



Pre-study: Flexible solutions to decrease greenhouse gas emissions from heating furnaces in the steel industry

WP 3: Conceptual scenario descriptions with different heating combinations.

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Table of contents

List of figures.....	3
1 Introduction.....	5
1.1 Background.....	5
1.2 Objective	5
2 Methodologies	5
3 Result	6
3.1 Requirements	6
3.2 Reheat furnace.....	6
3.3 Heat treatment furnace.....	7
3.4 Fuel availability in Sweden today and potential.....	8
3.4.1 Natural gas.....	8
3.4.2 Biogas.....	9
3.4.3 Syngas.....	10
3.4.4 Pyrolysis oil.....	14
3.4.5 Hydrogen	15
3.5 Fuel properties.....	16
3.5.1 Composition and heating value.....	16
3.5.2 Wobbe index.....	18
3.5.3 Flame speed.....	19
3.5.4 Auto-ignition temperature.....	19
3.5.5 Adiabatic flame temperature.....	20
3.5.6 Gas emissivity.....	24
3.6 Energy utilization with different combustion techniques.....	24
3.7 Case studies and calculation method for fuel need and CO ₂ emissions	28
3.7.1 Results case studies-Reheating	31
3.7.2 Results case studies- Heat treatment.....	38
4 Conclusions and discussion	44
5 References.....	45

List of figures

Figure 1: Diagram of the heating, quenching, tempering and cooling processes [5].....	7
Figure 2: Map over the piped network for natural gas in Sweden. [7].....	8
Figure 3: Historical annual biogas production in Sweden by source [9].....	9
Figure 4 Source distribution for the Swedish bio gas potential, forestry excluded [10].....	9
Figure 5: Schematic view of a downdraft gasifier with process steps/zones marked	10
Figure 6 Schematic view of a fixed bed updraft gasifier	11
Figure 7: Schematic view of a fixed bed downdraft gasifier	11
Figure 8: Schematic view of a bubbling fluidized bed gasifier	11
Figure 9: Schematic view of a circulating fluidized bed gasifier	11
Figure 10: Lahti/Finland Valmet design CFB 160 MW Waste Solid.....	12
Figure 11: Skive Denmark ~15 <MW [14].....	12
Figure 12: Two EF gasifiers operating under slagging condition.....	12
Figure 13: Schematic view of DTU developed Viking gasifier 75 kW.....	13
Figure 14: Höganäs Sweden, Cortus Woodroll 6 MW [15].....	13
Figure 15: schematic view of three different electrolysis cell technologies [27].....	15
Figure 16: Gas composition in volume percentage for a range of syngas from different technologies, hydrogen, biogas, natural gas and propane.....	17
Figure 17: Lower heating value for the different gas mixtures.....	18
Figure 18: Calculated values for Wobbe index of analyzed fuels	18
Figure 19: Burning velocities for different fuel compositions and equivalence ratios at ambient temperature and pressure [29]	19
Figure 20: Burning velocity for hydrogen-methane-air mixtures ($\Phi = 1$) at ambient temperature and pressure [29]	19
Figure 21: Auto-ignition temperature for hydrogen, natural gas, propane and syngas, light blue illustrates range between different syngases in degree Celsius [30, 31].....	20
Figure 24: Flue gas emissivity as a function of oxygen enrichment, 21% O ₂ corresponds to air combustion.....	24
Figure 25: Relative impacts of recuperative and regenerative burner system on fuel savings (ϵ is temperature efficiency).....	25
Figure 26: Conventional reheating furnace with the central unites heat recovery system.	26
Figure 27: Conventional furnace with decentralised heat recuperative burners system.....	26
Figure 28: Regenerative combustion system using a pair of burner with decentralized highly efficient flue gas recovery.....	27
Figure 29: Schematic view of recouperative combustion system with a centralizd flue gas heat recovery system.....	28
Figure 30: Schematic view of a regenerative combustion system with decentralized heat recovery.....	28
Figure 31: CO ₂ emissions per ton steel reheated as function of fuel and oxygen level in oxidizer.....	31
Figure 32: CO ₂ emissions per ton steel reheated as function of fuel and oxygen level in oxidizer	31
Figure 33: CO ₂ emissions, and calculated fuel usage per ton steel reheated as function of hydrogen enrichment	32
Figure 34: CO ₂ emissions, and calculated fuel usage per ton steel reheated as function of hydrogen enrichment	32
Figure 35: CO ₂ emissions, and calculated fuel usage per ton steel reheated as function of hydrogen enrichment	33
Figure 36: CO ₂ emissions, and calculated fuel usage per ton steel reheated as function of hydrogen enrichment	33
Figure 37: CO ₂ emissions per ton steel reheated as function of syngas enrichment for recuperative and regenerative combustion system with air and oxygen as oxidizer.	34
Figure 38: Biogenic and fossil CO ₂ emissions per ton steel reheated as function of syngas enrichment for recuperative and regenerative natural gas combustion system with air and oxygen as oxidizer.....	34
Figure 39: CO ₂ emissions (all biogenic) per ton steel reheated for recuperative and regenerative systems burning hydrogen-enriched syngas for both air and oxygen.	35
Figure 40: Schematic view of a furnace with electrical preheating of the steel.	36
Figure 41: Reduction of CO ₂ with regards to steel preheating ether by electricity or from the continuous casting process.	36

Figure 42: Schematic view of recuperative combustion system coupled with induction heating.....	37
Figure 43: Schematic view of regenerative combustions system coupled with induction heating.	37
Figure 44: CO ₂ reduction with induction heating after a zoon with fuel fired heating.....	37
Figure 45: CO ₂ emissions per ton steel heat-treated as function of fuel and oxygen level in oxidizer	38
Figure 46: CO ₂ emissions per ton steel heat-treated as function of fuel and oxygen level in oxidizer	38
Figure 47: CO ₂ emissions, and calculated fuel usage per ton steel heat treated as function of hydrogen enrichment	39
Figure 48: CO ₂ emissions, and calculated fuel usage per ton steel heat treated as function of hydrogen enrichment	39
Figure 49: CO ₂ emissions, and calculated fuel usage per ton steel heat-treated as function of hydrogen enrichment	40
Figure 50: CO ₂ emissions, and calculated fuel usage per ton steel heat-treated as function of hydrogen enrichment	40
Figure 51: CO ₂ emissions per ton steel heat-treated as function of syngas enrichment for recuperative and regenerative combustion system with air and oxygen as oxidizer.	41
Figure 52: Biogenic and fossil CO ₂ emissions per ton steel heat-treated as function of syngas enrichment for recuperative and regenerative natural gas combustion system with air and oxygen as oxidizer.	41
Figure 53: CO ₂ emissions (all biogenic) per ton steel heat-treated for recuperative and regenerative systems burning hydrogen-enriched syngas for both air and oxygen.	42
Figure 54: Reduction of CO ₂ with regards to steel preheating with electricity.....	42
Figure 55: CO ₂ reduction with induction heating after a zoon with fuel fired heating	43

1 Introduction

1.1 Background

The Swedish government has put up a goal that states that the net greenhouse gas emissions should be zero by the year of 2045. For the steel industry the process which carries the biggest amount of emissions is the reduction of iron ore into pig iron through the blast furnace. Researchers are investigating the opportunity of using hydrogen instead of coke for carbon free reduction of iron ore in a project called HYBRIT.

This report however looks into possibilities to reduce the emissions from downstream processes, namely the reheating and heat treatment processes. The furnaces related to these processes is generally heated by combustion of different liquid and gaseous fuels, but usually by natural gas and byproduct gases from the coke oven and the blast furnace. The availability of such byproduct gases will with future reduction methods using hydrogen no longer be available in steel treatment processes thus forcing some furnace to change fuel regardless the future goal of zero net emissions.

1.2 Objective

The objective of this work package is to analyze the possibilities for fuel change in the reheating and heat treatment process with focus on gaseous fuels together with oxygen enrichment and electric heating alternatives to quantify the CO₂ emissions per ton of steel processed as function of heating method and choice of fuel.

2 Methodologies

The list below shows the work that was carried out. The specific calculation methods are stated in the corresponding result sections.

- Review energy need and temperature for steel reheating furnace and heat treatment furnaces
- Review fuel availability in Sweden
- Review of gasification technologies in order to get fuel composition
- Review and calculation of fuel properties, such as Wobbe index, flame speed, auto ignition temperature, flammability limit, adiabatic flame temperature, flame emissivity in order to see which fuel can be used in existing equipment or requires changes such as burner change.
- Review limitations regarding fuel flexibilities
- Calculate CO₂ emissions and fuel need per ton steel with regards to fuel choice within chosen case studies (see subchapter below)
- Review electric heating solutions
- Propose flexible heating solutions combining fuel and electricity.

3 Result

3.1 Requirements

The annual energy usage in Swedish steel heating furnaces corresponds to 3.3 TWh [1].

Summary of below sub chapters in table format (values used in later calculations):

	Reheating furnace	Heat treatment furnace
T _{Steel in}	20 °C	20 °C
T _{Steel out}	1200 °C	850 °C
Energy usage (Natural gas)	1,21 GJ/ton _{steel} [2]	0,72 GJ/ton _{steel} [3]
Steel heat capacity	Temperature range °C 20 600,00 600 735,00 735 900,00 900 1200,00	Steel heat capacity J/kgK [4] $C_p=425+7,73 \cdot 10^{-1} \cdot T-1,69 \cdot 10^{-4} \cdot T^2+2,22 \cdot 10^{-6} \cdot T^3$ $C_p=666+13002/(738-T)$ $C_p=545+17820/(T-731)$ $C_p=650$

3.2 Reheat furnace

In the reheating process the steel stock is charged into usually a continuous reheating furnace where the steel stock passes through a preheating, heating and soaking zone. The steel is heated with the means of convective and radiation heat transfer from the burners and furnace walls. The temperature at which the steel enters the furnace may range from ambient conditions to 800 °C, followed by heating to 1100-1300 °C depending on the steel grade and the rolling processes [1]. The continuous reheating furnace is since year 1995 usually a walking beam furnace with lateral burners, maximum length of approximately 60 m. The power output from burners in the reheat furnace can be around 50 MW. The trending design feature is an extended (length-wise) preheating zone for increased thermal efficiency. Surplus heat from the preheating zone is used to preheat combustion air that is in excess in this kind of furnace to ensure complete combustion and also avoid sticky scale formation. For high carbon steel the excess air factor is kept low in temperature zones above 900 °C to avoid decarburizing and also to control the scale formation. Combustion air is preheated to around 450 up to 600 °C.

Burners that are especially relevant for low heating value gaseous fuels are regenerative, (self-) recuperative with oxygen enrichment. The burners' location in the furnace (top, bottom or side) affects the flame shape, which in turn affects the heat transfer and temperature profile of the product. Typical burner power output is a few MW each. Latest low NO_x technologies gives 120 mg/Nm³ at 3 % O₂ for NG. [2]

The average net specific consumption for large reheating furnaces (>100 ton per hour) burning natural gas is 1,21 GJ/ton [2]

3.3 Heat treatment furnace

The purpose of heat treatment process is to change the properties of a metal or alloy load, such as hardness, strength and toughness. This is done through heating and/or cooling processes that change the microstructure of the load. The basic heat treatment processes performed in furnaces and quench equipment include annealing, normalizing, neutral hardening, carburizing, decarburizing, solution treating and ausempering. For alloys, for example steel, the process steps are heating, quenching and then tempering. Generally, heat treatment processes include heating, cooling and sometimes another heating. Figure 1 shows these required processes although the diagram will be different alloys and for different type of processing. The most important parameters of a heat treatment process are the critical temperature, heating rate, the time of keeping the material at specific temperatures, and the cooling rate. [5]

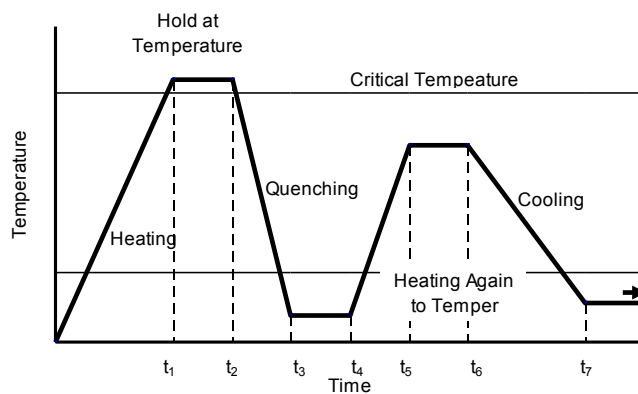


Figure 1: Diagram of the heating, quenching, tempering and cooling processes [5]

The heating critical temperature is obtained according to the group of metal and the aim of heating. This temperature is strictly limited. Heat-up rate, final temperature and holding time not only determines the furnace productivity and economy but also affect the properties of the treated materials. A typical annealing process of carbon tool steels includes slow heating to 680-720 °C and hold at this temperature for the desired length of time, for about 4-8 hours, followed by slow cooling rate. It is cooled slowly the furnace and sample. For normalizing process, it is heated slowly to 870 °C and holding for 1-2 hours, followed by air cooling. [5]

3.4 Fuel availability in Sweden today and potential

3.4.1 Natural gas

The Swedish market for natural gas is fully dependent on imports through Denmark. The total capacity of natural gas in the Swedish infrastructure is 22 TWh_a, while the consumption is around 15 TWh_a (2011). Any construction work or expansion of the natural gas infrastructure should be based on commercial supplies since the Swedish government does not finance or own any part of the system. As can be seen in Figure 2 of today's pipeline network that is limited to the South West part of Sweden. [6]



Figure 2: Map over the piped network for natural gas in Sweden. [7]

Natural gas (NG) distribution is however not limited to the piped network, as it can be transported by for example road, rail or sea transportation as compressed (CNG) or cooled to liquid (LNG). LNG has been well known since the first half of 1900s. In liquid state at $-162\text{ }^{\circ}\text{C}$ the volume of the gas is only 1/600 compared to normal conditions (ambient pressure and temperature). Ignition temperature: $580\text{ }^{\circ}\text{C}$, flammability limit in air: 5-15 %. Natural gas is considered to be a more environmentally friendly energy carrier with promising future compared to coal and crude oil. Carbon dioxide emissions from NG solution is 20 % less compared to crude oil, and 45 % less CO_2 emissions compared to coal. It is speculated that natural gas can fulfil world need for at least 100-150 years after the world's oil supply has ended. [8]

3.4.2 Biogas

Annual biogas production in Sweden corresponds to 2 TWh_a (2016), with co-digestion plants as main producer as can be seen in Figure 3 below.

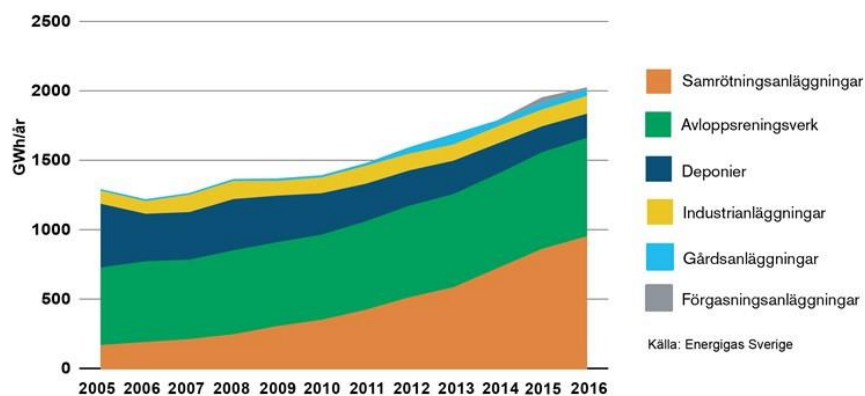


Figure 3: Historical annual biogas production in Sweden by source [9]

Potential biogas production from domestic household and agricultural waste is estimated to be 10,6-15,2 TWh_a when excluding feedstocks from the forests. The source distribution of the potential biogas is shown in Figure 4 below. Plans for big scale bio-digestive plants are in motion with production capacities of 50 GWh_a. If the residue from forestry and forest industry is included, the estimated total potential is 74 TWh_a. 59 TWh_a of the estimated total potential will be covered in the section syngas which is said to need technical innovations to become economically viable. [10]

The available biogas on the market is upgraded to natural gas composition (mostly methane) and injected into the piped natural gas network, and is sold in the same way as source guaranteed electricity, i.e. the seller's input the customer agreed amount of bio-methane into the piped network, not promising that the molecules from agreed source reach the end customer. [11]

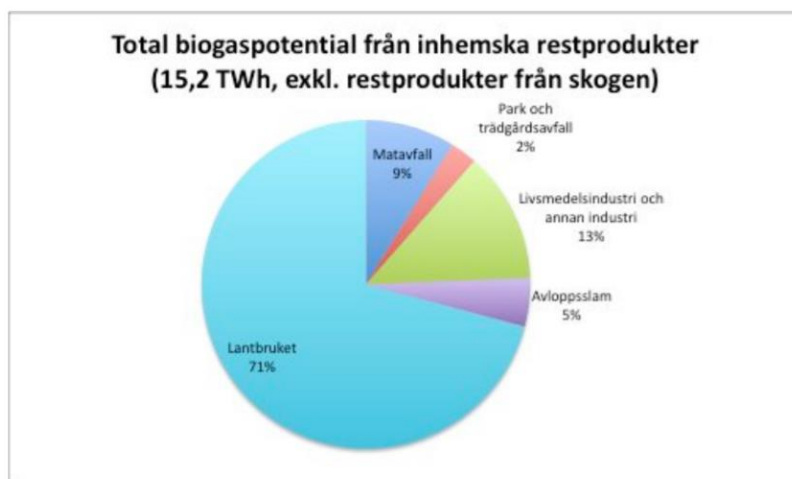


Figure 4 Source distribution for the Swedish bio gas potential, forestry excluded [10]

3.4.3 Syngas

In order to utilize the 59 TWh_a of “biogas potential” mentioned in the end of previous chapter (from residue and waste from the forestry and forest industry), the biomass has for our gaseous fuel purpose firstly change from solid to gas. Depending on gasification technology the product syngas composition changes and also its fuel properties.

Gasification is a method for converting solid or liquid feedstock into gaseous fuel that can be combusted for heat and energy purposes. Gasification and combustion are two related thermochemical processes. Gasification results in a gaseous fuel where energy is stored into chemical bonds of the produced gas, while combustion breaks those bonds through oxidation with energy release as a result. Hydrocarbons that gets gasified gets some of its carbon removed and depending on process hydrogen can be added witch results in a product gas with high hydrogen to carbon ratio.

Typical sequence of events during biomass gasification are as follows: drying, thermal decomposition (pyrolysis), partial combustion (of some gas, vapors and char) and gasification of decomposed products. For visualization, refer to Figure 5.

Pyrolysis is an endothermic thermal decomposition process in absence of oxygen not relying on oxidation as heat source. Gasification needs however a gasifying agent such as air, steam or oxygen to rearrange the molecular structure of the feedstock, in its quest of turning solid into gas. Depending on the choice of gasification agent, hydrogen can also be added to the products. [12]

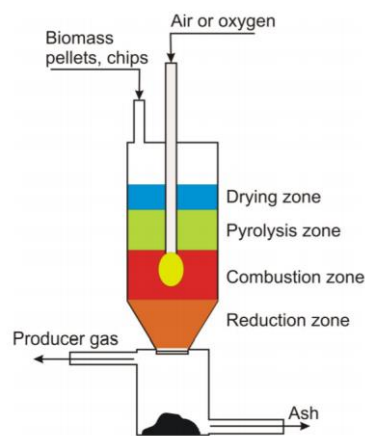


Figure 5: Schematic view of a downdraft gasifier with process steps/zones marked

There are many different kinds of gasifiers and commonly they are classified according to:

- Choice of oxidation agent: air, oxygen or steam
- Autothermal (direct) or allothermal (indirect) heating
- Pressurized or atmospheric coonditions
- Reactor design: fixed bed, fluidized bed, twin bed, entrained flow

Fixed bed gasifiers are simple in design and operation, suitable for applications in the range of a few hundred kW_{th}. Figure 6 and 7 below show two versions of the fixed bed design, updraft and downdraft. [13]

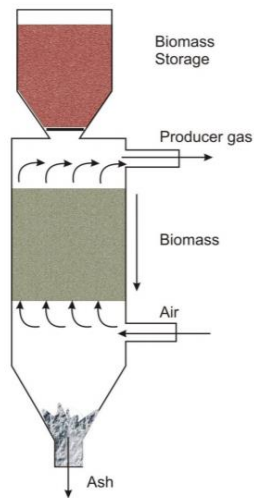


Figure 6 Schematic view of a fixed bed updraft gasifier

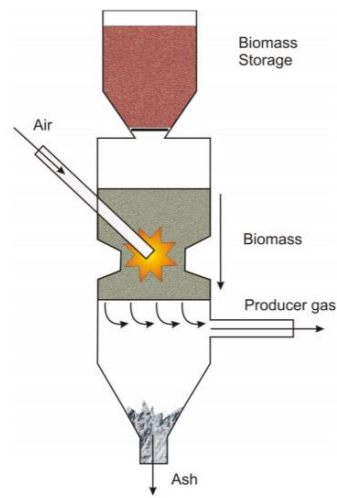


Figure 7: Schematic view of a fixed bed downdraft gasifier

For fluidized bed gasifiers the inlet gasification agent is injected under the feedstock and catalyst at a high enough velocity that the solid particles get suspended in the gas stream. Depending on flow velocity the fluidized bed will commonly be categorized as a bubbling (BFB) or circulating fluidized bed (CFB), schematics shown in Figure 8 and 9. The fluidization is used to increase heating rate of the particles that is being gasified. Suitable scale for BFB are in the range of 10-100 MW_{th} and CFB > 20MW_{th}. Industrial examples are shown in Figure 10 and 11.[13]

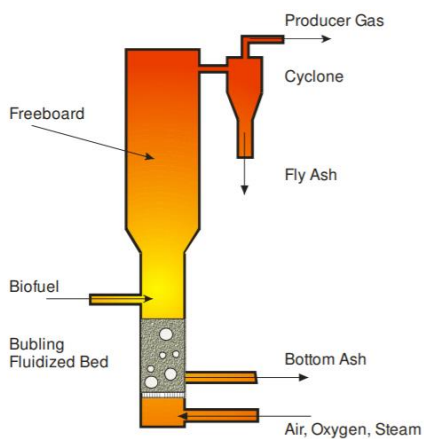


Figure 8: Schematic view of a bubbling fluidized bed gasifier

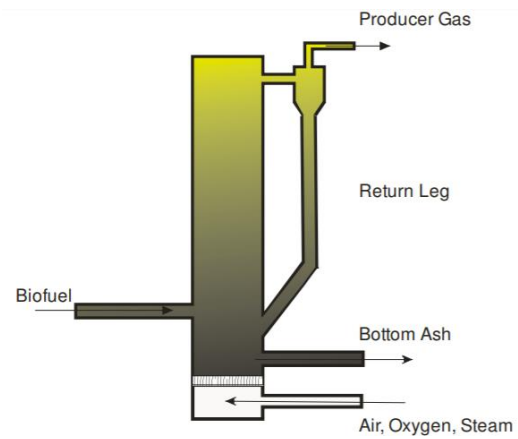


Figure 9: Schematic view of a circulating fluidized bed gasifier

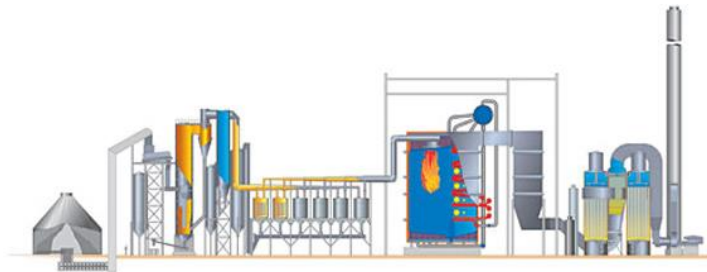


Figure 10: Lahti/Finland Valmet design CFB 160 MW Waste Solid

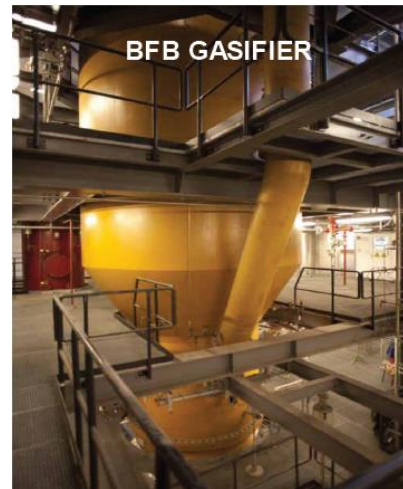


Figure 11: Skive Denmark ~15 <MW [14]

Entrained flow (EF) gasifiers need a very fine particle size since the feedstock is dropped into the reactor from the top or mixed with water to form a slurry that can be sprayed into the reactor together with the gasification agent that then is partially combusted with the help of a pilot flame. The EF gasifiers operate under very high temperature which results in that most of tar gets converted into product gas with lower requirements on downstream gas cleaning compared to other gasification technologies. The high temperature does however melt the ash in the feedstock forming highly corrosive slag. Figure 12 shows two different solutions of the EF gasifier slag problem. The complexity of the EF gasifier makes them suitable for installations over 100 MW_{th}.

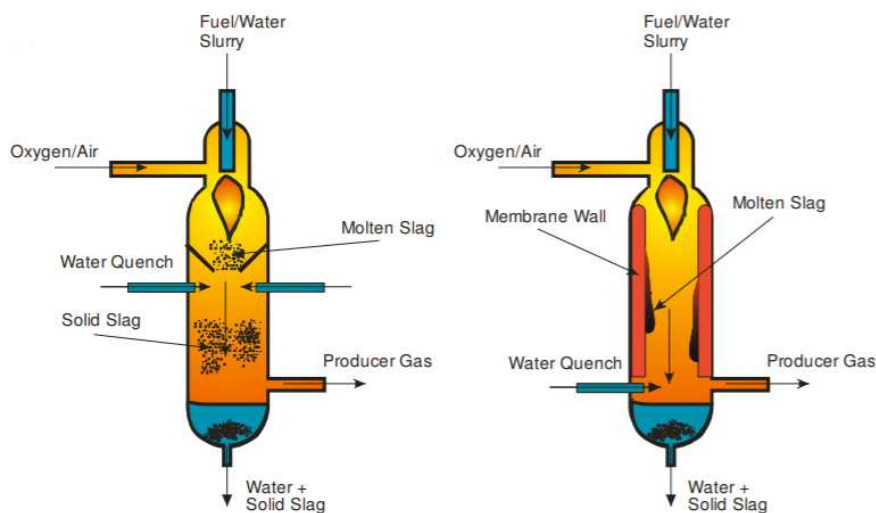


Figure 12: Two EF gasifiers operating under slagging condition

Gasifier designs where the pyrolysis zone is separated from the gasifier is in this report referred to as hybrid or multistep, examples of those are DTU (Technical University of Denmark)-developed Viking gasifier and Cortus WoodRoll-process from Sweden. The advantage of these multistep systems is a higher gas quality, with lower or no requirements on gas cleaning because of the low concentrations of tar in the

output gas from the gasifier. During the pyrolysis step with these designs, volatiles are being extracted and partially or fully combusted to generate enough heat for the bio-char gasification, i.e. the source of the tar are being burned off. Figure 13 and 14 below show mentioned systems.

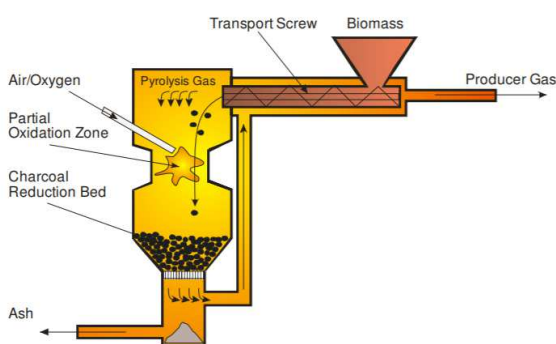


Figure 13: Schematic view of DTU developed Viking gasifier 75 kW.

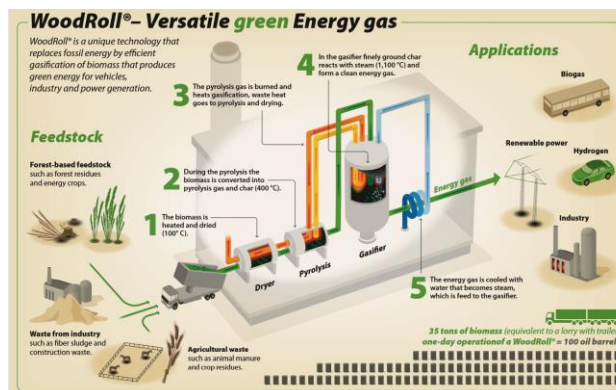


Figure 14: Höganäs Sweden, Cortus Woodroll 6 MW [15]

Table 1 below shows a list of identified gasifiers on the market, where it can be seen that Valmet is one of the major producers when it comes to circulating fluidized bed gasifiers (CFB), Carbona/Andritz produces bubbling fluidized bed reactors (BFB), and for hybrid or multistep solutions DTU and Cortus.

Table 1: Identified industrial size gasifiers on the market

Capacity	Feedstock	Producer/technology	Installations	Operational /source
160 MW	Waste (SFR)	Valmet CFB	Vaskiluodon Voima Oy, Vaasa, Finland	2012 [16]
140 MW, 50 electricity, 90 district heat	Biomass	Valmet CFB	Lahti Energia Oy, Lahti, Finland	2012 [16]
100 MW x2	Biomass (bark and wood residues)	Valmet CFB	OKI Pulp & Paper Mills, Indonesia	2016 expected [16]
~15 MW	Wood pellets	Carbona Andritz BFB	CHP-plant, Skive Denmark	[17]

8 MW feedstock	Biomass	Fast Internally Circulating Fluidized Bed (FICFB)	CHP-plant ,BKW, Güssing Austria	2002 [18]
20 MW 80-100 MW	Pellets Wood chip and bark (2016)	Valmet CFB	GoBiGas Göteborgs energy, Hissingen, Sweden	2015- [19-21] Big one postponed indefinitely for economic reasons
75 kW	Biomass pyrolysis followed by charcoal gasification	Viking gasifier DTU-design Hybrid	DTU- Technical university of Denmark	
6 MW	Biomass pyrolysis followed by charcoal gasification	Cortus Woodroll Hybrid	Höganäs, Swden	2019- [15]

3.4.4 Pyrolysis oil

Another bio-derived fuel from forest residue is bio oil from pyrolysis.

Bio-oil from pyrolysis of biomass is supposed to replace fuel oils in stationary applications such as boilers, furnaces, engines and turbines in future energy generations. The feedstock is steadily becoming available to the energy markets in for example Europe and North America [22]. However, bio-oil has different properties compared to petroleum based fuels and other bio-fuels. Compared to conventional liquid fuels, pyrolysis oil has a high water content which drastically reduces its heating value, lowers the adiabatic flame temperature and local combustion temperatures, as well as lowers the combustion reaction rates. Bio-oil also increases the ignition delay time. However, its high water content enhances the atomization properties of the fuel by reducing its viscosity. The fuel also leads to reduced NO_x-emissions due to the lower local temperatures as well as flame temperature [22-26]. The relatively low heating value of bio-oil requires a higher flow rate of fuel compared to fossil fuels, which affects the design of furnaces and burners in terms of for example spray characteristics (atomizing quality), modification of the nozzle and the design of the combustion chamber. The adiabatic flame temperature of bio-oil is typically 1400-1700°C, slightly lower than petroleum-based fuels (1700-2000°C) [23]. Air-to-fuel ratio must be taken into account when using bio-oil because of its high oxygen content compared to fossil fuels. Previous works have observed that bio-oil is more difficult to handle than a fossil-based hydrocarbon fuel, but once it has been ignited it can burn steadily [22].

3.4.5 Hydrogen

For large scale hydrogen production, the most common production route today is the so called steam methane reforming (SMR) eq.1 followed by a water gas shift reaction eq.2:



This process produces CO₂. As an alternative hydrogen gas can be produced by pyrolysis of methane without carbon dioxide emissions eq.3:



The downside is however that only half as much hydrogen gas is produced compared to SMR, but the energy needed is less and solid carbon is produced rather than CO₂. Catalyst coking is however a problem. Another way of producing hydrogen is with the help of electrolysis of water, where an electrical current is used to decompose the water into hydrogen and oxygen gas.

Three electrolysis technologies worth mentioning are: Alkaline Electrolysis Cells (AEC), Proton Exchange Membrane Electrolysis Cells (PEMEC) and Solid Oxide Electrolysis Cell (SOEC). Schematic view of the three technologies are shown in figure 15.

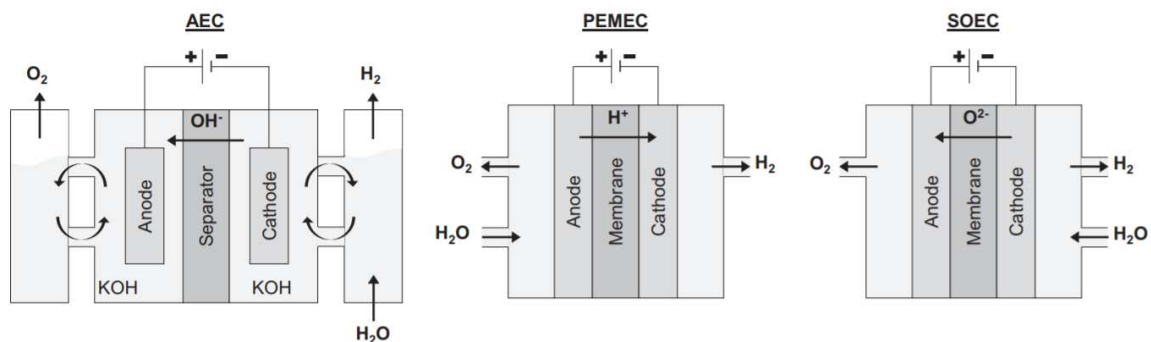


Figure 15: schematic view of three different electrolysis cell technologies [27]

AEC systems are widely used for large scale industrial applications since 1920 readily available, durable and relatively low capital cost since lack of noble metals. Low current density and operating pressure negatively affects system size and hydrogen production cost. System efficiency and product purity reduces with dynamic operation. Future cost reductions are most likely driven by economies of scale.

PEMEC systems which are based on solid polymer electrolyte was first introduced in the 60s by General Electric, thus not as mature as AEC, and mostly used in small scale applications. Advantages such as high power density and high cell efficiency, provision of highly compressed and pure hydrogen. Disadvantages are requirements of high water purity, high system complexity due to high pressure operation, expensive platinum catalyst and fluorinated membrane materials. Lifetime is at this stage shorter than AEC. R&D

are focusing on reducing system complexity, less expensive materials choices, and stack manufacturing processes to reduce capital cost in order to enable system scale up.

SOEC is the least developed technology, however systems has been developed and demonstrated on laboratory scale, and companies are currently aiming to bring the technology to market. The electrolyte or ion-conducting ceramic that is used withstands significantly higher operational temperatures. Potential advantages such as high electrical efficiency, low material cost and also the option to operate the unit in reverse as a fuel cell, or in co-electrolysis mod to produce syngas (CO + H₂) from steam and carbon dioxide. Material degradation is a key challenges and researchers are focusing on stabilizing existing -, developing new materials and lowering operational temperature.

Capital cost for 1 MW installations are around 1 000 000 €/ MWel for AEC, double for PEMEC and estimations regarding SOEC systems lies above PEMEC systems. [27]

3.5 Fuel properties

3.5.1 Composition and heating value

Depending on gasification technology and operational conditions, the gas composition of syngas will vary. The composition for the different gases considered in this report is shown in Table 2 and in Figure 16 below.

Table 2: Gas composition of different gaseous fuels: Fossil fuels, biogas, hydrogen and syngas produced from different technologies.

Fuel Composition: [% by volume]	Propane	Natural gas	Biogas (upgraded)	Biogas raw (dry)	Syngas: FBUD (air)	Syngas: Cortus	Syngas: CFB	Syngas: Gobigas	Syngas: Andritz BFB (air)	Syngas: Gussing FICFB	Syngas: Viking	Syngas: HITAG (air)	H ₂
Hydrogen (H ₂)				1	18	58	15	40	16	40	47	10	100
Carbon Monoxide (CO)					24	28	46	20	20	25	28	15	
Carbon Dioxide (CO ₂)				34	6	14	15	25	12	20	22	8	
Methane (CH ₄)	90	90	62	3	2	25	10	4	10	3	6		
Ethane (C ₂ H ₆)	5	5										0	
Propane (C ₃ H ₈)	100											1	
Oxygen (O ₂)			0	0									

Nitrogen (N2)	5	5	2	49				48	4	0	53	
Ethylene (C2H4)							5				6	

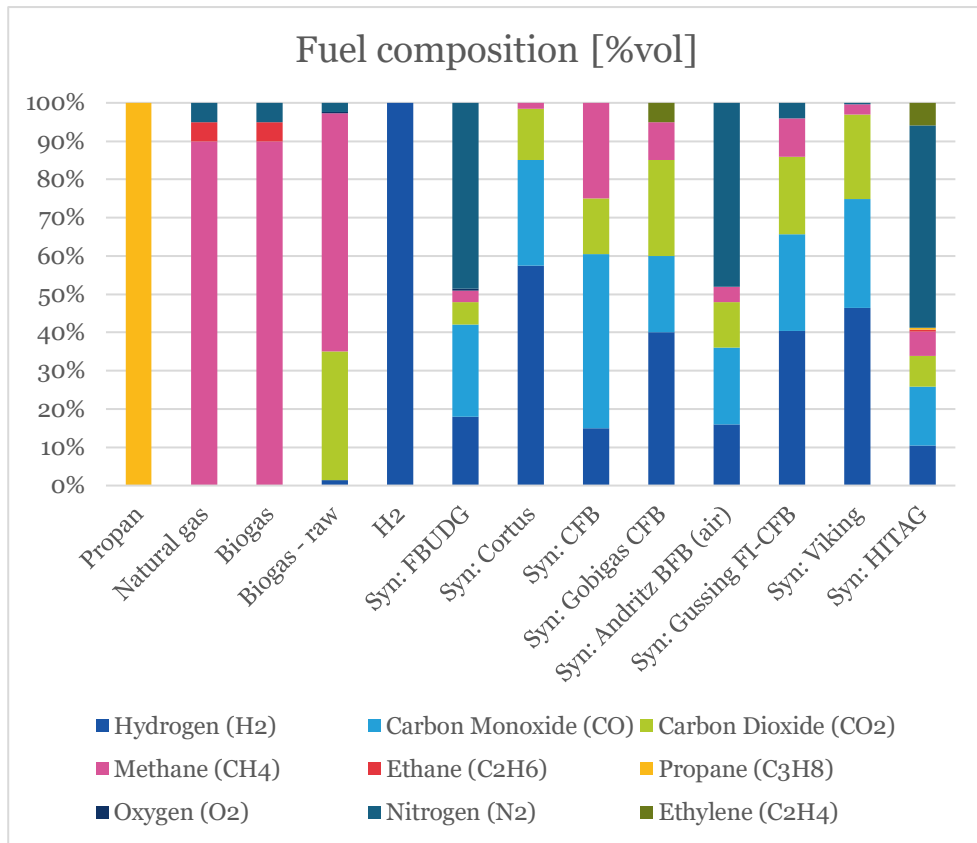


Figure 16: Gas composition in volume percentage for a range of syngas from different technologies, hydrogen, biogas, natural gas and propane

The lower heating value (LHV) on the basis of $\text{kJ/mol}_{\text{fuel}}$ of the different fuels was calculated by the difference in heat of formation of the reactants and products assuming complete combustion (eq.4). And for the basis of MJ/nm^3 the ideal gas relation of 1 mol gas corresponds to 22.4 liters at ambient pressure and temperature was used. Calculated results regarding LHV for the different gas mixtures are shown in Figure 17.

$$LHV = \sum \Delta H_{f_i}^0 * \text{Fuel composition}_i - \sum \Delta H_{f_i}^0 * \text{product concentration}_i \quad \text{eq.4}$$

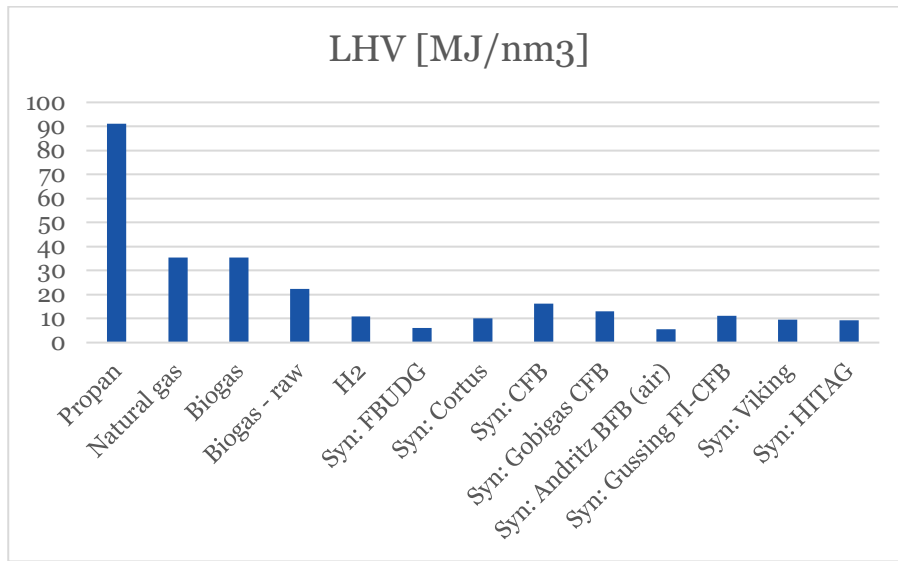


Figure 17: Lower heating value for the different gas mixtures.

3.5.2 Wobbe index

Wobbe index W_i is commonly used to quantify interchangeability of fuels with different density and volumetric heating values. The Wobbe index is defined as the ratio between volumetric energy density and relative density with respect to air (see eq. 5). A fuel change should be kept within manufacturer specification typically within a range of 5% of designed value, for the specific burner nozzle. [28] Calculation results regarding Wobbe index can be found in figure 18 below together with allowable range without changing burner geometry (+/- 5%) for a system designed to burn natural gas.

$$W_i = \frac{LHV}{\sqrt{\frac{\rho_{fuel}}{\rho_{air}}}} = LHV \sqrt{\frac{M_{air}}{M_{fuel}}}, \{LHV \text{ by volume}\} \quad \text{eq.5}$$

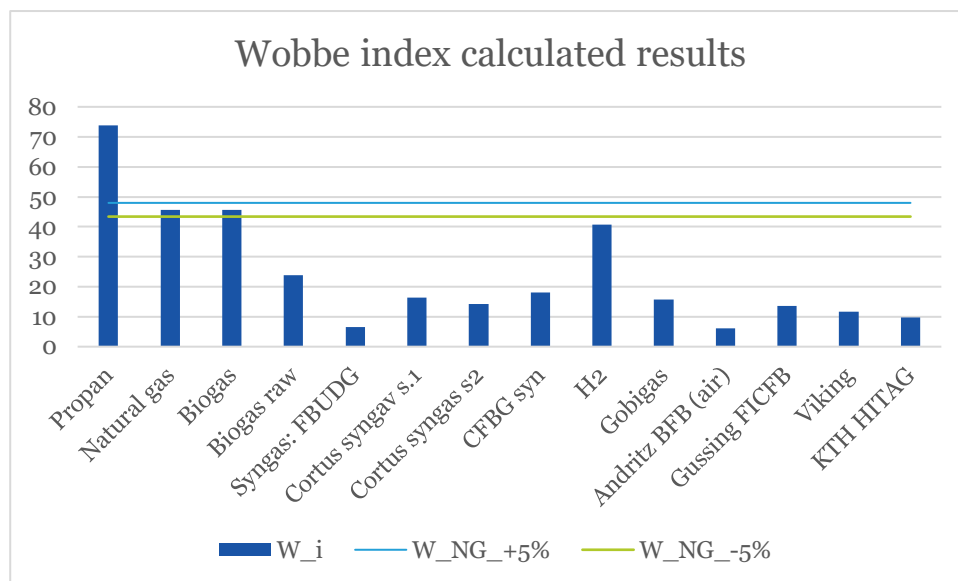


Figure 18: Calculated values for Wobbe index of analyzed fuels

3.5.3 Flame speed

The laminar burning velocity is an important factor for design and prediction of a combustion process or system, especially when hydrogen is used as a fuel. Figure 19 visualizes the significant difference of laminar flame speed for hydrogen, methane and a mixture of 50% each. This change of equivalence ratio shows the importance of proper air to fuel mixing to prevent local rich spots which would lead to hot spots (increases NO_x formation) but also has a detrimental effect on flash back resistance. If the equivalence ratio is fixed to 1, the laminar flame speed for different methane-hydrogen mixtures is shown in figure 20.

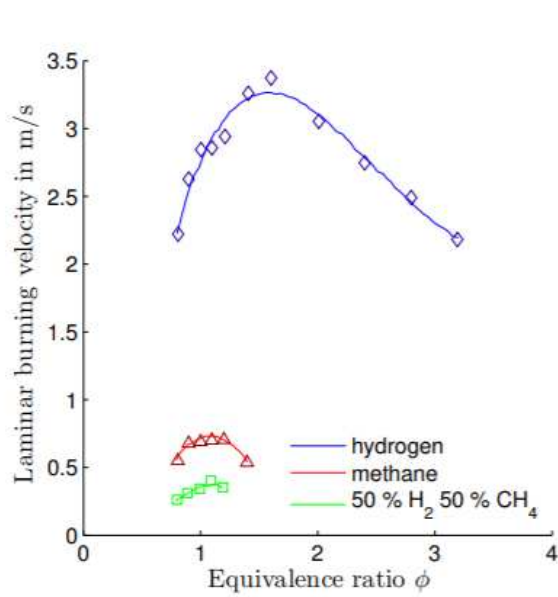


Figure 19: Burning velocities for different fuel compositions and equivalence ratios at ambient temperature and pressure [29]

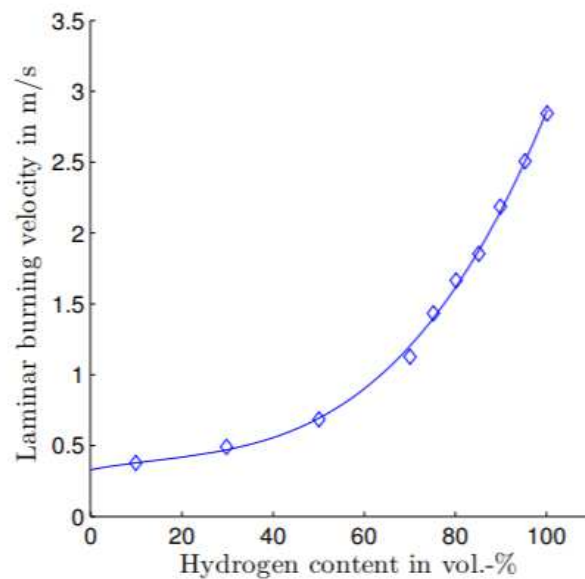


Figure 20: Burning velocity for hydrogen-methane-air mixtures ($\Phi = 1$) at ambient temperature and pressure [29]

3.5.4 Auto-ignition temperature

There are two different modes of ignition: forced and spontaneous. The auto-ignition temperature is defined as the temperature at which a gas mixture spontaneously ignites without the presence of a local energy addition (commonly a spark or pilot flame). Figure 21 shows values found in literature for the auto-ignition temperature of hydrogen, natural gas, propane and syngas. [30, 31]

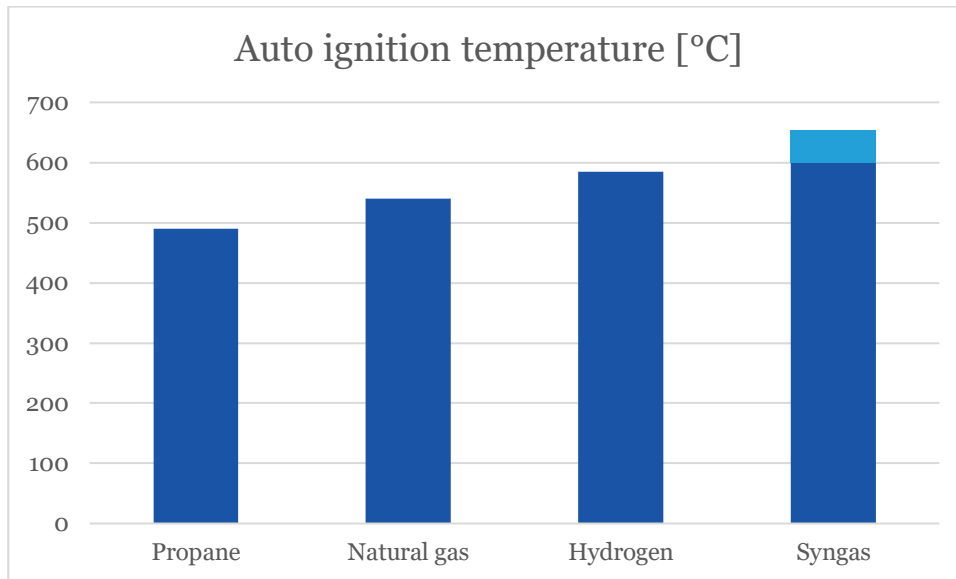


Figure 21: Auto-ignition temperature for hydrogen, natural gas, propane and syngas, light blue illustrates range between different syngases in degree Celsius [30, 31]

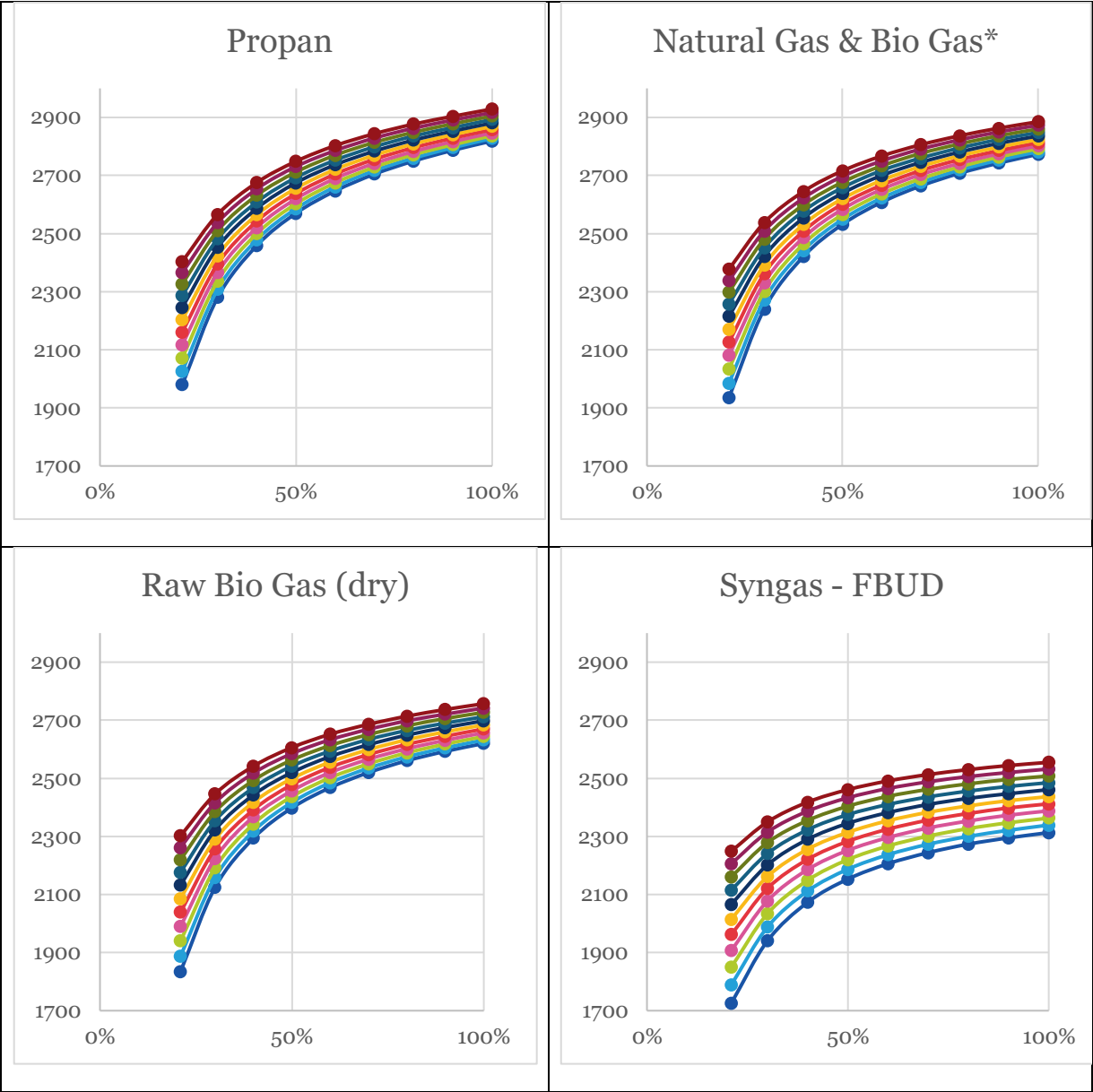
3.5.5 Adiabatic flame temperature

The adiabatic flame temperature is a theoretical temperature of a flame which has no heat transfer to the flames environment - all energy from the combustion is assumed to heat up the combustion products. The adiabatic temperature is therefore the highest theoretical temperature that a flame can reach.

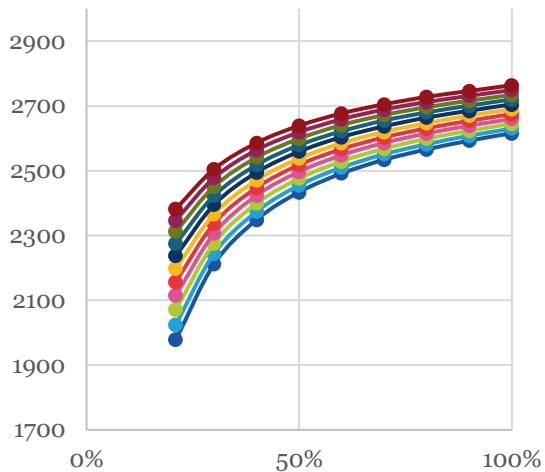
Depending on combustion technique different levels of preheating of the reactants (air and fuel) is achieved, which affects the flame and furnace temperature. Another way to increase the flame temperature is to use oxygen enrichment or oxyfuel combustion (by removing nitrogen from the combustion air, less inert gas has to be heated achieving higher combustion temperature). The diagrams in table 3 below show the results gained with the help of the program Gaseq, where the value axis shows the adiabatic flame temperature at different levels of preheat (diagram series) and oxygen concentration (diagram x-axis) in the oxidizer where 21% corresponds to traditional combustion with air (21% O₂ and 79% N₂), and 100% would correspond to pure oxyfuel combustion. All temperatures are in Celsius, and all calculations are based on combustion reaction at constant pressure (ambient) and an air-fuel equivalence ratio (λ) of 1,02.

Most fuels in this analysis reaches adiabatic flame temperature around 1900-2000°C. On the low side is raw biogas (digestive gas that has been dried) 1835 °C, Fixed Bed Up Draft syngas 1726 °C, Andritz syngas 1624 °C and the syngas from KTH:s High Temperature Air Gasifier 1784 °C. Common for these are that no nitrogen scrubbing has been performed before or after gasification giving the fuel mixtures a nitrogen content of roughly 50%. However they can also reach above 1900 °C such as natural gas combusted in air (21 % o₂), with preheating or oxygen enrichment. The HiTAG and FBUD syngas reaches 1900 °C with preheating temperatures of 200-300 °C, or with oxygen enrichment levels of a couple of percentage points (less than 30% oxygen in the oxidizer). The Andritz syngas that needs a little bit more help to reach the same temperature level; preheating of 400 °C or 34 % oxygen in the oxidizer.

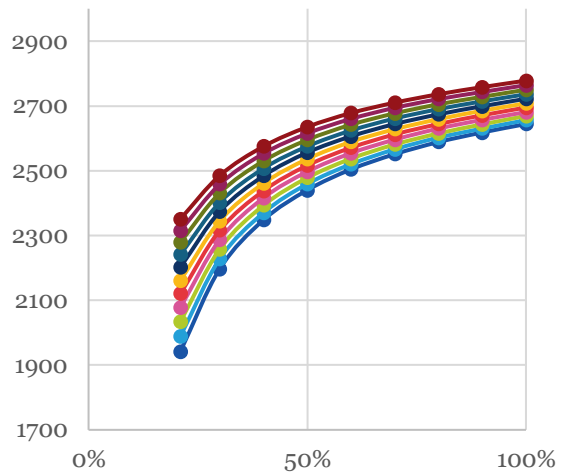
Table 3: Results for adiabatic flame temperature gained from Gaseq for analyzed gases with regards preheating temperature and oxygen enrichment. Value axis shows adiabatic flame temperature in [°C] for different preheating levels [°C] (diagram series, see color scheme in the bottom of table or ambient plus 100°C per line). X-axis shows the amount of oxygen in combustion oxidizer, where 21 % corresponds to air, 100 % - oxyfuel, and in between would be considered oxygen enrichment.



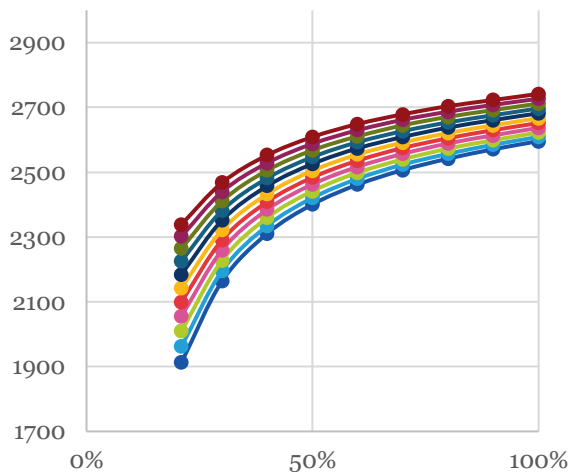
Syngas - Cortus



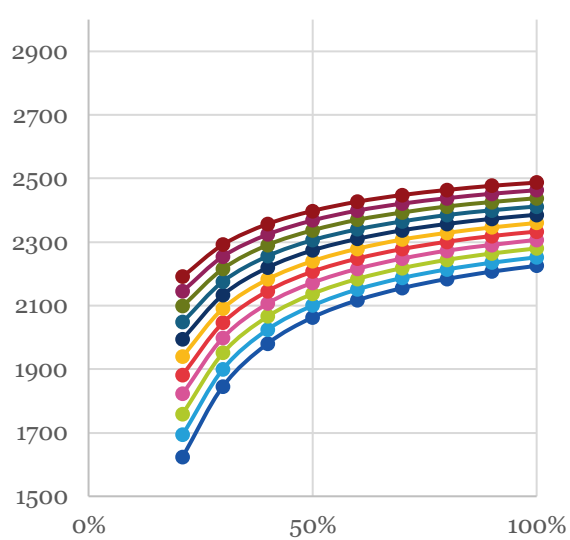
Syngas - CFB



Syngas - Gobigas



Syngas - Andritz



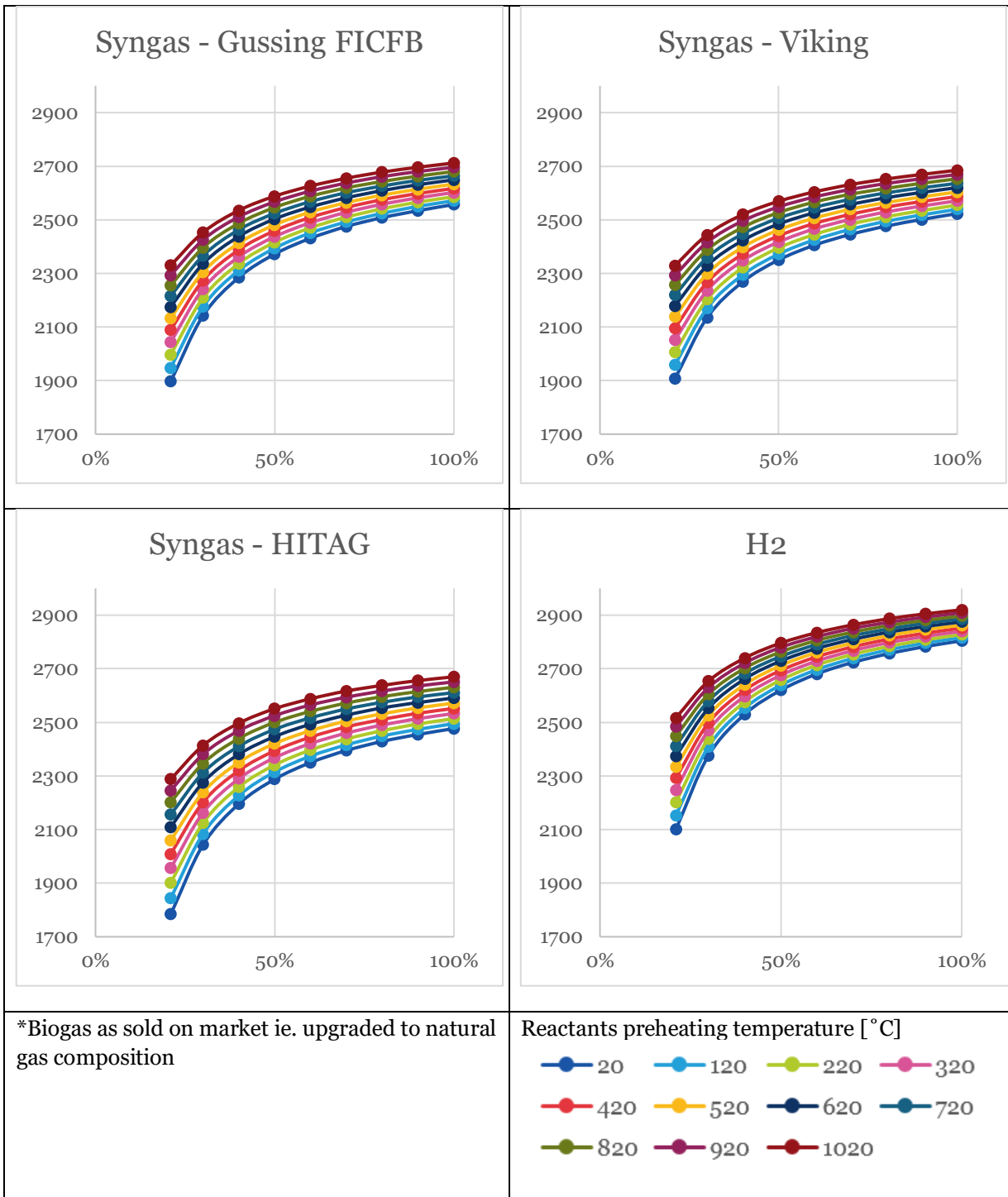


Table3: Results for adiabatic flame temperature gained from Gaseq for analyzed gases with regards preheating temperature and oxygen enrichment. Value axis shows adiabatic flame temperature in [°C] for different preheating levels [°C] (diagram series, see color scheme in the bottom of table or ambient plus 100°C per line). X-axis shows the amount of oxygen in combustion oxidizer, where 21 % corresponds to air, 100 % - oxyfuel, and in between would be considered oxygen enrichment.

3.5.6 Gas emissivity

It's considered as common knowledge that radiative heat transfer is the main mechanism of heat transfer inside a furnace, but what can be expected when switching fuel?

The gas emissivity was calculated for the different fuels that was chosen for the case studies, Natural gas, hydrogen and syngas. Where the syngas was agreed to be of the composition that is produced by the wood roll process designed by Cortus Energy.

The emissivity was calculated using a 3 term mixed grey-gas model for CO₂ H₂O and soot, originally designed for natural gas combustion, but since the syngas and hydrogen burns into the same flue gas components it was assumed that the model also is valid for those. [32]. The results shown in the figure below shows that the product gas emissivity from all tree fuels are in the same region and thereby will have similar radiative heat transfer capacity inside the furnace.

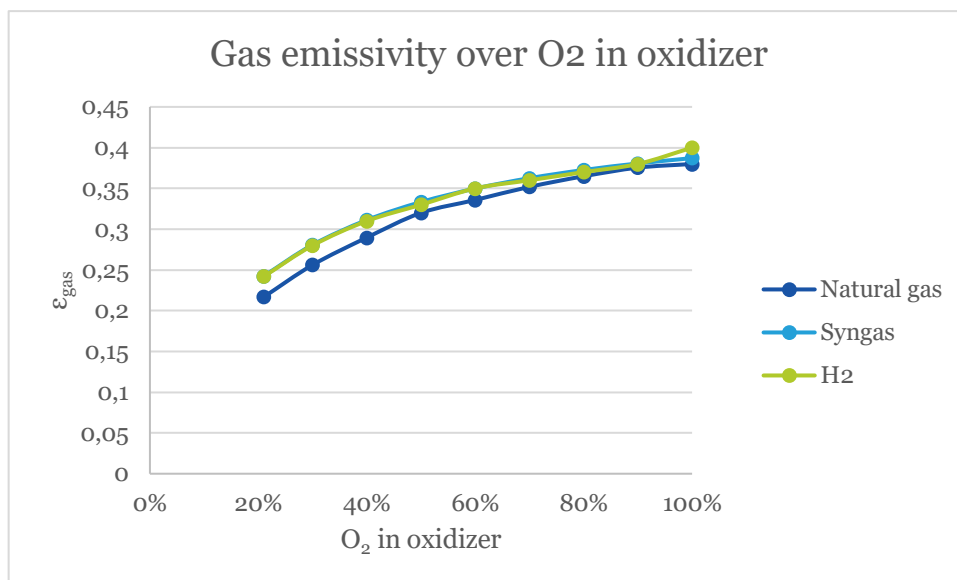


Figure 22: Flue gas emissivity as a function of oxygen enrichment, 21% O₂ corresponds to air combustion.

3.6 Energy utilization with different combustion techniques

Flue gas heat recovery significantly increases system efficiency and energy utilization. Steam and hot water generation in waste heat boilers are one way of recovering heat that would otherwise be lost and can be used on sight depending on needs or sold to district heating networks if available. KTH energy department has a small group for research in heat transportation by road "Värme på väg", to fill the gap where waste heat producers doesn't have available district heating networks. Another route that not just increase the energy efficiency but also decrease the fuel consumption for the furnace is to preheat cold stock by flue gases (needs very big furnaces, and might not be suitable for all processes because of the reactive nature of flue gases). The third option is to use the waste heat to preheat combustion air (and in some cases also the fuel), and within this option there are two types to choose from, recuperative and regenerative. Recuperative systems are commonly used and can preheat combustion air to maximum 600°C but in practice this level of preheat is rarely reached, instead usual preheat levels are in the region of 300-400°C. The recuperative performance is generally limited by heat exchanger surface area and

material constrains such as oxidation of the heat exchanger surfaces because of the preheated air. These and other limitations are circumvented by the more efficient regenerative combustion system.

A regenerative combustion system generally consists of two groups regenerators, two burners and the necessary control system. The regenerator is a two-chamber system that contains firebrick or a ceramic material for heat storage. These materials may be in the form of balls, honeycomb or even a granular refractory. Figure 25 shows the enhancement in energy utilization efficiency gained by recuperation and regeneration.

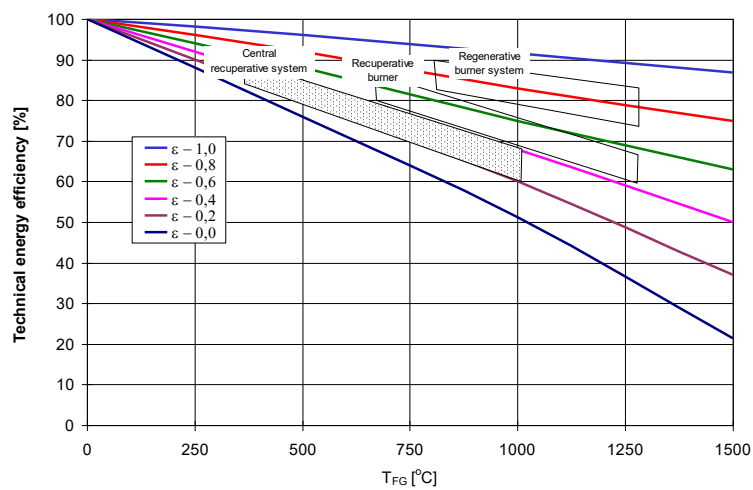


Figure 23: Relative impacts of recuperative and regenerative burner system on fuel savings (ϵ is temperature efficiency)

Both the recuperator and regenerator can be installed as central units after the furnace or decentralised units combined with burners. Central heat recuperator as shown in Figure 26 are installed after the furnaces. In both cases preheated combustion air is distributed between all burners installed along furnace, what increases investment and maintenance costs because of the high temperature, insulated piping must be used.

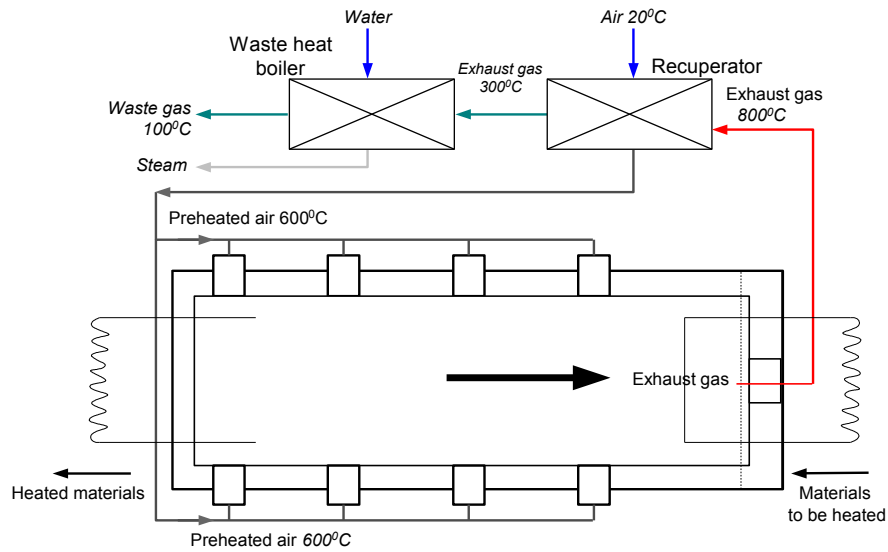


Figure 24: Conventional reheating furnace with the central unit heat recovery system.

Decentralised heat recuperator is also well known, as burners with heat recuperators are commonly available. In Figure 27 a conventional heating furnace with recuperators can be seen. In this furnace the hot flue gases have to be collected from each burner and transported to the boiler.

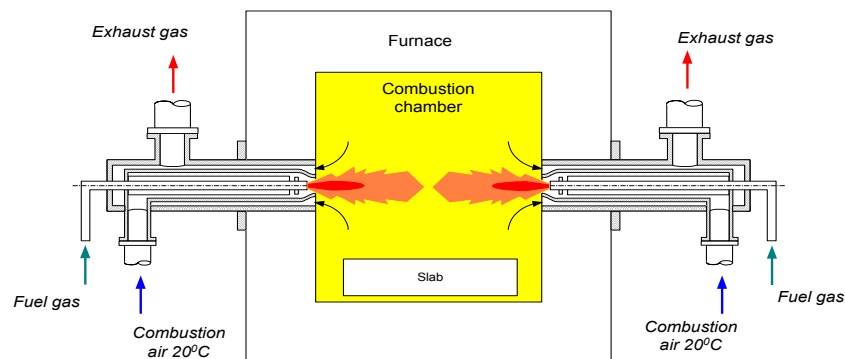


Figure 25: Conventional furnace with decentralised heat recuperative burners system

The concept of high temperature air combustion (HiTAC) is based on using highly preheated air. High temperature air is supplied by means of very efficient regenerators of waste heat. In order to avoid NO_x formation a new way of mixing between fuel and air is used. In high temperature air combustion, the temperatures of air and/or fuel are raised well above the auto-ignition temperature of the fuel, which means that the conditions for flame stabilization are very favorable. Exhaust gas recirculation, whether it is internal or external, is used for reducing flame temperature and thereby NO_x emissions. This technology has been studied in many years [33-35] and it offers to furnace users:

- Low NO_x and CO emission,
- Decreased CO₂ emission,
- Decreased energy consumption,

- Lower combustion noise,
- No need for extra energy saving devices,
- Smaller flue gas tubes,
- Even temperature distribution,
- Enhanced heat transfer,
- Increased product quality productivity,
- Longer lifetime of furnace.

HiTAC technology is being applied to the iron and steel industry, non-ferrous industry, pulp and paper industry, chemical industrial and gasification of the municipal solid wastes and biomass, and it has big potential of application in high-pressure combustion, particularly as concerns gas turbines for power generation

For HiTAC's industrial application, fuel nozzles and combustion air nozzles are arranged on the burner at a certain distance from each other, fuel and high temperature air are injected directly into the furnace at a high velocity. Because of the entrainment of these injection moments, the in-furnace gas in the zone near the burner is thoroughly mixed and its partial pressure of oxygen is lowered. The combustion stability of fuel direct injection into this zone of oxygen at low partial pressure is possible if the air-preheated temperature exceeds the auto ignition temperature of the fuel. In the industrial furnace, the combustion air can be obtained a temperature of 800-1350 °C, through the very effective recovery of waste heat by a high performance heat exchanger, for example, a regenerative heat exchanger switched in the high cycle, which can recover as much as 90-95% of the waste heat with a flue gas temperature of around 120 °C as shown in figure 28 below.[5]

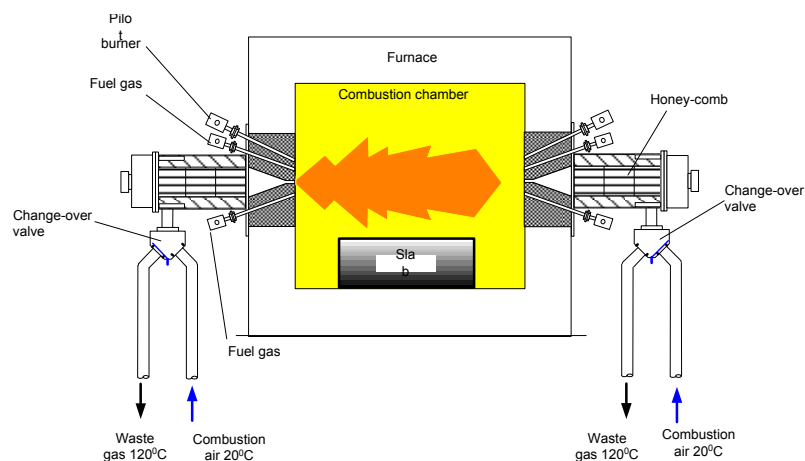


Figure 26: Regenerative combustion system using a pair of burner with decentralized highly efficient flue gas recovery.

3.7 Case studies and calculation method for fuel need and CO2 emissions

The agreed cases studies include two types of furnaces, two heating processes and a variety of gaseous fuel blends combusted in air, oxygen enrichment or full oxy-fuel. All variations analyzed are shown in table 4 below. The benefit with regards to heat recovery with the regenerative system is that it has a better heat recovery, capable of cooling down the flue gases to around 120 °C compared to 300 °C for the recuperative system with boundaries as depict in figure 29 and 30. The 300°C flue gases can be further recovered with a steam generator or similar but that is outside the furnace boundary in this study. For the different processes (reheating and annealing) excess air factor called lambda is assumed to be 1,1 and 1,03. The steel enters the furnace at 20 °C and is heated to 850 °C annealing and 1250 °C in the reheating cases. In the case studies involving syngas, the gas composition from the Cortus Energy process has been used, as decided on meeting with TO51.

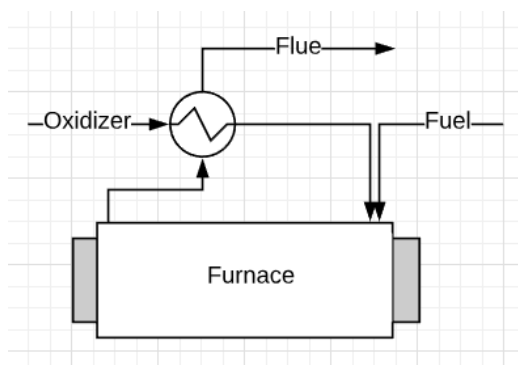


Figure 27: Schematic view of recuperative combustion system with a centralized flue gas heat recovery system

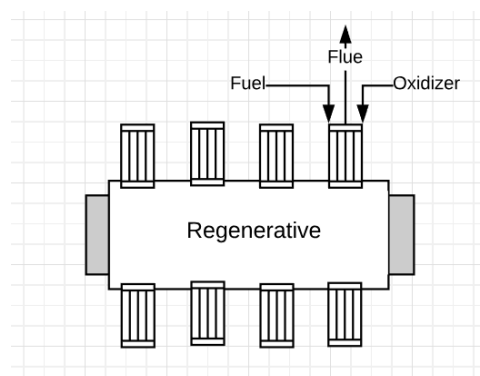


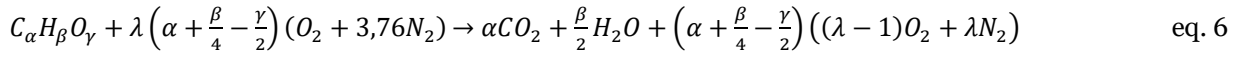
Figure 28: Schematic view of a regenerative combustion system with decentralized heat recovery

Table 4: With Jernkontoret TO51 board agreed case studies that is to be evaluated

Case	Fuel	Oxidizer	Reheating Output	Annealing Output
1 Recuperative	NG/Biogas, Syngas, Propane, Biooil (pyrolysis) - pine - popplar	Air + O ₂ enrichment		$\frac{kg_{CO_2}}{ton_{steel}} (\%_{O_2})$
2 Regenerative				
3 Recuperative				
4 Regenerative				
5 Recuperative	NG + H ₂ enrichment	Air		$m_{Fuel} (\%_{O_2})$

6 Regenerative			$\frac{kg_{CO_2}}{ton_{steel}}(\%_{H_2})$ $\dot{m}_{NG}(\%_{H_2}), \dot{m}_{H_2}(\%_{H_2})$
7 Recuperative		Oxygen	
8 Regenerative			
9 Recuperative	NG + Syngas enrichment	Air	$\frac{kg_{CO_2}}{ton_{steel}}(\%_{syngas})$
10 Regenerative	NG + Syngas enrichment	Oxygen	$\dot{m}_{NG}(\%_{syngas}), \dot{m}_{syngas}(\%_{syngas})$
11 Recuperative	Syngas + H ₂ enrichment	Air	$\frac{kg_{CO_2}}{ton_{steel}}(\%_{H_2})$ $\dot{m}_{syngas}(\%_{H_2}), \dot{m}_{H_2}(\%_{H_2})$
12 Regenerative			
13 Traditional	Syngas + H ₂ enrichment	Oxygen	
14 Regenerative			
15 Electric steel preheating	EL + fuel		$CO_2\text{reduction}(T_{preheating})$
16	Fuel + El (induction)		

Energy and mass balance has been carried out for all cases tabulated above. The lower heating value, fuel usage, combustion reaction products and CO₂ emissions has been determined as described in equation 6-10.



$$LHV_i = \sum \Delta H_{Reactants}^0 - \sum \Delta H_{Products}^0 \quad \text{eq. 7}$$

LHV	kJ/mol
n	mol
M	g/mol
λ	1,02
α, β, γ	volume or molar concentration [1]

$$\frac{n_{fuel}}{MWh} = \frac{3\,600\,000}{LHV_i} \quad \text{eq. 8}$$

$$\frac{n_{CO_2}}{MWh} = \alpha \frac{n_{fuel}}{MWh} \quad \text{eq. 9}$$

$$\frac{m_{CO_2}}{MWh} = \frac{n_{CO_2} \cdot M_{CO_2}}{MWh \cdot 10^6} \quad \text{eq. 10}$$

The average energy need for the specific types of furnaces was found in literature and assumed to be valid for the case of the recuperative combustion system, giving a value of efficiency in order to get a general number for total losses, fuel consumption and thereby carbon dioxide emissions per ton steel heated.

In the case of oxyfuel or oxygen enrichment equation 6 was changed so that the oxidizer $\left(\alpha + \frac{\beta}{4} - \frac{\gamma}{2} \right) (O_2 + 3,76N_2)$, corresponded to the correct oxygen nitrogen mixture, 21% O₂ for air combustion and 100% O₂ for full oxyfuel. Oxygen enrichment was carried out in 10% intervals in between.

With different kinds of fuel mixtures, ex. natural gas + hydrogen enrichment the first term in eq 6 was change in order to correlate with the mixture.

The difference between the regenerative and recuperative combustion systems was calculated as the change in energy loss due to the change flue gas temperature:

$$Q_{flue\ losses} = \int n_i C_{p_i}(t) dt \quad \text{eq. 11}$$

Where C_p_i for all flue gas species where found tabulated in literature.

The effects of electric heating was carried out in a similar manner with the energy need calculated with the help of

$$Q_{electrc} = \int m_{steel} C_{p}(t)_{steel} dt \quad \text{eq. 12}$$

evaluated at the case corresponding temperatures, and removed from the total heat need per ton steel (same equation but over the whole temperature range) in order to be able to calculate fuel need and carbon dioxide emissions with regards to electric preheating or induction. C_p for the steel was found in literature as function over different temperature levels.

3.7.1 Results case studies-Reheating

3.7.1.1 Case 1-4

Carbon dioxide emissions per ton steel reheated for recuperative (figure 31) and regenerative (figure 32) combustion system fueled by natural gas or biogas, syngas, propane and two types of bio-oil generated through pyrolysis from pine and poplar. Air combustion corresponds to 21 % O₂ in oxidizer and oxy-fuel equals 100 %, in between is considered as oxygen enrichment. Important with the carbon dioxide emissions is to consider origin of the fuel, only propane and natural gas is of fossil origin and the rest is biogenetic.

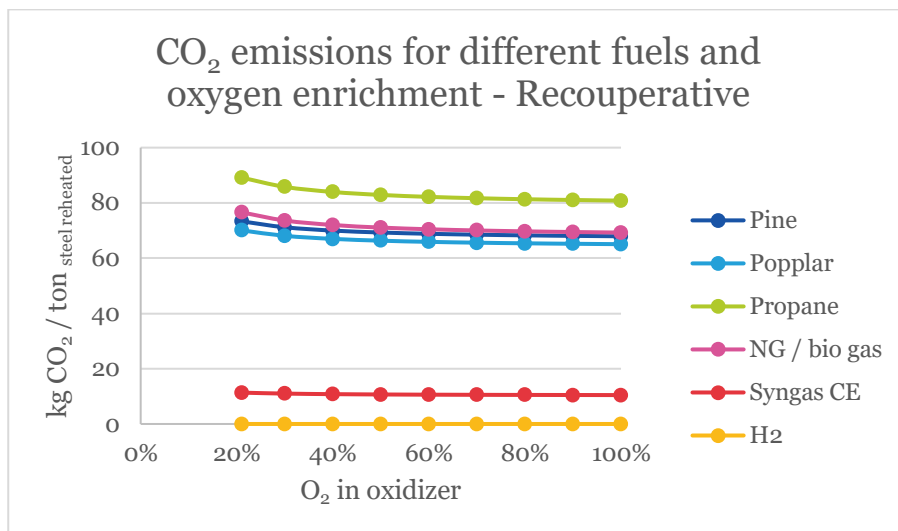


Figure 29: CO₂ emissions per ton steel reheated as function of fuel and oxygen level in oxidizer

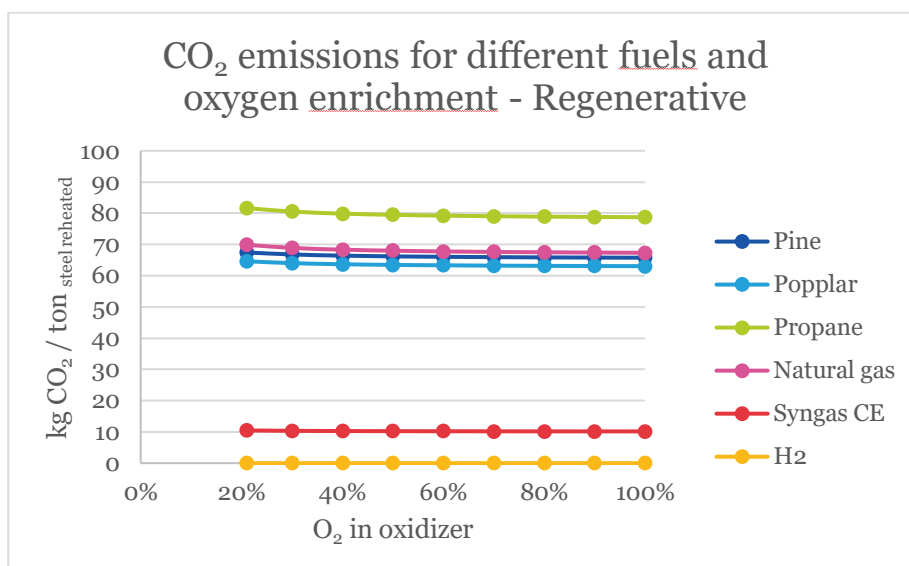


Figure 30: CO₂ emissions per ton steel reheated as function of fuel and oxygen level in oxidizer

3.7.1.2 Case 5-8

Carbon dioxide emissions per ton steel reheated for recuperative (figure 33) and regenerative (figure 34) combustion system fueled by natural gas combusted in air with different levels of hydrogen enrichment. Figure 35 and 36 shows the same with the exemption of oxygen as oxidizer instead of air.

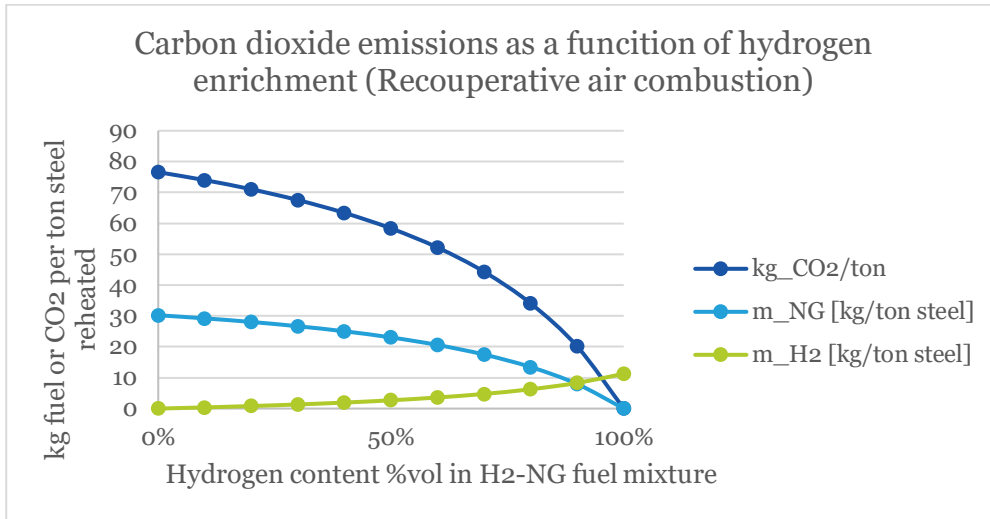


Figure 31: CO₂ emissions, and calculated fuel usage per ton steel reheated as function of hydrogen enrichment

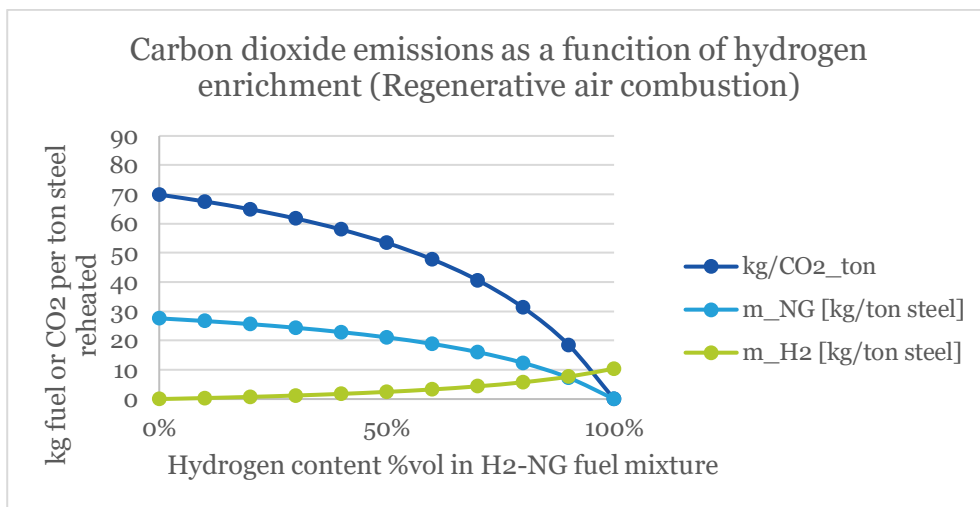


Figure 32: CO₂ emissions, and calculated fuel usage per ton steel reheated as function of hydrogen enrichment

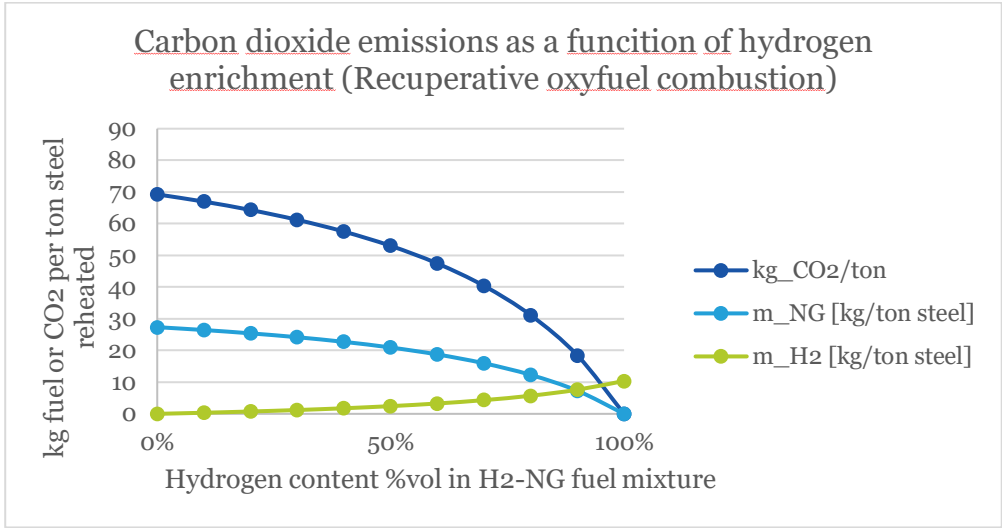


Figure 33: CO₂ emissions, and calculated fuel usage per ton steel reheated as function of hydrogen enrichment

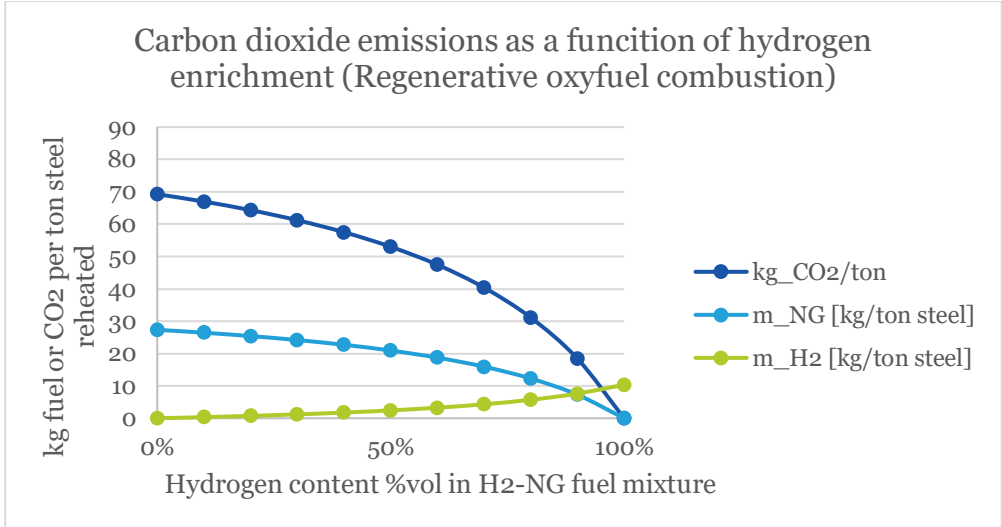


Figure 34: CO₂ emissions, and calculated fuel usage per ton steel reheated as function of hydrogen enrichment

3.7.1.3 Case 9-10

Carbon dioxide emissions per ton steel reheated for recuperative and regenerative as function of syngas enrichment, both combusted in air and oxygen are shown in figure 37. Figure 38 shows the same but has divided the carbon emissions as fossil respectively biogenic origin.

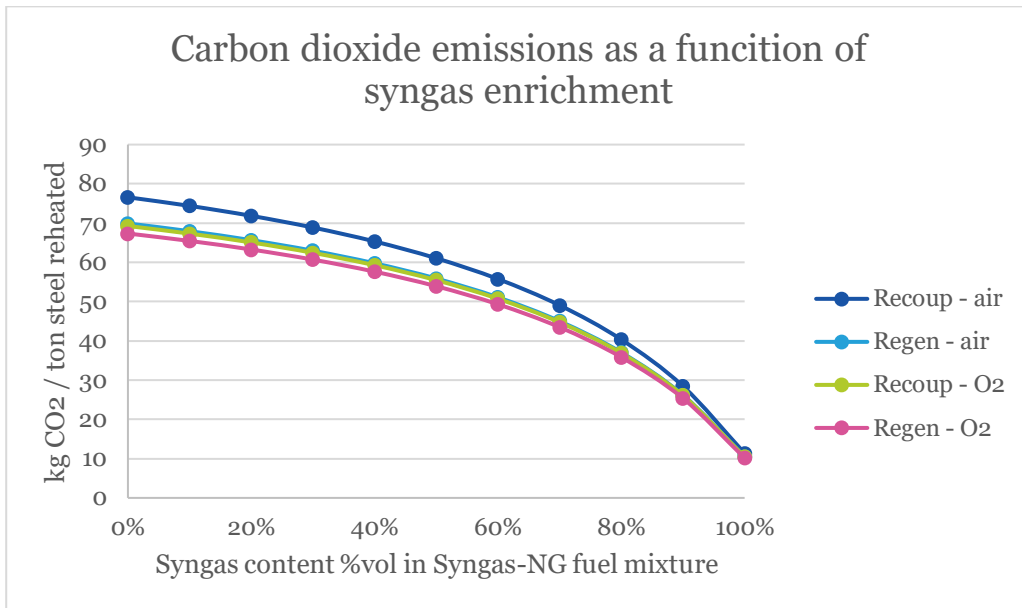


Figure 35: CO₂ emissions per ton steel reheated as function of syngas enrichment for recuperative and regenerative combustion system with air and oxygen as oxidizer.

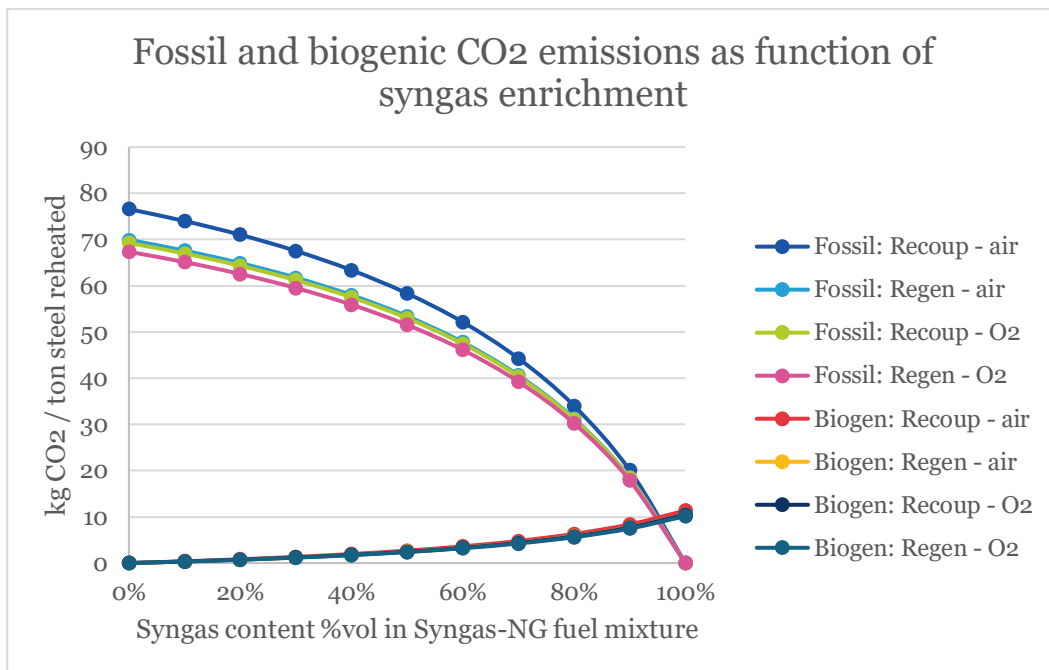


Figure 36: Biogenic and fossil CO₂ emissions per ton steel reheated as function of syngas enrichment for recuperative and regenerative natural gas combustion system with air and oxygen as oxidizer.

3.7.1.4 Case 11-14

Biogenic or non-fossil CO₂ emissions from combusting hydrogen enriched syngas per ton steel reheated for recuperative and regenerative burner system with air or oxygen.

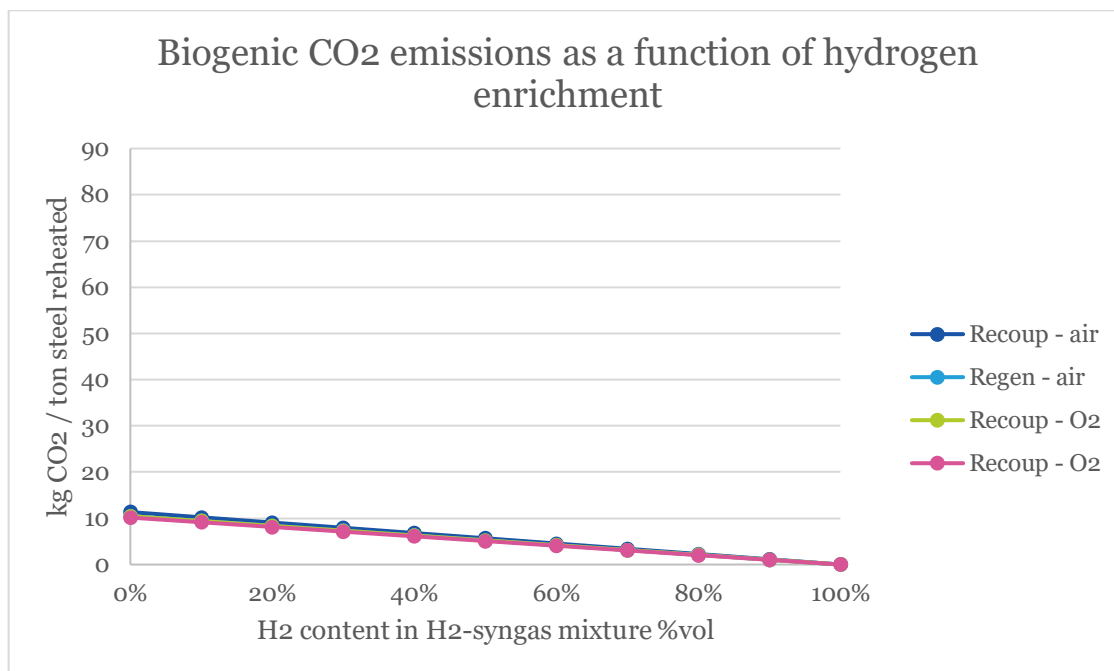


Figure 37: CO₂ emissions (all biogenic) per ton steel reheated for recuperative and regenerative systems burning hydrogen-enriched syngas for both air and oxygen.

3.7.1.5 Case 15

This case with electrical preheating of the steel is visualized in figure 40 below. The choice of regenerative burner system in comparison to recuperative is to avoid that the electrical heating elements has to work in an flue gas environment which has a tendency of corroding the elements as Swerim/Mefos experienced in their test furnace in Luleå. The flue gas path with the regenerative system can be controlled so the zone with electric heating elements won't be exposed to the flue gases because they are routed back into the burner itself.

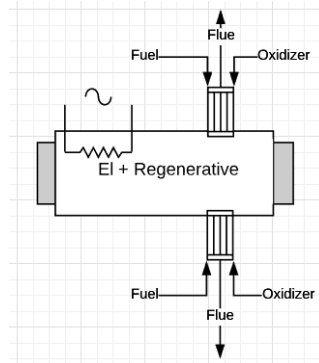


Figure 38: Schematic view of a furnace with electrical preheating of the steel.

The reduction of carbon dioxide emissions as function of preheating temperature of the steel is shown in figure 41 below. The result is also valid for a setup where hot slabs from the continuous casting is directly routed to the reheating furnace instead of being cooled down and transported to another facility where the reheating furnace is located since the CO₂ contribution from the electrical heating is assumed to be zero.

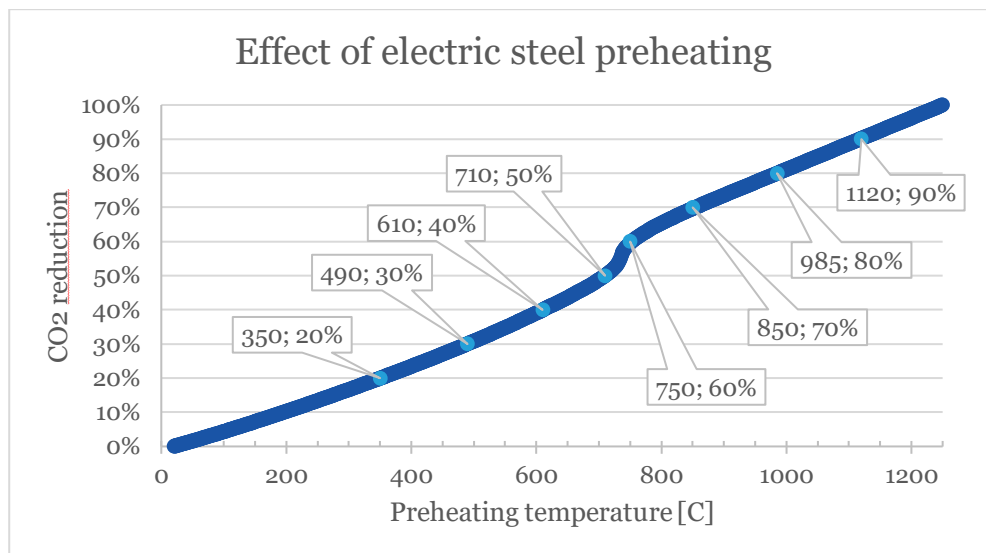


Figure 39: Reduction of CO₂ with regards to steel preheating ether by electricity or from the continuous casting process.

Kanthal is one producer of resistive heating elements, which can heat the steel well above 1250°C with up to 100 kW/m² furnace wall which makes 100% reduction possible.

3.7.1.6 Case 16

Induction has the highest potential for non-magnetic steel since it has higher penetration depth allowing for higher heating power. For magnetic steel induction has a tendency of only heating a small layer radially with the risk of melted edges if to high power is induced. However, magnetic steel loses its magnetic properties at the Curie point, which makes induction a viable heating option if preheating of other means is applied. Figure 42 and 43 below shows schematic views of how the system could look like.

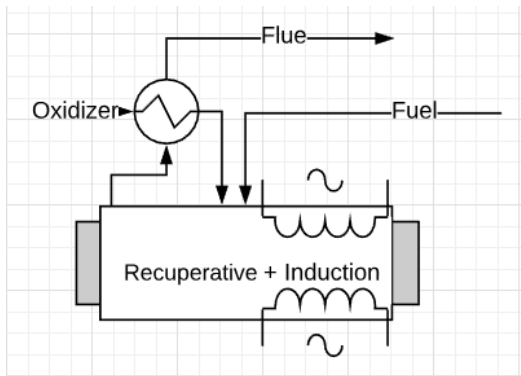


Figure 40: Schematic view of recuperative combustion system coupled with induction heating.

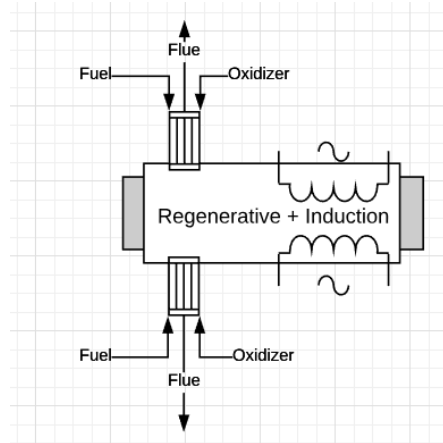


Figure 41: Schematic view of regenerative combustion system coupled with induction heating.

The reduction of carbon dioxide emissions for systems like this fuelled by natural gas could be in the order of 40 % in the case of reheating magnetic steel, as shown in figure 44. The figure shows reduction of fuel usage or carbon dioxide emissions as function of the steel temperature before entering the induction zone, which takes the slab to the final temperature of 1250 °C.

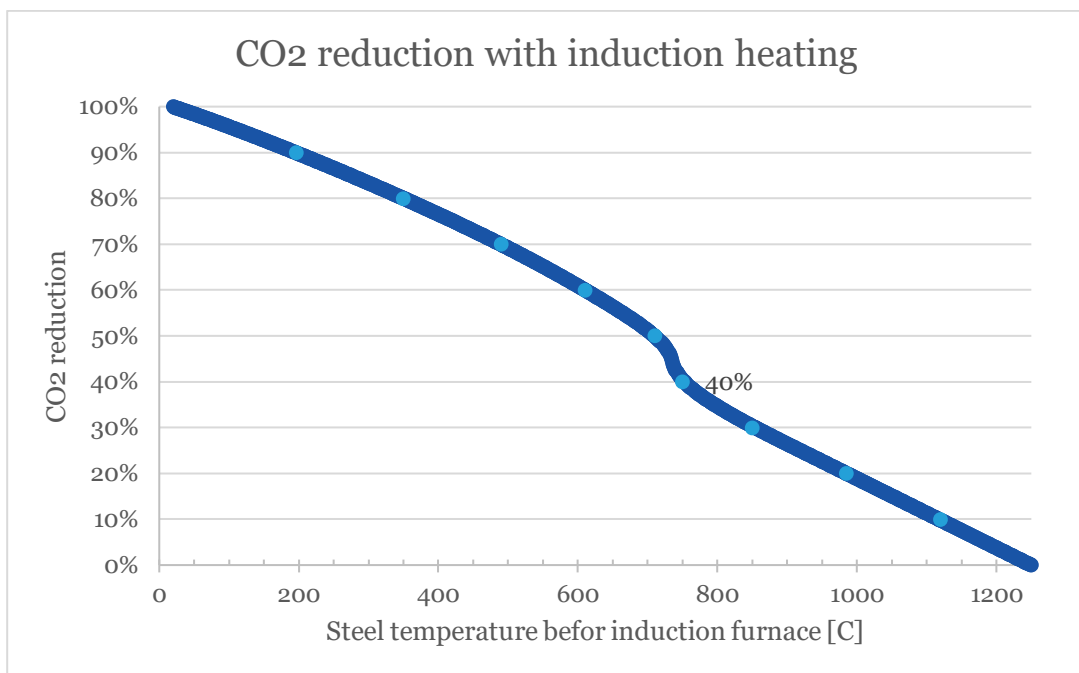


Figure 42: CO2 reduction with induction heating after a zoon with fuel fired heating

3.7.2 Results case studies- Heat treatment

3.7.2.1 Case 1-4

Carbon dioxide emissions per ton steel heat-treated for recuperative (figure 45) and regenerative (figure 46) combustion system fueled by natural gas or biogas, syngas, propane and two types of bio-oil generated through pyrolysis from pine and poplar. Air combustion corresponds to 21 % O₂ in oxidizer and oxy-fuel equals 100 %, in between is considered as oxygen enrichment. Important with the carbon dioxide emissions is to consider origin of the fuel, only propane and natural gas is of fossil origin and the rest is biogenic.

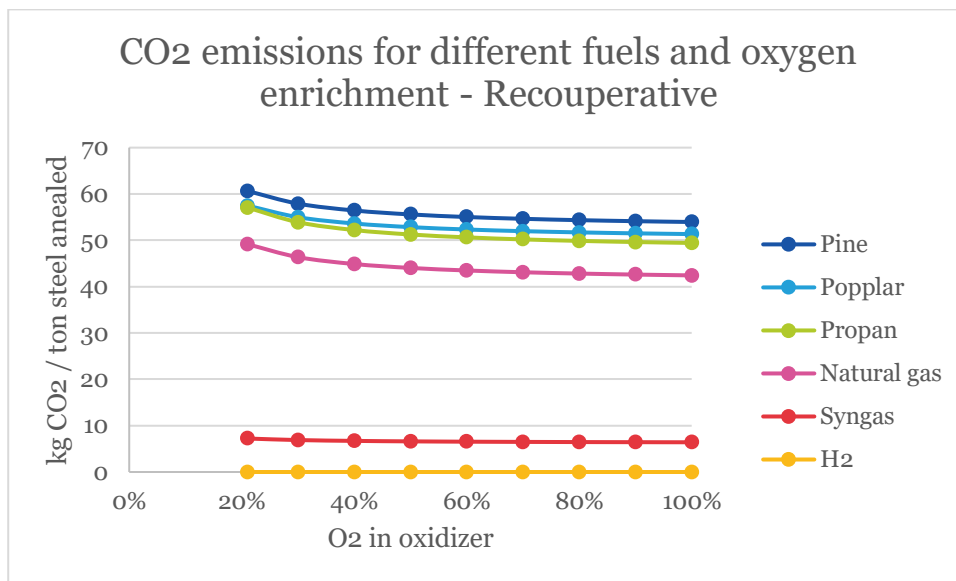


Figure 43: CO₂ emissions per ton steel heat-treated as function of fuel and oxygen level in oxidizer

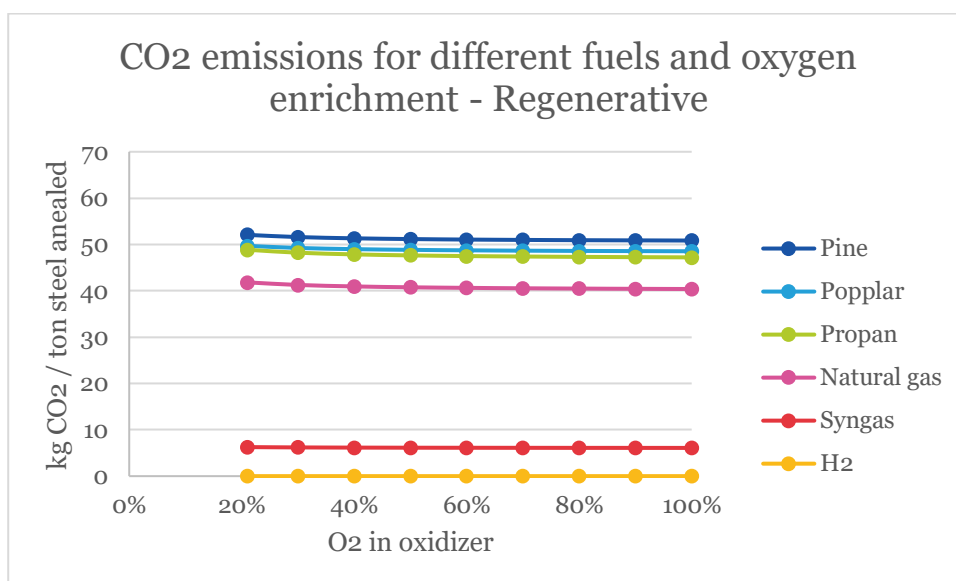


Figure 44: CO₂ emissions per ton steel heat-treated as function of fuel and oxygen level in oxidizer

3.7.2.2 Case 5-8

Carbon dioxide emissions per ton steel annealed for recuperative (figure 47) and regenerative (figure 48) combustion system fueled by natural gas combusted in air with different levels of hydrogen enrichment. Figure 49 and 50 shows the same with the exemption of oxygen as oxidizer instead of air.

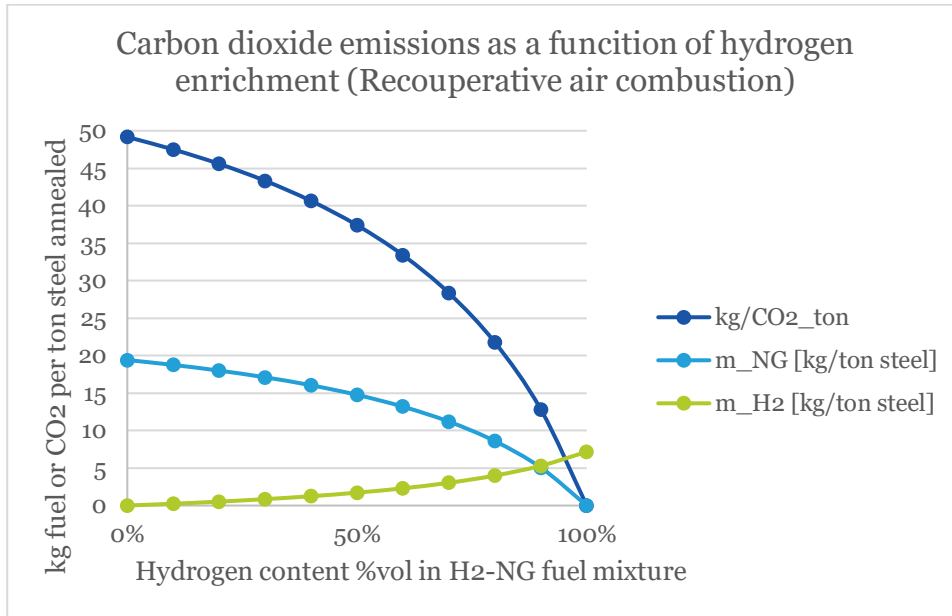


Figure 45: CO₂ emissions, and calculated fuel usage per ton steel heat treated as function of hydrogen enrichment

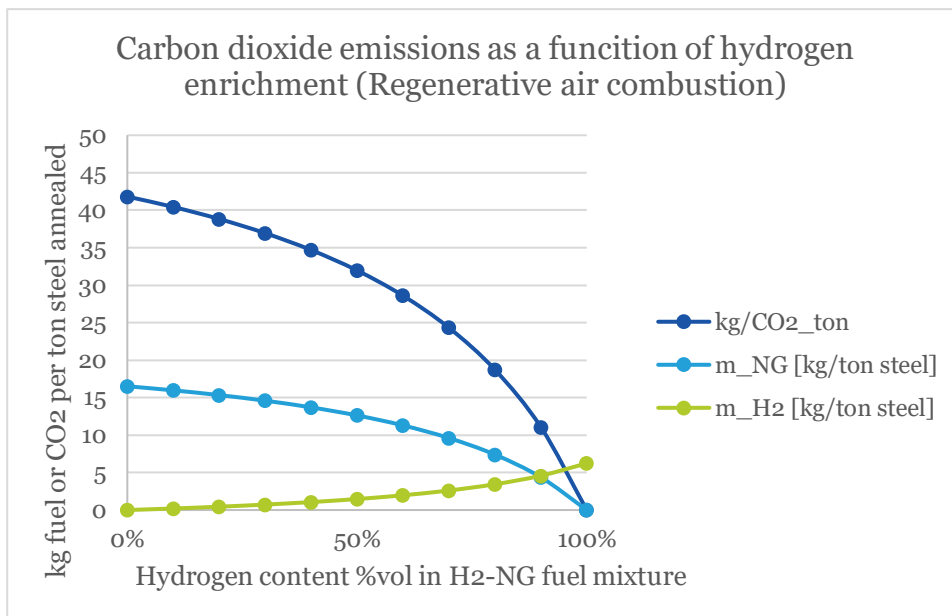


Figure 46: CO₂ emissions, and calculated fuel usage per ton steel heat treated as function of hydrogen enrichment

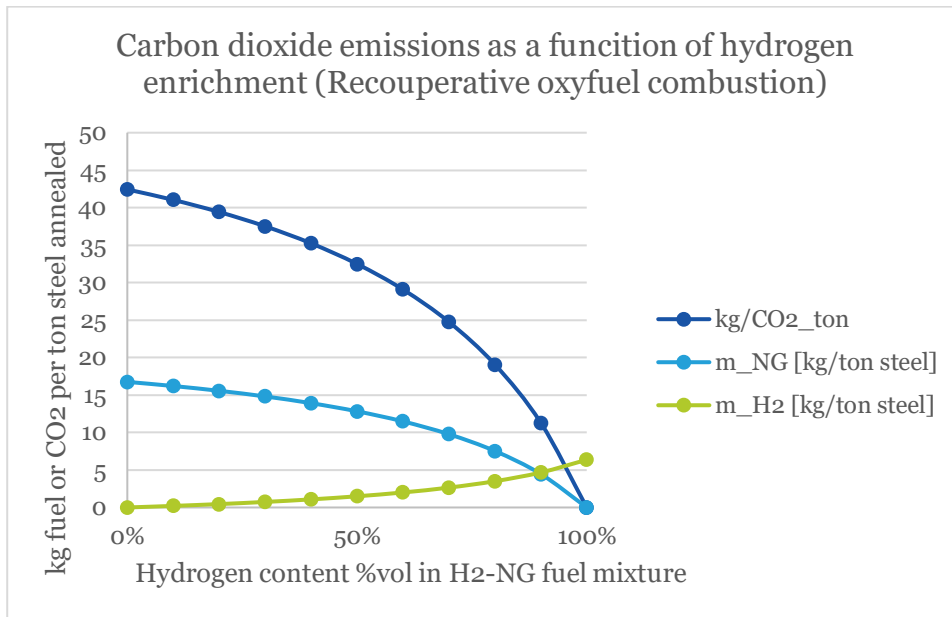


Figure 47: CO₂ emissions, and calculated fuel usage per ton steel heat-treated as function of hydrogen enrichment

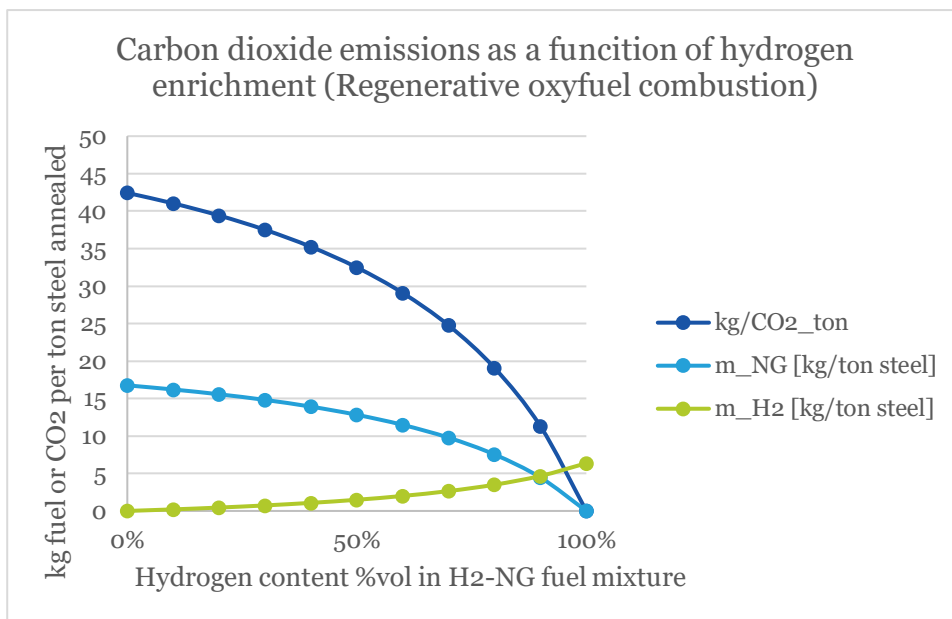


Figure 48: CO₂ emissions, and calculated fuel usage per ton steel heat-treated as function of hydrogen enrichment

3.7.2.3 Case 9-10

Carbon dioxide emissions per ton steel annealed for recuperative and regenerative as function of syngas enrichment, both combusted in air and oxygen are shown in figure 51. Figure 52 shows the same but has divided the carbon emissions as fossil respectively biogenic origin.

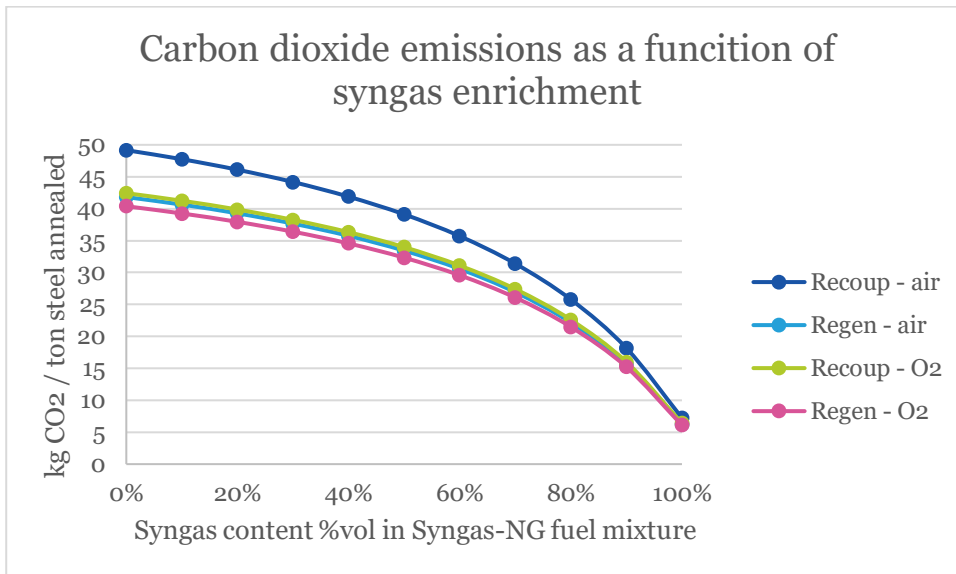


Figure 49: CO₂ emissions per ton steel heat-treated as function of syngas enrichment for recuperative and regenerative combustion system with air and oxygen as oxidizer.

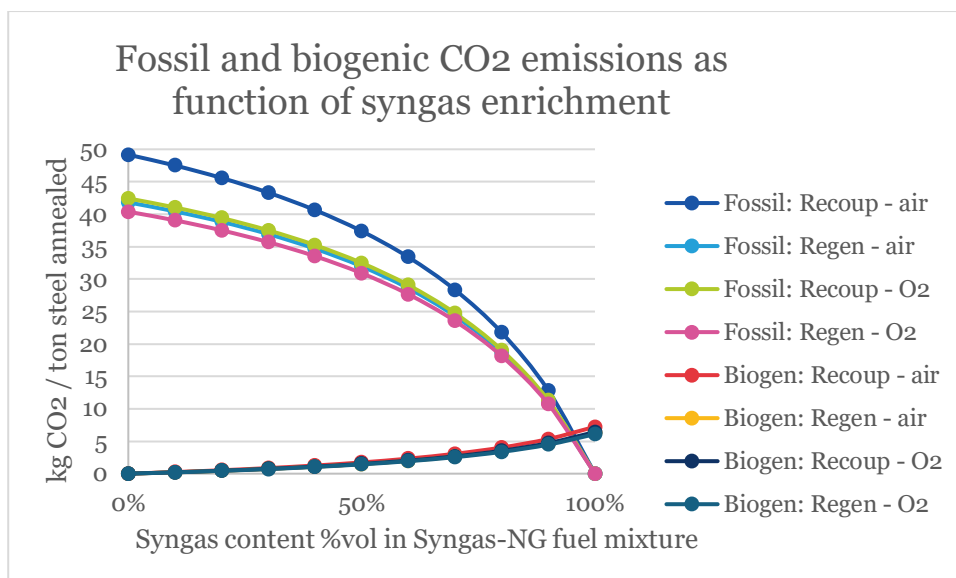


Figure 50: Biogenic and fossil CO₂ emissions per ton steel heat-treated as function of syngas enrichment for recuperative and regenerative natural gas combustion system with air and oxygen as oxidizer.

3.7.2.4 Case 11-14

Biogenic or non-fossil CO₂ emissions from combusting hydrogen enriched syngas per ton steel reheated for recuperative and regenerative burner system with air or oxygen is visualized in figure 53 below.

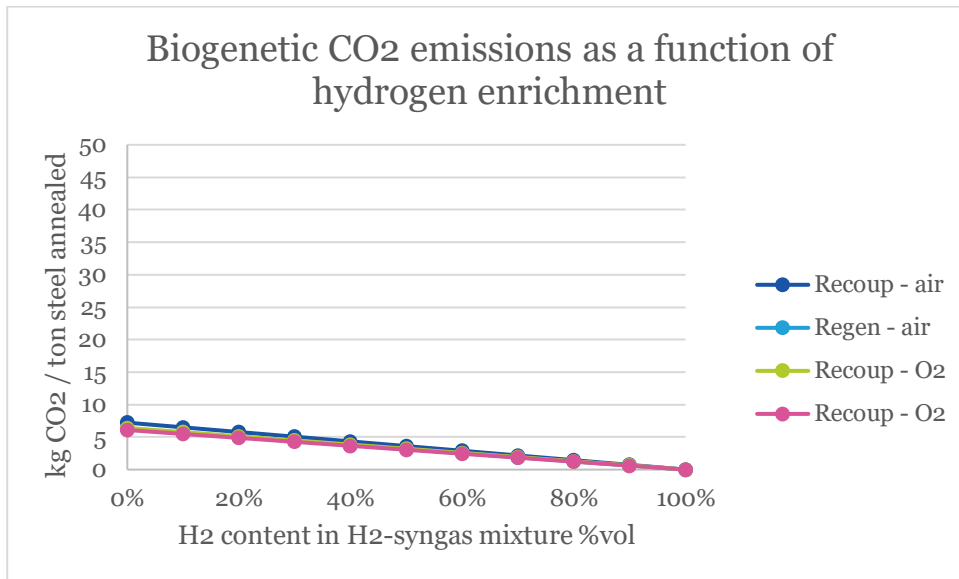


Figure 51: CO2 emissions (all biogenic) per ton steel heat-treated for recuperative and regenerative systems burning hydrogen-enriched syngas for both air and oxygen.

3.7.2.5 Case 15

The reduction of carbon dioxide emissions as function of preheating temperature of the steel with electricity is shown in figure 54 below.

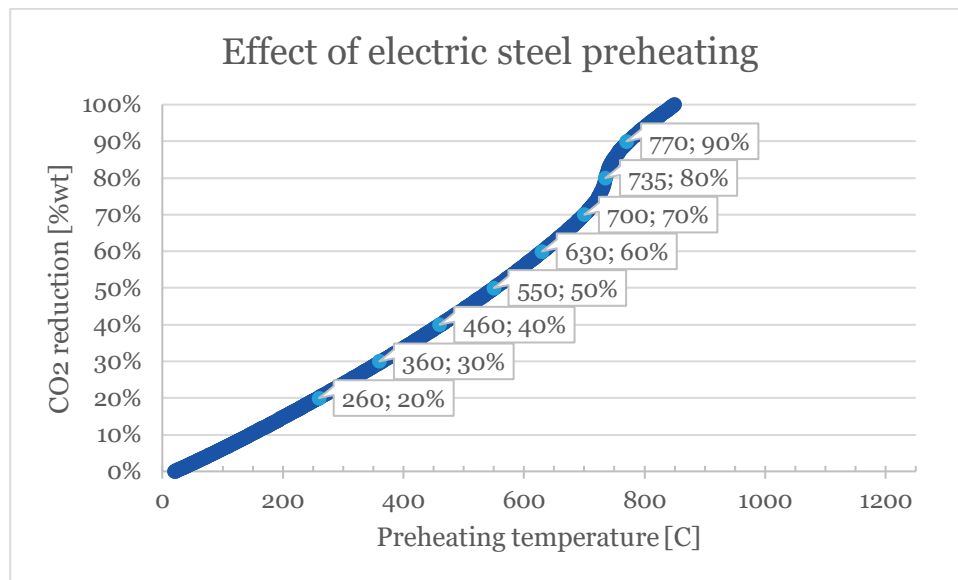


Figure 52: Reduction of CO2 with regards to steel preheating with electricity.

3.7.2.6 Case 16

The reduction of carbon dioxide emissions for systems that is fuel heated until the phase change followed by for example induction is the order of 15% in the case of heat treatment of magnetic steel, as shown in

figure 55. The figure shows reduction of fuel usage or carbon dioxide emissions as function of the steel temperature before entering the induction zone, which takes the slab to the final temperature of 850 °C.

Induction heating is however not limited to just be used at temperatures above the phase change but can be used in the whole temperature span allowing for 100% reduction but throughput or heating speed is highly dependent of what type of steel is to be heat treated.

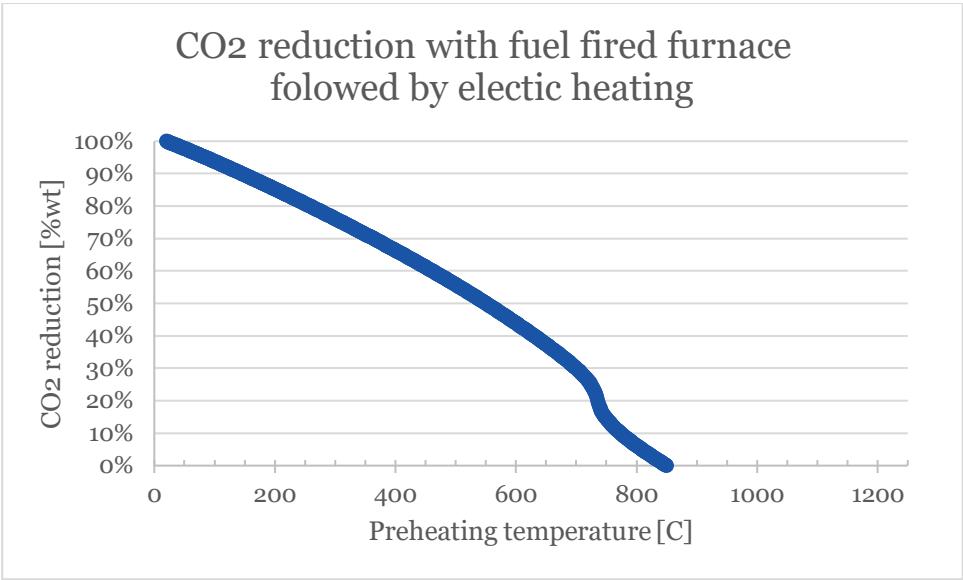


Figure 53: CO2 reduction with induction heating after a zoon with fuel fired heating

4 Conclusions and discussion

- Since the biogas that is put on the market is upgraded to become a natural gas equivalent this fuel switch does not involve any changes to the burners or furnace operation.
- Wobbe index: Only upgraded biogas fulfills Wobbe index range for burner designed for natural gas. All other fuels will need at least change of nozzle.
- Flame speed: Hydrogen enrichment could lead to flash back problems due to high variations in flame speed with different equivalence ratios (local conditions within the flame might be a starting point for flashback). Solutions with separate hydrogen burner might be a safer option if burner manufacture hasn't left any guarantees regarding allowed fuel mixtures.
- Auto ignition temperature: Both furnace types operates at temperatures high enough for spontaneous combustion of propane, natural gas, syngas and hydrogen.
- Flame temperature: Most fuel analyzed can achieve high enough flame temperature for the reheating and heat treatment furnaces, all if modest preheating and or oxygen enrichment is used.
- Increased fuel efficiency and thus reduction of CO₂ emissions is achieved with increased flue gas heat recovery as in the case with e.g. a regenerative burner system.
- CO₂ reduction and fuel efficiency is achieved using oxygen instead of air due to lower flue gas volumes. Our results for the effect of oxygen enrichment are on the low side in comparison to literature. This could be explained by the fact that our theoretical calculations are based on the energy consumption of the average European reheating/heat treatment furnace (which includes already oxyfuel burning furnaces) and with the assumption that the burners run with quite low amount of excess air, which may not be the case for most furnaces. So our result may be an indicator of what could be expected if all European furnaces (reheating/heat treatment furnace) transitions to oxyfuel burners.
- There is a clear correlation between fuel composition and carbon dioxide emissions. To be more specific: the amount of carbon in the fuel per unit energy content. With highest emitter to lowest: bio-oil (pyrolysis), propane, natural gas (/biogas), syngas used in case studies and hydrogen in our boundary of the furnace. Important to notice it the fuel origin, and however the biomass supposed to be turned into bio-oil would be left to decompose in nature or not. Declaring fossil carbon dioxide emissions the bio-oil, syngas, and biogas would be zero just as CO₂-free produced hydrogen.
- Electrification of furnaces reduces emissions and technology for reaching steel temperatures of 1250 °C exists (resistive) or are in development (induction).

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