Italian Case Study

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Revision History

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1. Introduction

As main part of the Hystories Work Package 8, the objective of the present work is to study the feasibility of implementing large scale storage of green hydrogen in a porous media, hypothetically located in Italy. The economics for the case has been evaluated by employing the joint methodology previously developed in T8.1.

Throughout Europe, there is a potential, significant underground storage capacity (around 113 billion m^3), mostly provided by depleted fields. Given Europe's high energy dependence on fossil fuels from other regions of the world, underground storage is an effective way to increase energy security (with high seasonal variability) and to be able to regulate and control market prices at each moment [1]. Given the current situation in Europe, in terms of energy supply, it is essential to develop robust strategies to achieve net-zero emissions targets, while maintaining security of supply and installed energy capacity.

This section aims to give an overview of the Italian case study and its state of the art on underground storage, in order to fill in the information related to the business cases proposed in the project.

1.1. Storage market: an overview

This section describes a review of the current state of the underground storage market in Italy: the existing Natural Gas storage capacities and who are the main players involved in these activities are described.

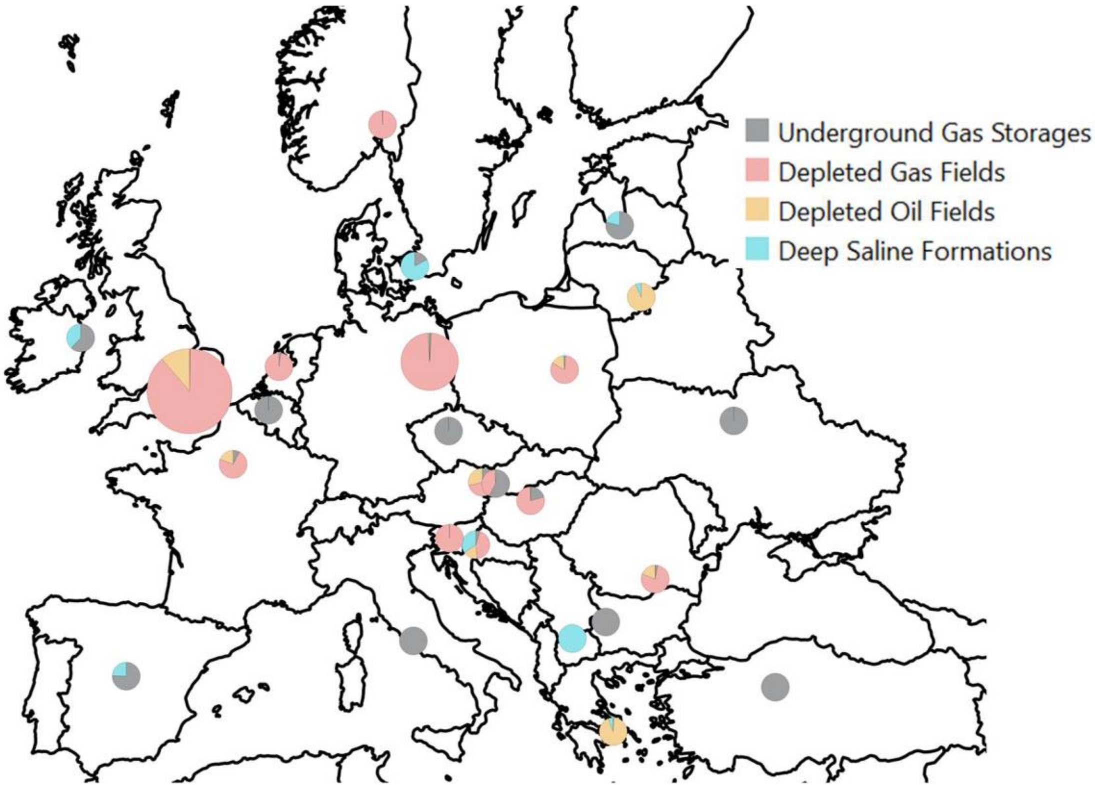


Figure 1 – Storage capacities per country (onshore and offshore). The size of the pie chart is proportional to the country capacity and represents the different categories of porous media storages. Source: D2.2-1

As can be seen in the map shown in Figure 1, taken from the deliverable "*D2.2-1 - 3D multi-realization simulations for fluid flow and mixing issues at European scale*", storage capacities across Europe are different, depending on the considered region. For the Italian case, underground capacities are concentrated in depleted gas/oil wells, known as porous underground storages.

Assuming that all underground natural gas storage in Europe will be transformed into storage, the storage capacities in Italy will be around 123 TWh (as can be seen in Figure 2) —which would correspond to approximately 60% of the overall electric energy consumption on the national territory during 2022 [2]— and can always be expanded with the creation of new wells in saline or porous media.

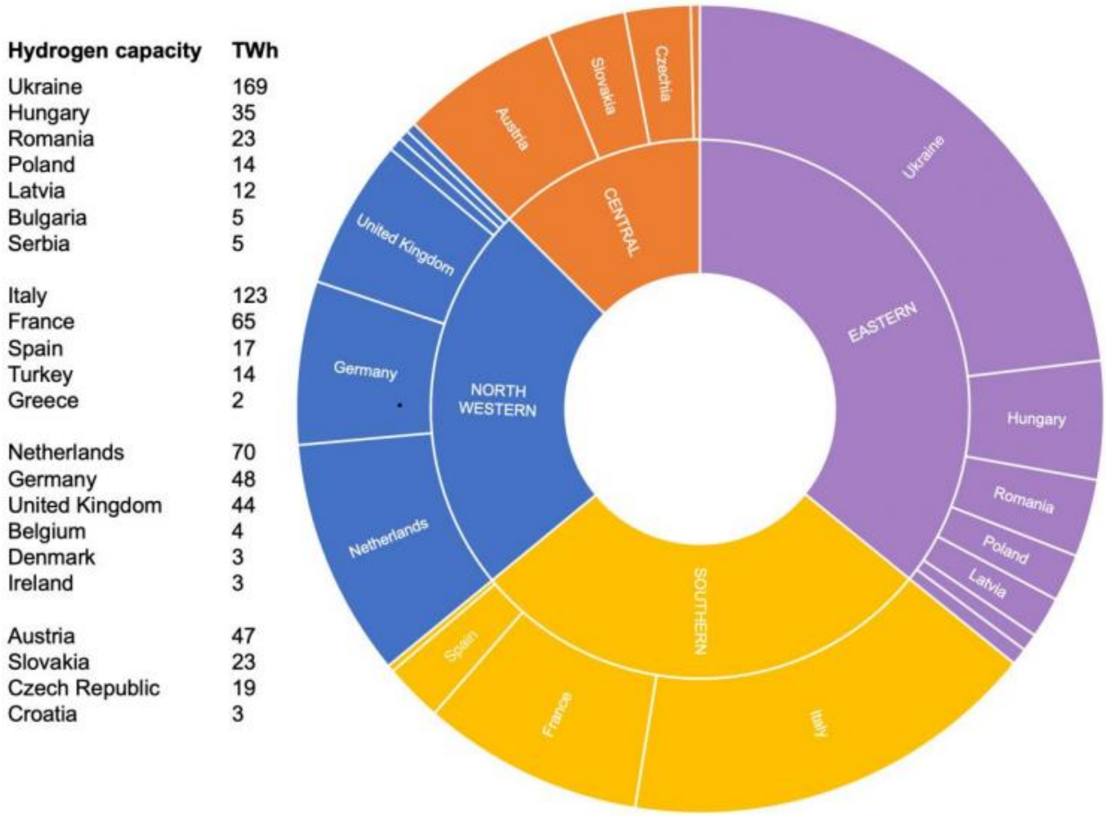


Figure 2 – European hydrogen storage capacity in porous reservoirs for existing natural gas storage by region and country. Source: HyUSPRe

1.1.1. Storage market in Italy: an overview

According to the data gathered from *Gas Infrastructure Europe*, in its biannual report on gas infrastructures, in 2021, Italy had a storage capacity on 19,7% of Natural Gas in Europe [3], behind Germany, making it one of the countries with the largest storage capacity.

In this country, underground storage facilities are former depleted oil or gas wells (see Figure 3), which are currently used as gas reservoirs, and could be potentially reused to store hydrogen in large quantities, in line with the foreseen objectives of the next transition of the European energy system.

Figure 3 – Planned and existing gas infrastructure in Italy 2021

The main players involved in this sector in Italy are the gas companies which manage a number of underground storage facilities, such as:

- **EDISON** (EDFGroup) – It is one of the long-running operating companies in Europe (135 years). Edison, together with Snam and Tenaris are developing projects to decarbonize the steel sector by introducing renewable hydrogen to replace Natural Gas. They own 3 currently active underground Natural Gas storages, Cellino (120 Mm3), Collalto (600 Mm3) and Cotignola & San Potito (400 Mm3), which agglutinates and operating gas volume 10,84 TWh [4].
- **IGS** – Gas Company, in possession of a gas field in Cornegliano, with an operating volume of 1,58 TWh.

- **Snam** – It is the company with the largest operating capacity in Italy. It is the most relevant gas company in the country, with 9 underground natural gas storage facilities in depleted fields, at Bordolano (53,11 MW), Brugherio (19,80 MW), Cortemaggiore (43,88 MW), Fiume Treste (57,40 MW), Minerbio (44,60 MW), Ripalta (46,66 MW), Sabbioncello (22,80 MW), Sergnano (47,00 MW) and Settala (22,80 MW), with a total operating volume of 34,53 TWh.

1.2. Italian storage potential

The underground storage potential that could be available to secure large-scale hydrogen supply for the energy transformation projected for the coming decades. The underground storage capacity in Italy was described in Hystories "D2.2-1 3D multi-realization simulations for fluid flow and mixing issues at European scale" in the annexes section, where both onshore & offshore storage capacities were taken into account.

The current installed capacities in Italy are estimated at approximately 71 TWh in depleted oil and gas fields spread throughout the Italian national territory.

In Italy, underground storage sites are owned, managed, and controlled by the Italian government.

Italy also has a very well-structured natural gas transmission network (see Figure 4), with a total of 6 international interconnection points, which places the country in a relevant position for the energy transition of the entire European Union.

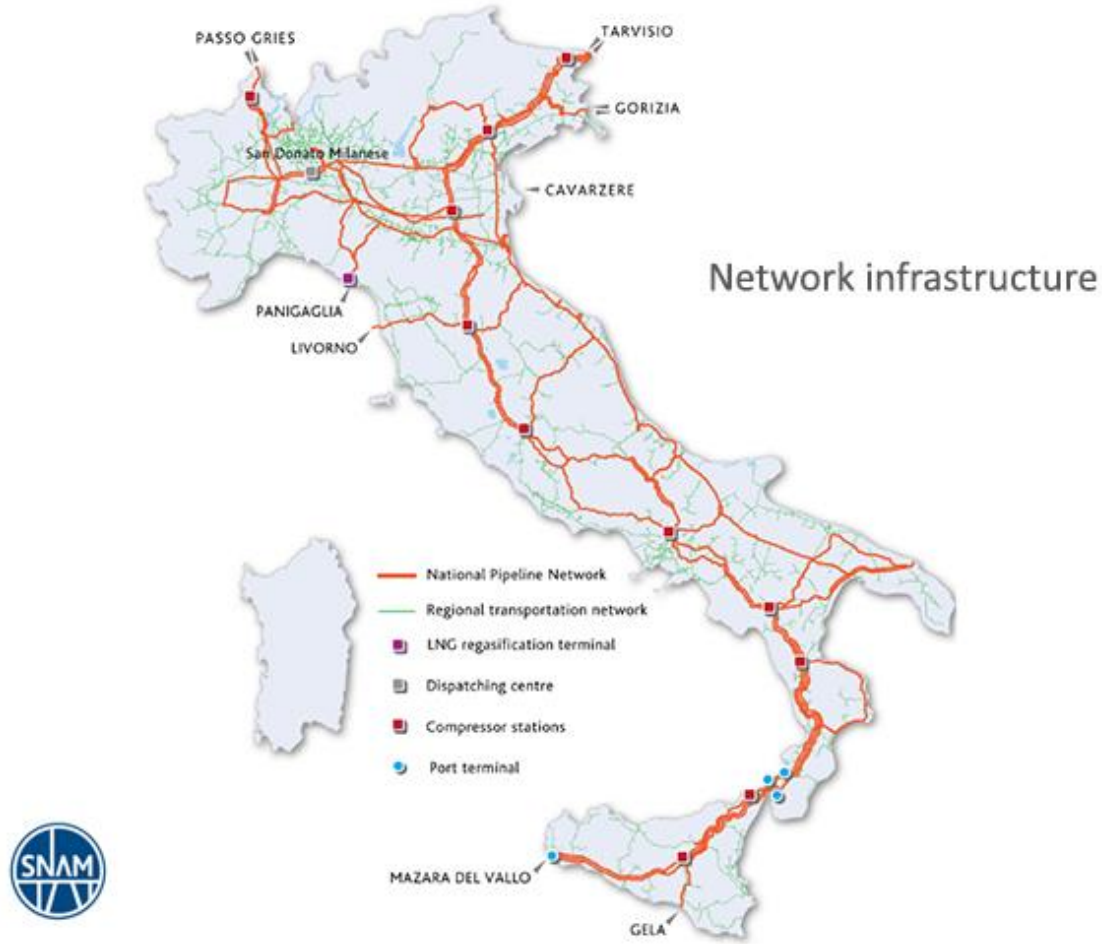


Figure 4 – Natural gas network infrastructure in Italy. Source: ISPI

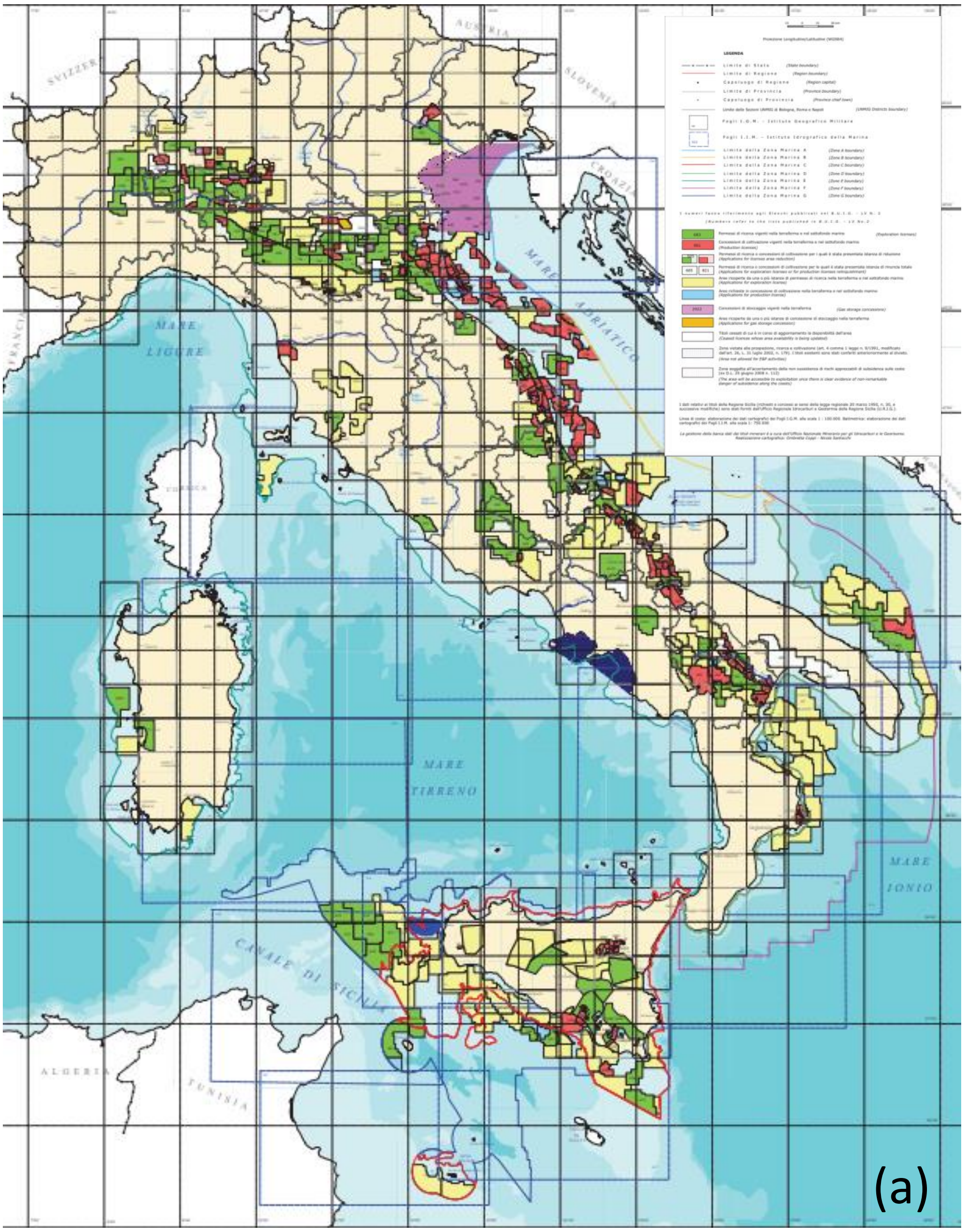
1.3. Italian regulatory framework

Taking as a reference the report "D6.1.1 Assessment of the Regulatory Framework", in Italy the Department for Energy, which is part of the Directorate General for Mineral and Energy Resources, has set itself the task of continuously adapting and managing the legislation necessary to guarantee the proper regulation of storage. However no normative on SHU is currently being drafted.

In Italy, underground storage of natural gas is subjected to the Law on Hydrocarbons and Mining Activities [5]. Thus, the national bodies regulating underground natural gas storage permits are the Ministries of Mining and Environment.

On the other hand, it is considered that Directive 2012/18/EU (SEVESO III) should be adapted for underground hydrogen storage, and it is noted that there are specific rules based on SEVESO III.

Currently, Italy does not have any legislation in place for underground hydrogen storage nor has any underground hydrogen storage gone through a legalization process.



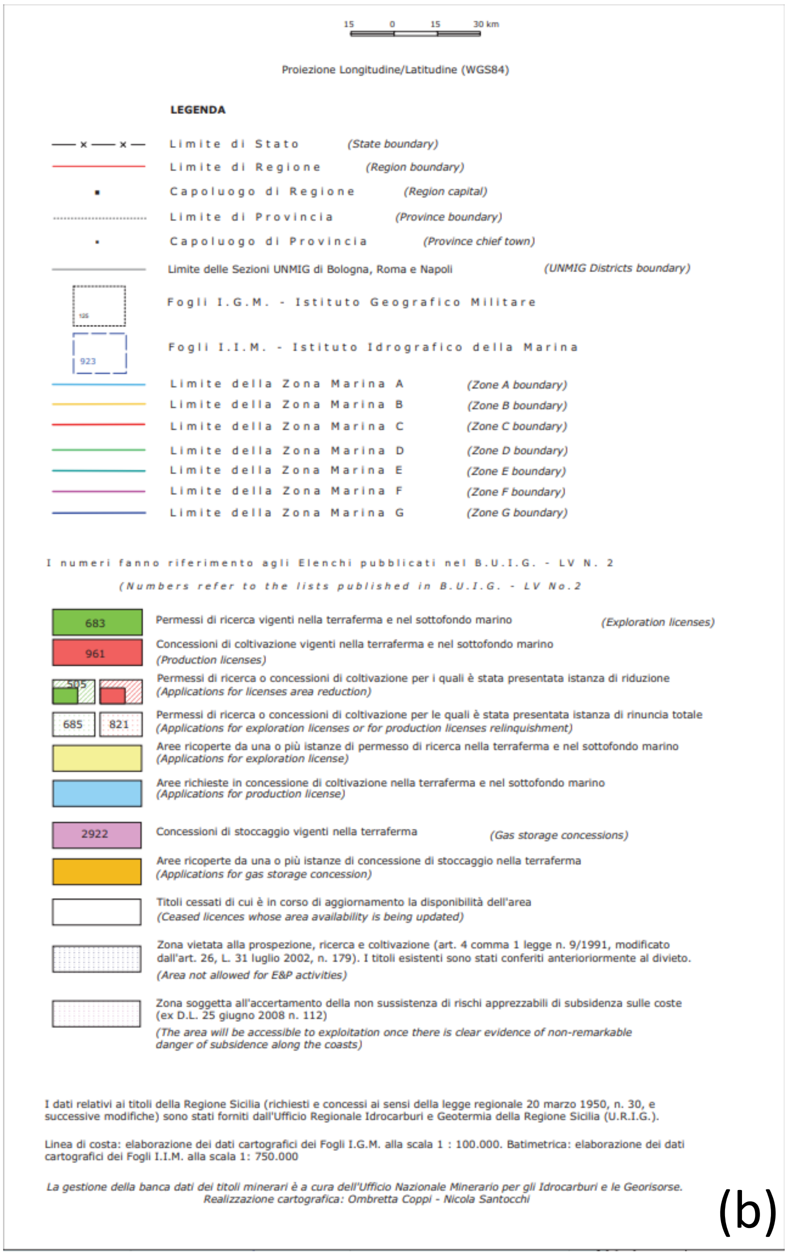


Figure 5 – Map of mining titles for the exploration, cultivation, and storage of hydrocarbons (a) and its respective legend (b). Source: [MISE]

2. Input parameters and main assumptions

The present study aims at giving detailed insights on development and operation of a porous media storage located in Italy. The overall assumptions taken into account in the model are described in this section.

The hypothetical porous media was sized assuming the MID case reported in D7.1 and D7.2, consisting into 25 operation wells and 6 observation wells. The developed business model comprehends an investment phase of 8 years (2022 – 2029) prior to the actual venture period of the case, starting from 2030 and finalizing in 2059. In elaborating the specific business cases for each of the selected EU Member States, several parameters were established for all the case studies, with the objective to create a common reference baseline, facilitating the future cases benchmarking, foreseen in the next T8.3. The baseline scenario is characterized by a null Net Present Value (NPV=0). It was achieved by properly adjusting the storage margin profit (%) applied to H_2 storage cost, which is equal to the levelized cost of storage (LCOS) by initial assumption. Table 1 and Table 2 gather the technical, economic and financial parameters set for the Italian case; the parameters in common with the other Member States business cases are marked in light blue.

Table 1 – Technical parameters of the underground porous media

Parameters	Description	Units	Value
	Geology and subsurface facilities		
V_{max}	Working Gas volume per well	[millions Sm^3]	22,00
V_{CG}	Cushion Gas Volume	[millions m^3]	550,00
$n_{WH,prod}$	Number of development (storage) wells	[nr.]	25
$n_{WH,obs}$	Number of observation wells	[nr.]	6
—	H_2 yearly throughput	[kg/yr.]	48.785.000
LCCS	Last cemented casing shoe	[m]	1200
DC_i	Drilling complexity index	[-]	1
L_{fw}	Fresh water pipeline length	[km]	15
L_{bd}	Brine disposal pipeline length	[km]	30
x_{porous}	Cushion gas/ Total gas ratio	[-]	0,5
V_{wg}	Working Gas volume	[millions Sm^3]	550,00
V_{wg}/Q_w	Storage to withdrawal capacity ratio	[days]	110,00
$Q_{debrining}$	Debrining flowrate per cavern	[m^3/h]	200
N_{fc}	Number of full cycles per year	[cycle/yr.]	1
$N_{fc,MAX}$	Maximum number of full cycles per year	[cycle/yr.]	1,58
d_{FGF}	Total duration of First Gas Fill	[years]	0,9
LF	Load factor	[-]	0,63
	Operating costs and surface facilities		
MCF_i	Material cost factor for injection (compression) stream	[-]	1
MCF_w	Material cost factor for withdrawal stream	[-]	1
Q_w	Total storage maximum withdrawal flowrate capacity	[millions Sm^3/day]	5
τ	Overall compression ratio (ratio of discharging pressure over suction pressure)	[-]	2,34
n	Number of required compression stages	[nr.]	1
WTIR	Withdrawal to injection capacity ratio	[-]	1,1
netOP	Minimum suction pressure of compression stream (pipeline operating pressure)	[barg]	55
MOP	Maximum storage operating pressure	[barg]	130
minOP	Minimum storage operating pressure	[barg]	60
L_{fl}	Field lines size	[km]	2
K_{purif}	Purification coefficient (Only for porous media)	[-]	1,5
COE	Cost of Electricity [€/MWh]	[€/MWh]	66

Table 2 – Economic and financial parameters adopted for the business case

Parameters	Units	Value
H_2 production cost	[€/kg]	6,29 [6]
H_2 cushion gas	[€/kg]	6,29 (same as H_2 prod. cost by assumption)
Other costs	[€/kg]	1,89 (30% of hydrogen prod. cost by assumption)
Subsidy	[€]	20.000.000,00
Venture period	[years]	30
Residual value	[%]	20
Storage cost	[€/kg]	3,76
Corporate tax	[%]	25
Financing fund	[€]	0
Interests	[%]	5
Financing duration	[years]	30
Rate of return (Discount rate)	[%]	5,75
Storage service margin profit	[%]	22,98

Additionally, Table 3 lists the parameters of the underground storage sizing model that have been detected as sensitive in the model. Their impact on the economics of the case scenario have been deeply analyzed through sensitivity analysis.

Table 3 – Sensitive parameters considered for the business case analysis.

Sensitive parameters	
A	Cost of Electricity
B	Storage Service Margin Profit
C	Number of Cycles
D	Corporate Tax
E	Number of Depleted Wells
F	Discount Rate

Finally, the energy model assumed for the Italian case is described as scenario "D" in the report "*D5.1 -Scenario definition for modelling of the European energy system*":

- **Scenario D** is characterized by considering all underground storage methodologies (salt caverns, depleted wells, aquifers, and widely installed surface storage facilities in Europe). It also considers a higher amount of hydrogen imports and a lower amount of hydrogen production than the other estimated cases.

The main criteria considered to design these scenarios were the different hydrogen production routes, available hydrogen storage technologies and geographical locations across Europe. Figure 6 shows a summary of the different cases considered in a summarized and comparative way.

	Scenario A	Scenario B	Scenario C	Scenario D
General assumptions				
GHG emission reduction targets (for EU-27 from 1990 levels)	(2025: -37.5%) | 2030: -55% | 2040: -78.5% | 2050: -100%			
Hydrogen demand	Identical for all scenarios to ensure comparability			
Scenario differentiation				
Hydrogen production pathways: Domestic vs. imports from non-EU v	**Mainly domestic,** limited imports	**Mainly domestic,** limited imports	Moderate domestic, **larger imports**	Moderate domestic **larger imports**
Hydrogen storage technologies: Salt caverns, porous media and aboveground technologies	**Salt caverns,** aboveground technologies	**Salt caverns, porous media,** aboveground technologies	**Salt caverns,** aboveground technologies	**Salt caverns, porous media,** aboveground technologies
Spatial distribution across Europe: Centralized/distributed H_2 production and storage	**Centralized storage** (where possible), distributed H_2 production	**Distributed** H_2 production and storage	**Centralized storage** (hubs in central Europe), distributed H_2 production	**Distributed** H_2 production and storage

Figure 6 - Selected scenarios for modelling od the European energy system.

3. Results

In this section, a detailed description of a business case for a porous media in Italy is given, comprehending the corresponding site costs breakdown and a sensitivity analysis, aiming at optimizing the business economic feasibility.

3.1. Site costs breakdown

Table 4 shows a well-detailed breakdown for all the expenditures related to the subsurface operations. The cost for the cushion gas resulted to be the most relevant among others, reaching 294.057.500 €, followed in order by the EPC costs for drilling (158.484.000 €), contingencies (91.357.275 €), and first gas fill costs (4.244.876 €). The resulting overall CAPEX for subsurface operations, obtained as the sum of the above-mentioned specific costs, resulted to be 548.143.652 €. The economic relevance of each specific cost related to the subsurface is expressed in percentage of the overall subsurface CAPEX and given in Figure 7. According to what explained above, the highest costs share of 53% belonged to the cushion gas, while development drilling cost and contingencies reached 29% and 17%, respectively, over the global costs distribution.

Table 4 - Overall CAPEX breakdown for subsurface operations

	CAPEX – subsurface	
Costs breakdown	Description	Value
EPC_3	First Gas Fill (FGF) costs	4.244.876 €
EPC_4	Development Drilling cost breakdown and main parameters	158.484.000 €
CG	Cushion gas for porous medias	294.057.500 €
$CONT_{subsurface}$	Contingencies related to subsurface	91.357.275 €
Total		**548.143.652 €**

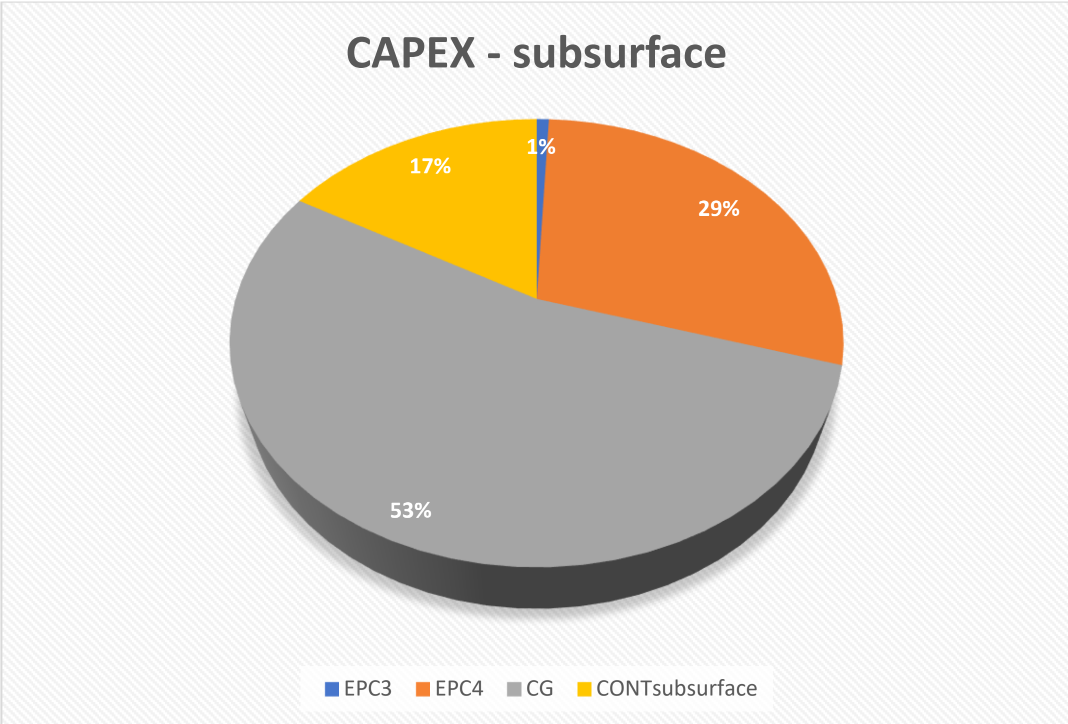


Figure 7 - Percent distribution of CAPEX – subsurface costs.

Concerning the CAPEX for surface facilities and operations, the largest expenditure belonged to hydrogen purification, with a cost of 181.472.445 € out of 505.141.801 € (see Table 5), corresponding to the largest share among all the surface specific costs analyzed (36%, see Figure 8). The expenditures for filtering, drying, compression and metering units resulted to be the second, most expensive (119.914.890 €), followed by the costs of wellhead – gas plant interconnections (86.706.364 €), contingencies (84.190.300 €), cost for balance of plant (27.664.357 €), and additional cost per kilometer between the reservoir wellhead and the gas plant (5.193.442 €).

Table 5 - Overall CAPEX breakdown for surface facilities and operations.

	CAPEX – surface	
Costs breakdown	Description	Value
EPC_1	EPC cost main parameters and breakdown for filtering, drying & compression, and metering units	119.914.890 €
EPC_2	EPC costs for interconnection WH - Gas Plant	86.706.364 €
EPC_3	EPC cost per additional kilometer between Gas Plant and nearest WH	5.193.442 €
EPC_4	EPC cost estimate for hydrogen purification at storage outlet	181.472.445 €
EPC_5	EPC cost main parameters and cost breakdown for Balance of Plant	27.664.357 €

$CONT_{surface}$	Contingencies related to surface facilities	84.190.300 €
Total		**505.141.801 €**

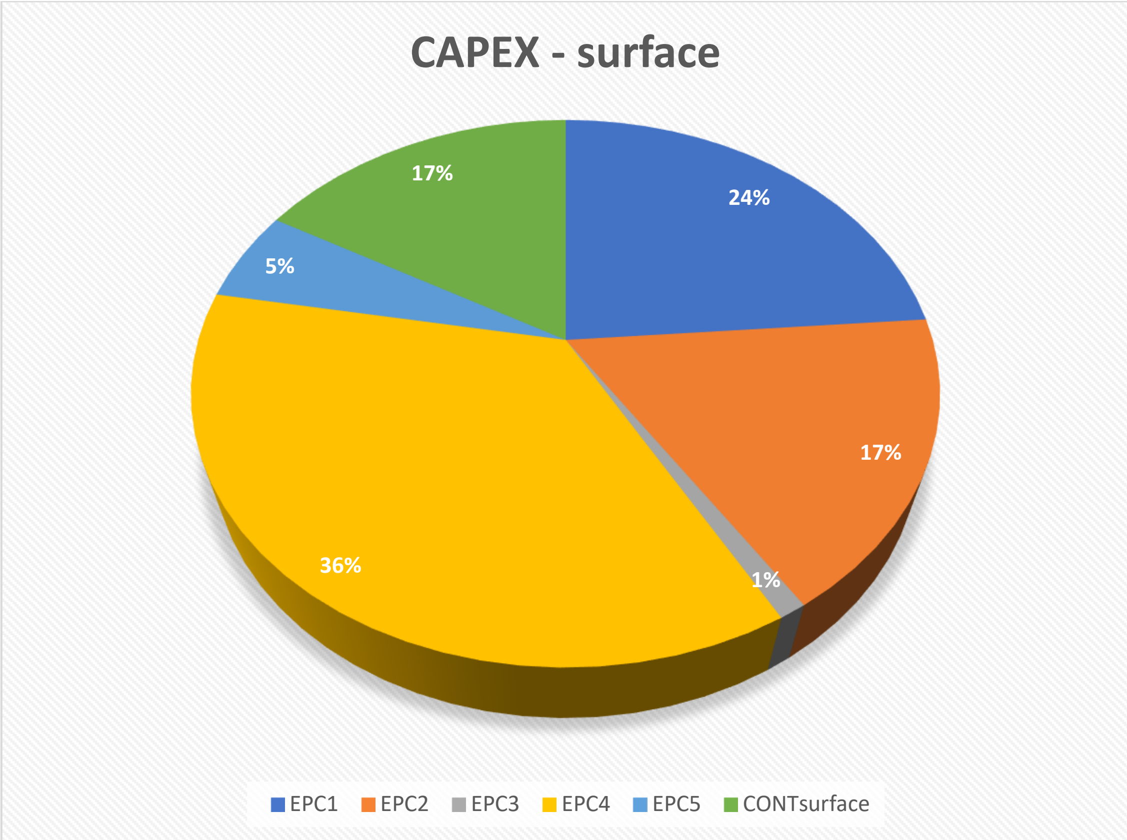


Figure 8 – Percent distribution of CAPEX – surface costs.

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Keeping in mind the main assumption of a constant yearly OPEX over the entire period of the site operation, the global expenditure corresponded to 30.253.822 €, accounting with subsurface operations (4.754.520 €) as well as fixed (18.938.060 €) and variable (6.561.242 €) costs annexed to the surface operations. The corresponding shares for each individual cost are visible in Figure 9.

Table 6 – Overall OPEX breakdown for subsurface and surface (fixed and variable) operations.

	OPEX	
Costs breakdown	Description	Value
$OPEX_{fix, UG}$	OPEX - Subsurface	4.754.520 €
$OPEX_{fix, AG}$	Fixed OPEX - Surface	18.938.060 €
$OPEX_{var, AG}$	Variable OPEX - Surface	6.561.242 €
Total		**30.253.822 €**

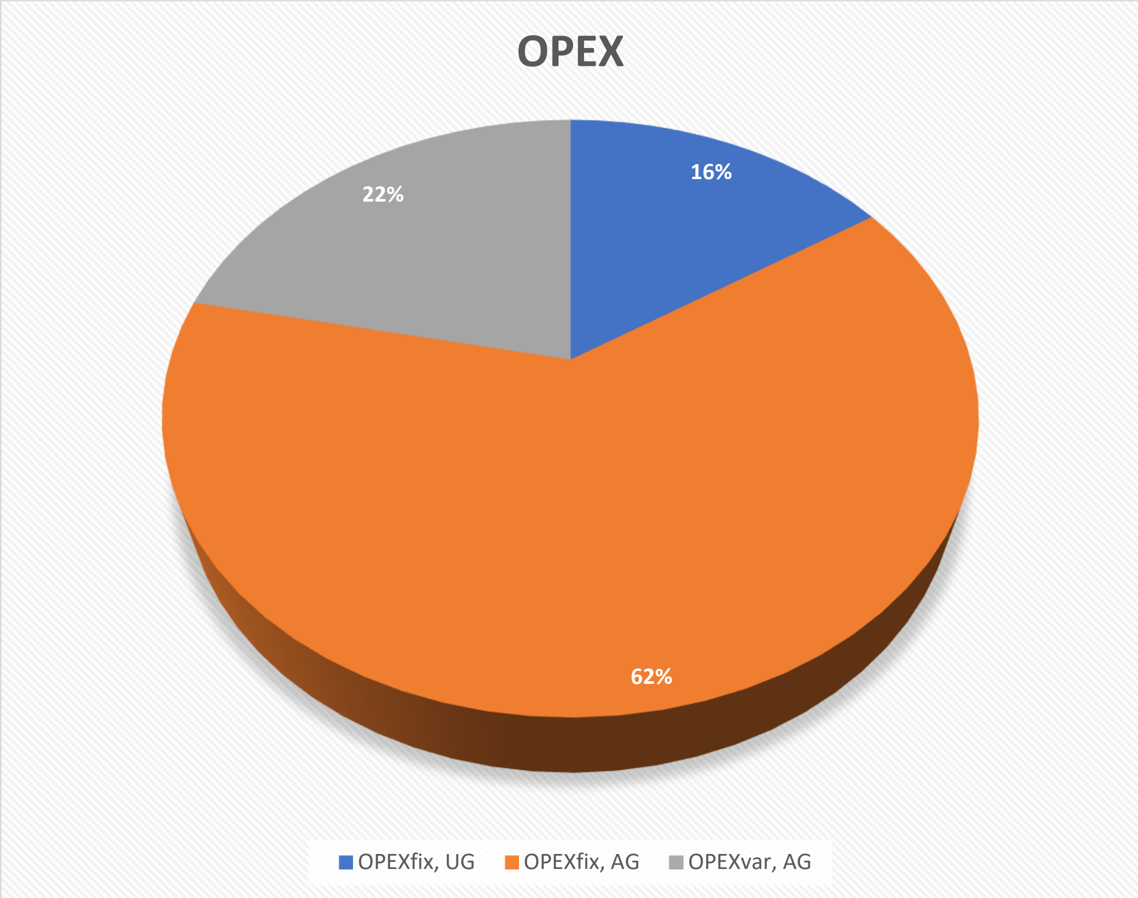

Figure 9 – Percent distribution of OPEX costs.

Finally, the ABEX for facilities and equipment amounted to 150.996.615 €, distributed between 49.968.255 € for the abandonment expenditure for subsurface (33% of the overall ABEX, see Figure 10), and 101.028.360 € for the abandonment expenditure for surface facilities (67% of the overall ABEX, see Figure 10).

Table 7 – Overall ABEX breakdown for subsurface and surface facilities.

	ABEX	
Costs breakdown	Description	Value
$ABEX_{subsurface}$	Abandonment Expenditure for subsurface	49.968.255 €
$ABEX_{surface}$	Abandonment Expenditure for surface facilities	101.028.360 €
Total		**150.996.615 €**

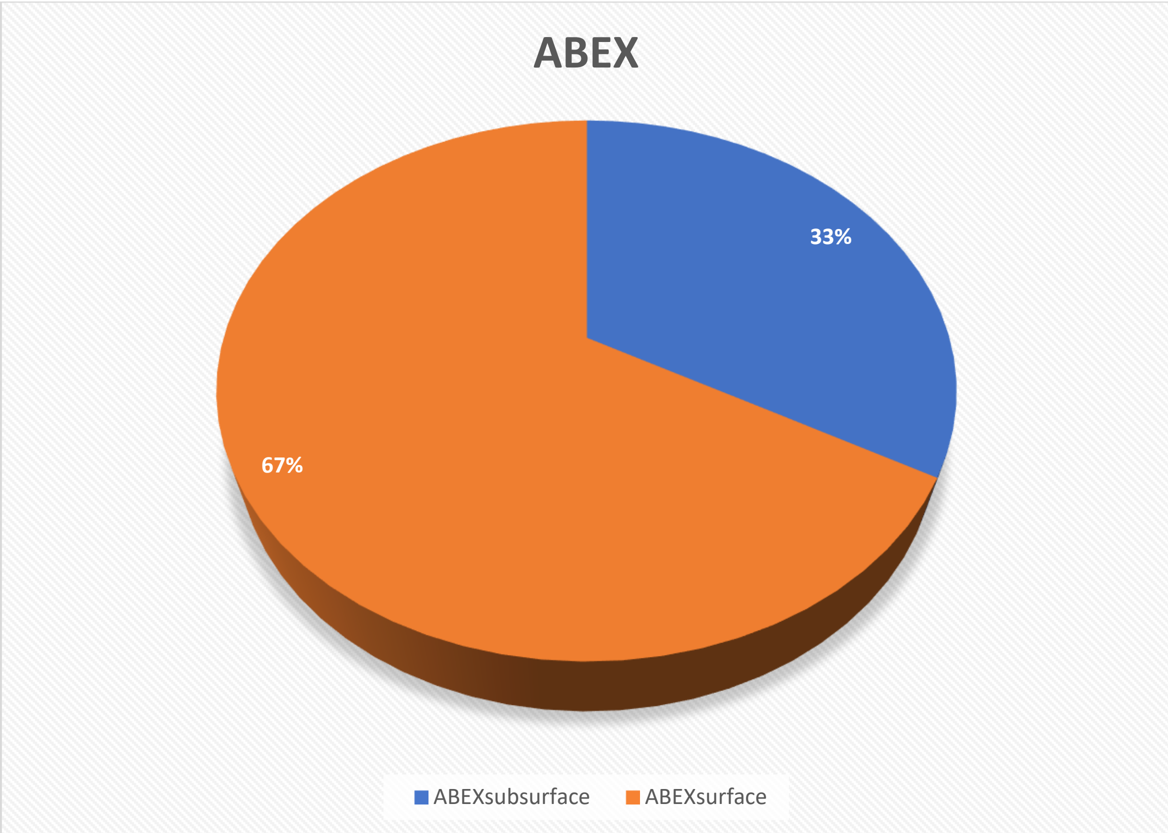

Figure 10 – Percent distribution of ABEX costs.

3.2. Cash flow analysis

In order to assess the economic feasibility of the geological storage of H_2 in the porous media, a number of financial KPIs were identified and taken into account (see Table 8): Net Present Value (NPV), Internal Rate of Return (IRR), Net Present Cost (NPC) and Levelized Cost of Storage (LCOS), defined as reported in D7.3 as well as in D8.1. At this point, it is important to remind that the baseline scenario described in this section was built to present the economic break-even conditions for the business case under investigation. Afterwards, it was used as starting point for the foreseen optimization study.

To achieve the null NPV for the baseline scenario, a storage service margin profit of 22,98% was applied on the LCOS (i.e., the storage cost), obtaining a quite high final H_2 storage service price of 4,63 €/kgH_2. Keeping in mind this and the assumptions made for H_2 production cost (6,29 €/kgH_2) as well as other costs (1,89 €/kgH_2), the resulting minimum hydrogen selling price would be 13,73 €/kgH_2. According to the null NPV condition, the IRR resulted to be equal to the discount rate chosen for the case (i.e., 5,75%). On the other hand, the NPC amounted to 1.660.379.874 €. The LCOS results are predicated on a series of assumptions; as such, the LCOS estimates are cycle-specific and may differ in alternative case studies where the number of cycles is optimized. In a broader context, LCOS exhibits a highly case-specific nature, as factors such as asset reutilization and meticulous site selection have the potential to substantially reduce costs, thereby altering the project's economic dynamics.

Looking at the trend provided in Figure 11, from 2022 to 2028, the cumulative net cash flow remained consistently negative, with values ranging from –170.180.800 € to –865.503.401 €, before reaching a negative peak of –2.086.570.906 € in 2029, according to the initial assumption of no revenues during the investment period. Starting from 2030 (i.e., venture period beginning), the net cash flow became less negative and started to improve. It gradually increased each year, indicating a positive trend. The values continued to rise from 2040 to 2059, moving from –283.400.709 € to 2.316.307.132 €.

Table 8 – Financial KPIs of the business case.

Finance		
Parameter	Description	Value
NPV	Net Present Value	0 €
IRR	Internal Rate of Return	5,75%
NPC	Net Present Cost	1.660.379.874 €
LCOS	Levelized Cost of Storage	3,76 €/kgH_2
—	Storage service margin profit	22,98%
—	H_2 storage service price	4,63 €/kgH_2

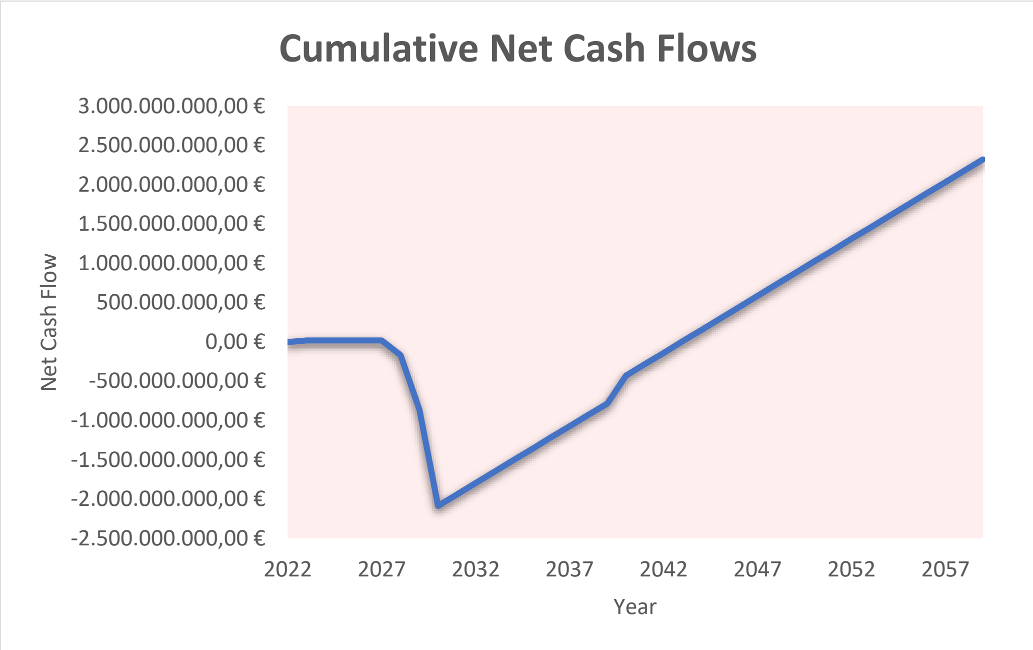

Figure 11 – Net Cash Flow trend along the investment years and the venture period.

3.3. Business case optimization

Starting from the findings obtained for the economic break-even of the baseline case, an unreplicated 2-level full factorial design with a center point [7] was adopted to evaluate the effects of the sensitive parameters listed in Table 3 (i.e., cost of electricity, storage service margin profit, number of cycles, corporate tax, number of wells, discount rate) — even considering the interaction effects among them (if any) — on the response variables chosen for the study: NPV, IRR, NPC and LCOS. The value ranges selected for the sensitive parameters are given in Table 9. As a result, a full set of 65 potential scenarios was generated and carefully analyzed. The structure of the regression model (using normalized values for factors in the range from –1 to 1, including 0 as center point of the factorial design) used during statistical analysis for the response variables was as follows:

$$\hat{y} = \beta_0 + \beta_1 A + \beta_2 B + \beta_3 C + \beta_4 D + \beta_5 E + \beta_6 F + \beta_{12} A \cdot B + \beta_{13} A \cdot C + \beta_{14} A \cdot D + \beta_{15} A \cdot E + \beta_{16} A \cdot F + \beta_{23} B \cdot C + \beta_{24} B \cdot D + \beta_{25} B \cdot E + \beta_{26} B \cdot F + \beta_{34} C \cdot D + \beta_{35} C \cdot E + \beta_{36} C \cdot F + \beta_{45} D \cdot E + \beta_{46} D \cdot F + \beta_{56} E \cdot F$$

where A, B, C, D, E and F are the response variables (see Table3), while β_0, β_i and β_{ij} are the intercept, linear, and 2-way interaction coefficients, respectively. All the statistical calculations were conducted using Minitab software (v17). The estimated regression coefficients and the adjusted coefficients of determination (R^2_{adj}) were taken as indicators of the goodness of regression models. This section covers the results obtained from the optimization of the business case studied here. The numerical results of the different scenarios generated are reported in Table 10.

Table 9 – Ranges of values selected for the sensitive parameters.

Parameter	–1	0	1
Cost of Electricity	33 €/MWh	66 €/MWh	99 €/MWh
Storage Service Margin Profit	5,75%	32,87%	60%
Number of Cycles	0,5	1	1,5
Corporate Tax	12,5%	25%	37,5%
Number of Operation Wells	12	25	37
Discount Rate	2,8%	5,75%	8,6%

Table 10 – Case scenarios obtained through the optimization study. The scenarios with a positive NPV are marked in bold.

Electricity	Storage profitability	Number of cycles	Corporate tax	Number of caverns	Discount rate	NPV (€)	IRR (%)	NPC (€)	LCOS (€/kgH2)	CAPEX - subsurface (€)	CAPEX - surface (€)	OPEX (€)	ABEX (€)
33 €/MWh	5,75%	0,5	12,5%	37	8,6%	-41.833.034 €	8,36%	1.792.873.560 €	9,02 €	800.263.377 €	557.581.810 €	29.911.600 €	183.511.007 €
99 €/MWh	5,75%	0,5	12,5%	12	2,8%	-9.284.069 €	2,74%	1.556.053.289 €	8,24 €	275.013.949 €	448.331.791 €	21.947.320 €	115.772.689 €
99 €/MWh	**60%**	**1,5**	**37,5%**	**37**	**2,8%**	**489.641.027 €**	**3,99%**	**3.830.132.872 €**	**2,19 €**	**798.567.759 €**	**909.512.414 €**	**61.063.898 €**	**253.840.608 €**
99 €/MWh	5,75%	1,5	37,5%	12	2,8%	-337.900.465 €	0,39%	1.632.250.184 €	2,88 €	275.013.949 €	448.331.791 €	26.671.414 €	115.772.689 €
99 €/MWh	5,75%	0,5	37,5%	12	8,6%	-239.456.550 €	5,53%	963.146.954 €	14,95 €	275.013.949 €	448.331.791 €	21.947.320 €	115.772.689 €
33 €/MWh	**60%**	**0,5**	**37,5%**	**37**	**2,8%**	**305.925.560 €**	**3,51%**	**2.806.944.419 €**	**4,62 €**	**800.263.377 €**	**557.581.810 €**	**29.911.600 €**	**183.511.007 €**
33 €/MWh	5,75%	1,5	12,5%	12	8,6%	-12.133.192 €	8,46%	963.146.954 €	4,98 €	275.013.949 €	448.331.791 €	21.947.320 €	115.772.689 €
99 €/MWh	**60%**	**1,5**	**12,5%**	**12**	**2,8%**	**769.358.346 €**	**6,80%**	**1.632.250.184 €**	**2,88 €**	**275.013.949 €**	**448.331.791 €**	**26.671.414 €**	**115.772.689 €**
33 €/MWh	**60%**	**0,5**	**12,5%**	**12**	**2,8%**	**716.020.519 €**	**6,56%**	**1.530.654.324 €**	**8,11 €**	**275.013.949 €**	**448.331.791 €**	**20.372.622 €**	**115.772.689 €**
99 €/MWh	5,75%	0,5	12,5%	37	2,8%	-22.676.743 €	2,73%	2.836.454.502 €	4,87 €	800.263.377 €	557.581.810 €	34.766.919 €	183.511.007 €
99 €/MWh	5,75%	1,5	12,5%	37	8,6%	-50.214.241 €	8,34%	2.342.015.645 €	3,93 €	798.567.759 €	909.512.414 €	61.063.898 €	253.840.608 €
99 €/MWh	5,75%	0,5	37,5%	37	2,8%	-635.013.569 €	0,51%	2.836.454.502 €	4,87 €	800.263.377 €	557.581.810 €	34.766.919 €	183.511.007 €
33 €/MWh	5,75%	1,5	37,5%	37	2,8%	-817.456.570 €	0,39%	3.595.192.446 €	2,06 €	798.567.759 €	909.512.414 €	46.497.939 €	253.840.608 €
33 €/MWh	**60%**	**1,5**	**37,5%**	**12**	**2,8%**	**186.960.526 €**	**3,91%**	**1.556.053.289 €**	**2,75 €**	**275.013.949 €**	**448.331.791 €**	**21.947.320 €**	**115.772.689 €**
99 €/MWh	**60%**	**1,5**	**12,5%**	**37**	**8,6%**	**1.061.511.310 €**	**13,02%**	**2.342.015.645 €**	**3,93 €**	**798.567.759 €**	**909.512.414 €**	**61.063.898 €**	**253.840.608 €**
33 €/MWh	5,75%	1,5	37,5%	12	2,8%	-340.638.791 €	0,37%	1.556.053.289 €	2,75 €	275.013.949 €	448.331.791 €	21.947.320 €	115.772.689 €
33 €/MWh	**60%**	**0,5**	**37,5%**	**12**	**8,6%**	**83.860.255 €**	**9,55%**	**954.479.732 €**	**14,81 €**	**275.013.949 €**	**448.331.791 €**	**20.372.622 €**	**115.772.689 €**
99 €/MWh	5,75%	1,5	37,5%	37	8,6%	-589.474.214 €	5,50%	2.342.015.645 €	3,93 €	798.567.759 €	909.512.414 €	61.063.898 €	253.840.608 €
99 €/MWh	**60%**	**0,5**	**12,5%**	**37**	**2,8%**	**1.323.752.752 €**	**6,32%**	**2.836.454.502 €**	**4,87 €**	**800.263.377 €**	**557.581.810 €**	**34.766.919 €**	**183.511.007 €**
33 €/MWh	**60%**	**1,5**	**37,5%**	**37**	**8,6%**	**174.551.038 €**	**9,41%**	**2.261.843.839 €**	**3,79 €**	**798.567.759 €**	**909.512.414 €**	**46.497.939 €**	**253.840.608 €**
99 €/MWh	**60%**	**0,5**	**12,5%**	**12**	**8,6%**	**445.060.627 €**	**13,17%**	**963.146.954 €**	**14,95 €**	**275.013.949 €**	**448.331.791 €**	**21.947.320 €**	**115.772.689 €**
99 €/MWh	**60%**	**1,5**	**12,5%**	**12**	**8,6%**	**458.711.502 €**	**13,29%**	**989.148.621 €**	**5,12 €**	**275.013.949 €**	**448.331.791 €**	**26.671.414 €**	**115.772.689 €**
99 €/MWh	**60%**	**0,5**	**37,5%**	**12**	**8,6%**	**87.110.463 €**	**9,59%**	**963.146.954 €**	**14,95 €**	**275.013.949 €**	**448.331.791 €**	**21.947.320 €**	**115.772.689 €**
33 €/MWh	5,75%	0,5	12,5%	37	2,8%	-26.616.890 €	2,72%	2.758.141.026 €	4,74 €	800.263.377 €	557.581.810 €	29.911.600 €	183.511.007 €
99 €/MWh	5,75%	0,5	12,5%	12	8,6%	-12.133.192 €	8,46%	963.146.954 €	14,95 €	275.013.949 €	448.331.791 €	21.947.320 €	115.772.689 €

33 €/MWh	5,75%	1,5	12,5%	37	8,6%	-54.247.885 €	8,34%	2.261.843.839 €	3,79 €	798.567.759 €	909.512.414 €	46.497.939 €	253.840.608 €
99 €/MWh	5,75%	0,5	12,5%	37	8,6%	-40.488.486 €	8,37%	1.819.597.496 €	9,16 €	800.263.377 €	557.581.810 €	34.766.919 €	183.511.007 €
99 €/MWh	60%	0,5	12,5%	37	8,6%	823.251.700 €	12,72%	1.819.597.496 €	9,16 €	800.263.377 €	557.581.810 €	34.766.919 €	183.511.007 €
33 €/MWh	60%	1,5	12,5%	12	2,8%	729.354.976 €	6,62%	1.556.053.289 €	2,75 €	275.013.949 €	448.331.791 €	21.947.320 €	115.772.689 €
99 €/MWh	5,75%	1,5	12,5%	12	2,8%	-5.450.413 €	2,77%	1.632.250.184 €	2,88 €	275.013.949 €	448.331.791 €	26.671.414 €	115.772.689 €
33 €/MWh	5,75%	0,5	37,5%	12	2,8%	-341.551.567 €	0,36%	1.530.654.324 €	8,11 €	275.013.949 €	448.331.791 €	20.372.622 €	115.772.689 €
99 €/MWh	5,75%	0,5	37,5%	12	2,8%	-340.638.791 €	0,37%	1.556.053.289 €	8,24 €	275.013.949 €	448.331.791 €	21.947.320 €	115.772.689 €
99 €/MWh	5,75%	1,5	12,5%	12	8,6%	-10.824.983 €	8,47%	989.148.621 €	5,12 €	275.013.949 €	448.331.791 €	26.671.414 €	115.772.689 €
99 €/MWh	60%	1,5	37,5%	12	2,8%	215.534.362 €	4,07%	1.632.250.184 €	2,88 €	275.013.949 €	448.331.791 €	26.671.414 €	115.772.689 €
99 €/MWh	5,75%	1,5	37,5%	37	2,8%	-809.013.399 €	0,42%	3.830.132.872 €	2,19 €	798.567.759 €	909.512.414 €	61.063.898 €	253.840.608 €
33 €/MWh	60%	1,5	12,5%	37	2,8%	1.664.176.027 €	6,41%	3.595.192.446 €	2,06 €	798.567.759 €	909.512.414 €	46.497.939 €	253.840.608 €
99 €/MWh	60%	0,5	37,5%	37	8,6%	142.350.977 €	9,39%	1.819.597.496 €	9,16 €	800.263.377 €	557.581.810 €	34.766.919 €	183.511.007 €
33 €/MWh	5,75%	0,5	37,5%	37	8,6%	-475.566.689 €	5,59%	1.792.873.560 €	9,02 €	800.263.377 €	557.581.810 €	29.911.600 €	183.511.007 €
33 €/MWh	60%	0,5	12,5%	37	8,6%	809.221.634 €	12,65%	1.792.873.560 €	9,02 €	800.263.377 €	557.581.810 €	29.911.600 €	183.511.007 €
33 €/MWh	60%	0,5	37,5%	37	8,6%	132.329.502 €	9,34%	1.792.873.560 €	9,02 €	800.263.377 €	557.581.810 €	29.911.600 €	183.511.007 €
33 €/MWh	60%	1,5	12,5%	12	8,6%	445.060.627 €	13,17%	963.146.954 €	4,98 €	275.013.949 €	448.331.791 €	21.947.320 €	115.772.689 €
33 €/MWh	5,75%	0,5	12,5%	12	2,8%	-10.561.955 €	2,73%	1.530.654.324 €	8,11 €	275.013.949 €	448.331.791 €	20.372.622 €	115.772.689 €
33 €/MWh	5,75%	1,5	37,5%	37	8,6%	-592.355.388 €	5,49%	2.261.843.839 €	3,79 €	798.567.759 €	909.512.414 €	46.497.939 €	253.840.608 €
99 €/MWh	5,75%	0,5	37,5%	37	8,6%	-474.606.298 €	5,59%	1.819.597.496 €	9,16 €	800.263.377 €	557.581.810 €	34.766.919 €	183.511.007 €
33 €/MWh	60%	1,5	37,5%	37	2,8%	-592.355.388 €	5,49%	2.261.843.839 €	3,79 €	798.567.759 €	909.512.414 €	46.497.939 €	253.840.608 €
99 €/MWh	60%	1,5	12,5%	37	2,8%	1.787.519.750 €	6,64%	3.830.132.872 €	2,19 €	798.567.759 €	909.512.414 €	61.063.898 €	253.840.608 €
99 €/MWh	60%	0,5	12,5%	12	2,8%	729.354.976 €	6,62%	1.556.053.289 €	8,24 €	275.013.949 €	448.331.791 €	21.947.320 €	115.772.689 €
33 €/MWh	5,75%	0,5	37,5%	12	8,6%	-239.768.028 €	5,52%	954.479.732 €	14,81 €	275.013.949 €	448.331.791 €	20.372.622 €	115.772.689 €
99 €/MWh	60%	1,5	37,5%	12	8,6%	96.861.088 €	9,69%	989.148.621 €	5,12 €	275.013.949 €	448.331.791 €	26.671.414 €	115.772.689 €
33 €/MWh	5,75%	1,5	12,5%	37	2,8%	-42.416.887 €	2,69%	3.595.192.446 €	2,06 €	798.567.759 €	909.512.414 €	46.497.939 €	253.840.608 €
99 €/MWh	5,75%	1,5	12,5%	37	2,8%	-30.596.447 €	2,72%	3.830.132.872 €	2,19 €	798.567.759 €	909.512.414 €	61.063.898 €	253.840.608 €
33 €/MWh	60%	0,5	37,5%	12	2,8%	177.435.914 €	3,85%	1.530.654.324 €	8,11 €	275.013.949 €	448.331.791 €	20.372.622 €	115.772.689 €
33 €/MWh	60%	0,5	12,5%	37	2,8%	1.282.638.178 €	6,23%	2.758.141.026 €	4,74 €	800.263.377 €	557.581.810 €	29.911.600 €	183.511.007 €

33 €/MWh	**60%**	**1,5**	**37,5%**	**12**	**8,6%**	**87.110.463 €**	**9,59%**	**963.146.954 €**	**4,98 €**	**275.013.949 €**	**448.331.791 €**	**21.947.320 €**	**115.772.689 €**
33 €/MWh	5,75%	0,5	12,5%	12	8,6%	-12.569.262 €	8,45%	954.479.732 €	14,81 €	275.013.949 €	448.331.791 €	20.372.622 €	115.772.689 €
33 €/MWh	5,75%	1,5	12,5%	12	2,8%	-9.284.069 €	2,74%	1.556.053.289 €	2,75 €	275.013.949 €	448.331.791 €	21.947.320 €	115.772.689 €
33 €/MWh	5,75%	1,5	37,5%	12	8,6%	-239.456.550 €	5,53%	963.146.954 €	4,98 €	275.013.949 €	448.331.791 €	21.947.320 €	115.772.689 €
33 €/MWh	5,75%	0,5	37,5%	37	2,8%	-475.566.689 €	5,59%	1.792.873.560 €	9,02 €	800.263.377 €	557.581.810 €	29.911.600 €	183.511.007 €
33 €/MWh	**60%**	**0,5**	**12,5%**	**12**	**8,6%**	**440.510.336 €**	**13,13%**	**954.479.732 €**	**14,81 €**	**275.013.949 €**	**448.331.791 €**	**20.372.622 €**	**115.772.689 €**
33 €/MWh	**60%**	**1,5**	**12,5%**	**37**	**8,6%**	**1.019.421.112 €**	**12,86%**	**2.261.843.839 €**	**3,79 €**	**798.567.759 €**	**909.512.414 €**	**46.497.939 €**	**253.840.608 €**
99 €/MWh	5,75%	1,5	37,5%	12	8,6%	-238.522.115 €	5,54%	989.148.621 €	5,12 €	275.013.949 €	448.331.791 €	26.671.414 €	115.772.689 €
99 €/MWh	**60%**	**0,5**	**37,5%**	**37**	**2,8%**	**326.721.784 €**	**3,78%**	**2.836.454.502 €**	**4,87 €**	**800.263.377 €**	**557.581.810 €**	**34.766.919 €**	**183.511.007 €**
99 €/MWh	**60%**	**0,5**	**37,5%**	**12**	**2,8%**	**186.960.526 €**	**3,91%**	**1.556.053.289 €**	**8,24 €**	**275.013.949 €**	**448.331.791 €**	**21.947.320 €**	**115.772.689 €**
66 €/MWh	**32,87%**	**1**	**25%**	**25**	**5,75%**	**137.210.188 €**	**6,50%**	**1.745.709.339 €**	**3,96 €**	**548.143.652 €**	**505.141.801 €**	**30.253.822 €**	**150.996.615 €**
99 €/MWh	**60%**	**1,5**	**37,5%**	**37**	**8,6%**	**204.615.465 €**	**9,54%**	**2.342.015.645 €**	**3,93 €**	**798.567.759 €**	**909.512.414 €**	**61.063.898 €**	**253.840.608 €**
R^2_{adj}						*91,83%*	*96,71%*	*93,72%*	*97,14%*	–	–	–	–

Figure 12 shows the impact of the sensitive parameters on NPV of the case. According to this normal plot of standardized effects, the storage service margin profit resulted to be the most influencing factor which positively affected the business case NPV, ranging between a minimum of –817.456.570 € and a maximum of 1.787.519.750 € among all the proposed scenarios. Another detected significant and positive effect worth to mention was due to an interaction between the storage margin profit and number of wells. In other words, an increase of both the mentioned factors led to a greater NPV, probably justified to the higher revenues resulting from the higher amount of H_2 eventually stored in the geological site. On the other hand, NPV markedly decreased when the applied corporate tax augmented. Furthermore, higher discount rates also contributed to reduce the NPV, accordingly to the financial model adopted: raising the discount rate made the business case progressively harder to be economically feasible. Eventually, among all the sensitive parameters considered in the present work, the choice of a proper margin profit for the provided storage service appeared to be crucial in order to achieve a positive NPV for the business case.

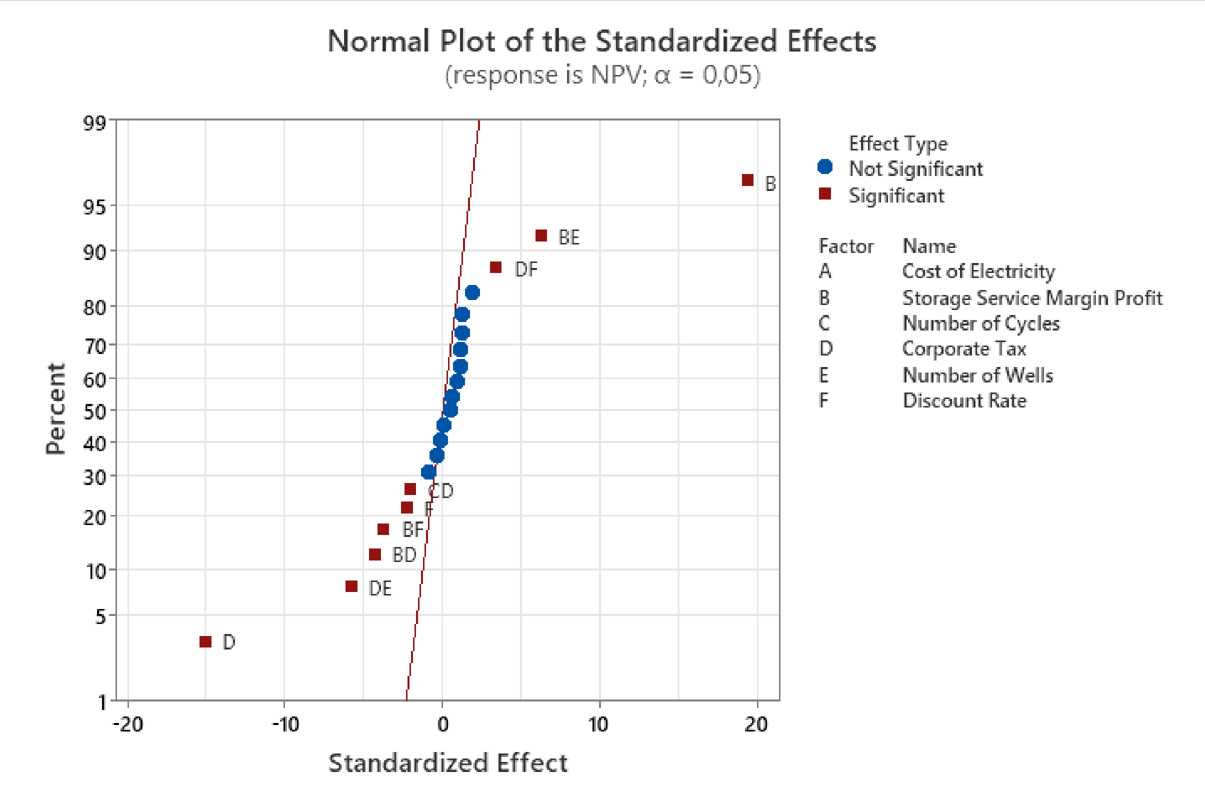

Figure 12 – Normal plot of standardized effects for NPV (square, significant effect; circle, non-significant effect).

As expected, the discount rate also showed a key influence on the IRR, since increasing the former it is possible to achieve higher values of the latter. It is also important to mention the significant effect of both the storage service margin profit and corporate tax: while the first one improved the final IRR, the second one negatively affected it. The overall range of IRR values was comprised between 0,36% and 13,29%.

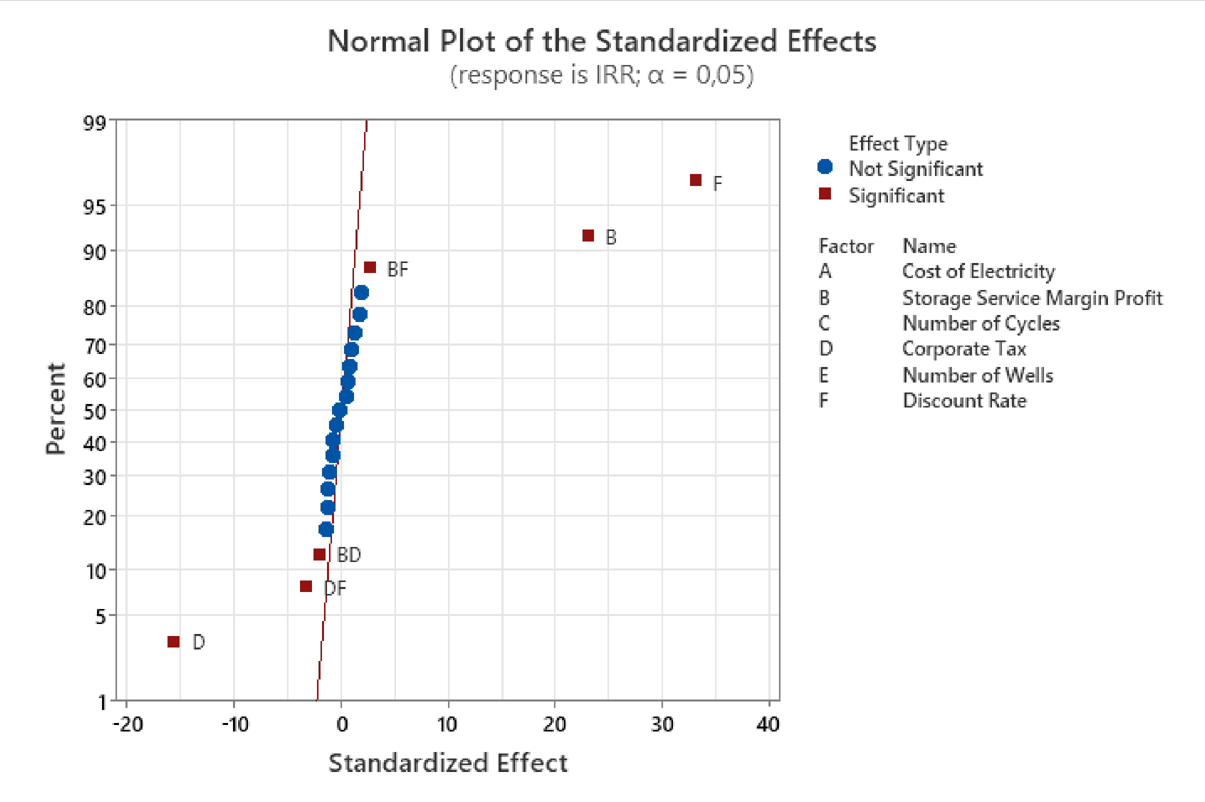

Figure 13 – Normal plot of standardized effects for IRR (square, significant effect; circle, non-significant effect).

The number of wells had a significant impact on the CAPEX of the geological site, which was reflected on a higher NPC (see Figure 14). Both number of cycles and cost of electricity also contributed to increase the overall NPC of the facilities, while the discount rate resulted to reduce it. It is worth to highlight that the resulting NPCs obtained for all the scenarios of the business case studied in the present sensitivity analysis were visibly higher if compared to the other EU Member States salt cavern-based business cases. In detail, the NPC for the Italian business case ranged between 954.479.732 € and 3.830.132.872 €.

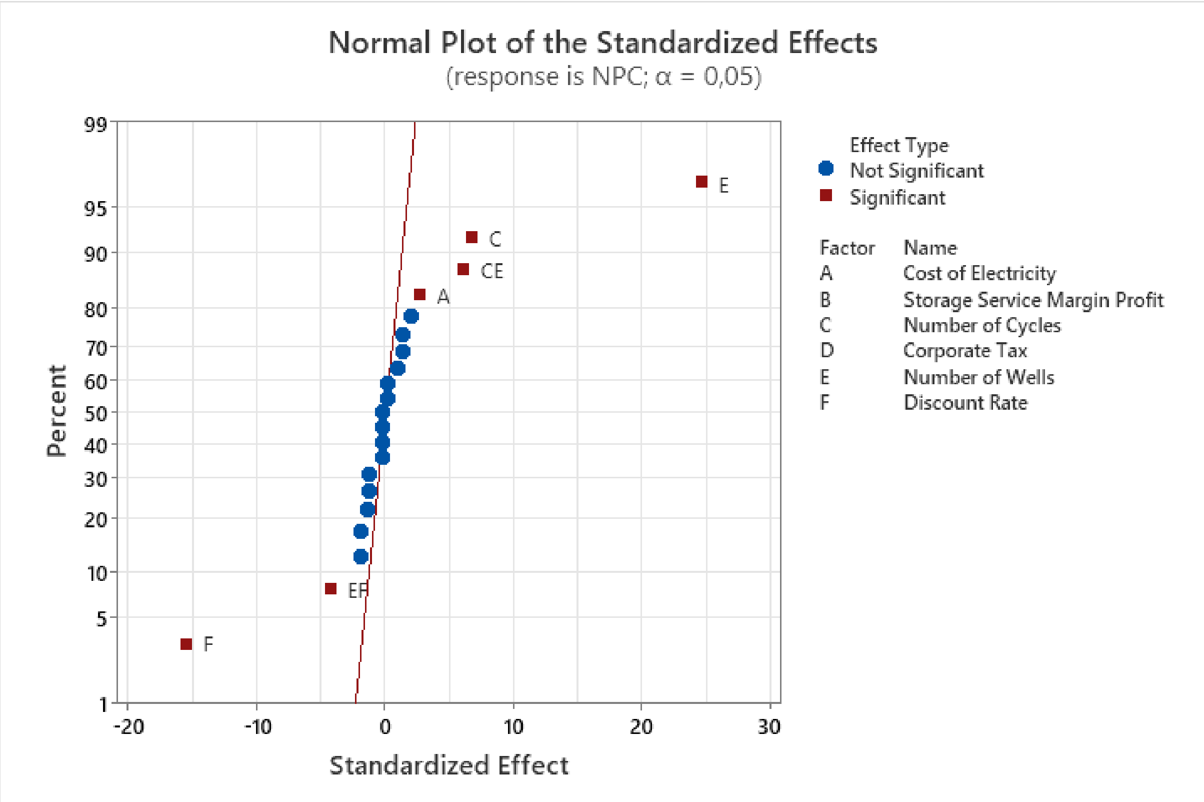

Figure 14 – Normal plot of standardized effects for NPC (square, significant effect; circle, non-significant effect).

Figure 15 shows the normal plot of standardized effects of the sensitive parameters on LCOS. At this point, it is important to keep in mind that LCOS is calculated as the ratio between NPC and the sum of the H_2 yearly throughputs discounted on the entire period of business (i.e., investment phase + venture period). As it is visible in Figure 15, higher discount rates led to higher LCOS; On the other hand, LCOS was markedly reduced by both number of cycles and number of wells, as a consequence of a larger H_2 throughput processed per year, which directly influenced the LCOS denominator, as explained above. Finally, a wide range of LCOS comprised between 2,06 €/kgH_2 and 14,95 €/kgH_2 resulted from the optimization study. It is not banal to note that a given case scenario with a positive NPV is not necessarily economically feasible. In this sense, ensuring a proper LCOS is crucial to make a business case profitable. Indeed, looking at Table 10, a large number of scenarios showed a positive NPV. Nevertheless, they might result inviable for a real business case, due to high LCOS not compatible with the upstream H_2 production cost.

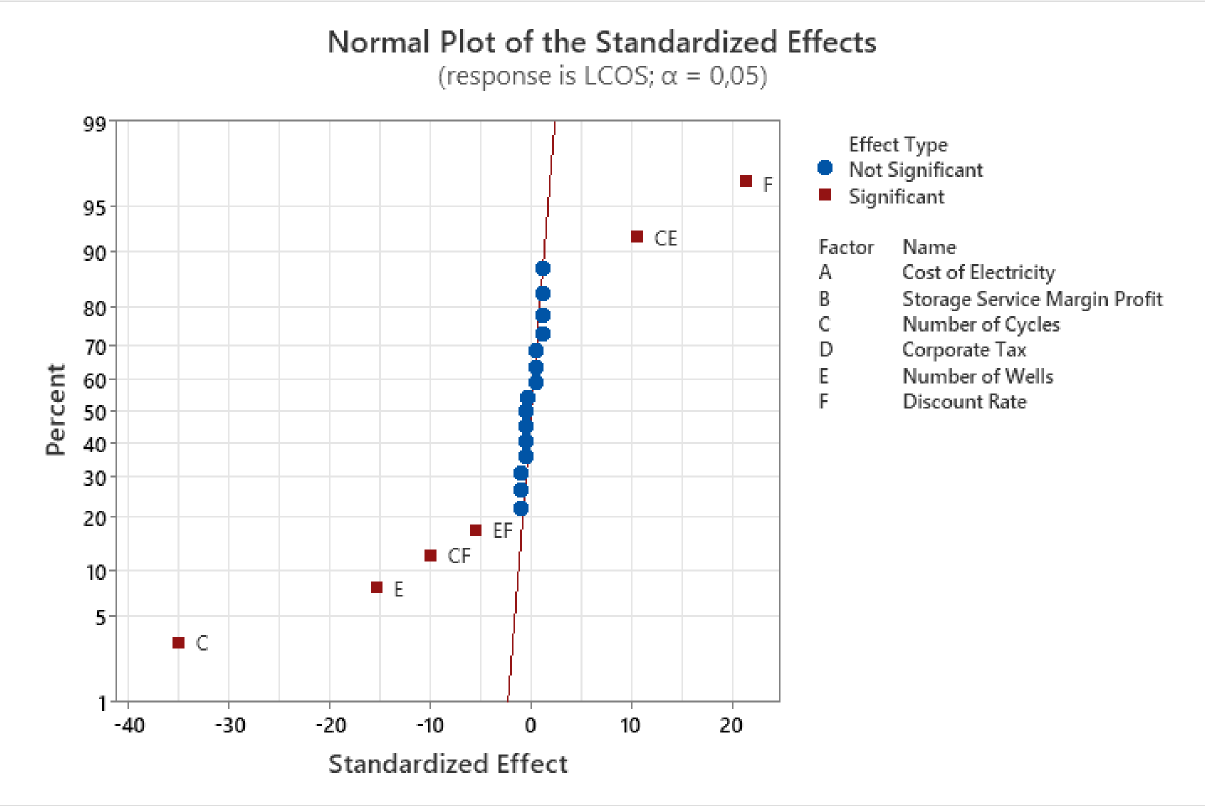

Figure 15 – Normal plot of standardized effects for LCOS (square, significant effect; circle, non-significant effect).

4. Conclusions

Despite the fact that there is not a unique combination in the set of the sensitive parameters capable to make the business case present in this work economically feasible, some useful considerations can be drawn from the results above discussed:

- The Internal Rate of Return (IRR) was strongly affected by the discount rate and the storage service margin profit, as well as negatively influenced by higher corporate taxes.
- A higher number of wells led to an increase in the resulting Net Present Cost (NPC) of the presented scenarios, reaching a maximum at 3.830.132.872 €.
- The Levelized Cost of Storage (LCOS) was visibly reduced by both number of cycles and number of wells, as a consequence of a larger H_2 throughput processed per year.
- Ensuring a positive NPV together with a proper LCOS (to be summed to a previous H_2 production cost and resulting in reasonable H_2 selling price) is crucial to accomplish the economic feasibility for a given scenario.

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Hystories project consortium

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