Techno-economic feasibility study and environmental performance analysis of a power generation plant with CCS system

In order to increase Italian national energy security (partially releasing energy production from imported primary sources) and to re-launch the economy in the Sulcis area (South-West Sardinia, Italy), the Italian Government and the Sardinian Regional Administration are strongly interested in the development of an industrial project for the construction of a 300-450 MWe power generation plant, equipped with a demonstration carbon capture and storage (CCS) system. The plant has been conceived to operate in close integration with a sub-bituminous coal mine in the Sulcis area, where the only Italian coal basin is located.

In this context, Sotacarbo is engaged in the development of a detailed study with the end to evaluate the feasibility of this project and to define the best plant configuration and operating parameters.

This paper shortly describes a portion of this study, in which a preliminary comparative analysis (from the technical, economical and environmental points of view) of all the technical alternatives allows to select the best plant configuration: an ultra supercritical pulverized coal combustion (USPCC) plant, equipped with a SNOXTM section for the combined removal of SOx and NOx and with a partial capture of CO_2.

Due to the potential unreliability of some assumption and to the impossibility to estimate with accuracy the future trend of some operating parameters, a sensitivity analysis has been assessed in order to evaluate the effects of these assumptions, with a subsequent reduction of the investment risk

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Studio di fattibilità tecnico-economica ed analisi dell'impatto ambientale di un impianto di generazione di potenza basato sulla tecnologia di cattura post-combustione della CO_2

Al fine di incrementare la sicurezza energetica nazionale e rilanciare l'economia dell'area del Sulcis, il Governo e la Regione Sardegna sono fortemente interessati allo sviluppo di un progetto dimostrativo delle tecnologie CCS, relativo ad un impianto di generazione di potenza da 300–450 MWe, integrato al sito di stoccaggio in una miniera di carbone sub-bituminoso nell'area del Sulcis. L'analisi comparativa delle diverse possibili alternative permette di individuare in un impianto al polverino di carbone Ultra Super Critico, equipaggiato con sistemi DeNOx, DeSOx e con parziale cattura della CO_2 con solventi, come la soluzione tecnologicamente ed economicamente più conveniente

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Introduction

Power generation in Italy is based for about 75% on fossil fuels, with an annual CO_2 emission of about 430 Mt [1]. Moreover, coal consumption amounts to about 13.4 million of tones of oil equivalent (toe), corresponding to only 8.8% of the global consumption of fossil fuels [2]. This involves a very high cost of electrical energy and a low energy security.

This justify the strong interest of the Italian Government and the Sardinian Regional Administration in the development of the only Italian coal basin, located in the Sulcis area, in South-West Sardinia. Since 1994, a series of national laws has been promulgated in order to promote the construction of a Sulcis coal feed power generation plant capable to enhance the national energy security and the weak and poor economy of the Sulcis area. In particular, the Italian law n. 99 (July 23, 2009) requires the construction of a 300-450 MWe power generation plant strictly integrated with the Sulcis coal mine and feed with at least 50% (lower heating value – LHV – basis) of local coal (characterized by a very high sulphur content, of about 6-7% in weight), which can be assimilated to renewable sources as for the access to the incentives for the selling of the electric energy. Moreover, the plant must be equipped with a demonstration carbon capture and storage (CCS) section.

In this scenario, Sotacarbo (in cooperation with ENEA, the Italian National Agency for Energy and Environment) is currently supporting the Italian Ministry of Economical Development and the Sardinian Regional Administration to define the guidelines for the development of such a project.

This paper presents a hint about the preliminary results of a technical, economical and environmental analysis which has been carried out in order to assess the feasibility of this project. In particular, a series of technical and environmental cases led the choice of two plant configuration, based on IGCC (integrated gasification combined cycle) and USPCC (ultra supercritical pulverized coal combustion) technologies, re-

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spectively. For both these plant configurations, a preliminary economical analysis suggested that USPCC is most profitable than IGCC, and a more detailed prefeasibility study has been carried out for the ultra supercritical plant configuration, in order to determine the best plant size and the main operating conditions, together with the analysis of the investment on the basis of the main economical parameters.

Power generation plant configuration

A preliminary analysis of the state-of-the-art of the technologies currently available for power generation in the Sulcis area through a medium-scale (300-450 MWe) power plant initially indicated four main potential technologies for power generation section: ultra supercritical pulverized coal combustion (USPCC), supercritical circulating fluidized bed combustion (CFBC), supercritical pressurized fluidized bed combustion (PFBC) and integrated gasification combined cycle (IGCC), the latter based on a dry-feed Shell gasification technology.

In particular, for the three combustion-based technologies, two different flue gas treatment processes have been considered: a conventional flue gas desulphurization (FGD) system for SOx removal with a selective catalytic reduction (SCR) system for NOx removal or an advanced SNOX™ system (licensed by Haldor Topsøe) for a combined separation of nitrogen and sulphur oxides. On the other hand, a Selexol™ (licensed by UOP LLC.) system for sulphur compounds removal and a Claus/SCOT system for sulphur recovery and tail gas treatment have been selected for the IGCC plant.

Choice of plant configuration

A preliminary analysis of the environmental performance of each plant configuration restricts the choice to USPCC plant with SNOX™ system and IGCC. As a matter of fact, all the considered plant configurations allow to achieve very low emissions of SOx, NOx and particulate (20-100 mg/Nm^3 for both SOx and NOx and about 5 mg/Nm3 for particulate), whereas the solid and liquid wastes production is strongly different.

In particular, both the fluidized bed combustion processes (CFBC and PFBC) involve a large amount of not recoverable solid residues; moreover, flue gas treatment with FGD process involves a high production of liquid and solid wastes. This high residues production does not respect the recommendations included in the above cited law n. 99/2009.

On the other hand, USPCC plant equipped with SNOX™ system and IGCC configurations can be considered near zero emissions plant: as a matter of fact, solid residues (bottom ash or slag) are inert and recoverable for both plant configurations [3], the production of waste liquids is negligible and the main by-products (sulphuric acid from SNOX™ process or solid sulphur from Claus process) are characterized by a high commercial value [4].

A preliminary economical analysis (which considers both plant configuration equipped with CCS system) indicates USPCC technology as the most promising for this specific application (with a plant scale between 300 and 450 MWe). As a matter of facts, with respect to IGCC plant, USPCC allows a lower capital cost and a higher plant availability, with a subsequent higher global profit.

Selected power generation technology

The selected power generation plant is based on an ultra supercritical boiler which operates at about 25-28 MPa and 580-600 °C (steam superheater process conditions) and allows a very high efficiency of the combustion phase and of the steam cycle [5], whereas the bottom ash is inert and it could be permanently stored in the exhausted seams of the coal mine or recovered as building material [6].

Flue gas is sent to a fabric filter, which operates the particulate separation, and to the SNOX™ section, in which the sulphur oxides contained in the flue gas are removed and recovered as commercial grade sulphuric acid, whereas NOx is reduced to N2. This system does not consume water or other materials, except for the ammonia used for the catalytic NOx reduction; more-

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over, it does not generate any secondary source of pollution, such as waste water, slurries or solids [7-9].
The overall plant efficiency, considering its basis configuration (without CCS), is 45.0% [10].

Carbon capture section

As mentioned, the considered power generation plant needs to be equipped with a demonstration carbon capture and storage system.
A post-combustion CO_2 absorption system based on an aqueous solution of monoethanolamine (MEA) has been considered in this study. This system treats the plant flue gas and operates chemical absorption of carbon dioxide at atmospheric pressure and at about 45-50 °C, with a CO_2 removal efficiency of about 90% [11].
The introduction of CCS system involves a significant decreasing (typically 8-12 percentage points) of the overall plant efficiency, due to the high energy consumption of the process; in particular, solvent regeneration requires a significant amount of steam (extracted from the steam turbine, with a subsequent reduction of power output), whereas CO_2 compression requires a high power absorption [12-13].

Carbon dioxide geological storage

As for the CO_2 geological storage, two different technologies have been considered in this analysis: the storage in saline aquifers below the Sulcis coal basin and the storage through ECBM (enhanced coal bed methane) technique.
The storage in the saline aquifers takes place injecting compressed CO_2 at a depth of about 1000-1200 m in the southern area of the Sulcis coal basin, where the aquifers are located. In the same area of the basin, the ECBM technique should be tested at a depth of about 800-1.000 m; in particular, compressed CO_2 injected into the unminable coal seams is adsorbed by the mineral material, thus displacing methane.
Preliminary studies show that the Sulcis coal basin is capable for the application of both carbon sequestration technologies due to a series of cases such as the

	0Plant configurations		
	300 MWe plant (total capture)	450 MWe plant (total capture)	450 MWe plant (partial capture)
Gross thermal input (MW)	857	1285	1173
Overall plant efficiency (LHV basis)	35.0%	35.0%	38.0%
Basis plant efficiency (without CCS)	45.0%	45.0%	45.0%
Plant availability (hours/year)	7000	7000	7000
Net power output (GWh/year)	2100	3150	3150
Flue gas production (Nm3/hour)	953 585	1 428 539	1 374 447
Percentage of flue gas treated by CCS system	100%	100%	67%
Percentage of Sulcis coal (LHV basis(a))	50%	50%	50%
Sulcis coal consumption (Mt/year)	0.518	0.777	0.710
Imported coal consumption (Mt/year)	0.435	0.653	0.596
SOx emissions (b) (mg/Nm3 – t/year)	40–200	40–300	40–290
NOx emissions (b) (mg/Nm3 – t/year)	20–133	20–200	20–192
Particulate emissions (b) (mg/Nm3 – t/year)	5 – 33	5 – 50	5 – 48
CO_2 capture efficiency	90.0%	90.0%	90.0%
Produced CO_2 (Mt/year)	2.065	3.097	2.827
Emitted CO_2 (Mt/year)	0.206	0.310	0.969

Notes: (a) A LHVof 20.83 MJ/kg and 24.79 MJ/kg has been considered for Sulcis and imported coal, respectively. (b) Specific emissions of SOx, NOx and particulate are referred to an oxygen concentration in flue gas of 6% in volume.

TABLE 1 Main technical assumption for the selected plant configurations
Fonte: Sotacarbo

extension of the saline aquifers, the homogeneity of the reservoir, the rank of the sub-bituminous Sulcis coal, the permeability of the coal bed and the presence of a natural cap-rock which allows a permanent segregation [6, 14].

Assumptions on plant configuration and size

As previously mentioned, the Italian law n. 99/2009 recommends a plant scale between 300 and 450 MWe. In this study, both these extreme sizes have been considered for the CO_2-free plant. Moreover, a third hybrid configuration considers a power generation plant which produce 450 MWe and with the CCS system designed to treat only a portion of flue gas (corresponding to that produced by a hypothetical 300 MWe CO_2-free power generation plant). This third possibility could represent a good compromise, from the economical point of view, considering that the aim of CCS system is to demonstrate the feasibility of the technology and the corresponding cost could be partially supported by the Italian Government.

Table 1 shows the main technical assumptions of the three mentioned plants. In particular, a plant availability of 7000 hours per year has been considered for each case. This value has been precautionary assumed lower than that corresponding to the state-of-the-art (typically 7600-8000 h/yr.) taking into account the demonstration nature of the CCS system and the subsequent implications in the management of the power generation plant (which could operate even during the shut-down of the capture system, with a lower fuel consumption).

Economical and financial assumption

The economical and financial analysis here reported for the three considered plant configurations takes into account every cost (mainly capital and operating costs for power generation and for CO_2 capture and storage) and profit (for the selling of electrical energy and CO_2 assigned amount units).

Capital costs

The assessment of the plant capital cost considers the overall plant construction and the adjustment of the infrastructure. Capital cost estimation for each plant configuration is shown in table 2 [6, 10]. In the financial assessment, the investment has been considered with its distribution during the construction period of four years (since 2012 to 2015). In particular, 24% of the capital cost is invested during the first year of construction, whereas 39%, 32% and 5% are invested during the following three years, respectively.

A typical detailed cost distribution for plant construction, recently proposed by the U.S. Department of Energy [5], is shown in table 3. The total investment cost is composed by the sum of equipment costs, material costs, direct and indirect labour, engineering costs and other capital costs. As for the equipments, the most significant contribute in the total plant cost comes from the ultrasupercritical boiler and for the CO_2 capture and compression system (which globally represents about 52.3% of the total capital cost).

Capital cost affects significantly the behaviour of the annual cash flow. For this reason, this cost has been considered with its financial amortization schedule. Table 4 shows the main economic parameters assumed in this analysis. In particular, 80% of the capital costs has been assumed funded by the banks, with a

	Capital costs (M/)		
	300 MWe CCS 100%	450 MWe CCS 100%	450 MWe CCS 67%
Power generation plant	1090.9	1380.0	1254.5
-"basis" configuration	736.4	988.2	900.0
-CCS system	354.5	391.8	354.5
Other capital costs [(a)]	87.3	110.4	100.4
Contingencies [(b)]	21.8	27.6	25.1
TOTAL	1200.0	1518.0	1380.0

Notes: (a) 8% of the plant cost; they include engineering, start-up, spare parts, royalties and working capital. (b) 2% of the plant cost.

TABLE 2 Capital costs
Fonte: Sotacarbo

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	Equipm.	Material	Labur (direct)	Labour (indir.)	Engin. &fee	Other costs	TOTAL
Coal/sorbent handling	1.25%	0.34%	0.75%	0.00%	0.21%	0.38%	2.93%
Coal/sorbent prepar. and feed	0.85%	0.05%	0.22%	0.00%	0.10%	0.18%	1.10%
Feedwater and misc. BoP	3.42%	0.00%	1.61%	0.00%	0.46%	0.90%	6.40%
PC boiler and accessories	12.23%	0.00%	6.86%	0.00%	1.86%	2.09%	23.04%
Flue gas cleanup	6.31%	0.00%	2.15%	0.00%	0.81%	0.93%	10.20%
CO_2 removal and compr.	14.69%	0.00%	4.48%	0.00%	1.83%	8.26%	29.26%
Ductwork and stack	1.09%	0.06%	0.74%	0.00%	0.17%	0.27%	2.34%
Steam turbine generator	5.25%	0.07%	1.43%	0.00%	0.62%	0.87%	8.25%
Cooling water system	1.29%	0.62%	1.15%	0.00%	0.29%	0.45%	3.81%
Ash/spent sorbent handling	0.33%	0.01%	0.44%	0.00%	0.08%	0.09%	0.94%
Accessory electric plant	1.57%	0.67%	1.88%	0.00%	0.36%	0.56%	5.05%
Instrumentation and control	0.63%	0.00%	0.63%	0.00%	0.11%	0.24%	1.61%
Improvements to site	0.21%	0.12%	0.42%	0.00%	0.07%	0.16%	0.98%
Buildings and structures	0.00%	1.55%	1.47%	0.00%	0.27%	0.49%	3.78%
TOTAL	49.14%	3.48%	24.24%	0.00%	7.26%	15.89%	100.0%

TABLE 3 Power generation plant cost distribution[5]
Fonte: Sotacarbo

Plant construction period (a) (years)	4
Plant operating life (b) (years)	21
During of financial amortization (years)	10
Annual discount rate (c)	10%
Annual inflation rate	2%
Plant value at the end of operating life (M/)	0.00
Percentage of external funding	80%

Notes: (a) Since 2012 to 2015. (b) Since 2016 to 2037. (c) Source: Dominichini, 2009 [10].

TABLE 4 Main financial assumptions
Fonte: Sotacarbo

discount rate of 10% (precautionary); the annual rate of the capital cost (which is the addition of the constant capital share and the decreasing annual interest and amounts to 258 M€, with reference to the year 2016 and to the CO_2-free 450 MWe configuration) has been calculated according with the straight-line method.

Overall operating costs

The overall operating cost of the power generation plant considers the purchasing of Sulcis and imported coal (65 €/t and 60 €/t, respectively, including transport and delivery), the operation and maintenance (O&M) of the plant, together with the cost for material handling and taxes.

In particular, the operating and maintenance cost includes all the costs for conduction and maintenance of the power generation plant and, in particular, the cost of labour, the day-by-day maintenance, the cost for spare parts and so on.

The evaluation of these costs has been carried out on the basis of a previous assessment [6], adjusting every cost component in order to consider the different plant configuration and scale. All these costs have been considered with an annual increasing of 2% in order to take into account the current trend of the price.

This evaluation does not consider the cost for ash handling and disposal into the exhausted seams of the coal mine; it has been assumed that this cost is fully compensated by the selling of the by-products (sulphuric acid from SNOX™ process) [6].

Profit for CO_2 assigned amount units

In this study, the profit for the selling of the CO_2 assigned amount units (AAUs) has been considered, according with the Emissions Trading System (ETS), for the evaluation of the annual cash flow. In particular, the CO_2 emission limit has been calculated according with the last available Italian national allocation plan (NAP) for the period 2008-2012, with the assumption that the same value will be constant during all the plant operating life. In particular, for the considered plant configurations, the emission limit amounts to 1603 Mt/yr. for the 300 MWe plant, to 2407 Mt/yr. for the CO_2-free 450 MWe plant and to 2198 Mt/yr. for the 450 MWe configuration with partial capture.

Moreover, an averaged value of 25 €/t has been considered for the CO_2 AAUs during all the plant operating life. Globally, the profits for the selling of the AAUs amounts to 35.12 M€/yr. for the CO_2-free 300 MWe plant, to 52.70 M€/yr. for the CO_2-free 450 MWe plant and to 30.90 M€/yr. for the 450 MWe plant with partial capture.

It is important to underline that these assumption are arbitrary, being impossible to preview the future trend of CO_2 value. Therefore, a sensitivity analysis has been carried out in order to assess the effects of this parameter.

Profit for electrical energy production

The electrical energy produced by the power generation plant is sold to the national electric grid (and, in particular, to GSE SpA, the Italian national company for the management of the electrical services) and represents the main profit of the industrial application. Its cost has been calculated with reference to the Italian ordinance CIP 6/1992 [15], which defines the price of electricity on the basis of the "avoided costs". Moreover, for the first eight years of the plant operating life (since 2016 to 2023), GSE pays an extra incentive for energy selling, according with the Italian law d.p.r. 28/01/94. The price of the electrical energy sold to the national grid is shown in table 5, with reference to the first year of the plant operating life (2016).

	Price [(a)] (c€/kWh)
Overall avoided cost	8.585
- plant avoided cost	2.295
- operating avoided cost	0.790
- fuel avoided cost	5.500
Incentive [(b)]	7.025
Overall price of electrical energy	15.610

Notes: (a) Referred to the first year of plant operation (2016).
(b) Only for the first eight years of operation (2016-2023)

TABLE 5 Price of electrical energy
Fonte: Sotacarbo

After the eighth year (since 2024), when the payment of incentive is suspended, a slight charge of the energy price (initially 0.85 c€/kWh) must be also considered, according with the Italian law d.p.r. 28/01/94.

Every component of the overall price of the electrical energy (except for the fuel avoided cost, according with ordinance CIP6) has been calculated for every year of the plant operating life, considering an annual increasing of 2%.

Cost for CO_2 geological storage

This study considers a CO_2 geological storage through injection in the saline aquifers under the coal mine. In particular, carbon dioxide is dried and compressed, at about 10 MPa (and, in any case, higher than the critical pressure: 7.5 MPa) [16-17], and send, through a pipeline, to the injection wells, located about 20-30 km far from the power generation plant. The overall specific cost for CO_2 compression, transport and injection has been considered constant for each year (except for the annual increasing of 2% due to inflation); moreover, they include both capital and operating costs, except for CO_2 compression (which capital cost is included in the initial investment for the capture section).

The compression technology, based on a multistage intercooled compressor, is quite mature and does not need further development for applications with CO_2, except for the optimization of its integrations with the specific power plant [18]. A compression cost of 0.75 c€ per kilogram of CO_2 [19] has been assumed. On the other and, pipelining CO_2 is a well-estabilished technology, which uses the normal gas construction methods [20-21]. A transport cost of 2.5 c€/t km, referred to onshore pipeline [22], has been assumed. Finally, an injection cost of 3.4 c//t has been considered for the carbon sequestration in saline aquifers.

Results and discussion

The economical and financial assessment of the investment has been carried out by the evaluation, year by year, of the effective and actualized cash flow, the latter referred to the first year of the project financing phase (2012). A comparison between the different plant solution has been carried out with reference to the typical economical indicators, i.e. net present value, internal rate of return and payback time.

In particular, the net present value (NPV) is defined as the sum of the present values of the individual cash flows.

The internal rate of return (IRR) is the value of the discount rate that makes the net present value of all cash flows equal to zero, whereas payback time (PBT) is defined as the period of time required for the return on the investment (based on actualized cash flows).

Moreover, in order to quantify the economical plant performance, the cost of electricity, of CO_2 separation and of "avoided CO_2" have been also determined. In particular, the cost of electricity (CoE, in c€/kWh) is the ratio between all the plant cost (capital and operating, including fuel) during the full duration of the project and the overall electrical energy produced during the same period. In parallel, CO_2 separation cost is the ratio between the overall (capital and operating) cost of CCS (capture, compression, transport and injection) and the whole amount of stored CO_2, during all the project life. Finally, the cost of avoided CO_2 can be defined as:

$$Ca = (CoE_{ccs} - CoE_{basis}) / (e_{basis} - e_{ccs}) \qquad (1)$$

where CoE is the previously defined cost of electricity and *e* is the CO_2 specific emission (in kg/kWh) in both basis and CCS configuration; the subscript *CCS* indicates the assumed plant configuration, whereas the subscript *basis* indicates the corresponding configuration without CCS, both considered with the same thermal input. Table 6 shows a synthesis of the main results of the comparative economical analysis expressed on the basis of the above defined parameters.

As expected, the investment for a 300 MWe CO_2-free plant appears not feasible from the economic point of view; as a matter of fact, the small plant scale (and its subsequent high specific cost, in €/kWe) does not allow to obtain a positive NPV. The 450 MWe plant with partial capture is significantly more convenient (higher NPV and a moderate value of payback) than the corresponding CO_2-free configuration. Moreover, with reference to the 450 MWe plant scale, the configuration with partial capture involves a higher CO_2 emission, and a subsequent higher cost of avoided CO_2, with respect to the CO_2-free unit. The high value of the internal rate of return (except for the 300 MWe configuration) indicates a secure investment, which remains

	300 MWe CCS 100%	450 MWe CCS 100%	450 MWe CCS 67%
Net present value (M/)	-197.2	158.3	332.4
Internal rate of return (%)	8.27	11.03	12.31
Payback time (a) (years)	-	18	14
Cost of electricity (b) (c€/kWh)	8.98	7.60	7.31
CO_2 separation cost (€/t)	29.34	24.69	29.35
Cost of avoided CO_2 (b) (€/t)	17.36	12.46	15.28

Notes: (a) Including construction period. (b) The assessment considers a cost of AAUs of 25 //t.

TABLE 6 Comparison of the main economical results
Fonte: Sotacarbo

profitable even if the discount rate (which, in this analysis, has been prudentially overestimated) increases.
It is important to notice that the CO_2 separation cost here determined corresponds to the typical values reported in the scientific literature, between 15 and 30 €/t[23].

Sensitivity analysis

Some of the parameters assumed in this study are affected by an uncertainty, being determined by a large series of key factors which are impossible to foresee. Therefore, in order to assure a security of the potential investment, the effects of the variation of these parameters on the main economical indicators (the results here reported are mainly referred to the net present value) has been evaluated. The results here reported are referred to the 450 MWe power generation plant with partial CO_2 capture and sequestration, applied to 67% of produced flue gas; moreover, three different costs of CO_2 AAUs have been considered: 25 €/t (reference case, which represents the most probable scenario in a short-term future), 15 €/t (current value) and 0 €/t (a precautionary assumption).

Sensitivity analysis on plant capital cost

A detailed value of the plant capital costs can be only evaluated as the results of the detailed plant design. In this preliminary phase, it has been assumed in line with previous evaluation coming from the recent scientific literature.
Figure 1 shows, for three different values of the CO_2 AAUs, the linear variation of NPV by varying the capital cost between 1260 (a future scenario, when the technology will be industrially mature) and 1500 M€ (precautionary case). In particular, the behaviours of NPV have been presented (figure 1.a) together with

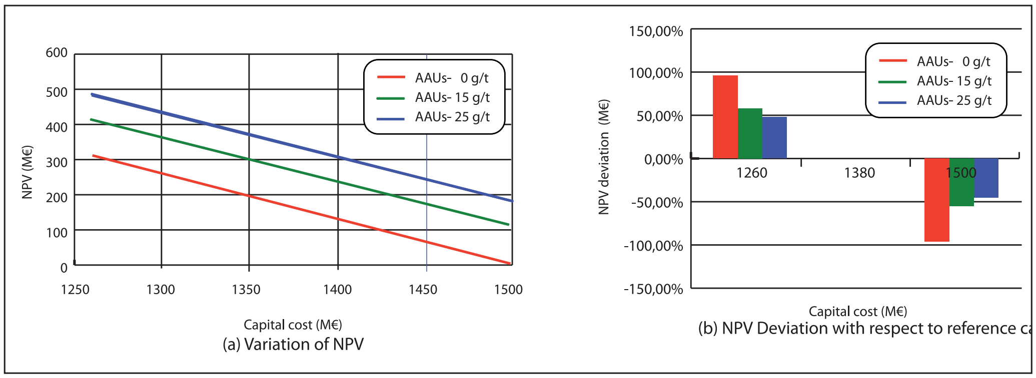

FIGURE 1 Sensitivity analysis on plant capital cost
Fonte: Sotacarbo

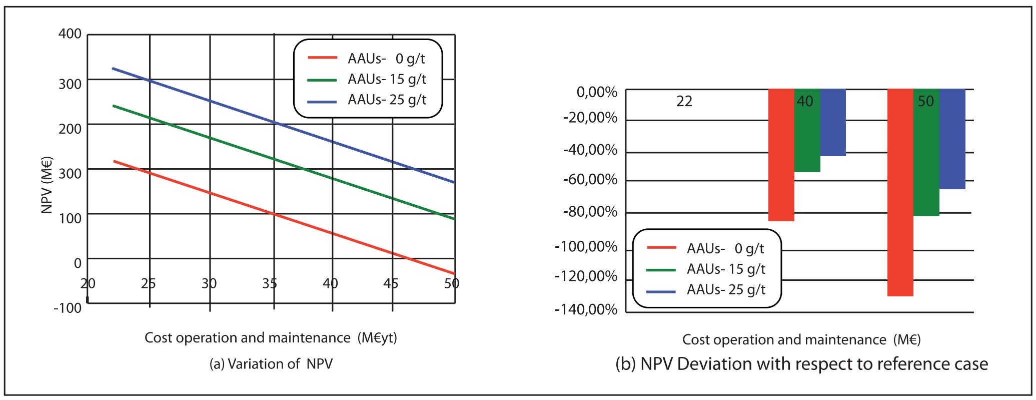

FIGURE 2 Sensitivity analysis on plant O&M cost
Fonte: Sotacarbo

the maximum values of deviation (figure 1.b) with respect to reference capital cost (1380 M€).
As expected, an increasing capital cost involves a significant reduction of the net present value (this variation is particularly significant when the cost of CO_2 AAUs is low). On the other hand, cost of electricity raises from 7.18 €/t (for a capital cost of 1260 M€) to 7.74 (for a capital cost of 1500 M€). In any case, in all the considered range of variation, the investment remains profitable.

Sensitivity analysis on plant operating and maintenance cost

The reference case considered in this work includes an operating and maintenance (O&M) cost of about 22 M€ per year (referred to the first year of plant operating life); this value is fully consistent with that reported in the scientific literature. In any case, it depends by a series of technical and social aspects such as costs of labour, equipments, spare parts and so on. As shown in figure 2, a raise of O&M costs (up to 50 M€/yr) involves a significant linear reduction (about 60%) of the net preset value and a corresponding increasing (14.6%, up to 9.4 c€/kWh) of the cost of electricity. Even in this case, this variation is particularly significant when the cost of CO_2 AAUs is low.

Sensitivity analysis on costs for CO_2 geological storage

The reference case of this study considers an overall cost for CO_2 storage (including compression, transport and injection) of 3.4 M€ for the first year of plant operating life (with an annual increasing of 2%). This value is referred to carbon dioxide geological storage in the saline aquifers located under the Sulcis coal mine, at a depth of 800-1000 m.
As mentioned, the possibility to operate CO_2 storage through ECBM (enhanced coal bed methane technology) is also under investigation, due to the closeness of the considered power plant to the Sulcis coal basin. In particular, CO_2 injected into coal seams displaces methane, thereby enhancing coal-bed methane recovery [24]. As for this technology, a typical cost of 30 M€ per year (with the hypothesis that the extraction of methane is negligible) or lower (depending by the profits for methane selling) can be considered.
As shown in figure 3, this cost strongly influences the NPV, which is null when the cost of CO_2 storage is about 27-28 €/t. In these case, the investment became unprofitable. Due to the demonstration nature of the CCS section, a plausible scenario could consists in a combined storage in which about 70% of captured CO_2 is stored in saline aquifers, whereas the remaining 30% is injected in the unminable coal seams, with an annual overall cost of about 15 M€ (referred to the first year of plant operating life). In this scenario, NPV decreases to 171.5 M€ (-48.3%), whereas CoE raises up to 8.3 c€/kWh (11.3%). Moreover, cost of avoided CO_2 increases from 16.6 to 21.5 €/t whereas cost of CO_2 separation raises from 29.3 to 43.6 €/t

Sensitivity analysis on other significant parameters

The influence of other significant parameters on the

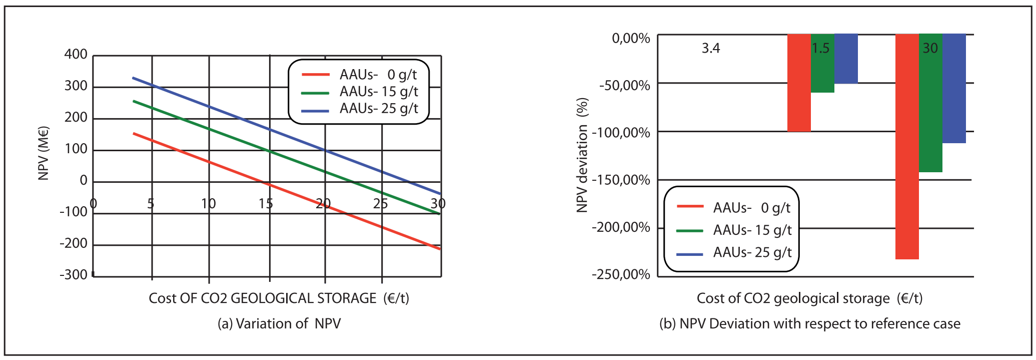

FIGURE 3 Sensitivity analysis on costs for CO_2 geological storage
Fonte: Sotacarbo

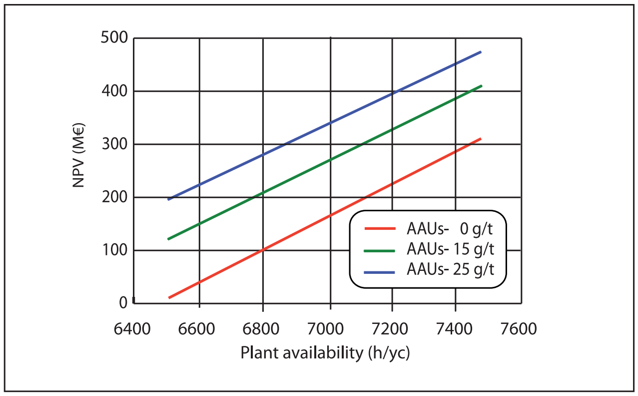

FIGURE 4 Sensitivity analysis on plant annual availability
Fonte: Sotacarbo

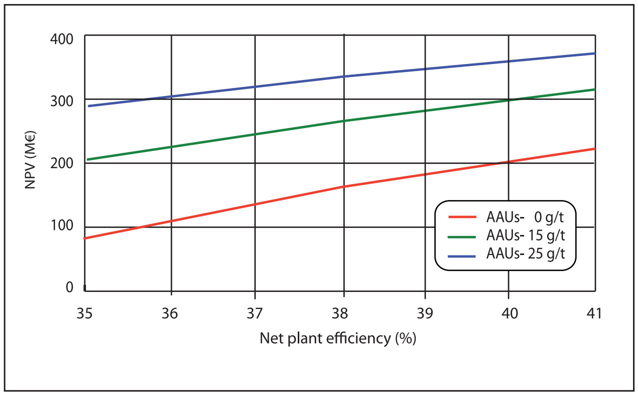

FIGURE 5 Sensitivity analysis on plant efficiency
Fonte: Sotacarbo

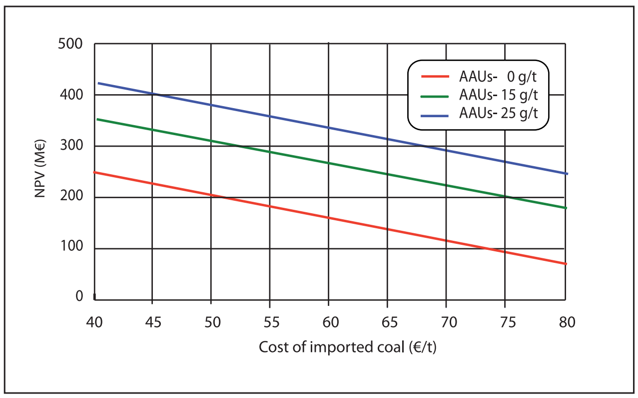

FIGURE 6 Sensitivity analysis on the cost of imported coal
Fonte: Sotacarbo

economic performance of the investment has been also assessed. In particular, plant availability significantly influences the annual profit (due to energy selling); an increasing value of this parameters up to 7500 h/yr. involves a raise of NPV (figure 4) of about 42% (92-93% if the cost of AAUs is null), whereas the cost of electricity decreases to 7.28 c€/kWh.

The overall net plant efficiency of a CCS plant is one of the most controversial aspects in the development of this kind of technology. As mentioned above, in this study a net efficiency of 45% (LHV basis) has been considered for the basis configuration; it decreases down to 38% as a consequence of the introduction of the CCS system designed to treat only a portion of flue gas. Considering the reference case, with a cost of AAUs of 25€/t, a variation of the overall plant efficiency between 35 and 41% involves an increasing of the NPV, between 286 and 370 M€ (figure 5), and a subsequent decreasing of CoE from 7.72 to 7.25 c€/kWh.

Finally, the economical performance of the investment is significantly affected by the cost of imported coal. In particular, an increasing of this cost up to 80 €/t (figure 6) should involve a reduction of the net present value of about 26.8% (about 240 M€) and a corresponding increasing of CoE of 6.17% (7.92 c€/kWh).

Conclusions

In order to increase Italian energy security (partially releasing energy production from imported primary sources) and to re-launch the economy in the Sulcis area, Sotacarbo is cooperating with national and regional administrations to develop a project for the construction of a power generation plant, equipped with a demonstrating CCS system, strictly integrated with the Sulcis cola mine.

Between all the available technologies, the most profitable plant configuration includes a 450 MWe power generation plant, based on the pulverized coal combustion in an ultra supercritical boiler, equipped with a SNOX™ system and a MEA-based post-combustion

CO_2 capture plant which treats about 67% of the plant flue gas (corresponding to an hypothetical 300 MWe CO_2-free plant).

The analysis here presented takes into account capital (about 1380 M€) and operating costs, together with the profits for the selling of electrical energy and CO_2 AAUs, according with the international Emissions Trading System. The proposed solution appears significantly profitable, with a net present value of 332 M€; moreover, the high internal rate of return (12.31%) and the relatively low payback time (14 years) assure a good reliability of the investment.

As results from the sensitivity analysis, the evaluation of capital and O&M cost strongly influences the economical performance of the investment, which remains in any case profitable if the cost of CO_2 AAUs will remain around 15-25 €/t during the plant operating life. Moreover, the relatively high profit margin allows and suggests to test both the selected CO_2 sequestration techniques: geological storage in saline aquifers and through ECBM, the latter (which is characterized by a very high operating cost) applied only for a portion (around 20-30%) of captured carbon dioxide.

It is important to specify that this study is only a small portion of a more detailed feasibility analysis which will lead, in its first phase, to the definition of all the main technical and economical parameters of the overall project and, in a second phase, to the development of the plant detailed design.

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