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Technical and Economical Assessment of CO_2 Capture-Based Ammonia Aqueous

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Abstract: In the context of climate change and the reduction in CO_2 emissions from fossil fuel combustion, the integration of CO_2 capture technologies in steam power plants is a key solution. The aim of this study was to analyze the use of ammonia, at different mass concentrations, in capturing post-combustion CO_2 in a coal-fired power station and comparing it with the reference 30% MEA case. In this regard, a multi-criteria model was developed to establish the optimal solvent used, considering the least impact on technical performance, economic, and environmental indicators. As a result, the lowest CO_2 capture cost was obtained for the CO_2 capture process based on 7% NH_3, with 59.07 €/tCO_2. Integration of the CO_2 capture process is more economically viable when the CO_2 emissions tax is higher than 70 €/tCO_2 for 7% NH_3 and 15% NH_3, 80 €/tCO_2 for 5% NH_3 and 30% MEA, and 90 €/tCO_2 for 2% NH_3. Regarding the overall efficiency, the energy penalty associated with the CO_2 capture process integration varied between 15 and 35%, and the lowest value was obtained for 15% NH_3. The GWP indicator ranged between 113 and 149 kg_CO_2_eq/MWh for NH_3 compared to MEA 133 kg_CO_2_eq/MWh and the case with no CO_2 capture was 823 kg_CO_2_eq/MWh.

Keywords: CO_2 capture; chemical absorption process; aqueous ammonia; monoethanolamine; life cycle assessment; steam power plant

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1. Introduction

To limit the temperature increase below 2 °C and achieve net-zero emissions by 2050 under the European Green Deal, we need to take several actions [1] including the need to rapidly reduce greenhouse gases (GHG) from energy (electricity, heat, and transport), which account for 73.2% of total GHG emissions [2]. Using fossil fuels, CO_2 emissions from power and heat generation account for the largest share of total greenhouse gas emissions [3]. Due to the pandemic, CO_2 emissions from the energy sector decreased in 2020 by 6% compared to 2019. However, in 2021, the CO_2 emissions increased by 5% compared to 2020 [3]. One solution to limit CO_2 emissions from fossil fuel combustion consists of integrating CO_2 capture technologies in power plants [4]. The most viable solution to reduce CO_2 emissions from installed power plants is integrating post-combustion CO_2 capture technology [5].

Several processes have been developed in the last decades to separate CO_2 from flue gases by absorption, adsorption, membrane separation, and cryogenic and chemical looping [6]. Post-combustion CO_2 capture technology by the chemical absorption process (CAP) is the most widely developed and implemented on an industrial scale [7]. In order to limit the effects of integrating such CO_2 capture technology into a power plant (e.g., decrease in overall efficiency, increase in electricity prices), new separation solutions are being sought or existing ones are being developed [8]. Ionic liquids are a new category of solvents. However, ionic liquids have the disadvantages of low absorbency, toxicity, and high acquisition cost [9]. CO_2 capture by adsorption is another technology developed in recent years such as the use of calcium oxide as an adsorbent [10,11], or the functionalization of solid adsorbents with amines [12].

The selection of the most competitive CO_2 capture process is dependent on the characteristics of the power plant, the type of fuel used, the performance of the CO_2 capture process, and the economical consideration [13]. The previous research focused on developing CO_2 capture processes and reducing the costs associated with integrating the capture process in line with reduced energy consumption for the regeneration of chemical solvents [14]. Based on Oh et al. (2016), the thermal energy consumed in the chemical absorption process-based MEA can be minimized by structural modification of the absorption and desorption column [15]. The cost can also be reduced by optimizing the capture process and improving the solvent properties [16]. Given the concept of sustainable development, focusing on technical and economic aspects alone, however, is not sufficient to select the optimum carbon capture process. The question of identifying the ecological influence of the integrating CO_2 capture processes in steam power plants was raised in this context [17]. The integration of CO_2 capture technology increases the consumption of resources used for energy production [18]. Even if CO_2 emissions decrease, other pollutants can increase significantly and affect the environment [19].

According to Corsten et al. (2013), the big difference between existing CO_2 capture technologies is highlighted due to the results obtained on the overall environmental impact. From a climate change perspective, the integration of CCS technologies has led to the reduction in the Global Warming Indicator (GWP) to values between 25–75 $kg\_CO_2\_equiv/GJ_e$ for natural gas thermal power plants, and respectively between 20 and 65 $kg\_CO_2\_equiv/GJ_e$ for steam power plants [20].

Reducing the climate impact of steam power plants equipped with CCS technologies is achieved by optimizing parameters such as the volumetric composition of flue gases in O_2, SO_2, PM10, PM2.5, the CO_2 capture process efficiency, and the energy consumption of the CO_2 capture process [21]. Thus, a 5% increase in CO_2 capture efficiency leads to about a 20% decrease in GWP. However, by integrating the CO_2 capture process in coal [22] and natural gas [23] steam power plants, an increase in other environmental indicators was observed: human toxicity (HTP), eutrophication (EP), creation of photochemical ozone (POCP), acidification (AP), etc. For example, by integrating the CO_2 capture process in natural gas power plants, a 65% decrease in GWP can be achieved as well as a 20% higher AP and a 60% higher HTP.

In this research, life cycle assessment (LCA) was used to collect data for the energy systems analyzed. In [24], the LCA methodology was applied for the technical and economic comparison of different life cycles of lignite-based energy systems fitted with CCS technology.

Due to the reduction in the steam power plant efficiency (PP) by fitting post-combustion CO_2 capture technology by CAP, additional fuel is required to produce the same amount of electricity generated by PP without CO_2 capture technology. Therefore, PPs fitted with post-combustion capture technology require a greater amount of solvent (e.g., ammonia or NaOH) in order to reduce emissions of NO_x and SO_x for the same amount of electricity generated by using additional fuel.

In addition, for coal-based PP, the amount of waste generated (ash, boiler slag, etc.) is higher, proportional to the increase in the amount of fuel used due to the use of a greater amount of fuel per electricity unit. Moreover, the amount of water used for the chemical solvent cooling system used to capture CO_2 is greater. By reducing the net efficiency of the steam power plant using a CO_2 capture process with a capture efficiency of 90%, the net CO_2 emissions are reduced from 88 to 85% for the same amount of electricity produced [25]. However, as the net efficiency of the steam plant increases, the impact related to the integration of CO_2 capture technology decreases. The penalty applied to the net yield of the PP results from the heat consumption required to regenerate the chemical solvent (60%) as well as the electricity consumption required to compress the CO_2 flow (30%) or needed to drive the pumps (10%) [26].

The aim of this article was to develop a multi-criteria model (MCM) to select the optimal chemical solvent considering the technical, economic, and ecological indicators of a coal-fired power plant. It focused on the effects of post-combustion CO_2 capture by the chemical absorption process using either a solution of different mass concentrations (wt.) of ammonia (NH_3), or a solution of 30% monoethanolamine (MEA) mass concentration. Thus, the technical, economic, and environmental effects of integrating the chemical absorption process in a 200 MW steam power plant were analyzed.

2. Methodology

2.1. Description of the Steam Power Plant

The reference case (without CO_2 capture process) is a steam power plant with subcritical parameters and 200 MW installed capacity, located in Govora (Romania) and consists of three main parts: air preheating, heat recovery boiler, and steam cycle. The main steam parameters analyzed for the Govora power plant were 580 °C temperature and 200 bar pressure. The coal used (lignite) was characterized by proximate analysis (moisture content, ash, volatiles, and fixed carbon) and ultimate analysis (carbon, hydrogen, oxygen, nitrogen, sulfur, water, and ash content) as well as by analyzing its sulfur compounds (pyrite, sulfate and organic products). The ultimate analysis of the fuel and its lower heating value are shown in Table 1 [27].

Table 1. Coal composition.

Ultimate Analysis (wt.%)							**LHV, kJ/kg**
Carbon	**Hydrogen**	**Oxygen**	**Nitrogen**	**Sulfur**	**Ash**	**Water**	
58.00	2.00	1.80	1.00	0.80	18.30	18.10	21,421

To calculate the performance of the steam power plant, the mathematical model described in the work of Hubel et al. (2017) was used [28].

The steam turbine outlet condensing pressure was set at 0.054 bar and a temperature of 34.25 °C. The pressure, temperature, and steam flow at each steam turbine blend outlet are shown in Table 2, and the steam power plant characteristics are presented in Table 3.

Table 2. Steam characteristics at different extraction points.

Turbine Stage	**Outlet Pressure (Bar)**	**Outlet Temperature (°C)**	**Flow (kg/s)**
HP	200	580	149.34
IP	40.10	576.90	136.96
IP	22.11	483.03	137.96
IP	9.97	369.40	130.33
IP	5.56	294.65	124.72
LP	2.54	206.15	118.86
LP	1.01	119.54	113.21
LP	0.34	72.25	107.77
Outlet LP	0.05	34.25	102.52
Condenser	0.05	34.25	102.52

Table 3. Steam power plant characteristics with subcritical parameters.

Indicators	**Values**
Electric power at the generator terminals, MW	200
Annual operating hours, h/an	7500
Number of preheated steps, -	7
HP heaters number, -	2
Electricity produced, GWh/an	1346.42

Table 3. *Cont.*

Indicators	Values
Steam pressure, bar	200
Steam temperature, °C	580
Condensing pressure, bar	0.05
Condensing temperature, °C	34.25
Steam flow, kg/s	149.34
Generator losses, MW	2.60
Generator efficiency, %	98.71
Mechanical losses, MW	0.82
Internal power ST, MW	203.42
Mechanical efficiency, %	99.60
Internal mechanical work, kJ_{int}/kg	1364.50
Specific heat amount, kJ/kg	2819.63
Specific energy, kJ_{el}/kg	1341.60
Thermal efficiency, %	48.40
Overall efficiency, %	42.44
Coal flow, kg/s	19.03
Flue gases flow, kg/s	241.32

Three types of criteria have been proposed for the assessment of the steam power plant with and without CO_2 capture technology, namely technical, economic, and environmental.

The cases studied in this article are as follows:

Case 1: Steam power plant without carbon dioxide capture;
Case 2: Steam power plant with CAP using NH_3 in 2% wt.;
Case 3: Steam power plant with CAP using NH_3 in 5% wt.;
Case 4: Steam power plant with CAP using NH_3 in 7% wt.;
Case 5: Steam power plant with CAP using NH_3 in 15% wt.; and
Case 6: Steam power plant with CAP using MEA in 30% wt.;

2.2. Description of the CO_2 Chemical Absorption Capture Process

The process for CO_2 separation is conventional. The flue gases are first compressed to compensate for losses in the absorption column and where ammonia solutions have been used to avoid NH_3 losses. They enter a heat exchanger where they are cooled, after which they are counter currently backwashed with an aqueous ammonia solution. The chemical solvent rich in CO_2 is pumped before the regeneration column, in order to compensate for losses and minimize the final compression effort. The chemical solvent rich in CO_2 is pre-heated in a second heat exchanger by the recovered lean solvent at the bottom of the absorption column. The heat required for the chemical solvent regeneration is supplied by the condensation of water vapor at low pressure. Regeneration reduces the solvent CO_2 charge to a low charge. Afterward, before being reintroduced into the absorption column, the solvent is pumped out and cooled. The lower the charging rate, the greater the amount of steam for regeneration. The recovered CO_2 flow at the top of the desorption column was compressed to 65 bars with intermediate cooling. This was dehydrated by the triethylene glycol (TEG) process. The residual mole fraction was set at 20 ppm to minimize the hydrate formation risk and corrosion during pipeline transport. The CO_2 flow was finally compressed to 150 bars and cooled to 30 °C to increase the density of the CO_2 and reach the value required for transport. The chemistry of the CO_2 capture process based on ammonia is illustrated in Figure 1 [29], and in Reactions (1) and (2), the absorption and desorption process between MEA and CO_2 is shown [30,31].

$$2RNH_2 + CO_2 \rightarrow RNCOO^- + RNH_3^+ \tag{1}$$

$$RNHCOO^- + RNH_3^+ \rightarrow 2RNH_2 + CO_2 \tag{2}$$

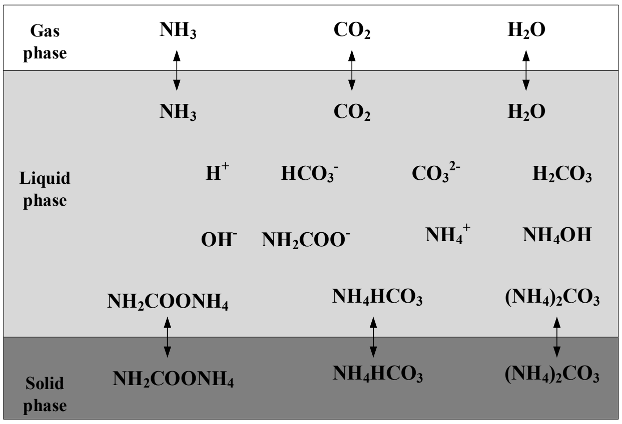

Figure 1. Chemical species and vapor−liquid−solid equilibrium phase for the $NH_3-CO_2-H_2O$ system [29].

The simulation of the capture process was carried out in Chemcad software. An aqueous ammonia solution was used as a chemical solvent at different mass concentrations (2, 5, 7, and 15%) and MEA at a mass concentration of 30% for 90% CO_2 capture efficiency. The schematic diagram of the process is presented in Figure 2 [32], and the process parameters are shown in Table 4.

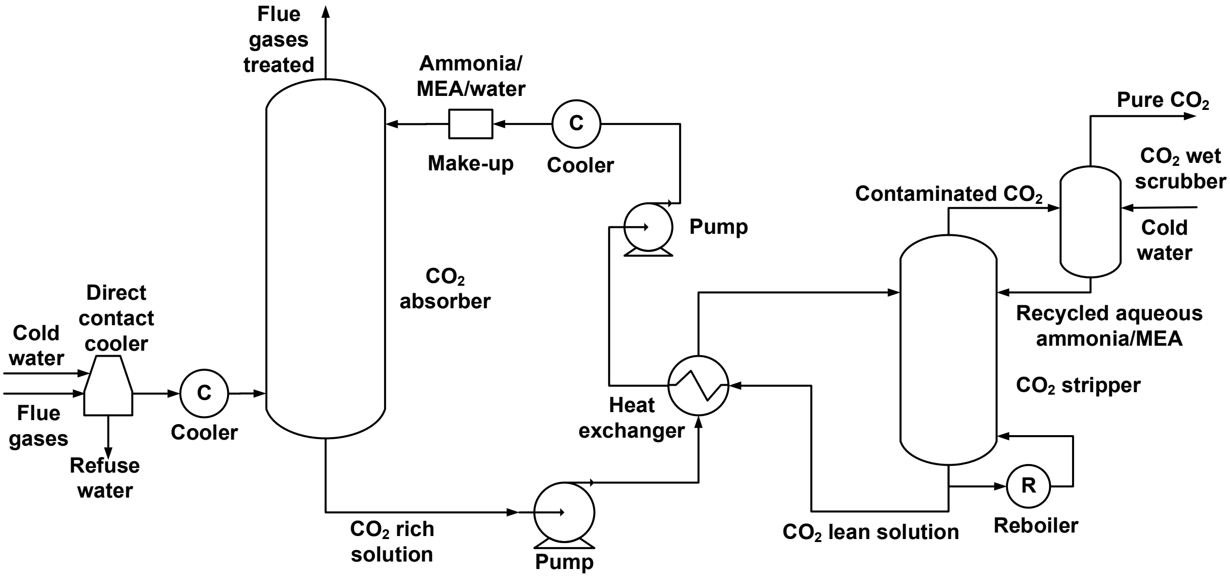

Figure 2. Schematic diagram of the chemical absorption capture process [32]. Reproduced with permission from [Nela Slavu, Cristian Dinca, Adrian Badea], [Scientific Bulletin, Series C: Electrical Engineering and Computer Science]; published by [Ecaterina Andronescu], (2019).

Table 4. Data CO_2 capture process data input.

Parameter	CAP Using NH_3 (2, 5, 7, 15% wt.)	CAP Using MEA (30% wt.)
Flue gases temperature at the inlet at absorption column, °C	20	20
Temperature of the chemical solvent at the inlet of the absorption column, °C	0	40
Flue gases pressure, bar	1.2	1.1
Chemical solvent pressure, bar	1.1	1.1
Number of absorption column steps, -	19	19
Number of desorption column steps, -	15	15
SCH temperature CO_2 lean/rich solvent, °C	70	70
CO_2 lean loading solvent, $mol_{CO2}/mol_{NH3/MEA}$	0.3	0.21

2.3. Description of the Technical, Economic, and Environmental Indicators

2.3.1. Technical Indicators

Integrating the CO_2 capture process by chemical absorption in a steam power plant has a significant impact on its overall performance, decreasing the overall efficiency due to the necessary heat for the regeneration process and to cool the flue gases and chemical solvent. Thus, an analysis of the performance of the steam power plant before and after integrating the CO_2 capture process was conducted, based on the thermal and overall efficiency. Relationships (3)–(5) show the method of calculating the thermal efficiency, overall efficiency, and penalty efficiency after integrating the CO_2 capture process.

Thermal efficiency:

$$\eta_{thermal} = L_{in}/q_{in} \cdot 100, [\%] \tag{3}$$

where L_{in} is the internal mechanical work, in kJ/kg and q_{in} is the heat quantity, in kJ/kg.

Overall efficiency:

$$\eta_{overall} = \eta_{thermal} \cdot \eta_{mechanic} \cdot \eta_{generator} \cdot \eta_{bolier} \cdot 100, [\%] \tag{4}$$

where $\eta_{mechanic}$ is the mechanical efficiency; $\eta_{generator}$ is the generator efficiency; and η_{boiler} is the boiler efficiency.

Overall efficiency of penalties:

$$P_{ef} = \frac{\eta_{overall\_without\_CAP} - \eta_{overall\_with\_CAP}}{\eta_{overall\_without\_CO_2\_capture}} \cdot 100, [\%] \tag{5}$$

where $\eta_{overall\_without\_CAP}$ is the overall efficiency of steam power plant without chemical absorption process and $\eta_{overall\_with\_CAP}$ is the overall efficiency of steam power plant with chemical absorption process.

2.3.2. Economic Indicators

As part of this analysis, the following economic and financial indicators were calculated:

Levelized cost of electricity—*LCOE*;
Capture cost per ton of CO_2;
Net present value—*NPV*;
Internal rate of return—*IRR*;
Discounted payback period—*DPP*; and
Profitability index—*PI*.

The *LCOE* was determined as the sum of investment costs, maintenance costs, and operating costs, relative to the electricity produced and taking into account the devaluation of money in time through the discounted rate considered (Relation (6)). The variable costs of maintenance and operation, respectively, of thermal power plants fitted with capture technology, do not include the CO_2 transport and storage costs [33].

$$LCOE \frac{\sum_{y=1}^{l}(I + C_0 + C_m + C_d)\cdot(1+r)^{-l}}{\sum_{y=1}^{l} E_{el}\cdot(1+r)^{-l}} = \frac{(I + l\cdot C_0 + l\cdot C_m)\cdot(1+r)^{-l}}{l\cdot E_{el}\cdot(1+r)^{-l}}, \ [€/\text{MWh}] \tag{6}$$

where *LCOE* is the levelized cost of electricity, in €/MWh; I is the initial investment in the steam power plant plus the CO_2 capture technology investment cost, in €; C_0 is the operating costs, in €; C_m is the maintenance costs, in €; C_d is the dismantling costs, in €, in this analysis, these costs were considered as 0; r is the discount rate, considered $r = 8\%$ (for the energy sector, the discount rate was chosen between 8–12%); and y is the lifetime of the steam power plant, in years, $(y \in 1 \ \ldots \ l)$. In this study, l was envisioned for 30 years, starting to generate electricity after three years, in the first three years after the investment has been made; and E_{el} represents the electricity produced in MWh.

To determine the costs associated with the integration of the CO_2 capture unit into the steam power plant, the CO_2 capture cost ($Cost\_CO_{2\_captured}$, in €/kgCO_2) was calculated with Relation (7) [33]:

$$Cost\_CO_{2\_captured} = \frac{LCOE_{with\_CAP} - LCOE_{without\_CAP}}{CO_{2\_captured}},\ [€/\mathrm{t}] \quad (7)$$

where $LCOE_{with\_CAP}/\ LCOE_{without\_CAP}$ is the discounted cost of electricity with and without capture technology, in €/MWh; $CO_{2\_captured}$ is the amount of CO_2 captured, in relation to electricity production (emission factor), in kg/MWh; and $CO_{2\_without\_CAP}/\ CO_{2\_with\_CAP}$ is the amount of CO_2 emitted without/with collection technology linked to electricity production, in kg/MWh.

The CO_2 emissions tax is an indicator that measures the cost avoided thanks to CO_2 emissions generated in the environment compared to steam power plants without CO_2 capture technology. The CO_2 emissions tax is calculated according to the tax per ton of CO_2 $\left(T_{CO_2}\right)$ and the quantity of CO_2 produced from the combustion of the fuel (M_{CO_2}) (Relation (8)). The integration of CO_2 capture technology into the steam plant will therefore reduce CO_2 emissions considerably and thus increase the cost of electricity produced.

$$C_{CO_2} = M_{CO_2} \cdot T_{CO_2},\ [€/\mathrm{an}] \quad (8)$$

The *NPV* indicator is calculated as the sum of the annual discounted net income. This indicator is strongly influenced by the delay in updating the net result. In Relation (9), the determination of *NPV* is shown [34]:

$$NPV = \sum_{y=1}^{l_f} \frac{IN_y - C_y - A_y}{(1+r)^i} - \sum_{y=1}^{l_{pi}} I_y \cdot (1+r)^y,\ [€] \quad (9)$$

where IN_y is the income for year y, in €/year; C_y is the operating and maintenance costs for year y, with taxes and duties, but without depreciation, in €/year; A_y is the annuity for year y, in the event of a loan, in €/year; I_y is the equity investment made for year y, in €/year; r is the discount rate for the energy sector between 8 and 12%; l_f is the functional life of the steam power plant, in years; and l_{pi} is the initial investment period, in years. For the second amount, if the investment made is not the same each year, the time axis must be taken into account (the time axis of the investment has the opposite meaning to the time axis of the investment project).

An investment project is economical if $NPV \geq 0$. If we compare several cases of the investment project, the optimal case is the one for which $NPV = max$.

The *IRR* is equal to the discount rate for which the *NPV* is 0 (Relation (10)) [34].

$$NPV = \sum_{y=1}^{l} \frac{IN_y - C_y - I_y}{(1+IRR)^y} = 0,\ [€] \quad (10)$$

The *IRR* can have the following economic interpretations, if it has a single value: (1) *IRR* represents the percentage of interest, in the case of investments, of working capital, for which the project does not generate losses; and (2) *IRR* is the highest rate of annual profit that the investment project is expected to generate.

The *DPP* (Relation (11)) is the duration after the initial investment is paid back [34].

$$DPP = \sum_{y=1}^{DPP} \frac{IN_y - C_y - I_y}{(1+r)^y}, [€] \quad (11)$$

For an investment project to be profitable in terms of return on investment, it is compared to its lifespan. Therefore, in the case of *DPP*, it must be less than the service life.

Relation (12) presents the determination of *PI* [34].

$$PI = \frac{NPV}{DI} = \frac{DIN - DC}{DI} = \frac{NPV + DI}{DI} \quad (12)$$

where NPV is the discounted income, the difference between the discounted revenue, and discounted expenditure; DI is the updated investment; DIN is the discounted income; and DC is the discounted expenditure.

An investment project is economically efficient if $PI \geq 1$; if $PI < 1$, the project becomes economically inefficient.

2.3.3. Environmental Indicators

The LCA method was applied to calculate the environmental indicators. The LCA method consists of four stages according to ISO 14040: goal and scope definition, inventory analysis, impact assessment, and interpretation [35].

According to this methodology, the first step is to clearly identify the field of study for the systems studied. We also identified all the input and output flows of the processes that take place in the field of study [36–39].

The data collected and the results for the analyzed steam power plants are related to the functional unit (FU). In this article, the functional unit is given by 1 MWh produced by the steam power plant.

To simplify the analysis carried out in this study, the fuel life cycle is composed of two stages: extraction, treatment, and transport processes are part of the first stage, while the fuel combustion process is part of a second stage. This analysis did not consider the manufacture of equipment used in the two stages or their dismantling during the life cycle. The electricity consumed during the stages of the life cycle was also considered to come from the national energy sector.

The steam power plant was analyzed with and without CO_2 capture by the chemical absorption process. The CO_2 compression, transport, and storage steps were considered in this analysis.

The quantified impact indicators are abiotic depletion potential—ADP, global warming potential—GWP, eutrophication potential—EP, acidification potential—AP, photochemical ozone creation potential—POCP, and human toxicity potential—HTP. Table 4 presents the pollutants that contribute to each impact class, their contributions, and their specific relationship.

The impact indicators were determined from the emissions identified in the inventory analysis. Equation (13) was used to quantify the impact classes [40].

$$E = \sum_{k} E_k \cdot m_k, \quad [\text{kg\_eq/F.U.}] \tag{13}$$

where E_k is the impact of pollutant k on indicator E, in kg_eq/kg; and m_k is the amount of pollutant produced, in kg/FU. For the ADP, m_r is the mass of fuel (coal), in kg/FU and E_r is the impact of coal on the ADP indicator, in kg_eq/kg (Table 5).

2.4. Description of the Multi-Criteria Model

To determine the optimal chemical solvent for integrated CO_2 capture by the chemical absorption process in a steam power plant in accordance with the technical, economic, and environmental criteria, a MCM based on the MUNDA and ELECTRE IV method was used [41,42].

The standardization of closed-ended evaluations [0 . . . 1] for ecological criteria and part of the economic criteria (CO_2 capture cost, LCOE, and DPP) is the ratio to the highest value obtained by an energy system for the values corresponding to each energy system, according to the proposed criterion. In the case of technical and economic criteria (NPV, IRR, and PI), standardization consists of relating the values obtained for each energy system to the lowest of the evaluations corresponding to the proposed criterion. Due to the standardization of ratings, the lower the rating, the better the energy system considered in terms of the proposed criteria.

Table 5. Classification and quantification of emissions [41].

Impact Evaluation	Pollutants	Equation Used	Values
ADP [kg_Sb_eq/FU]	-	$ADP = \sum_r ADP_r \times m_r$ ADP_r—ADP for each resource "r", [kg_Sb_eq/kg] m_r—quantity used for the resource "r", [kg/FU]	$ADP_{natural\ gas} = 0.0187$ $ADP_{hard\ coal} = 0.0134$ $ADP_{lignite} = 0.00678$
GWP [t_CO$_2$_eq/FU]	CO_2, CH_4, N_2O	$GWP = \sum_k GWP_k \times m_k$ GWP_k– GWP for each pollutant "k", [kg_CO$_2$_eq/kg] m_k—quantity used for the pollutant "k", [kg/FU]	$GWP_{CO2} = 1$ $GWP_{CH4} = 21$ $GWP_{N2O} = 310$
AP [t_SO$_2$_eq/FU]	SO_2, NH_3, NO_2	$AP = \sum_k AP_k \times m_k$ AP_k—AP potential for each pollutant "k", [kg_SO$_2$_eq/kg] m_k—quantity used for the pollutant "k", [kg/FU]	$AP_{SO2} = 1.2$ $AP_{NH3} = 1.6$ $AP_{NO2} = 0.5$
POCP [t_C$_2$H$_4$_eq/FU]	CO, SO_2, CH_4, CH_2O, NO_2	$POCP = \sum_k POCP_k \times m_k$ $POCP_k$—POCP potential for each pollutant "k", [kg_C$_2$H$_4$_eq/kg] m_k—quantity used for pollutant "k", [kg/FU]	$POCP_{CO} = 0.027$ $POCP_{SO2} = 0.048$ $POCP_{CH4} = 0.006$ $POCP_{CH2O} = 0.519$ $POCP_{NO2} = 0.028$
EP [t_PO$_4^{3-}$_eq/FU]	NO, NH_3, NO_2, COD, NH_4	$EP = \sum_k EP_k \times m_k$ EP_k—EP potential for each pollutant "k", [kg_PO$_4^{3-}$_eq/kg] m_k —quantity used for the pollutant "k", [kg/FU]	$EP_{NO} = 0.2$ $EP_{NH3} = 0.35$ $EP_{NO2} = 0.13$ $EP_{COD} = 0.022$ $EP_{NH4} = 0.35$
HTP [t_1.4DCB_eq/FU]	SO_2, NH_3, NO_2, Dust, CH_2O, Pb, Phenol, HCl, HF	$HTP = \sum_k \sum_{com} HTP_{com,k} \times m_{com,k}$ com: compartment (air, water soil); $HTP_{com,k}$—HTP potential for each pollutant "k", and for each compartment, [kg_1.4DCB_eq/kg] $m_{com,k}$—quantity used for the pollutant "k" and compartment, [kg/FU]	$HTP_{SO2} = 0.096$ $HTP_{NH3} = 0.1$ $HTP_{NO2} = 1.2$ $HTP_{Dust} = 0.82$ $HTP_{CH2O} = 0.83$ $HTP_{Pb} = 3300$ $HTP_{Phenol} = 0.52$ $HTP_{HCl} = 0.5$ $HTP_{HF} = 94$

The appurtenance of energy systems to the negative class for each criterion, g_i, is defined by the range of values $[1-\alpha_i,\ 1]$, or $\alpha_i = (1 - g_{min,i})\cdot\alpha$, where α_I is the negative discrimination criterion for criterion I, its value being determined by the value of α established by the user provided that $\alpha + \beta = 1$, or β represents the threshold for positive discrimination. The minimum score obtained by each energy system (S_j) according to criteria I is designated by $g_{min,i}$.

The range of ratings for criterion I, which belong to the positive class, is defined as $[g_{min,i}, g_{min,i} + \beta_i]$, where $\beta_i = (1 - g_{min,i})\cdot\beta$, where β_I is the negative discrimination criterion for criterion I, its value being determined by the value of β. Figure 3 shows that the separation of the two evaluation intervals meets the following requirement: $1 - \alpha_i = g_{min,i} + \beta_i$, from which it follows that if $g_{min,i} = 0$, $\alpha_i + \beta_i = 1$ for each criterion proposed.

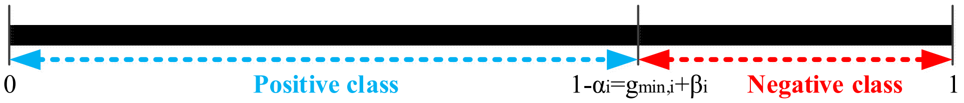

Figure 3. The appurtenance of energy systems to the positive or negative class.

To establish the appurtenance of an energy system in a class for criterion I, the following rules apply:

If the energy system S_j belongs only to the negative class $\left(g_i\left(S_j\right) \in [1-\alpha_i, 1]\right)$ or to the positive class $\left(g_i\left(S_j\right) \in [g_{min,i}, g_{min,i} + \beta_i]\right)$, then its appurtenance in the negative or positive class is: $\mu_{negative_{gi}}\left(S_j\right) = \mu_{positive_{gi}}\left(S_j\right) = 1$;

If n energy systems simultaneously belong to the positive and negative class, then their appurtenance to a class is: $\mu_{negative_{gi}}(S_j) = \mu_{positive_{gi}}(S_j) = \frac{1}{n}$;
If the energy system S_j does not belong to the negative or positive class, then its appurtenance is: $\mu_{negative_{gi}}(S_j) = \mu_{positive_{gi}}(S_j) = 0$.

After establishing the appurtenance of the energy system S_j to the positive class and to the negative class, for each criterion I, the overall evaluation of each system in the two classes was determined, taking into account all the criteria $(i \in 1 \ldots m)$ proposed using Relations (14) and (15).

$$\mu_{positive}(S_j) = \frac{\sum_{j=1}^{n}\sum_{i=1}^{m}\left(P_i \cdot \mu_{positive_{gi}}(S_j)\right)}{\sum_{i=1}^{m} P_i} \tag{14}$$

$$\mu_{negative}(S_j) = \frac{\sum_{j=1}^{n}\sum_{i=1}^{m}\left(P_i \cdot \mu_{negative_{gi}}(S_j)\right)}{\sum_{i=1}^{m} P_i} \tag{15}$$

where P_i represents the weight (depending on the importance of the criterion analyzed), corresponding to the criterion i.

The global evaluation of an energy system S_j, taking into account its appurtenance to the two classes for each criterion I, is determined by Relation (16). The higher the value of the overall evaluation of an energy system, the better that energy system is taken into account. For an energy system S_j, whose scores for all criteria $(i \in 1 \ldots m)$ are in the positive class, the overall score is 2. Otherwise, if the scores belong to the negative solution class, the overall score is 0.

$$\mu_{overall}(S_j) = \mu_{positive}(S_j) + 1 - \mu_{negative}(S_j) \tag{16}$$

3. Results and Discussion

3.1. Technical and Economic Evaluation

The NH_3 capture process was analyzed for different mass concentrations of 2, 5, 7, and 15% respectively, comparing the results with the CO_2 capture reference process based on MEA in 30% mass concentration. All results presented were for 90% CO_2 capture efficiency. The annual number of operating hours of the plant was estimated at 7500 h/year. The generator efficiency was 98.7% and the mechanical efficiency was 99.6%. Generator losses were between 2.6 and 3.1 MW and mechanical losses between 0.8 and 0.9 MW. The quantity of heat per 1 kg of steam was approximately 2820 kJ/kg for all cases studied. The solvent temperature at the regeneration inlet was 363.15 K and at the regeneration outlet, it was between 398 and 433 K. The specific electrical consumption includes the electrical consumption of pumps, compressors, and the cooling of ammonia solutions. The results for the technical and economic indicators are shown in Table 6.

Before the CO_2 capture process, the overall efficiency of the steam power plant was 42.45%. After integration, the overall efficiency fell to about 27.58% for NH_3 = 2% wt. and 30.83% for MEA = 30% wt.%. In the case of using NH_3 in 2 and 5% wt., the energy penalty was higher due to the electricity consumption to cool the solution at the inlet of the absorption column. Although better results have been obtained using mass concentrations greater than NH_3 in solution, it is not preferable to select a mass concentration greater than 7% due to the volatilization of ammonia in the absorption process. The overall efficiency of the power plant decreased by 6.17 to 14.87 percentage points in the case of NH_3 use, depending on the mass concentration. In the case of MEA, the overall efficiency decreased by 11.62 percentage points. In the study conducted by Molina and Bouallou (2017), a decrease in the overall efficiency for a 450 MW coal-fired power plant of 7.2 percentage points was obtained when using NH_3 in a mass concentration of 3%. In the case of using MEA in a mass concentration of 30%, they obtained a decrease of 11.82 percentage points [43].

Table 6. Technical and economic indicators.

Technical Indicators	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Electricity produced, GWh/year	1346.4	1009.9	1090.2	1101.7	1125.7	1172.0
Internal mechanical work, kJ_{int}/kg	1364.5	1081.8	1250.8	1281.3	1321.7	1071.0
Quantity of specific heat, kJ_{el}/kg	1341.6	1064.3	1230.0	1259.9	1299.5	1052.7
Fuel flow rate, kg/s	19.03	22.79	20.44	19.91	19.31	23.66
Flue gases flow rate, kg/s	241.32	289.01	259.18	252.52	244.84	300.04
CO_2 Capture Process Indicators	**Case 1**	**Case 2**	**Case 3**	**Case 4**	**Case 5**	**Case 6**
NH_3/H_2O or MEA/H_2O concentration, % wt.	-	2	5	7	15	30
CO_2 capture efficiency, %	-	90	90	90	90	90
L/G ratio, $[kg_{solvent}/kg_{flue\_gases}]$	-	2.08	0.94	0.71	0.38	1.13
Solvent flow, kg/s	-	599.70	243.63	179.29	93.04	339.04
Steam output for regeneration, kg/s	-	75.16	25.65	18.00	8.52	34.12
Regenerator heating capacity, MW_e	-	175.94	60.08	42.16	19.97	79.85
Specific process heat, GJ/tCO_2	-	8.27	2.83	1.99	0.94	2.96
Specific consumption of electrical energy, kWh/tCO_2	-	259.19	146.13	123.79	92.13	25.86
Overall efficiency of power plant, %	42.45	27.58	33.19	34.44	36.28	30.83
Penalty overall efficiency, %	-	35.01	27.98	20.61	15.31	21.35
Economic Indicators	**Case 1**	**Case 2**	**Case 3**	**Case 4**	**Case 5**	**Case 6**
Investment costs, €/kW	2497	4333	4333	4333	4333	4333
Fuel cost, M€/year	28.25	33.84	30.35	29.56	28.67	35.13
NH_3 or MEA cost, M€/year	-	0.77	1.92	2.69	5.77	8.17
Operating and maintenance costs, M€/year	10.44	21.10	21.13	21.06	21.09	21.07
Levelized cost of electricity, €/MWh	42.48	86.95	78.42	77.56	77.86	82.33
CO_2 capture cost, €/tCO_2	-	76.21	60.90	59.07	59.46	68.57
CO_2 avoided cost, €/tCO_2	-	87.81	69.81	67.93	68.22	79.06

The investment costs for a steam power plant without carbon capture process were 2497 €/kW, whereas after integration of the capture process, they amounted to 4333 €/kW. The price of the fuel used was estimated at 55 €/t [44], a discounted rate of around 8%, and a lifespan of 30 years. An important advantage of using ammonia in the chemical absorption capture process is that it has a lower purchase price of 0.672 €/kg, compared to the MEA purchase price of 2 €/kg per liter [27]. Once the CO_2 capture process was integrated, the LCOE increased by 53.8−104.7% compared to the LCOE for the steam power plant without CO_2 capture. Only in the case of NH_3 = 2% wt. was a higher LCOE value obtained than in the case of MEA = 30% wt. due to the higher specific electricity consumption and specific heat, which led to a lower amount of electricity produced. In terms of the CO_2 capture cost, according to the analysis made by the IEA in 2021, for the energy sector, it is between 45–90 €/tCO_2, depending on the type of CO_2 capture technology used [3]. In this study, the CO_2 cost capture ranged from 59.07 to 76.21 €/tCO_2.

An analysis of the costs of electricity is presented below, approximated by considering the cost of a ton CO_2 certificate. Currently, energy regulations on reducing greenhouse gases have led to a tax on carbon dioxide emitted into the atmosphere by steam power plants. The CO_2 emissions tax varies depending on the certificate market. The CO_2 emissions tax was 31.62 €/tCO_2 in 2021, and it reached 96.93 €/tCO_2 in 2022 [45]. Thus, this analysis considered the price of a certificate for a ton of CO_2 emitted into the atmosphere to vary between 15 €/tCO_2 and 100 €/tCO_2 to observe when the integration of the chemical absorption capture process was better in terms of LCOE compared to when a capture process was not integrated, and the CO_2 emissions tax was paid.

For a CO_2 emissions tax of around 70 €/MWh, ammonia solutions with a mass concentration of 7 and 15% were better in terms of LCOE. Where MEA = 30% by weight, a lower LCOE was only obtained if the CO_2 the tax was greater than 80 €/MWh (Figure 4). In this case, if the cost of a ton-CO_2 certificate continues to grow (this has increased over the last decade to reach the average last year of 60 €/MWh), capture technologies can become a reliable alternative to reduce CO_2 emissions from steam power plants.

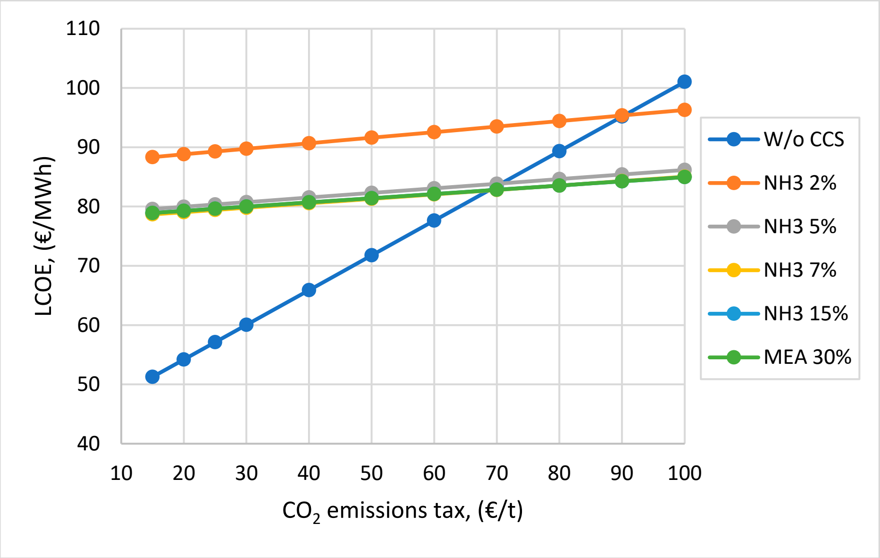

Figure 4. The LCOE with and without a CO_2 capture process according to the CO_2 emissions tax.

Regarding the economic criterion of the NPV (Figure 5), we note that without the integration of a carbon capture technology, the project is profitable even if a CO_2 emissions tax of 100 €/tCO_2 is considered, but the NPV was decreased by 65%. In the case of solutions with a capture process, it was found that the capture process using a mass concentration ammonia solution at 2% is not economically efficient if the CO_2 emissions tax is 100 €/tCO_2, the NPV value being less than 0. For 5%, 7%, and 15% solvent mass concentration of NH_3, the NPV had positive values regardless of the CO_2 emissions tax. Regarding the MEA solution for a CO_2 emissions tax of 60 €/tCO_2, the NPV was 163 M€. NH_3 capture solutions (7% and 15% by mass concentration) were economically better than the MEA solution, because the amount needed to regenerate the solvent is lower, and therefore a smaller additional amount of fuel is used, resulting in lower fuel costs. Another reason why the NH_3 based solution was best is that the cost of purchasing ammonia is much lower than the cost of purchasing MEA. Regarding the other economic indicators (Figures 6–8), the same conclusions can be drawn as for the NPV indicator. The PI indicator shows, for example, that the case based on NH_3 in a mass concentration of 2% is not a cost-effective solution as the PI is less than 1 for a CO_2 emissions tax of 100 €/tCO_2. For all other cases studied, the PI indicator had values greater than 1, which means that they are profitable (Figure 8).

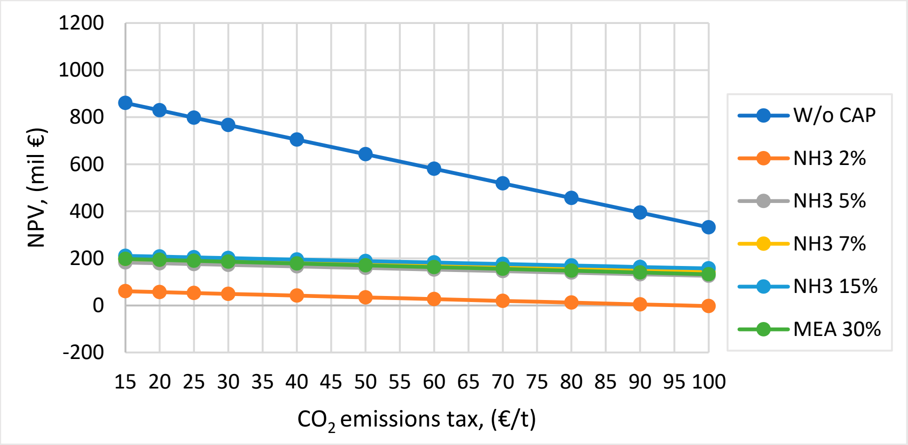

Figure 5. NPV with and without the CO_2 capture process according to the CO_2 emissions tax.

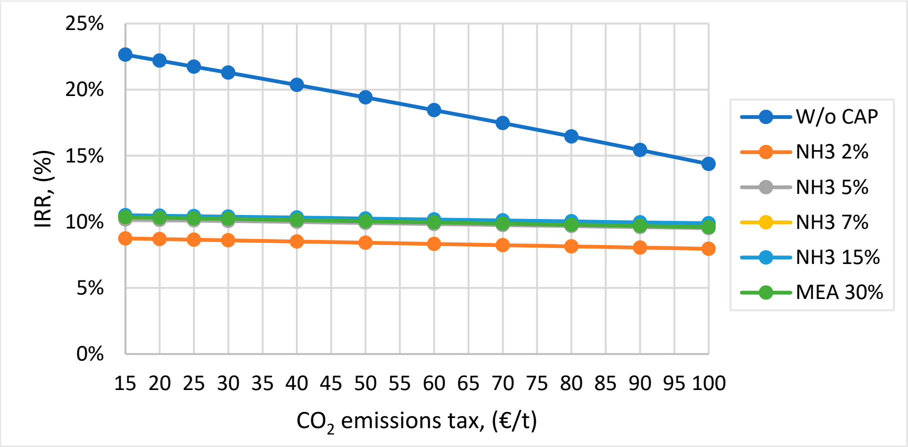

Figure 6. IRR with and without the CO_2 capture process according to the CO_2 emissions tax.

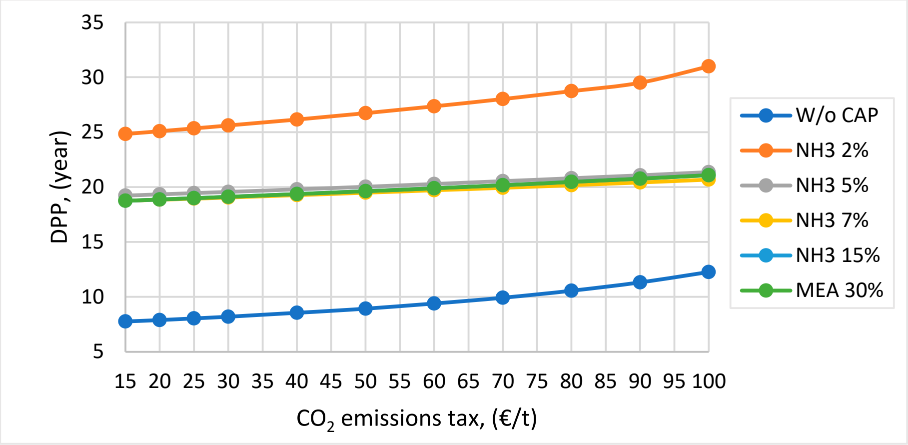

Figure 7. DPP with and without the CO_2 capture process according to the CO_2 emissions tax.

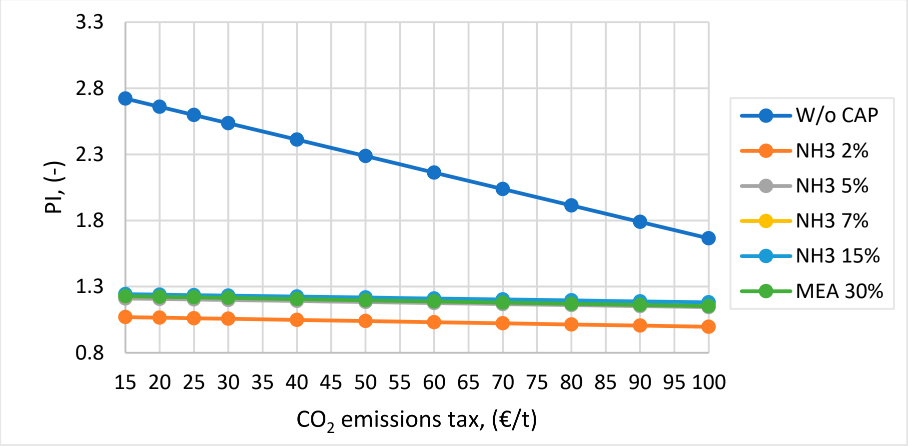

Figure 8. PI with and without the CO_2 capture process according to the CO_2 emissions tax.

3.2. Environmental Evaluation

The values of the impact indicators quantify the emissions from the two stages of the fuel life cycle, namely extraction, processing, transport (stage 1) and combustion (stage 2). For ADP, only the mass of fuel from the extraction step was taken into account.

Table 7 presents the results for the impact indicators for the functional unit considered (1 MWh of electricity).

Table 7. Values of impact indicators relative to 1 MWh.

Impact Indicator	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
ADP, kg_Sb_eq/MWh	3.71	5.93	4.93	4.75	4.51	5.31
GWP, kg_CO_2_eq/MWh	823.83	149.15	123.91	119.44	113.37	133.42
EP, kg_PO_4^{3-}_eq/MWh	0.55	2.25	4.62	6.89	23.94	0.78
AP, kg_SO2_eq/MWh	8.02	14.18	14.54	16.45	33.01	11.46
POCP, kg_C_2H_4_eq/MW	0.35	0.56	0.47	0.45	0.43	0.50
HTP, kg_1.4DCB_eq/MWh	5.53	8.83	7.34	7.07	6.71	7.90

The ADP indicator increased compared to the baseline scenario (steam power plant without CO_2 capture technology) for all variants where the CO_2 capture process was integrated. If ammonia was used, the highest increase in the ADP indicator was recorded for a mass concentration of 2%, since in this case, the amount of heat required for regeneration was the highest, and therefore, a greater amount of fuel was used to produce electricity. When comparing the process of chemical absorption using NH_3 with the MEA process at 30% mass concentration, it should be noted that for MEA, the ADP indicator was the highest, with an increase of 24.3% over the baseline.

In terms of GWP, the highest value was obtained for the case without CAP, since the other cases included CO_2 capture process, and thus reduced CO_2 emissions by 90% at the combustion stage. For CO_2 capture, the GWP values did not differ significantly, ranging from 149 to 134 kg_CO_2_eq/MWh, with a decrease of between 85% and 89% of this life cycle indicator. For this indicator alone, the percentage of emissions in the combustion phase that contributed to the total value was 87.43% while the remaining 12.57% represented the emissions from the extraction, processing, and transport stages. For the other indicators, the combustion stage emissions had a percentage greater than 96%.

The results obtained for EP shows that the increases are significant for this indicator during the integration of the chemical absorption process NH_3, as the amount of ammonia lost in the CO_2 capture process is taken into account based. Compared to the case without CCS, for a mass concentration of NH_3 = 2%, there was an increase of 206.6%; for a mass concentration of NH_3 = 5%, an increase of 579.7%; for a mass concentration of 7%, an increase of 924.3%; and an increase of 3533.2% for a mass concentration of 15%. All this indicates that in terms of this indicator, the NH_3 capture process is less advantageous compared to the MEA capture process, with only a 24.3% increase in EP compared to power generation without carbon dioxide capture technology.

For the AP indicator, as for the EP indicator, a significant increase was noted in all cases of ammonia. However, in this case, such large increases were no longer present, as SO_2 emissions were also taken into account. Thus, the percentage increases varied between 24.3 and 243.9%, with the highest value for NH_3 = 15 wt.%, and the lower value for MEA = 30 wt.%.

In the case of the POCP impact class, it should be noted that the highest value was obtained with MEA, because in this case, a greater amount of fuel was used to provide the necessary heat to the chemical solvent regeneration, while the lowest value was obtained when NH_3 was used at a mass concentration of 15%. The same variations were observed for the HTP impact class as for the POCP impact class. Compared to the variant without CAP, both for POCP and HTP, there was a 24.3% increase in MEA, while in NH_3 = 15 wt.%, there was an increase of 1.5%.

3.3. Multi-Criteria Evaluation

Table 8 sets out the results obtained for the technical, economic, and environmental criteria taken into account in the MCM, for all cases where the chemical absorption process is integrated. Regarding the economic criteria, the value considered for the CO_2 emissions tax was of 60 €/tCO_2 (last year average).

Table 8. Multi-criteria analysis input data.

Criterion	Case 2	Case 3	Case 4	Case 5	Case 6
Technical					
C1—Overall efficiency, %	27.58	33.19	34.44	36.28	30.83
C2—Penalty overall efficiency, %	35.01	27.98	20.61	15.31	21.35
Economic					
C3—CO_2 capture cost, €/tCO_2	25.59	9.24	7.45	7.56	16.66
C4—LCOE, €/MWh	92.56	83.08	82.05	82.13	87.31
C5—NPV, M€	27	152	168	182	163
Environmental					
C6—ADP, t_Sb_eq	5996.90	5378.53	5239.06	5081.18	6225.83
C7—GWP, t_CO2_eq	150,622	135,091	131,588	127,622	156,372
C8—EP, t_PO43-_eq	2274.18	5042.00	7598.22	26,950.87	922.26
C9—AP, t_SO2_eq	14,329.2	15,853.9	18,129.8	37,165.11	13,437.4
C10—POCP, t_C2H4_eq	574.49	515.25	501.89	486.77	596.42
C11—HTP, t_1.4DCB_eq	8925.21	8004.88	7797.32	7562.34	9265.92

Since the variant where a CO_2 capture process was not integrated showed the best evaluations for most criteria considered, our MCM only applies to solutions in which the CO_2 capture process is integrated (i.e., a multi-criteria analysis was carried out for solutions 2, 3, 4, 5, and 6). After gathering the results on the analyzed criteria, the evaluations were normalized in the range [0 . . . 1], with the resulting values given in Table 9.

In order to determine the discrimination thresholds, α_i, β_i, the values of the coefficients α and β must be chosen. Thus, in the first phase, we considered that $\alpha = \beta = 0.5$. With this assumption, the values of the positive and negative discrimination thresholds were the same.

Table 9. Normalization of assessments.

Criterion	Case 2	Case 3	Case 4	Case 5	Case 6
Technical					
C1	0.99	0.85	0.83	0.80	1.00
C2	1.00	0.79	0.58	0.43	0.61
Economic					
C3	1.00	0.71	0.68	0.68	0.85
C4	0.97	0.86	0.85	0.82	1.00
C5	1.00	0.03	0.02	0.02	0.03
Environmental					
C6	0.96	0.86	0.84	0.81	1.00
C7	0.96	0.86	0.84	0.81	1.00
C8	0.08	0.18	0.28	1.00	0.03
C9	0.38	0.42	0.48	1.00	0.36
C10	0.96	0.86	0.84	0.81	1.00
C11	0.96	0.86	0.84	0.81	1.00

3.3.1. Results of the Technical Criteria Evaluation

The results obtained for each family of criteria are given below, taking the same weighting for all the criteria analyzed, $Pi = 1$. Figure 9 shows the overall evaluation of the cases considered in terms of the technical criteria family.

Note that case 2 was the lowest, with a 0.5 score for the technical evaluation, with the highest percentage decrease in thermal efficiency and an overall efficiency penalty. Cases 4 and 5 showed the best ratings, both with a score of 1.33. Even if, in terms of actual values of thermal efficiency and overall penalty efficiency, cases 4 and 5 differed, these cases obtained the same score due to the choice of the α and β coefficients of 0.5, which influenced the thresholds for positive and negative discrimination, and therefore whether a case belonged to the positive or negative class.

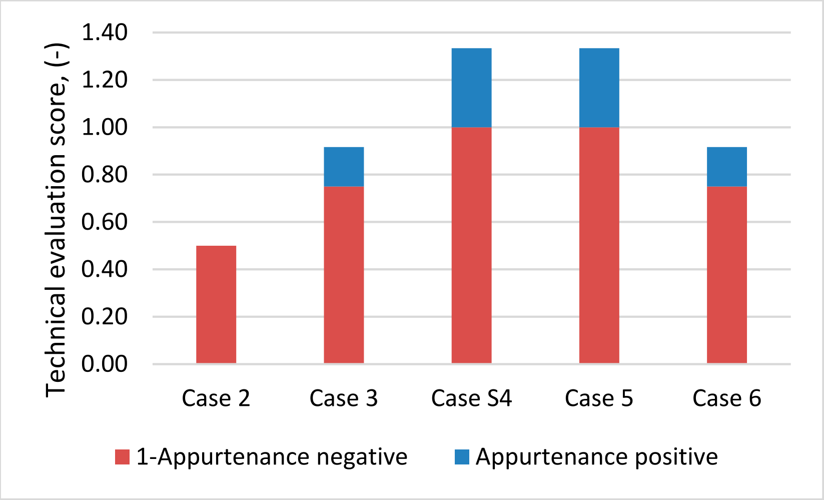

Figure 9. The overall evaluation of the cases studied according to the technical criteria.

3.3.2. Results of the Economic Criteria Evaluation

The overall evaluation values are shown in Figure 10. If the cases studied belonged to the negative class, we noted that the NH_3-based cases studied at mass concentrations of 5, 7, and 15% were better, and the value of 0 was obtained in all variants and for all the economic criteria analyzed, than the case based on MEA, for which the negative appurtenance value was 0.5. However, as with positive appurtenance, a value of 0 was obtained for NH_3-based cases in a mass concentration of 2%. Thus, it was concluded that case 3 was the best from an economical point of view, with an overall evaluation of 1.31, followed by cases 4 and 5, with an overall evaluation of 1, while the weakest was case 2, with an overall rating of 0.33.

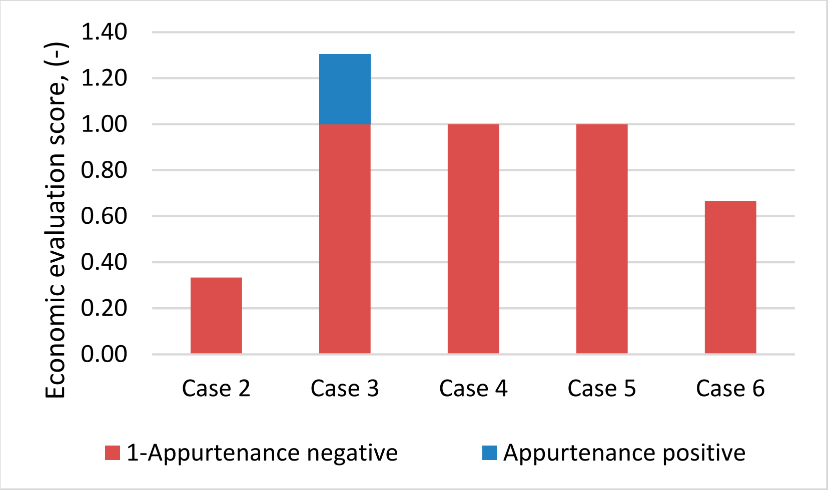

Figure 10. The overall evaluation of the cases studied according to the economic criteria.

3.3.3. Results of the Environmental Criteria Evaluation

In the case of environmental criteria, it appeared that the negative class appurtenance was smaller and that the positive class appurtenance was higher for criteria C6, C7, C10, and C11 for cases 3, 4, and 5. For criteria C8 (eutrophication) and C9 (acidification), the negative class belonging to Case 5 was the highest due to the ammonia lost in the absorption process and its contribution to the calculation of impact indicators.

Regarding the overall evaluation of the solutions in terms of environmental criteria (Figure 11), cases 3 and 4 were the best, with the same score of 1.31. The weakest cases were cases 2 and 6, both with a score of 0.75.

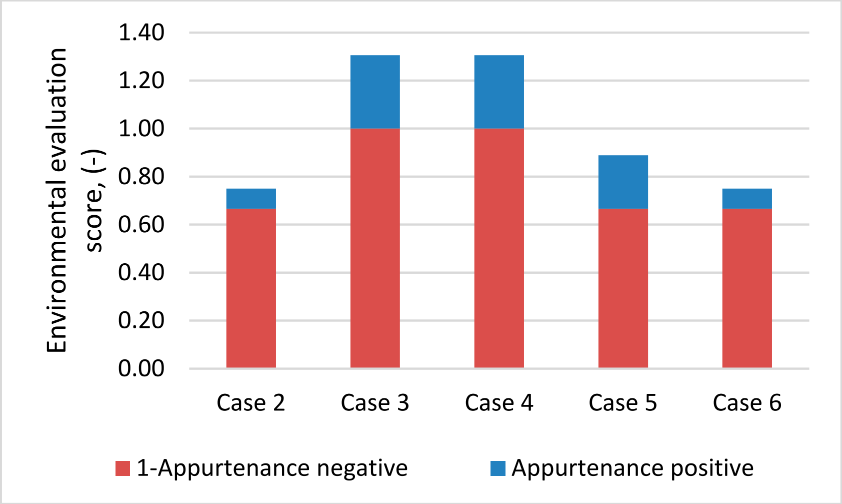

Figure 11. The overall evaluation of the cases studied according to the environmental criteria.

3.4. Overall Evaluation

The following is the evaluation of the solutions for all the criteria considered by a radar chart (Figure 12). This diagram shows that case 3 had a better evaluation for all the criteria families. However, it is difficult to know which is the best energy system regarding the three families of criteria.

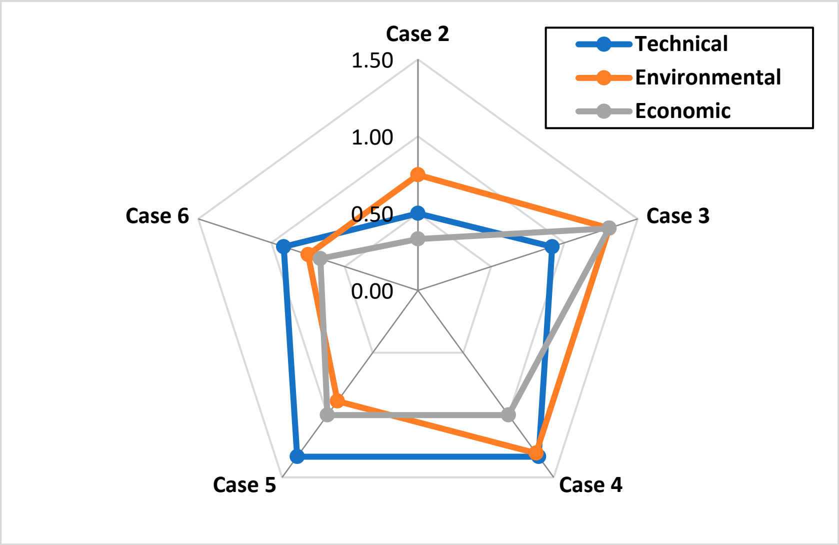

Figure 12. Global evaluation of solutions according to the three families of criteria.

In order to determine the overall evaluation of the three families of criteria, we used Heron's formula to calculate the area of the triangle with dimensions as values obtained during the evaluation for each family of criteria. The overall evaluation for each case was then equal to the percentage represented by the area of the triangle or the total area of the triangles for all cases. Thus, case 4 had the best overall evaluation with a percentage of 30.1%, followed by cases 3 and 5 with a percentage of 28.3% and 23.5%, respectively. The lowest overall ratings are for cases 2 and 6, with 5.7% and 12.4% respectively.

3.5. Robustness Analysis

The robustness analysis aimed at varying the β and the α coefficients to assess the impact on the results established in § 3.4. The weighting values of all the criteria of this sensitivity analysis were 1. The situations considered were $\alpha = 0.6$, $\alpha = 0.7$, $\alpha = 0.8$, and $\alpha = 0.9$.

For the first two situations, $\alpha = 0.6$, $\alpha = 0.7$, both the evaluations by the family of criteria and the overall evaluation were the same as for the previous ones, $\alpha = \beta = 0.5$ obtaining the same classification of cases studied with the same scores.

If, in the situations where $\alpha = 0.5$, $\alpha = 0.4$, and $\alpha = 0.3$, the classification of cases for the overall evaluation has not changed and if the range of appurtenance to the positive class is reduced by 70%, $\alpha = 0.8$, the classification of the studied cases is modified, with case 5 ranked first, with a value of 34.2%. Case 3 obtained 16.7% and Case 4, which had been the best rated so far, obtained 27.4%, as the second case. Case 2 remained the weakest solution and case 6 obtained a score of 12.5%. If the range of cases to the positive class, $\alpha = 0.9$, was reduced by 80%, case 5 had the highest score, which was 47.8%, followed by cases 4, 3, 6, and 2. The 80% reduction in appurtenance range in the positive class changed the case hierarchy for the 70% reduction and the initial variant, where the ranges were equal. We can say that the choice of coefficients α and β had a significant impact on the classification of cases according to the three families of criteria.

Figure 13 shows the values of the global evaluations for all the discrimination thresholds studied. There was no change in the order of the solutions for the positive discrimination threshold, β, 0.3, 0.4, and 0.5. Instead, the impact of the positive discrimination threshold on the ranking of optimum solutions was observed for values of 0.1 and 0.2.

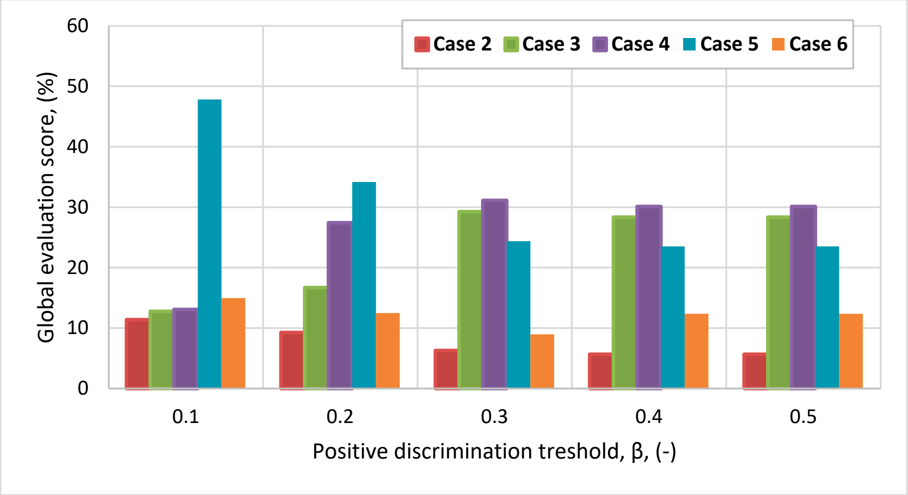

Figure 13. Global evaluation of the cases studied according to the positive discrimination threshold.

4. Conclusions

The integration of CO_2 capture technologies into steam power plants plays an important role in decarbonizing the energy sector. Selecting the most competitive CO_2 capture process with minimal impact on the technical, economic, and environmental performance of the power plant depends on several factors such as specific parameters of the power plant, solvent used in the capture process, and the CO_2 emissions tax. Thus, in this study, the CO_2 capture process by chemical adsorption at different mass concentrations of ammonia in the chemical solvent was analyzed and compared with the reference CO_2 capture process based on MEA at a mass concentration of 30%. A multi-criteria model was applied to take into account the three categories of indicators calculated for a steam power plant (technical, economic, and environmental) in choosing the optimal CO_2 capture process. In terms of technical indicators, the efficiency penalty associated with the integration of the CO_2 capture process into the steam power plant had values between 15.31–35.01%, with the highest value in the case of using NH_3 = 2% wt. In terms of economic indicators, the results obtained were influenced by the CO_2 emissions tax. Thus, for the cases studied in this article, for a CO_2 emissions tax higher than 70 €/tCO_2, the steam power plant with

CO_2 capture is more profitable than the steam power plant without CO_2 capture. With regard to environmental indicators, the main disadvantage consists of the fact that when integrating the CO_2 capture process, the amount of primary resources used increases. This leads to an increase in the amount of other pollutants (SO_x, NO_x, solid particles). On the other hand, the CO_2 emissions decrease significantly depending on efficiency of the CO_2 capture process.

The multi-criteria model can be applied to compare different processes, systems, or products. The ranking of the analyzed solutions depends on the importance given to each criterion and the values of the discrimination thresholds. After applying the multi-criteria model and under the assumptions made (positive and negative discrimination threshold equal to 0.5, same weight given all criteria considered), the solution that obtained the highest score of 30.1% was the one based on 7% NH_3.

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Nomenclature

Abbreviations	
ADP	Depletion of natural resources
AP	Acidification potential
CA	Chemical absorption process
CCS	Carbon Capture and Storage
DPR	Discounted payback period
EP	Eutrophication potential
F.U	Functional unit
GWP	Global warming potential
HP	High pressure
HTP	Human toxicity potential
IP	Intermediate pressure
IRR	Internal rate of return
LCA	Life cycle assessment
LCOE	Levelized cost of electricity
LHV	Lower heating value
LP	Low pressure
MEA	Monoethanolamine
MCM	Multi-criteria model
NPV	Net present value
PI	Profitability index
POCP	Photochemical ozone creation potential
PP	Thermal power plant
ST	Steam turbine
TEG	Triethylene glycol

Greek letters and Symbols

i	Criterion, $(i \in 1 \ \ldots \ \ m)$
S_j	Energy system/solution, $(j \in 1 \ \ldots \ \ n)$
g_i	Appurtenance of energy systems to negative class for each criterion i
$g_{min,i}$	Minimum rating for S_j for criterion i
α	Negative discrimination threshold
β	Positive discrimination threshold
α_i	Negative discrimination criterion for criterion i
β_i	Positive discrimination criterion for criterion i
$\mu_{negative_{gi}}(S)$	Appurtenance of an energy system S in negative class for criterion i
$\mu_{positive_{gi}}(S)$	Appurtenance of an energy system S in positive class for criterion i
$\mu_{negative_{gi}}(S)$	Appurtenance of an energy system S in negative class for all criterion i
$\mu_{positive}(S)$	Appurtenance of an energy system S in positive class for all criterion i
$\eta_{thermal}$	Thermal efficiency, [-]
$\eta_{thermal}$	Net efficiency, [-]
$\eta_{overall}$	Overall efficiency, [-]
P_i	Weight corresponding to criterion i
l	Lifespan of thermal power plant, [year]
$\mathrm{l_f}$	Functional lifespan of thermal power plant, [year]
$\mathrm{l_{pi}}$	Period of initial investment, [year]
eq	Equivalent
E_k	Contribution of pollutant k to impact class E, [kg equivalent]
E_r	Contribution of fuel r to impact class E, [kg equivalent]
m_k	Mass of pollutant, [kg]
m_r	Mass of fuel, [kg]
r	Discount rate
w/o	Without
wt.	Mass concentration
y	Year

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