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Integrated Systems for Electricity and Hydrogen Co-production from Coal and Biomass*

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Abstract

This paper describes the results of thermodynamic and economic modelling based on integrating an existing large size steam power plant with a hydrogen production and purification plants fed by coal or biomass mixed with coal. The high quality of the hydrogen produced would guarantee its usability for distributed generation and for public transport. The proximity of a hydrogen production plant to a steam power plant could favour connections in terms of energy requirements exchange; systems proposed could represent an attractive approach to co-production of hydrogen and electricity. Two different technologies for the syngas production section are considered: pyrolysis process and direct pressurised gasification.

Keywords: Economics, coal, biomass, hydrogen, gasification, pyrolysis.

1. Introduction

The growing attention being paid to the environmental impact of industrial civilization and increased sensitivity to global warming are forcing us to search for alternative solutions which can significantly reduce carbon dioxide emissions into the atmosphere (IPCC, 2005).

Nowadays the utilisation of coal has strong attractions from an economic point of view: coal is a widely available, low cost energy source which greatly reduce our dependence on the oil-exporting countries. Otherwise coal utilisation is limited by environmental problems: the CO_2 specific emission from the use of this fuel is extremely high compared with natural gas. Moreover, the high concentration of sulphur forces to adopt expensive plants for the exhaust post-treatment in order to comply with the limits on emissions into the atmosphere imposed by national and international legislation.

Many thermodynamic and economic studies have been carried out on the production of energy from coal with low CO_2 emissions, using “pre-combustion capture” (Chiesa et al., 2005; Fantini et al., 2007), “post-combustion capture” (Abu-Zahra et al., 2007), and “oxy-fuel” (Valero and Usón, 2006; Donatini et al., 2005) strategies. In this context the aim of this work is to investigate the feasibility of a new concept: integrated systems for hydrogen and electricity co-production from coal and biomass. The main objective of this paper is to evaluate the thermodynamic and economic impact of integrating a hydrogen production system with a traditional steam power plant.

Biomass is considered attractive in the field of energy production in terms of CO_2 emissions avoided and is here investigated as a fuel for mixing with coal. The results were obtained using WTEMP code (Web-based ThermoEconomic Modular Program), developed by the TPG (Thermochemical Power Group) of DiMSET (Dipartimento di Macchine, Sistemi Energetici e Trasporti) of the University of Genoa, Italy (Traverso et al., 2004).

2. Thermodynamic Analysis

2.1 Plant Layouts

In this paper different plant layouts are considered, in order to explore the behaviour of a traditional coal-burning station when integrated with a hydrogen production plant. The reference thermoelectric power plant (referred below as REF) is the 660 MW_e ENEL coal-fired plant at Brindisi, which is able to achieve 41.2% net efficiency. The operating data for this plant has been provided directly by ENEL, one of the main Italian power utilities. The plants considered in this paper are identified by the following letters:

- The first letter identifies the processes in the syngas production section: the Pyrolysis process (P) and Gasification process (G).
- The second letter identifies the fuel used in the syngas production section: Coal (C) and Biomass mixed with coal (B) (25% Biomass / 75% Coal by weight).
- The third letter identifies the technology used for hydrogen separation: Pressure Swing Adsorption unit (P) or dense Membrane unit (M).

Table 1 shows properties of various types of coal and biomass. Biomass composition reported is calculated from four average biomasses (poplar, mischantus, wood residuals, husks). Figure 1 shows the plant configuration for an atmospheric pyrolysis system integrated with the steam power plant. The reference system for syngas production section is the 800 kW_{th} ENEL pyrolysis plant placed at Bastardo (near Perugia, Italy). A detailed model of the plant was created using system data provided by (ENEL, 2007).

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Table 1. Properties of Different Types Coal and Biomass.

Dry Weight %	Ashland	South Africa	Sardinian Sulcis	Biomass
C	75.19	70.4	60.08	49.8
H	4.44	4.0	4.39	6.1
N	1.21	1.6	1.46	0.6
S	0.82	0.59	6.76	0.09
O	7.75	7.98	7.7	42.47
Cl	0.09	0.03	0.11	0.11
Moisture	3.0	8.0	11.5	20.0
Volatile Matter	32.2	26.7	42.4	78.7
Fixed Carbon	57.3	57.9	38.1	16.8
Ash	10.5	15.4	19.5	4.0
LHV (MJ/kg)	29.35	27.44	20.83	18.8

The heat needed to bring about devolatilization of the coal is provided by recirculated hot sand. The hot sand is obtained inside the combustor reactor through the reaction between char separated in the preceding cyclone and air. Volatile pyrolysis products (syngas and tar) are separated from the char and sand by another cyclone, and sent to a tar cracking component capable of improving the hydrogen composition. A portion of the syngas produced is sent to the pyrolyser, where it acts as a fluidising gas for the solid material. The pyrolysis process takes place in reducing conditions at a temperature of about 750 °C.

Tar cracking has been modelled as a black box in which syngas and tar are assumed to reach equilibrium, minimizing the Gibbs free energy. The syngas produced is compressed to 25 bars and sent to an acid gas removal and sulphur recovery section. The method used for sulphur removal section is the Selexol process, which is based on physical absorption and admits only pressurized syngas (Korens et al., 2002). The decision to introduce this technology into the system was mainly due to the high partial pressure of the H_2S to be removed in the syngas and the lower energy consumption of physical removal technology compared with that of a chemical process.

Purified syngas is then sent to a reformer section to convert the high concentration of methane produced in the pyrolytic process into hydrogen. To avoid the presence of CO in the syngas produced, a double shift section (high and low temperature) is provided. Hydrogen is finally separated from syngas in a PSA unit. Figure 2 shows the general layout of an integrated system using the gasification process.

The gasifier unit considered is a pressurised gasifier integrated with an ASU and fed by coal-slurry or coal mixed with biomass. Steam for the gasification process is provided by the steam power plant. The syngas produced passes through a purification section (cyclone and scrubber) and sent to a double shift section (high and low temperature).

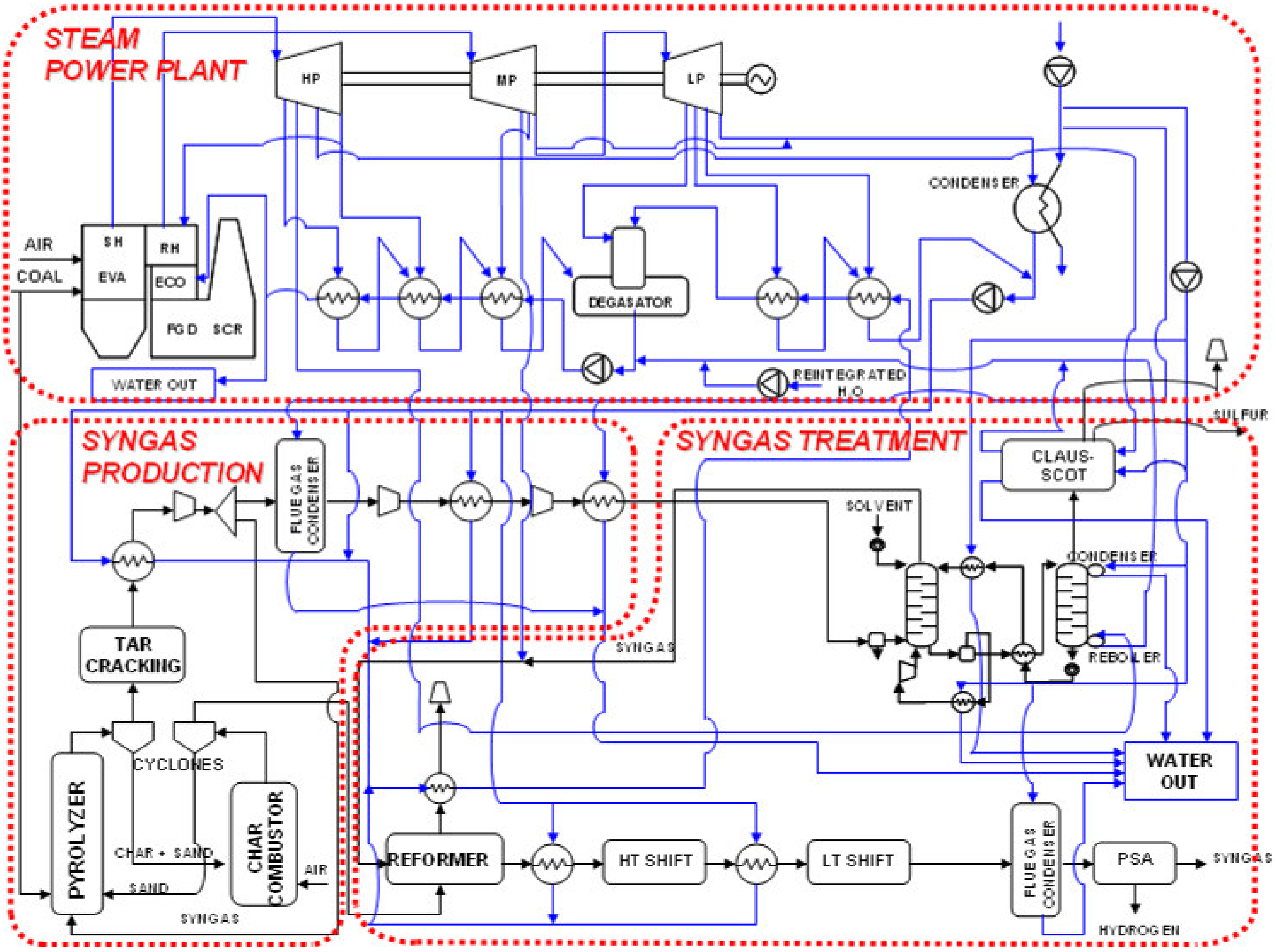

Figure 1. General Scheme of the Integrated system: Syngas Production (Pyrolysis)-Syngas Treatment Section-Steam Power Plant.

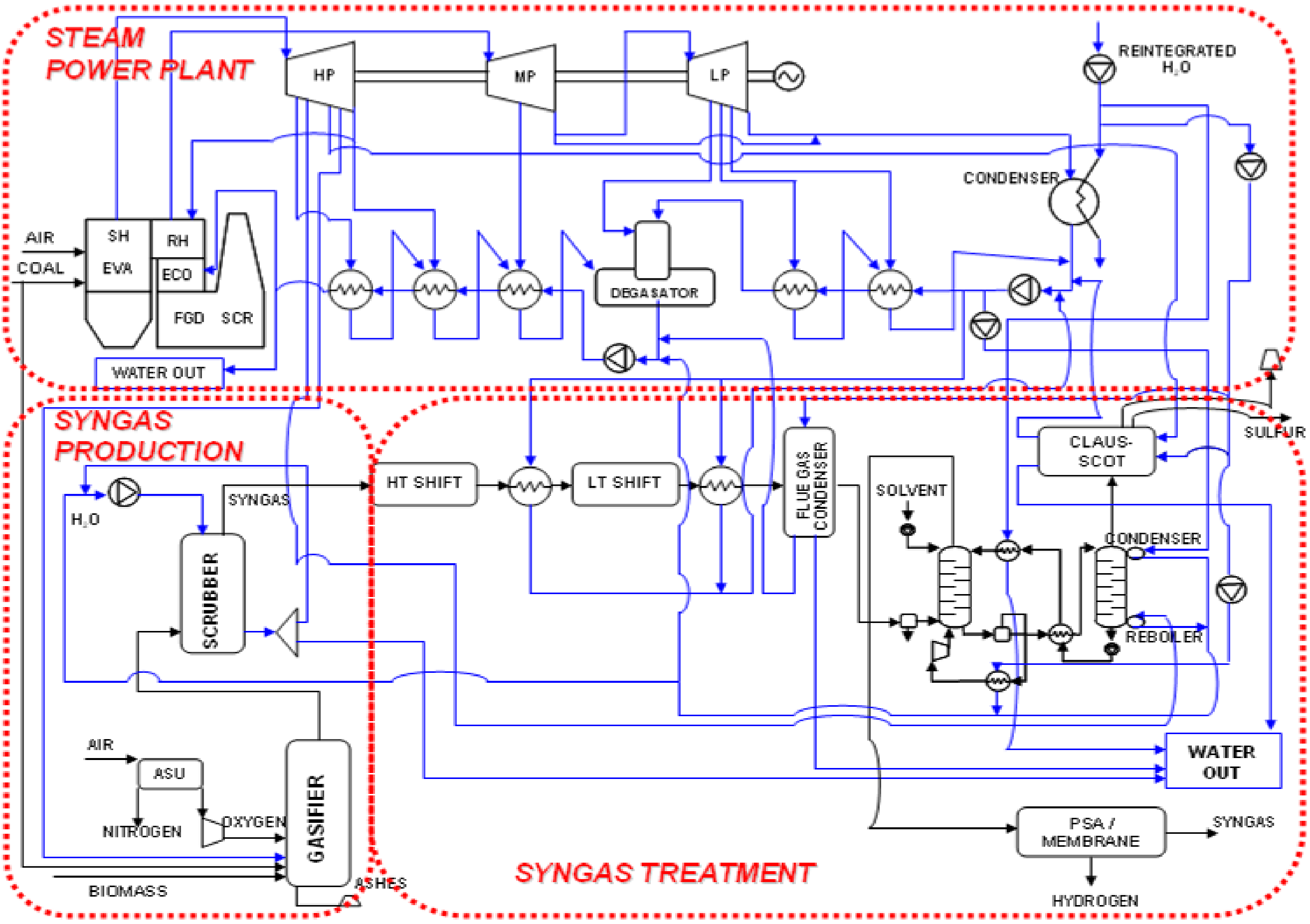

Figure 2. General Scheme of the Integrated system: Syngas Production (Gasification)-Syngas Treatment Section-Steam Power Plant

Shift reactors can tolerate considerable amounts of H_2S (up to 100 ppm) (Daza, 2004) and they can guarantee complete hydrolysis of COS. The syngas is sent to the acid gas removal and sulphur recovery section and subsequently two technologies, PSA unit and Palladium dense membrane, are considered for hydrogen separation. The layout with dense membrane unit needs an additional compression stage out of the membrane unit for increasing hydrogen pressure to the same value of the hydrogen which comes out from PSA unit. Water and steam requirements, necessary for cooling and heating of the complete systems, are provided by the adjacent thermoelectric power plant as shown in Figures 1 and 2.

2.2 Thermodynamic Models

The kinetics models for coal pyrolysis introduced in WTEMP code are:

- Thermal Decomposition Model by D. Merrick (Merrick, 1983; Donatini et al., 2006).
- Chemical Percolation Devolatilization Model (CPD-Model) proposed by T. Fletcher (1999).

The CPD-model describes the devolatilization of coal under a rapid heating rate and is based on the chemical structure of coal. Both models show similar results in terms of the tar, char and volatiles fraction, thus for greater clarity only the CPD results are reported in this paper. In Figure 3 the mass fraction of volatile composition calculated by using the CPD model for the South African coal, selected as reference case, with respect to the pyrolysis process temperature is shown.

It is important to note the high presence of CH_4 in the composition of the syngas, (up to 38%) which requires the presence of a steam reformer element. Reformer is placed after the acid gas removal section because of it cannot accept H_2S over 10 ppm.

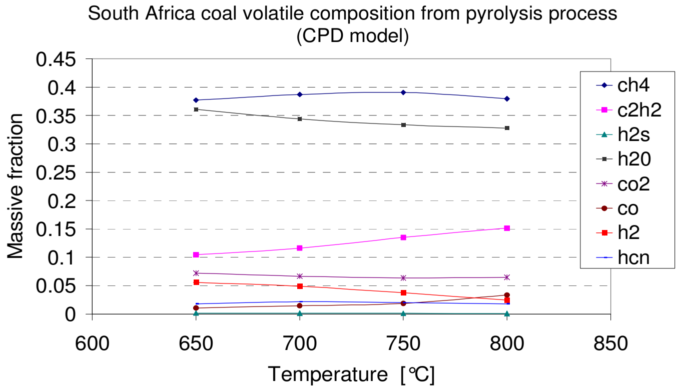

Figure 3. Mass Fraction of Volatile Composition for South African Coal from Pyrolysis Process (CPD model).

The model created for H_2S removal section considers the theoretical set up of the problem for the estimation of the number plates of the absorption column. The simulation of the whole plant section was carried out using ProVision® commercial software: the performance map for this section was imported into WTEMP code.

The PSA unit model refers to the PSA unit developed in Chlendi (1993) and it assumes different inputs such as the PSA outlet pressure, the active carbon length, the column length and the pressure reduction of purified hydrogen. Membrane model refers to Kluiters (2004). The membranes considered are composed of Palladium, and the module is able to determine the hydrogen flux through the membrane (regulated by a solution/diffusion mechanism) given the permeability of the membrane and the partial pressure of the species in the flux.

2.3 Thermodynamic Results

The main thermodynamic assumptions are stated in Table 2. A sensitivity analysis on pyrolysis and gasification section size is conducted. In Figure 4 the efficiency of the reference steam power plant and the efficiency of the steam power plants integrated with systems for hydrogen production are compared. Thermal power input (calculated on LHV basis) considered for syngas production section varies from 100 MW_{th} up to 250 MW_{th}.

Table 2. Main Thermodynamic Assumptions.

Steam power plant	
Boiler Efficiency [0-1]	0.95
Temp out SH [°C]	540
High pressure pump [bar]	295
Feeding pump [bar]	8
Pump electrical efficiency [0-1]	0.95
Alternator electrical efficiency [0-1]	0.965
Pressure gas side loss [0-1]	0.02
Pressure water/steam side loss [0-1]	0.03
Syngas production-Pyrolysis	
Pyrolysis temperature process [°C]	750
Syngas recirculated temperature [°C]	50
Sand heat specific value [kJ/kg°C]	0.799
Syngas production-Gasification	
Gasification temperature process [°C]	1200
Gasification pressure process [bar]	35
ASU consumption [kWh/kgO_2]	0.265
Syngas Treatment	
Reformer steam to carbon ratio	>4
High Temperature Shift [°C]	450
Low Temperature Shift [°C]	250

Thermal power is defined as ($\dot{m} \times LHV$). The flow rate and the lower heating values are those of the respective streams considered (coal, biomass, produced syngas, produced hydrogen).

SPP efficiency is the global net thermodynamic efficiency of the system, i.e. the ratio between the net power (gross power less auxiliary consumptions) and the thermal power input (fuels). The reference power plant can achieve a net thermodynamic efficiency of 41.2%. It is evident that the pyrolysis integrated systems (especially the large ones) improve the efficiency of the steam power plant slightly compared to gasification integrated systems.

PC plant shows an increasing efficiency for larger pyrolysis plants due to the increasing heat recovery that takes place outside the char combustor. In this case the char combustor not only provides the maintenance of the pyrolysis process, but it also guarantees the heat necessary for the reforming process and a massive heat recovery for low pressure water in the steam power plant.

Gasification integrated systems (GC) show lower efficiencies, between 38.7% and 39.7%. The integration of gasification systems has a larger effect on the efficiency of the steam power plant as a result of drawing off the steam necessary for the gasification process. Moreover, as gasifier size increases, a reduction in efficiency takes place: heat recovery cannot completely compensate for the thermal losses due to the steam drawn off.

Plant efficiencies are related to the quality of fuel fed to the syngas production section: the amount of sulphur in the fuel directly affects the steam quantity necessary for the regenerator stripping tower in the sulphur removal system. Sardinian Sulcis coal causes the greatest losses while the use of biomass has less impact on the efficiency.

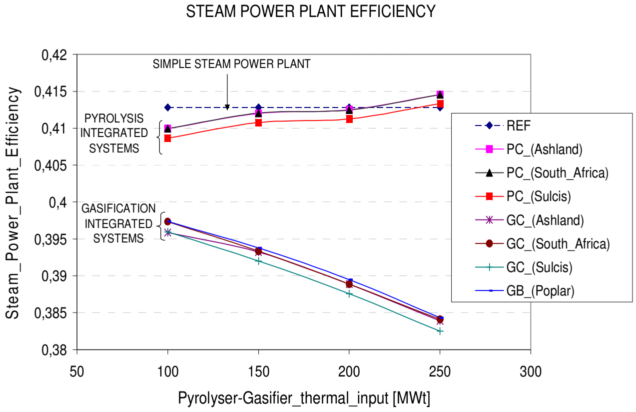

Figure 4. Power Plants Efficiency vs Pyrolysis-Gasification Thermal Power Input.

In Figure 5 equivalent efficiency defined as the ratio between the sum of net electrical and chemical (syngas and hydrogen) products against the thermal power input calculated on LHV basis, considering the coal or the mix of coal and biomass used feeding the whole system is reported.

$$\eta_{eq} = \frac{P_{el} + P_{th_{H_2}} + P_{th_{syngas}}}{P_{th_{coal\_biomass-inlet}}} \tag{1}$$

Thus the equivalent efficiency takes into account also the usable chemical products of the system in addition to the electrical power generation.

It is possible to note how pyrolysis integrated systems show a lower equivalent efficiency compared with gasification integrated systems. This is basically due to the greater production of hydrogen and syngas in the gasification process compared with the pyrolysis process. The use of biomass seriously affects equivalent efficiency, reducing the gasification system syngas and hydrogen production.

Summarizing the thermodynamic results, gasification is more effective when compared to the pyrolysis process in terms of hydrogen and syngas production, as reported in Appendix A. From the tables in Appendix A it is also plain to calculate the reduction of carbon dioxide emission due to the use of mixture of coal and biomass as fuel respect to systems fed by coal.

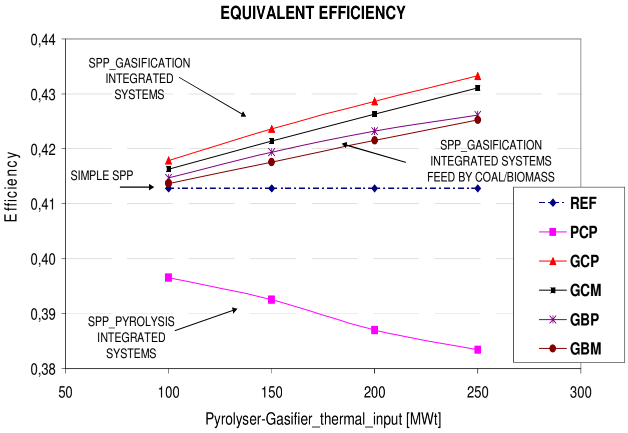

Figure 5. Equivalent Efficiency vs. Pyrolysis-Gasification Thermal Power Input.

3. Economic Analysis

WTEMP software is provided with “cost/costing equations” (Massardo and Scialò, 2000), that evaluate individual component capital costs on the basis of the thermodynamic and physical parameters. In Table 3, the main economic assumptions are reported. Main economic assumptions have been taken in accordance with (Bejan et al., 1996). The price of electricity and the prices of coal and biomass (including transport costs) are based on information provided directly by ENEL.

Table 3. Main Economic Assumptions.

Inflation	3.0 %
Nominal escalation rate of PEC	3.0 %
Nominal escalation of Fuel and other supplies	3.0 %
Plant Economic Life	30 years
Average Income tax rate	30 %
Fuel price (coal)	2e-6 €/kJ
Fuel price (biomass)	5.45e-6 €/kJ
Sale Price of Electric Power	2.7e-5 €/kJ
Equivalent operating hours at nominal load	8000

In Figure 6 the cost of Electricity for 200 MW_{th} size Pyrolysis and Gasification plants fuelled by Ashland coal are reported. The first bar on the left side represents the cost of electricity of the reference steam power plant, divided into capital and variable costs.

The cost of electricity for the reference plant is 3.8 c€/kWh with an incidence of capital costs respect to the overall cost of about 54%. COE increases until 4.2 c€/kWh for PC plants (incidence of capital costs of about 53%) and further, at about 4.8-4.9 c€/kWh, for GC and GB plants (incidence of capital costs slightly increases near 58%). Therefore PC plants show an increase in cost of about 0.36 c€/kWh, while GCP and GCM plants show an increase of about 0.96 c€/kWh: this increase is basically due to the higher fuel flow rate in input (variable cost) and, in GC plants, due to pressurised gasifier and ASU components (capital cost) too. The introduction of biomass into GBP and GBM systems maintains the COE essentially constant to the GC options. Hydrogen cost is calculated as follows and reported in Figure 7.

$$H_2COST = \frac{ENP_{REF} - ENP_{PLANT} - SNP}{H_2 produced} \qquad (2)$$

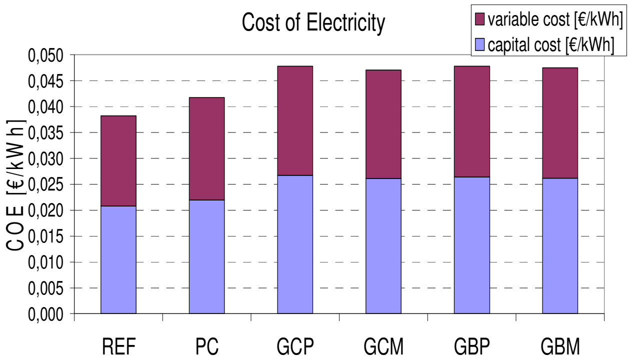

Figure 6. Cost of Electricity in the First Operating Year.

SNP (Syngas Net Profit) is calculated assuming the same sale price for syngas produced (per calorific value) as for natural gas. The cost of hydrogen is compared in Figure 7 with the cost of natural gas (first column). It is evident that hydrogen produced from PC plants seems to be more competitive than hydrogen from GC and GB plants. The hydrogen cost for pyrolysis (PC) plant is 85% higher than the cost of natural gas, while the hydrogen cost from coal gasification (GCP and GCM plants) is about 100% higher. Introducing biomass into gasifier (GBP and GBM) plants evidently increases the cost further, rising it to almost 2E-5 €/kJ.

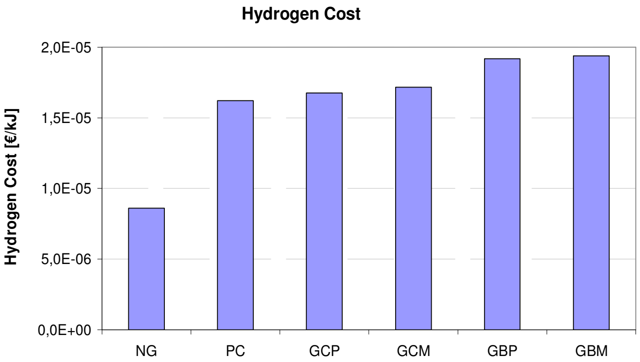

Figure 7. Hydrogen Cost.

4. Conclusions

A thermodynamic and economic analysis of integrated systems for co-production of electricity (from traditional steam power plant) and hydrogen (from pyrolysis and gasification processes) has been conducted.

Thermodynamic results show that gasification systems have a greater effect on the electrical efficiency of the steam power plant than pyrolysis systems. The integration of a 200 MW_{th} size gasification system causes an efficiency loss of about 2.5 percentage points while a 200 MW_{th} pyrolysis system can guarantee at least the same performance to the steam power plant. On the other hand gasification systems show a higher equivalent efficiency than pyrolysis systems, due to the more efficient hydrogen conversion process and the higher amount of syngas production.

Economic analysis shows interesting results in terms of hydrogen cost: the gasification process proves to be more expensive due to higher capital costs (pressurised gasifier and ASU) and to the revenue reduction due to the efficiency loss in the power plant. Therefore pyrolysis systems appear an attractive option to co-produce electricity and hydrogen. However gasification can be considered a reliable technology at the moment while pyrolysis technology still needs further development, especially for large size plants.

Acknowledgements

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Nomenclature

ASU	Air Separation Unit
COE	Cost of Electricity [eurocents/kWh]
CPD	Chemical Percolation Devolatilisation
ENP_{REF}	Electricity Net Profit of reference power plant [€]
ENP_{PLANT}	Electricity Net Profit of integrated power plant [€]
FC	Fixed Carbon ratio
LHV	Low Heating Value [kJ/kg]
NG	Natural Gas
P_{el}	Electrical Power [kW, MW]
P_{th}	Thermal Power [kW, MW]
PEC	Purchase Equipment Cost [€]
PSA	Pressure Swing Adsorption unit
REF	Reference Steam Power Plant
SNP	Syngas Net Profit [€]
SPP	Steam Power Plant
η_{eq}	Equivalent efficiency

Subscripts

e	electrical
th	thermal

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APPENDIX A: Thermodynamic Parameters and Mass Fractions of the Main process Streams for the Layouts Studied: 200 MW_{th} Plant Size.

Table A1. 1200 MW_{th} Size Gasification Plant with PSA Unit Fuelled by Ashland Coal.

Ashland Gasifier Stream	Flowrate (kg/s)	Temperature (°C)	Pressure (bar)	Mass fraction (%) CH_4	O_2	H_2O	N_2	CO_2	CO	H_2	H_2S
Gasifier inlet											
- oxygen (from ASU)	6.03	29.6	32.		95.6			4.3			
- steam	3.4	278.2	40.4			100.					
- coal	7.4	15.	1.013	composition as reported in Table 1 for Ashland coal							
Gasifier outlet	16.83	1200.	31.36	0.16		8.43	2.17	12.88	72.54	3.39	0.4
WGS inlet	32.52	450.	30.12	0.08		54.77	1.07	6.36	35.83	1.68	0.2
WGS outlet	32.52	224.	28.35	0.08		31.94	1.07	62.12	0.34	4.23	0.2
DeSOx inlet	22.17	30.	27.22	0.11		0.15	1.57	91.15	0.5	6.2	0.29
DeSOx outlet/PSA inlet	20.57	36.8	25.45	0.12		0.05	1.7	90.91	0.54	6.67	
PSA outlet[1]	19.43	36.8	1.5	0.13		0.06	1.8	96.2	0.57	1.23	

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[1] H_2 production at PSA outlet is 1.14 kg/s at 25 bar. LHV_{syngas} =1600 kJ/kg

Table A2. 200 MW_{th} size Gasification Plant with PSA Unit Fuelled by Ashland Coal Mixed with Biomass.

Ashland + Biomass Gasifier Stream	Flowrate (kg/s)	Temperature (°C)	Pressure (bar)	Mass fraction (%) CH_4	O_2	H_2O	N_2	CO_2	CO	H_2	H_2S
Gasifier inlet											
- oxygen (from ASU)	6.03	29.6	32.		95.6			4.3			
- steam	3.4	278.2	40.4			100.					
- coal	5.55	15.	1.013	composition as reported in Table 1 for Ashland coal							
- biomass	1.85	15.	1.013	composition as reported in Table 1 for biomass							
Gasifier outlet	16.83	1200.	31.36	0.06		13.8	2.04	20.	60.8	3.	0.3
WGS inlet	32.84	450.	30.12	0.03		57.38	1.	9.87	30.	1.48	0.15
WGS outlet	32.84	212.	28.35	0.03		38.16	1.	56.82	0.18	3.64	0.15
DeSOx inlet	20.34	30.	27.22	0.05		0.14	1.63	91.75	0.3	5.87	0.24
DeSOx outlet/PSA inlet	18.88	37.	25.45	0.05		0.05	1.75	91.52	0.32	6.3	
PSA outlet[2]	17.89	37.	1.5	0.05		0.06	1.85	96.53	0.33	1.15	

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[2] H_2 production at PSA outlet is 0.99 kg/s at 25 bar. LHV_{syngas} =1500 kJ/kg

Table A3. 200 MW_{th} Size Pyrolysis Plant with PSA Unit Fuelled by Ashland Coal.

Ashland Pyrolyzer	Flowrate (kg/s)	Temperature (°C)	Pressure (bar)	Mass fraction (%)							
Stream				CH_4	C_2H_2	H_2O	N_2	CO_2	CO	H_2	H_2S
Pyrolyzer inlet											
- coal	7.4	15.	1.013	composition as reported in Table 1 for Ashland coal							
- recirculated syngas	18.3	61.	1.3	35.08		1.28	0.05	17.3	37.98	6.62	1.68
- sand	203.6	1075.	0.973								
Pyrolyzer outlet[3]	229.5	750.	1.274	36.66	0.69	6.35	0.02	15.66	32.72	6.08	1.77
Tar cracking inlet[4]	20.47	750.	1.25	36.66	0.69	6.35	0.02	15.66	32.72	6.08	1.77
Tar cracking outlet	20.47	748.	1.22	35.08		1.28	0.05	17.3	37.98	6.62	1.68
DeSOx inlet	2.25	30.	26.92	35.08		1.28	0.05	17.3	37.98	6.62	1.68
DeSOx outlet	1.91	31.5	24.77	32.56		0.51	0.06	15.12	44.	7.75	
Reformer inlet	7.52	337.6	24.77	8.28		74.69	0.02	3.85	11.19	1.97	
Reformer outlet	7.52	868.4	24.28	0.82		59.15	0.02	21.32	13.1	5.59	
WGS inlet	7.52	450.	24.28	0.82		59.15	0.02	21.32	13.1	5.59	
WGS outlet/PSA inlet	7.52	204.	22.38	0.82		50.82	0.02	41.67	0.15	6.52	
PSA outlet[5]	7.12	204.	1.5	0.87		53.65	0.02	43.99	0.16	1.32	

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[3] The flow rate is the sum of char, sand, ash, tar and syngas flow rates. Mass fractions refer only to syngas flow rate that is equal to 19.47 kg/s. TAR flow rate is 1. kg/s

[4] Flow rate is the sum of syngas and tar flow rates, after the cyclone. Mass fractions refer only to syngas flow rate.

[5] H_2 production at PSA outlet is 0.4 kg/s at 22 bar. LHV_{syngas} =2000 kJ/kg