



**KAUNAS UNIVERSITY OF TECHNOLOGY  
FACULTY OF MECHANICAL ENGINEERING AND DESIGN**

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**THE GENERATION OF PYROLYSIS GAS FROM BIOMASS  
AND USAGE IN A COGENERATION PLANT**

Master's Degree Final Project

**Supervisor**

dr. Valdas Lukoševičius

**KAUNAS, 2017**

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**FACULTY OF MECHANICAL ENGINEERING AND DESIGN**

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AND USAGE IN A COGENERATION PLANT**

Master's Degree Final Project  
Thermal Engineering (code 621E30001)

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"The Generation of Pyrolysis Gas from Biomass and Usage in a Cogeneration plant"

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**THE FINAL TASK OF MASTER'S DEGREE UNIVERSITY STUDIES  
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The final project of Master's studies aimed to gain the master's qualification degree is a research or applied type project. 30 credits are assigned for its completion and defence. The final project of a student must demonstrate the more profound and extensive knowledge acquired in the main studies as well as the gained skills enabling the student to outline and solve an actual problem when in possession of limited and/or contradictory information, to independently conduct scientific or applied analysis and to interpret data properly. By completing and defending the final project of Master's studies, a student must demonstrate creativity, ability to apply fundamental knowledge, understanding of social and commercial environment(s), Legal Acts and financial limitations, to demonstrate information search skills as well as ability to carry out analysis requiring advanced qualification(s), to use quantitative research methods, to apply relevant software, to use common information processing techniques and correct language and to demonstrate the ability of formulating proper conclusions.

1. Title of the Project:

**The Generation of Pyrolysis Gas from Biomass and Usage in a Cogeneration Plant.....**

**Pirolizinių dujų generacija iš biomasės ir panaudojimas kogeneracinėje jėgainėje.....**

Confirmed by Dean order Nr. V25-11-8 on 21<sup>st</sup> of April 2017.....

2. Aim of the Project: To make a project of biomass gasification usage in a cogeneration plant. ...

3. Structure of the Project:.....

**Introduction** .....

**1) Global Use of Biomass** .....

**2) Importance of Biomass Gasification and CHP** .....

**3) Gasification** .....

**4) Comparison of Quality and Quantity Parameters of Natural Gas and Syngas**.....

**5) Potential Feedstock for Biomass Gasification in Lithuania**.....

**6) Case study: Vilnius CHP-2 Power Plant**.....

**7) Gasifier and Auxiliary System Selection**.....

**8) Energy Balances and Production** .....

**9) Economical Evaluation of the Project**.....

**10) Environmental Impact**.....

**Conclusions. References. Appendices**.....

4. Requirements and conditions: **The master's thesis must fulfil the requirements that are demanded for the final task of master's degree.** .....

5. Project submission deadline: 23 May 2017

6. This task assignment is an integral part of the final project.

Given to a student **Justas Mackėla** .....

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## SUMMARY

The major goal of the Master's thesis is the study of biomass gasification usage in a cogeneration plant. Firstly, a study of biomass (characteristics, advantages and disadvantages), gasification technologies available, biomass gasification process and potential applications has been carried out.

The second part of the project is focused on biomass gasifier integration into Vilnius CHP-2 power plant. The gasifier would produce synthetic gases to feed an old BKZ-75-39 boiler that was firing natural gas previously. A Low Temperature Circulating Fluidised Bed gasifier (LT-CFB) was chosen because it is capable to exploit low cost feedstock that contains bigger fraction of alkali metals and other inorganics. Besides, the CFB technology has some commercially successful examples in Finland and Denmark.

A gasifier of 70 MW was designed for multiple low cost feedstock, such as straw or peat. The calculations and energy balances were done for the whole technology including gasifier, gas cooler, boiler, turbine, condenser, condensing economizer and district heating network. The overall efficiencies and losses of the system were evaluated.

Financial feasibility of the project was evaluated according to investment, fuel and O&M costs as well as revenues from electricity and heat production. It was done according to various assumptions of investment, energy production and electricity price. The Net Present Value was calculated for different cases showing that biomass gasifier integration in Vilnius CHP-2 power plant can be profitable.

The environmental impact was estimated. In comparison with natural gas combustion, biomass gasification would lead to reduced emissions of GHG's and money savings due to CO<sub>2</sub> penalty for fossil fuel based energy generation.

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## SANTRAUKA

Šiame magistro projekte buvo išnagrinėta biomasės gazifikacija ir jos pritaikymas kogeneracinėje jėgainėje. Pirmiausia buvo aprašytos biomasės gazifikacijai naudojamos technologijos, įvertintos labiausiai tinkamos biokuro žaliavos, sintetinių dujų parametrai ir kiti svarbūs faktoriai, nulemiantys šios technologijos panaudojimo perspektyvas.

Antroje projekto dalyje, buvo pasirinktas konkretus objektas – Vilniaus antroji termofikacinė elektrinė. Šioje elektrinėje yra trys BKZ-75-39 tipo dujiniai katilai, kurie dėl didelės gamtinių dujų kainos yra nekonkurencingi rinkoje. Viename tokio paties tipo katile jau yra įdiegta biomasės verdančio sluoksnio pakura. Tačiau šis sprendimas nepasiteisino dėl iškilusių techninių sunkumų. Todėl kitas pasirinkimas galėtų būti sintetinių dujų, gautų biomasės gazifikacijos būdu, deginimas.

Sintetinių dujų gamybai buvo pasirinktas žemos temperatūros cirkuliuojančio verdančio sluoksnio gazifikatorius. Ši technologija jau yra įdiegta bei pasiteisinusi Suomijoje ir Danijoje. Žemos temperatūros gazifikacijos reaktorius geba naudoti daugiau neorganinių junginių turinčią žaliavą, kaip šiaudai ar durpės.

Esamo dujinio katilo aprūpinimui sintetinėmis dujomis buvo parinktas 70 MW gazifikatorius. Taip pat buvo sudaryta technologinė schema ir energijos balansai. Į technologinę schemą įeina: gazifikatorius, sintetinių dujų aušyklė, katilas, turbina, kondensatorius, kondensacinis ekonomaizeris ir centralizuoto šilumos tiekimo sistema. Sudarius energijos balansus buvo apskaičiuoti elektrinės naudingumo koeficientai ir įvertinti sistemos nuostoliai.

Ekonominis jėgainės įvertinimas buvo atliktas sudarant įvairias energijos gamybos, investicijų ir energijos kainų prielaidas. Apskaičiavus grynąją dabartinę vertę (angl. NPV) buvo nustatyta, kad gazifikacijos integravimas į Vilniaus antrąją termofikacinę elektrinę gali būti pelningas.

Projekto pabaigoje buvo nustatytas jėgainės poveikis aplinkai. Pakeitus gamtines dujas sintetinėmis, būtų smarkiai sumažintos CO<sub>2</sub> emisijos ir nereikėtų pirkti taršos leidimų už anglies dioksido išskyrimą į aplinką.

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## LIST OF ABBREVIATIONS

CHP	Combined Heat and Power
GHG's	Greenhouse gases
NG	Natural gas
SNG	Synthetic natural gas
BFB	Bubbling fluidised bed
EU	European Union
SRF	Solid recovered fuel
CFB	Circulating fluidised bed
LT-CFB	Low temperature circulating fluidised bed
LHV	Low heating value
HHV	High heating value
WI	Wobbe index
RDF	Refused derived fuel
DH	District heating
CE	Condensing economiser
O&M	Operation and maintenance
FCF	Free cash flow
NPV	Net present value

## INTRODUCTION

Nowadays, the energy sector still relies on fossil fuels. People behaviour of burning them pollutes the environment and cause many problems. Continued emissions of greenhouse gases will cause further warming and changes in all components of climate system. Therefore, a conversion towards renewable energy is needed.

In Lithuania, the most promising renewable source of energy is biomass. This feedstock can be applied to various technologies. In case of electricity and heat production, the most efficient application is Combined Heat and Power plants, which can either use raw biomass or synthetic gases. Both solutions have its benefits and drawbacks that need to be discussed.

Gasification technology is rarely deployed yet. However, there are some demonstrational and commercial examples that shows promising future for its integration in energy production. The main interest would be installing biomass gasification technology in an existing CHP power plant that was firing fossil fuels previously. It would lead to reduction of GHG's, energy independence due to utilization of domestic fuel and increase in renewable energy production.

In the present work, Vilnius CHP-2 power plant will be analysed. It has 3 natural gas firing BKZ-75-39 boilers that are not competitive in energy markets due to high price of NG. For that reason, one boiler of this type was already converted to firing forest residues, peat and straw. The boiler was reconstructed to biomass firing BFB boiler. However, it faced some technical problems related with slagging and clogging of boiler surfaces and heat exchangers in a flue gas shaft. Therefore, the power plant must be fully shut down for cleaning and is feasible to work less time than estimated.

The biomass gasification could be the solution to this problem as it produces almost clean gases. Most of the ashes and impurities are left in a gasifier or gas cleaning systems. Thus, feasibility study and economical evaluation of biomass gasification use in BKZ-75-39 boilers will be done.

# 1 GLOBAL USE OF BIOMASS

As the whole world is concerned about the climate change, it is expected that biomass, in combination with solar and wind, will play a big role in the future energy systems. Biomass is a renewable and sustainable source of energy that is currently capable to replace fossil fuels in many applications in environmentally effective way. Therefore, it can significantly reduce the greenhouse gas emissions in the atmosphere and help to achieve the targets of “Paris Agreement”.

Nowadays, bioenergy accounts for around 10% of total primary energy supply in the world and is estimated to increase in the next years. The amount of electricity production by this renewable source of energy is shown in a Figure 1.1 below. Europe remains the main user of biomass in power sector while the total electricity generation grows every year.

The main technologies to produce electricity from bioenergy are following:

- Combined heat and power (CHP) plants;
- Co-firing with coal in large power stations;
- Biomass power plants producing only electricity.

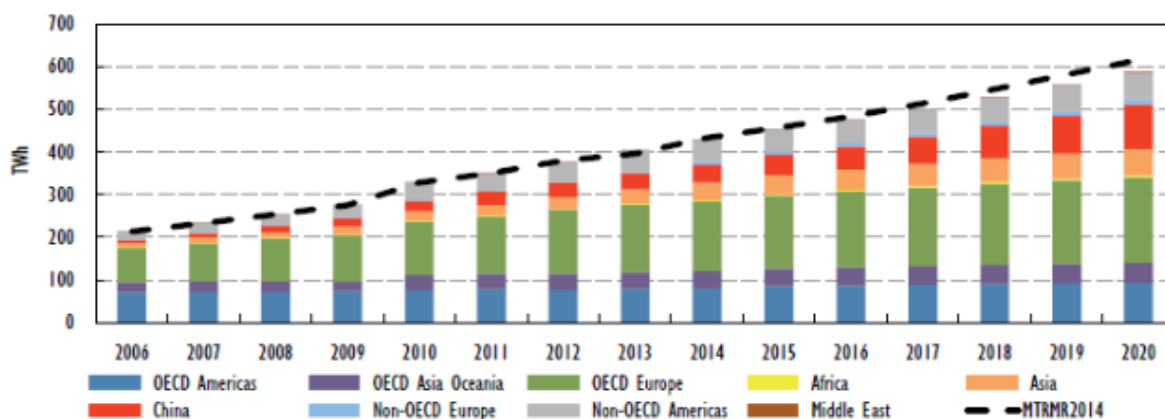


Figure 1.1. Bioenergy power generation and forecast by region [1]

In general, biomass is a fuel formed from organic materials and used to produce power, heat, biofuels or other source of energy. It can be forest residues, crops, such as wheat or straw, manure, some types of waste residues and many other plants or agricultural waste.

Biomass can be used as a domestic fuel and help countries to get rid of imported fossil fuels as well as improve energy security of a country. It can be used not only directly to produce power or heat. The other and more advanced way of biomass utilization is converting raw biomass to liquid biofuels for transportation sector or synthetic natural gas (SNG) for power and heat production. The SNG, generated by pyrolysis or gasification, can be used in more convenient way: storage and transportation of gas become easier and more efficient. Furthermore, the conversion to syngas increases the density of a fuel, which heating value depends on the feedstock used as a raw material. [2]

However, direct combustion to produce heat is still the main application of biomass in the world. Although the technologies of biomass combustion are rather simple, it has some drawbacks as well:

- the transportation and treatment of biomass is much more complicated compared to gaseous fuel;
- it releases more emissions of CO, NO<sub>x</sub> and HC to the atmosphere.

It is important to use energetic urban waste as a feedstock in energy production in order to diminish the problems of waste disposal and provide energy instead of eliminating it. These installations of incineration are common in many of EU countries. However, around 31% of municipal waste is still landfilled in EU (e.g. 64% in Lithuania or 25% in Finland) [3].

To sum up, further developments of energy production techniques from biomass are needed in order to use its potential in a more efficient way. As this resource is available in most of the countries, expanding biomass usage can lead to energy independence of a country, money savings, development of agricultural regions and providing more jobs for the people.

## **2 IMPORTANCE OF BIOMASS GASIFICATION AND CHP**

Biomass gasification is not a highly-developed technology yet. However, it can have a significant impact in mitigating the climate change in the next decades. Deployment of this technology has many benefits comparing to the usage of fossil fuels or even direct firing of biomass. The resource of biomass is highly distributed over the countries. Thus, it can be used not only in urban areas, but in rural as well. This could lead to distributed power generation, increase of energy efficiency and people employment.

The biomass gasification can become one of the main technologies to balance the energy system in the future. The availability of other renewable sources of energy, such as solar or wind, is limited and fluctuated during the day, month or year. Direct firing of biomass can be barely used in covering the variation of electricity or heat demand due to difficulty of changing the load. It is much easier to perform with gaseous fuel. As it is desired to cut off the use of fossil fuels until the middle of century, synthetic gas might be one of the best solution for balancing the energy systems of a country.

The synthetic natural gas could even replace natural gas in the existing power plants making the solution of biomass gasification much more attractive. The particular interest would be integrating biomass gasifiers in the cogeneration power plants, which is the most efficient way of heat and power production and is one of strategic elements of EU energy policies. The gasifiers can be integrated in the power plants or just used to deliver the produced gas directly to the gas grid. To sum up, the usage of syngas could provide a reliable grid quality electricity and heating, if CHP mode power plant is used, for meeting the energy demand.

The importance of cogeneration in future energy systems is significant. CHP helps the EU to achieve its energy and environmental objectives. Nowadays, 11% of electricity and 15% of heat needs are covered by cogeneration. Combining the generation of heat and power instead of producing it separately can reduce the primary energy needs by 25% [4].

From the environmental point of view, growth of CHP leads to reduction of greenhouse gas emissions and in particular CO<sub>2</sub>, as fuel is used more efficiently. Using biomass as a feedstock in CHP power plants would also increase energy independence of a country, which would then rely on their domestic renewable energy resources rather than using imported fossil fuels. The good example is Eastern European countries where huge amount of natural gas is imported from Russia.

The other application of using synthetic gas is co-firing it in power boilers. In this case, the main fuel would remain the same. It could be fossil fuel, like coal, oil or natural gas. Share of renewable gas could be freely chosen. Depending on the amount of biofuel used, the GHGs emissions would be reduced proportionally. However, seeking to increase the production of green electricity with integration of gasification technologies have several issues to be solved:

- Gasifier and fuel handling requires space in layout;
- The complexity of system increases, which leads to higher initial investment, maintenance and operational costs.

From the technological point of view, gasifier integration in an existing natural gas firing boiler has several advantages over direct firing of biomass. Firstly, the combustion process of synthetic gases can be operated much easier than direct firing of biomass. Furthermore, gaseous fuel is much cleaner because all the inorganic compounds are left in the gasifier and gas cleaning systems. If direct firing of biomass is installed in an old boiler that was design for firing gaseous fuel, clogging of heat exchangers in a flue gas shaft can occur. It leads to reduced efficiency of the power plant, higher maintenance costs and more shutdowns needed.

In conclusion, the biomass gasification can play a huge role in futures energy systems while replacing currently fossil fuel based power generation. It has advantages over fossil fuel or even direct firing of biomass technologies. However, cost reduction of biomass gasification systems and further research are needed to accelerate further deployment.

## 2.1 Current Status

In 2012, the installed CHP electrical capacity was 109 GW<sub>e</sub> in the European Union. The electrical and heat capacities in EU-28 countries can be seen in a Figure 2.1 below [4].

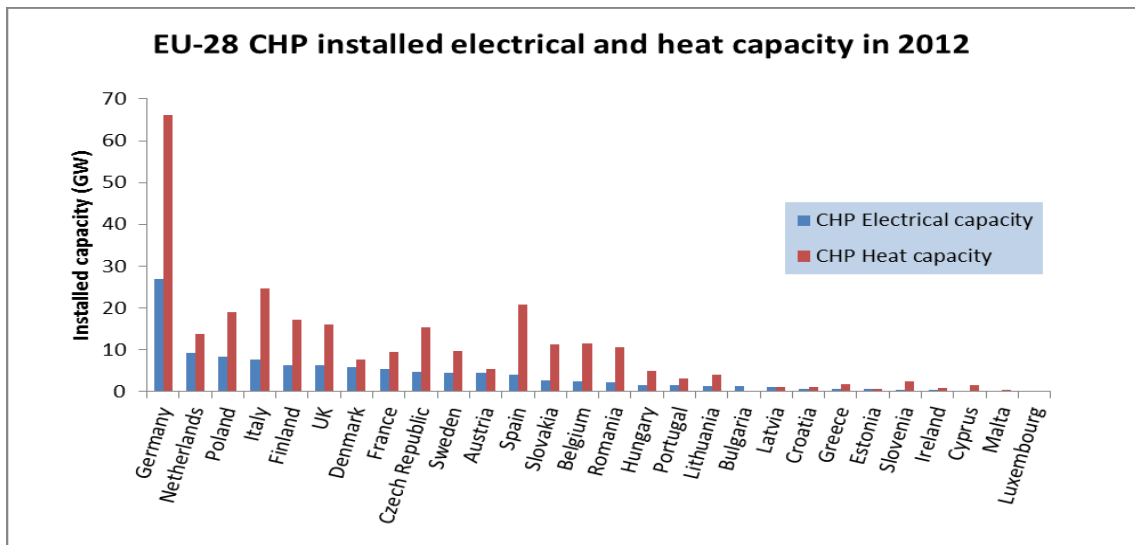


Figure 2.1. Electrical and heat capacities of CHP in EU-28

At the moment, the shares of feedstock used for CHP applications in Europe are:

- 48% of natural gas;
- 21% of solid fossil fuels;
- 16% of renewable fuels;
- 15% of others.

Renewable fuels still have a small part in the total fuel consumption. However, the situation is going to change in the future as bio-CHP and biomass gasification applications are developing faster. The integration of biomass gasifiers in existing CHP power plants can substitute the consumption of natural to synthetic gases. The good example of such application is Lahti Energy's Kymijärvi II power plant (Figure 2.2).

### ➤ *LAHTI ENERGY:*

It is a CHP power plant which has successfully integrated gasification of solid recovered fuel (SRF). The power plant produces 50 MW<sub>e</sub> of electricity and 90 MW<sub>th</sub> of heating. Electricity is provided to the grid while thermal energy is used in district heating network to cover the needs of Lahti and Hollola region.

The feedstock for gasification is energy containing waste that is not suitable for material recycling (i.e. unclean plastic, paper, cardboard and wood). Energy wastes are collected from industry, retail trade, construction sites or residential buildings [5].



Figure 2.2. Lahti Energy's power plant

The processes of Lahti's power plant start from the storage of feedstock. From there the fuel is transported by apron conveyor to the gasifiers. The gasification technology consists of two atmospheric pressure circulating fluidized bed (CFB) reactors. Each of them have a capacity of 80 MW<sub>th</sub> and fuel efficiency of 86.7%. The temperature of gasification process is kept between 850-900 °C.

After the gasifier, the product gas is cooled down to about 400 °C. At this temperature, materials that cause corrosion turns from gas to solid phase and can be removed. Gas cleaning is done by mechanical hot filtering. The heat taken from product gas in cooling process is transferred to the feedwater that goes to the boiler afterwards. Thus, it is not wasted.

Clean gases are provided to the steam boiler where combustion occurs. The boiler is started up by natural gas and after ignition fuel is changed to product gas, which is then used as primary fuel. Boiler produces superheated steam that goes directly to turbine. It is connected with a shaft to generator for electricity production. The remained heat is finally supplied to district heating network.

The Lahti's power plant is one of the best examples of gasification technology in the world and has a significant environmental impact. Thus, the success of Lahti's project can accelerate further development and deployment of gasification plants.

➤ *DONG ENERGY*

A low temperature circulating fluidized bed (LT-CFB) gasifier is a good example of biomass gasification as well. This type of gasifier is more suitable for low cost feedstock that contain higher share of alkali metals as the gasifier is operating below their melting points. The gasifier is designed for firing agricultural residues, energy crops, peat and certain waste fractions.



The Danish company DONG Energy is currently developing LT-CFB technology under product name “Pyroneer”. The demonstration gasifier of 6 MW was installed in existing coal boiler at Asnæs, Kalundborg in 2011. The concept is based on results from operation of 3 pilot plants (50 kW, 100 kW and 0,5 MW) [6].

The Pyroneer gasifier (Figure 2.3) typically consists of three main components: a pyrolysis chamber, a char reactor and a recirculating cyclone. Cleaning the gas may simply be done with a second cyclone.

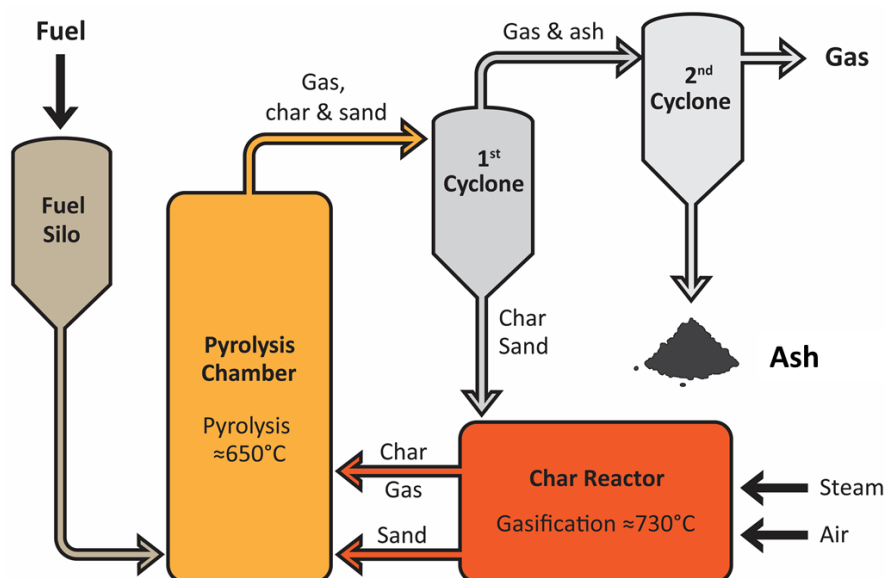


Figure 2.3. Process diagram of Pyroneer technology

Fuel enters the pyrolysis chamber, where the fuel particles are pyrolysed at approximately 650°C upon contact with sand and ash particles. The pyrolysis chamber is a Circulating Fluidized Bed gasifier. The low pyrolysis temperature and residence time results in the formation of only light tars.

The residual char and the pyrolysis gases are blown upwards to the primary cyclone. This cyclone separates the sand and char particles to a char reactor, where the char is gasified. The gases generated in the char reactor is recycled to the pyrolysis chamber. Some steam can be added in order to improve the conversion without increasing the temperature. Due to the low and stable temperature, limited ash melting takes place, and the use of additives to avoid bed agglomeration is not necessary.

The gases leaving the first cyclone continue to the 2nd cyclone. This cyclone is more efficient than the 1st cyclone and therefore most of the finest ash particles are separated out here. Ash particles may re-circulate several times until they are sufficiently small to escape through the primary cyclone. In this way, it is possible to retain 90-95% of the ash. The remaining dust may be removed by adding a hot-gas filter operating above the tar dew-point.

The char reactor is a bubbling bed reactor, where the char is gasified at approximately 730°C using mainly air.

Table 2.1. Features of the gasifier

<b>Feedstock*</b>	straw, manure fibres, local residues, sewage sludge
<b>Operating temperature</b>	around 650 °C
<b>Efficiency**</b>	~ 95%
<b>Capacity</b>	6 MW <sub>th</sub> / 1.5 tonne straw per hour
<b>Location</b>	ASV 2, Kalundborg
<b>Commissioning date</b>	Spring 2011

\* Max 30% moisture

\*\* LHV in the fuel that enters the boiler

Results of the operating tests of the demonstration plant [7]:

- ✓ 2850 operation hours with air blower incl. start-up and cold test;
- ✓ 2000 tons of straw gasified;
- ✓ 190 tons alternative fuels gasified (10t dry sludge).

Gas Characteristics:

- ✓ 650 °C hot syngas containing CO, CO<sub>2</sub>, H<sub>2</sub>, N<sub>2</sub>, CH<sub>4</sub>, H<sub>2</sub>O & Tars;
- ✓ LHV ~ 4.5 - 6 MJ/kg (depending on fuel);
- ✓ The raw gas contains both dust and tars;
- ✓ Carbon Conversion: 95%;
- ✓ Gas composition of straw gasification test:

Table 2.2. Gas composition of straw gasification test

H <sub>2</sub>	CO	CO <sub>2</sub>	N <sub>2</sub>	H <sub>2</sub> O	CH <sub>4</sub>	LHV
~ 6%	~ 11%	~ 13%	~ 34%	~ 29%	~ 7%	5.9 MJ/kg*

\* Tar compounds are an essential contributor to the LHV of 5.9 MJ/kg

Operation:

- ✓ Sand is used as bed material;
- ✓ No additives, agglomeration avoided due to low temperature;
- ✓ Fuel feed from 4.5 MW to 7.5 MW;
- ✓ Stable and safe operation;
- ✓ Highly automated;
- ✓ Start-up after trip to full load in less than 10 minutes;
- ✓ Partly automated start-up from cold in less than 24 hours;
- ✓ The gas is combusted in a separate burner.

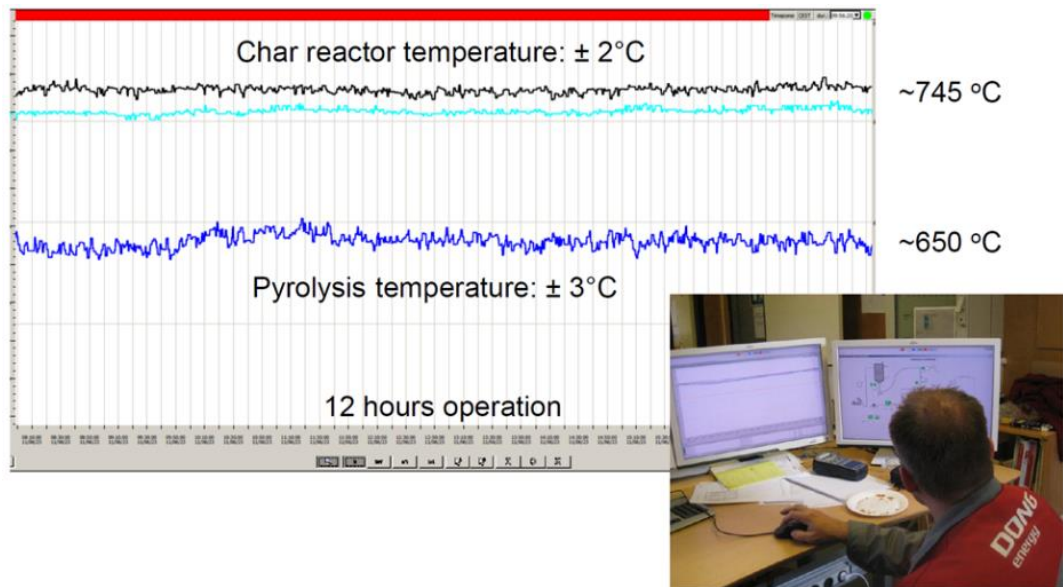


Figure 2.4. Temperature curves of straw gasification test

### 3 GASIFICATION

#### 3.1 Processes of biomass gasification

At first, the term of gasification needs to be defined. Gasification is a thermo-chemical process of converting solid fuels containing carbon, such as biomass or coal, to synthetic gases. The conversion occurs when feedstock is contacting with a lack of oxygen while heated to high temperatures at the same moment. The generated gases mainly consist of hydrogen ( $H_2$ ), carbon monoxide ( $CO$ ), methane ( $CH_4$ ) and some higher hydrocarbons as well as some unwanted compounds such as tar, dust, nitrogen ( $N_2$ ), water,  $NO_x$ ,  $SO_x$  and carbon dioxide ( $CO_2$ ) [8].

These outlet gases can go through some chemical reactions and create synthetic gases. The syngas can be used to produce power, heat, fuels for transport or can be delivered to the grid.

The whole conversion of biomass follows several main processes. These processes depend on type of gasifier but the general sequence is explained below:

➤ **Biomass pre-treatment and drying:**

The composition of biomass varies in a wide range during the year. In particular moisture and ash amount in a fuel. The energy processes in gasifiers are sensitive to the variations of these parameters. For that reason, the relevant quality of biomass has to be provided to gasifiers. It must contain specific amount of humidity (10-20% preferable), be in particular range of size, shape and density.

Drying is usually done in between 100-120 °C temperatures and requires a lot of energy to evaporate huge amount of water. This heat can be provided either from external sources or taken

from processes of a plant. Due to decrease of moisture in biomass, the efficiency of gasifier increases. However, drying costs increases quickly below 10% of humidity.

Sizing is also very important. When the particles of biomass become smaller, the surface area increases and gasification reactions happen faster. Thus chipping, cutting and chopping are used to diminish the size of particles.

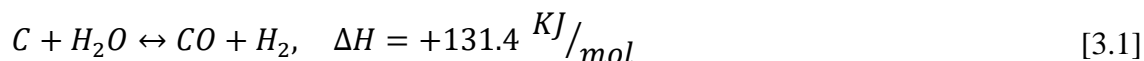
➤ Gasification:

After biomass is pre-treated, it is provided to the gasifier. Then starts the pyrolysis – a thermal degradation of biomass in the absence of oxygen. At first, the feedstock is heated and volatile compounds quickly vaporise. The biomass is divided to gases, vapour and char. This phase is called devolatilization. Some of volatile products are condensable and form liquid called tar. The volatile elements are mainly H<sub>2</sub>, CO, CO<sub>2</sub>, CH<sub>4</sub>, HC gases, tar and water vapour. The composition, quality and quantity of gaseous products, tar and dust depend on reactor geometry and the gasification agent used: air, steam or oxygen.

The pyrolysis process starts in the temperature of 200-250 °C. However, it may differ due to biomass composition. Remained solid char, which is full of carbon, also reacts with the particular gasification agent. However, the reaction between solid and gaseous compounds is much slower and it lowers the velocity of gasification process.

The main reactions that occur in a gasifier are presented below [9]:

- Steam gasification



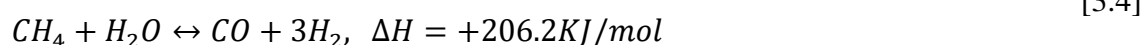
- Boudouard reaction



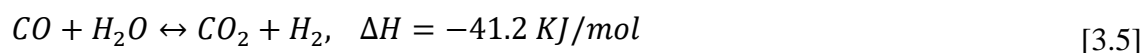
- Methanation reaction



- Steam reforming reaction



- Water gas shift reaction



- Carbon conversion



➤ Combustion:

Most of the gasification reactions require heat that can be supplied either by partial combustion in the reactor or by external sources. It is determined by gasifier technology. However, partial combustion is more usual way of providing heat, when part of the feedstock is burned inside the gasifier with a controlled amount of air or oxygen. If external sources are used, heat can be supplied by superheated steam, heated bed materials or by separate combustion of some chars or gases.

➤ Gas cleaning:

The outlet gas of gasifier have lots of undesirable particles and impurities that must be cleaned as they can be harmful to further equipment. Those solid components can be removed by cyclones and hot gas filters and returned back to the combustion chamber. It is important to keep the temperature above the tar dew point that tar would not condense. Tars are separated in the tar removal system and can be returned to the gasifier in order to transform it to gaseous components.

Alkali metals are common in the biomass feedstock. These metals are especially harmful because they can cause surface corrosion or erosion of turbine blades. Thus, there are several techniques to remove them, such as absorption or leaching.

The other components that have to be eliminated in order to produce bio-SNG are carbon dioxide and hydrogen sulphide. It can be done by absorption, diffusion or chemical conversion.

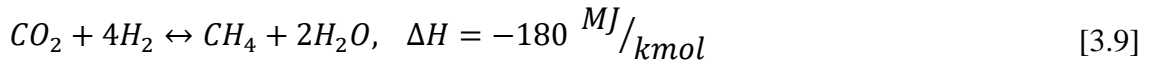
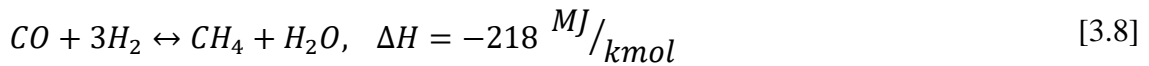
When product gases leave the gasifier, it has high temperature (about 600-800 °C) and enthalpy. If it is not recovered before gas cleaning processes, the thermal energy turns into losses. For that reason, a heat exchanger is usually installed in between of gasifier and gas cleaning systems. The heat is used for steam generation to run the processes or generate electricity. It is important to cool down the product gases until particular temperature, as below that temperature the tar can start to condense.

➤ Methanation:

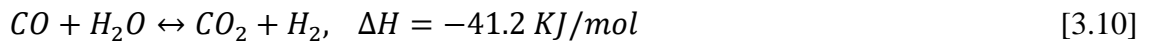
The next process after gas cleaning is methanation. Generally, it means that methane is produced through various chemical reactions from carbon monoxide, carbon dioxide, hydrogen and higher hydrocarbons. The reactor is pressurised to 5-60 bar in the temperature below 400 °C and sulphur-sensitive nickel-alumina catalysts are used most often.

There are four core reactions occurring in the methanation process:

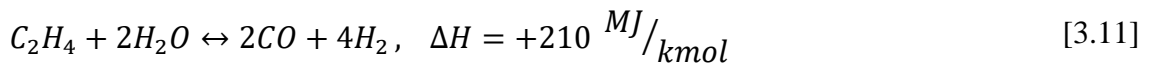
- Reverse reforming reactions:



- Water-gas shift reaction:



- Steam reforming reaction:



### ➤ Gas upgrading

The last step before providing synthetic gases to the grid is gas upgrading. There are two issues that needs to be finally solved:

- The pressure of synthetic natural gas has to be adjusted to the pressure of gas grid;
- The concentration of bio-SNG has to be adapted to the concentration of natural gas.

## 3.2 Gasifier Classification

Various types of gasifiers have been developed already. They are classified depending on several operating factors and layout differences. The main criteria of separation are presented below:

- Biomass feeding. It can be provided to the reactor from different directions, such as top, side or bottom, and moved inside either by gravity or air flows.
- Gasification agent. As oxidant for thermochemical processes are used: air, steam or oxygen. Using pure oxygen might be too expensive but produced gases would have much higher heating value compared to air-blown gasifiers (air 3-6 MJ/m<sup>3</sup>, oxygen 10-12 MJ/m<sup>3</sup>). Steam is usually used when desired product is syngas. The combinations, like oxygen rich air, can be blown to gasifiers as well.
- Heating source. Heat can be provided either by partial combustion of feedstock, called direct heating, or by using external sources of heat or second combustion chamber (indirect heating). Heat is transferred by inert product, like sand, in case of indirect gasifiers.
- Operating pressure. The pressure in gasifier can be atmospheric or elevated.
- Contact of solid and gas. Depending on it, gasifiers are classified to entrained bed, fluidized bed (circulating and bubbling), spouted bed, fixed or moving bed, and dual fluidized bed gasifiers. Solid fuel is filled to the gasifiers with possible additional usage of inert solid, such as

sand. The difference between various phases of bed material in contact with gases can be seen in a Figure 3.1 below.

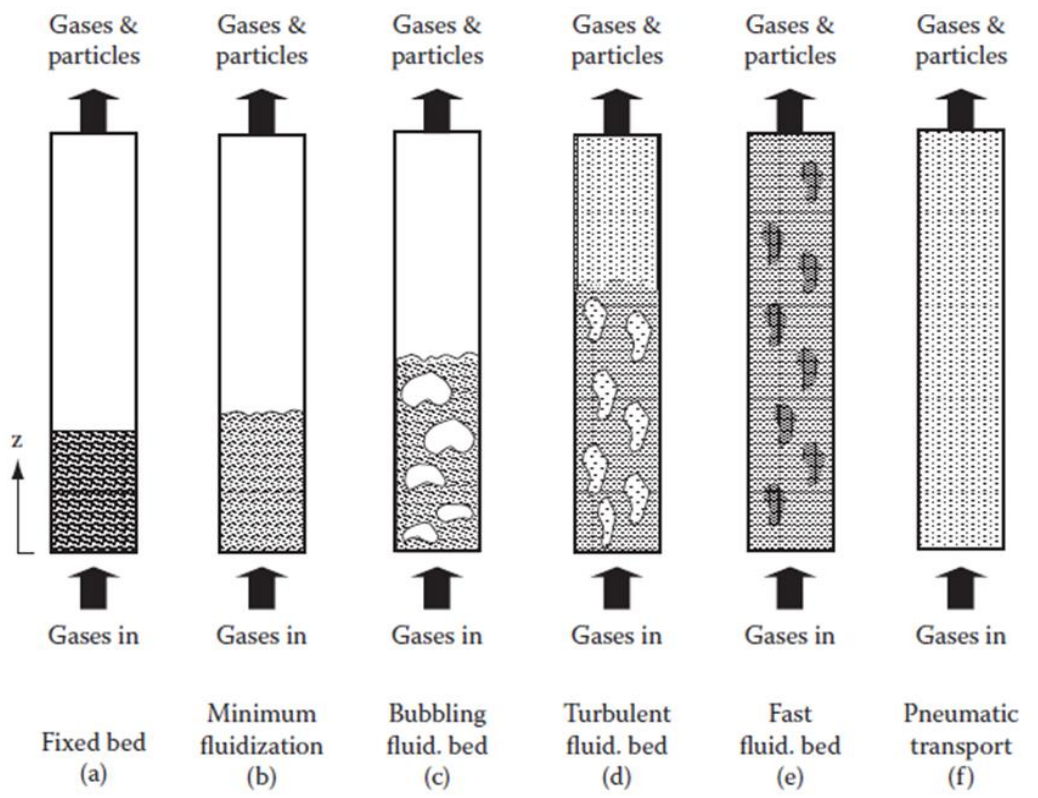


Figure 3.1. Difference of particle beds

If the gas velocity entering the reactor does not overcome gravity force of solid particles, the feedstock remains fixed. Fixed bed gasifiers are usually called moving bed due to movement of particles without the expansion of bed. When inlet gas speed is increased until minimum fluidization phase, the particles start to detach from each other and from then fluidized bed state is reached. The further increase of velocity leads to expansion of bed and beginning of bubbling.

If the increase of gas velocity continues, turbulent and further on fast fluidized bed become apparent. The turbulent state can be noticed when particles are crossing the bubbles, while fast fluidization makes bubbles and bed surface difficult to recognize. The last phase is called pneumatic transport, in which gas moves even faster than solid particles.

Most common classification is presented in Table 3.1 below [10].

Table 3.1. Main gasifier classification

Gasifier Type	Flow Direction		Support	Heat Source
	Fuel	Oxidant		
Updraft Fixed Bed	Down	Up	Grate	Combustion of Char
Downdraft Fixed Bed	Down	Down	Grate	Partial Combustion of Volatiles
Bubbling Fluidized Bed	Up	Up	None	Partial Combustion of Volatiles and Char
Circulating Fluidized Bed	Up	Up	None	Partial Combustion of Volatiles and Char

### 3.3 Types of Gasifiers

In this chapter main types of gasifiers, that are currently developed, will be presented. The special attention will be paid for general operating principles, applications, benefits and drawbacks comparing particular gasification technology with the rest of gasifiers available.

#### ➤ Fixed bed gasifiers

Fixed bed gasifiers are separated to two types depending on the flow direction of feedstock and gasification agent:

- Updraft (Figure 3.2, a))

In this technology, the gasification agent is introduced in the bottom of the reactor and feedstock is fed in the top. They both move to opposite directions. The heat for reactions to occur is provided by combustion of char that falls to the grate after gasification. Produced gases are released at the top while ashes are collected under the grate.

This technology is simple and can work with high moisture containing fuels. Also, feedstock with high inorganic content can be fed, such as municipal wastes. However, the main drawback is high share of tar in the syngas (10-20% by weight) requiring better cleaning before further applications.

- Downdraft (Figure 3.2, b))

In this case, the gasification agent is fed in the middle of reactor and the feedstock at the top. Unlike in updraft system, this time both gasification agent and biomass move to the same direction. The major difference between those types is that downdraft gasifier can combust nearly all of the tar formed, resulting in a low tar content in the syngas. This is done by burning some of the biomass which forms bed of hot charcoal. When gases go through that zone, quality of syngas increases. The produced gases leave the gasifier at the bottom and the ash falls down under the grate. The downdraft technology is simple as well. However, it needs more drying of feedstock (<20% moisture).

Fixed bed gasifiers are mainly used for low capacities (less than 100 kW<sub>th</sub>) and a few higher than 10 MW<sub>th</sub>.

#### ➤ Fluidized bed gasifiers

The fluidized bed gasifiers are more flexible in handling variation of fuels, they also can convert feedstock to syngas in higher efficiency and produce cleaner gases with less tar content. The main characteristic of this type gasifiers is that all gasification reactions in particular zones occur at the same time, the flow is better mixed and more homogenous. Fluidized bed gasification



technology is mainly suitable for large scale applications. There are two groups of fluidized beds: circulating and bubbling.

- Bubbling Fluidized Bed (BFB) gasifier (Figure 3.2, c))

For this type of gasifiers, a bubbling bed of fine inert material, like sand, is used. The gasification agent is introduced at the bottom of reactor and forms a boiling state inside. Biomass is fed from the side. It is broken by inert material, mixed and burned to produce the syngas. Inert material also ensures good heat transfer between fuel and gas. Producer gas leaves the gasifier at the top of reactor and enters the cyclone to remove solid particles.

BFB gasifiers can handle wide range of particles size, produces low tar syngas and converts carbon in very high rates. It operates below 900 °C to avoid ash melting and sticking. The reactors can be pressurised to increase the conversion capacity.

- Circulating Fluidized Bed (CFB) gasifier (Figure 3.2, d))

Generally, it is modified BFB gasifier. In this case, the gasification agent is blown faster. Thus, there are more solid particles in producer gases, which are removed in cyclones and introduced again at the bottom of gasifier. Biomass is fed from the side and follows the same reactions as described before.

This gasification technology is suitable for fast reactions. It has high conversion rates and results in synthetic gases containing low tar. However, heat exchange is not so efficient comparing to bubbling fluidized bed gasifiers.

- Entrained flow gasifier (Figure 3.3)

The entrained flow gasifiers are capable to produce very high quality syngas with low share of tar and high heating value. However, the pre-treatment step is much more complicated. Biomass must be fed to the gasifier in very fine particles. Powdered fuel is blown together with pressurized gasification agent (oxygen and/or steam) at the top of reactor. Some of biomass is rapidly burned in turbulent flame supplying huge amount of heat for further gasification reactions. The temperatures of 1200-1500 °C can be reached that allows a formation of slag. It causes further problems because slag can block the bed or heat exchanger and must be regularly removed to avoid it.

Fixed and fluidized beds gasifiers that were already described are presented in the Figure 3.2 below [11]:

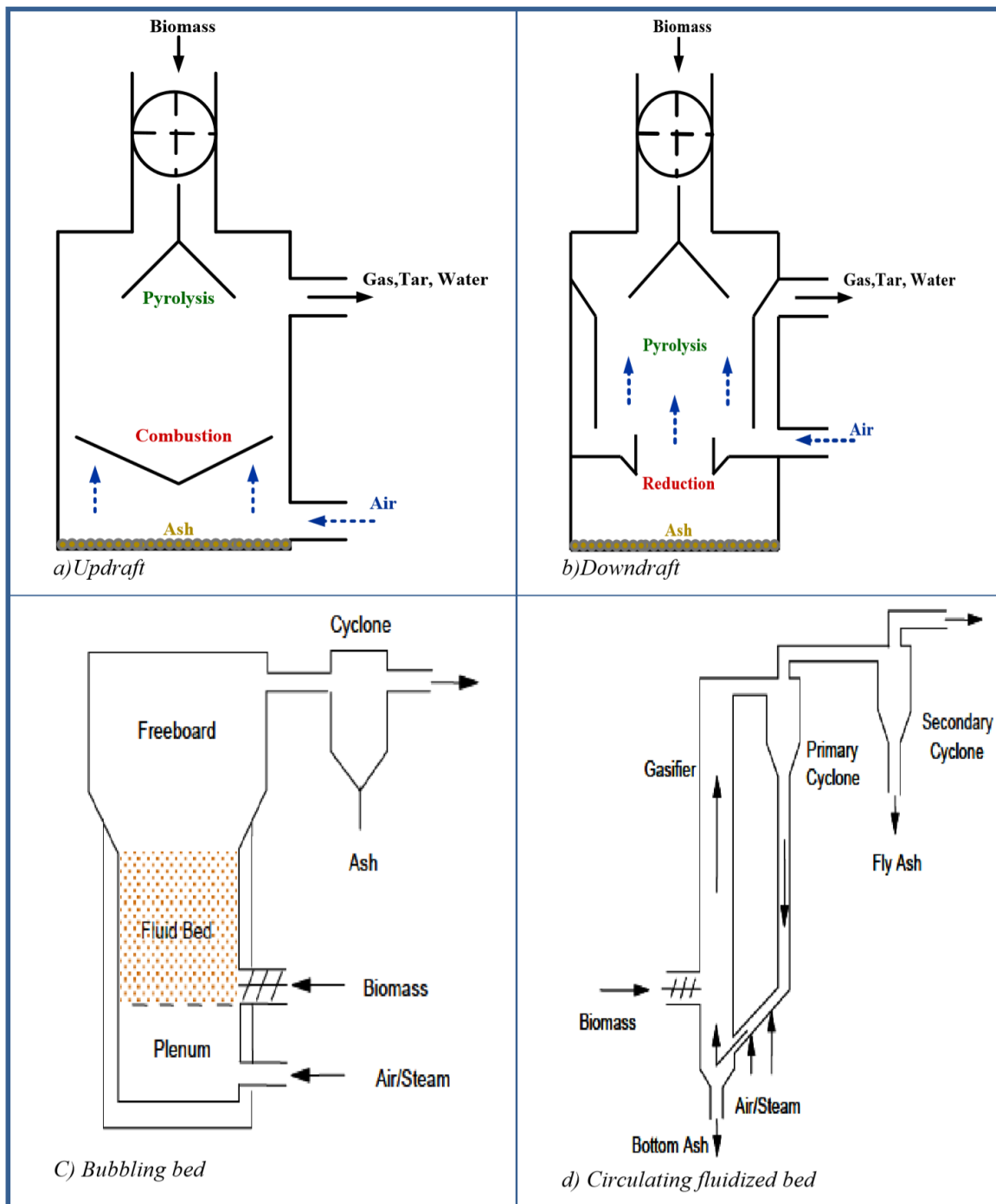


Figure 3.2. Gasifier types

Entrained flow gasifier is shown in Figure 3.3:

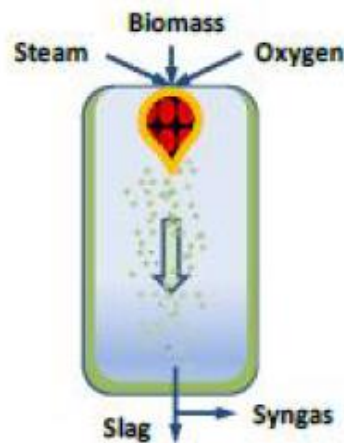


Figure 3.3. Entrained flow gasifier

➤ Dual fluidized bed gasifier (Figure 3.4, Figure 3.5)

The general principle of this technology is that gasification and combustion processes are separated. This solution leads to production of nearly nitrogen free gases.

The facility consists of two chambers. The main one is usually BFB or CFB gasifier and the other is combustion chamber.

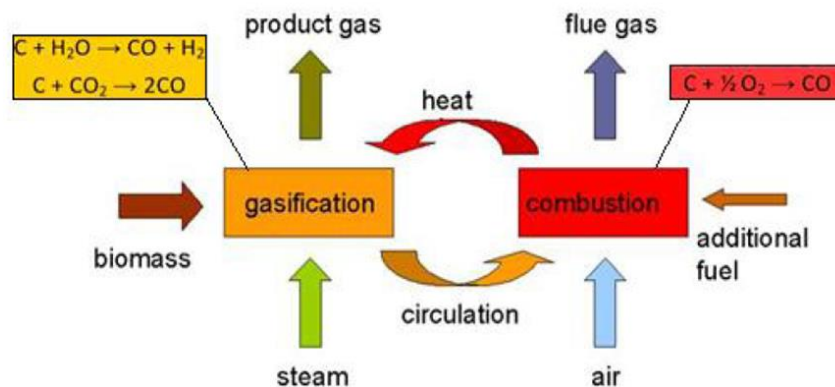


Figure 3.4. Principle scheme of dual fluidized bed gasification technology

At first biomass is fed to the gasifier and steam is blown inside to begin the gasification process. The producer gases rise and leave the reactor. It then goes to cyclone where solid particles are removed and taken back to fluidized bed. Char that was not fully converted to gases goes together with bed material to the combustion chamber. Additional fuel and air is introduced to it as well.

Combustion chamber works as an external heating source for gasification processes. The temperature at combustor is around 900 °C. Bed material, like sand, is used to transfer heat from combustor to gasifier. All the combustion products (both gas and solid) goes through the cyclone, flue gas is separated from solid particles, which are fed at the top of gasifier. The mission of those

particles is to bring the heat for endothermic reactions to happen. There is an intermediate loop between combustor and gasifier. Its function is to prevent mixing of flue and product gases.

Some commercial dual fluidized bed gasifiers are already developed, such as: the FICFB by Vienna University of Technology; SilvaGas by Batelle (USA) and the MILENA from ECN [12].

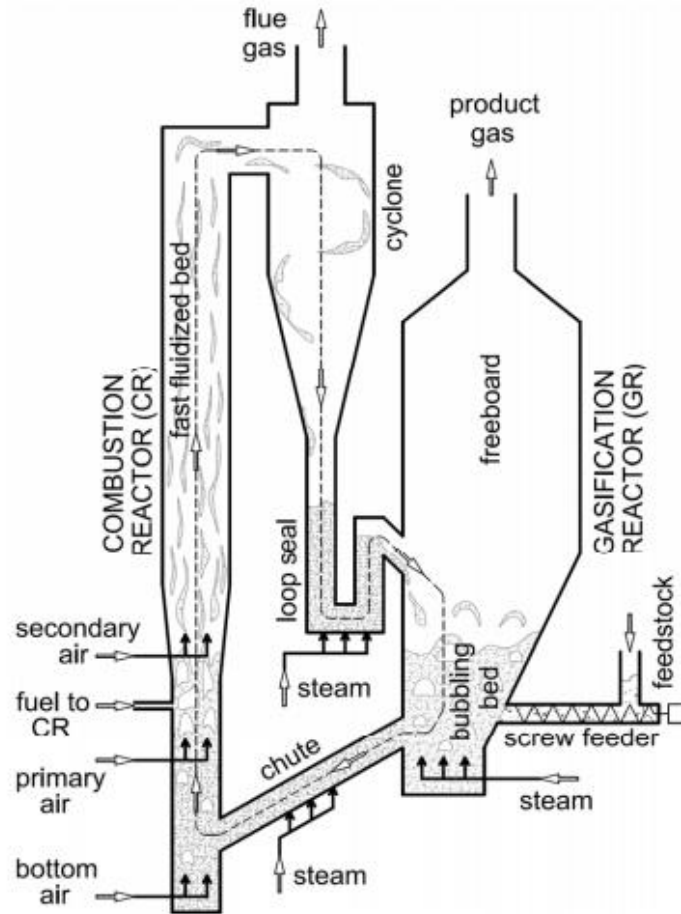


Figure 3.5. Dual fluidized bed gasifier

#### 4 COMPARISON OF QUALITY AND QUANTITY PARAMETERS OF NATURAL GAS AND SYNGAS

It is very important to identify what is the quality of synthetic gases, as it will further determine proper applications for biomass gasification. If we want to use syngas directly in gas engines or turbines for CHP generation, we need to know how it may affect the equipment of power plant and especially what changes are needed in the burner for its utilization. Thus, the chemical composition, heating value and other parameters of syngas must be compared with the values of natural gas.

Typical volumetric analysis is shown in Table 4.1 that demonstrates a great difference between NG and syngas compositions. The natural gas mainly consists of methane, when wood produce gas just have up to 5% of CH<sub>4</sub>.

Table 4.1. Typical volumetric analysis of NG and wood producer gas [13]

Species	Natural gas	Wood producer gas
CO	-	18-25%
H <sub>2</sub>	-	13-15%
CH <sub>4</sub>	80-95%	1-5%
C <sub>2</sub> H <sub>6</sub>	<6%	Trace
> C <sub>2</sub> H <sub>6</sub> <sup>a</sup>	<4%	Trace
CO <sub>2</sub>	<5%	5-10%
N <sub>2</sub>	<5%	45-54%
H <sub>2</sub> O	-	5-15%

<sup>a</sup> contains hydrocarbons heavier than C<sub>2</sub>H<sub>6</sub>

Table 4.2 shows the comparison of higher (HHV) and lower (LHV) heating values of NG and wood producer gas.

Table 4.2. HHV and LHV of natural gas and wood producer gas

Fuel	HHV		LHV	
	(MJ/m <sup>3</sup> ) <sup>a</sup>	MJ/kg	(MJ/m <sup>3</sup> ) <sup>a</sup>	MJ/m <sup>3</sup>
NG	38.3	53.5	34.6	48.3
Wood producer gas	4.8	5.1	4.0	4.2

<sup>a</sup> at 1 atm, 25 °C

The chemical composition and heating value of syngas can vary due to gasification media chosen for gasification. It can be air, oxygen or steam. The compositions and LHV depending on gasifying agent are shown in Table 4.3 below.

Table 4.3. Composition and LHV of product gas for different gasifying media

Gasifying agent	Air	Oxygen	Steam
H <sub>2</sub> [%-vol, dry]	11-16	23-28	35-40
CO [%-vol, dry]	13-18	45-55	22-25
CO <sub>2</sub> [%-vol, dry]	12-16	10-15	20-25
CH <sub>4</sub> [%-vol, dry]	2-6	<1	9-11
N <sub>2</sub> [%-vol, dry]	45-60	<5	<1
LHV [MJ/Nm <sup>3</sup> ]	4-6	10-12	12-14

We can see from the Table 4.3 that LHV of syngas is more than 2 times lower when air is used as gasifying media. It is mainly because of nitrogen that is worthless ballast of a fuel. Although using oxygen would let to obtain much higher LHV, this process leads to higher costs.

Having in mind all the difference of NG and syngas, the substitution towards sustainable gaseous fuel is desirable for the burner. To use a new gaseous fuel, the burner should be adjusted to maintain the same heat rate, flame stability and shape. If the substitute fuel is similar, as using propane instead of methane, it may be quite easy to adjust the airflow to achieve appropriate equivalence ratio.

However, if the gas composition is much different, the fuel flow rates have to be adjusted by changing the fuel pressure or orifice size to keep the same heat rate. The heat rate  $q$  equals the volumetric flow rate of the fuel times the heating value of the fuel per unit volume (eq. 4.1) [13].

$$q = \dot{V} \cdot (HHV); \quad [4.1]$$

The volumetric flow rate is calculated by eq. 4.2:

$$\dot{V}_f = \sqrt{\frac{2 \cdot \Delta p}{\rho_f}} A_f; \quad [4.2]$$

where:

$\Delta p$  is the pressure drop across the fuel orifice;

$A_f$  is the effective area of the fuel orifice;

$\rho_f$  is the density of the fuel.

For a fixed orifice size, fuel pressure and temperature, the heat rate is given by eq. 4.3:

$$q = K \cdot \frac{HHV}{\sqrt{sg_f}} = K(WI); \quad [4.3]$$

where:

$K$  is the system constant;

$WI$  is the Wobbe Index, which is a measure of interchangeability of fuels.

Wobbe Index is calculated (eq. 4.4):

$$WI = \frac{HHV}{\sqrt{sg_f}}; \quad [4.4]$$

Wobbe index is the main indicator of the interchangeability of fuel gases such as natural gas or SNG. If  $WI$  of substitute fuel is significantly different from the design fuel, the burner must be modified. In this case the flame length, flashback and blow-off characteristics should be considered as well.

Let's compare the Wobbe index for syngas from straw gasification to the index for NG and estimate the interchangeability of these fuels (eq. 4.5).

$$\frac{WI_{producer}}{WI_{natural}} = \left( \frac{HHV}{\sqrt{\rho}} \right)_{producer} \cdot \left( \frac{\sqrt{\rho}}{HHV} \right)_{natural} = \frac{HHV_{producer}}{HHV_{natural}} \cdot \sqrt{\frac{\rho_{natural}}{\rho_{producer}}}; \quad [4.5]$$

The volumetric higher heating values of synthetic gas from straw gasification and natural gas are 7.1 MJ/m<sup>3</sup> and 38.3 MJ/m<sup>3</sup>, respectively.

The ratio of the specific gravities is proportional to the ratios of the density of the gases and then the ratio is proportional to the molecular weight as follows (eq. 4.6):

$$\frac{\sqrt{Sg_{natural}}}{\sqrt{Sg_{producer}}} = \frac{\sqrt{\rho_{natural}}}{\sqrt{\rho_{producer}}} = \sqrt{\frac{[pM]_{natural}}{[pM]_{producer}}} = \sqrt{\frac{M_{natural}}{M_{producer}}}; \quad [4.6]$$

The molecular weight of synthetic gas from straw gasification is 24.8 and the molecular weight for NG is about 17. Then we can calculate WI ratio by eq. 4.7:

$$\frac{WI_{sg (straw)}}{WI_{natural}} = \frac{HHV_{sg (straw)}}{HHV_{natural}} \cdot \sqrt{\frac{M_{natural}}{M_{sg (straw)}}} = \frac{7.1}{33.9} \cdot \sqrt{\frac{17}{24.8}} = 0.17; \quad [4.7]$$

The Wobbe Index of producer gas is approximately 6 times lower than the value of natural gas. It means that the flow rate of fuel must be greatly increased to maintain the same heat output and the burner has to be modified to assure stability. For that reason, the valves and orifices of the burner must be extended.

The combustion of low heating value gases may have many technical difficulties associated with ignition and stability due to the fluctuating composition and high inert content. The other way of syngas utilization is to mix the syngas with natural gas. Share of renewable gases could be freely chosen according to the gas composition and burner flexibility of firing lower heating value gases.

Furthermore, it is necessary to assure that no mechanical impurities enter the burner and the producer gas have low content of lighter HCs and H<sub>2</sub>S that are produced during gasification. Thus, gas cleaning systems are needed before using syngas in the burners. The gas clean-up stage has a variety of available methods and is one of the most important and costly steps which decides the final application of the producer gases.

At last, the feedstock for biomass gasification must be responsibly selected as it greatly impacts the quality and quantity of producer gases.

## 5 POTENTIAL FEEDSTOCK FOR BIOMASS GASIFICATION IN LITHUANIA

Wide range of different biomass feedstock is available in Lithuania. This is generally a real advantage, because it means that the best and economically attractive fuel for biomass gasification can be selected.

Biomass resources mainly include:

- wood and waste wood (bark, sawdust, wood chips, wood scrap);
- agricultural crops and their waste by-products (wheat, straw);
- solid recovered fuel (SRF);
- residues from agro-industrial and food processes;
- peat.

Furthermore, the large number of possible combinations of above mentioned fuels can be selected (i.e. different fuel mixes with wood and bark, wood chips based on SRF, forest residues in combination with peat and so on).

One of the most available biomass is wood. However, it is a valuable material due to its current applications and for that reason is not considered as a potential feedstock for gasification. Wood residues (misshapen pieces, bark, sawdust), however, have very little market value and are prime candidates to be used.

The analysis of feedstock recently used for biomass gasification in various power plants all over the world is shown in Table 5.1 below.

Table 5.1. Comparison of feedstocks used in existing biomass gasification based power plants

Power Plant	Feedstock	Key insights
Lahti Energia	Solid recovered fuel (SRF)	250 000 tonnes annually
Vaskiluodon Voima Oy	Forest chips and sawmill by-products 90% (50-100%), Agrobiomass 0-5%, Peat 0-50%.	900 GWh fuel required annually
Rüdersdorfer Zement	Waste wood, waste, plastics, RDF	500 tonnes daily
Essent, Amer 9	Waste wood, demolition wood, contaminated waste wood	90 000 tonnes annually
Electrabel, Ruien	Wood chips from recycled fresh wood, bark, hard and soft board residues and coal	-
Metsä Fibre Joutseno Pulp Mill	Local bark, side product of the mill	-
Södra Cell Våro Pulp Mill	Bark, by-product from pulp production	-
Agnion Technologies	Waste wood	80 000 tonnes annually
Skive Fjernvarme CHP	Local wood pellets	40 000 tonnes annually



These biomass feedstocks greatly differ in chemical composition, energy, ash and moisture content. Therefore, let's analyse what influence on the gasification system these biomass properties have. Key insights of the analysis are shown in Table 5.2.

Table 5.2. Influence of biomass properties on gasification system [14]

Biomass properties		Impact on gasification system
Physical	High moisture content	<ul style="list-style-type: none"> <li>• Decrease in heating value of fuel;</li> <li>• Storage durability;</li> <li>• Fuel transportation costs;</li> <li>• Lower process temperature;</li> <li>• Reduction in producer gas quality, gasification efficiency and fuel conversion;</li> <li>• Optimal moisture content for gasification 10-15%</li> </ul>
	Low apparent density	<ul style="list-style-type: none"> <li>• Energy density → transportation, storage and handling costs;</li> <li>• Feeding system.</li> </ul>
	Porosity	<ul style="list-style-type: none"> <li>• Reactivity of fuel</li> </ul>
Thermochemical	Cellulose, hemicellulose, and lignin content	<ul style="list-style-type: none"> <li>• Reactivity of fuel.</li> </ul>
	C, H, O content	<ul style="list-style-type: none"> <li>• Heating value of fuel.</li> </ul>
	N content	<ul style="list-style-type: none"> <li>• Mainly transformed to NH<sub>3</sub> and HCN. → design of gas cleaning section;</li> <li>• Emissions.</li> </ul>
	S content	<ul style="list-style-type: none"> <li>• Mainly transformed into H<sub>2</sub>S and COS. → design of gas cleaning section;</li> <li>• Interaction with alkali metals: emissions, deposits, corrosion.</li> </ul>
	Cl content	<ul style="list-style-type: none"> <li>• Decrease of softening temperature of ash;</li> <li>• Emissions, corrosion and ash sintering.</li> </ul>
	High volatile content, low fixed carbon content	<ul style="list-style-type: none"> <li>• Reactivity of fuel.</li> </ul>
	Ash content	<ul style="list-style-type: none"> <li>• Decrease of fuel heating value;</li> <li>• Energy density → transportation costs;</li> <li>• Emissions;</li> <li>• Ash disposal costs.</li> </ul>

Peat is a desirable feedstock for biomass gasification. It is highly available and lower cost fuel comparing to wood or forest residues. However, it has higher amount of nitrogen and sulphur in composition. Therefore, the gasification of peat leads to higher amounts of undesirable NH<sub>3</sub>, HCN, H<sub>2</sub>S and COS in producer gases. These contaminants in syngas pose numerous technical and working problems. For example, H<sub>2</sub>S is responsible for equipment corrosion.

Forest biomass is good for gasification because of high cellulose, hemicellulose, and lignin content. These components play a significant role during thermochemical conversion process. The proportion of cellulose and hemicellulose are directly related to the volume of gaseous products while the lignin content determines the oil in the product. Therefore, the higher the ratio of cellulose and hemicellulose to lignin in biomass, the higher the gaseous product yields from gasifying it [15].

Straw is an attractive fuel for biomass gasification due to lower cost. However, it possesses high content of alkali metals and some technical issues must be solved. Alkali metal and chlorine species can cause fouling, slagging, and corrosion. Therefore, the gasification temperature must be kept below 650 °C due to possible melting of these inorganics.

Danish company “DONG Energy” proved that straw gasification is technologically possible in low temperature CFB gasifier. Therefore, straw will be used as a feedstock for calculations of synthetic gas production and further use in an existing CHP power plant. However, a gasifier is capable to operate with multiple fuels and the feedstock can be substituted to another if needed.

## **6 CASE STUDY: VILNIUS CHP-2 POWER PLANT**

Vilnius CHP-2 Power Plant is selected for further analysis. It has 3 Russian-made BKZ-75-39 boilers firing natural gas. However, they cannot compete in energy markets due to high price of fuel. Conversion for firing biofuels in these old gas boilers and production of renewable energy is desirable.

One boiler of this type was already converted to firing forest residues, peat and straw. The boiler was reconstructed to biomass firing BFB boiler. Fuel feeding system, electrostatic filter and some other equipment were added or changed. However, it is not a successful project as the power plant faces many technical problems and, therefore, shutdowns are needed too often.

The other option to produce renewable energy in these boilers is using syngas produced by biomass gasification. Therefore, the feasibility study of biomass gasification use in BKZ-75-39 boilers will be done.

### **6.1 BKZ-75-39 boiler**

It is a natural circulation boiler (Figure 6.1) that has a steam drum and vertical steam-water tubes. The saturated steam exits the steam drum and goes to superheater that is placed in horizontal shaft of flue gas. The superheated steam is further used in a steam turbine. The rotating movement is converted into electricity with a generator connected to the shaft. The residual steam leaving the turbine still contains a lot of energy, which is conducted to the district heating network through district heat exchangers.

Economiser and air heater units take place after superheater in vertical part of the boiler and recover lower temperature heat from flue gas to feedwater and air, respectively.

The main boiler parameters are shown in Table 6.1 below:

Table 6.1. The main parameters of a BKZ-75-39 boiler [16]

Parameter	Unit	Value
Boiler capacity range	t/h	35÷75
Nominal fuel power	MW	60
Steam pressure	bar	40
Steam temperature	°C	450
Thermal tension	kW/m <sup>3</sup>	132

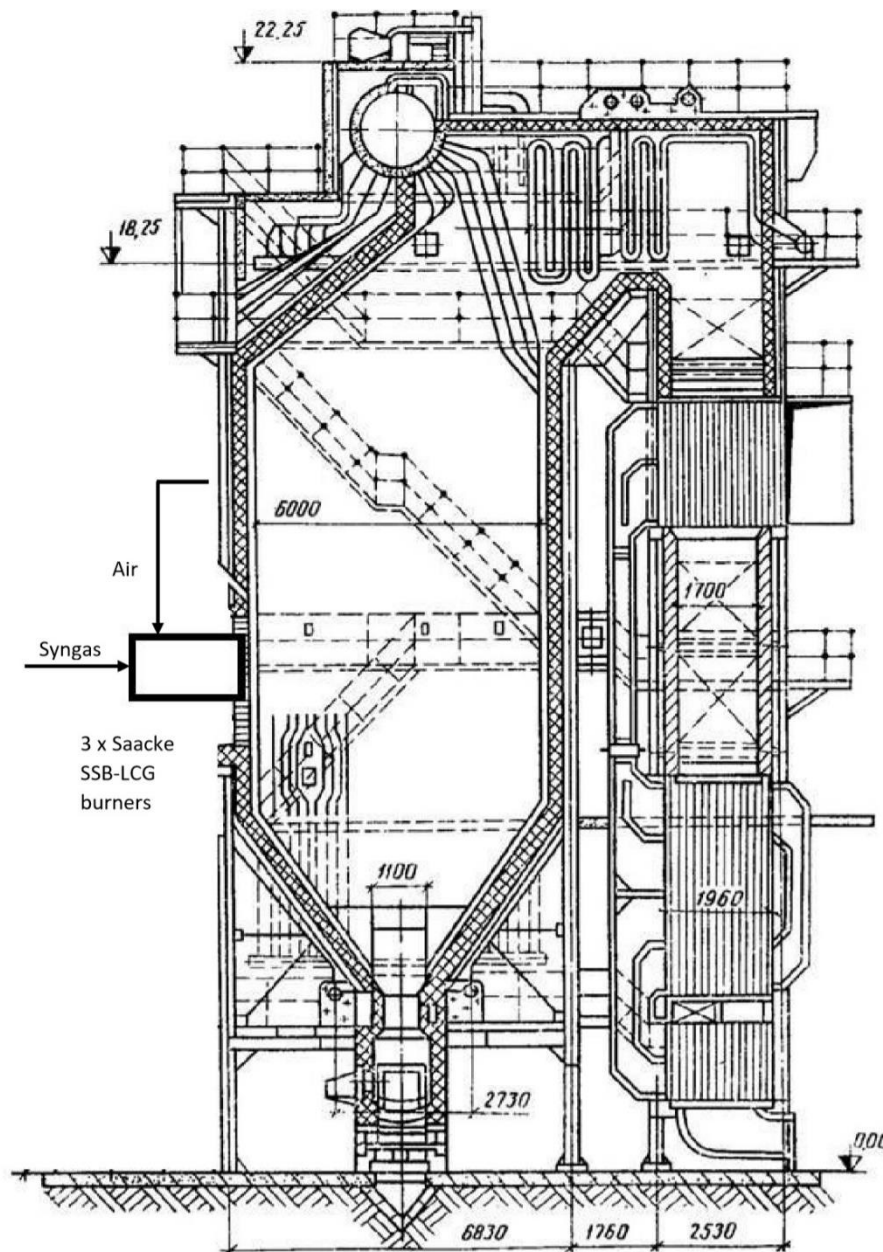


Figure 6.1. BKZ-75-39 boiler

The aim is to substitute natural gas to syngas for renewable energy production. It is known that syngas has lower LHV and for that reason bigger flow of fuel must be produced to the combustion chamber to maintain the same boiler power. The quantity of air needed to combust syngas and quantity of flue gases will be different from quantities of natural gas combustion. Therefore, calculations of these parameters must be done in order to know if its technically possible to use the same blowers, exhaust gas fan and boiler itself for substitute gas.

The synthetic gas composition for further calculations will be taken from the test results of straw gasification done by DONG Energy [3.1]. The composition of dry and wet syngas as well as composition of natural gas are presented in Table 6.2 below.

Table 6.2. Syngas and natural gas compositions.

Component	Wet syngas composition	Dry syngas composition	Natural gas composition
CO	11 %	15.5 %	-
H <sub>2</sub>	6 %	8.5 %	-
CH <sub>4</sub>	7 %	9.9 %	88 %
CO <sub>2</sub>	13 %	18.3 %	0.3 %
N <sub>2</sub>	34 %	47.9 %	9.3 %
C <sub>2</sub> H <sub>6</sub>	-	-	1.9 %
C <sub>3</sub> H <sub>8</sub>	-	-	0.2 %
C <sub>4</sub> H <sub>10</sub>	-	-	0.3 %
H <sub>2</sub> O	29 %	-	-

The theoretical oxygen quantity that is needed to combust 1 m<sup>3</sup> of syngas is calculated by eq. 6.1:

$$V_{O_2} = 0.5 \cdot \frac{CO^s}{100} + 0.5 \cdot \frac{H_2^s}{100} + \sum \left( m + \frac{n}{4} \right) \cdot \frac{C_m H_n^s}{100} - \frac{O_2^s}{100}; \quad [6.1]$$

where:

CO<sup>s</sup>, H<sub>2</sub><sup>s</sup>, C<sub>m</sub>H<sub>n</sub><sup>s</sup>, O<sub>2</sub><sup>s</sup> - % of carbon oxide, hydrogen, particular hydrocarbon and oxygen in unit volume of dry gases.

$$V_{O_2} = 0.5 \cdot \frac{15.5}{100} + 0.5 \cdot \frac{8.5}{100} + \left( 1 + \frac{4}{4} \right) \cdot \frac{9.9}{100} - \frac{0}{100} = 0.317 \text{ m}^3/\text{m}^3;$$

Then theoretical quantity of air ( $V_{Tair}$ ) needed for combustion will be (eq. 6.2):

$$V_{Tair} = \frac{V_{O_2}}{0.21}; \quad [6.2]$$

0.21 means the fraction of oxygen in the air.

$$V_{Tair} = \frac{0.317}{0.21} = 1.509 \text{ m}^3/\text{m}^3;$$

In practice, more air is needed for complete combustion. Thus, 10% of excess air will be used (eq. 6.3).

$$V_{air} = V_{Tair} \cdot \alpha; \quad [6.3]$$

where:

$\alpha$  – coefficient of excess air ( $\alpha = 1.1$ ).

$$V_{air} = 1.509 \cdot 1.1 = 1.66 \text{ m}^3/\text{m}^3;$$

Volume of flue gases ( $V_{fg}$ ) is calculated by eq. 6.4:

$$V_{fg} = V_{RO_2} + V_{N_2} + (\alpha - 1) \cdot V_{Tair} + V_{H_2O}; \quad [6.4]$$

where:

$V_{RO_2}$  – volume of triatomic flue gases when 1 m<sup>3</sup> of syngas is combusted;

$V_{N_2}$  – nitrogen volume in flue gases;

$V_{H_2O}$  – steam volume in flue gases.

$V_{RO_2}$  is calculated by eq. 6.5:

$$V_{RO_2} = 0.01 \cdot (CO_2^s + CO^s + \sum mC_mH_n^s); \quad [6.5]$$

$$V_{RO_2} = 0.01 \cdot (18.3 + 15.5 + 1 \cdot 9.9) = 0.437 \text{ m}^3/\text{m}^3;$$

Volume of  $V_{N_2}$  will be (eq. 6.6):

$$V_{N_2} = 0.79 \cdot V_{air} + 0.01 \cdot N_2^s; \quad [6.6]$$

$$V_{N_2} = 0.79 \cdot 1.66 + 0.01 \cdot 47.9 = 1.79 \text{ m}^3/\text{m}^3;$$

Volume of  $V_{H_2O}$  will be (eq. 6.7):

$$V_{H_2O} = 0.01 \cdot (H_2^s + \sum \frac{n}{2} \cdot C_mH_n^s + 0.124 \cdot m_g) + 0.0161 \cdot V_{air}; \quad [6.7]$$

where:

$m_g$  – moisture content in gaseous fuel (g/m<sup>3</sup>) (eq. 6.8).

$$m_g = \frac{M_{H_2O}}{22.4} \cdot \frac{H_2O}{100} \cdot 1000 \quad [6.8]$$

$$m_g = \frac{18.02}{22.4} \cdot \frac{29}{100} \cdot 1000 = 233.15 \text{ g/m}^3;$$

$$V_{H_2O} = 0.01 \cdot \left( 8.8 + \frac{4}{2} \cdot 9.9 + 0.124 \cdot 233.15 \right) + 0.0161 \cdot 1.66 = 0.598 \text{ m}^3/\text{m}^3;$$

Total volume of flue gases will be:

$$V_{fg} = 0.437 + 1.79 + (1.1 - 1) \cdot 1.509 + 0.598 = 2.98 \text{ m}^3/\text{m}^3.$$

The results show that 1.66 m<sup>3</sup> of air is needed to combust 1 m<sup>3</sup> of syngas and 2.98 m<sup>3</sup> of flue gases will be produced.

The same calculations were done for natural gas combustion. All the results are presented in Table 6.3 below.

Table 6.3. Volumes of air and flue gases for syngas and NG combustion

Parameter	Unit	Syngas	NG
LHV	(MJ/m <sup>3</sup> )	6.53	33.9
V <sub>O<sub>2</sub></sub>	(m <sup>3</sup> /m <sup>3</sup> )	0.317	1.85
V <sub>Tair</sub>	(m <sup>3</sup> /m <sup>3</sup> )	1.509	8.82
V <sub>air</sub>	(m <sup>3</sup> /m <sup>3</sup> )	1.66	9.7
V <sub>RO<sub>2</sub></sub>	(m <sup>3</sup> /m <sup>3</sup> )	0.437	0.939
V <sub>N<sub>2</sub></sub>	(m <sup>3</sup> /m <sup>3</sup> )	1.79	7.75
V <sub>H<sub>2</sub>O</sub>	(m <sup>3</sup> /m <sup>3</sup> )	0.598	1.99
V <sub>fg</sub>	(m <sup>3</sup> /m <sup>3</sup> )	2.98	11.6

The fuel flow of synthetic gases to maintain the power of 60 MW will be (eq. 6.9):

$$B_{sg} = \frac{Q}{LHV}; \quad [6.9]$$

where:

B<sub>sg</sub> – flow of synthetic gases;

Q – thermal power of the boiler;

LHV – lower heating value of syngas.

LHV of synthetic gases is 5.9 MJ/kg or 6.53 MJ/m<sup>3</sup> (when density ρ=1.106 kg/m<sup>3</sup>).

$$B_{sg} = \frac{60 \text{ MW}}{6.53 \text{ MJ/m}^3} = 9.2 \text{ m}^3/\text{s};$$

Then the flow of flue gases (eq. 6.10):

$$\dot{V}_{fg,sg} = V_{fg,sg} \cdot B_{sg}; \quad [6.10]$$

$$\dot{V}_{fg,sg} = 2.98 \cdot 9.2 = 27.4 \text{ m}^3/\text{s};$$

The NG flow (eq. 6.11):

$$B_{NG} = \frac{Q}{LHV_{NG}}; \quad [6.11]$$

$$B_{NG} = \frac{60}{33.9} = 1.77 \text{ m}^3/\text{s};$$

Then flue gas flow of firing NG (eq. 6.12):

$$\dot{V}_{fg,ng} = V_{fg,ng} \cdot B_{ng}; \quad [6.12]$$

$$\dot{V}_{fg,ng} = 11.6 \cdot 1.77 = 20.5 \text{ m}^3/\text{s}.$$

Table 6.4. Fuel input and flue gases of syngas and NG combusted in BKZ-75-39 boiler

Parameter	Unit	Syngas	Natural gas
Fuel input	m <sup>3</sup> /s	9.2	1.77
Flue gases	m <sup>3</sup> /s	27.4	20.5

If we maintain the same power in the boiler, the flow of flue gases will increase by ~34%. However, there will be no changes in boiler construction and flue gases fan will remain the same because the nominal flow of flue gas fan is even higher (200 000 m<sup>3</sup>/h or 55 m<sup>3</sup>/s) [16].

According to Darcy-Weisbach equation, the pressure loss due to viscous effects depends on velocity squared. Thus, it will increase by ~78% leading to higher power of flue gas fan and increase of electricity needs.

The thermal tension of boiler will remain the same (132 kW/m<sup>3</sup>) when boiler volume is 454 m<sup>3</sup>.

## 6.2 Burners selection

The existing burners of BKZ-75-39 boiler are not suitable for syngas combustion. The main reason is LHV of syngas which is much lower comparing to firing NG. Wobbe index is approximately 6 times lower than firing NG (calculated in Chapter 4). Thus, new burners will be selected and integrated to the boiler. They will substitute the old burners in the boiler layout (Figure 6.2).

Three new burners SSB-LCG manufactured by Saacke are chosen. The nominal thermal power of each burner is 20 MW. They are suitable for firing gases which lower heating value is greater than  $2.5 \text{ MJ/m}^3$ . [17]



Figure 6.2. Saacke SSB-LCG burner

The syngas firing system consists of a SAACKE swirl burner with a special burner muffle into which gas with a low heating value is fed. The burner thus achieves nearly emission-free combustion without any supporting fuels.

A fuel with a high heating value is required to start up the system. As soon as the burner and its muffle have reached the operating temperature, the starting fuel is no longer necessary.

The combustion air of the SSB-LCG consists of two partial flows that enter the combustion chamber with a pronounced swirling effect. This swirling and the hot lining of the muffle ensure that the lean gas ignites reliably and burns stably at all power stages.

The price of 20 MW SSB-LCG burner is approximately 120 000 € (asked from manufacturer). This price does not include any control system, combustion air or gas supply. Thus, higher investment cost must be considered. The price for 3 burners with all additional equipment is assumed to be 500 000 € for further calculations.

These new burners will be placed instead of existing natural gas firing burners.

## 7 GASIFIER AND AUXILIARY SYSTEM SELECTION

The atmospheric pressure circulating fluidized bed (CFB) gasifier manufactured by Metso is selected. It was successfully integrated in CHP power plant in Lahti and is one of the most advanced gasification technologies available. The principal scheme of Metso technology integrated in BKZ-75-39 is shown in Figure 7.1.



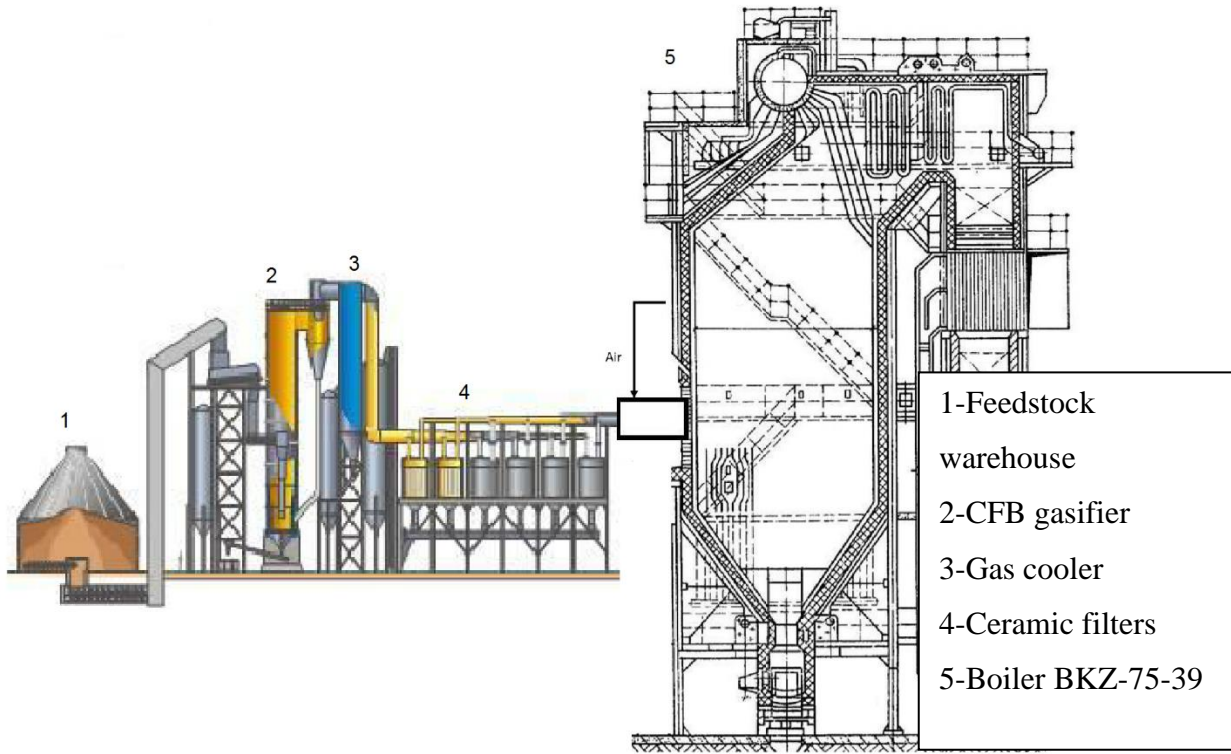


Figure 7.1. Metso gasification technology [5]

## 7.1 Gasifier calculations

Main gasifier parameters:

Thermal power of gasifier: 80 MW<sub>th</sub> (gasifier integrated in Lahti);

Fuel efficiency: 86.7 %;

Then, nominal syngas power: 80 MW<sub>th</sub> · 86.7 % = 69 MW;

Gasification temperature: 650 °C;

Syngas temperature after gasifier: 600 °C.

The power of gasifier exceeds the needs of a boiler. Thus, let's assume that gasifier of lower capacity will be designed.

The thermal power of a gasifier that is needed to fulfil needs of a boiler (eq. 7.1):

$$Q_{gasifier} = \frac{Q_{boiler}}{\eta_{fuel}}; \quad [7.1]$$

$$Q_{gasifier} = \frac{60}{0.867} \approx 70 \text{ MW}_{th}.$$

Let's calculate the quantity of straw needed to maintain 70 MW<sub>th</sub> thermal power of gasifier:

The LHV of straw: 15 MJ/kg.

Then eq. 7.2,

$$B_{straw} = \frac{Q_{th, gasifier}}{LHV_{straw}}; \quad [7.2]$$

$$B_{straw} = \frac{70}{15} = 4.67 \text{ kg/s} = 16.8 \text{ t/h.}$$

## 7.2 Gas cooler calculations

Syngas contain a lot of heat after gasification which can be recovered. Thus, the gas cooling system will be applied. The heat will be used for warming up water that comes from district heating network.

Recommended speed  $w$  of syngas in the ducts is 20 m/s. Then a diameter of a duct from gasifier to gas cooler will be (eq. 7.3):

$$d_{sg, cooling} = \sqrt{\frac{4 * B_{sg}}{w * \pi}}; \quad [7.3]$$

$$d_{sg, cooling, 1} = \sqrt{\frac{4 * 9.2}{20 * \pi}} = 0.77 \text{ m};$$

However, hot gas ( $t=600$  °C) cover larger volume. The coefficient of temperature change  $k$  is calculated by eq. 7.4:

$$k = \frac{t + 273}{273}; \quad [7.4]$$

$$k = \frac{600 + 273}{273} = 3.2$$

The syngas flow ( $m^3/s$ ) depends on both volume and velocity of gas. Let's assume that velocity remains 20 m/s and volume increases 3.2 times (eq. 7.5):

$$B_{sg2} = B_{sg} \cdot 3.2; \quad [7.5]$$

$$B_{sg2} = 9.2 \cdot 3.2 = 29.4 \text{ m}^3/\text{s};$$

Then a real diameter of a duct from gasifier to gas cooler will be:

$$d_{sg, cooling, 2} = \sqrt{\frac{4 * 29.4}{20 * \pi}} = 1.37 \text{ m.}$$

So, the diameters of ducts will be:

Duct from gasifier to gas cooler: 1.37 m;

Duct from gas cooler: 0.77 m.

Partial water vapor pressure in syngas is 0.15 bar. According to that value, the condensing of water in gas cooler will occur at 55 °C. Lets assume that syngas temperature after gas cooler will be 65÷75 °C that vapor would not condense.

The mean specific heat value between  $t=65\div 600$  °C:  $c_{pm}$  is 1.402 kJ/kgK (calculations in Table 7.1).

Table 7.1. Calculations of mean specific heat [18]

Gas	Fraction (%)	M (g/mol)	g=M <sub>i</sub> /M (%)	C <sub>pm</sub> (kJ/kgK)	C <sub>pm</sub> (kJ/kgK), T=330 °C
H <sub>2</sub>	6	2.02	0.5	$C_{pm} = 14.33 + 0.0005945 \cdot t$	14.526
CO	11	28.01	12.4	$C_{pm} = 1.035 + 0.00009681 \cdot t$	1.067
CO <sub>2</sub>	13	44.01	23.1	$C_{pm} = 0.8725 + 0.0002406 \cdot t$	0.952
N <sub>2</sub>	34	28.01	38.4	$C_{pm} = 1.032 + 0.00008955 \cdot t$	1.062
H <sub>2</sub> O	29	18.02	21.1	$C_{pm} = 1.833 + 0.0003111 \cdot t$	1.936
CH <sub>4</sub>	7	16.04	4.5	$C_{pm} = 3.602$	3.602
Syngas	100	24.80	100	$C_{pm} = \sum_{i=1}^{i=n} C_{pm,i} \cdot g_i$	<b>1.402</b>

The power of gas cooler (Q<sub>c</sub>) will be (eq. 7.6):

$$Q_c = B_{s,g} \cdot \rho_{sg} \cdot c_{pm} \cdot (t_1 - t_2); \quad [7.6]$$

where:

$\rho_{sg}$  – density of syngas;

$t_1$  – syngas temperature after gasifier;

$t_2$  – syngas temperature after gas cooler.

$$Q_c = 9.2 \cdot 1.106 \cdot 1.402 \cdot (600 - 75) = 7585 \text{ kW} \approx 7.6 \text{ MW}.$$

DH water will be primary heated in a condensing economiser (CE) and will further go to gas cooler. Therefore, the calculations of DH water will be done in the next chapter.

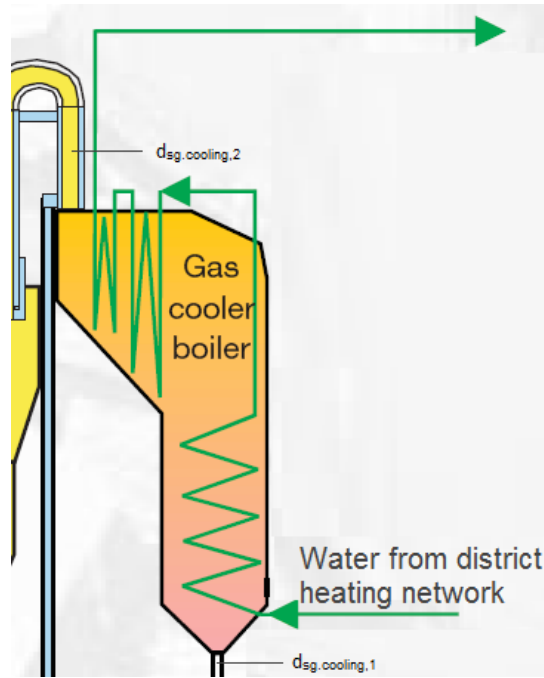


Figure 7.2. Gas cooler

### 7.3 Condensing economiser

The temperature of flue gas is 185 °C after boiler. Therefore, it is a good solution to add a condensing economiser to the system to diminish the heat losses through the chimney.

The thermal capacity of flue gas condenser will be calculated by eq. 7.7:

$$Q_{FGC} = \dot{V}_{fg} \cdot C_{v,fg} \cdot (T_{fg,in} - T_{fg,out}) + m_{fg,w} \cdot l; \quad [7.7]$$

where:

$Q_{FGC}$  – thermal power of flue gas condenser, MW;

$\dot{V}_{fg}$  – flow of flue gas, m<sup>3</sup>/s;

$C_{v,fg}$  – specific heat of flue gas, kJ/m<sup>3</sup> K;

$T_{fg,in}$  – inlet temperature of flue gas, °C;

$T_{fg,out}$  – outlet temperature of flue gas, °C;

$m_{fg,w}$  – mass flow of water vapor in a flue gas, kg/s;

$l$  – latent heat trapped in flue gas, kJ/kg.

The outlet temperature is assumed to be the same as condensation of water vapor in flue gas. It is calculated according to partial pressure of water vapor in flue gases ( $p=0.215$  bar):

$$T_{fg,out} = 61.5 \text{ °C.}$$

The values of other parameters are:

$$C_{v,fg} = 0.967 \text{ kJ/m}^3\text{K (from flue gas tables);}$$

$$T_{fg,in} = 185 \text{ }^\circ\text{C};$$

$$m_{fg,w} = 2.61 \text{ kg/s};$$

$$l = 2360 \text{ kJ/kg (from steam tables).}$$

Then, the nominal power of flue gas condenser will be:

$$Q_{FGC} = 25.7 \cdot 0.967 \cdot (185 - 61.5) + 2.61 \cdot 2360 = 9.2 \text{ MW}.$$

However, it is impossible to get all this heat from flue gas. Let's assume that condensing economiser has the efficiency of 75%. Then, the power of CE will be about 7 MW.

The flue gas condenser will be used to heat up the district heating water that comes back from DH network. The inlet temperature is assumed to be 45 °C and the outlet temperature – 57 °C).

The DH water flow ( $\text{m}^3/\text{s}$ ) is calculated by the following eq. 7.9 that is got from eq. 7.8:

$$Q_{FGC} = V_{DH,w} \cdot C_{p,w} \cdot (T_{out} - T_{in}); \quad [7.8]$$

Then eq. 7.9:

$$V_{DH,w} = \frac{Q_{FGC}}{C_{v,w} \cdot (T_{w,out} - T_{w,in})}; \quad [7.9]$$

where:

$C_{v,w}$  – specific heat of water,  $\text{kJ/m}^3 \text{ K}$  (4124  $\text{kJ/m}^3\text{K}$  when  $T=50 \text{ }^\circ\text{C}$ );

$T_{w,out}$  and  $T_{w,in}$  – outlet and inlet temperatures of DH water.

$$V_{DH,w} = \frac{7 \cdot 10^3}{4124 \cdot (57 - 45)} = 0.14 \text{ m}^3/\text{s} = 504 \text{ m}^3/\text{h}.$$

This DH water will be further heated in a gas cooler which was previously calculated. The water temperature after gas cooler (eq. 7.10):

$$T_{w2} = T_{w1} + \frac{Q_c}{\rho \cdot V_{DH,w} \cdot C_p}; \quad [7.10]$$

$$T_{w2} = 57 + \frac{7.6 \cdot 10^6}{980 \cdot 0.14 \cdot 4188} = 57 + 13 = 70 \text{ }^\circ\text{C}.$$

where:

$T_{w1}$  – water temperature before gas cooler;

$\rho$  – density of water (T=65 °C);

$C_p$  – specific heat of water (T=65 °C).

During the summer season, less DH water will go through the heat exchangers of CE and gas cooler. The DH water will warm up to 70 °C and will be supplied directly to DH network. The syngas temperature after gas cooler would be 75 °C.

During the heating season, the DH water temperature that is supplied to the network is higher. For that reason, higher flow of DH water could go through the heat exchangers and be directed to the boiler plant afterwards to increase the temperature till needed. This would lead to lower temperature of syngas ( $\pm 60$  °C) and better performance of gas cooler.

## 8 ENERGY BALANCES AND PRODUCTION

Energy balances are made in order to determine the electrical power of a plant, heat that could be produced to district heating network and thermal losses of the main system components (Figure 8.1).

Fuel efficiency of gasifier determines the power of synthetic gases that is obtained by gasifier. It takes into account the losses of gasifier and physical energy of hot syngas that is recovered in gas cooler later. The losses of gasifier consists of heat losses by radiation and energy lost in form of charcoal.

The efficiency of a boiler working in cogeneration mode is 85 %, when electrical efficiency is 25 %.

The heating power to DH network consists of thermal energy that is obtained from steam condenser and thermal energy that is recovered from gas cooler and flue gas condenser.

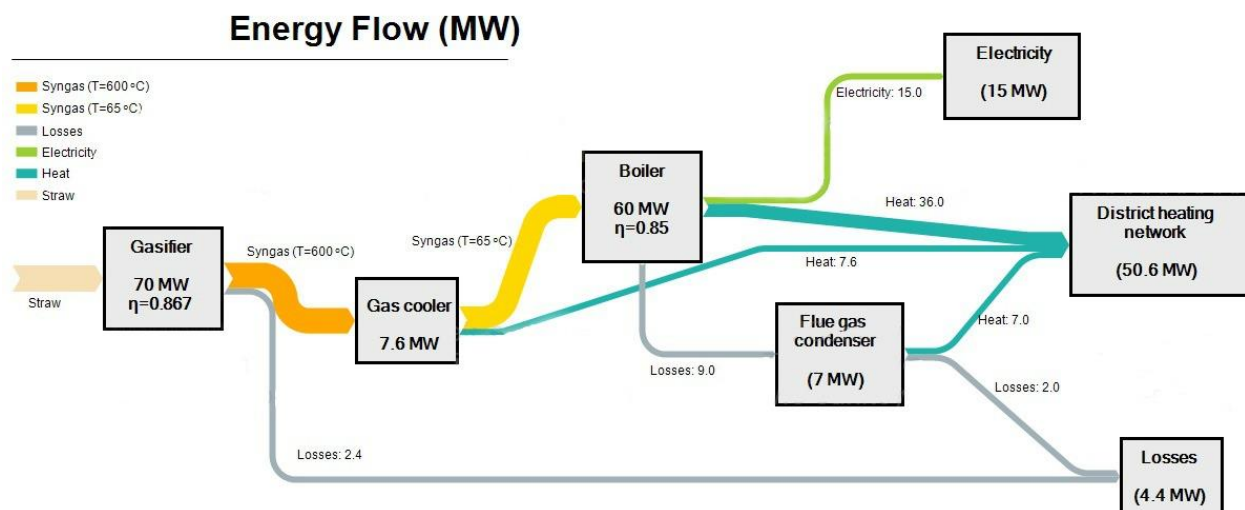


Figure 8.1. Energy balance of a CHP power plant

Overall efficiencies of the power plant (eq. 8.1-8.3):

$$\text{Thermal: } \eta_{th} = \frac{Q_{DH}}{Q_{gasifier}} \cdot 100 \% = \frac{50.6}{70} \cdot 100 \% = 72.3 \% \quad [8.1]$$

$$\text{Electrical: } \eta_e = \frac{W_e}{Q_{gasifier}} \cdot 100 \% = \frac{15}{70} \cdot 100 \% = 21.4 \% \quad [8.2]$$

$$\text{Total: } \eta_T = \frac{Q_{DH} + W_e}{Q_{gasifier}} \cdot 100 \% = \frac{50.6 + 15}{70} \cdot 100 \% = 93.7 \% \quad [8.3]$$

The principal scheme of the power plant is shown in a Figure 8.2 below.

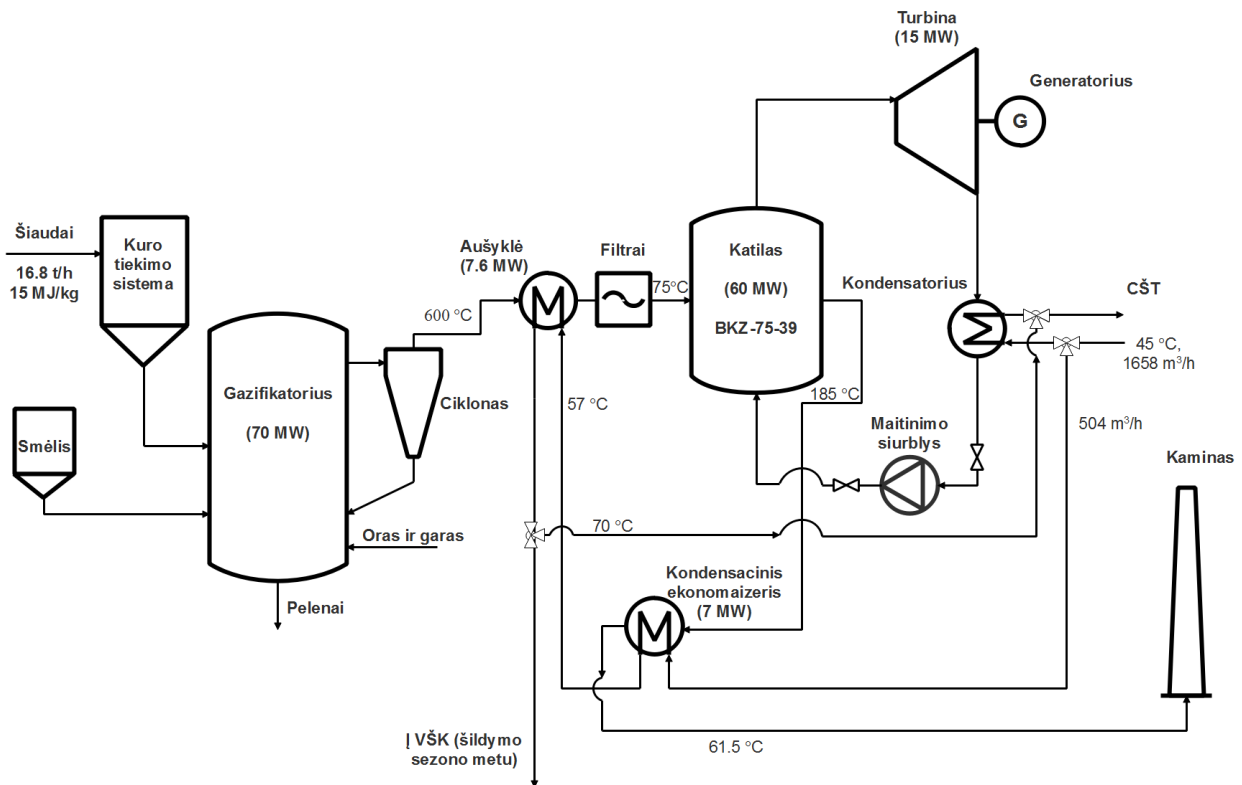


Figure 8.2. Principal scheme of the power plant

## 8.1 Energy production

The quantity of electrical and thermal energy that is produced by the power plant working in a cogeneration mode will be calculated assuming that:

- year is divided to warm and cold season (when heating is used in the buildings). Cold season lasts 180 days;
- the power plant will be working on full load during the cold season and on partial load during the warm season;
- the reduction coefficient of 0.6 will be used for energy production in warm season;
- the power plant will be stopped for 1 month/year for maintenance during warm season.

Electricity production (E) will be calculated by the eq. 8.4:

$$E = P_E \cdot n; \quad [8.4]$$

where:

$P_E$  – electrical power;

n – working hours.

Electricity production during cold season (c), when n=4320:

$$E_c = 15 \cdot 4320 = 64\,800 \text{ MWh}_e;$$

Electricity production during warm season (eq. 8.5):

$$E = k \cdot P_E \cdot n; \quad [8.5]$$

where:

k – reduction coefficient of energy production during warm season (k=0.6), when n=3720;

$$E_w = 0.6 \cdot 15 \cdot 3720 = 33\,480 \text{ MWh}_e;$$

Thermal energy (Q) to district heating network will be calculated (eq. 8.6):

$$Q = P_Q \cdot n; \quad [8.6]$$

where:

$P_Q$  – total thermal power supply to DH.

Thermal energy (Q) to district heating network during cold season:

$$Q_c = 50.6 \cdot 4320 = 218\,592 \text{ MWh}_{th};$$

Thermal energy (Q) to district heating system during warm season, when power reduction coefficient is 0.6:

$$Q_w = 0.6 \cdot 50.6 \cdot 3720 = 112\,939 \text{ MWh}_{th}.$$

Thermal energy generated in the gasifier will be calculated in order to determine the feedstock needs per year (eq. 8.7).

$$Q_G = P_G \cdot n; \quad [8.7]$$



where:

$P_G$  – thermal power of gasifier;

$$Q_{G,c} = 70 \cdot 4320 = 302\,400 \text{ MWh}_{th} = 26\,002 \text{ toe};$$

$$Q_{G,w} = 0.6 \cdot 70 \cdot 3720 = 156\,240 \text{ MWh}_{th} = 13\,434 \text{ toe}.$$

The results are shown in Table 8.1 below:

Table 8.1. Fuel input and energy production

	Fuel input (toe)	Electricity production (MWh)	Heat production (MWh)
Cold season	26 002	64 800	218 592
Warm season	13 434	33 480	112 939
Total	39 436	98 280	331 531

## 9 ECONOMICAL EVALUATION OF THE PROJECT

Financial feasibility will be evaluated according to investment, fuel and O&M costs as well as revenues from electricity and heat production.

The investment costs include costs of gasifier, condensing economiser and three burners (Table 9.1):

Table 9.1. Investment costs

Equipment	Cost, €/kW	Cost, mln. €
Gasifier	500*	35
Condensing economiser	300	2.1
Burners	-	0.5
Total	-	37.6

\* ducts, gas cooler and syngas cleaning system is also included in gasifier price [19].

The operation and maintenance costs include (Table 9.2):

O&M<sub>year</sub> costs of gasifier: 2.4 €/MWh<sub>fuel</sub> [19];

O&M<sub>year</sub> costs of flue gas condenser: 2% of investment cost;

O&M<sub>year</sub> costs of existing equipment of power plant 2 €/MWh<sub>th, boiler</sub> [20].

Table 9.2. Operation and maintenance costs

O&M	Cost, €
Gasifier	1 100 736
Flue gas condenser	42 000
Existing equipment	786 240
Total	1 928 976

The fuel price varies each month. Therefore, mean price of 2016 will be used for calculations. The mean price of straw in 2016 was: 116.04 €/toe [21].

Then, money spent for feedstock of gasifier per year will be (eq. 9.1):

$$\text{€ fuel} = 39\,436 \text{ toe} \cdot 116.04 \text{ € /toe} = 4\,576\,153 \text{ €} . \quad [9.1]$$

It is forecasted that straw price will remain nearly the same in the next 15 years. For that reason, the constant value of straw price will be used in the calculations [22].

Revenues from energy sales:

The electricity price is expected to remain fixed for 12 years. Fixed electricity price of reconstructed CHP power plant that is firing biofuels is: 35 €/MWh<sub>e</sub> [21].

An assumption is made that 5% of electricity generated is used for power plants own use: blowers, pumps, fuel handling system, etc.

Then, money income from electricity production per year (eq. 9.2):

$$\text{€ from electricity} = 0.95 \cdot 98280 \text{ MWh} \cdot 35 \text{ €/MWh} = 3\,267\,810 \text{ €}; \quad [9.2]$$

The average price of heat supplied to DH network is determined during the auction where different suppliers offer their price on the monthly basis. Therefore, comparing the average price of the heat supplied to DH network in different heating seasons, the differences can be explained by different weather conditions (e.g. warmer winter), changes in supply capacity (e.g. new suppliers entering the market) and other external factors.

For the calculations, average heating prices for winter season (November – March) and summer season (April – October) will be forecasted.

For winter season, the average price over the period from November 2016 to March 2017 will be used (26.82 €/MWh<sub>th</sub>) [21].

For summer season, the adjusted average price over the period from April 2016 to October 2016 will be used. The unadjusted average of the heating price over this period was equal to 23.38 €/MWh<sub>th</sub>. However, due to a moderate reduction of heating price in the beginning of 2017,

compared to 2016, the heating price for the summer season will be adjusted to avoid inconsistencies in the calculations. The average heating price in 2017 winter season (November – March) was 18 percent lower compared to 2016 winter season (November – March) (respectively 27.3 and 33.4 €/MWh<sub>th</sub>). Therefore, for the calculation purposes, the reduction coefficient of 0.82 will be used to adjust summer season heating price (the price of 19.1 €/MWh<sub>th</sub> will be used for further calculations).

Then, revenues from heating sales will be (eq. 9.3):

$$\text{€ heating} = 218\,592 \cdot 26.82 + 112\,939 \cdot 19.1 = 8\,019\,776 \text{ €}. \quad [9.3]$$

The economical evaluation will be done for 12 years. It is a period when electricity price remains constant due to fixed green energy tariff.

The bank loan will be taken to cover the investment costs. The bank interest rate is 7%. Then, the expenditures for a bank loan over period of 12 years will be (eq. 9.4):

$$A_p = \left[ P - \left( \frac{n+1}{1} - 1 \right) \frac{P}{n} \right] nj + P; \quad [9.4]$$

where:

$A_p$  – total expenditures for a bank loan;

$P$  – bank loan (investment costs);

$n$  – period of economical evaluation;

$j$  – interest rate of bank.

$$A_p = \left[ 37.6 \cdot 10^6 - \left( \frac{12+1}{1} - 1 \right) \cdot \frac{37.6 \cdot 10^6}{12} \right] \cdot 12 \cdot 0.07 + 37.6 \cdot 10^6 = 54\,708\,000 \text{ €}.$$

The expenditures for a bank loan per year (eq. 9.5):

$$A_{p,y} = \frac{A_p}{n} = \frac{58\,345\,500}{12} = 4\,862\,125 \text{ €}. \quad [9.5]$$

All the revenues and expenditures of a power plant per year have already been calculated. The free cash flow (FCF) will be (eq. 9.6):

$$FCF = \sum Revenues - \sum Expenditures; \quad [9.6]$$

$$FCF = 11\,287\,586 - 6\,505\,129 - 4\,862\,125 = 223\,457 \text{ €}.$$

Therefore, we can now evaluate if the project is profitable or not. For that reason, net present value (NPV) will be calculated assuming that discount rate is 4%.

The NPV shows the difference between the present value of cash inflows and the present value of cash outflows. If this difference is positive, then we can say that the investment is profitable.

The equation of NPV (eq. 9.7):

$$NPV = \sum_{n=1}^n \frac{FCF}{(1+r)^n} - Inv; \quad [9.7]$$

where:

n – time periods (12 years);

r – discount rate

Inv – initial investment.

In this case, the expenditures for a bank loan were already included when calculating free cash flow (Inv=0).

$$NPV = \sum_{n=1}^{12} \frac{223\,457}{(1+0.04)^n} = 2\,097\,162 \text{ €.}$$

The investment to this project has a profit of about 2 mln. €. The results of economical evaluation and intermediate values are shown in ANEX 1.

Several more assumptions of energy production, electricity price and investment without a bank loan will be made to evaluate if the project could become profitable. The main results are shown in Table 9.3 below.

Table 9.3. Economic analysis of a project based on different assumptions

CASE Nr.	Assumptions	NPV, €	Result	More details
CASE 1	Discount rate 4%; Bank interest rate 7%; Reduction coefficient of energy production during warm season 0.6.	2,097,162	Profitable	ANEX 1
CASE 2	Discount rate 4%; Initial investment 37.6 mln €; Reduction coefficient of energy production during warm season 0.6.	7,283,713	Profitable	ANEX 2
CASE 3	Discount rate 4%; Bank interest rate 7%; Power plant works on a full load both seasons.	14,802,229	Profitable	ANEX 3

CASE Nr.	Assumptions	NPV, €	Result	More details
CASE 4	Discount rate 4%; Initial investment 37.6 mln €; Power plant works on a full load both seasons.	19,988,780	Profitable	ANEX 4
CASE 5	Discount rate 4%; Bank interest rate 7%; Reduction coefficient of energy production during warm season 0.6; Electricity price 107* €/MWh <sub>e</sub> .	70,121,584	Profitable	ANEX 5

\* electricity tariff for biogas (for power plants using biogas derived from anaerobic digestion or other biodegradable organic waste or substrates).

## 10 ENVIRONMENTAL IMPACT

From the environmental point of view, the energy production from straw, based on gasification technology, leads to lower emissions of GHG's comparing to direct firing system. Gaseous fuel can be premixed with proper air quantity and release less emissions of CO, NO<sub>x</sub> and HC after combustion.

The main environmental benefits of biomass gasification:

- reduced carbon emissions as a result of improvement in energy efficiency;
- a lower level of exhaust emissions of major air pollutants;
- financial benefit due to reduction of CO<sub>2</sub> emissions.

In the case study, the primary fuel is solid biomass and, for that reason, the emission limit values for over 50 MW power plant firing biomass will be applied. According to the Industrial Emissions directive 2010/75/EU these values are [23]:

Table 10.1. Emission limit values

Pollutant	Unit	Value
SO <sub>2</sub>	mg/m <sup>3</sup>	200
NO <sub>x</sub>	mg/m <sup>3</sup>	250
CO	mg/m <sup>3</sup>	-
PM	mg/m <sup>3</sup>	20

One of the main advantages of biomass gasification over fossil fuel based power generation is CO<sub>2</sub> reduction. Let's compare the CO<sub>2</sub> emissions and annual costs of polluting the environment for NG and syngas firing power plant.

The energy production from biomass sources is considered as CO<sub>2</sub> neutral. Thus, the carbon reduction of fossil CO<sub>2</sub> emissions and money savings will be calculated if the power plant is operated at full load 8040 hours per year.

The input values are taken from previous calculations [6.1] and shown in Table 10.2:

Table 10.2. Input data for calculations of CO<sub>2</sub> emissions

Parameter	M <sub>CO2</sub>	V <sub>M</sub>	V <sub>CO2</sub>	B <sub>NG</sub>
Units	kg/kmol	m <sup>3</sup> /kmol	m <sup>3</sup> / m <sup>3</sup>	m <sup>3</sup> /s
Value	44.01	22.4	0.939	1.77

V<sub>CO2</sub> – volume CO<sub>2</sub> in flue gases when 1 m<sup>3</sup> of natural gas is combusted;

B<sub>NG</sub> – natural gas flow to maintain the nominal power of 60 MW.

The flow (m<sup>3</sup>/s) of CO<sub>2</sub> is calculated as following (eq. 10.1):

$$\dot{V}_{NG} = V_{CO2} \cdot B_{NG}; \quad [10.1]$$

$$\dot{V}_{NG} = 0.939 \cdot 1.77 = 1.66 \text{ m}^3/\text{s};$$

The mass flow (kg/s) will be (eq. 10.2):

$$\dot{G}_{CO2} = \frac{\dot{V}_{NG} \cdot M_{CO2}}{V_M}; \quad [10.2]$$

$$\dot{G}_{CO2} = \frac{1.66 \cdot 44.01}{22.4} = 3.26 \text{ kg/s};$$

The mass of CO<sub>2</sub> emitted per year (eq. 10.3):

$$t \text{ CO}_2 = \frac{\dot{G}_{CO2} \cdot 3600 \cdot n}{1000}; \quad [10.3]$$

where:

n – operating hours of the power plant (8040).

$$t \text{ CO}_2 = \frac{3.26 \cdot 3600 \cdot 8040}{1000} = 94 \text{ 357 t.}$$

The gasifier helps to reduce 94 357 t/a of CO<sub>2</sub> emissions.

If penalty of CO<sub>2</sub> emissions is 10 €/t CO<sub>2</sub>, money savings of using biomass as a primary feedstock instead of firing NG would be 943 570 € per year.

## CONCLUSIONS

The global goal of the present project is the study of biomass gasification usage in a cogeneration plant. Firstly, a study of biomass (characteristics, advantages and disadvantages), gasification technologies available, biomass gasification process and potential applications has been carried out.

The second part of the project is focused on biomass gasifier integration into Vilnius CHP-2 power plant. The gasifier would produce synthetic gases to feed an old BKZ-75-39 boiler that was firing natural gas previously. A Low Temperature Circulating Fluidised Bed gasifier (LT-CFB) was chosen due to several reasons:

- ✓ CFB technology is more suitable for large scale applications;
- ✓ there are successful examples of integration (Lahti Energy, DONG Energy, etc.) into fossil fuels firing boilers;
- ✓ LT-CFB system is capable to gasify low cost feedstock that contains bigger fraction of alkali metals and other inorganics.

Key results of the project:

1. The syngas and natural gas greatly differ in LHV values ( $6.53 \text{ MJ/m}^3$  and  $33.9 \text{ MJ/m}^3$  respectively). Thus, bigger flow of syngas ( $9.2 \text{ m}^3/\text{s}$  and  $1.77 \text{ m}^3/\text{s}$ ) is needed to maintain the same power of 60 MW in the boiler. The flow of flue gases would increase by approximately 10 %.
2. Wobbe index was calculated to estimate the interchangeability of fuels in the same burner. WI is 6 times lower for syngas. Thus, three new Saacke SSB-LCG burners were selected (20 MW each) that are capable to combust low heating value gases.
3. A gasifier of 70 MW was designed for multiple low cost feedstock, such as straw or peat. However, all the calculations in this project were done for straw gasification. Results show that 16.8 t/h of straw is needed to maintain the thermal power of 70 MW.
4. Syngas contain a lot of heat after gasification which can be recovered. The temperature of gases leaving the gasifier is  $600 \text{ }^\circ\text{C}$ . For that reason, gas cooling system was designed. Synthetic gases will be cooled down to  $65\text{--}75 \text{ }^\circ\text{C}$  that allows to obtain 7.6 MW of heat in gas cooler.
5. Condensing economiser was applied to reduce the losses with flue gases. It has a thermal power of 7 MW.
6. Gas cooler and condensing economiser will heat up the district heating water that returns from DH network. During the summer season, the combination of GC and CE systems will warm DH water until  $70 \text{ }^\circ\text{C}$ . However, during the heating season

DH water will be further heated in the boiler plant until the demanded temperature is reached.

7. Financial feasibility was evaluated according to investment, fuel and O&M costs as well as revenues from electricity and heat production.
8. For calculations of energy production, year was divided to cold and warm seasons. Two separate calculations were done. The first one included energy production reduction rate of 0.6 during warm season while the second calculation assumed that power plant works on a full load during both seasons.
9. Several more assumptions of energy production, electricity price and investment with or without a bank loan were made to evaluate if the project could become financially profitable. Economic evaluation of the project was done for five different cases.
10. The Net Present Values were calculated. The NPVs show that investment to biomass gasification technology can be profitable. The results greatly differ between the cases and vary between 2 to 70 M€.
11. The environmental impact of biomass gasification was analysed. In comparison with NG firing power plant, it reduces 94 357 t/a of CO<sub>2</sub> emissions and leads to money savings of 943 570 € due to CO<sub>2</sub> penalty.



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## ANEX 1. ECONOMIC ANALYSIS (CASE 1)

Year	0	1	2	3	4	5	6	7	8	9	10	11	12
<b>CALCULATIONS</b>													
Revenues, €		<u>11,287,586</u>	<u>11,287,586</u>	<u>11,287,586</u>	<u>11,287,586</u>	<u>11,287,586</u>	<u>11,287,586</u>	<u>11,287,586</u>	<u>11,287,586</u>	<u>11,287,586</u>	<u>11,287,586</u>	<u>11,287,586</u>	<u>11,287,586</u>
Electricity, €		3,267,810	3,267,810	3,267,810	3,267,810	3,267,810	3,267,810	3,267,810	3,267,810	3,267,810	3,267,810	3,267,810	3,267,810
Heating, €		8,019,776	8,019,776	8,019,776	8,019,776	8,019,776	8,019,776	8,019,776	8,019,776	8,019,776	8,019,776	8,019,776	8,019,776
Expenditures, €		<u>-6,505,129</u>	<u>-6,505,129</u>	<u>-6,505,129</u>	<u>-6,505,129</u>	<u>-6,505,129</u>	<u>-6,505,129</u>	<u>-6,505,129</u>	<u>-6,505,129</u>	<u>-6,505,129</u>	<u>-6,505,129</u>	<u>-6,505,129</u>	<u>-6,505,129</u>
Fuel, €		-4,576,153	-4,576,153	-4,576,153	-4,576,153	-4,576,153	-4,576,153	-4,576,153	-4,576,153	-4,576,153	-4,576,153	-4,576,153	-4,576,153
O&M costs, €		-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976
<b>Operating result, €</b>		<b>4,782,457</b>	<b>4,782,457</b>	<b>4,782,457</b>	<b>4,782,457</b>	<b>4,782,457</b>	<b>4,782,457</b>	<b>4,782,457</b>	<b>4,782,457</b>	<b>4,782,457</b>	<b>4,782,457</b>	<b>4,782,457</b>	<b>4,782,457</b>
Investment costs, €		-4,559,000	-4,559,000	-4,559,000	-4,559,000	-4,559,000	-4,559,000	-4,559,000	-4,559,000	-4,559,000	-4,559,000	-4,559,000	-4,559,000
<b>Free cash flow, €</b>		<b>223,457</b>	<b>223,457</b>	<b>223,457</b>	<b>223,457</b>	<b>223,457</b>	<b>223,457</b>	<b>223,457</b>	<b>223,457</b>	<b>223,457</b>	<b>223,457</b>	<b>223,457</b>	<b>223,457</b>
<b>NPV</b>	<b>2,097,162</b>												

### ASSUMPTIONS

Discount rate	4%
Bank interest rate	7%
Reduction coefficient of energy production during warm season	0.6

## ANEX 2. ECONOMIC ANALYSIS (CASE 2)

Year	0	1	2	3	4	5	6	7	8	9	10	11	12
<b>CALCULATIONS</b>													
Revenues, €		11,287,586	11,287,586	11,287,586	11,287,586	11,287,586	11,287,586	11,287,586	11,287,586	11,287,586	11,287,586	11,287,586	11,287,586
Electricity, €		3,267,810	3,267,810	3,267,810	3,267,810	3,267,810	3,267,810	3,267,810	3,267,810	3,267,810	3,267,810	3,267,810	3,267,810
Heating, €		8,019,776	8,019,776	8,019,776	8,019,776	8,019,776	8,019,776	8,019,776	8,019,776	8,019,776	8,019,776	8,019,776	8,019,776
Expenditures, €		-6,505,129	-6,505,129	-6,505,129	-6,505,129	-6,505,129	-6,505,129	-6,505,129	-6,505,129	-6,505,129	-6,505,129	-6,505,129	-6,505,129
Fuel, €		-4,576,153	-4,576,153	-4,576,153	-4,576,153	-4,576,153	-4,576,153	-4,576,153	-4,576,153	-4,576,153	-4,576,153	-4,576,153	-4,576,153
O&M costs, €		-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976
<b>Operating result, €</b>		<b>4,782,457</b>	<b>4,782,457</b>	<b>4,782,457</b>	<b>4,782,457</b>	<b>4,782,457</b>	<b>4,782,457</b>	<b>4,782,457</b>	<b>4,782,457</b>	<b>4,782,457</b>	<b>4,782,457</b>	<b>4,782,457</b>	<b>4,782,457</b>
Investment costs, €	-37,600,000	0	0	0	0	0	0	0	0	0	0	0	0
<b>Free cash flow, €</b>	<b>-37,600,000</b>	<b>4,782,457</b>	<b>4,782,457</b>	<b>4,782,457</b>	<b>4,782,457</b>	<b>4,782,457</b>	<b>4,782,457</b>	<b>4,782,457</b>	<b>4,782,457</b>	<b>4,782,457</b>	<b>4,782,457</b>	<b>4,782,457</b>	<b>4,782,457</b>
<b>NPV</b>	<b>7,283,713</b>												

### ASSUMPTIONS

Discount rate	4%
Initial investment	37.6 mln.€
Reduction coefficient of energy production during warm season	0.6

### ANEX 3. ECONOMIC ANALYSIS (CASE 3)

Year	0	1	2	3	4	5	6	7	8	9	10	11	12
CALCULATIONS													
Revenues, €		13,673,619	13,673,619	13,673,619	13,673,619	13,673,619	13,673,619	13,673,619	13,673,619	13,673,619	13,673,619	13,673,619	13,673,619
Electricity, €		4,215,750	4,215,750	4,215,750	4,215,750	4,215,750	4,215,750	4,215,750	4,215,750	4,215,750	4,215,750	4,215,750	4,215,750
Heating, €		9,457,869	9,457,869	9,457,869	9,457,869	9,457,869	9,457,869	9,457,869	9,457,869	9,457,869	9,457,869	9,457,869	9,457,869
Expenditures, €		-7,537,409	-7,537,409	-7,537,409	-7,537,409	-7,537,409	-7,537,409	-7,537,409	-7,537,409	-7,537,409	-7,537,409	-7,537,409	-7,537,409
Fuel, €		-5,608,433	-5,608,433	-5,608,433	-5,608,433	-5,608,433	-5,608,433	-5,608,433	-5,608,433	-5,608,433	-5,608,433	-5,608,433	-5,608,433
O&M costs, €		-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976
<b>Operating result, €</b>		<b>6,136,210</b>	<b>6,136,210</b>	<b>6,136,210</b>	<b>6,136,210</b>	<b>6,136,210</b>	<b>6,136,210</b>	<b>6,136,210</b>	<b>6,136,210</b>	<b>6,136,210</b>	<b>6,136,210</b>	<b>6,136,210</b>	<b>6,136,210</b>
Investment costs, €		-4,559,000	-4,559,000	-4,559,000	-4,559,000	-4,559,000	-4,559,000	-4,559,000	-4,559,000	-4,559,000	-4,559,000	-4,559,000	-4,559,000
<b>Free cash flow, €</b>		<b>1,577,210</b>	<b>1,577,210</b>	<b>1,577,210</b>	<b>1,577,210</b>	<b>1,577,210</b>	<b>1,577,210</b>	<b>1,577,210</b>	<b>1,577,210</b>	<b>1,577,210</b>	<b>1,577,210</b>	<b>1,577,210</b>	<b>1,577,210</b>
<b>NPV</b>	<b>14,802,229</b>												

#### ASSUMPTIONS

Discount rate	4%
Bank interest rate	7%
Power plant works on a full load both seasons	



## ANEX 5. ECONOMIC ANALYSIS (CASE 5)

Year	0	1	2	3	4	5	6	7	8	9	10	11	12
CALCULATIONS													
<b>Revenues, €</b>		<b>18,535,736</b>	<b>18,535,736</b>	<b>18,535,736</b>	<b>18,535,736</b>	<b>18,535,736</b>	<b>18,535,736</b>	<b>18,535,736</b>	<b>18,535,736</b>	<b>18,535,736</b>	<b>18,535,736</b>	<b>18,535,736</b>	<b>18,535,736</b>
Electricity, €		10,515,960	10,515,960	10,515,960	10,515,960	10,515,960	10,515,960	10,515,960	10,515,960	10,515,960	10,515,960	10,515,960	10,515,960
Heating, €		8,019,776	8,019,776	8,019,776	8,019,776	8,019,776	8,019,776	8,019,776	8,019,776	8,019,776	8,019,776	8,019,776	8,019,776
<b>Expenditures, €</b>		<b>-6,505,129</b>	<b>-6,505,129</b>	<b>-6,505,129</b>	<b>-6,505,129</b>	<b>-6,505,129</b>	<b>-6,505,129</b>	<b>-6,505,129</b>	<b>-6,505,129</b>	<b>-6,505,129</b>	<b>-6,505,129</b>	<b>-6,505,129</b>	<b>-6,505,129</b>
Fuel, €		-4,576,153	-4,576,153	-4,576,153	-4,576,153	-4,576,153	-4,576,153	-4,576,153	-4,576,153	-4,576,153	-4,576,153	-4,576,153	-4,576,153
O&M costs, €		-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976	-1,928,976
<b>Operating result, €</b>		<b>12,030,607</b>	<b>12,030,607</b>	<b>12,030,607</b>	<b>12,030,607</b>	<b>12,030,607</b>	<b>12,030,607</b>	<b>12,030,607</b>	<b>12,030,607</b>	<b>12,030,607</b>	<b>12,030,607</b>	<b>12,030,607</b>	<b>12,030,607</b>
Investment costs, €		-4,559,000	-4,559,000	-4,559,000	-4,559,000	-4,559,000	-4,559,000	-4,559,000	-4,559,000	-4,559,000	-4,559,000	-4,559,000	-4,559,000
<b>Free cash flow, €</b>		<b>7,471,607</b>	<b>7,471,607</b>	<b>7,471,607</b>	<b>7,471,607</b>	<b>7,471,607</b>	<b>7,471,607</b>	<b>7,471,607</b>	<b>7,471,607</b>	<b>7,471,607</b>	<b>7,471,607</b>	<b>7,471,607</b>	<b>7,471,607</b>
<b>NPV</b>	<b>70,121,584</b>												

### ASSUMPTIONS

Discount rate	4%
Bank interest rate	7%
Reduction coefficient of energy production during warm season	0.6
Electricity price	107 €/MWh