Techno-economic analysis for the integration of a power to fuel system with a CCS coal power plant

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ABSTRACT

In this paper, an analysis of the integration of a carbon capture unit and a power to fuel system for methanol synthesis with a coal power plant is presented from the energetic, environmental and economic standpoints. The study is carried out in three different sections. In the first part, the impact of the integration of a carbon capture system (CCS) and of a power to fuel plant (PtF) for methanol production is investigated in terms of plant average efficiency, fuel consumption, CO_2 emissions. In the second part, the annual fixed and variable costs of the power plant, and the annual cost of electricity (COE) are assessed for different plant configurations. Additionally, future scenarios are analyzed considering the impact of European policies on the CO_2 emission's cost, defined by the European Emission Trading System (ETS). Finally, an economic feasibility analysis of the power to fuel plant is performed and the methanol production is evaluated. Moreover, a sensitivity analysis is carried out to evaluate the impact of the most affecting parameters (electrical energy cost, the methanol selling price and the capital cost of the electrolyzer) in terms of Internal Rate of Return (IRR).

Keywords: power to fuel, CO_2 Sequestration and Utilization, coal power plants, economic analysis, CO_2 emission trading system.

NOMENCLATURE

Abbreviation

CEPCI	Chemical Engineering Plant Cost Index
CFPP	Coal-fired power plant
COE	Cost Of Electricity
CCS	Carbon Capture Unit
PBP	Pay Back Period
EU	European Union
EUA	European Emission Allowances
ETS	Emission Trading System
GHG	Greenhouse gas

MEA	Methyl ethylamine
MPC	Methanol Production Cost
NPV	Net Present Value
PEM	Proton Exchange Membrane
PtF	Power to Fuel
RES	Renewable Energy Sources
TCC	Total Capital Cost
TPG	Thermochemical Power Group

1. INTRODUCTION

Greenhouse gas (GHG) emissions are one of the most important environmental issues of the 21st century. The largest source of GHG is carbon dioxide (CO_2), whose emissions have increased in the last decades, due to anthropogenic activities, in particular, fossil fuels combustion (i.e. for electrical energy production). In order to limit the effects related to CO_2 increase, the European Union (EU), promoted the Emission Trading System (ETS): the EU ETS, set up on 1st January 2005, operates in 31 Countries (28 EU Countries, plus Iceland, Lichtenstein and Norway) and represents the largest world's platform of this kind [1]. The EU ETS works on the 'cap and trade' principle. A cap is set on the total amount of certain GHGs that can be emitted by installations covered by the system: within the cap, companies receive or buy emission allowances, which they can trade with one another as needed. After each year, a company must surrender enough allowances to cover all its emissions, otherwise heavy fines are imposed. EU ETS limits emissions for more than 10,000 energy-intensive companies and airlines operating in the above-mentioned Countries.

EU energy policy targets, already defined for 2020- and 2030-time horizons [2], include also higher and higher penetration of renewable energy sources (RES) and the promotion of energy efficiency. In particular, the recent increase of RES (i.e. solar and wind) has caused significant issues in the management of traditional large size power plants (e.g. coal steam power plants and natural gas combined cycles), forcing them to operate in off-design, with frequent startup/shutdown that reduce their efficiency and lifetime. Because of the above-mentioned policies, hard coal consumptions in EU 28 in the period 1990 – 2016 have reduced significantly, from around 450 Mtons up to 239 Mtons; in a similar way, also lignite's consumption has decreased in the same period, by more than 40%, compared to 1990 levels [3].

Power-to-fuel (PtF) systems can be a worthy solution for the future energy scenarios: a PtF technology concerns a process that is able to store electrical energy (i.e. produced by large size power plants) into a chemical form, to be employed in a second time [4]. The conversion of electrical energy into more convenient forms of energy carriers can represent a way to increase the efficiency of large size power plants otherwise forced to operate at partial loads and lower efficiencies due to the presence of new kind of production plants based on RES. Moreover, this solution allows avoiding or at least significantly reducing, the frequent shutdowns that are affecting several large size power plants.

An interesting energy carrier for the PtF systems is represented by methanol (CH_3OH): it presents liquid form at atmospheric conditions, that make its storage and handling easy and economic, and it is used for the synthesis of important chemical derivatives such as formaldehyde, MTBE and acetic acid [5].

Moreover methanol has excellent combustion properties: in fact, thanks to its high octane number (108 for methanol, 95 for gasoline), it allows higher pressures in the combustion chamber, with consequent efficiency increase when used within an internal combustion engine [6][7]. Specific energy applications were developed basing on Fuel Cell focusing on portable generation: in standard applications with a reformer plus a PEMFC or SOFC [8][9][10] are adopted while when a low temperature is crucial the preferred solution is a Direct Methanol Fuel Cell [11],

As already described in previous publications of the authors [12][13], methanol can be produced from a mixture of hydrogen and carbon dioxide: hydrogen is produced by water electrolysis employing electrical energy and CO_2 can be sequestrated from the flue gas of traditional power plants [14][15][16][17]. This process represents an eco-friendly solution for methanol production by mitigating CO_2 emissions. The catalytic reaction takes place in ranges of temperature and pressure of 250 – 300 °C and 50 -100 bar, respectively on $CuO/ZnO/Al_2O_3$ as catalyzer [18][19]:

$$3H_2 + CO_2 \rightarrow CH_3OH + H_2O \quad (1)$$

This work has been carried out within the contest of the EU MefCO2 (methanol fuel from CO_2) project (accepted in SPIRE framework of the Horizon 2020 EU Research and Innovation program)[19]. The project's main target is the design of an innovative methanol production technology with a low carbon footprint: the concept of the MefCO2 is the capture and the sequestration of CO_2 from fossil fuel plant and its use in reaction with hydrogen, produced by water electrolysis, in order to synthesize methanol. Several academic and industrial partners are involved in the project. The main activities of the research are (i) development of innovative catalyst for the methanol reaction from H_2 and CO_2; (ii) development of innovative PEM electrolyser for hydrogen production; (iii) design and installation of demonstrative pilot plant and grid integration; (iv) process optimization and thermo-economic analysis of the plant considering different economic scenarios. The activities of the University of Genoa as a project partner mainly deal with the thermo-economic analysis.

2. METHODOLOGY

In this paper, the integration of a Carbon Capture Unit (CCS) and a power-to-fuel (PtF) plant for methanol production with a traditional coal power plant is investigated.

The analysis results are presented in different sections.

- **Part I – Technical Analysis:** the impact of the CCS integration and of a connection of a PtF plant is investigated in terms of plant average efficiency, fuel consumption, CO_2 emissions. Three different configurations are investigated, considering the CCS installation, the coupling of the coal plant with a PtF plant and the combination of the two.
- **Part II – COE assessment:** annual cost of electricity (COE) of the different configurations are compared, considering the annual fixed and variable costs; moreover, the impact of the forecasted increase of theCO_2 cost was investigated to compare the COE of the proposed solutions over the years.
- **PtF economic sensitivity analysis:** focusing on the PtF plant for methanol production, an economic feasibility analysis is performed in order to evaluate the viability of the system in terms of methanol production cost. Moreover, a sensitivity analysis is carried out to investigate the impact of some of the most affecting parameters on the Internal Rate of Return (IRR).

In the following paragraphs the main technical and economic assumption are reported.

2.1 Plant Layouts, main hypotheses and technical assumptions

Four different cases are analyzed and compared from the energetic, economic and environmental standpoints:

- CASE 1 - Reference case: 300MW coal-fired power plant without a system for the CO2 capture.
- CASE 2 - 300MW coal-fired power plant with CCS integration: a system for the carbon capture is assumed to be installed and its impact in terms of plant performance, costs and emission is investigated.
- CASE 3 - 300MW coal-fired power plant with PtF plant connection: the study case including the coal power plant and the methanol plant (without the CCS system). This case is considered as a basis for comparison with Case 4.
- CASE 4 - 300MW coal-fired power plant with CCS integration and PtF plant connection: it is assumed to couple a methanol production plant to the coal-fired power plant equipped with the CCS system. From the energy point of view, the PtF plant is considered as an additional user of the power plant. Instead, from the CO2 management point of view, the methanol plant represents a consumer: the power plant provides the PtF plant of the necessary amount of CO2 at zero cost.

In Figure 1, a scheme of the general concept of the system under investigation is reported.

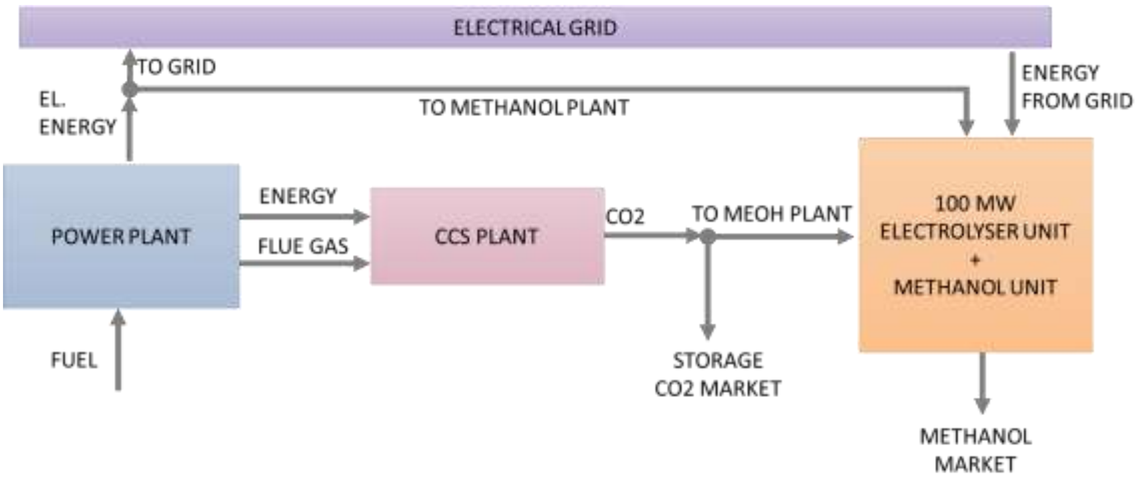

Figure 1 Concept Scheme

In the following, the main system components are described.

Coal Fired Power Plant (CFPP)

The reference case is represented by a 300MW coal-fired power plant with a nominal efficiency of 45%. The minimum load is fixed at 25% of the nominal power [21] and the specific CO_2 emission rate based on fuel consumption is assumed equal to 0.35 tCO2/MW_{th} [22]. The main technical data of the reference plant are reported in Table 1.

Table 1 Coal-fired power plant main technical data [21] [22] [23]

Nominal Power	300	MW
Nominal efficiency	45	%
Min. Load	25	%Pmax
Plant availability	98	%
CO_2 emission factor	0.35	tCO2/MWh_{th}

The dimensionless off-design curve of the power plant is reported in Figure 2. On its basis, the punctual efficiency of the plant has been calculated and consequently the fuel consumption.

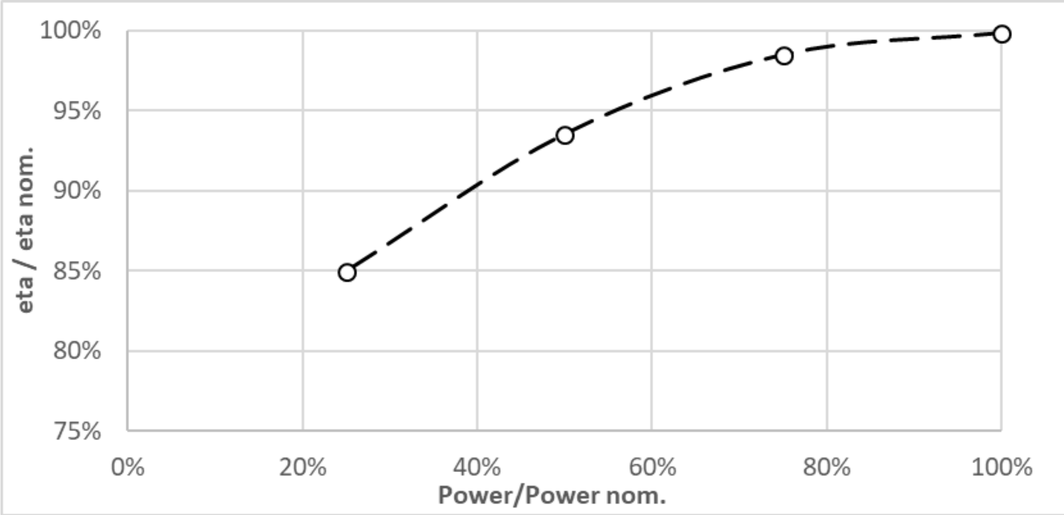

Figure 2 Coal-fired power plant off-design curve [21]

In Figure 3, the weekly profile of the reference plant is reported. Because of the increasing RES penetration on the national grid, the fossil-fueled power plant is forced to operate in discontinuous conditions during the day; in particular, it is forced to be shut down during weekend days when the energy demand is lower, and the RES are able to cover most of the demand. As consequence, the total operating hours of the coal-fired power plant decreases significantly with a strong negative effect on the average annual electrical efficiency. In the case under investigation, the weekly profile reported in Figure 3 is replicated for 51 weeks per year with one week of out of operation for scheduled maintenance.

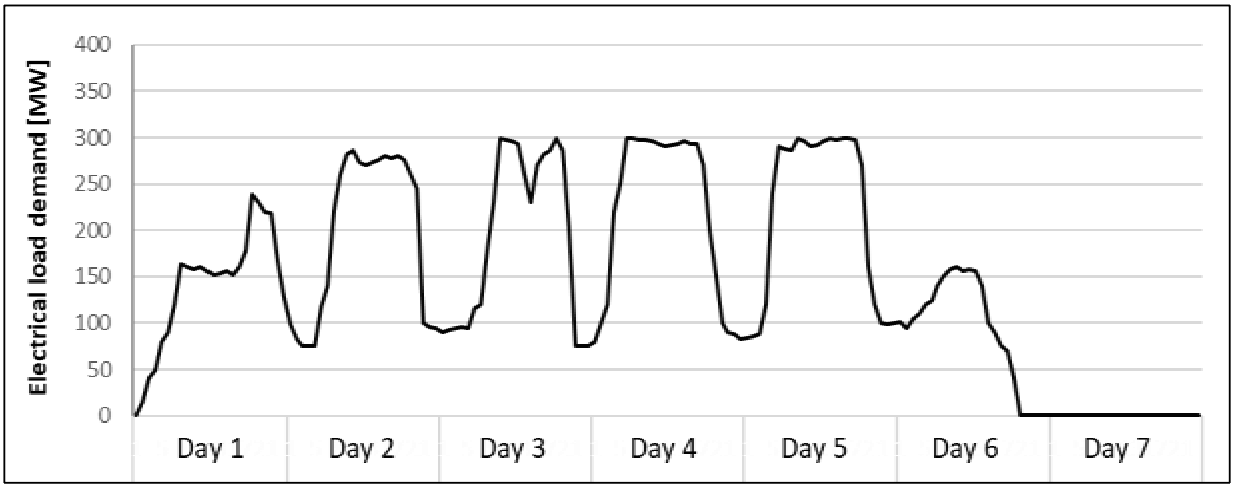

Figure 3 Coal-fired power plant weekly profile

Carbon Capture Unit (CCS)

The carbon capture technology considered in present work is an amine-based absorption system using a 30% MEA solvent. The CO_2 capture rate is assumed equal to 90% and the thermal and electrical energy consumptions are assumed equal to

2.9GJ/ton and 100 kWh$_e$/ton respectively. The percentage content of CO_2 in the flue gas is assumed around the 15 vol% dry [21]. In Table 2, the main technical assumptions related to the CCS are reported.

Table 2 CCS Main technical assumption [24][25][26][27]

CO2 capture rate	90%	-
Thermal energy requirement	2.9	GJ/ton
Electrical energy requirement	100	kWhe/ton
SOLVENT	30%	MEA
Amine lean solvent loading	0.28	mol CO_2/ mol MEA
Solvent rate	25	m3/ton CO_2
MEA LOSS	0.5	kgMEA/ton CO_2

In the following section, the three different plant configurations are analyzed in detail, comparing them to the reference case (CASE 1) of a coal-fired power plant. The results are compared in terms of energy (throughout average efficiency, fuel consumption and equivalent operating hours), of global pollutant emissions (represented by CO_2) and in economic terms (represented by COE), in order to determine the best configuration.

Power to fuel (PtF) plant - Methanol synthesis unit

The PtF plant is composed by a 100 MW system of PEM electrolyzers, producing oxygen and hydrogen, and a methanol synthesis unit with a capacity of about 84 kton/year of methanol.

The scheme of the PtF section is shown in Figure 4. The hydrogen and the carbon dioxide captured from the exhaust gas of the power plant, are sent to the synthesis unit for the methanol production. The PtF plant is electrically connected to the power plant. The methanol reactor is assumed to operate constantly at nominal conditions throughout the whole year; therefore, when electrical energy from the power plant is not available, the required energy is purchased from the grid at industrial market price.

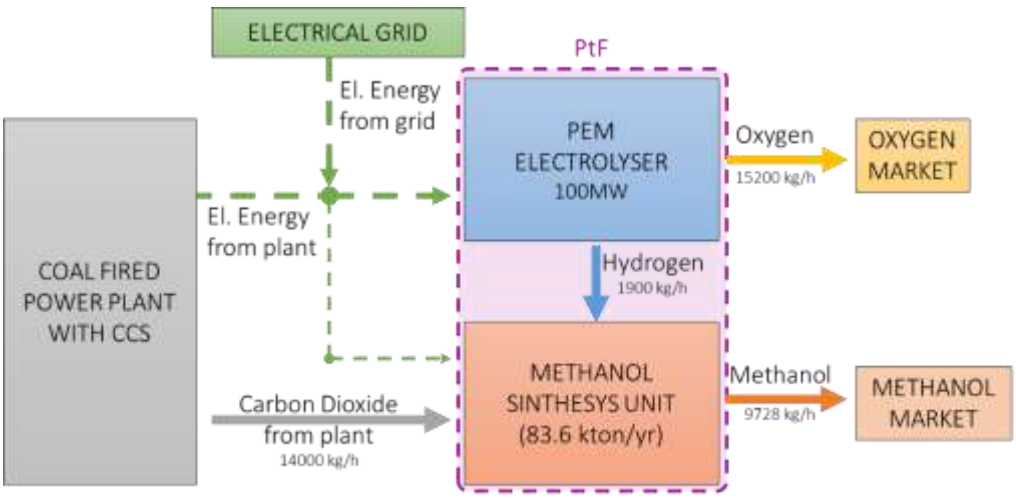

Figure 4: PtF plant integration

The PtF plant is mainly composed by 100MW PEM electrolyzers system operating at 30 bar and with a specific energy consumption of about 4.7 kWh/Nm^3 and a methanol synthesis unit, operating at 80 bar, which includes also the compression trains for CO_2 and Hydrogen. PEM electrolysers are based on the solid polymer electrolyte concept for water electrolysis. The technology is less mature than alkaline electrolysers and mostly used for small-scale applications [28], even if several producers have recently started to develop larger size units (>1 MW for module). Key advantages are high power density and cell efficiency, provision of highly compressed and pure hydrogen and oxygen, fast response and low start-up time. The main drawbacks are the shorter lifetime and the higher costs, due to platinum catalyst and to expensive materials for membrane. However, costs have reduced significantly in the last years and the future developments are aimed at lowering them further. In Table 3, the main technical assumptions for both the electrolyzers and the methanol synthesis unit are reported.

Table 3: PtF plant [29][30][31][32]

100 MW PEM Electrolysers	
Electrical consumption	4.7 kWh/Nm^3 di H_2
Pressure	30 bar
Efficiency	75%
PEM availability	98%
Methanol Unit	
Working Pressure	80 bar
Temperature	240 °C
Recirculation factor of unreacted syngas	0.85
Conversion efficiency	96%
Molar H_2: CO_2 ratio	3:1

2.2 Economic assumption for the Assessment of the Cost of Electricity

The COE is used as a term of comparison for the different case studies evaluation. It is defined as the average annual value of the electrical energy production cost and it is calculated as the ratio between the annual electrical energy production and the annual overall cost comprising the TCC annual fraction, the annual fixed costs, and the annual variable costs.

$$\mathrm{COE} = \frac{Annual\ Overall\ Cost}{Annual\ el.energy\ production}\ [€/MWh] \tag{2}$$

In order to perform the economic analysis of the system, the fixed and variable costs of the power plant, the CCS system, and the PtF plant respectively have to be evaluated.

Following the technical results, the different cases are evaluated and compared from the economic point of view. For each case, fixed costs, variable costs and Cost Of Electricity (COE) are calculated.

Fixed costs

Fixed costs refer to the capital cost, installation cost, and the fixed O&M costs of the Coal Fired Power Plant (CFPP), the CCS, and the PtF respectively. In Table 4, the capital cost functions used in the present study are reported. All the cost functions are the result of the extrapolation of several literature data updated to 2017 with the CEPCI coefficient.

The cost functions for the power plant and the CCS system reference to the total capital cost (TCC) and include both the purchased equipment cost and the installation cost. Instead, the cost functions of the electrolyzer and the methanol unit refer to the purchased equipment costs. The TCC of the PtF plant is calculated considering a correction factor on PEC value, estimated as 2.22 [33], in order to take into proper account the additional costs related to installation and plant commissioning.

Table 4 Capital cost functions [34][35][36][37][38][39]

Coal-fired Power Plant	$TCC_{CFPP} = 20.67 * 10^6 * \left(P_{inst[MW]}\right)^{0.6}$
Carbon Capture Unit	$TCC_{CCU} = 4.1811 * 10^6 * \left(M_{CO2_{nom}[ton/h]}\right)^{0.7}$
PEM electrolyzer	$CC_{PEM} = 1.2 \cdot 10^6 * P[MW]^{0.85}$
Methanol production unit	$CC_{MeOH} = 20.4 \cdot 10^3 * Min\left[\frac{kg}{h}\right]^{0.65}$

As result, for the 300MW coal-fired power plant under investigation, the specific capital cost of the plant with and without the CCS resulted equal to about 2111€/kW_{inst} and 2885 €/kW_{inst}, respectively.

The fixed O&M cost refers to costs for the plant operating that are independent by the running hours but are a function of the plant size. The Power Plant specific fixed O&M costs are assumed equal to 32€/$kW_{inst,year}$, while for the CCS they are calculated as the 10% of the TCC[37].

Variable costs

Variable costs are related to the operation and maintenance of the power plant (with and without the CCS) and of the PtF plant. For the power plant, they are made of the consumed fuel costs, the variable O&M costs (that depend on the operating hours and are expressed as a function of produced energy), the start-up costs (that are distinguished between cold and warm start-ups), and the costs of the CO_2 emission that are evaluated as the average of the 2017 and 2018 EUA values [40].

Plant lifetime

In order to calculate annual costs, the TCC of the CFPP, of the CCS, and of the PtF are divided by the respective plant lifetimes, which are assumed equal to 40 years, 20 years and 20 years respectively, according to literature data.

In Table 5, the main economic assumptions for the power plant and the CCS are summarized.

Table 5: Main economic assumptions for CFPP and CCS [37-49]

Plant lifetime	40	years	
CCS lifetime	20	years	
Capital & Installation Costs			
Coal Plant w/o CCS	2111	€/kW_inst	
Coal Plant w CCS	2885	€/kW_inst	+ 37%
Fixed Costs			
Fixed O&M cost	32	€/kW year	
Fixed CCS cost	10%	% TCI_{CCS}	
Variable Costs			
Fuel cost	12	€/MWh	
Variable O&M cost w/o CCS	3.5	€/MWh	
Variable O&M cost w CCS	8	€/MWh	+ 56%
COLD start-up (>120h of standstill)	280	€/MW	
WARM Start-up (24-120h of standstill)	160	€/MW	
CO2 emission cost	10	€/ton	

3. RESULTS

3.1 Part I: Technical analysis results

<u>CASE 1 – Reference case</u>

The Coal plant capacity factor results lower than 50% and the average efficiency is about 43% (2 percentage p.ts lower than the nominal values). The weekly-shut down results in 50 warm start-ups (24-120h of standstill) while the scheduled maintenance causes one cold start-up (>120h of standstill). The "warm" and "cold" terms refer to the metal temperature of the turbine and it depends on the number of hours of the stand still period between two operating periods. The longer the standstill phase and the lower the system temperature, the higher the cost of the start-up since the start-up fuel consumption increases, the auxiliary power demand increases and also the maintenance costs grow because the thermal cycle strongly impact on the wear and tear of the components [43]. The operating cost associated to these procedures were considered in the economic assessment (Part II). In Table 4, the main performance data related to the reference plant are reported.

Table 6: coal power plant main results

Energy production	1302.72	GWh
Tot fuel consumed	3015.13	GWh
Avg. efficiency	43%	%
Capacity factor	49.8%	%
Eq. Operating hours	4343	h
Cold start-up (>120h of standstill)	1	n.
Warm Start-up (24-120h of standstill)	50	n.
CO2 emission	1,055,296	ton/yr
CO2 emission rate	0.81	Ton CO2/MWhe

Assuming a CO_2 emission factor for the hard coal-fired plant equal to 0.35 tCO_2/MWh_{th}, the average CO_2 emission rate of the reference plant resulted in about 0.81 $tCO_2/MWh_{el,prod}$, corresponding to about 1,055 kton/year.

CASE 2 – CCS integration

The CCS integration entails a significant reduction in terms of nominal net power output (from 300 MW to 245 MW, about –18%) and in the nominal efficiency (from 45% to 37%, about 8 percentage points). In order to satisfy the energy demand of the CCS plant, part of the working steam is spilled from the coal plant, resulting in a reduction of the amount of electrical energy that can be produced and sold to the grid. If on the one hand, the integration of a CCS in an existing coal plant reduces the maximum power output, on the other hand, it allows for a reduction of the minimum electrical load (around 45MW) of the plant and, hence, increases the plant flexibility.

Figure 5 reports the comparison between the traditional coal power plant (CASE 1) and the coal power plant equipped with CCS (CASE 2). The presence of CCS leads to a decrease in terms of energy efficiency: electrical energy production decreases of about 8% on yearly basis, while primary energy input in terms of fuel consumption is about 10% higher than in the traditional case. On the other hand, CO_2 emissions are considerably reduced, allowing for a consequent saving in terms of emissions.

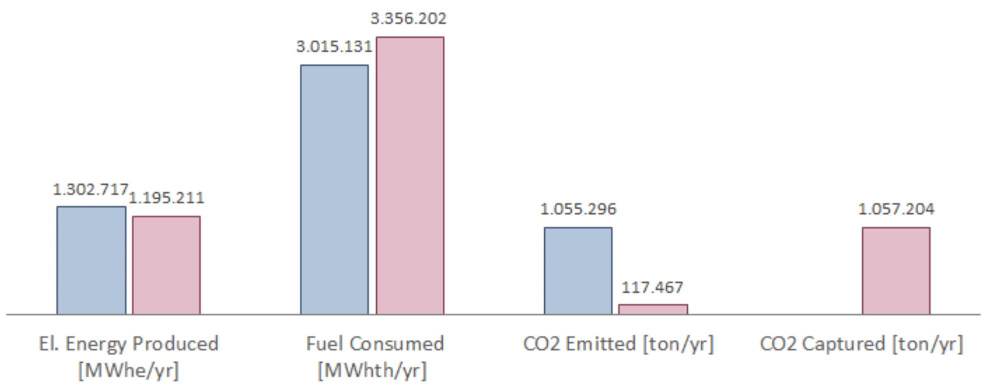

Figure 5: Energy and environmental comparison between CASE 1 and CASE 2

CASE 3 (coal plant w/o CCS + MeOH plant)

CASE 3 considers the coal plant connected with the PtF plant: this study case highlights just the effect of the increase in the power plant operating hours and can be considered as a basis for comparison with Case 4: for this reason, the CO_2 required by the PtF plant operation was not taken into account. The analysis shows an average efficiency of 44% (an increase of 1 percentage point with respect to case 1) due to an increase of equivalent operating hours from 4343 up to 6501. Consequently, fuel consumption and CO_2 emissions increase as well.

CASE 4 (coal plant with CCS + MeOH plant)

Figure 6 shows the operational management of the coal-fired power plant, equipped with CCS, in case of coupling with the PtF plant for methanol synthesis: the maximum power output of the plant is 245MW due to the CCS integration; the dashed area represents the amount of electrical energy produced by the coal plant and employed to feed the electrolyzers and the other components (i.e. CCS, compressors) included in the PtF plant. Coupling the two plants represents some advantages in terms of management of the coal plant: first, weekend shutdowns and related costs are avoided; moreover, the global average efficiency increases of more than 1 percentage point.

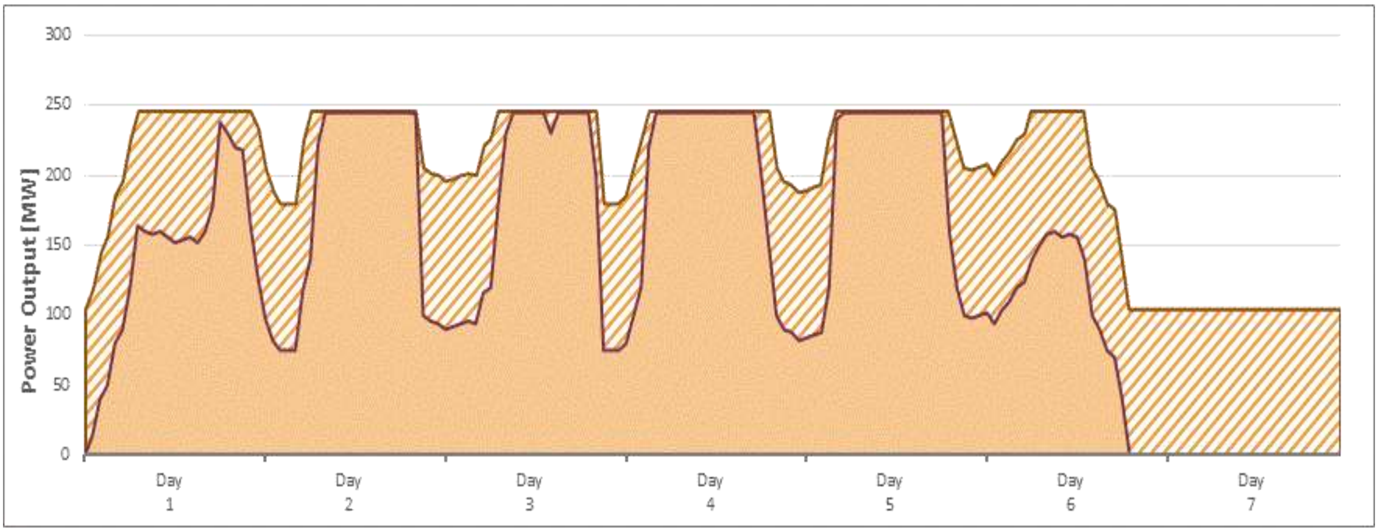

Figure 6: Week operational management of the case 4 (coal plant with CCS + MeOH plant)

The annual energy production increases up to 1756 GWh and the plant operating hours increased up to 7165 hours (+47% compared to CASE 2), corresponding to a capacity factor around 82%.

On the base of the above-reported assumptions, the total amount of produced methanol results 83.6 kton/year, with a carbon dioxide utilization of 119.8 kton/year and a total energy consumption of 900 GWh/year (62% from the power plant and 38% purchased from the grid). In addition, the PtF plant produces 130.6 kton/year of Oxygen that can be sold to industrial users.

In Figure 7, the electrical energy management of the PtF plant is reported.

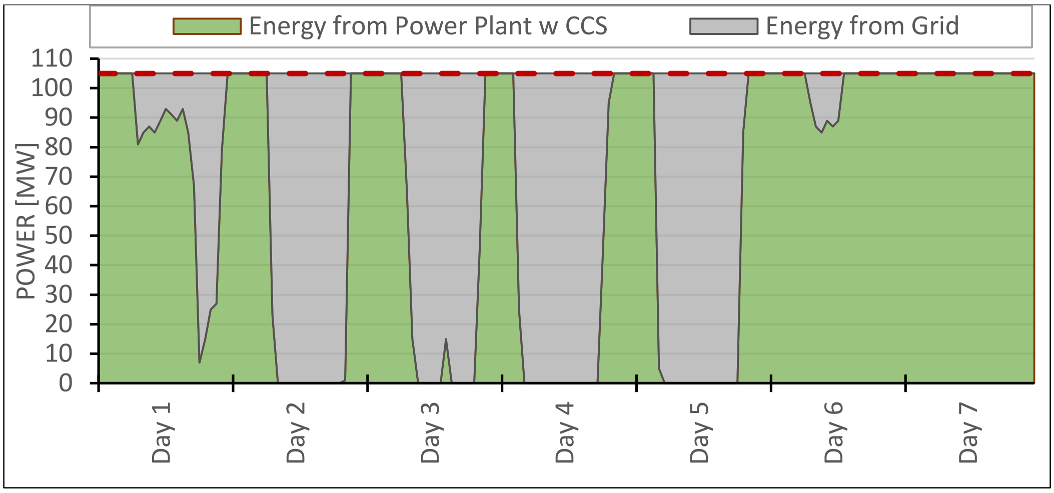

Figure 7 PtF plant electrical energy management

Case comparison

Figure 8 reports a comparison from both the energy and the environmental point of views of three configurations with the reference case, represented by the coal-fired power plant without CCS. In particular, the percentage variation of different parameters, such as annual average efficiency, CO_2 emissions, fuel consumption and annual electrical energy production, are reported for case 2 (coal plant with CCS), case 3 (coal plant with only methanol plant), and case 4 (coal plant with CCS and methanol plant). The configuration of the case 2 results the worst option from the energy standpoint, leading to lower efficiencies and electrical energy production and to higher fuel consumption; on the other hand, it assures a significant decrease (-89%) in terms of CO_2 emissions. Solution 3 (coal plant coupled to PtF plant) guarantees the best results in terms of energy production, efficiency and capacity factor, but it also implies an increase of 48% in terms of CO_2 emissions, due to fuel consumption increase. The case 4 (including CCS and PtF plant coupled to the coal plant) allows for a significant reduction of CO_2 emissions (-84% compared to reference case) and for an increase of energy production and therefore of the capacity factor (+35%); the annual average efficiency decreases compared to the reference case, but less than in case 2.

Table 7: coal power plant main results

	CASE 1 (Ref. Case)	CASE 2	CASE 3	CASE 4
Nominal Power [MW]	300	245	300	245
Energy production [GWh]	1,303	1,195	1,950	1,756
Tot fuel consumed [GWh]	3,015	3,356	4,470	4,786
Avg. Efficiency [%]	43%	36%	44%	37%
Capacity factor [%]	50%	45%	74%	67%
CO2 emission [kton/yr]	1,055	118	1,565	168
CO2 captured [kton/yr]	-	1,057	-	1,508
CO2 Avoided [kton/yr]	-	937	-	1,397

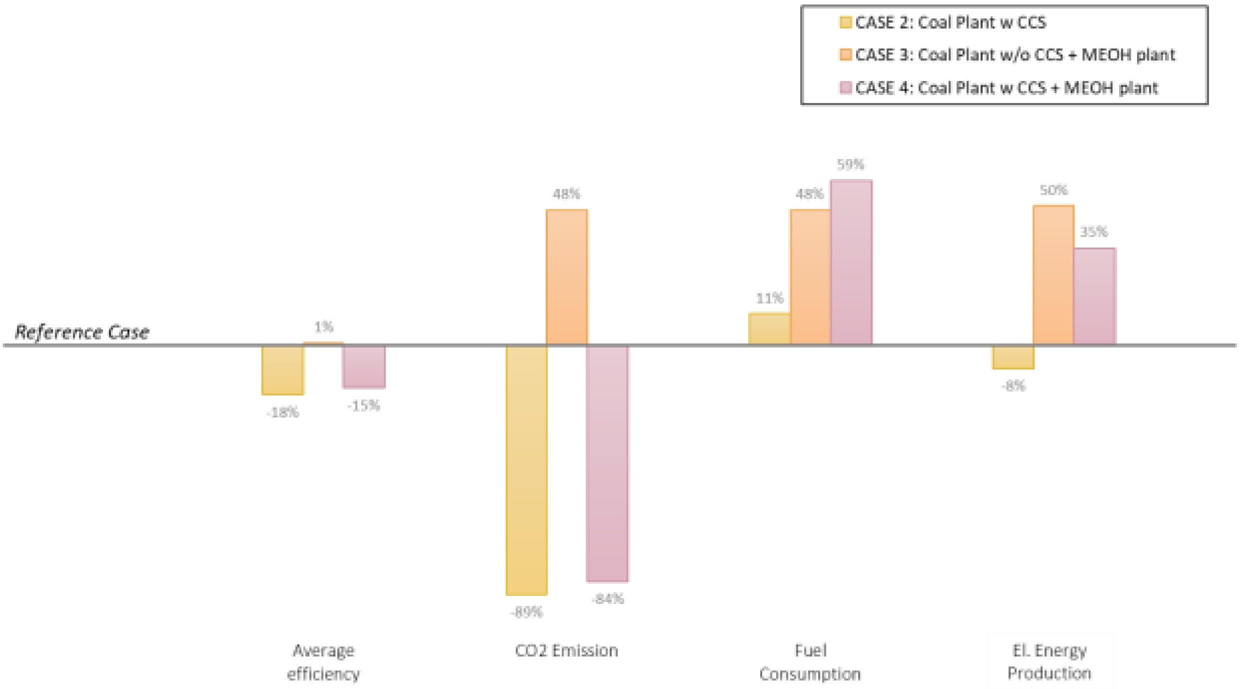

Figure 8: Energy and environmental comparison, referred to CASE 1

3.2 Part II: COE assessment results

Figure 9 shows the costs' distribution for the four cases. In case 1 (reference CFPP), the overall annual costs (including both fixed and variable costs) are about 79M€: the most important voice is represented by fuel costs (46%), followed by annual plant costs (20%); it is worth noting that CO_2 costs are not negligible (13%), since the high amount of emissions. The warm and cold start-up costs contribution is about 3%, but, even if their direct economic impact is not so relevant, they can lead to a reduction of plant lifetime, neglected in this analysis; moreover, a cold start-up implies critical aspects in terms of management, since large size coal-fired power plants are characterized by a considerable thermal inertia [54]. In case 2 (CFPP and CCS integration), the overall annual costs increase up to around 92M€ (14%) due to the installation of the CCS that impact on both the fixed capital cost (purchase and installation) and the variable costs (O&M and fuel). On the other side, the cost of the CO_2 allowances decreases by about 89%, with a saving of around 9.3 M€.

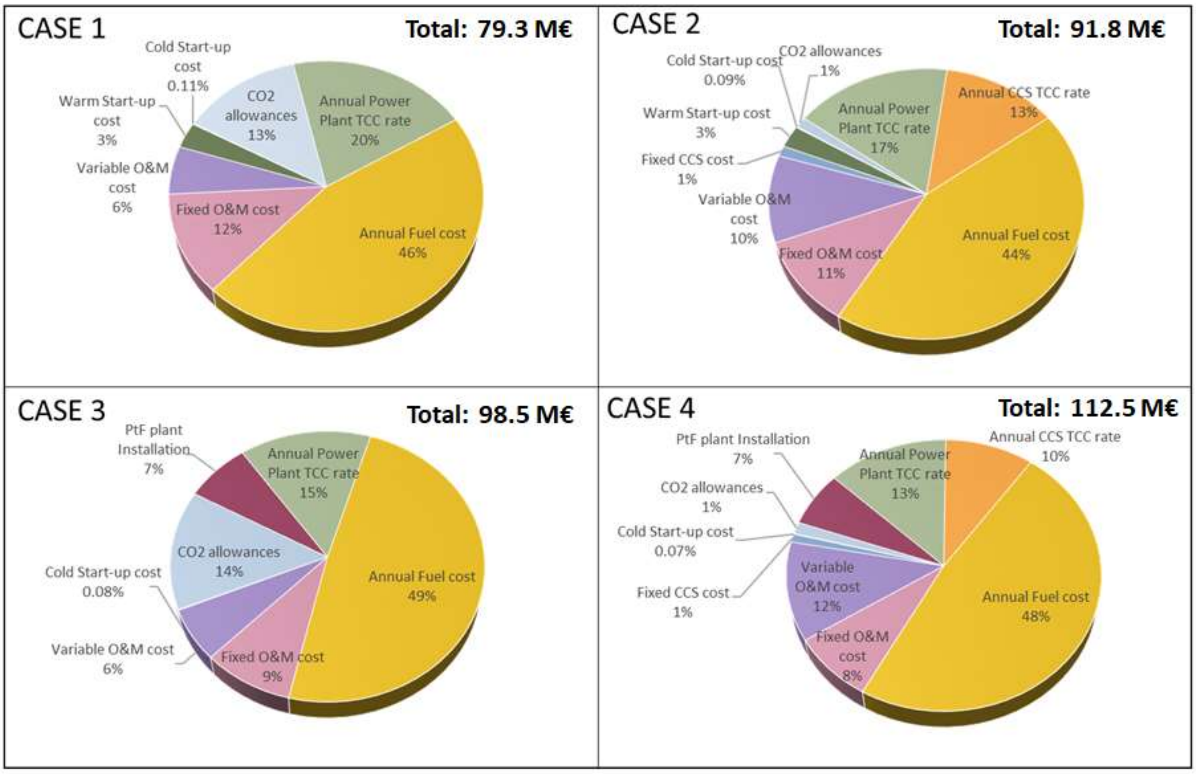

Figure 9: Annual fixed and variable cost breakdown for case 1 (reference coal-fired power plant), case 2 (coal-fired plant and CCS integration), case 3 (coal-fired plant and PtF integration), case 4 (coal-fired plant and CCS – PtF integration)

As regards the power to fuel plant with a capacity of about 84 ton/yr of produced methanol, purchased equipment costs of the electrolyzers and of the MeOH synthesis unit are about 60.4M€ and 11M€, respectively. The annual rate of total capital costs (including the purchase equipment cost and the installation) results equal to about 8M€.

In order to compare the different cases under analysis from the economic point of view, the COE is chosen as term of comparison. Figure 10 reports the comparison between the reference case and the other three configurations in terms of COE and total annual CO_2 emission.

The effects of the installation of a CCS unit in the CFPP under analysis are evident: the CCS installation leads to an increase in terms of investment and O&M costs. The resulting COE for case 2 is about 21% higher than the one of the reference case (from 61 €/MWh to 77 €/MWh). Considering the actual value of the ETS CO_2 emission allowances cost (10 €/ton), the reduction in terms of CO_2 taxation is not sufficient to balance the above-mentioned increased costs. In a similar way, comparing the case3 and case 4, the COE increases of about 19.6% (from 56 to 67 €/MWh).

The integration of the electrical demand of a PtF plant for MeOH synthesis allows for an increase in terms of plant's capacity factor and operating hours, as shown in the previous section (Figure 5). Thus, the contribution of the investment cost on the COE is reduced and the COE gets lower as well.

The effect of the capacity factor increase is highlighted comparing the reference case and case 3: the COE decreases of 8%, from 61 to 56 €/MWh. In a similar way, comparing case 2 and case 4, the COE decreases by about 13% (from 77 to 67 €/MWh). It is worth noting that the installation of the PtF plant affects the COE for only 6%.

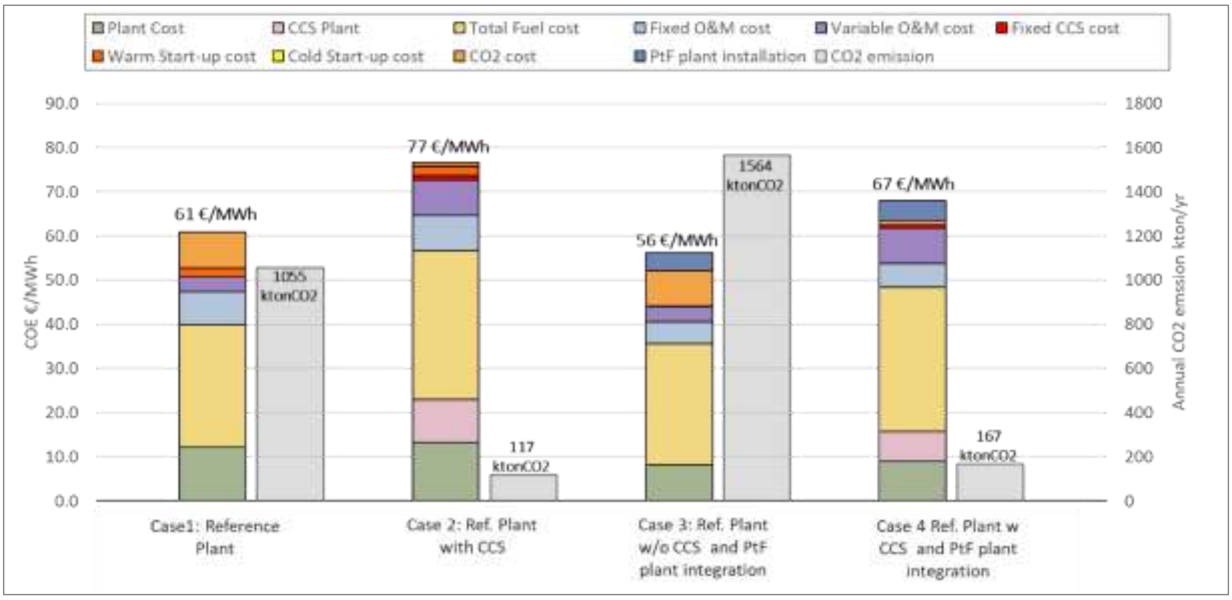

Figure 10: Economic comparison in terms of Cost Of Electricity (COE)

The best solution from the economic standpoint seems to be the case 3 (Coal plant + PtF plant without CCS) showing the lowest COE (56 €/MWh). Nevertheless, this solution presents also the highest annual CO_2 emissions value (about 1564kton), on the other side without CCS the CO_2 necessary would not be available. Whereas, in case 4, the COE increase is compensated by a strong reduction in the CO_2 emissions (about 90%). Considering the evolution of the ETS system for CO_2 emissions, in the next section a further analysis is performed, in order to evaluate a next future scenario

<u>ETS Carbon price in future scenarios</u>

The results presented in the previous section show a not negligible contribution of the voice of cost related to CO_2 emissions: in fact, coal-fired power plants are characterized by important emission of this kind, thus by quite significant costs. The calculations in the previous section are performed considering the average CO_2 emission cost between 2017 and 2018, as reported by the ETS [1]. However, it is worth observing that this cost is expected to increase quite significantly in the next years, considering the European policies of decarbonization for the future (after 2020). A study of the ETS reports different forecast scenarios about the CO_2 cost trend up to 2050. Based on this a sensitivity analysis is performed, analyzing the impact of the CO_2 emission cost on the COE in the next future. Figure 11 reports the COE values for each analyzed cases, in different time-frame: it clearly shows how the configurations without CCS would be no more feasible in the future, because of higher costs related to CO_2 emissions. In particular, in case of an average cost of 31 €/ton (medium scenario for 2030), the configuration with CCS and PtF plant would be more attractive from an economic standpoint. The break event point for which the cases 1 and 4 and 3 and 4 have the same COE value, corresponds to a CO_2 cost of about 18€/ton and 25€/ton, respectively.

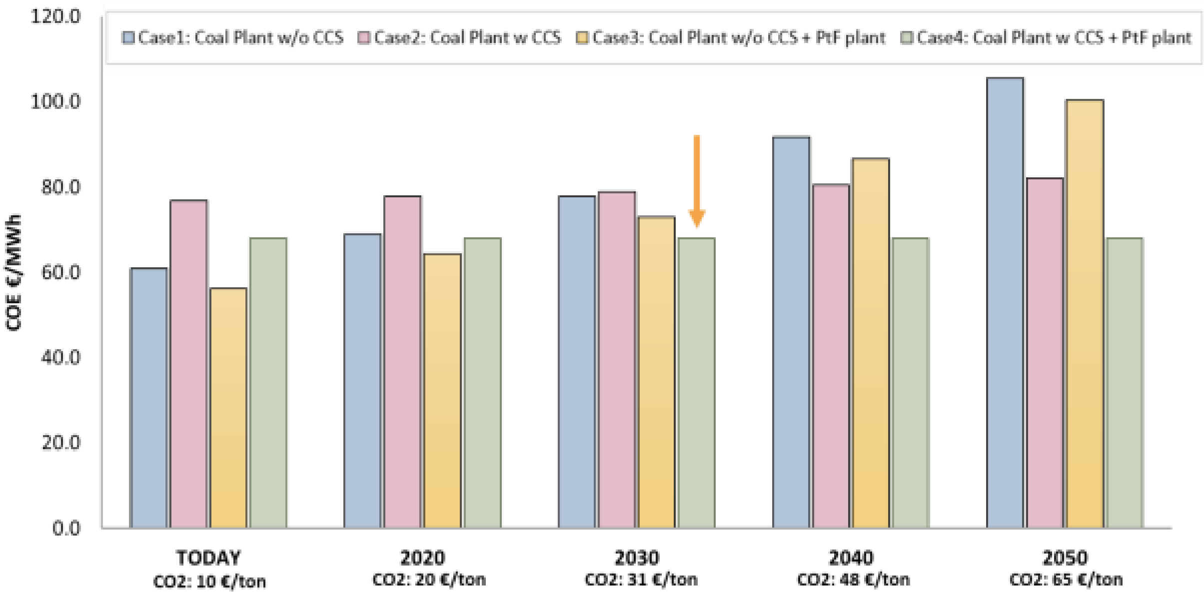

Figure 11: Economic comparison in terms of Cost Of Electricity (COE)

4. POWER TO FUEL PLANT ECONOMIC FEASIBILITY STUDY AND SENSITIVITY ANALYSIS

In this section, the economic viability of the investment for the installation of a PtF plant is investigated. In particular, the methanol production cost is evaluated for a reference scenario and, eventually, a sensitivity analysis is carried out in order to evaluate the impact of different parameters on the sustainability of the investment.

It is assumed that the PtF plant is connected to the power plant that provides both the electrical energy, when available, and the required CO_2. The main economic assumption for the reference scenario are reported below:

- **Electrical energy purchasing cost**: the energy provided by the coal plant is assumed to be purchased at the COE value of 63 €/MWh corresponding to the case 4 without the installation cost of the PtF plant that here is considered separately; the energy from the grid is purchased at 70€/MWh;
- **Carbon dioxide cost:** the CO_2 necessary for the methanol production is purchased from the CFPP at the sequestration cost (15 €/ton);
- **Oxygen selling price**: the oxygen co-produced by the electrolyzer is assumed to be sold at an estimated price of 150 €/ton, which is the minimum value of high purity oxygen for medical application[12][56];

The aim of the economic analysis is to determine the methanol production cost (MPC), in order to evaluate if the investigated solution can be viable from the economic standpoint. Two different MPCs are calculated: the first one does not consider additional revenues from O_2 sale, while the second one is corrected taking into account the revenues associated with O_2:

$$MPC = \frac{annual\ fixed\ costs + annual\ variable\ costs}{annual\ methanol\ production} \quad [€/ton] \qquad (3)$$

$$MPC_{O2sale} = \frac{annual\ fixed\ costs + annual\ variable\ costs - O_2\ sale\ revenues}{annual\ methanol\ production} \quad [€/ton] \qquad (4)$$

The main economic results are reported in Table 7. As far as capital costs are concerned, it is worth noting that most of the costs are due to PEM electrolyzers. Regarding variable costs, the most important voice is due to electrical energy, while CO_2 annual cost is considerably lower.

Table 7: economic results for PtF plant

Purchased equipment cost	71.3 M€
Methanol unit	10.9 M€
Electrolyzers	60.4 M€
Total Capital Investment	158.3 M€
PtF plant lifetime	20 years
Fixed Annual Costs	**8 M€**
Annual Variable Costs	**61 M€**
Electrical energy from Plant	35.3 M€
Electrical energy from Grid	23.8 M€
CO_2purchased from plant	1.8 M€
Annual Methanol production	83.6 kton/yr
Methanol production cost	**823 €/ton**
Methanol Production Cost O_2 sale	**589 €/ton**

The resulting MPC is around 823 €/ton; considering selling the oxygen at 150€/ton, it decreases by about 30%. Nevertheless, considering that the actual methanol market price is 400 - 450 €/ton, the investigated solution does not seem economically viable from the PtF standpoint in the actual economic scenario. On the other hand, the advantages from the environmental point of view are not negligible: the PtF allows for an increase in the average efficiency of the power plant and recycling about 120,000 ton/yr of CO_2.

<u>Sensitivity Analysis</u>

In order to investigate the economic viability of PtF in some possible short-to-midterm future scenarios, a sensitivity analysis is performed considering the variation of some economic parameters that are likely to change in the next future. In particular:

- **Methanol selling price**: considering the use of the methanol as a fuel in automotive transportation, it is reasonable to assume that its market price at refueling station will be higher than the actual market price (around 400 €/ton as 2018 average [57]). A range of variation from 400 up to 1000 €/ton is chosen.
- **Oxygen selling price**: considering the actual price of 150€/ton [12][56]an increment of the actual value up to 200 and 250 €/ton is considered.
- **El. Energy cost from the grid**: in order to take into account different future economic scenarios, a variation of +/- 30 €/MWh compared to the reference value of 70€/MWh is considered (considered range: 40 – 100 €/MWh).
- **PEM electrolyzers capital cost**: the electrolyzers resulted in the most expensive components, but considering that it is a rather new technology, it seems likely that its development in the next future will lead to a reduction in the production cost. For this reason, a percentage reduction in the PEM electrolyzers capital cost of 30% up to 50% is considered.

For each parameters' values combination, the Internal Rate of Return (IRR) is calculated as follow:

$$IRR = \frac{Annual\ net\ cash\ flow}{Initial\ Investment} x\ 100 = \frac{1}{PBP} x100 \quad [\%] \qquad (5)$$

The IRR is an economic indicator useful to evaluate the economic viability of a plant (at a pre-feasibility level): IRR equal to 10% is considered the threshold value for the economic viability of the plant. Below, the results of the sensitivity analysis are presented and discussed.

Figure 12 reports a matrix of contour graphs reporting the IRR values as a function of the methanol selling price and the electricity cost for different values of the oxygen selling price and of the percentage reduction in the PEM electrolyzers capital cost. In particular, 4 different areas are outlined: (i) the light blue area corresponding to IRR values greater than 20%; the green area corresponding to IRR values greater than 10%;(ii) the orange area corresponding to IRR values greater than 5% and represents the limit for the system viability; (iii)the red area corresponding to IRR values lower than 5% and the system results not feasible;(iv) in the end, the grey area represents "no-existing area" including the cases where the costs are greater than the revenues.

Thanks to these maps, it is possible to define the minimum methanol selling price that allows a target IRR value to be achieved. For example, for the actual condition, with electricity cost fixed at 70€/MWh and the oxygen selling price equal to 150€/ton, considering the 100% of the PEM electrolyzers capital cost, the minimum price of the methanol to achieve the 10% of IRR is about 683€/ton. However, if the capital cost was reduced by 30% or 50% (by technological development), the methanol price would decrease to 635€/MWh (-7%) and 603€/MWh (-12%) respectively. On the other hand, for 100% of PEM electrolysers capital cost and for the same value of the electricity cost from grid (70€/MWh), if the oxygen selling price increased up to 200 or 250 €/ton, the minimum methanol selling price would be reduced by 11% (605 €/ton) and 23% (527€/ton), respectively. Instead, if the electricity cost increased or decreased by 30€/MWh (40€/MWh and 100€/MWh), the MeOH price would be 561€/ton (-18%) and 765€/ton (+18%), respectively.

The sensitivity analysis showed that the most affecting factor in terms of methanol selling price variation is the electrical energy cost, followed by the oxygen price and the percentage reduction of PEM electrolyzers capital cost; in fact, for a variation of 30% of these three parameters, the MeOH price varies in a range of 13%, 10%, and 7%.

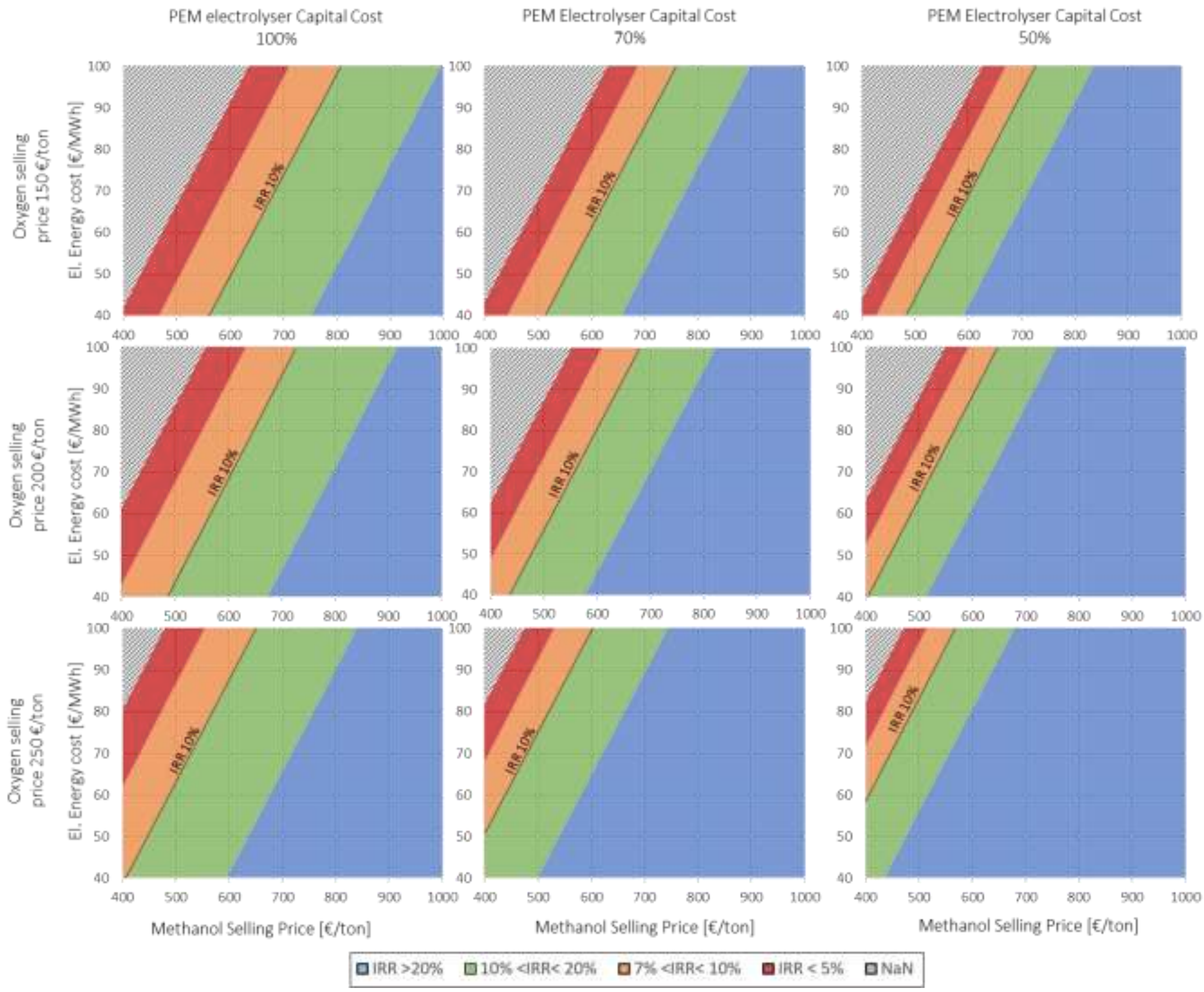

Figure 12 Sensitivity analysis results

5. CONCLUSIONS

In this paper, the integration of a CCS and of a PtF system for methanol production with a coal power plant was investigated from the technical, environmental and economic point of view. The study was carried out in three different steps: firstly, the impact of the CCS installation and PtF plant coupling on the coal power plant performances was analyzed comparing four different configurations. In the second part, the annual cost of electricity (COE) of the different configurations has been assessed and compared; moreover, an analysis considering the forecasted increase of theCO_2 allowances cost was investigated to compare the COE of the proposed solutions over the years. Finally, a feasibility economic analysis of the methanol plant was performed, including a sensitivity analysis to evaluate the impact of the most affecting parameters (Purchasing cors t of the electrical energy, selling price of oxygen and methanol, capital cost reduction of PEM Electrolyser driven by a further technology development).

From the obtained results, the following conclusions can be drawn:

- The integration of the PtF plant (cases 3 and 4) allows for an increase in terms of the capacity factor (+50% and +35% respectively), avoiding weekend shutdowns and the related operating costs;
- Considering the average energy efficiency of the coal plant, the best solution is represented by case 3 (+1% thanks to the coupling with the PtF plant which increase the coal plant's capacity factor). Cases 2 and 4 show a decrease in terms of average efficiency due to the energy consumption of the CCS (-18% and -15% respectively);
- Considering the environmental aspect, cases 2 and 4 are worthy solutions, thanks to the presence of CCS that allows for a reduction of more than 80% of CO_2 emissions; Instead, the case 3 come out to be the worst option in terms of carbon footprint;
- In terms of COE, the integration of the CCS brings to an increase of about 21% compared to re Reference case. The lowest COE value is related to the Case 3 (56 €/MWh); however, considering the expected increase in CO_2 emission cost for the next decades, the CCS's presence will be fundamental in order to avoid an increase in terms of COE. Considering the forecasted increase in the cost of EU ETS CO_2 emission allowances, since 2025 the price is expected to overcome 25 €/ton and case 4 becomes the option with the lowest COE;
- Thanks to the PtF integration, the capacity factor of case 4 increases of about 47%, compared to the case 2, leading to a decrease in COE of about 13% (from 77 to 67 €/MWh). It is worth noting that the installation cost of the PtF plant affects the COE of Case 4 for only 6%.

- As regards the PtF economic feasibility analysis, the results showed that, in the actual scenario, the methanol production cost would be not fully competitive, being higher than the actual market price (around 400 €/ton);
- The sensitivity analysis on the IRR of the PtF showed that the most affecting parameter is the purchasing electrical energy cost, followed by the oxygen selling cost and the reduction in the electrolyzer capital cost.
- On the other hand, in a future scenario, considering a potential reduction of electrolyzers' capital cost and of electrical energy cost, methanol production cost would be significantly reduced, up to values very close to the actual market ones. Nevertheless, assuming to employ the so produced methanol for automotive transportation, the target value should be compared to the actual diesel and gasoline costs (1.27 €/l and 1.34 €/l, respectively in Germany at refuelling station [58]) considering also the benefit in terms of emission related to the methanol combustion in ICE

Finally, it is worth observing that in this study methanol is produced by recycling a significant amount of the carbon dioxide emitted by a coal-fired power plant, avoiding at the same time CO_2 emissions related to traditional methods for methanol synthesis.

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