International Journal of Engineering and Management Research e-ISSN: 2250-0758 | p-ISSN: 2394-6962
Volume-12, Issue-3 (June 2022)
www.ijemr.net https://doi.org/10.31033/ijemr.12.3.11

Theoretical Estimation of CO_2 Compression and Transport Costs for an hypothetical Carbon Capture & Storage requalification of the Saline Joniche Power Plant Project

Luca Rosati[1], Angelo Spena[2] and Fedora Quattrocchi[3]
[1]Department of Enterprise Engineering, University of Rome Tor Vergata, Rome, ITALY
[2]Department of Enterprise Engineering, University of Rome Tor Vergata, Rome, ITALY
[3]Department of Enterprise Engineering, University of Rome Tor Vergata, Rome, ITALY

[1]Corresponding Author: luca.rosati@alumni.uniroma2.eu

ABSTRACT

SEI S.p.a. presented a project to build a 1320 MW coal-fired power plant in Saline Joniche, on the Southern tip of Calabria Region, Italy, in 2008. A gross early evaluation about the possibility to add CCS (CO_2 Capture & Storage) was performed too. The project generated widespread opposition among environmental associations, citizens and local institutions in that period, against the coal use to produce energy, as a consequence of its GHG clima-altering impact. Moreover the CCS (also named Carbon Capture & Storage or more recently CCUS: Carbon Capture-Usage-Storage) technology was at that time still an unknown and "mysterious" solution for the GHG avoiding to the atmosphere. The present study concerns the sizing of the compression and transportation system of the CCS section, included in the project presented at the time by SEI Spa; the sizing of the compression station and the pipeline connecting the plant to the possible Fosca01 offshore injection site previously studied as a possible storage solution, as part of a coarse screening of CO_2 storage sites in the Calabria Region. This study takes into account the costs of construction, operation and maintenance (O&M) of both the compression plant and the sound pipeline, considering the gross static storage capacity of the Fosca01 reservoir as a whole as previously evaluated.

Keywords-- Carbon Capture and Storage, Power Plants, Greenhouse Gasses, Cost Assessment

I. INTRODUCTION

A. Energetic Scenarios during the Climate-Change Hypothesis and during the Natural Gas Crisis among Russia and Ucraine

In December 2015, at COP 21 in Paris, 195 Countries signed the Paris Climate Agreement [1]. The long-term climate goals of the agreement were defined as:

- Limiting the average global warming well below 2 °C compared to pre-industrial times, with the aspiration to limit the heating to 1.5 °C.
- Achieving a balance between emission sources and wells (often referred to as net zero emissions) in the second half of this century.

So far, global climate models have not been able to achieve really useful results for the reduction of greenhouse gases (GHG) from the atmosphere and/or economically advantageous/sustainable while remaining consistent with the objectives of the 2015 Paris Agreement, without taking into account critical technologies such as CCS (Carbon Capture & Storage), bioenergy and their combination (BECCS) [2].

The gap between the global efforts currently underway and the emissions reductions needed to reach the 2 ° C target agreed in Paris is immense. It requires approximately 760 gigatonnes (Gt) of CO_2 emissions reduction across the energy sector between now and 2060 [2].

Although the transition from fossil fuels to renewable sources is concrete and indisputable, the statistics and projections propose scenarios still characterized by an important presence of natural gas and coal in the field of electricity generation, from now to the next 30 years [3].

According to data provided by British Petroleum concerning the year 2019 (still Business as Usual, BaU, before the COVID19 crisis), primary energy consumption grew by 1.3%, which was less than half the rate of 2018 (2.8%). Nevertheless, this still represents the 10^{th} consecutive year that the world set a new all-time high for energy consumption.

The largest share of the increase in energy consumption, 41%, was contributed by renewables. Natural gas contributed the second largest increment with 36% of the increase. However, as an overall share of energy consumption, oil remained on top with 33% of all energy consumption. The remainder of global energy consumption came from coal (27%), natural gas (24%), hydropower (6%), renewables (5%), and nuclear power (4%) [4].

However, all the statistics and estimations made before February 2022 will probably have to be updated. In fact, Russia's invasion of Ukraine, where a political crisis started in 2014 among Russian and Ucrainian ethnic parties, and the unprecedented economic sanctions. that have followed have thrown the global energy market into chaos, sending fossil fuel prices soaring and raising questions in many countries about whether climate ambitions need to be softened in order to keep the lights on by the two main solutions i.e., by the clean coal technologies or the nuclear power respectively.

Though Western sanctions have not yet directly targeted Russian oil, coal or gas, the European Union has announced plans to end its energy reliance on Russia, while companies across the globe, wary of reputational and financial risks now associated with the country, look to suppliers elsewhere.

To adapt to the EU continent's energy crisis, coal appears an obvious short-term choice, given an evident lack of enough existing Liquid Natural Gas (LNG) infrastructures. France has temporarily allowed power plants to burn more coal, Italy has raised the possibility of reviving decommissioned coal plants, and Germany has announced plans to build its coal reserves and signaled its coal phase-out date may have to be delayed [5]. Considering the actual geo-political situation with the rising demand of coal worldwide caused by the Russia-Ucraine's crisis, the present study carried out with the aim of proposing a possible solution for the conversion to CCS of Italian coal-fired power stations, now existing without this technology, in order to exploit newly the idea of the clean coal technologies (CCT) and to make the coal-fired electricity production reliable with the climate goals set in Paris in 2015.

B. An Ancient Project CCT Possibly to be "reloaded"

The Saline Joniche coal power plant was a project presented by SEI S.p.A in 2008, with the aim to retrain an ancient archeo-industrial - chemical area, abandoned in the region from 1977.

The project consisted of the construction of an ultra-supercritical 1320 MW steam cycle plant composed by two groups of 660MW [6],[7].

The industrial area chosen would have been located parallel to the Calabrian Ionian coast, bordered to the North by State Road no.106 'Ionica', and to the South by the Reggio Calabria-Metaponto railway line. Southward the railway would have been located the industrial port facility. To the South-East of the possible plant, located a state-owned area would have been that would have been used for the construction of the new sea water intake as well as desalination and chlorination plants. Also on the state-owned (port) the area would have been part of the facilities for the solid materials handling system (including coal, biomass, inerts and limestone) and by-products (gypsum and ash).

The thermoelectric power plant, as mentioned before, would have been consisted of two 660 MWe gross twin units and the auxiliary units necessary for their operation.

The main equipment and units of the possible Power Plant to considerate, are as follows [6]:

a) coal and biomass unloading, storage and handling system;
b) two ultra-supercritical coal-fired boilers, each with its own denitrification system
c) catalytic denitrification (De-NOx), flue gas cleaning (bag filters);
d) two wet flue gas de-sulphurisation (De-SOx) units; one per boiler;
e) exhaust, storage and handling system for flue gas treatment system reagents (urea, limestone);
f) 2 side-by-side smokestacks (180 m high and 6.4 m diameter at the mouth), one per boiler, for evacuation of fumes to the atmosphere, connected by a single stiffening and containment frame storage, handling and loading system for solid by-products from combustion and flue gas treatment (ash and gypsum);
g) two condensing steam turbines with reheating, each consisting of a high, medium and low pressure section;
h) two condensers for the steam discharged by the turbines, cooled by sea water in open circuit;
i) a seawater intake, supplying water to the turbine condensers and to the machine cooling system in a closed circuit; the system includes a hydraulic turbine for recovering the energy from the water, before returning it to the sea, with a capacity of approximately 3 MW;
j) a machine cooling water system, consisting of fresh water in a closed circuit, cooled with sea water;
k) a sea water desalination and de-mineralisation plant using reverse osmosis and ion exchange resins;
l) a diesel-powered auxiliary generator;
m) a waste water collection and treatment plant;
n) the fire-fighting system;
o) two electric generators, with related machine switch and transformers;
p) a HV station, consisting of two transformer posts, two line posts and a busbar system, with junction for connection to the National Transmission Grid;
q) the electrical auxiliary distribution system;
r) a system of photovoltaic modules located on the Southern slope of the roof of the coal cell with an installed peak power of 1 MW;
s) all the auxiliary services necessary for the proper operation of the plant.

The Thermoelectric Power Plant was functionally divided into a number of main units, listed below with their design capacities:

Main Process Units

a) Coal supply:

- unloading ships and transport to storage: 3,000 t/h, common to the two groups;
- storage building: 300,000 t, common to the two groups;
- handling and grinding from storage to boilers: 2 x 1,500 t/h, common to the two groups (two lines, of which one of which is a reserve).

b) Biomass Supply:

- unloading ships and transport to storage: 500 t/h, common to the two groups;

e-ISSN: 2250-0758 | p-ISSN: 2394-6962
Volume-12, Issue-3 (June 2022)
https://doi.org/10.31033/ijemr.12.3.11

- storage building: 19,000 t, common to the two groups;
- handling and milling from storage to boilers: 200 t/h, common to the two groups.

c) Boilers:

- Thermal input: 1,383 MWt, per boiler.

d) Steam Turbine:

- Gross power generated: 660 MWe, per turbine.

e) Limestone Supply:

- unloading ships and transport to storage: 500 t/h, common to both groups
- storage silos 15,000 t total, common to the two groups;
- handling and grinding from storage to De-SOx: 250 t/h, common to the two groups (two lines, of which one in reserve).

f) Gypsum Handling:

- handling from De-SOx to storage: 250 t/h, common to the two groups (two lines, one of which is a reserve);
- storage building: 15,000 t, common to the two groups;
- transport from storage and ship loading: 500 t/h, common to both groups. Ash handling:
- handling from boilers to storage: 250 t/h, common to the two groups (two lines, of which one as a reserve);
- storage silos: 30,000 t total, common to the two groups;
- transport from storage and ship loading: 500 t/h, common to the two groups;

Auxiliary Units (common to the two groups)

a) Sea water intake (civil works): 210,000 m^3/h, sized for a possible future CO_2 capture plant nearby;
b) Sea water intake (pump station): 160,000 m^3/h, in "CO2 capture ready" configuration;
c) Service water production: 300 m^3/h;
d) Demineralised water production: 50 m^3/h;
e) Plant / instrument air production: 1,600 Nm^3/h.

The data of interest are shown in table 1.

Table 1: Characteristics of the Saline Joniche possible coal power plant

Power Plant capacity	1,320 MW
CO_2 emissions p.c.	22,774.4 t/d
CO_2 emissions p.c.	7,591,466.67 t/y

II. RESULTS: DESIGN AND COMPRESSION SYSTEM

A. CO_2 Compression Power Calculation

After its separation from the flue gases emitted from a power plant or an energy complex, the CO_2, before reaching a CO_2 pipeline, must be compressed starting from atmospheric pressure (P_{in} = 0.1 MPa), the pressure at which it exists as a gas, up to a pressure suitable for the transport on pipeline (generally P_{fi} = 10-15 MPa), pressure at which CO_2 is liquid or in the "dense phase" region, depending on its temperature. Depending on the phase of the CO_2, a compressor is used when it is in the gas phase, while when it is in the liquid / dense phase, a pump must be used. It can be assumed that the cut-off pressure ($P_{cut-off}$) at which we have the switch from the compressor to the pump is the critical CO_2 pressure: 7.38 MPa [8].

Table 2: pressure values considered for the compression plant project

P_{in}	0.1 MPa
$P_{cut-off}$	7.38 MPa
P_{fi}	11.80 MPa

The sizing procedure of the compressor is more laborious than that relating to the pump since each equation must be applied to each individual stage. However, this procedure is necessary because the properties of the CO_2 in the gas phase have an unusual trend and change at each stage. The number of compressor stages (N_{stage}) is conventionally assumed to be 5. The first step consists of the calculation of the optimal Compression Ratio (CR) for each stage using the eq. 1:

$$CR = \left(\frac{P_{cut-off}}{P_{in}}\right)^{\frac{1}{N_{stage}}} \quad (1)$$

The next step is the calculation of the power required for compression in each stage (Ws, i) through the eq. 2:

$$W_{s,i} = \frac{1000}{24*3600} * \frac{mZ_sRT_{in}}{M\eta_{is}} * \frac{K_s}{K_s-1} + (CR^{\frac{K_s-1}{K_s}} - 1) \quad (2)$$

where :

- R = 8.314 [kJ/(kmol*K)];
- M = 44.01 [kg/kmol];
- T_{in} = 313.15 [K];
- η_{is} = 0.8;
- 1000 indicates the kg in one ton;
- 24 indicated the hours in one day;
- 3,600 indicates the seconds in one hour;
- m indicates the CO_2 mass flow rate in [tons/day].

Table 3: Pressure, Z_s, K_s values for each stage of the compression plant

Stage	Pressure step	Z_s	K_s
1	0.1 – 0.24 MPa	0.995	1.277
2	0.24 – 0.56 MPa	0.985	1.286
3	0.56 – 1.32 MPa	0.970	1.309
4	1.32 – 3.12 MPa	0.935	1.379
5	3.12 – 7.38 MPa	0.845	1.704

The required powers, calculated for each stage, must then be added together to obtain the total power required by the compressor (Ws-total). According to the IEA GHG PH4 / 6 report, the maximum size of a series of compressors built, according to modern technologies,

e-ISSN: 2250-0758 | p-ISSN: 2394-6962
Volume-12, Issue-3 (June 2022)
https://doi.org/10.31033/ijemr.12.3.11

is 40 MW, this reason which is why, if the total power required by the compressor is greater than this threshold, the CO_2 flow rate and the power request must be distributed in a "train" of compressors in series, arranged in parallel. The number of compressor series must obviously be an integer and is calculated through the eq. 3:

$$N_{train} = ROUND_{UP} * \left(\frac{W_{s-total}}{40{,}000}\right) \qquad (3)$$

The power required for pumping is obtained through the eq. 4:

$$W_p = \frac{1000*10}{24*36} * \frac{m*(P_{fi} - P_{cut-off})}{\rho * \eta_p} \qquad (4)$$

where:

- m = CO_2 mass flow rate in [tons/day];
- ρ = CO_2 density, 630 kg/m^3;
- η_p = 0,75;
- 1000 = kg in one ton;
- 24 = hours in one day;
- 10 = pressure in bar corresponding one MPa;
- 36 = (m^3 * bar)/(hr * kW).

According to the IEA GHG PH4/6 report [1], the maximum size of one compressor train is 40 MW. So if the total compression power requirement (Ws-total) is greater than this value, then the CO_2 flow rate and total power requirement must be split into N_{train} parallel compressor trains, each operating at 100/N_{train} % of the flow/power. Of course, the number of parallel compressor trains must be an integer value.

As can be seen from the values, the overall power used by the compression is equal to 85,79 MW so the first part of the compression, from ambient pressure to 73 bar has been operated by a 3 parallel compressor trains.

Once the power required by the pump has also been calculated, we can calculate the total power required for CO_2 compression.

The dependence of the power required for the flow rate compression is linear, both in the case of the compressor and in the case of the pump; however, the power required for pumping is lower than that required for compression, due to the fact that the compressors increase the CO_2 pressure from 0.1 to 7.38 MPa (with a compression ratio equal to 73.8), while the pump increases the pressure from 7.38 to 11.65 MPa (with a compression ratio of only 2). Following the model proposed by McCollum, a 5-stage system was hypothesized, each interspersed with water-cooled inter-cooling. The presence of intercooling is of fundamental importance also because in this way, at each stage, it is possible to separate the condensate (to minimize the presence of water in the CO_2 flow, which could be the cause, together with carbon dioxide, of corrosive processes). The power used by the pump to arrive from critical conditions to those optimized for entry into the pipeline (11,80 Mpa) is much less than required by the compressor trains (about 2.22 MW). The CO_2 is subsequently sent to an intermediate tank (which acts as a separator) from which, eventually, it will be sent to the pump used for compression up to the pressure chosen for entry into the pipeline. Considering a daily mass flow rate of 20,516.88 tons/day equal to 237.23 kg/s, a summary scheme of the system simulation is given in the table below.

Table 4: Results of the sizing of the compression plant

N° compression stages	5
N° compression train	3
Mass flow rate (m)	20,516.88 t/d
$P_{initial}$	0.1 Mpa
$P_{cut-off}$	7.38 Mpa
P_{final}	11.80 Mpa
Compressor Ratio (CR)	2.36
$W_{stage,1}$	17.63 MW
$W_{stage,2}$	17.49 MW
$W_{stage,3}$	17.33 MW
$W_{stage,4}$	17.00 MW
$W_{stage,5}$	16.35 MW
$W_{compressor-total}$	85.79 MW
η_{is}	0.80
η_p	0.75
W_{pump}	2.22 MW

B. Investment Costs, Operation and Maintenance Costs, Levelized Costs

The investment (capital), Operating and Maintenance (O&M) costs and the normalized costs per ton of compressed carbon dioxide were calculated starting from the power required for the CO_2 compression.

Compression capital costs, obtained from McCollum & Odgen paper, 2006, are expressed by the eq. 5:

$$C_{comp} = m_{train} N_{train*} \left[(0.13 * 10^6) * (m_{train})^{-0.71} + + (1.40 * 10^6) * (m_{train})^{-0.60} * \ln\left(\frac{P_{cut-off}}{P_{initial}}\right)\right] \qquad (5)$$

The capital cost relative to the pumping can then be calculated through eq. 6:

$$C_{pump} = \{(1.11 * 10^6) * (Wp/1000)\} + 0.07 * 10^6 \qquad (6)$$

Once the two cost items were added together, in order to calculate the annual costs, the Capital Recovery Factor (CRF) was introduced. Annual costs are expressed by the eq. 7:

$$C_{annual} = C_{total} * CFR \qquad (7)$$

Where CRF is a sort of annual amortization rate that takes into account the useful life of the project and which is taken on average equal to 0.15 (McCollum & Odgen paper, 2007, [8]). In order to calculate the real mass flow rate of compressed CO_2, the daily flow rate was multiplied for 365 days, taking into account a "Capacity Factor" equal to 0.913, considering the plant

e-ISSN: 2250-0758 | p-ISSN: 2394-6962
Volume-12, Issue-3 (June 2022)
https://doi.org/10.31033/ijemr.12.3.11

active for 91.3% of the time (8000 hours/year). Regarding the levelized costs, the annual compression and pumping cost was simply divided by the annual amount of CO_2 compressed (tons).

Table 5: Compression costs

Capital cost (compression)	269,342,647.63 €
Capital cost (pumping)	4,191,520.89 €
Total capital cost	273,534,168.52 €
Annualized capital cost	41,030,125.28 €
CO_2 mass flow rate	6,832,320.00 tons/year
Levelized capital cost	6.01 €/tonne

Annual O&M costs were considered by McCollum & Odgen to be equal to 4% of the capital cost.

Table 6: O&M costs

O&M factor	0.04 €
O&M annual cost	10,941,366.74 €
O&M levelized cost	1.60 €/tonne

Regarding the electricity costs, McCollum & Odgen suggest using the eq. 8, obtained from Kreutz et al., that allows to estimate the price of electricity for a power plant combined with CO_2 capture:

$$E_{annual} = E_{comp} + E_{pump} = pe * \left(W_{s-total} + W_p\right) * (CF * 24 * 365) \quad (8)$$

Table 7: Electricity costs

Electricity price	0.09 €
O&m annual cost	50,682,814.84 €
O&M levelized cost	9.28 €/tonne

Summarizing the total costs as a sum of the three components, as shown in the eq. 9, we obtain the values shown in table 8:

$$C_{tot} = C_{capital} + C_{O\&M} + C_{electricity} \quad (9)$$

Table 8: Total costs of compression

Total annual cost	102,654,306.86 €
Total levelized cost	16.88 €/tonne

All costs have been discounted to 2022.

III. TRANSPORT BY PIPELINE

A. Pipeline Design

The pipeline route chosen for the CO_2 transport form the Saline Joniche thermal plant to the Fosca 01 injection well is composed by a first onshore section with a length of 108 km, and second offshore section with a length of 29 km.

During the pipeline design phase, we tried to minimize the overall cost of the work considering the cost of the pipeline and the compression plant as a reference (both in terms of investment cost and operating cost during the entire estimated lifetime for the project, since the first costs are fundamental in the pipeline while the second are predominant in the compression plant).

We tried to identify the shortest way, avoiding infrastructure and residential areas as much as possible and possibly skirting a viable road for means of transport to limit the costs for moving of all the materials necessary for the realization and for future ordinary or extraordinary maintenance.

We also tried to avoid going from a lower to a higher elevation in order not to have to resort to a recompression plant, which entails a considerable increase in costs.

The chosen route, taken from the Google Earth Pro software is shown in figure 1.

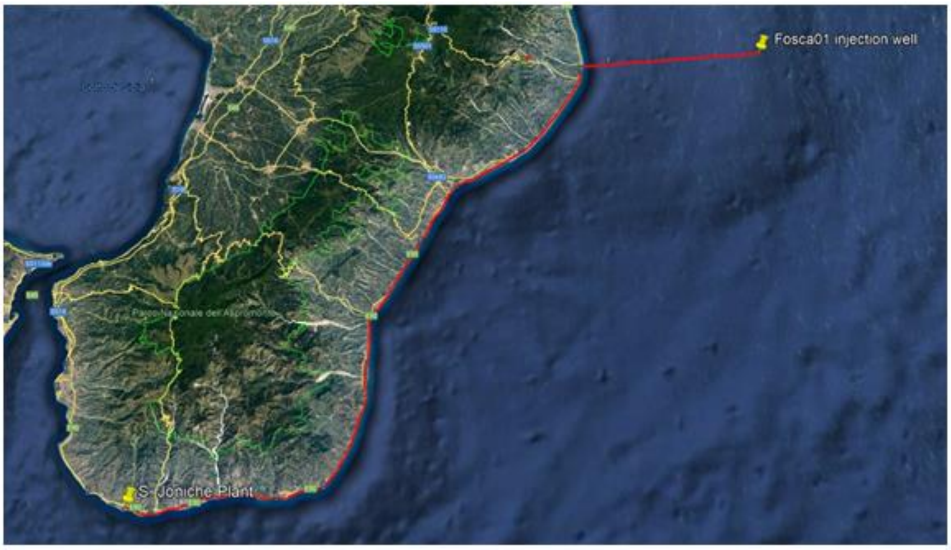

Figure 1: The chosen route, taken from the Google Earth Pro software

e-ISSN: 2250-0758 | p-ISSN: 2394-6962
Volume-12, Issue-3 (June 2022)
https://doi.org/10.31033/ijemr.12.3.11

In terms of dimensioning the onshore section, regarding the choice of materials, for reasons of compatibility with the components of the gas that flows through the pipeline, CO_2 pipelines are usually built using carbon steel, for the use of which it is however necessary to comply with certain specifications and operating conditions. This material was also chosen because of its characteristic of being able to withstand up to -80 ° C, the temperature reached in the event of depressurization.

Since the CO_2 before entering the pipeline undergoes a drying process, it can be considered non-corrosive.

Under these conditions it is therefore not necessary to protect the pipeline internally from corrosion.

Externally, however, due to the atmospheric agents and the composition of the soil where the pipeline is buried, it must be protected with a coating that ensures its protection from corrosion as an alternative to the more complicated cathodic protection and made of HDPE (High Polyethylene Density).

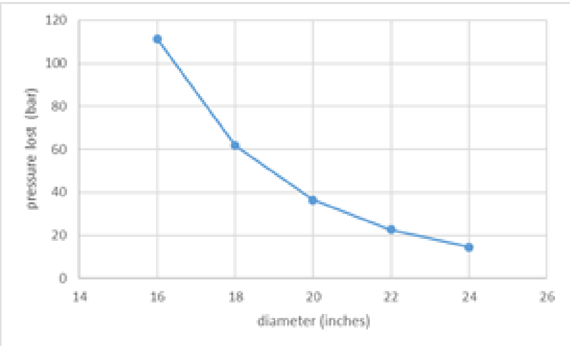

Figure 2: Pressure drop as a function of the pipeline's diameter

For the off-shore pipeline, in terms of constituent materials, considerations apply similar to those reported for the on-shore pipeline. Due to the high bending stresses during laying and external pressures, the steels used must also have high mechanical strength (API 5L class X65 and above).

In addition, however, this section of pipeline is characterised by the presence of a protective outer layer made of meshed concrete called "concrete coating". This layer takes on the function of protection above all against shocks and collisions and ensures (although this is especially the case for large diameters) that the buoyancy does not exceed the weight of the pipe, causing it to rise.

As mentioned, the design of the pipeline was based on a technical and economic evaluation with the aim of minimizing investment and operating costs.

In this regard, the evaluation of the diameter of the pipeline is fundamental as it is a function of the pressure loss along the pipeline itself which in turn influences the choice of the compression system.

The sizing of the pipeline's diameter has been carried out considering the pressure drop of the onshore section taking into account that the minimum CO_2 stream pressure occurs in the switching point from the onshore section to the offshore section.

The pressure value at the switching point has been set at 80 bar in order to maintain the CO_2 stream in the dense phase.

It must be considered in fact, that in the offshore section, thanks to the increasing of the depth, the pressure drop occurred in the onshore section will be partially reduced resulting in an increasing of the injection pressure.

The pipeline pressure drop can be calculated using the eq. 10 [8]:

$$\Delta P = \lambda * (L/D) * (1/2) * \rho * v^2 \qquad (10)$$

Where:

- ΔP = pressure drop [Pa];
- λ = friction factor;
- L = pipeline length [m];
- D = pipeline diameter [m];
- ρ = CO_2 density [kg/m^3];
- v = average flow velocity [m/s].

In the above flow equation, the velocity term, *v*, is a function of the mass flow rate and the cross-sectional area (i.e., diameter) of the pipeline.

Thus, the eq.11 can be rearranged to form the Eq. 11:

$$D^5 = (8 * \lambda * m^2)/(\pi^2 * \rho * {}^{\Delta P}/_{L}) \qquad (11)$$

Where:
m = CO_2 mass flow rate.
Key data used for the calculation are:

- The length of pipeline to be covered is 108km onshore and 29km offshore;
- The minimum outlet pressure from the pipeline section set at 80 bar t the switching point (to keep the current always above critical conditions in order to have CO_2 in the dense phase regardless of temperature);
- The inlet temperature set at 28 ° C in order to keep the fluid in the dense phase.
- The transported CO_2 flow rate of 6.83 Mt / year (considering a catch rate of 90%)

Regarding the offshore section, for the pressure drop calculation, the eq.10 and eq.11 were used in combination with the Bernoulli's formulation, eq. 12, to also take into account the change in altitude (used in its integral expression given the near incompressibility of CO_2 in the dense phase under consideration):

$$\frac{p_2-p_1}{\rho g} + (z_2 - z_1) + \frac{w_2{}^2-w_1{}^2}{2g} = -\frac{\Delta p_p}{\rho g} \qquad (12)$$

Based on the previous analyzes and considerations, the evaluation carried out has led to the results illustrated in the following graphs, where to each diameter considered for the analysis is associated the corresponding pressure drop between inlet and outlet, as a function of the density variation (in turn linked to the variation in temperature) and the length of the section.

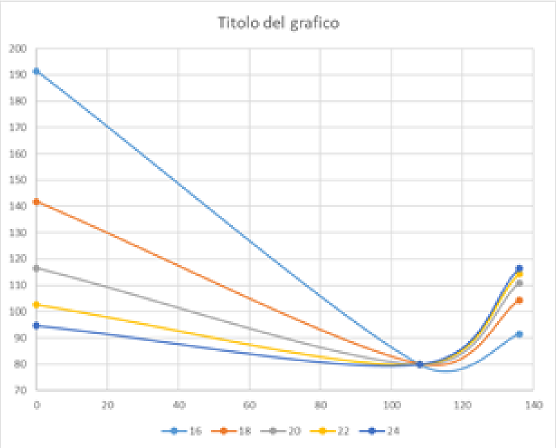

Figure 3: pressure trend from the pipeline inlet to the outlet

According to this value, it is therefore possible to go back, since the minimum outlet pressure of the pipeline had previously been set, to the required inlet pressure for the pipeline (and therefore of fundamental importance for the compression plant).

As previously anticipated, the final choice of the diameter of the two sections under consideration was made according to a technical-economic optimization. With the choice of diameter, we tried to minimize the overall costs of the compression-transport section of the present project.

It must be considered, in fact, that as the diameter increases, there is a decrease in pressure losses and therefore consequently a decrease in pressure drop along the pipeline as well as of the cost of the compression plant, but at the same time the cost of construction of the pipeline increases.

Based on these assessments, and using a series of economic models (which will be shown in the following paragraph) to evaluate the aforementioned costs, the value of the diameter that optimizes this analysis has been reached.

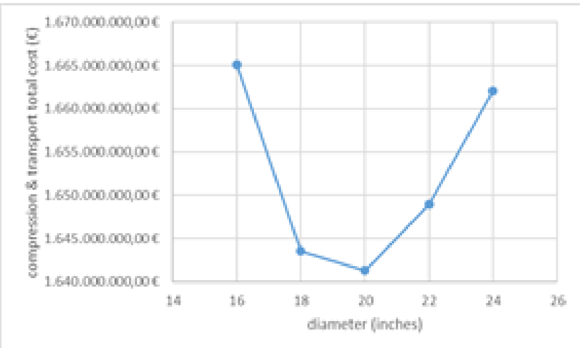

Figure 4: Total investment cost as a function of pipeline's diameter

The analysis of the graphs presented shows that the diameter that optimizes the analysis conducted is that of 20 inches (11.80 Mpa).

B. Investment Costs, Operation and Maintenance Costs, Levelized Costs [8]

The capital costs have been calculated using the IEA GHG PH4/6 model.

Woodhill Engineering developed several pipeline cost equations for the IEA GHG PH4/6 study based on in-house estimates. For onshore pipelines, they give three equations, one for each of three different ANSI piping classes: 600# (P < 90 bar), 900# (P < 140 bar), and 1500# (P < 225 bar).

At the higher pressures likely required for CO_2 transport, the ANSI Class 1500# pipe would be used. The capital cost equation for ANSI Class 1500# pipe is given by the eq. 13:

$$Pipeline\ Capital\ Cost\ (\$) = FL * FT * 10^6 * [(0.057 * L + 1.8663) + ((0.00129 * L) * D) + (0.000486 * L + 0.000007) * D^2] \quad (13)$$

Where:

- F_L = location factor,
- F_T = terrain factor,
- L = pipeline length [km],
- D = pipeline diameter [in],

In our case, we assumed for the location factor the value of 1.0 and for the terrain factor the value of 1.10. Equations for O&M costs were also developed. The O&M cost equation for liquid CO_2 onshore pipelines is given by the eq. 14:

$$Annual\ Pipeline\ O\&M\ Costs\ (\$/yr) = 120{,}000 + 0.61(23{,}213 * D + 899 * L - 259{,}269) + 0.7(39{,}305 * D + 1694 * L - 351{,}355) + 24{,}000 \quad (14)$$

Where:

- D = pipeline diameter [in]
- L = pipeline length [km])

Lastly, the total annual cost and levelized cost are calculated by the eq. 15 and eq. 16:

$$Total\ Annual\ Cost\ \left(\frac{\$}{yr}\right) = (Total\ Capital\ Cost * CRF) + Total\ Annual\ O\&M\ Costs \quad (15)$$

Where:

- CRF = Capital Recovery Factor

$$Levelized\ Cost\ (\$/tonne\ CO2) = Total\ Annual\ Cost\ (\$/yr) / \{ m * CF * 365 \} \quad (16)$$

Where:

- m = CO_2 mass flow rate [tonnes/day]
- CF = plant capacity factor
- 365 = days per year

In order to calculate the real mass flow rate of compressed CO_2, the daily flow rate was multiplied for 365 days, taking into account the plant capacity factor (CF= 91,3%)

Regarding the levelized cost it was considered a capital recovery factor of 0, 15.

Table 9: Pipeline costs

Capital cost	89,604,760.00 €
O&M annual cost	2,285,407.81 €
Total annual cost	15,726,121.81 €
Pipeline levelized cost	2.30 €/tonneCO_2

IV. STORAGE SITE

A. Geophysical Characteristics of the Reservoir

The Fosca 1 well is located offshore, approximately 30 km from the coast, with the drilling beginning from the seabed at a depth of 464 m below sea level.

The well, drilled up to a depth of 2398 meters, has a powerful caprock characterized by a thickens of 521 m above the potential geological CO_2 storage reservoir and has been classified with grade WQF= 4 [9],[10]. The stratigraphic characteristics of the caprock are shown in table 10. Below the caprock, there is a saline aquifer, between 985 m and 1656 m, which includes the "S.Nicola dell'Alto" formation.

This formation is constituted by polygenic conglomerates consisting of crystalline elements of eruptive and metamorphic rocks dispersed in a sandy matrix of silicoclastic quartz-feldspathic nature. This lithology, as widely reported in scientific literature [11], [12], [13] is particularly potentially effective in trapping CO_2 through the "mineral trapping" process. In fact, aquifers in ultramafic rocks (such as eruptive ones), as well as in silico-clastic rocks (such as quartz-feldspathic sandstones) have the greatest potential for CO_2 sequestration [11]. The acidity due to the dissolution of CO_2 in water causes the alteration of silicate minerals whose dissolution is accompanied by the re-precipitation of some components of the mineral, generally as clay minerals [14].

The precipitation of clay minerals increases the waterproofing of the reservoir, preventing the migration of fluids from the saline aquifer and sealing (self-sealing) any ascent pathways (faults and / or fractures). Among the minerals that can precipitate, the "dawsonite" should have an important role [15], [16].

The precipitation of this secondary mineral is favored by the high concentrations of Na^+ in saline aquifers, by the high solubility of CO_2 and by the presence in solution of Al^{3+} generally produced by the dissolution of alum-silicates (e.g. K-feldspar).

Table 10: features of the Fosca 01 well

Fosca 1 well - *offshore*					
Intervallo (m)	Spessore (m)	Formazione	Litologia	Età	Manifestazioni
464-765	301	Santerno's clays	Clays	Lower Pliocene	Caprock
765-879	114	n.d.	Clays	Miocene	
879-985	106	Ponda's clays	Marly Clays	Serravallian - Tortonian	
985-1755	770	S. Nicola dell'Alto sands	Conglomerate Sands		Saline Acquifer 985-1656
1755-2125	370	n.d.	Clays	Langhian - Serravallian	
2125-2398	273	Undifferentiated Allochthonous	Clays	n.d.	

B. Static Gross CO_2 Storage Capacity

In order to know the storage capacity of the injection site, it is first necessary to calculate the volume of the deep structure crossed by the Fosca01 well. In this regard, the geometry of the tectonic structure was reconstructed in detail [17] using all seismic reflection profiles of interest in the area under consideration. In this paper is not discussed this CO_2 storage calculation as a whole. These historical AGIP profiles are located in the UNMIG database on deep wells, drilled for hydrocarbons research, archived together with seismic lines available on the Italian territory. These data as a whole are also accessible in the database of the INGV library in collaboration with the University of Roma Tre (scientific - technology area), during the CCS projects activity managed by Fedora Quattrocchi.

It was performed a gross reconstruction of the deep geological structure, with the interpretation of the available seismic/borehole logs data, reported in the aforementioned database and the relative structural maps (isochronous in double times), drawing the "top" of the deep reservoir, represented by "S.Nicola dell'Alto " Formation, as soundest seat for the drilling of the Well Fosca01.

For the scope of the analysis structural maps extracted from the database of hydrocarbon exploration concessions on Italian territory of the University of Rome 3 Scientific and Technological Area library were used.

The structural maps of interest used refer to the FR9AG marine concession, and are related to the two surfaces of the Lower Pliocene transgression horizon, and the top of the S.Nicola Formation of the Upper Pliocene (top of the potential reservoir).

According the mentioned INGV reports, a CO_2 gross evaluation of the storage volume around the Fosca 01 well, still confidential, could be deepened as a positive solution, despite in this paper is not discussed and simply we are stating that is enough to start a CO_2

sequestration in saline aquifer for the coal power station as discussed here, at least for 20 years.

V. CONCLUSIONS

The aim of this work has been to propose a possible CCS retrofit solution for the Italian power plants fueled by coal for which the CO_2 capture plant should be standard and not discussed here. The power plant under study is the Saline Joniche thermal power plant, which would have been located in the Calabria Region, Italy.

The saline Joniche coal power plant was a project presented by SEI Spa in 2008 with the aim of requalificate the old chemical area abandoned in the region from 1977.

The project consisted in the construction of an ultra-supercritical 1320 MW steam cycle plant composed by two groups of 660MW.

The industrial area chosen would have been located parallel to the Calabrian Ionian coast, bordered to the north by State Road no.106 'Ionica', and to the south by the Reggio Calabria-Metaponto railway line. South of the railway would have been located the port facility. To the south-east of the plant would have been located a state-owned area that would have been used for the construction of the new sea water intake and the desalination and chlorination plants. Also on the state-owned (port) area would have been part of the facilities for the solid materials handling system (including coal, biomass and limestone) and by-products (gypsum and ash).

The work was divided into three sections. In the first section, where a possible compression system associated with the possible future capture system (not object of this study) was proposed, the choice fell on a system composed by 3 trains of 5-stage compressors set in parallel mode necessary to bring the pressure from atmospheric to critical (7.34 Mpa), combined with a pump with the aim of reaching the desired pressure of the CO_2 in the dense phase. For the calculation of the compression costs, the model proposed by McCollum & Odgen "Techno-Economic Models for carbon Dioxide Compression, Transport, and Storage" was used.

In the second section, dedicated to the pipeline necessary to connect the plant to the storage site consisting of the Fosca01 well, the result of the sizing, based on a calculation of head losses associated with a technical-economic analysis for the minimization of the costs of the pipeline, allowed to identify the optimal values for the pipeline diameter, i.e. 20 inches. In this case, the IEA GHG PH4/6 model was used for the economic dimensioning of the pipeline.

In the third and final section, we hint to go ahead with the CO_2 storage site selection, after mentioning preliminary INGV reports, dedicated to a gross analysis of the CO_2 storage selected site, at the site Fosca01 offshore well (located 30 km far from the Calabria Region coast) due to the good geological properties of caprock and reservoir and the presence of preliminary exploration to eventually carry out the injection of CO_2 (following the dictates of Legislative Decree 162/2011 on the geological storage of CO_2). The estimate of the storage capacity for the entire structure, synthesis of INGV studies, was carried out and reported through algorithms for the static calculation of the injectable volume of CO_2, on input databases usually used by oil companies. According the mentioned INGV reports, a CO_2 gross evaluation of the storage volume around the Fosca 01 well, still confidential, could be deepened in future as a positive solution, despite in this paper is not discussed and simply we are stating that is enough to start a CO_2 sequestration in saline aquifer for the coal power station as discussed here, at least for 20 years.

REFERENCES

[1] Charlotte Streck, Paul Keenlyside & Moritz von Unger. (2016). The Paris agreement: A new beginning. *Journal for European Environmental & Planning Law, 13,* 3-28. Available at: https://www.climatefocus.com/sites/default/files/The%20Paris%20Agreement%20A%20New%20Beginning.pdf.

[2] Global CCS Institute. (2017). *The global status of CCS: 2017*. Australia.

[3] Angelo Spena. (2008). Early barriers to be removed for deployment of large scale CO2 capture and storage systems un Europe and foreign countries. *II AIGE National Congress. Pisa, Italy*.

[4] Robert Rapier. (2019). *Fossil fuels still supply 84 percent of world energy — and other eye openers from BP's annual review*. Available at: https://www.forbes.com/sites/rrapier/2020/06/20/bp-review-new-highs-in-global-energy-consumption-and-carbon-emissions-in-2019/?sh=c08844666a16.

[5] Igor Todorović. (2022). *Europe switching on coal plants amid energy crisis*. Available at: https://balkangreenenergynews.com/europe-switching-on-coal-plants-amid-energy-crisis/.

[6] www.cevreadaleti.org/conflict/ilva-of-taranto.

[7] *Ecoter CPA S.r.l. (2012). Progettazione definitiva della nuova centrale termoelettrica a carbone(2x660MWe) a Saline Joniche (RC).* Available at: https://vdocuments.net/a-saline-joniche-rc-repower.html.

[8] McCollum, D. L & Ogden, J. M. (2006). *Techno-economic models for carbon dioxide compression, transport, and storage & correlations for estimating carbon dioxide density and viscosity*. UC Davis: Institute of Transportation Studies. Available at: https://escholarship.org/uc/item/1zg00532.

[9] Moia F., Quattrocchi F., Buttinelli M., Cantucci B., Locatelli G., Procesi M. & Rondena E. (2007). A preliminary evaluation of the CO_2 storage capacity of the Italian geological reservoirs based on the interpretation

e-ISSN: 2250-0758 | p-ISSN: 2394-6962
Volume-12, Issue-3 (June 2022)
https://doi.org/10.31033/ijemr.12.3.11

of deep well data. *Third International Conference on Clean Coal Technologies for our Future. Cagliari, Sardinia, Italy*. DOI: 10.13140/2.1.1464.5124

[10] Quattrocchi, F., Buttinelli, M., Procesi, M., Cantucci, B. & Moia, F. (2008). Development of an Italian Catalogue of potential CO_2 storage sites: an approach from deep wells data. *Geophysical Research Abstracts*, 10, EGU2008-A-09717.2008 SRef-ID: 1607-7962/gra/EGU2008-A-09717.

[11] Gunter W. D., Perkins E. H. & McCann T. J. (1993). Aquifer disposal of CO_2-rich gases: reaction design for added capacity. *Energy Conversion and Management*, *34*, 941-948. DOI: 10.1016/0196-8904(93)90040-H.

[12] Xu, T., Apps, J.A. & Pruess, K. (2004). Numerical simulation of CO_2 disposal by mineral trapping in deep aquifers. *Applied Geochemistry, 19*, 917–936. DOI: 10.1016/j.apgeochem.2003.11.003.

[13] Marini L. (2006). *Geological sequestration of carbon dioxide, thermodynamics, kinetics, and reaction path modeling*. Elsevier. ISBN: 9780444529503.

[14] Ottonello G. (1997). *Atlante degli acquiferi del Comune di Genova*. Pacini Editore.

[15] Johnson J. W., Nitao J. J., Steefel C. I. & Knauss K. G. (2001). Reactive transport modeling of geologic CO_2 sequestration in saline aquifers: the influence of intra-aquifer shales and the relative effectiveness of structural, solubility, and mineral trapping during prograde and retrograde sequestration. *First National Conference on Carbon Sequestration*. *Washington, D.C*, pp. 60.

[16] Johnson J.W., Steefel C.I. & Knauss K.G. (2002). Reactive transport modeling of geologic CO_2 sequestration. *6th Int. Conf. on Greenhouse Gas Control Technologies, Kyoto, Japan, 1*, pp. 327-332. DOI: 10.1016/B978-008044276-1/50053-2.

[17] Fedora Quattrocchi, Buttinelli Mauro, Cantucci Barbara, Anselmi Mario, Cinti Daniele, Galli Gianfranco, Mele Giuliana, Nazzari Manuela, Pizzino Luca & Sciarra Alessandra. (2007). Studio di fattibilità dello stoccaggio geologico di CO_2 nei dintorni del polo energetico di Saline ioniche (RC). *INGV Internal Report. Unpublished*.

NOMENCLTURE

C_{annual}	annualized capital cost, €/yr
C_{comp}	capital cost of compressor(s), €
Clev	levelized capital costs pump&compressors, €/tonne CO_2
C_{pump}	capital cost of pump, €
C_{total}	total capital cost of compressor(s) and pump, €
$C_{O\&M}$	O&M costs, €/tonne CO_2
CF	capacity factor
CRF	capital recovery factor, -/yr
CR	compression ratio of each stage
D	pipeline diameter, inches
E_{annual}	total annual electric power costs of compressor and pump, €/yr
E_{comp}	electric power costs of compressor, €/yr
E_{pump}	electric power costs of pump, €/yr
F_L	location factor
F_T	terrain factor
k_s	average ratio of specific heats of CO_2 for each individual stage
L	pipeline length, km
$O\&M_{annual}$	annual O&M costs, €/yr
$O\&M_{factor}$	O&M cost factor, -/yr
$O\&M_{lev}$	levelized O&M costs, €/tonne CO_2
pe	price of electricity, €/kWh
ΔP	pressure drop in pipeline, MPa
P_{in}	initial pressure, MPa
P_{fi}	final pressure of CO_2, MPa
$P_{cut\text{-}off}$	pressure compression/pumping, MPa
M	molecular weight of CO_2, kg/kmol
m	CO_2 mass flow rate, tonnes/day
N_{stage}	number of compressor stages
m_{train}	CO_2 mass flow rate, kg/s
N_{train}	number of parallel compressor trains
R	gas constant, kJ/kmol-K
T_{in}	CO_2 temperature at compressor inlet, K
v	average flow velocity, m/s
$W_{s,i}$	compression power requirement for each individual stage, kW
$(W_s)_1$	compression power for stage 1, kW
$(W_s)_2$	compression power for stage 2, kW
$(W_s)_3$	compression power for stage 3, kW
$(W_s)_4$	compression power for stage 4, kW
$(W_s)_5$	compression power for stage 5, kW
W_p	pumping power requirement, kW
$W_{s\text{-}total}$	total combined compression power requirement for all stages, kW
Z_s	average CO_2 compressibility for each individual stage

Greek symbols

π	pi
λ	friction factor
ρ	CO_2 density, kg/m^3
η_{is}	isoentropic efficiency
η_p	pump efficiency