temperature level of the heat demand. To maximize the electric output of the CHP system, the temperature of the steam before expansion should be as high as possible. ***Material constraints due to high temperature corrosion here present the practical limit to what one may achieve, and the corrosiveness of the flue gas produced in the boiler is a critical factor.*** Flue gas from natural gas combustion has a, relatively speaking, low corrosiveness, due to its low levels of chlorine and sulphur, while flue gases from combustion of waste are on the other end of the scale, due in particular to their high chlorine contents. Woody biomass falls in between.

In general, the steam superheater temperature of biomass combustion systems will presently usually be below 700 K for corrosion reasons. It is however possible to push this limit in at least four different ways:

1. Reheat: The steam is superheated to a modest level in the biomass boiler, expanded partially in the first stage of the turbine, then directed back to the boiler for reheating, and then finally expanded to its final temperature in the turbine's second stage.
2. Superheating by less corrosive flue gas: One may e.g. decide to use biomass only for evaporation and limited superheating, and perform the high-temperature superheating in a separate boiler fired by natural gas, biogas or some other fuel source with low levels of corrosive components.
3. Use of additives: Add components that will react with the corrosive components in the flue gas in order to inhibit their corrosive nature. As an example, peat has shown to have corrosion inhibiting effects when co-fired with other biomass, and shredded tyres when co-fired with municipal solid waste.
4. Special materials: More corrosion resistant materials than ordinary carbon steel may be used in the superheaters. So-called duplex materials are frequently used, consisting of an outer layer of a tube in an expensive corrosion resistant material that can withstand high temperature fused together with an inner tube of less expensive and less corrosion resistant material that can withstand high pressure.

The least expensive form of steam turbine to use for CHP applications is the ***backpressure*** turbine. Here the turbine is designed so that the steam in its entirety exits at the conditions demanded by the heat consumption. There is no condensation in a backpressure CHP plant, and thus limited requirements for cooling water. The ***extraction*** turbine is an alternative to the backpressure turbine, more flexible but also more expensive. Parts of the steam is here extracted from the turbine at the conditions required by the heat consumption, while the rest of the steam is fully expanded down to a lower temperature level and then condensed by cooling water. If the heat input to the plant is relatively constant, but the heat demand exhibits large variations over time, the extraction turbine makes it possible run the plant at full speed even when the heat demand is low. In waste combustion plants, where the fuel has a negative price, this may be a useful option. In plants where the fuel has to be paid for, the use of extraction turbines may be less interesting.

2.2 Technical and economical challenges

Technical and economical challenges are both important. Promising technical solutions may never be realised due to economical constraints. Hence, it is always important to consider the economical framework conditions for any technical solution.

2.2.1 Technical challenges

Steam turbines represent a well established technology, and may be expected to have a long lifetime and require little maintenance. It is however crucial to ensure that the feed water quality is sufficient and is maintained over time. Steam cycles have more strict feed water quality requirements than simple heating plants producing hot water. High pressure steam also represents a safety hazard. Steam boilers may explode and release large amounts of energy, so operators in steam plants must be qualified. Their qualifications must be certified.

The thermodynamic efficiency of small steam turbines is limited, and their partial load performance is in general not very good. Presently there are only a small number of producers of small steam turbines internationally, and steam turbine design and manufacturing is not mass produced by any of them. It is therefore not expected that the present situation is going to improve significantly over the next decade. Small turbines are already mature, they are robust work horses, and they are expected to remain that way.

Most existing heating plants in the 10-15 MW range use smoke tube boilers. These are compact and have historically been inexpensive, but they have a limitation: They will rarely be suitable for the ***pressures*** desired in CHP, and may thus give reduced electrical efficiencies. In such systems, the pressure may become the limiting factor rather than the temperature.

If reheat is used, this will affect the dynamics of the boiler system. Without reheat, the turbine is a true downstream “backend” to the boiler system, but with reheat the turbine gives feedback to the boiler system. It is important that this coupling is properly understood by the operators.

Gas fired superheaters used to be an option only in a few locations where gas was available, but this is no longer the case: LNG distribution by sea and by road can presently cover most of the country, where prices in the range of 0.40-0.45 NOK/kWh (heating value) may be expected[14]. This price range is presently similar to the expected cost of producing and upgrading biogas.

Superheaters in special material qualities may be expected to be up to 8 times more expensive than ordinary carbon steel, and it is not always the case that they last 8 times longer. It is thus a trade-off whether one decides to accept more corrosion and use less expensive materials, and whether one aims for lower maintenance costs at the expense of lower steam parameters and thus lower electric efficiency.

The fuel related technical challenges are connected to fuel feeding and the fuel composition. Different elements in the fuel contribute to various amounts of operational challenges and emissions. Operational aspects will always to some extent influence the effect of the fuel related challenges. Hence, there is a need to consider the fuel as a part of a system, where several other factors will influence the fuel related challenges. This means that the picture may fast become complex for solid fuels such as biomass, due to the inherent characteristics of solid fuels as fuels, and the heterogeneity of solid fuels with respect to fuel properties. **Figure 13** shows the whole supply chain and typical scopes of improvements connected to medium to large-scale biomass and waste CHP and power plants. Many of these scopes of improvements are also essential for small-scale plants, being also heavily influenced by fuel quality aspects.

[14] Naturgass Møre, personal communication with Mr. Ståle Nogva, March 2009.

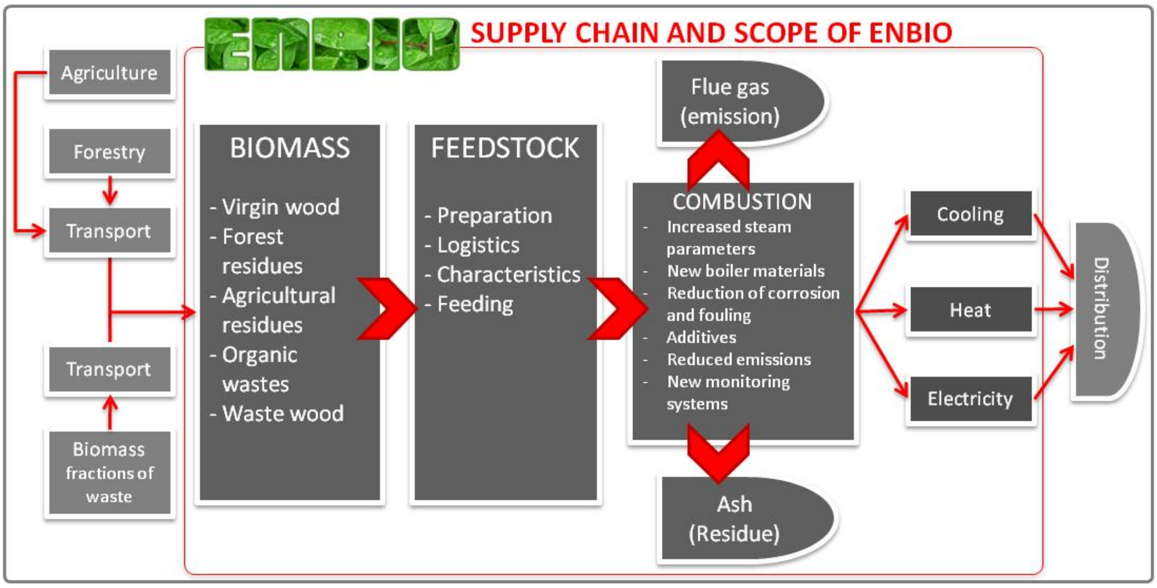


Figure 13 The whole supply chain and typical scopes of improvements connected to medium to large-scale biomass and waste CHP and power plants.[15]

Figure 14 shows the efficiency dependency on the steam parameters in the current state-of-the-art power generation systems. There is a potential for significant improvements in the electric efficiency if the negative effects of poor fuel qualities can be minimised.

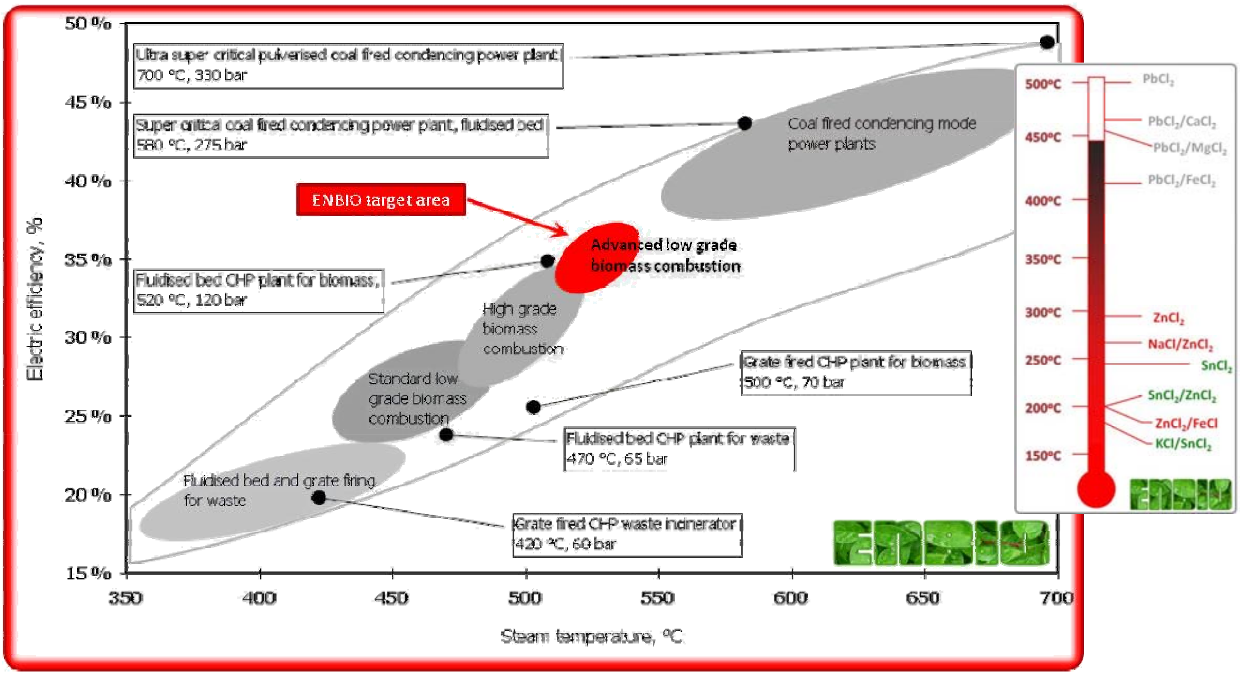


Figure 14 Efficiency dependency on the steam parameters in the current state-of-the-art power generation systems.[15]

Figure 15 shows a roadmap of development and demonstration for the combustion route for cost-effective commercial operation of biomass and waste CHP and power plants.

[15] SINTEF FP7 application: ENBIO

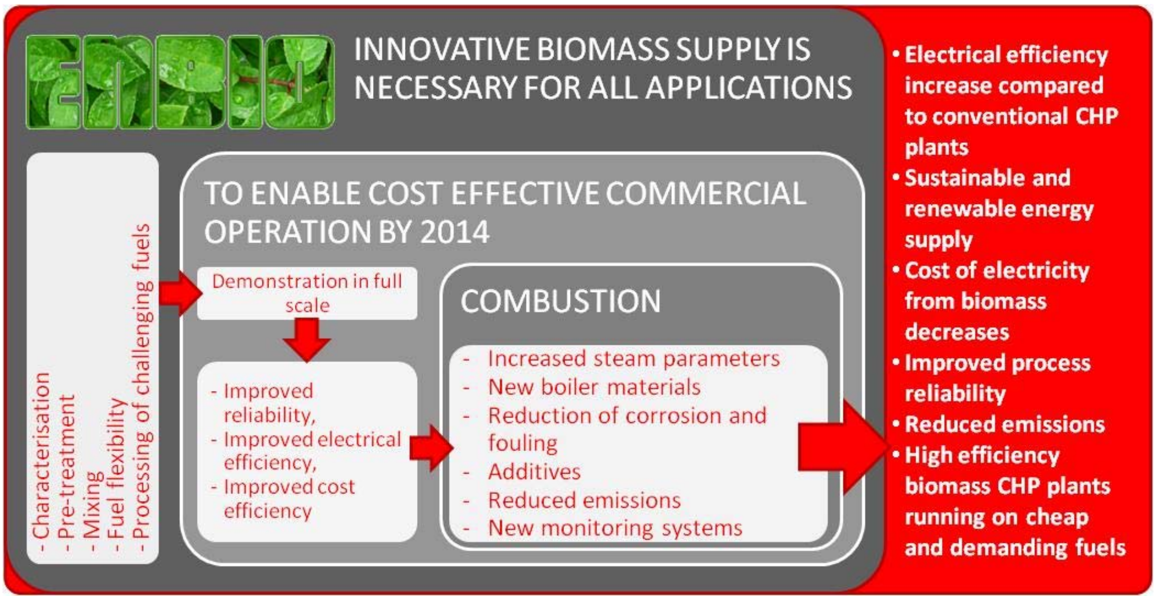


Figure 15 Roadmap of development and demonstration for the combustion route for cost-effective commercial operation of biomass and waste CHP and power plants.[15]

SINTEF, as a part of the aCOM project[16], investigated the priorities according to the respective aCOM partners with regards to what they regarded as the challenges in the waste combustion area. In this area, based on a list worked out during a workshop where the same partners participated, the partners, some of them generating electricity from municipal solid waste, should select and rank the three greatest challenges. The list worked out was:

- Electric efficiency
- NOx
- Slagging/sintering
- Burnout (grate)
- Capacity (grate)
- Temperature control (secondary chamber)
- Burnout (secondary chamber)
- Capacity (secondary chamber)
- Fouling (radiating section)
- Fouling (convective section)
- Corrosion
- Others

Ten aCOM partners participated in the investigation, covering the majority of the waste combustion plants in Norway. The following aCOM partners participated:

- Bergen Interkommunale Renholdsverk (BIR)
- Energigjenvinningsetaten (EGE) Oslo
- Energos (Trondheim)
- Forus Energigjenvinning (Stavanger)
- Fredrikstad Vann, Avløp og Renovasjonsforetak (Frevar KF)
- Hafslund/Viken Fjernvarme (Oslo)
- Hallingdal Renovasjon

[16] http://www.energy.sintef.no/prosjekt/acom/

- Norges Teknisk-Naturvitenskapelige Universitet (NTNU) Trondheim
- Trondheim Energi
- Østfold Energi

Giving three points for the number one challenge, two points for the number two challenge and one point for the number three challenge resulted in **Figure 16**. Two aspects are regarded as especially challenging; fouling and corrosion. However, also temperature control, NOx and electric efficiency were regarded as challenging. Hence, the importance of fuel influence on plant performance, economy and emissions cannot be underestimated.

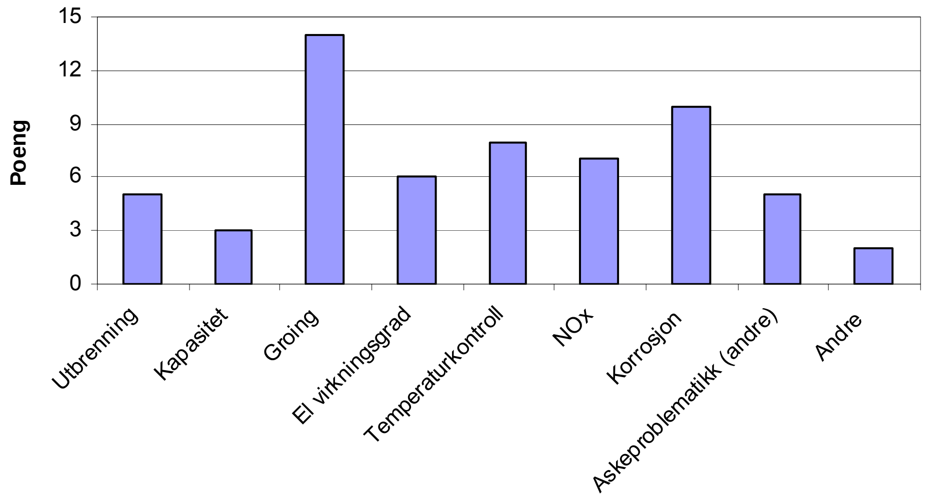


Figure 16 Waste combustion challenges according to the aCOM project partners.[17]
(Poeng=Points, Utbrenning=Burnout, Kapasitet=Capacity, Groing=Fouling, El virkningsgrad=Electric efficiency, Teperaturkontroll=Temperature control, Korrosjon=Corrosion, Askeproblematikk (andre)=Other ash related problems, Andre=Others)

A selection of methods for minimisation of the main fuel related problems are discussed below.

Process control and monitoring:
Variations in the fuel composition (heating value, moisture, or irregular sized particles blocking the fuel transport) will lead to variations in both energy output and in internal temperatures. The variations in internal temperatures will have a negative impact on the maintenance of the plant, and should thus be avoided. Usually, good control of the oxygen level out of the plant is used to take care of this requirement (scale back the addition of secondary air when the temperature out of the plant drops and the oxygen level increases). The fuel input is usually controlled by the setpoint for energy duty output, but if the problem is blockage of the fuel transport, this automatic control loop will not work, and manual intervention is required. More sophisticated control systems may be able to detect when there is a fuel transport line blockage and deal with it, but most systems would just shut down in this case and revert to energy input through an auxiliary burner (or stand-by backup boiler), typically oil-fired or electric. Frequent shutdowns of this kind due to unsatisfactory fuel quality (or inappropriate design of fuel transport and input systems) may ruin the economic performance of the plant.

[17] SINTEF report TR A6616, Ny teknologi innen avansert forbrenning av avfall og biomasse – Litteraturstudie, 2007.

Oxygen/nitrogen enriched combustion:
This includes different methods for oxidant-fuel interaction:

- Oxygen enriched combustion
- Staged air combustion
- Flue gas recirculation
- Reburning – Staged fuel combustion
- Patented solutions combining different innovative concepts

Staged air combustion is primarily developed for NOx reduction while flue gas recirculation also contributes to improved temperature control. Oxygen enhanced combustion introduce more extensive process changes and effects. Through optimisation all methods are effective in reducing the NOx emission level and will influence the combustion process positively. Oxygen enhanced combustion is promising, but challenging with regards to retrofitting of existing plants due to higher temperatures. The costs of retrofitting can be compensated by improved combustion and higher plant capacity. Staged air combustion is commonly implemented in biomass and waste combustion plants, but more advanced systems may offer significantly improved NOx reduction performance. Staged fuel combustion is mainly used for coal as primary fuel and natural gas or coal as reburn fuel. However, promising results have been achieved with biomass as reburn fuel. Waste is not considered as a reburn fuel option, and would demand pre-treatment before such use. Waste as primary fuel and biomass as secondary fuel could be an option. With respect to retrofitting staged fuel combustion will demand extensive modifications of the combustion chamber. Flue gas recirculation is to some extent used in biomass and waste combustion. Retrofitting is an option, but may become expensive, and it should be expected that addition of recirculation to a plant will reduce its nominal capacity.

Additives:
Research results on additives can to some extent seem scattered and contradictory. The effect and mode of operation of an additive depends on many factors, both factors connected to physical and chemical properties of a fuel and factors connected to process conditions, including the combustion technology. The results may therefore also be rather plant specific. However, one can say that two classes of additives work quite well in corrosion reduction in biomass and waste combustion plants:

- Al/Si: Aluminium silicates (not all)
- S: Sulphates

However, also different fuels or residues with specific properties can be used as additional fuels (e.g. sewage sludge, ash or coal) that contain high levels of protective elements, especially Al and Si and S.

Many aspects are important concerning additives. Mechanisms and mode of operation of additives are:

- Chemical sorption
- Physical sorption
- Chemical reaction

The mode of operation is most often a mix of a sorption (solid phase/gas) mechanism or is based on chemical reaction (liquid/gas).

The dominating mechanism for aluminium silicates is chemical sorption:
$Al_2O_3.xSiO_2$ (s) + 2 MCl (g) + H_2O (g) → $M_2O.Al_2O_3.xSiO_2$ (s) + 2 HCl (g)
Cl in the form of HCl does not condense on a superheater surface, and corrosion is therefore reduced.

The mechanism for sulphates is a chemical reaction:
(1) Destruction of sulphates at elevated temperature:
$(NH_4)_2SO_4$ (l) → 2 NH_3 (g) + SO_3 (g) + H_2O (g)
or $X_2(SO_4)_3$ (l) → 3 SO_3 (g) + X_2O_3 (s)   X: Fe, Al
(2) SO_3 sulphates alkali chlorides:
SO_3 (g) + 2 MCl (g) + H_2O (g) → 2 HCl (g) + M_2SO_4 (s)
Alkali sulphates are less corrosive than alkali chlorides and as mentioned, HCl does not condense on a superheater surface.
s: solid phase; g: gas phase; l: liquid phase. M: Na or K.
The above mentioned sulphates are included in patents.

Methods of additive addition:

- ”In situ” use, i.e. mixed with the fuel before feeding or sprayed into the combustion chamber before the superheaters using a separate system or with existing arrangements (e.g. limestone injection system)
- Downstream use, where the flue gas goes through a bed of additives

The method of addition is primarily decided by the temperature where the additive is most efficient, and by what products that are formed in the reaction between additive and corrosive components. The sulphates should be added in the combustion chamber before the superheaters at temperatures high enough for their destruction and, hence, allowing sulphatation. Use of aluminium silicates is mainly done in situ, either mixed with the fuel or added together with limestone. However, this is not applicable for all the aluminium silicates.

Combustion technology

- Fluidised bed
- Grate
- Use of turbine/engine

Additives are used for reduction of corrosion and fouling for grates, while for fluidised beds agglomeration (sintering) is a main issue.

Chemical target

- Alkali chlorides, for corrosion reduction
- Heavy metals, mainly for reduction of heavy metals emissions,
  even though Pb and Zn are involved in corrosion

How the sulphates and the aluminium silicates react with the heavy metals (especially Pb and Zn) is scarcely studied and still unclear. Even if this problem is limited for many types of biomass, it can be relevant for wastes.

Limitations/challenges

What a good additive is, is a complex question. A perfect additive should react without leading to environmental problems or downstream handling problems, and at the same time be cheap and simple in use. No additives fulfil all these criteria and prioritisation must be done in practise.

The following technical challenges should be mentioned for the selected additives. Ca can react with sulphates, while products formed when using aluminium silicates can be unstable (leaching), especially at high temperatures. For additives introduced with the fuel a dilution of the protective elements in the main fuel will occur, together with increased concentrations of problematic elements introduced with the additive, especially heavy metals.

Evaluation

Evaluation, either quantitative or qualitative, is complicated. Reduced corrosion rates leads to increased lifetime for superheaters and increased plant availability. However, faster and more advanced evaluation techniques are needed in practical evaluation approaches. These evaluation techniques are often complex, including different techniques of sampling at ideally well controlled conditions. The goal is to determine the distribution of especially chlorine in the different ash (bottom ash, fly ash), particle, deposits and gas fractions.

Analytical methods includes: LPI (Low Pressure Impactor), ion chromatography, absorption spectrometry, DMA (Differential Mobility Analyzer), CPC (Condensation Particle Counter), micro-scale, SEM/EDS, IACM, probes, HPMS (High Pressure Mass Spectroscopy), XRD (X-Ray Diffraction), ICP-OES (Inductively Coupled Plasma - Optical Emission Spectrometry) and FTIR (Fourier Transform Infrared Spectroscopy). Quantitative results must/can be combined with more qualitative methods to achieve a complete picture. Evaluation of an additive can be carried out in a laboratory, but should also be carried out in full-scale tests, where the evaluation becomes even more challenging.

Dosing

The mode of operation of an additive gives an idea of the theoretical amount of additive necessary, which is dependent on the fuel composition. Different indicators, often molar element relationships, are used. However, no consensus regarding these indicators exists. The theoretical amount of additive needed is, due to different limitations (local conditions, transport, kinetics, interferences, etc.) lower than the practical limit. Optimisation of the dosing is simpler using online measurements of key components (e.g. gas phase alkali chlorides), especially if the fuel is heterogeneous (e.g. waste).

Economy

The costs are related to the additive itself but also to the system that needs to be built or retrofitted to be able to store and add the additive and for potential after-treatment of it. Cost-efficiency evaluations must be carried out.

2.2.2 Economical challenges

Fundamentally, there are three economical challenges related to the proliferation of biomass CHP in Norway, and these apply to combustion based systems as well as others:

1. The added value for production of electricity rather than heat is presently small.

2. The number of sizeable potential heating customers is limited, so the majority of potential plants will be small.
3. Norwegian biomass is, with few exceptions, relatively expensive.

This implies that the profit margins for heat and power from biomass are small. When the profit margin of a sector is small, the sector may be expected to be conservative. This is rational behaviour, since the expected return on willingness to take risk is low.

Even if power production in steam turbines may be guaranteed to be a well proven and mature technology with limited technology risk, it may be perceived as a risky business by a plant developer who faces the choice between developing a pure heating plant and a CHP plant: What are the economic impacts of increased plant complexity, of increased operator competence requirements, of increased safety measures, and of increased maintenance costs due to increased corrosion?

Fuel related economical challenges are directly connected to the fuel costs and the need for handling and upgrading of the fuel, and the fuel quality will also indirectly influence both investment costs and especially operation and maintenance costs. The direct fuel cost is a market availability and demand issue, and the direct fuel costs will always be an important economic factor, often the most important one. Hence, low-cost fuels are advantageous with respect to direct fuel costs. However, handling and upgrading costs may then become considerable, as well as operation and maintenance costs, in addition to the need of increased investments connected to this. **Figure 17** shows an illustration of the electrical efficiency versus relative lifetime for superheater materials, expectations in 2020 versus current technology. The goal must be to both increase the electric efficiency and the lifetime for superheater materials in plants utilising low-cost fuels.

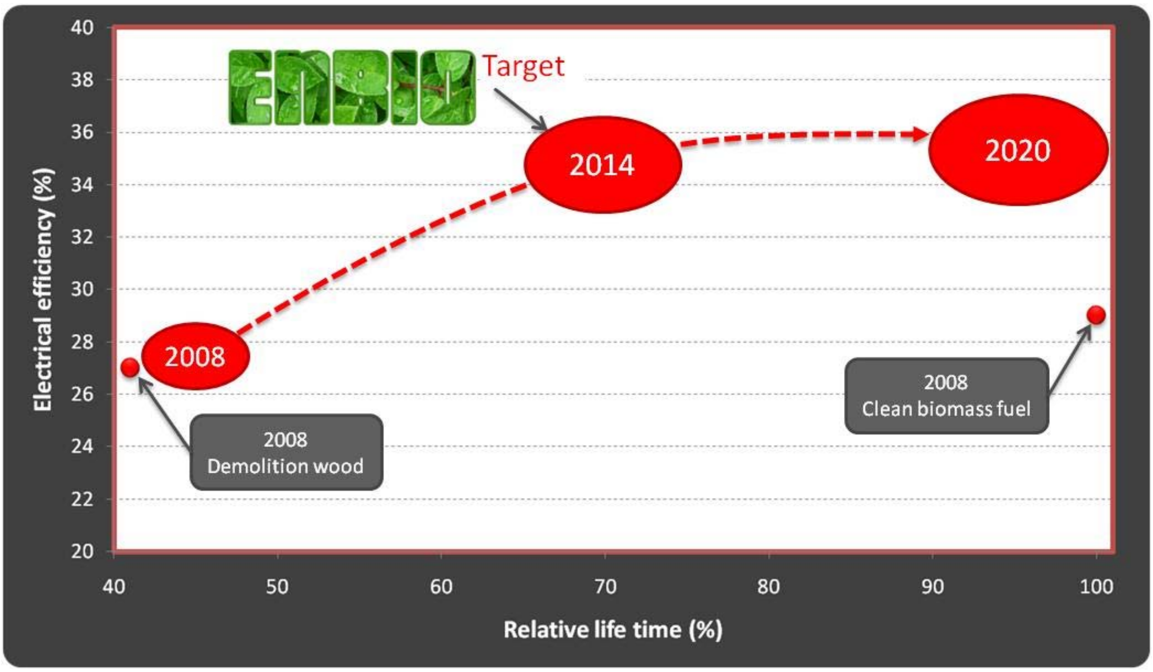


Figure 17 Electrical efficiency versus relative lifetime for superheater materials, expectations in 2020 versus current technology.[15]

2.2.3 Cost-efficiency

The cost-efficiency of biomass based CHP is first and foremost dependent on the cost-efficiency of the heat produced. Electric power will usually not comprise more than 1/5 of the total sold energy, so the selling price and production cost of heat is most important. A recent Enova study[18] presents the production cost of heat from biomass for district heating as illustrated in **Figure 18**. In the figure GL means base load, SL means peak load, and it is assumed that the plants are dimensioned so that the full capacity equivalent number of operating hours is 2 200 per year. It should be noted that the cost of the required peak load capacity contributes substantially to the overall heating cost, an issue that is frequently forgotten when the cost of bioenergy is calculated in isolation.

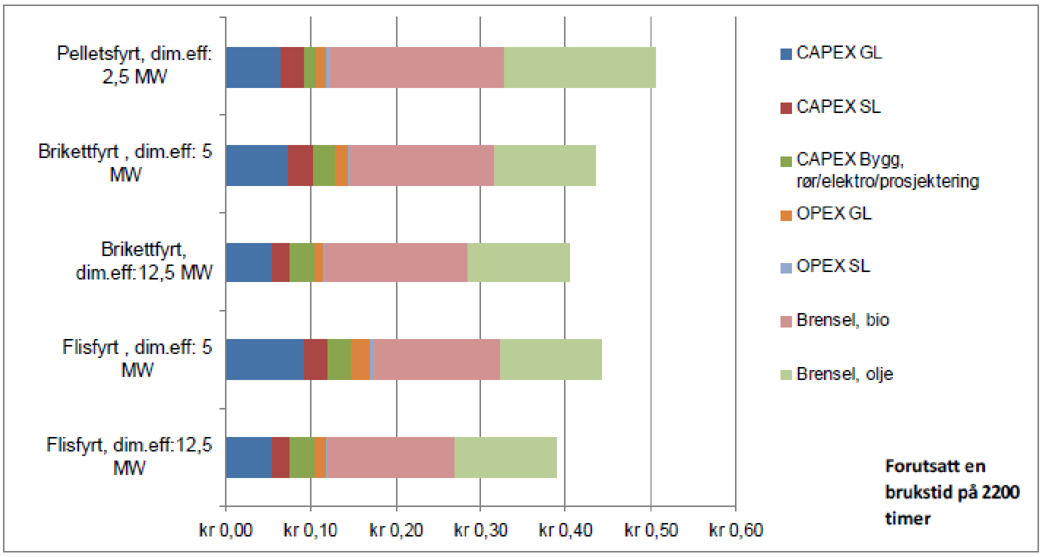


Figure 18 Production cost of heat (2200 operating hours per year assumed) from biomass for district heating.[18]

(Pelletsfyrt=Pellets based, dim.eff.=dimensioning effect; Brikettfyrt=Briquettes based, Flisfyrt=Wood chips based; kr=Norwegian kroner, CAPEX=Capital costs, SL=peak load, Bygg=Buildings, rør=tubing, elektro=electro, prosjektering=design and erection, GL=base load, OPEX=Operating costs, Brensel=Fuel, bio=biomass, olje=oil)

Distribution costs from the heating plant to the customers must be added to the above, and for the customer, the sum of this must be favourable compared to the customers alternative cost. The Enova study also presents a number of representative alternative costs for various heating alternatives, for different types of customers, in different parts of the country. This is illustrated in **Figure 19**.

[18] "Fornybar varme 2020", Enova, 2007

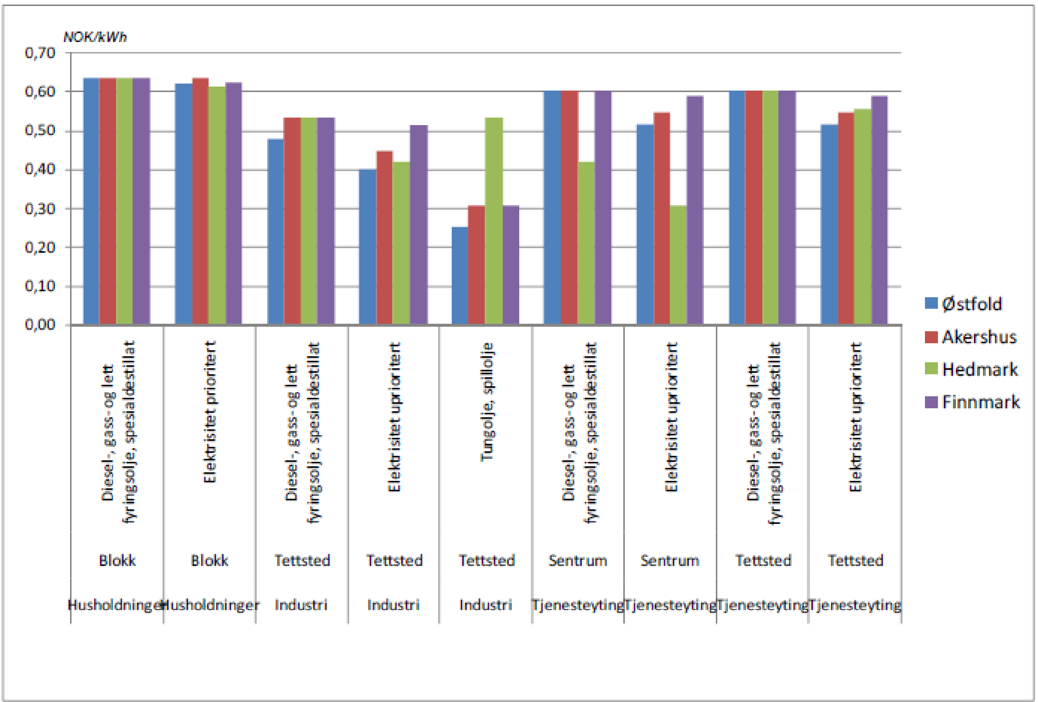


Figure 19 Production cost of heat from alternatives to biomass for district heating in four counties in Norway.[18]

(NOK=Norwegian kroner, gass=gas, og=and, lett fyringsolje=paraffin, spesialdestillat=special distillate, Elektrisitet prioritert=Electricity prioritised, Tungolje=Heavy oil, spillolje=waste oil, Blokk=block of flats, Husholdninger=Households; Tettsted=Community, Industri=Industry, Sentrum=Town, Tjenesteyting=Services)

Distribution costs vary widely, depending strongly on both population density and on the type of area where the pipelines are to be laid, but as an illustration consider the following: Assume that the line density (energy delivered per year per km pipeline) is 5 GWh/yr and that the cost is 5 000 NOK per m (These are not unrealistic figures, although the variation is large). Then the capital part of the distribution cost will be 1 NOK per annual kWh heat distributed. That is equivalent to 9 øre per kWh (7% interest, 25 years), and if heat losses in the pipeline system and operational costs are added it is reasonable to assume a representative distribution cost on the order of 15 øre per kWh. From the figures above it is evident that in many of the illustrated cases, such a distribution cost is not economically viable. In order to bridge this gap the government has recently established new and extended support programs for financial support to district heating.

It is interesting to note that the production of power may not require the same investments in backup and peak load capacity as the production of heat. This reduces the overall potential production cost of power vs. heat, which is somewhat counterintuitive since the boiler must be designed for higher pressures, and a superheater, turbine and generator is required. The details of the economic tradeoffs will naturally be strongly project dependent here, so no general statements may be made, but there will obviously be cases where power production may be interesting, also financially.

Clearly, the fuel cost is a, or the, major factor influencing the cost-efficiency of today's commercial biomass CHP plants. Today, commercial operation of biomass CHP plants is not possible in Norway except for plants using negative cost, free or very low-cost fuels. The current economic incentives with respect to electricity generation from biomass in Norway are too low, and far from the incentives seen in other Nordic countries or other parts of Europe. Hence, the incentives must be much improved to get a wide introduction of biomass CHP in Norway, and the fuel cost and the costly effects of poor fuel qualities must be minimised through improved or optimised solutions or new innovative concepts.

2.2.4 Research needs and potential impact

Research needs are connected to the various technological, operational and cost-efficiency challenges. The development potential connected to the existing technologies will mainly be connected to different small, but important, improvements with respect to technology and plant operation. Hence, we will primarily see a future evolution, and not a revolution. The goal then becomes to speed up the evolution process, which demands significant research efforts. The suitable research efforts depend on economical framework conditions, as will also any product development or implementation process. The main research needs are:

1) How to best improve the electric efficiency with acceptable reductions in availability and increases in maintenance costs. Candidates for solution are gas fired superheating, reheat or multiple steam levels.
2) Reducing operational, and economical, problems connected to the fuel properties by co-combustion with fuels that inhibit corrosion and fouling, by fuel quality improvements or additives use.
3) Emission reduction

2.3 Potential in a Norwegian context

The technical biomass CHP potential in Norway is substantial. The decisive factor then becomes the cost-efficiency of the different technology options. By year 2020 the bioenergy use in Norway is expected to increase with a factor of two, to close to 30 TWh/year. A significant fraction of this could be in CHP plants, including small- and medium-scale. Standalone large-scale electricity generation from biomass is also a future option. Bioelectricity will realistically never become a major contributor to the Norwegian electricity system, but may contribute with some TWh/year to the grid in a longer term perspective. The future extent of bioelectricity generation in Norway will be influenced by the choice of bioelectricity technologies and their performance. It is essential to select the proper technologies in a Norwegian context, a context which is not static and which can be influenced by incentives. The need for biomass heat and steam for domestic or industrial purposes will limit the bioelectricity generation, be it in the form of heat controlled CHP units/plants, electricity controlled CHP units/plants or standalone bioelectricity units/plants.

Steam based biomass CHP plants are only feasible beyond a certain size (MW-plants), and only where heat is a priority. The optimistic power/heat ratio is 1:4, i.e. 20 % electric efficiency. **ENOVA's Renewable Heat Potential** study 2007[12] states that the technical potential in 2020 is 18 TWh, while the economically feasible potential is 7.5 TWh. District heating of this (i.e. MW-sized heating plants, industrial plants included) is 0.7-1.7 TWh without subsidized heat distribution infrastructure and **2.8 TWh** if heat distribution is subsidized with 1.5 billion NOK. Assuming that 50 % of this will be built using biomass (wood + waste) this gives 2.8 * 0.5 * 0.2 = **0.3 TWh in new capacity.**

Existing District heating capacity suitable for conversion is about 1.5 TWh (1 TWh waste, 0.5 TWh biomass). If all this is converted this gives 1.5 TWh * 0.2 = **0.3 TWh.**

Conversion of existing industrial heating plants to (more efficient) CHP: According to SSB[19], presently around 5 TWh wood waste and by-products, and about 0.5 TWh power produced from this already. The potential is at most another about **0.5 TWh**, mostly in the pulp and paper and wood industries.

New potential major heat sinks are:
CO_2 capture, where 3–4 GJ heat/ton CO_2 captured is needed with amine scrubbing. Heat can partially be provided by bioenergy CHP plants with natural gas superheating and reheat, with a backpressure turbine operating with e.g. a backpressure of 3.5 bars and a temperature of 140 ºC. This will give about **0.5 TWh bioelectricity, for each CO_2 capture plant**.

2nd generation biofuels production, e.g. syngas production by gasification followed by FT-synthesis. The gasification process is a high-temperature process, best controlled in allothermal gasification processes. The producer gas needs to be cooled down to the FT-synthesis temperature, and a substantial amount of electricity can therefore be generated in a steam-turbine, with possibilities also for process steam and heat production. The FT-synthesis is exothermal, at a temperature of about 250 ºC. Distillation is endothermal, but may probably use energy from FT-synthesis. Hence, there is a limited net heat demand at low temperature. There is a possibility of electricity generation in the FT-stage, possibly combined with CO_2-capture. Biomass syngas has hydrogen deficiency with respect to FT-synthesis, i.e. a carbon surplus.

Standalone electricity generation from biomass with high electric efficiency is an option, maybe in the near future. Electric efficiencies of 50% can be achieved in large combined cycles or in plants using natural gas superheaters. This might become an acceptable option if the heat cannot be utilised or produced by other means, i.e. via heat pumps. Hence, even standalone electricity generation from biomass is eventually connected to the heating market, and the use of heat pumps has the potential to produce more heat per fuel unit than any standalone heating plant. Additional benefits are connected to local emissions and infrastructure considerations. The drawback is investment costs and in-house heat distribution infrastructure, and in Norway today's low incentives for bioelectricity compared to heat production.

3 GAS BASED BIOMASS CHP TECHNOLOGIES

Gas based biomass CHP technologies are much less applied than steam based CHP technologies. Compared to steam turbines for biomass CHP the gas based biomass CHP technologies are less technical mature, except for biogas and landfill gas applications. However, they have several technical advantages. The cost-efficiency then becomes the critical aspect, where all direct cost involved must be taken into account. The gas based systems generate a combustible gas from the solid biomass (e.g. through gasification or anaerobic digestion), which then is cleaned and

[19] http://www.ssb.no/indenergi/tab-2008-06-27-02.html

combusted and expanded in a turbine or combusted directly in an engine to provide mechanical work and electricity or electrochemically converted in a fuel cell to generate electricity.

The first industrial gasifier was patented already in 1922: The German Winkler gasifier, probably the first industrial fluidized bed kind of equipment. Later on, from 1934, the Lurgi fixed bed gasifier came along. These gasifiers operated with coal as their feedstock, and they were crucial for providing Germany with liquid automotive and aviation fuels during the 2nd World War. By the 50ies, the Lurgi gasifier was generally accepted as the most reliable one, and was crucial to South Africa for their production of liquid fuels during the South African oil embargo. More recently, entrained flow gasifiers have been developed by a number of companies, including Shell and Texaco. The entrained flow gasifier is presently viewed as the more versatile kind of gasifier, since it is able to produce a relatively pure synthesis gas from a variety of feedstock qualities. An overview of the co-gasification of biomass with coal is presented by Ricketts et al.[20], essentially presenting a number of large-scale gasifier solutions, along with an analysis concluding that.

1. Gasification is expensive
2. Small-scale gasification is even more expensive
3. At the time of writing (2002), electricity production by gasification technologies only seems economically viable for biomass or waste if it is co-gasified with coal in very large plants.

This analysis did however not consider CHP, only electric power plants, so even if its conclusions should be noted, it is not guaranteed that they are valid in scenarios where large amounts of heat are being produced and sold at a good price.

In the 1990ies, waste gasification was in a number of European countries viewed as an environmentally benign alternative to waste incineration. The need for expanded waste treatment capacity combined with public and NGO scepticism towards waste incineration created a situation in the late 1990ies where a number of companies promoted new gasification based solutions.

The Siemens / Westinghouse **Schwelbrenn process**[21] uses a rotary kiln with an internal heat exchanger for waste pyrolysis in 1 h at about 500°C. Larger mineral and metal pieces in the char material are separated out on a 5 mm sieve. The brittle char grains are then milled and the fine ca. 0.1 mm powder is combusted at about 1300°C (λ ca. 1.3) in a downward entrained flame together with the pyrolysis gas. The molten slag is shock-cooled in water. The leach-resistant, glasslike granules may be utilized, e.g. as an additive in concrete or for other simple purposes.

In the **Thermoselect process**[22], municipal waste is first compacted to about 1 t/m^3. The compressed packs are then pyrolysed in a flat, externally heated channel for 2 h at temperatures up to about 600°C. Large char pieces are obtained and fed directly into a fixed bed gasifier together with the pyrolysis gas. Technically pure oxygen is fed at the bottom of the gasifier and converts the carbon into CO at local temperatures up to 2000°C. Secondary oxygen is fed into the gas space above the bed, to ensure complete gasification by keeping the gas exit at 1200°C. At the

[20] http://miranda.hemscott.com/static/cms/2/4/2/6/binary/5940929141/123027.pdf
[21] http://www.fzk.de/fzk/groups/itc-cpv/documents/internetdokument/id_032180.pdf
[22] http://www.thermoselect.com/news/2004-07%20JFE%20Technical%20Report%20Thermoselect%20Process.pdf

gasifier bottom, some molten iron accumulates, covered by a thick layer of molten slag. The glasslike slag gravel obtained by shock cooling and subsequent magnetic iron separation can be used in the same way as above.

An accident in the first plant made Siemens abandon its waste gasification entirely in Europe, but the technology has later been licensed to Mitsui in Japan, where plants have been built and are operating successfully for recycling of car shredder residue and electronics scrap. The economic success is here primarily due to the reclamation of valuable metals between the low temperature pyrolysis step and the high temperature combustion / gasification step, partly because of the economic contribution of the recovered metals, and partly due to the fact that high recoveries of these metals are mandatory.

In Norway, "two and a half" small-scale waste gasification technologies have been promoted since the 1990ies: Organic Power, PyroArc and Energos.

The Organic Power gasifier is a small downdraft gasifier where the product gas is subsequently combusted in a boiler, producing hot water or steam. A number of Organic Power plants were built during a short period, but all of these have later been closed down due to technical underperformance. The technology has however been licensed to Kentec in South Korea, who have built a number of plants there that seem to operate satisfactorily for local conditions.

The PyroArc gasifier is a small low-temperature updraft gasifier followed by thermal decomposition of the gas in a high temperature electrically driven plasma arc. The gas is subsequently cooled down, and may be used in either a motor or in a boiler. One small plant was built in Norway, processing hazardous waste. After having filed for bankruptcy, the plant presently appears to have been refinanced and reopened again. A number of other PyroArc projects have been in development over the last decade, but none of these have been realized. The main reason appears to be that this technology, even though it works quite well even on complex waste fractions, is too expensive.

The "last half" of the "two and a half" technologies in Norway is characterized in this way because it may be argued both that the Energos technology is a gasification technology and that it is a waste incinerator. The most proper characterization is probably that it is a grate based incinerator with staged combustion of the product gas, first in an under-stoichiometric gasification chamber, and then subsequently in an over-stoichiometric secondary chamber. Between 1997 and 2002, Energos built five plants in Norway (Ranheim, Averøy, Hurum, Forus and Sarpsborg) and one in Germany, and all these are still operating. Energos had to file for bankruptcy in 2004, and was then bought by new British owners and re-established under the same name. Recently Energos have landed new contracts both in the UK and in Norway, and they are presently building a second plant in Sarpsborg.

The general lessons learnt from waste gasification so far is that in general, the primary mover is not the potential for increased electric efficiency, but rather that some well-paid waste fractions may be processed more conveniently in gasifiers than in ordinary incinerators.

Parts of the pulp and paper industry have potentially interesting possibilities for use of gasification technology. In Sweden, there was substantial academic interest in black liquor gasification in the 1990ies. Presently, black liquor is usually being combusted and power produced by a steam cycle, but if conversions are made from combustion to gasification, present power production may be doubled. The Swedish company Chemrec[23] is now marketing oxygen-blown entrained-flow gasifiers for gasification of black liquor, producing syngas for subsequent production of DME, methanol or FT-diesel. Their primary vision is to turn around pulp and paper plants to become ***biorefineries***, but the synthesis gas produced in their plants may also be used efficiently for power production.

Choren Industries[24] is a German company marketing a gasification solution based on pyrolysis of wood chips followed by an oxygen-blown entrained-flow gasifier. Compared to the Chemrec process Choren's solution has the advantage that it is not dependent on the coproduction of pulp, but at the same time this may also be a disadvantage, especially related to the established logistics of existing large plants.

3.1 Technology options and status

Early commercial and demonstration biomass gasification plants exist from large- to small-scale internationally. However, the number is small (about 50 [10]), and the plants are or have been heavily supported by research funds and can thereafter only be commercially operated with significant economical incentives with respect to the electricity price. The next phase will be long term operation to farm out the operational and project related challenges (reliability, availability, safety, need for backup / topping, real world economics). It is hard to see this happen in Norway without backing from solid developers. No biomass gasification CHP plants exist in Norway. Even though biomass gasification is a very interesting option from a technical viewpoint considering the advantages, no Norwegian suppliers are directly involved in development in biomass gasification CHP plants. However, through the years, several actors have as mentioned been involved in development of two-stage like gasification/combustion processes, with direct combustion of the gas after the primary chamber in a secondary combustion chamber (Organic Power, Energos; using waste) or a burner (Agder Biocom[25]; using biomass). Two-stage combustion has its advantages, e.g. with respect to lowering NOx emissions and achieving an improved combustion control and gas burnout, however, these are not generally considered as gasification processes. Only if the combustible gas can be directly utilised (after cleaning) in e.g. a gas turbine or an engine, the electricity yield benefits of gasification processes can be achieved.

For biogas and landfill gas the situation is quite different, since the gas is easily available, and can easily be cleaned and combusted in e.g. an engine. Several engines running on biogas or landfill gas are in operation in Norway.

The most likely gasification project in Norway to be realised is in connection with 2nd generation biodiesel production through FT-synthesis. Xynergo is planning such a large-scale 2nd generation biodiesel plant, for the production 14% of the Norwegian diesel need for transport and 10% of the

23 http://www.chemrec.se
24 http://www.choren.com/en
25 http://www2.scriptor.no/tratecgroup.com/db/repository/x0311200811749.pdf

Norwegian heating oil need per year[26]. The larger the plant, the more economic it can become. However, biomass supply is a limiting factor, and a coastal location is necessary for large-scale plants. A commercial scale plant will be a large-scale plant also with respect to integrated electricity and low-temperature heat generation from excess process heat.

3.2 Technical and economical challenges

Also for gas based biomass CHP technologies the economical challenges are closely connected to the technical challenges.

3.2.1 Technical challenges

Tars are a main problem. Tars can be cracked, reformed or cleaned, but at a cost. Proper fuel quality is essential in gasification plants, but the fuel quality demands will vary depending on the gasification technology. Safety is always an issue, adding to the costs. Small-scale plants without continuous human supervision are hard to imagine, as process control in biomass gasification plants are significantly more complex than for biomass combustion plants. This result in more frequent down-time, reduced reliability and reduced availability. An industrial organization is required to operate a commercial biomass gasification CHP plant.

Fuel related challenges in biomass gasification systems are connected to both the physical and chemical properties of the fuel. The gasification route offers important advantages with respect to minimisation of fuel related problems through gas cleaning in advance of downstream utilisation of the producer gas. However, gasification processes, especially small-scale systems, are more sensitive to the physical properties of the fuel, especially inhomogeneity with respect to fuel size and size distribution and moisture content. The reason for this is the challenging task of the gasification process control. Constant biomass feeding is necessary for smooth gas production. The hardware selection and it's quality and the control system are key aspects.

Several gasification concepts, and the typical success stories within gasification, are based on solutions for improved gasification process control. This can be achieved by allothermal solutions where the gasification process is controlled by an external process, e.g. a twin combustion process. One example of biomass gasification success stories are the Fast Internally Circulating Fluidised Bed (FICFB) concept[27] implemented in the Güssing steam gasification plant, and recently in a second plant in Austria, in Oberwart. The Oberwart plant is also coupled to an ORC, increasing the electric efficiency of the plant. Another example is the Carbo-V gasification technology of Choren[28]. A third example is the Kymiarvi power station in Lahti, Finland. Other examples of biomass gasification success stories are given in Handbook Biomass Gasification[29].

3.2.2 Economical challenges

The increased electric efficiency offered by biomass gasification CHP plants is beneficial, but the major question is if this can become profitable compared to the competition. Sufficient annual

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[26] http://www.xynergo.com/products
[27] http://www.ficfb.at/
[28] http://www.choren.de/
[29] Handbook Biomass Gasification (Editor: Harrie Knoef), BTG Biomass Technology Group, 2005

operating time is needed, and hence, reliability and availability becomes critical issues. Hence, there will be a balance between improved electric efficiency and incomes/savings due to this, and increased costs due to additional capital and O&M costs due to a more complicated thermal conversion process.

Higher demands with regards to fuel quality mean that the typical free or very low-cost fuels are not very suitable for gasification systems. This means higher fuel costs, but lower fuel induced downstream costs.

3.2.3 Cost-efficiency

Biomass gasification CHP plants are most suited for industrial scale, and are interesting in a biofuels context. For large-scale a gas turbine followed by a steam turbine or ORCs are interesting options. In the small-scale area, gas engine / ORC or gas engine / Stirling engine are possible options.

Depending on the relationship between increased fuels costs and reduced downstream induced fuels costs the cost-efficiency aspect with regards to the fuel can go both ways. Since biomass gasification systems still must be regarded as being in a commercial introduction phase, the investment costs will be higher compared to the fuel costs compared to comparable size commercial steam based biomass CHP solutions. Hence, incentives regarding technology development and introduction are needed in Norway to achieve an acceptable cost-efficiency.

3.2.4 Research needs and potential impact

There is a need for improved and cost-effective gasification technologies. Reliability and availability is a key issue, and more robust systems are needed, and more flexible systems are wished for. However, flexibility (e.g. with respect to fuel quality) and robustness of the systems at the same time is a considerable challenge. Even though biomass gasification has been a subject of research and demonstration for decades, today's limited amount of biomass gasification CHP plants and the not fully commercial status of these clearly indicates to challenges connected to this. The challenges are connected to increasing reliability and availability in a cost-effective manner.

Specific research needs are:
- Improved gasification process control
- Optimising the producer gas quality
- Gas conditioning and cleaning
- Additives use or fuel mixture use to reduce downstream challenges (fouling and emissions)

3.3 Potential in a Norwegian context

Biomass gasification can cover part of the potential for steam and heat mentioned earlier (i.e. GWh range, not TWh). There is a large potential with respect to 2nd generation biodiesel production and high-efficiency electricity generation (combined cycles) if commercially viable compared with the competition, all economic incentives taken into account.

4 COMBINED BIOMASS CHP TECHNOLOGIES

Combined systems are systems where excess heat (or fuel) from a primary cycle is utilised in a bottoming cycle, in more or less complex system configurations, to further increase the overall electric efficiency. Combining biomass CHP technologies will be beneficial with respect to especially electric efficiencies, e.g. in a biomass integrated gasification combined cycle plant (BIGCC). However, combinations are also possible in small-scale plants, e.g. using an organic Rankine cycle (ORC) as a bottoming cycle to increase the electric efficiency with a few percent using excess low-temperature heat sources.

4.1 Technology options and status

Combined cycles based on biomass gasification have received limited focus. This is due to the costs involved and the not fully commercial status of biomass gasification. Combined cycles focus on optimising the electric efficiency of a plant. This gives additional capital and O&M costs, which must be counteracted by the economical benefits of an increased electric efficiency. Possible combined cycles are:

- Gasification in combination with gas turbine, followed by a steam turbine
- Gasification combined with gas engine and ORC (as in the Oberwart plant)
- Gasification in combination with gas engine and slipstream to fuel cell

There are many possible system configurations that can be proposed from a technical viewpoint, but from an economical viewpoint the number of possibilities will be limited.

4.2 Technical and economical challenges

Also for gas combined biomass CHP technologies the economical challenges are closely connected to the technical challenges.

4.2.1 Technical challenges

Combined biomass CHP solutions face the same fuel related challenges as steam based and gas based biomass CHP solutions. The primary biomass conversion technology will be the decisive one with respect fuel related effects. For large-scale systems, gasification combined with a gas turbine and followed by a steam cycle can achieve a very high electric efficiency. In this case the fuel related challenges are connected to the gasification process. For gasification combined with a gas turbine and followed by an ORC or a Stirling engine the same is the case. However, if the producer gas is taken directly from the gasification process as a slipstream to a secondary CHP technology, bypassing the primary CHP technology, fuel related effects can be important, depending on the CHP technology and the producer gas quality. E.g. a high-temperature fuel cell will be sensitive to impurities in the producer gas not normally removed in a gas cleaning processes applied for gas turbines or gas engines. For direct combustion conversion processes combined with a CHP technology, bottoming cycles are not economically relevant, but also here combinations of different CHP technologies are technically possible.

Interfacing between electricity generating technologies are also a challenge, i.e. having two or more electricity generation systems where all are intended to supply electricity to the grid.

4.2.2 Economical challenges

Combined biomass CHP technologies are today too expensive considering the Norwegian electricity prices and incentives. The standard solution is therefore one electricity generation technology, e.g. a boiler / steam turbine combination. The technology challenges of combined technologies lies primarily in the coupling of the single technologies and the control and operational aspects connected to this. The solid fuel conversion process, and the challenges connected to this will be essentially the same. Exceptions occur when the combined systems both are gas based, e.g. a system where the primary technology is a gas engine and the secondary technology is a fuel cell utilising a fraction of the producer gas. The fuel cell will then add additional complexity with regards to gas quality demands.

Combined biomass CHP technologies have the potential to increase the electric efficiency of the biomass CHP system, and as such improve the fuel utilisation if electricity is the main focus. However, the overall system efficiency may decrease due to the increased focus on electricity generation. With regards to the biomass conversion technology and the primary CHP technology, the fuel related economical challenges are the same as for standalone biomass CHP systems, i.e. as for gasification based biomass CHP technologies.

Biogas and landfill gas utilization plants are often established primarily to deal with environmental problems, and the energy produced is an added benefit. Size and location will determine whether electric power production is an option, or whether it is more rational to produce heat for distribution.

4.2.3 Cost-efficiency

Combined biomass based CHP systems have a potential for significantly improved cost-efficiency when considering only the fuel utilisation, however, the additional investment- and O&M costs connected to a plant with more than one CHP technology implemented will counteract this benefit. Hence, the cost-efficiency may overall suffer if a combined biomass CHP system is chosen. Economical incentives can counteract this, which is a matter of political will within the framework of economically allowable measures.

4.2.4 Research needs and potential impact

The research needs connected to combined biomass CHP technologies are the same as for single biomass CHP technologies, but with the additional aspects connected to the system integration and if any, additional fuel influence effects on the secondary CHP technology, e.g. a fuel cell. The reader is referred to the previous chapters for further information.

4.3 Potential in a Norwegian context

Combined biomass CHP technologies can cover part of the potential for steam and heat mentioned earlier (i.e. GWh range, not TWh). There is a large potential with respect to high-efficiency electricity generation (combined cycles) if commercially viable compared with the competition, all economic incentives taken into account. The heat will then have low or no priority, and the electricity is the focus. Combined solutions in the small-scale size range are interesting with respect to increased electric efficiency from primarily gasification based systems, using e.g. an ORC as a bottoming process.

5 DISCUSSIONS

Cost-efficiency is the key word. Any commercial operation of a biomass CHP plant demands that the operation can be carried out in a profitable way. For the majority of biomass CHP plants this will today include the need for incentives, i.e. investment support and incentives directly aimed at the products (i.e. electricity) and negative incentives connected to the competition (e.g. taxation of fossil fuels). The only reason that some biomass CHP plants exist in Norway today, is the availability of fuel that you get paid to receive (waste), fuel that is available anyway and that has negative impact (landfill gas) and fuel that are by-products from the wood industry (bark, sawdust) or agriculture (biogas). The additional costs of the electricity generation part of the plant cannot be justified for plants using virgin wood, e.g. wood chips or pellets. As such the introduction of biomass CHP in Norway is not dependent on technology limitations. There are several technologies on the market that can be implemented today, and this has indeed been done in other Nordic countries for decades. Hence, a political will to support biomass CHP directly and indirectly continuously and in a long-term perspective is needed in Norway.

However, this does not mean that the biomass CHP technology area has reached a level which is sufficient. Commercial technologies (boilers) are operating with limiting parameters to avoid operational problems (waste/waste wood incineration). The practical biomass CHP plant performance is in many case significantly or much lower than anticipated. For not fully commercial biomass CHP technologies there are a variety of research efforts that can improve these technologies to the level of possible fully commercial operation. Some biomass CHP technologies are clearly in demonstration or development stages, and their possible contribution to the future Norwegian biomass CHP picture is very debatable.

An important study[30] on the practical performance of CHP systems was carried out in the EU Altener programme, and was reported in 2006. The aim of the study was performance comparison and recommendations for future CHP systems utilising biomass fuels. Their conclusions can be summarised as follows:

Big is beautiful: For plants in operation one observes that higher efficiency, lower own consumption and better availability for the larger plants, which means that larger plants perform significantly better in fossil fuel substitution and in operational economic performance. Larger plants also show lower investment cost relative to the size of the plant. Hence, for the resources given (capital, biomass, manpower) the bigger the plant, the more renewable energy is produced. However, the biomass CHP systems are limited by the biomass availability and the size of the heat market they can be connected to. For biogas and landfill gas engine systems the size dependency is less significant than for other commercially competing technologies of today. Market development and series production might bring down future capital costs for small-scale systems.

Capacity and utilisation: There is a general tendency that the CHP plants are built with a too high capacity, i.e. a low utilisation factor. Selecting the right size of a CHP system is a challenge due to seasonal variations and the price of electricity versus heat, and if relevant estimation of the future heat demand.

[30] Evald A, Witt J. Biomass CHP best practice guide, 2006, http://bio-chp.dk-teknik.dk/cms/site.aspx?p=802

CHP or not CHP: Depending on incentives and other factors, CHP may not be very beneficial, resulting in low utilisation of the heat. Biogas and landfill gas plants may only to a limited extent utilise the heat, and gate fees for e.g. animal manure and economic incentives favouring electricity generation may give less focus on heat utilisation in such plants. However, as long as some heat is utilised, they are still CHP plants. A similar situation can occur for large waste incineration plants, if the heat customers are too few, and therefore not all the heat is utilised. Due to gate fees economical operation is still possible.
Balancing heat and power: Electricity should be the most valuable product from an efficiency viewpoint, however, for industrial plants (steam and process heat), and for plants located where renewable heat has a high value (e.g. Nordic countries) the value of electricity and heat may become more balanced.
Choosing the right technology: Many biomass CHP technology options exist, giving different electric efficiencies. Incomes from electricity sales must be balanced against the additional costs of the electricity generation part of the plant. Hence, optimising the electric efficiency will be very important, and steam cycles are very sensitive to the scale of operation in this respect.
Industrial systems: Industrial systems are often built to provide industrial processes with steam and process heat, often with one specific customer in mind. Hence, focus on optimum electric efficiency in industrial CHP plants is often less prioritised.
Reducing own consumption: A CHP plant's own electricity consumption may consume a significant part of the electricity generated by the plant. The net electricity generated in a plant is what you can sell, and depends on the choice of CHP technology and the electricity need of auxiliary equipment in the plant. Modern plants are more efficient than old ones. For CHP technologies with a relatively low gross electric efficiency, a very large fraction of that electricity may be needed within the plant.
Operational problems: Operational problems are connected to fuel related effects as sintering, fouling and corrosion, and fuel moisture content variations. Due to the operational problems the electric efficiency decreases and the O&M costs increase, significantly influencing the total economy of the plant.

5.1 Small-scale biomass CHP versus larger scale

Small-scale biomass CHP has some advantages compared to large-scale biomass CHP, however, in general large-scale CHP plants are favourable from a cost-efficiency viewpoint. The main challenge related to larger scale CHP plants is to find large enough heat customers willing to pay for the heat. Small-scale solutions may be or become competitive in areas not connected to the main electricity grid, areas with insufficient heat infrastructure and for the very smallest systems also in standalone buildings or single houses.

5.2 Small-scale biomass CHP in a Norwegian context

In a Norwegian context, small-scale CHP can contribute to the Norwegian national bioenergy goals and to bioelectricity generation through the following technology and scale scenarios:

- Electrification of all existing biomass district heating plants (combustion and steam turbine)
- Increased utilization of biogas and landfill gas for CHP in engines
- Erection of new CHP district heating plants (combustion and steam turbine)
- Electrification of industrial heating plants, if low-cost fuel is available (combustion and steam turbine)

- Introduction of gasification based CHP systems, and combinations of CHP technologies (gas engine, ORC)

Large-scale:
- CHP in combination with gasification and 2nd generation biodiesel production (producer gas cooling and steam turbine)
- Standalone electricity generation in large-scale biomass power plants (BIGCC, gasification-gas turbine followed by steam turbine)
- Direct or indirect co-firing of producer gas in natural gas fired combined cycle power plants (gasification-gas turbine followed by steam turbine)
- CHP in combination with CCS (heat demanding) in natural gas fired combined cycle power plants (combustion and steam turbine)

5.3 The potential role of small-scale biomass CHP in Norway towards 2020

The potential role of small-scale biomass CHP in Norway towards 2020 will depend on several factors, including framework conditions. Depending on the framework conditions the following scenarios can be envisioned:

1) No improved framework conditions: small-scale biomass CHP will only slowly develop, based on negative cost, free or very low-cost biomass, in addition to biogas and landfill gas. Research work should then be focussed on optimising the conversion technologies used in such systems, included fuel quality related aspects. Increased electric efficiency and energy utilisation should be a key aspect, included retrofit options, together with minimising environmental impacts. Biomass gasification will only be interesting for 2nd generation biodiesel production.
2) Partly improved framework conditions, but no major change in today's bioelectricity incentives: Steam cycle CHP solutions based on higher cost biomass fuels may become feasible. Conversion of existing biomass heating plants based on wood chips or pellets is a possibility. Research work should be focussed as in 1)
3) Framework conditions similar to other Nordic and European countries: Higher cost fuels can be utilised and significant incentives on bioelectricity will make it feasible to develop new biomass CHP projects based on wood chips and pellets, primarily using steam turbines. Gasification of biomass may become an option for both biomass CHP and standalone power generation in BIGCC plants. Research work should be focussed as in 1) and on a wider spectre of biomass CHP technology options, combinations and scales.

6 RECOMMENDATIONS

Recommendations are given based on both Norwegian considerations and KRAV project considerations.

6.1 Norwegian considerations

Norwegian framework conditions for biomass CHP are special in a Nordic context, special meaning considerably less favourable incentives for biomass CHP. Hence, currently it seems not likely that there will be a major development, but rather a development according to scenario 1, or maybe scenario 2.

6.2 KRAV project considerations

The KRAV project deals with small-scale (< 10 MWth) biomass CHP. This means that you are in a range where the plant size limits the achievable electric efficiency in a steam turbine. This provides increased opportunities for other technologies, due to potential increased electric efficiency gap between steam turbines of this size and the other technologies. However, still, the steam turbines are reliable and proven also for small-scale applications. Steam engines are one competitor in the lower half of the small-scale size range, it is a proven technology, but also has its disadvantages. An organic Rankine cycle is an alternative option, but mainly where high-temperature heat is utilised for other purposes, and where low-temperature heat then can be used in the organic Rankine cycle, as a bottoming process. A Stirling engine is one option for very small-scale systems, with a high theoretical efficiency but with limited efficiency in practise. This is a closed system, where (combustion) heat is transferred to a working medium in the Stirling cycle. Also other closed systems based on heat transfer exist, e.g. hot-air turbines.

If considering gas based biomass CHP, several technologies exist, covering a wide size range and with potentially superior electric efficiency compared to steam based biomass CHP options. Fuel cells, especially a SOFC, are an option for high electric efficiency already in very small units. However, the costs are very high and the technical challenges when using biomass based gas, especially producer gas, as fuel, are very high. Micro-turbines are one option for quite high efficiency in kW size units. However, all aspects considered, the most promising gas based technology is gasification in combination with gas engines for small-scale units, and gas turbines for large-scale units.

Combined solutions provide for higher electric efficiencies. However, e.g. a BIGCC system is not a realistic option for small-scale systems. Using e.g. ORC is an option where some electricity is needed, or as a bottoming cycle.

In the KRAV project, considering the national goals of increasing the bioenergy use with a factor of two within 2020, and at the same time expecting an increased efficiency of use, it cannot be expected that the very non-mature and/or very expensive small-scale CHP technology options of today will become of any significant importance in Norway within 2020.

In light of this the selection of the small-scale CHP technology or sub-system technology to be studied in detail in the last two years of the KRAV project should be based on one or more of the following criteria:

1) Established technologies with significant potential for improvements or **retrofit solutions** (e.g. biogas fired superheaters)
2) **Technology combinations** with focus on increased electric efficiency (e.g. system analysis of such combinations)
3) General **fuel aspects directly influencing the cost-efficiency** of biomass CHP plants (e.g. corrosion and fouling)
4) General **fuel aspects influencing emissions** from biomass CHP plants (e.g. NOx)
5) Technology aspects directly influencing cost-efficiency and emissions from biomass CHP plants (e.g. grate design)
6) New CHP technologies that have the potential to become of significant importance in Norway within 2020 (e.g. gasification based)

As earlier mentioned **the recommendation is to also include medium-scale plants** (up to 30 MWth) in the KRAV project.

Included in the KRAV project is a PhD scholarship and a PostDoc scholarship, where detailed studies on selected aspects will be carried out. The PhD study will focus on NOx emission reduction and the focus of the PostDoc study is planned to be biomass CHP system analysis.

Industrial viewpoints regarding the selection of the small-scale CHP technology or sub-system technology to be studied in detail in the last two years of the KRAV project will also be important.

7 CONCLUSIONS

This report has presented and discussed a number of aspects connected to biomass CHP, regarding technologies, cost-efficiency considerations, Norwegian framework conditions and research challenges connected to the relevant biomass CHP technologies. Depending on the framework conditions several scenarios can be envisioned with respect to the future of biomass CHP in Norway.

Considering the current framework conditions, the following scenario can be envisioned:
No improved framework conditions: small-scale biomass CHP will only slowly develop, based on negative cost, free or very low-cost biomass, in addition to biogas and landfill gas. Research work should then be focussed on optimising the conversion technologies used in such systems, included fuel quality related aspects. Increased electric efficiency and energy utilisation should be a key aspect, included retrofit options, together with minimising environmental impacts. Biomass gasification will only be interesting for 2nd generation biodiesel production.

In light of this the selection of the small-scale CHP technology or sub-system technology to be studied in detail in the last two years of the KRAV project should be based on one or more of the following criteria:

1) Established technologies with significant potential for improvements or **retrofit solutions** (e.g. biogas fired superheaters)
2) **Technology combinations** with focus on increased electric efficiency (e.g. system analysis of such combinations)
3) General **fuel aspects directly influencing the cost-efficiency** of biomass CHP plants (e.g. corrosion and fouling)
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5) Technology aspects directly influencing cost-efficiency and emissions from biomass CHP plants (e.g. grate design)
6) New CHP technologies that have the potential to become of significant importance in Norway within 2020 (e.g. gasification based)

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