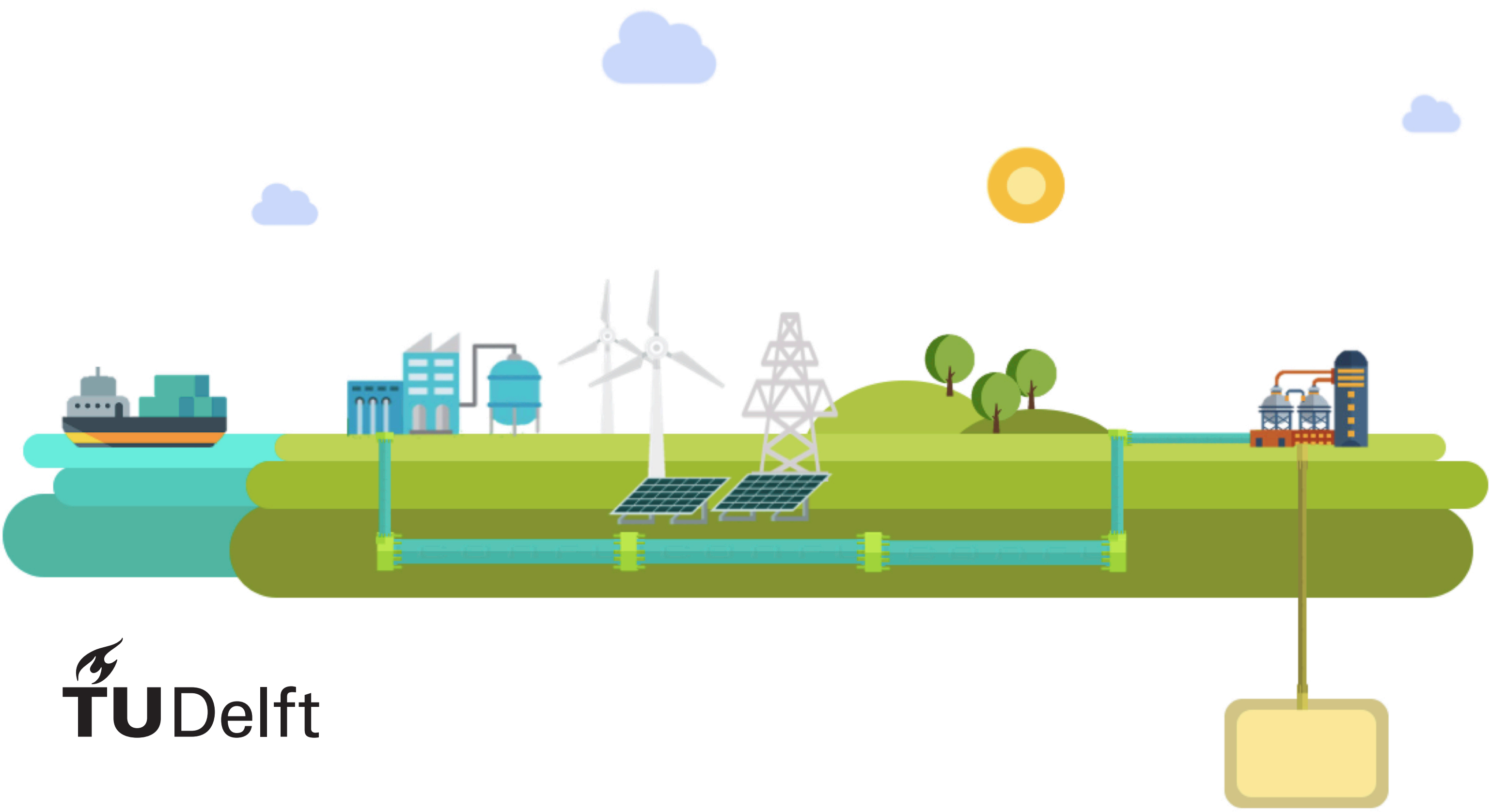
Sines H_2 Hub

a cost perspective of the transmission & storage infrastructure of the Sines green hydrogen hub

Pedro Quintela de Saldanha



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by

Pedro Quintela de Saldanha

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at the Delft University of Technology,
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Preface

Over these past years, my experience at TU Delft has been truly extraordinary. This thesis marks the end of that period and the beginning of my professional career. It has been a chapter in my life characterized by profound academic and personal growth that I will always cherish. I will remember Delft as the place where I had every resource needed to succeed and be the best version of myself. Supportive, balanced, inclusive, innovative and sustainable - more than qualities easily found at the university, these were the values that I adhered to and stand by.

In a graduation support session, I had a conversation with my academic counsellor to help me guide on which thesis path to follow. To my surprise, she noted the excitement in my eyes whenever I talked about pursuing this *Sines* H_2 *Hub* option. As a soon to be engineer, those are not the aspects usually considered when assessing where you are planning to dedicate your next 8 months. But I thought about the point she made and then came to the conclusion on why this project has such impact on me: it combines 3 topics that I am passionate about. 1 Green hydrogen - the innovative and needed solution to the future of sustainability. 2 Economics - a subject I have always been fascinated by. And 3 Portugal - my home country which I am very attached to.

The COVID-19 pandemic sure had it's impact. On the one hand, my life was restrained to an absolute minimum of social interactions during the entire duration of this work, thus, I had the space to fully focus on the project - a positive externality of the pandemic. On the other hand, that came at a costly price for resilience and motivation. Luckily, being surrounded by highly knowledgeable and captivating people kept me engaged. Prof. dr. A. J. M. van Wijk was one of those people. My sincere gratitude for guiding me all these months with so much patience. This gratitude extends to the other members of the Committee, whose feedback improved this research. Furthermore, I am also very grateful to Marc Rechter for sharing his vision and providing me with crucial data to conduct this research. A special thanks to my parents and all my loved ones who kept me motivated and pushing that extra mile whom without this work would not be possible. Let us enjoy together with those same excited eyes, this chapter that now starts.

Pedro Quintela de Saldanha
Madrid, April 2021

Abstract

The *Sines H_2 Hub* aims to take advantage of Portugal's solar resources and push for a green hydrogen hub centred in Sines. To do so, a 1GW electrolyser is expected to be built by 2030. The gas produced, which will have the same production profile as the solar irradiance, can be injected in the gas grid, distributed by truck or shipped to the Netherlands. Due to hydrogen's high volumetric energy density, ammonia is considered a suitable energy carrier for the shipping option. However, ammonia production requires a stable hydrogen supply - which is not compatible with a profile dependant on solar irradiance. To face this issue, a technological option that stands out is using the existing Carriço salt caverns, located 280km north of Sines and connected by pipeline, as a buffer to store the hydrogen during the day and supply it back to Sines at night. This research aims to calculate the levelized cost of hydrogen transmission by pipeline from Sines to Carriço, storage in the Carriço salt caverns and transmission back to Sines. Based on the stabilized hydrogen production, a model is developed and 4 pathways are considered for each of the possible infrastructure combinations: new or retrofitted transmission and new or retrofitted storage. Dependant on the infrastructure selected, the cost model developed found a total levelized cost of hydrogen transmission and storage of: 0.17-0.25 [$€ \cdot kg_{H_2}^{-1}$]. By considering a competitive green hydrogen production cost of 1-1.5[$€ \cdot kg_{H_2}^{-1}$], the transmission & storage costs along with the rest of the direct hydrogen supply, will translate into an added 10% expense - on top of production - to provide a stable hydrogen supply to the ammonia plant. The result, which is aligned with literature, is expected to provide solid input in assessing hydrogen's price competitiveness and contribute to the decision process of using retrofitted or new infrastructure.

Keywords: Green hydrogen, Cost analysis, Sines hub, Salt caverns storage, Pipeline transmission

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Nomenclature

List of abbreviations

Symbol	**Description**
$CAES$	Compressed Air Energy Storage
CET	Central European Time
$DGEG$	Directorate General for Energy and Geology
GHG	Green House Gas
$IPCEI$	Important Project of Common European Interest
LNG	Liquified Natural Gas
$LOHC$	Liquid Organic Hydrogen Carrier
$NECP$	National Energy and Climate Plan
REN	Rede Electrica Nacional
ROW	Right of Way
$TPES$	Total Primary Energy Supply
TSO	Transmission and System Operator
UGS	UnderGround Storage
$WACC$	Weighted Average Cost of Capital

List of Greek symbols

Symbol	**Description**	**Units**
η	Isentropic efficiency	$[-]$
γ	Gas specific gravity	$[-]$
μ	Gas viscosity	$[cp]$

List of Roman symbols

Symbol	Description	Units
$CapEx$	Capital Expenditures	[€]
D	Pipeline internal diameter	$[m]$
D_c	Cavern diameter	$[m]$
E	Flow efficiency factor	$[-]$
HHV	Higher Heating Value	$[MWh \cdot kg^{-1}]$
$LCoH$	Levelized Cost of Hydrogen	$[€ \cdot kg_{H_2}^{-1}]$
LFE	Load Factor Equivalent	[%]
LHV	Lower Heating Value	$[MWh \cdot kg^{-1}]$
k	Ratio of specific heats	$[-]$
M	Molar mass	$[g \cdot mol^{-1}]$
$\dot{m}$	Mass flow rate	$[kg \cdot s^{-1}]$
n	Chemical amount of substance	$[mol]$
ns	Number of compressor stages	$[-]$
$OpEx$	Operational Expenditures	[€]
$O\&M$	Operation and Maintenance	$[-]$
p	Pressure	$[Pascal]$
Q_{sc}	Gas flow rate	$[ft^3 \cdot day]$
R	Universal gas constant	$[KJ \cdot kg^{-1} \cdot mol^{-1} \cdot K^{-1}]$
T	Temperature	$[K]$
tpd	tonnes per day	$[-]$
V	Volume	$[m^3]$
W	Work	$[Joules]$
Z	Compressibility factor	$[-]$

1
Introduction

1.1. European scope

The Paris Agreement set the framework for climate action on an international level. On December 2015, 195 countries decided to limit global warming well below 2°C. The agreement aims to peak Green House Gas (GHG) emissions as soon as possible via independent National Determined Contributions towards such goal.

No other continent or political institution has a higher ambition on dealing with climate change than the European Union. Ursula von der Leyen, the current president of the European Commission made the European Green Deal her number one priority, aiming for climate neutrality by 2050. As she stated, different generations had different aspirations for Europe, and the generations to come wish to live in a sustainable continent [53]:

> *"For the generation of my parents, Europe was an aspiration of peace in a continent too long divided. For my generation, Europe was an aspiration of peace, prosperity and unity that we brought to life through our single currency, free movement and enlargement. For the generation of my children, Europe is a unique aspiration. It is an aspiration of living in a natural and healthy continent."* - Ursula von der Leyen

On top of political ambition, concrete climate action is also necessary to achieve such policy objectives. Already revised upwards, EU targets by 2030 include: (1) 55% reduction in GHG emissions compared to 1990 levels, (2) 32% share of renewables in the energy mix and (3) 32.5% energy efficiency improvement. Additionally, all member states are required to have a long term National Energy and Climate Plan (NECP), which sheds light into the road-map each country plans to follow [12].

In order to supply clean and resilient energy, the European Commission has considered hydrogen a key technology to incorporate with renewables and close the intermittency gap towards decarbonization. In July 2020 the EU released it's first hydrogen strategy, which plans to kick-start the industry's scaling up by forming an *European Clean Hydrogen Alliance*.

The organism plans to bring together all stakeholders and provide a clear pipeline of viable investment projects in the technology, which according to [14], can generate up to €180-470bn of investment and a significant positive impact on employment. The vision also sets out a road-map that details an ambition of 6GW of green hydrogen electrolysers by 2024 and

40GW by 2030. Furthermore, it intends to boost demand in end-use sectors, plan the market rules, the appropriate infrastructure and promote further research and innovation along with the strengthening of the EU's international dimension [13].

1.2. Portuguese scope

Aligned with the Paris Agreement and the EU's targets, Portugal plans to achieve climate neutrality by 2050. Having that target in mind and as part of it's NECP for 2030, it's energy sector targets are ambitious. Namely, achieve 47% of renewables integration in the final consumption mix, 80% in the electricity sector, 20% in the transport sector, increase 15% electricity interconnections, reduce 35% it's primary energy consumption and reduce to 65% it's energy dependency [43].

Portugal has a net import energy balance and the 6th highest energy dependency in the EU (75%) [15]. The country does not produce oil, coal or natural gas, thus, the prospects of becoming more renewable also contribute to it's import-export balance, for example, the project under study - *Sines H_2 Hub* - has the potential to reduce €300-600m natural gas imports by 2030 [35]. Nowadays, oil still accounts for 40% of TPES, followed by natural gas, renewables and coal. In figure 1.1, one can note that since early 2000's, the TPES has slightly decreased and introduced renewables such as wind and solar and phased-in natural gas since 1997.

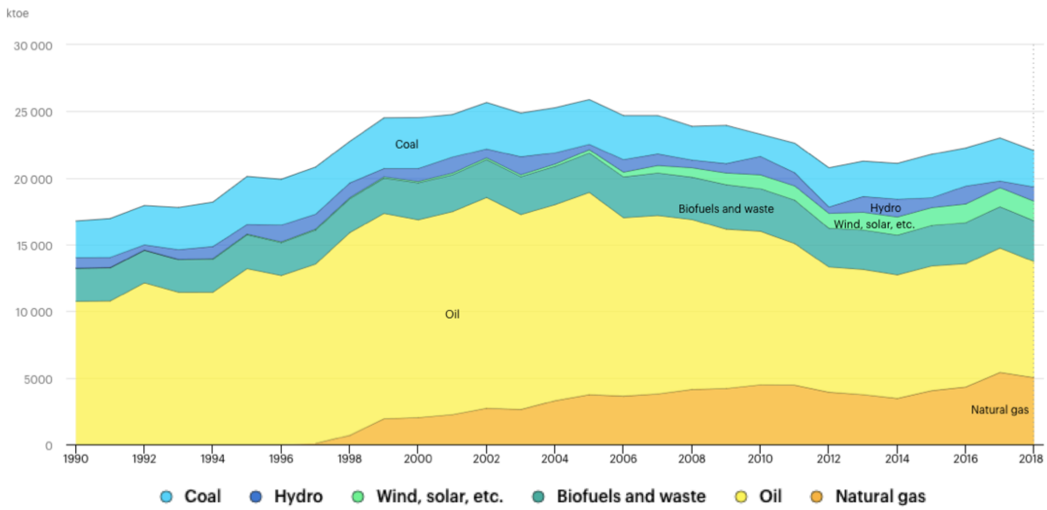


Figure 1.1: Total primary energy supply (TPES) by source, Portugal 1990-2018, [25]

Regarding the power sector, which has been following an upwards trend and accounted to 48.9TWh in 2018, it's main consumers are the industry sector (35%), the service sector (34%) and the household sector (28%) [35]. Such power supply can be broken down into three main blocks, with similar weights (33%), one third coming from fossil fuels (coal and natural gas mostly), one third coming from hydro (always dependant on every year's precipitation) and one third from other renewables (mostly wind, but with a fast uprising of solar PV) [25].

At least since 2018, the DGEG (Directorate General for Energy and Geology) has been studying the country's potential to develop and harness the benefits of an active contribution towards a hydrogen economy. In May 2020, Portuguese authorities published a draft of it's first national strategy for hydrogen to collect inputs from civil society. The document defines the vision, targets, measures and funding that the government plans to take forward. The goals include a 5% hydrogen share in the final energy consumption, on the road transport and on the industry sectors. It also aims to achieve 50-100 fuelling stations and up to 2GW of electrolysing capacity by 2030. The plan foresees €7bn in investments and €900m to support production [35].

At the centre of such plan is the *Sines H_2 Hub* which consists of adapting a natural gas and coal focused strategic region towards an industrial green hydrogen production cluster. Sines is located on the Atlantic coast near critical gas infrastructures, an industrial zone with current and potential hydrogen consumers and also good solar resources [35].

1.3. *Sines H_2 Hub*

The plan, initially developed in 2018 by Marc Rechter CEO of Resilient Group, was named *Green Flamingo*. Over these past months, other companies have also shown interest in executing the project and the consortium named *H2Sines* which includes: EDP, Galp, Martifer, REN (the Portuguese gas TSO), Vestas and Engie, was also formed. As of now, the companies are in early stage applications for IPCEI funding.

The project aims to boost a green hydrogen economy centered in Sines. It foresees a +1GW investment in renewables (mostly solar PV) supplying green electricity to a 1 GW electrolyser. The hydrogen produced is then injected in the gas grid, distributed via truck or shipped to the Netherlands. This location is particularly interesting for several reasons:

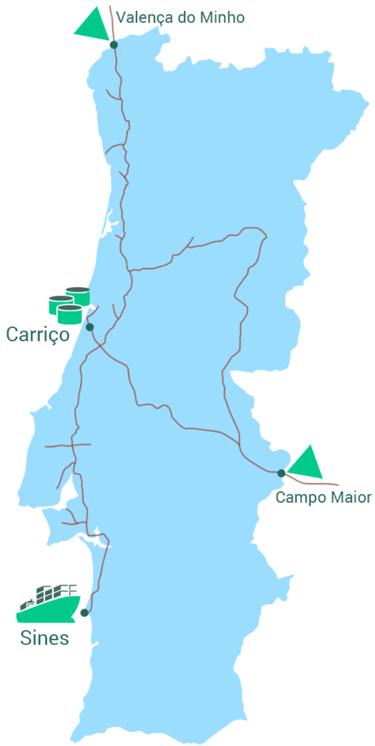


Figure 1.2: Portuguese natural gas infrastructure. Outlined connections to Spain, Carriço underground unit and Sines port.[39]

- Portugal has a high solar irradiance throughout the year, the Portuguese government organized a solar PV auction that hit a record of historically low prices with a minimum of 14€/MWh and a weighted average of 23€/MWh [28];

- A 1.25GW coal power plant is going to be phased-out by 2023, which will facilitate possible electricity grid injection [11];

- It has land availability and is close to energy intensive industries that can use hydrogen as feed-stock;

- Sines is a key point in the Portuguese gas network. It receives, transports and stores natural gas and gasifies Liquified Natural Gas (LNG). Its' deep sea maritime port receives LNG from Northen Africa, which can be advantageous when considering hydrogen exports through shipping.

1.4. Research Aim & Structure

A critical infrastructure of the natural gas grid is the Carriço Underground Storage Salt Caverns. Located 250km north of Sines, the six caverns with a total capacity of 335Mm^3 currently store part of the natural gas injected in the gas pipelines in Sines. Given the fact that segments of the gas infrastructure can be easily adapted for hydrogen transport and storage, it is of special interest to analyse the adjustments that can be made to Carriço and its' supply infrastructure to change it from natural gas to hydrogen. To better understand the feasibility of such option, it's cost competitiveness must be considered, thus the main research question will be:

In the context of the Sines green hydrogen hub, what is the cost of transitioning to hydrogen and operating the Carriço salt caverns storage and its supply infrastructure?

To answer the main question, this thesis will develop a model simulating the storage needs the *Sines H_2 Hub* will have. Then, it will set the system's design and boundaries required for a pure hydrogen operation with such characteristics. And finally, by looking at the costs associated with the necessary infrastructure and the regular daily operation, it will determine a levelized cost of hydrogen transport and storage. Such price, determined in €/kg of H_2, will expose the financial feasibility and cost competitiveness of the option under study.

A lose collaboration will be established with Resilient Group, the company promoting the *Sines H_2 Hub* , thus the results will contribute to both: university by adding new academic knowledge and to the company by adding scientific and financial insight to the project.

As above mentioned, the thesis will focus on: simulating a model that replicates the project's operating conditions; re-designing the current natural gas system towards a hydrogen based; and then calculating the costs associated with its' upgrade and operation. To do so, the main question will be broken down into the following research sub-questions (for a better understanding of the research flow and simulation model described below please check the appendix):

1. What are the characteristics and current technological status of using salt caverns for large scale hydrogen storage and natural gas pipelines for hydrogen transport?

   This sub-question intends to give an insight to the state of the art of the technologies associated with the salt caverns and gas pipelines. Key deliverables include: an introduction to the salt caverns geographical location, construction, operating technology description and cost overview. Similarly, a technology description and cost overview of hydrogen transport in gas pipelines will also be presented. The methodology implemented at this initial stage will be based on literature review, more specifically, when possible, on existing similar hydrogen projects.

2. What are the current characteristics of Carriço and its' supply infrastructure relevant for hydrogen transport & storage?

   Secondly, it is important to understand the hydrogen flows of the project and the current status of all the infrastructures which will be analysed and are already installed . Based on public information from REN - the TSO - and on the collaboration with Resilient Group, this data collection will set the initial boundaries of the project. Here, there will be three focuses: on the hydrogen production in Sines, on the gas pipelines and on the salt caverns. Pressure ranges, operating temperatures, hydrogen quantities will be some of the inputs collected. This information along with the literature review from the previous question, will feed into the next question.

3. Based on the system's current characteristics and on the expected H_2 production, what is a sound design of the upgraded hydrogen system?

   This question will develop the model simulating the storage profile of the *Sines* H_2 *Hub* . As inputs, it will have the hourly hydrogen production in Sines over 1 year, which will be required to determine the storage needs hourly profile, over one year as well. Then and also based on the outputs of sub-questions 2 and 3 (characteristics of hydrogen storage in salt caverns and current characteristics of Carriço and their supply infrastructures), one will be able to determine a sound system design able to accommodate the project's needs.

4. What are the OpEx and CapEx costs that Carriço and its' supply infrastructure will undergo when operating and transitioning to hydrogen?

   This question will focus on developing a cost model that calculates the project's CapEx and OpEx. Such will be done based on data from previous sub-questions outputs and on other relevant assumptions and data sources. The cost model should be comprehensive enough and at the same time detail and breakdown each cost driver. Dependent on the cost drivers, the cost will be allocated proportionally according to the system's capacities and unitary variable costs.

5. What is the system's added Levelized Cost of Hydrogen Transmission and Storage ($LCoH_{Transmission\&Storage}$)?

   Finally, sub-question 5 will combine all the data previously obtained and calculate the levelized cost of hydrogen storage that the system adds to the kilogram of hydrogen produced in Sines. This total cost, based on the simulation and calculated via economic modeling, is relative to the total amount of hydrogen stored in Carriço, it's operational costs (OpEx) and its' capital costs spent of upgrading infrastructures from natural gas to hydrogen (CapEx). This final value will be of use to: assess the projects' financial feasibility; analyse the competitiveness of this specific hydrogen storage option; and also for accurate hydrogen pricing. Additionally, an impact analysis, conclusions and recommendations will be made.

2

Literature Review

This literature review plans to shed light into the key basics of the storage and transmission components under study. Initially, section 2.1 will approach the most common hydrogen storage methods and compare them between each other. Then, section 2.2 will further investigate the specific method of storing hydrogen in salt caverns. Here, a technology description will be given, followed by a presentation of ongoing project and by a cost overview. Then, section 2.3 will shift the focus to hydrogen transmission where an overview of the different technologies will be given. This will be further elaborated on hydrogen pipeline transmission, section 2.4, where a technology description and cost overview will be addressed.

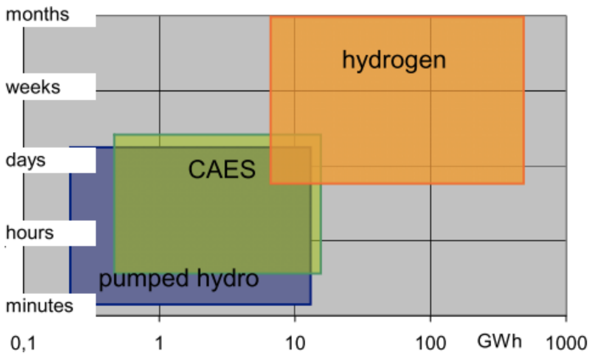
2.1. Large scale energy storage

The current installed capacity of energy storage in the EU is estimated to be 50 GW [42]. Most of this supply comes from CAES or pumped hydro storage due to their high efficiencies. Nevertheless, with the increasing trends of electrification and renewables intermittency, the need for energy storage will surpass the available capacities of those technologies.

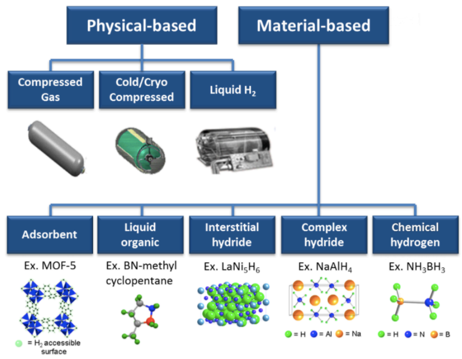
Hydrogen, is the only available technology capable of reaching ranges of 100 GWh of storage capacities. As seen in figure 2.1a, when compared to CAES and Pumped hydro, hydrogen not only has a significant larger range in terms of capacity storage but can also have a significant impact in long term storage without compromising the daily flexibility. For these reasons, hydrogen, is seen as a very promising technology when one mentions large scale storage. Additionally, one can note in figure 2.1b that there is a large range of possible hydrogen storage technologies, which can be separate in physical and material based.

When one mentions large scale hydrogen storage its' low volumetric density must be considered. Furthermore, other variables to have in mind include: stored volume, charge/discharge speeds and storage duration. Different hydrogen storage possibilities offer different characteristics, as noted in figure 2.1b, the molecule can be stored physically, either as gas or liquid, or using materials via adsortion or absortion. The latter is still at early research stages, thus this research will focus on the first: physically-based hydrogen storage.

The boiling point of hydrogen is -252.8°C, thus cryogenic temperatures are necessary to maintain it as a liquid. Maintaining a liquid at such temperatures, will have a significant impact on the boil-off rate which is about 0.2% daily [31]. This could eventually be used to supply a fuel cell transporting the ship or truck, thus making the technology more suitable for long



(a) Preferential areas of large scale storage options, [10]



(b) Hydrogen storage possibilities, [52]

Figure 2.1: Hydrogen comparison with: other technologies (left) and storage possibilities (right)

distance and large scale transport. Having this particularity in mind, this research will further focus on hydrogen storage as gas.

Figure 2.2 presents a cost comparison of possible gas storage alternatives. One can note the different cycles per year and pressure levels among the different technologies, thus, the comparison will not be at the same level playing field. Nevertheless, it can be seen that the impact pressurization has on cost is significant for pressure vessels (due to the relatively low volume, a significant cost would have to be spent on compressing hydrogen) and that salt caverns, aquifer and depleted gas fields are in the same cost range for the same pressure and relatively similar cycle ranges.

For these reasons, underground storage is an interesting and cost competitive technology for large scale and long term hydrogen storage. Salt caverns in particular are a proven and sound technology that will be analysed in this report and further elaborated in the following section.

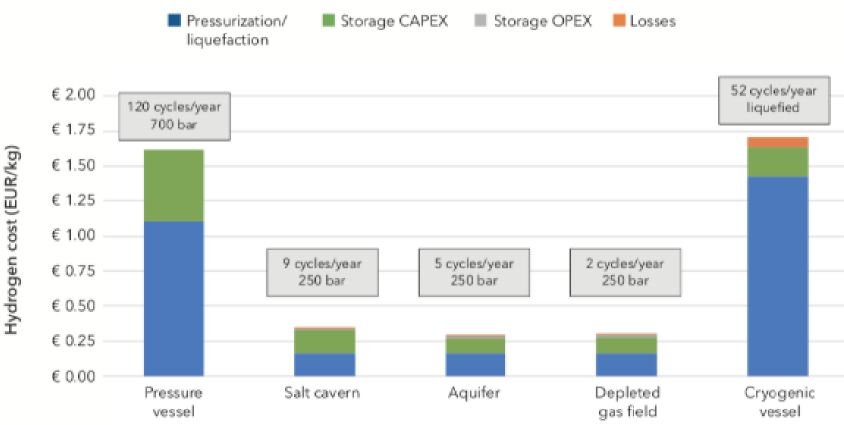


Figure 2.2: Overview of storage costs of hydrogen based on throughput, [19]

2.2. Hydrogen storage in salt caverns

The concept of storing gas in underground formations such as fossil fuel reserves, water reservoirs and salt caverns is not new. Natural gas has been stored in depleted oil wells since the early 1900's and with the technological advancements it has turned into a common and mature technology. Due to their large scales, such options generally offer good solutions for seasonal storage while requiring little land availability and low construction costs [40]. Salt caverns in particular, are seen as a very promising technology for three main reasons:

1. They require little cushion gas volume (volume necessary in a storage unit for maintaining adequate pressure and operational safety) when compared to its' peers. This value can vary dependant on pressure swings but typical values are in the range of 30% [10] but can go as high as up to 50%. As one can note from table 2.1 salt caverns have the lowest ratio between cushion gas and total volume;

2. They have a high peak withdraw capacity which allows several injection cycles each year to meet peak demand;

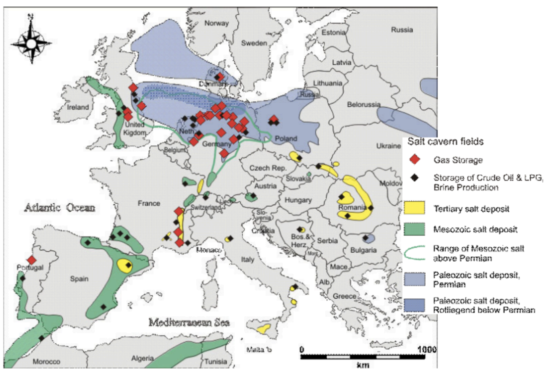
3. Are attractive due to their inert nature and large sealing capacity. Respectively, this prevents contamination and major gas escapes with theoretical leakage rates of 0.01% p.a. [10].

Table 2.1: Worldwide distribution of underground storage unit types and specifications, adapted, [40]

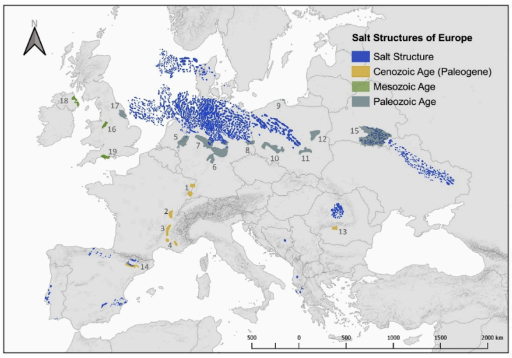
Storage type	**No of UGS**	**Working gas volume** $[10^6 m^3]$	**Cushion gas volume** $[10^6 m^3]$	**Peak withdraw capacity** $[10^6 m^3/h]$	**Cushion gas share of total volume** [%]
Gas field	428	274 298	291 395	138 648	51.5
Oil field	39	17 713	15 110	14 297	46.0
Aquifer	86	44 199	68 074	29 151	60.6
Salt cavern	74	16 198	6 660	34 428	29.1

2.2.1. Geographical Location

Salt formations, also known as evaporites, were originated from concentration and crystallization via consequent evaporation of large masses of water, or put more simply, evaporation of oceans and seas. Dependant on the locations they were formed over the Palaeozoic, Mesozoic and Cenozoic eras. Such salt formations can be found a bit all over Europe, nevertheless, as one can note in figure 2.3a, significant deposits from the Palaeozoic era can be found in the Zechstein seabed (North-East Netherlands, North Germany and West Poland) and deposits from the Mesozoic can mostly be found in the Iberian peninsula and UK.



(a) Potential [10]



(b) As a result of suitability assessment for underground hydrogen storage, [7]

Figure 2.3: Maps of European salt deposits and salt structures

[7] conducted an analysis to calculate the technical potential for hydrogen storage in salt caverns. Figure 2.3b presents the European map of the feasible locations which have such potential. As expected, a large concentration of viable salt structures can found in the Zechstein

area, in East Ukrain, in Romania, and some in the Iberia peninsula. Moreover, other bedded salt deposits are also feasible in the UK and East France. Having this said, it can be noted that despite Sines not having a large feasible area such as Zechstein close by, some Mesozoic salt structures located in the Carriço area are considered feasible. This fact makes the *Sines* H_2 *Hub* unique in the sense that not many locations have such high solar irradiance, and consequent low electricity prices, combined with viable large scale hydrogen storage options like the one above mentioned.

2.2.2. Cavern construction

After conducting the relevant geological and feasibility studies comes the process of constructing the salt cavern. The cavern must comply with certain parameters to maintain its' geological safety. [55] concludes that the minimum thickness of the salt layer on top of the cavern must be of at least 75% of the cavern's diameter (Dc) and that the salt layer under the cavern of at least 20%. As for the height to diameter ratio, it should be around 0.5. Additionally, regarding the placement of multiple caverns, their central axis should keep a distance of at least 4 times the cavern's diameter. The construction of such a cavern can be divided into the phases that follow and which are detailed in figure 2.4:

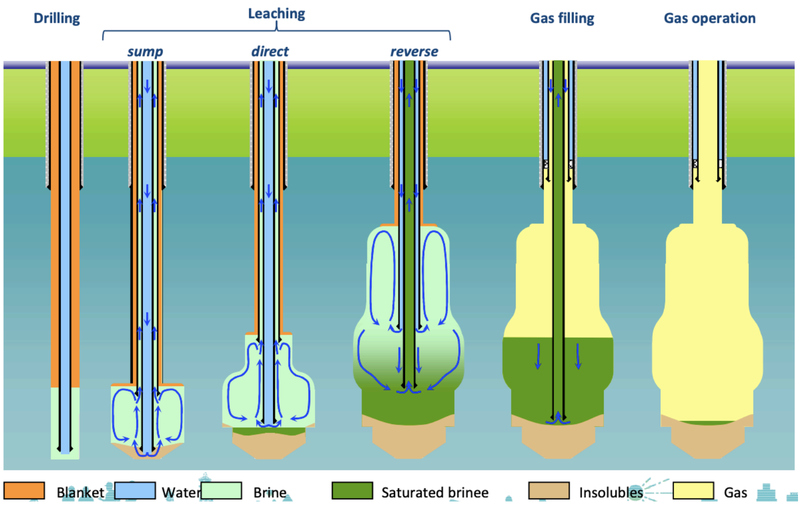


Figure 2.4: Salt cavern construction steps [22]

1. **Drilling:**
   This fist step consists of building an access-well at the determined location. This will be done by drilling a hole (d<1m) and with a depth ranging from 300-2000m, dependant on the geological aspects. Then a pipeline with an inner and outer segments are installed and the remaining space is sealed with cement, making it gas tight.

2. **Leaching**:
   Then comes the solution mining. In this stage, water is injected through the central pipelines, which dissolves the salt and shapes the cavern, creating a brine solution. This solution, composed of salt and water is then extracted via the outer pipelines and can be used in: salt production, chemical processes or deposited in the ocean. This operation can also run in reverse - water through outer pipe and brine through inner - to better shape the cavern. In total this stage can take 1 to a few years.

3. **Debrining:**
   After the final shape of the cavern has been achieved, the remaining brine must be

removed through the pipeline. This will be done by injecting gas through the outer pipe and collecting the brine through the central one. Since the pipepline does not reach the bottom of the cavern, it will not be possible to collect all of the solution.

4. **Filling:**
After the first gas injection to remove the vast majority of the brine, the pipeline must be splitted from the beginning of the cavern downwards. Due to the fact that it can not be pull up due to the deformations created by the intense flows, it must be splitted through a controlled detonation. After the detonation, the bottom part of the pipeline system will be left at the bottom of the cavern indefinitely and the upper one will be changed to a system proper for storage, injection and withdraw of gases.

2.2.3. Technology description

Regarding the operating pressure of a hydrogen salt cavern, it must comply with the limits presented in figure 2.5 and there are two distinct modes of regulating it:

- Constant pressure: here brine is used to compensate the gas that is removed/injected in the cavern. On the one hand, this method reduces the stress that is put on the cavern's structure but on the other hand, the hydrogen withdrawn will have a high level of brine particles, thus requiring a more active water separation. As a reference, a complex in the UK operating three salt caverns under this system at a depth of around 350m, keeps a constant pressure of 45-50 bar;

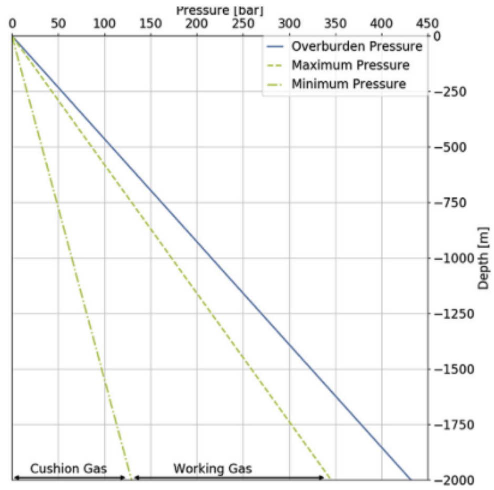


Figure 2.5: Estimated pressure limits as function of depth for hydrogen storage in salt caverns, [7]

- Variable pressure: the pressure of the cavern varies with the flows of hydrogen. Here, a certain level of gas must be kept in the cavern, the cushion gas, to maintain the minimum pressure and a maximum safety pressure should not be surpassed. The pressure should be kept at 0.3-0.8 of lithostatic pressure, and as it is limited as a function of depth, its' operating pressures range from 70-200bar.

The operation and characteristics of the hydrogen based cavern are relatively similar to a natural gas run cavern. However, since hydrogen has about one third of volumetric energy density that of natural gas, when compared, hydrogen will require additional energy to compress a same given cubic meter. Moreover, hydrogen has an inverse Joule-Thompson effect of 0.035°C/bar, meaning that a decrease in pressure of 1 bar leads to an increase in temperature of 0.035°C.

Figure 2.6 presents a simplified process of hydrogen storage in a salt cavern. After arrival to the facility via pipeline, the hydrogen passes through a filter to remove any unwanted particles that might damage equipment downstream. Then the gas is compressed, usually in centrifugal compressors, and cooled or heated up to the approximate temperature of the cavern. This will be dependant on the temperature the gas will arrive at the facility and the final temperature it needs to be at to enter the cavern. Most likely, in a scenario where the gas has traveled a long distances underground, which experiences significant cooling to soil temperature, a heater will be required. Finally, when injecting it or removing it from the cavern, it will pass through a metering station. [32].

When removing the gas from the cavern, it will go again through a metering station and filter for the reasons above mentioned. Additionally, a water separator will further remove entraint salt and water that the gas absorved when exposed to the brine at the bottom of the cavern. After this, the gas will pass through a radial flow turbine that will expand the gas and reduce its' pressure. Please note that for systems such as the one in Teesside operating at low pressure, 45bar, such procedure is not necessary [32].

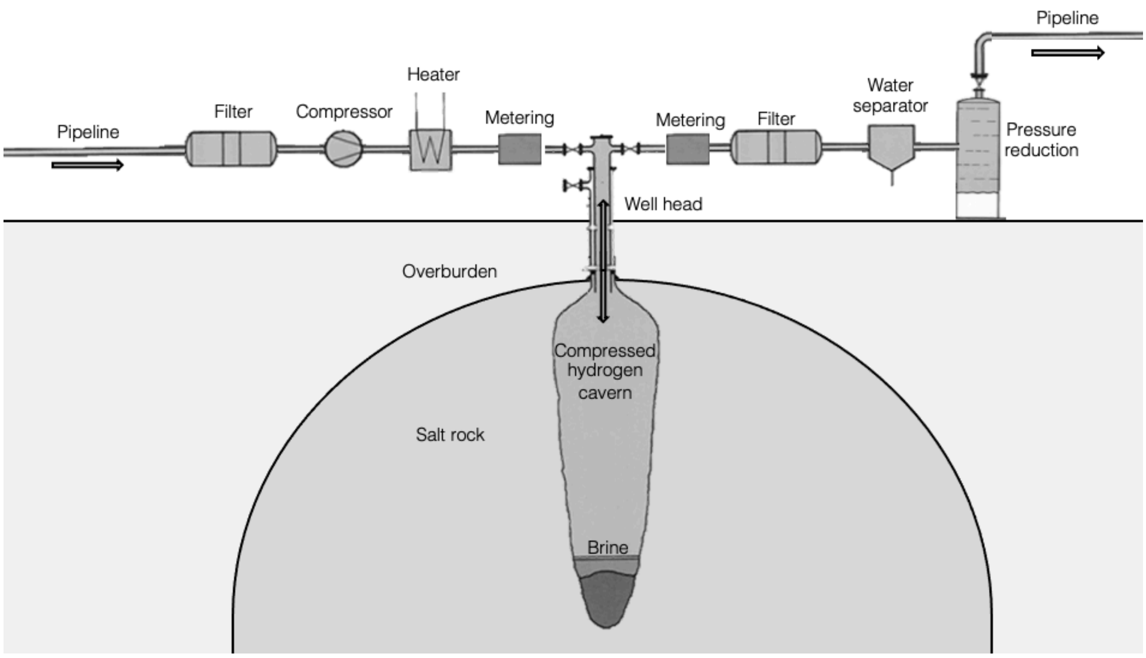


Figure 2.6: Storing process of hydrogen in salt caverns, adapted from [40] and [3]

2.2.4. Other ongoing projects

As previously described, hydrogen storage in salt caverns is not a new technology, it has been in use since the 1970's. Nevertheless the technology is not widespread due to limited hydrogen demand. Currently, there are four caverns in use: 3 in Texas, US and 1 in Teesside, UK.

The caverns in the US are used by the chemical industry also have attached pipelines for hydrogen transport in the range of several hundred kilometers , aiming to provide a constant supply of hydrogen. The cavern in the UK runs in a constant pressure - 45bar - operation and stands on 50m layer of salt. Its' use is relatively similar: acting as a buffer for the chemical demands on the region. Further details of each of the cavern's specifications can be seen in table 2.2. It is important to outline the year the Teeside cavern was commissioned. In comparison to the others that use a different technology, one can critically deduct that the constant pressure technology, such as the one used in the UK's cavern, is outdated.

Table 2.2: Key metrics of existing hydrogen salt caverns [31]

	Teeside (UK)	Clemens Dome (Texas)	Moss Bluff (Texas)	Spindletop (Texas)
Salt formation	Bedded salt	Salt dome	Salt dome	Salt dome
Operator	Sabic Petrochem.	Chevron Philips Chem. Comp.	Praxair	Air Liquide
Commissioned	1972	1986	2007	n/a
Geometrical volume $[m^3]$	210 000	580 000	566 000	906 000
Mean cavern depth [m]	365	1 000	1 200	1 340
Pressure range [bar]	45	70 - 135	55 - 152	68 - 202
Net energy stored [GWh]	27	81	123	274
H_2 **mass** [ton]	810	2 400	3 690	8 230
Net volume [Mm^3 std]	9.12	27.3	41.5	92.6

2.2.5. Cost overview

The costs of transitioning or building and operating a hydrogen salt cavern can be divided between Capital Expenditures (CapEx) and Operational Expenditures (OpEx) costs. CapEx are considered the goods and equipment that are purchased in benefit of the long term operation of the company. They can be physical goods, such as compressors, or not, such as the drilling of a cavern and their value depreciates over time. As for OpEx, they are the costs that the company incurs on a day to day basis which are linked to the company's regular activity. They can range from salaries to electricity bills and can be deducted from taxes [49].

The most relevant CapEx costs in building and operating a hydrogen salt cavern include: geological site preparation, cushion gas and equipment capital costs (compressor and well). As for the OpEx costs, they include: compression costs and well O&M. The total levelized cost of hydrogen storage can be calculated by considering all the mentioned variables. Different sources present various final levelized costs of hydrogen storage in salt caverns.

[2] develops a comprehensive analysis comparing several hydrogen storage methods. The study concluded that dependant on the storage needs amount, different technologies would be more suitable: for a hydrogen storage of less than 20 tones, underground pipelines are the most economical option, while for larger than 20 tones, salt caverns are, in general, a more feasible option. For a given storage capacity of 500 tones, it finds a levelized cost of hydrogen storage of $0.21\$/kg_{H2}$, equivalent to $0.18€/kg_{H2}$ given a conversion rate of 0.85 USD to EUR.

As noted in figure 2.2, [19] also present a levelized cost for hydrogen storage in several different technologies: pressure vessel, salt cavern, aquifer, depleted gas field and cryogenic vessel. For salt caverns in particular a value around $0.35€/kg_{H2}$ is given for an operation at 250bar and at 9 cycles per year.

[34] describes an economic analysis of underground hydrogen storage. The study compares salt caverns to aquifers, depleted gas fields and hard rock. The data collected on salt caverns was adapted from the Clemens Dome cavern, check table 2.2. The fact that it is based on data from a single specif cavern must be considered with a critical mind: it is important that real costs are exposed but assumptions to other projects can be dangerous given the different aspects such as: year of commission, region, technology etc.. Furthermore, the study outlined that different cycle frequencies were not considered and that factor can have a

significant impact on the overall system cost. The final levelized cost of hydrogen storage in salt caverns was modelled and found to be $1.6\$/kg_{H2}$ equivalent to $1.4€/kg_{H2}$ given a conversion rate of 0.85 USD to EUR.

[33] when approaching the topic of costs of hydrogen storage in salt caverns points out: *"It is noted that the costs vary from 0.1 €/kg to around 10 €/kg; the assumptions and business models games are probably very different between the different cases, but unfortunately very poorly described or nonexistent"*. Although the upper value of the range seems extremely overestimated, the fact that there is a wide cost range between several projects is worth noting.

One can conclude that literature is not highly consistent on the topic which is highly dependant on each project's conditions. This research plans to contribute to that research gap by giving a cost perspective of the whole transport and storage value chain of the *Sines H_2 Hub* and in particular, the hydrogen storage in the Carriço salt caverns.

2.3. Hydrogen transport

When one mentions hydrogen transport, the most cost competitive technologies will vary according to the distance, infrastructure, quantity being transported, geographic and market characteristics [56]. Having that said, one can outline that the most suitable technologies include: compressed gas trucks, cryogenic liquid trucks or gas pipelines.

Given the scope of this research, when a gas pipeline is mentioned, a pure hydrogen gas pipeline will be the assumed, thus, options such as hydrogen blending into the natural gas will not be considered. Additionally, other options such as conversion to ammonia or LOHC's are also considered out of the scope of this research. This is due to the fact that the whole point of this project is to provide a stable hydrogen supply and buffer to those exact possibilities downstream.

To liquefy hydrogen, the gas needs to be cool down to -253°C, thus increasing its' volumetric density from around 0.089 $[kWh/m^3]$, at standard test conditions, to 2,366 $[kWh/m^3]$. Nevertheless, such process will impact the cost competitiveness of the technology [48]. To transport hydrogen as liquid, [26] refers that the maximum capacity a truck can support is 4000kg, while for gaseous hydrogen is 1100kg.

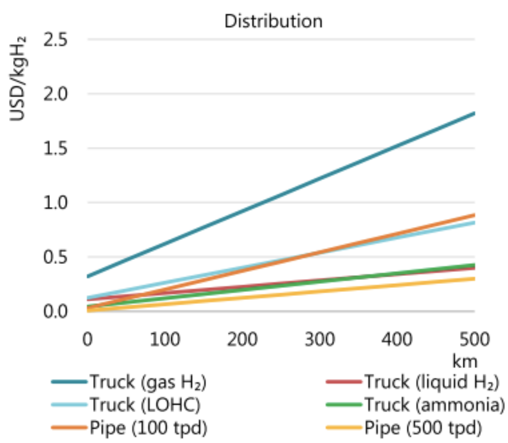


Figure 2.7: Cost of hydrogen distribution to a large centralised facility, [26]

Pipelines, on the other hand, do not have such strict volume restrictions to transport hydrogen. When distributing 500 tonnes of hydrogen per day, pipeline is the most cost competitive option. As one can note in figure 2.7, a 500tpd pipeline transport is consistently the cheapest option. While if the volume in the pipeline is reduced to 100tpd, liquid hydrogen becomes the most cost competitive option at around 100km distance. It is also worth noting that transporting hydrogen as gas via truck stand out as a more costly option for any given distance.

[56] also compare the different hydrogen transportation options. In the techno economic analysis, which dates back to 2007 therefore it does not include most recent technology developments, the authors conclude that for short distances and small amounts, gas trucks are preferred. Then, for long distances up to 500km, and amounts up to 70 tons/day, liquefied hydrogen via truck is the most cost effective technology. And lastly, for distances higher than 500km and high volumes of hydrogen flows, the decision should be of constructing a dedicated pipeline.

Every option has its' pros and cons and should be used according to the variables above mentioned (distance, volume, infrastructure, etc.) which determine the most cost effective option. Gas pipelines consistently prove to be relevant for distances over 500km - although always dependant on the volumes. This research is in the scope of the *Sines H_2 Hub* , thus, that distance benchmark of 500km of transmission will be surpassed. Furthermore, the gas pipelines are already built - currently at use for natural gas transport - but a possible retrofit to keep the costs low is a relevant characteristic of the project. For these reasons the following section will further elaborate on the hydrogen transport in gas pipelines.

2.4. Hydrogen transport in pipelines

Hydrogen transport in pipelines is not a new technology. As of 2016 there were more than 4500km of pure hydrogen pipelines built worldwide [4]. In Europe in particular, Air Liquide operates more than 1.600km of hydrogen pipelines in the Rhine region. The challenge the industry faces is the scale up of the technology in a cost effective at a time market conditions such as supply and demand of green hydrogen also need to be stimulated.

In this context, the use of the existing natural gas pipeline infrastructure can have significant role in unlocking the industry's potential. Thus, when hydrogen transport in pipelines is mentioned, two options emerge: the use of retrofitted natural gas pipelines or the construction of newly dedicated pipeline infrastructures. The following section will further elaborate on these two options.

2.4.1. Technology description

As previously exposed, hydrogen transport through pipelines is considered as a very interesting and cost effective option. Such can be made by modifying the current natural gas pipelines, or by building new dedicated infrastructure. Hydrogen blending in the current natural gas system will not be considered because it is out of the scope of this project, which consists of operating a pure hydrogen infrastructure. Regarding the first option, due to the lower volumetric energy density of hydrogen when compared to natural gas, it's capacity is restricted to 80%. Moreover, analysis by different TSO's demonstrate that by further reducing the maximum capacity there can be relevant cost reductions due to the significant savings in the electricity bill of the compressors. For example, a 48 inch pipeline that transported 20.7GW (LHV) of natural gas, can transport 17GW of hydrogen (LHV) which can be properly optimized if run at 13GW capacity, thus a balance between extra compressing costs and extra pipeline capacity must be found to optimize the system [54]. Please note that these numbers as exposed in the report are relevant only for sake of comparison, the HHV should be the variable used when representing the real energy content.

The operation of hydrogen transport through pipelines does not significantly differ from the operation of natural gas. It requires large diameter steel pipelines covering long distances, compression stations along the system to control pressure drops, valves along the system to ensure a safe operation and maintenance and metering stations to accurately monitor the hydrogen flows. The following sections aim to further detail these equipment necessary for a sound operation.

Pipelines

Pipelines are the main infrastructure carrying the gases from one point to another. Typically composed of high pressure steel, in Europe they have diameters ranging from 400 to 1400mm and operating pressure from 16 to 100 bar. As above mentioned, there are no significant changes in the operation of a hydrogen or natural gas transport, thus, the reuse of the natural gas infrastructure can prove to be game changing in the implementation of a hydrogen economy.

[54] indicate that building a new dedicated hydrogen infrastructure can be 10-50% more expensive than a natural gas one. Furthermore, the cost of adapting an existing natural gas system towards hydrogen is only 40-60% that of building a newly dedicated one. Having this in mind, one can note the importance of establishing a comprehensive plan focused on shifting natural gas pipelines towards hydrogen. To do so, several steps must be taken when converting the pipelines which include: nitrogen purging, identification of cracks along the pipes, replacement of valves already in use for long periods. Furthermore, to prevent hydrogen embrittlement, a process that degrades and induces cracks in the steel, an internal coating layer could be applied. By doing so and with regular monitoring and steady pressures, it is possible to achieve a safe operation at reasonably high pressures.

Compressors

The transport of hydrogen along the pipelines is dependant on pressure drops which are generated by compression stations. These stations ensure that the gas is properly pressurized thus the distance between compressors and compressor capacity are key aspects to consider. This can be done using two types of compressors which are presented in figure 2.8. The reciprocating compressor, shown on the left image, increases the pressure by reducing the volume using a piston cylinder (similar to combustion engines). The centrifugal compressor, presented on the right image acts through the rotation and centrifugal force of an impeller that converts the kinetic energy to the pressurised gas.

Figure 2.8: Schematic comparing reciprocating and centrifugal compressors, [54]

Regardless of the use of any of the compressors, it is important to note that the energy costs of compression can represent a relatively large share of the transmission cost. This factor will be dependant on the electricity price which will be further elaborated over section 2.4.2. The compressor's sizing in particular can have a relevant role in optimizing the system's since a high pressure gap leads to higher electricity bills in a non linear way.

Metering Stations & Valves

Since small measurement error can have a significant financial and operational impact, metering stations are of high importance to all stakeholders involved in the value chain of the gas. The ones currently in use are natural gas based, thus, their adaptation or change will be necessary. Nevertheless, it's cost represents a very small share of the total transmission cost, therefore, given the scope of this research it will not be subject of much attention.

The valves, used along the system to ensure a safe operation and maintenance, act as important gateways placed every 8-30km. Their use in a retrofitted system is likely to remain the same. Nevertheless, current research is focused on designing and operating suitable ones for a sound operation in a hydrogen dedicated infrastructure.

2.4.2. Cost overview

[54] investigated the levelized cost of hydrogen transmission through European pipelines. The report outlines various pathways for a European hydrogen pipeline system with three different period implementations and with two different technological options: either retrofitting the existing pipelines or building new dedicated systems. The analysis is based on several assumptions such as pipeline capacity at full load of 13GW (LHV), a diameter of 48 inches, a given suction pressure of 30-40 bar, a load factor of 5000 hours/year and distance between compressors of 100-600km, among others.

Table 2.3: Estimated levelized cost of hydrogen transport through pipeline infrastructure, [54]

	Low	Medium	High
Levelized cost, 100% new infrastructure [€/kg/1000km]	0.16	0.20	0.23
Levelized cost, 100% retrofitted infrastructure [€/kg/1000km]	0.07	0.11	0.15
Levelized cost, European Hydrogen Backbone (75% retrofitted) [€/kg/1000km]	0.09	0.13	0.17

As exposed in table 2.3, the report projects the levelized costs of a proposed 75% retrofitted and 25% new infrastructure over three scenarios: low, medium and high. For each scenario it uses three different cost inputs, more or less conservative, for parameters such as unitary CapEx of pipelines, compressors and electricity prices. Regarding the latter, the authors assume an electricity cost of 40€/MWh for the low scenario, 50€/MWh for the medium and 90€/MWh for the high.

When one looks into the average electricity prices of non-household consumers in the EU-27 over the past 10 years, as outlined in figure 2.9, one can note that the for any given non-household category, the average prices in 2010 ranged between 60-70€/MWh and in 2019 they ranged between 45-55€/MWh. Given the downwards trend and overall ranges, one can point out that the electricity cost of 90€/MWh used in the high scenario can have a large impact overestimating the final levelized cost of transportation.

[29] also investigate the levelized costs of hydrogen transport normalized on a quantity and distance base. Their research focuses on comparing the cost of long distance transport of electrical or chemical energy independent of production method or end-use. The analysis digs into electrical transmission lines, liquid pipelines and gas pipelines and includes the costs of CapEx for materials, labor, Right of Way (ROW), pumping/compression stations, and miscellaneous expenses.

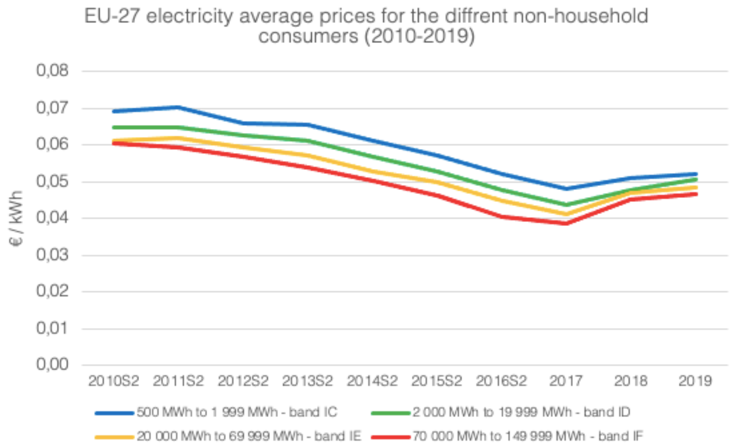


Figure 2.9: EU-27 average electricity prices for the different non-household consumer categories (2010-2019), data retrieved from [15] and elaborated on excel

Figure 2.10 presents the output of the analysis already amortized for each of the different technologies. One can note that transmitting hydrogen via pipeline is a factor of 10 cheaper than via electrical transmission lines. It is also interesting to compare the value obtained for hydrogen transmission via pipeline of 4.97$/MWh/1000mi to the values from the previous reference [54]. To do so, a conversion rate of 0.85 USD to EUR is considered, along with a conversion factor of 1 kg_{H2} = 0.039 MWh (HHV) and a conversion factor of 1.6 miles to km. After such adjustments, the levelized cost of hydrogen transport is found to be 0.10€/kg/1000km, which is 0.06€ cheaper than the low scenario exposed in by [54] for a 100% new infrastructure.

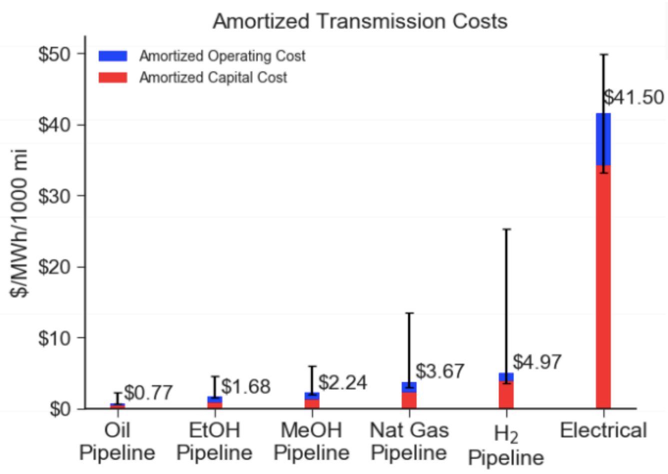


Figure 2.10: Amortized transmission costs comparison [29]

3
Methodology

This chapter aims to describe the methodology followed to calculate the cost of hydrogen transmission and storage. Firstly, section 3.1 will outline the structure and the overall approach which was followed. Secondly, section 3.2 will expose the design and boundaries that this system will have. This will help having a better understanding of pressures, temperatures, distances etc. considered. Then, from section 3.3 to section 3.7 the model will be described in 5 sections: hydrogen production, compressors, salt caverns, gas pipelines and final cost. For each of these sections it will be explained how the data was collected, how the system was designed and its' contribution towards the cost model. Section 3.7 in particular, will consolidate the data from the previous sections and elaborate the final cost of hydrogen transport and storage.

3.1. Research approach

As previously outlined, the *Sines H_2 Hub* intends to produce green hydrogen based on cheap and renewable solar energy. A +1GW of solar capacity investment is expected in the region to supply electricity to the hydrogen facility. As a consequence the hydrogen production will have a similar profile as the solar irradiance, i.e., whenever the sun shines, hydrogen will be produced, if not, there will be no output. Under study is the possibility of converting hydrogen to other energy carriers such as ammonia, a sound cost effective option for shipping it to the Netherlands. Nevertheless such option requires a stable hydrogen supply [51], which is not compatible with a profile dependant on solar irradiance.

For this reason it will be investigated the possibility of transporting the surplus of a certain target of stable hydrogen supply to a storage site. Then, in times of shortage, for example at night, the hydrogen is expected to travel back to Sines and compensate up to that certain stable supply target. Having this in mind, this research will investigate the possibility of re-using an existing natural gas pipeline and salt cavern located in Carriço, Portugal.

The research will be developed on a Matlab model which will be explained over 5 main blocks: hydrogen production, salt caverns, gas pipelines, compressors and total cost. Each of these blocks has its' specific research flow and different dependencies on the other blocks. Figure 3.1 presents the 5 blocks, its' specific approach and the relations it has.

Section 3.3 analyses the hydrogen production that the Sines facility will have. With data on the hourly hydrogen profile, collected from the consortium coordinating the project, the section will create three scenarios that propose different production stabilization scenarios: daily,

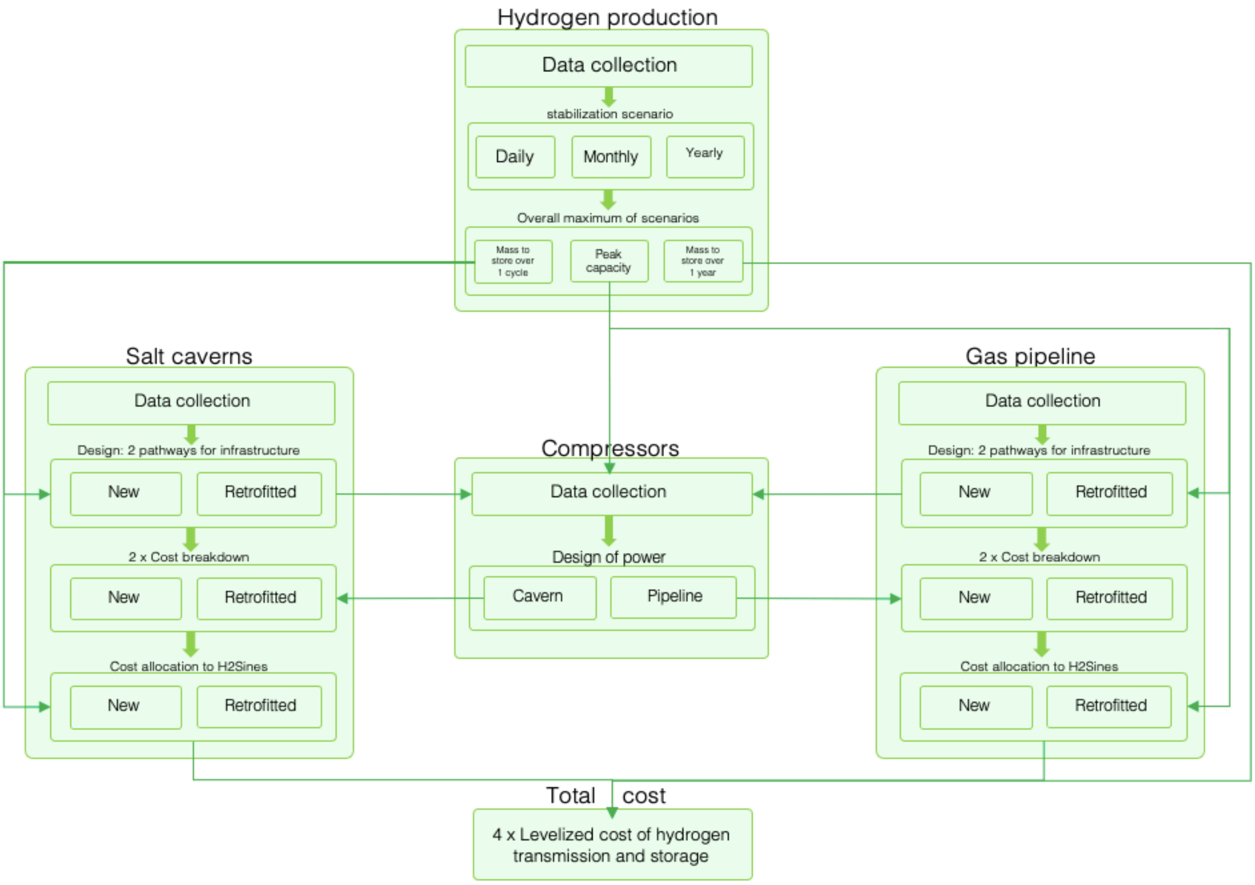


Figure 3.1: Research approach scheme

monthly and yearly. This will mean that each of the scenarios will have a different storage needs profile. Based on such profile, the overall maximums over the three scenarios of: capacity, mass stored over one cycle and mass stored over 1 year will be used as inputs for other research blocks of this study.

The block described over section 3.4, will elaborate the topic of both Cavern and Pipeline compressors. These compressors alone do not represent an independent infrastructure such as storage or transmission, but are integrated in those. Since they were the object of some study and the same methodology was followed for both, they will be approached in a dedicated section. Data on peak capacity and on the design of infrastructure (either cavern or pipeline, dependant on which compressor is being considered) will serve as input to design the power of the compressors. This will then be incorporated in the back into the cost model of each respective infrastructure.

Section 3.5 on Salt caverns, will analyse the data available from the Carriço caverns and then propose a system design. It was determined that the best solution would be to look into both possibilities of building a new dedicated salt cavern or use an existing one. This proposed design will then serve as input to calculate the costs associated with both options. It will also be confirmed that both options can accommodate the maximum mass of hydrogen needed to store over a cycle. Then, after the overall costs of implementing such infrastructure are calculated, only a proportional share will be allocated to the *Sines* H_2 *Hub* .

A similar structure will be followed for the Gas pipeline section, 3.6. Initially, data on the existing infrastructure connecting Sines to Carriço will be analysed. Then, 2 system designs will be proposed: building a new dedicated pipeline or retrofit the existing one. In order to differentiate them from the scenarios considered for the Hydrogen production section, they will be mentioned as *pathways*. For both pathways it will be confirmed that the infrastructure can accommodate the project's peak capacity needs. Then, the costs will be covered and the allocation to the *Sines* H_2 *Hub* made.

Lastly, section 3.7 will consolidate the data from both Salt cavern (storage) and Gas pipelines (transmission). The levelized cost of the 4 possibilities of infrastructure combinations of hydrogen transmission and storage of this project will be calculated. This will be made with data from each of the sections previously detailed and the total mass stored over the complete year as detailed in the hydrogen production section. Economic factors relevant for the calculation, such as annuities, equipment lifetime and others will be exposed in this section.

3.2. System design & boundaries

Summed up in figure 3.2 is presented a flowchart that outlines the different processes involved in the most relevant parts of the value chain. It is important to have in mind that the main scope of this research is the transmission and storage infrastructure.

To have a better understanding, the flowchart outlines in green the processes which were considered in this investigation and in grey other relevant sections of the value chain that were not considered but are important to mention. Additionally, the temperature and pressure ranges conditions which were considered are exposed. The way the data was retrieved or calculated will be elaborated later in the report. Furthermore, other factors such as distances and location are also presented.

Overall, the system will initiate at the outlet of the hydrogen production facility. Then, the compression and transmission up to Carriço will be covered along with the compression and storage in the salt cavern. The transmission back to Sines up to the inlet of the ammonia production facility will also be considered. Aspects related to temperature adjustment and pressure reduction in Carriço will not be approached as they are believed to be insignificant in terms of cost assessment. Nevertheless they were exposed to have a comprehensive view on the the temperature and pressure fluctuations.

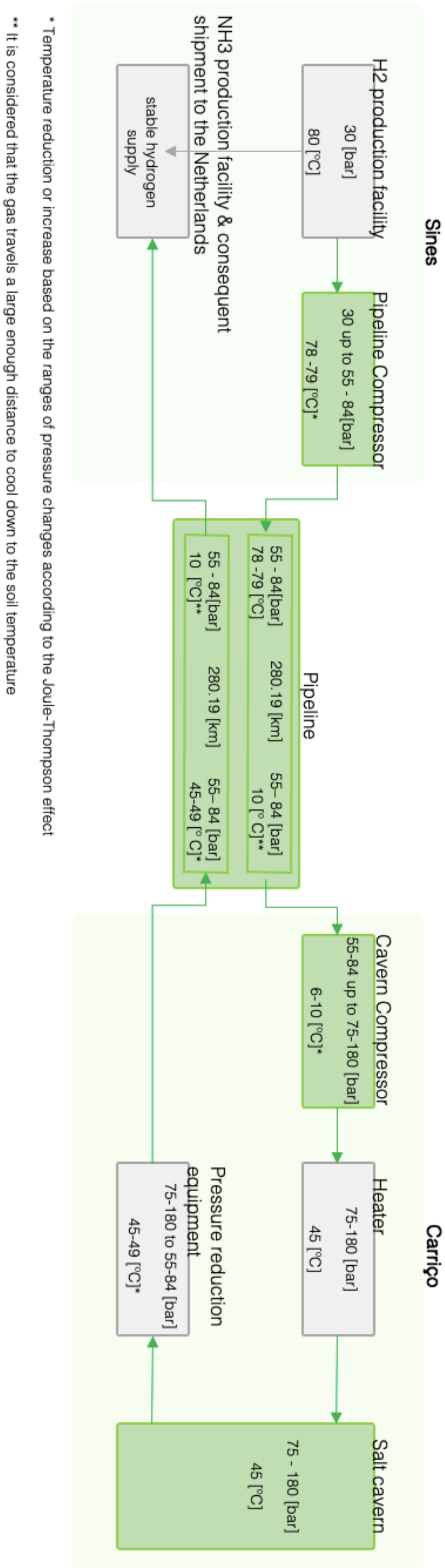


Figure 3.2: Flowchart of system design and boundaries. In green what is covered in this study, in grey what is outside the scope

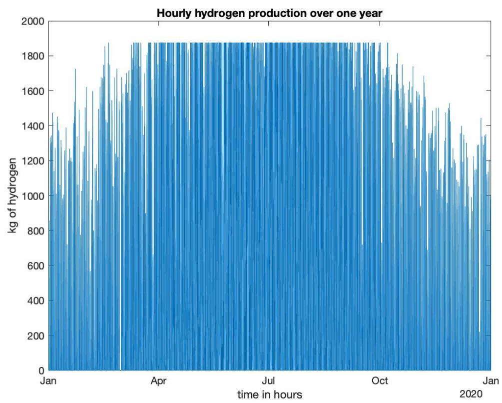
3.3. Hydrogen production

This section will focus on studying the expected hydrogen production in Sines. This will be elaborated based on data shared by Resilient Group and analysed in Matlab [47]. Section 3.3.1 will be dedicated to understand the data retrieved by collecting total mass volumes, maximum capacities, etc. Then, section 3.3.2 will manipulate the data according to the project's transport and storage needs. This data will be valuable for three main research components:

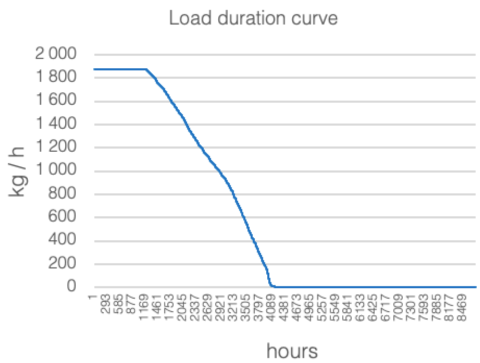
1. making sure that the system designed can accommodate the hydrogen volumes of this specific project;
2. accurately allocate the overall costs to the project in specific;
3. normalize the final levelized hydrogen cost of storage and transport to a kg base.

3.3.1. Data collection

A hydrogen production facility is expected to be built in Sines with a capacity of 1GW by 2030. The consortium coordinating the project kindly shared its' expected hydrogen production on a hourly basis for a complete year [47], which can be seen in figure 3.3a. One can note that the production varies on a daily basis, because it is dependant on daily solar irradiance. Additionally, it also stands out that the production is capped at 1 865kg/h, this happens due to the system's overall capacity, which was set by [47] and its' analysis is outside the scope of this research. It is also possible to outline the seasonal fluctuation - higher outputs in Summer months - also due to increased solar irradiance during this period when compared to Winter. As it can be seen in table 3.1, Summer total production is by a factor or around 1.7 larger than Winter's.



(a) Expected hourly hydrogen production, data provided by Resilient Group and plotted in Matlab



(b) Load duration curve, data provided by Resilient Group and plotted in Excel

Figure 3.3: Hydrogen production in Sines over one year

Throughout the year there are 1 998 hours which the hydrogen production facility is being run at full power (1 865 kg/h). In figure 3.3b which presents the hourly production in descending order regardless of the timestamp, this is depicted by the constant initial plot stable at 1 865. Then, in a somewhat linear manner the overall production decreases up to 0 - mostly representing nights. If these productions which are not at full power nor at zero, are accumulated and divided by the maximum capacity, one can get the equivalent number of hours if ran at full power, i.e., the equivalent full load which is 2 857 hours, about 32.6% of a complete year.

Table 3.1: Key data on hydrogen production, data retrieved from [47]

Parameter	Value
Total yearly production [kg]	5 338 928
Peak capacity [kg/h]	1 865
Hours at peak capacity [h]	1 998
Equivalent hours if production is at full capacity [h]	2 847
Share of hours in a year at equivalent full capacity [%]	32.6
Summer total production (May to October) [kg]	3 394 768
Winter total production (November to April) [kg]	1 944 160
Ratio total Summer by Winter production [-]	1.7
Pressure at outlet [bar]	30
Temperature at outlet [°C]	80

Table 3.1 presents other relevant data such as the pressure and temperature conditions at the outlet of the production facility: 30 bar and 80 °C, respectively. It is important to note that these conditions will be the same conditions at the pipeline inlet. Furthermore, given the scope of this project: transmission and storage of hydrogen to act as a buffer to a possible ammonia or LOHC conversion, there is a need to stabilize the hydrogen production. Thus, the storage system will act on a daily basis to either store the extra hydrogen not needed at the conversion facility or to supply it [51]. This aspect will be covered in the following section.

3.3.2. Production stabilized: daily, monthly & yearly

As previously pointed out, there needs to be a stable hydrogen supply, thus, the real production as seen in figure 3.3a needs to be handled in a way that the surplus of a certain target is stored and then supplied in times of hydrogen shortage - at night. In order to stabilize it, three possible stabilization scenarios (targets) were created: over one day, over one month and over one year. This way the model is adapted so that the flexibility of a future ammonia facility is not compromised. Figure 3.4 presents such stabilisations which, if the storage needs model runs smoothly, will be the final hydrogen supply to such facility. In blue one can note 365 average productions, i.e., the daily stabilization scenario. In red, 12 average productions, i.e., the monthly stabilization scenario. And in yellow the average of total production, i.e., the yearly stabilization scenario.

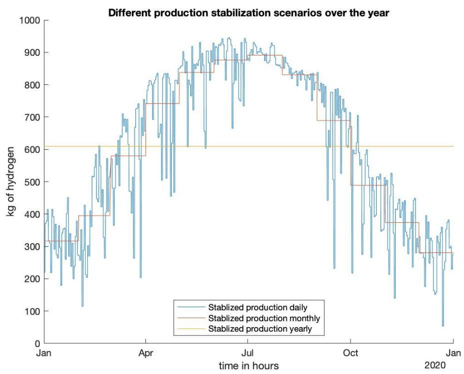


Figure 3.4: Stabilized hydrogen productions: daily, monthly and yearly

For each of the scenarios, figure 3.6 presents both the respective stabilized production (target) in red and the real production in blue, which is common for the three scenarios. Here one can clearly note the differences between the different scenarios over a typical week that ranges between two months (so that the difference between monthly and yearly could be outlined): 28th of March to 4th of April.

The storage needs are possible to calculate by computing the difference between the stabilized production (target) and the real production. If the real production is higher than the target, there will be a need to transport and store hydrogen to the salt cavern. On the other hand, if it is lower, the need will be to withdraw it from the cavern and transport it back to Carriço. These storage needs were calculated for each of the scenarios over the whole year. To have a better understanding of such behaviour, the storage needs over the same typical week can be seen in figure 3.7.

To fulfill the three purposes outlined at the beginning of this *Hydrogen production* section, it is interesting to calculate three variables for each of the storage needs scenarios as outlined in table 3.2: maximum absolute peak capacity, maximum absolute mass to store/withdraw over a *cycle* and total mass stored over a complete year.

The first will be given by the maximum absolute value of the storage needs. This will be calculated first by determining the maximum and minimum values of each of the plotted scenarios and then retrieve the absolute maximum of each. This variable will indicate the minimum capacity that infrastructure such as gas pipelines will need to have. The second variable, maximum absolute mass to store/withdraw over a *cycle*, will be computed by calculating the areas between each of the *storage needs plot* and the *x-axis*. This integration will be the mass that needs to be stored or withdrawn over the "largest cycle", thus, it will later be used for sizing allocations in the salt cavern. Initially it will be calculated by determining the absolute maximums of the mass to store and the maximums of the mass to withdraw. Then, the absolute maximum of the two (store or withdraw) will determine the maximum absolute mass to store/withdraw over a *cycle*. The third variable, total mass stored over a complete year is the exact same as the total mass withdrawn over a complete year. By calculating it, one will have an insight on the total mass of hydrogen that the transmission and storage system *processed*. This variable can be determined by calculating the whole area that lies above **or** below the x-axis and the storage needs plot and will be used to normalize the final levelized cost of hydrogen transmission and storage.

These variables will then serve as input for other parts of this research, thus, for sake of simplicity and to be conservative using the data, the absolute maximum between the three scenarios will be the value which will be considered for the following sections - 4th column of table 3.2. This will guarantee that the system designed will be flexible enough to accommodate and adapt to any of the stabilization scenarios: daily, monthly or yearly. For example, as seen in table 3.2 the maximum capacity for the daily, monthly or yearly scenarios is: 1 483, 1 480 and 1 266, respectively. This means that to design a system capable of accommodating the three scenarios, it would need to have a capacity of at least 1 483 kg/h (daily scenario), whereas, if one looks at the maximum mass to store/withdraw over 1 cycle, the maximum value between the three scenarios, comes from the yearly stabilization scenario.

Table 3.2: Comparison of storage needs scenarios data

	Daily	**Monthly**	**Yearly**	Absolute maximum
Max peak capacity [kg/h]	1 483	1 480	1 266	1 483
Min peak capacity [kg/h]	-945	-891	-609	945
Max absolute peak capacity [kg/h]	1 483	1 480	1 266	1 483
Max mass to store in 1 cycle[kg]	10 512	12 065	14 729	14 729
Max mass to withdraw in 1 cycle [kg]	-10 534	-10 867	-24 089	24 089
Max absolute mass to store/withdraw in 1 cycle[kg]	10 534	12 065	24 089	24 089
Total mass stored over 1 year [kg]	2 859 911	2 883 683	3 038 191	3 038 191
Total mass withdrawn over 1 year [kg]	-2 859 911	-2 883 683	-3 038 191	3 038 191
Load Factor Equivalent [%]	22.0	22.2	27.4	27.4
Total number of cycles [-]	370	375	372	n/a

Furthermore, it is possible to calculate the Load Factor Equivalent for each scenario. This value will represent the equivalent share of time over a complete year needed to process the hydrogen mass throughput at maximum capacity. For each of the scenarios such calculation was made having in mind their respective profiles and exposed in equation 3.1, where the following variables were considered: Total Mass Stored Over 1 Year, in [kg], Max Absolute Peak Capacity, in [kg/h]. In order to maintain a conservative approach, out of the 3 scenarios, the highest value: 27.4% will be considered as input for future parts of the research.

$$LoadFactorEquivalent = \frac{TotalMassStoredOver1Year}{MaxAbsolutePeakCapacity} \cdot \frac{1}{8760} \cdot 100 \quad [\%] \tag{3.1}$$

Additionally, it is interesting to look at the number of cycles each scenario has over one year. As one can note from table 3.2, the daily has 370, the monthly 375 and the yearly 372. Despite the maximum absolute mass to store over one cycle of the yearly scenario being significantly larger than the others, such dimension does not implicate fewer cycles over one year. The difference that makes the yearly scenario have a much larger mass to store comes from the stabilization target (around 600kg) throughout the whole year. While the other scenarios “adjust” their target to the production throughout the year.

This will translate into longer periods at which the difference between target and real production will be high. Alternatively, in the other two scenarios, the target will be more adjusted to that period’s production. Thus, there will be less periods in which target and real production differ the most. Therefore, in the yearly scenario such peak capacity storage needs sustained for several periods will demand a larger mass to store/withdraw.

As for the number of cycles being more than the 365 days of the year, it can be explained by the weather patterns. The hydrogen production is dependant on solar irradiance, thus, only when the sun shines, there will be production. One regular sunny day implicates one cycle: storage of extra hydrogen during the day and withdraw at night. Nevertheless, there will be cloudy days in which hydrogen production will be very irregular during the day. Figure 3.5 presents an example of the impact that solar irradiance can have on the storage needs profile. One can note that on the 9th of February, in what would be a period to store hydrogen, for some periods the storage needs profile actually needs to withdraw hydrogen. Therefore, for this day in particular more than 1 cycle will be needed, hence the more than 365 cycles over 1 year.

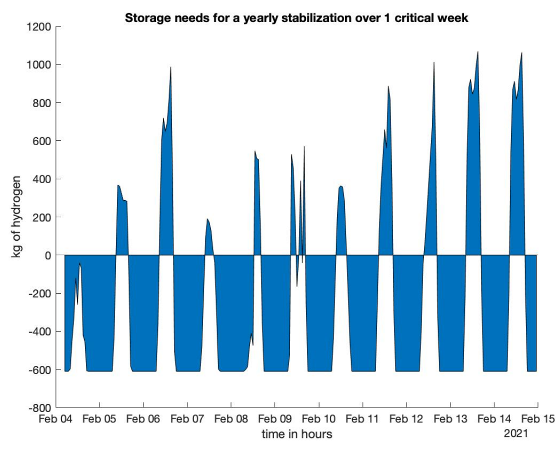
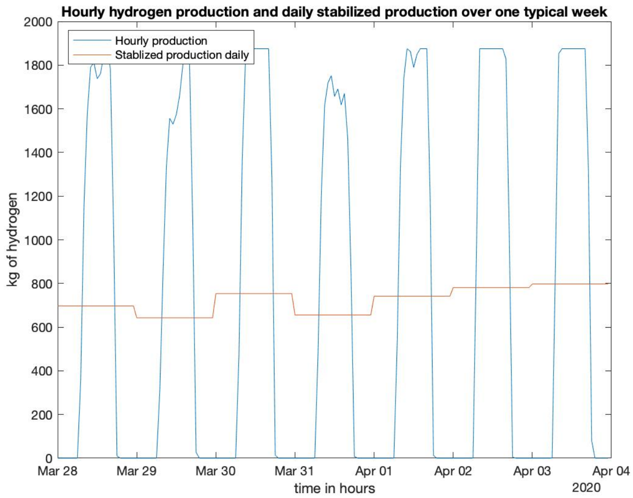
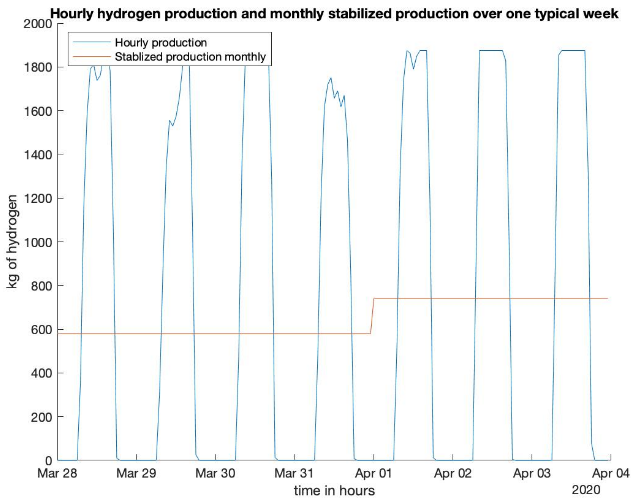


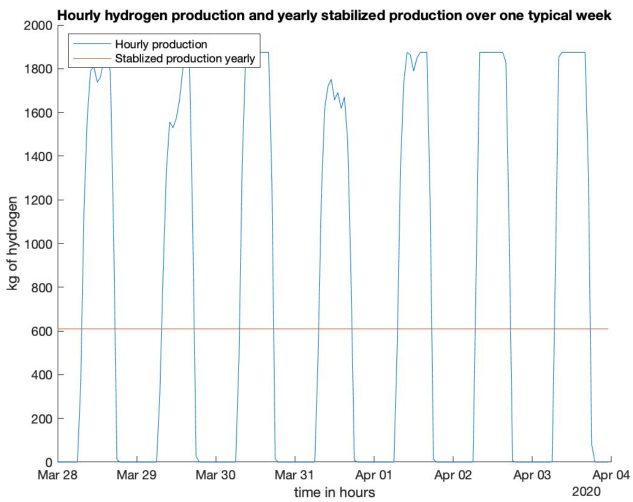
Figure 3.5: Example of period with more cycles than days



(a) Stabilized daily

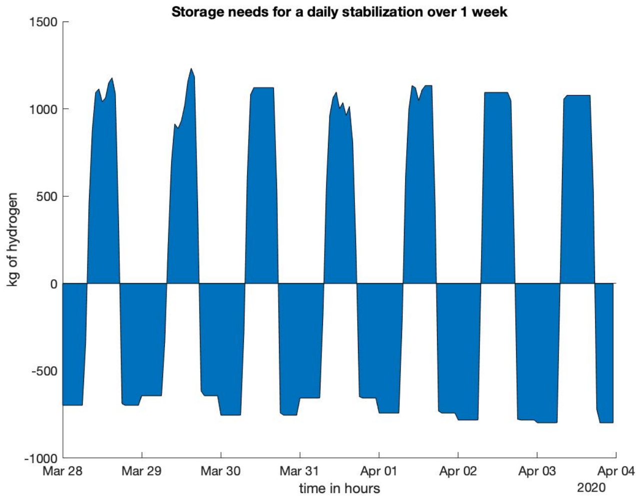


(b) Stabilized monthly

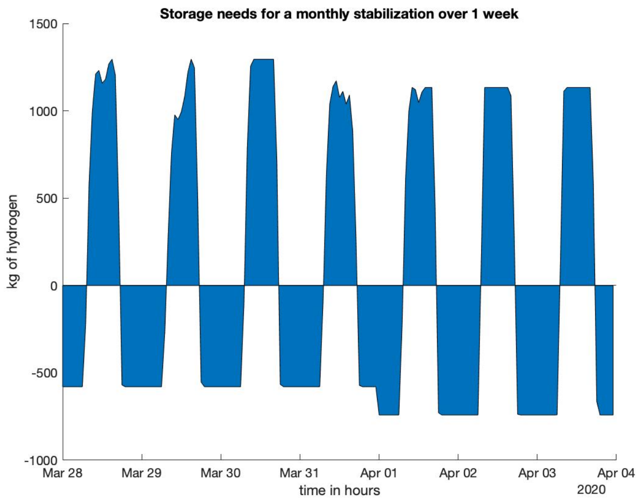


(c) Stabilized yearly

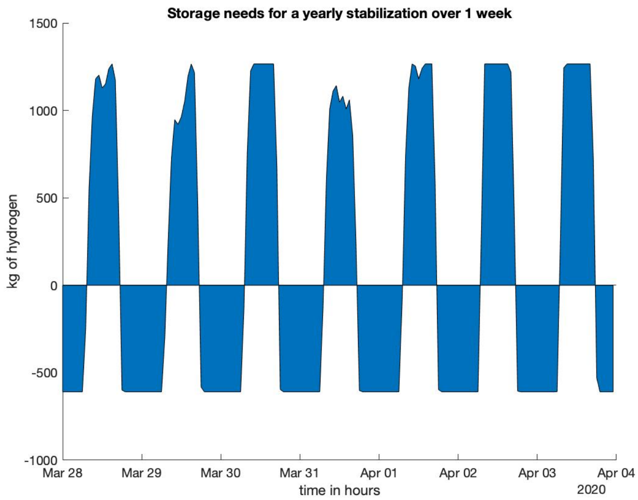
Figure 3.6: Hourly production and stabilized production over one typical week 28.03-04.04



(a) Given daily stabilization



(b) Given monthly stabilization



(c) Given yearly stabilization

Figure 3.7: Storage needs over one typical week 28.03-04.04

3.4. Compressors

This section will describe the theory and model considered for the power design of the cavern and pipeline compressors. Given the importance of the power design in the storage and transmission infrastructures, this will be made in a dedicated section which collected inputs from their respective pathways and literature, calculate the power and then feed back into the respective cost models, as outlined in the research scheme 3.1.

The work of an isothermal compression, assuming an ideal gas behaviour is given by the following expression, where p_0 and p_1 are the initial and final pressures in [Pascal], respectively, and V is the volume, in $[m^3]$:

$$W = p_0 \cdot V \cdot ln\left[\frac{p_1}{p_0}\right] \quad [J] \tag{3.2}$$

It is important to have in mind that in practice the compression will not be isothermal. Heat will be formed in the process of compression which can have consequences dependant on the easiness the system will have in dissipating the heat. For very slow processes it will be able to dissipate most of it to the surroundings, but for high pressure systems when such is not possible, the heat will be kept inside the system. Figure 3.8 presents the impact an adiabatic compression can have on the required energy in compression when compared to a isothermal one. Also outlined is the practical compression that ends up occurring and which can be given by the average of the two: isothermal and adiabatic [30].

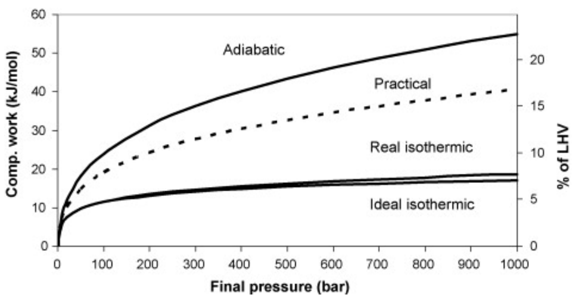


Figure 3.8: Energy required to compress hydrogen from 1 bar to the final pressure specified on the primary axis, [30]

Furthermore, other aspects such as isentropic efficiency, compressibility factor and a compression in several stages can be also considered. Thus, by manipulating the equation and inputting such variables, one ends up with the equation used by [8] in its' Argonne model:

$$Power = Z \cdot \dot{m} \cdot R \cdot T \cdot ns \cdot \frac{1}{\eta} \cdot \frac{k}{k-1} \cdot \left[\frac{P_{outlet}}{P_{inlet}}^{\frac{k-1}{n \cdot k}} - 1 \right] \quad [kW] \tag{3.3}$$

Where, Z is the mean compressibility factor, dimensionless [-], $\dot{m}$ is the mass flow rate in $[kg \cdot mol \cdot s^{-1}]$, R is the universal gas constant in $[KJ \cdot kg^{-1} \cdot mol^{-1} \cdot K^{-1}]$, T is the inlet gas temperature in [K], ns is the number of stages, dimensionless [-], η is the isentropic efficiency, dimensionless [-], k is the ratio of specific heats, dimensionless [-], P_{outlet} is the compressor discharge pressure, in [Pascal] and P_{inlet} is the compressor inlet pressure, in [Pascal].

The required power for the two compressor systems - cavern and pipeline system - was modeled in Matlab using the same methodology, previously exposed, but different inputs, dependant on the characteristics of each infrastructure. It is important to note that these characteristics vary between cavern and pipeline compressor (infrastructure), but do not vary between each respective pathway. This is because the temperature and pressure conditions change throughout the overall system (e.g: pressure inside the cavern is different than the pressure in the pipelines) but are assumed to be the same for the pathways of each infrastructure (e.g: temperature inside the new pipeline is assumed to be the same as the temperature inside the retrofitted pipeline).

On the other hand, there will be some inputs common for both compressors due to the same characteristics such as: the maximum flow or hydrogen being the gas compressed. These inputs given for both compressors can be summarized in the following table:

Table 3.3: Inputs common for both compressors - pipeline and cavern

Input	Value	Source
$\dot{m}$ [kg/h]	1483	Based on storage needs profile. Presented in table 3.2
R [J/mol/K]	8.3145	Given
n [-]	2	Assumed to be the same as the one used in the Argonne model, [8]
η [-]	0.88	Assumed to be the same as the one used in the Argonne model, [8]
k [-]	1.4	Given

Having this said, it is now possible to expose the inputs and consequent result used for the power calculation of the two different compressors. It is important to note that the compressors were designed to have sufficient power to compress the maximum possible pressure difference. In practice, this will mean that, when possible, the lowest value in the range at the inlet and the highest value in the range at the outlet will be considered. To better understand this it is useful to have in mind the flowchart presented in figure 3.2. Please note that the assumptions and reasoning for each of the following inputs will be later exposed in the data collection subsections of the respective infrastructures.

Table 3.4: Inputs for each compressor - pipeline and cavern

	Pipeline	Cavern
T [°C]	80	10
P_{inlet} [bar]	30	55
P_{outlet} [bar]	84	180
Z [-]	Calculated for the given p,T conditions	Calculated for the given p,T conditions
$Power$ [kW]	774	748
Max Energy Intensity $[kWh \cdot kg^{-1}]$	0.52	0.50

As noted in the table, the maximum energy intensity, in $[kWh \cdot kg^{-1}]$ was also calculated for each of the infrastructures. This value represents how much energy it costs per kg of hydrogen to compress from 30 to 84 bar (for the pipeline compressor) and from 55 to 180 bar (for the cavern compressor). Please note that according to equation 3.3, the inlet temperature will play a critical role, thus, a larger pressure difference does not necessarily mean higher power needs. Having this said, the maximum energy intensity can be given by:

$$MaxEnergyIntensity = \frac{Power_{Compressor}}{MaxPeakCapacity} \quad [kWh \cdot kg^{-1}] \tag{3.4}$$

Where the $Power_{Compressor}$ is the power previously calculated for either pipeline or cavern compressors, in [kW], and the Maximum Peak Capacity is the maximum hydrogen flow, exposed in table 3.2 of 1 483 [kg/h]. These Maximum Energy intensity factors will then serve as inputs in determining the energy bill costs of both infrastructures.

3.5. Salt caverns

This section will expose the relevant methodology related to the cost calculation of the storage infrastructure in the context of the *Sines H_2 Hub* . Firstly, subsection 3.5.1 will elaborate on the characteristics of the existing storage infrastructure in Carriço. Then, subsection 3.5.2 will expose the approach which was considered in designing the system. Thirdly, the cost parameters considered will be exposed over subsection 3.5.3. And lastly, subsection 3.5.4, will be give an explanation on how the calculated costs were allocated to the *Sines H_2 Hub* .

3.5.1. Data collection

To assess the best technological option for hydrogen storage in the Carriço, technological data must be collected on the system. REN Armazenagem is TSO operating the system, thus, several approaches for a possible collaboration were made, nevertheless, they were not successful. Having this in mind, other sources which have that same TSO as a direct source were used. These sources mostly focus on technological aspects, therefore, no relevant economic data on the caverns was possible to collect.

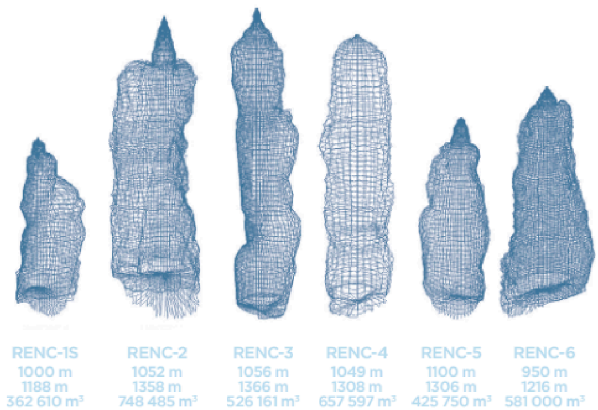


Figure 3.9: Schematic of the 6 Carriço salt caverns volume, [44]

The relevant data which will be used as input in future parts of this report, can be summarized in table 3.5. The Carriço system, which currently stores natural gas, comprises of 6 salt caverns with volumes ranging 362 610 – 748 485m^3. Additionally, the facility also operates infrastructure of brine and water removal. Aligned with pressure-depth limits outlined in figure 2.5, the caverns operate at a variable pressure ranging from 75-180 bar at a depth ranging from 950-1366m.

Table 3.5: Key data on Carriço salt caverns

Parameter	**Value**	**Source**
Pressure range [bar]	75-180	[50]
Temperature [°C]	45	[3]
Volume [m^3]	6 different caverns with different volumes ranging from 362 610 – 748 485	[44]
Depth [m]	950-1366	[44]
Height [m]	200-300	[44]
Total natural gas storage capacity [GWh]	3 967	[44]
Total natural gas storage capacity [Mm^3(n)]	333	[44]
Availability to build extra caverns [-]	Yes	[9]

It is important to note that the site has technical and geological conditions to build additional caverns. Several studies indicate there is the possibility of expanding up to 25 caverns [9]. Thus, it is an option to consider building a new cavern dedicated to a pure hydrogen operation. This way there would be no interference with the natural gas operation currently in place.

3.5.2. Design of 2 pathways: new or retrofitted cavern

Given the fact that no technical nor economic information is available on the possibility of converting the existing caverns to a hydrogen based operation, a two pathway approach will be followed. This approach will consist of keeping open both possibilities of: building an extra cavern or retrofitting an existing one to hydrogen. Furthermore, this way a more informed and data driven decision will be possible to make in the future on which pathway to follow.

For the option of retrofitting an existing cavern to a hydrogen based operation, the temperature and pressure conditions exposed in the previous section will be considered. Furthermore, the selected cavern will be the one with the smallest volume: 362 610 m^3, as it will later be confirmed to be sufficient to store the project's hydrogen storage needs. For the newly built cavern, it will be assumed to have the same temperature and pressure conditions as the existing ones - same geological conditions are assume to lead to same cavern conditions. As for the volume, it will be considered that it will have the same geometrical volume as the average volumes of the existing salt caverns with variable pressure - detailed in table 2.2 - of: 684 000 m^3.

Having this said, the cost model soon to be exposed will have two pathways determining the different costs of storing hydrogen in the salt cavern. The inputs and data will be based on the values just previously mentioned.

To confirm that the cavern designs outlined can accommodate the storage needs and also for the calculation of inputs later used in the cost model, it is of interest to calculate the total mass of hydrogen that can be stored under such conditions in both cavern pathways. This assessment will be made using the *Ideal gas law* which is given by:

$$p \cdot V = n \cdot R \cdot T \tag{3.5}$$

Where p is the pressure in [Pascals, Pa] at which the gas is at, V the volume it occupies in [m^3], n the number of moles [-], R the universal gas constant of 8.3145 [J/mol/K] and T the temperature in [Kelvin, K]. In practice, at high pressures the gas behaviour might not be represented by such equation, thus, a compressibility factor is usually added to represent this adjustment to practical gas behaviour [1]. By manipulating the equation and introducing such factor one can end up with the following equation:

$$m_{H_2} = \frac{p \cdot V \cdot M}{R \cdot T \cdot Z} \tag{3.6}$$

Where m_{H_2} is the mass in [g, grams], M is the hydrogen's molecule molar mass of 2 [g/mol] and the compressibility factor Z is dimensionless. Then, to calculate the total mass of hydrogen that the cavern can store, the following inputs will be considered and converted to the units previously noted: a 45°C temperature, a pressure range of 75-180 bar to illustrate the mass it can store according to the pressure swings, both cavern geometric volumes of 362 610 and 684 000 m^3, the given molar mass and gas constant and a compressibility factor. This compressibility factor will be calculated by Van der Waals equation of state through the matlab model developed by [20].

The results are presented in table 3.6. It is important to highlight that what most differentiates both pathways are the very different cavern volumes of 362 610 m^3 and 684 000 m^3 for the retrofitted and newly built caverns, respectively. Furthermore, it is possible to note that both pathways have range limits way above the maximum mass to store over one cycle, as determined by the storage needs - check table 3.2, of 24 tons H_2. This means that both pathways are confirmed as suitable to accommodate the storage needs - in a context of a broader use of the salt cavern by third party hydrogen storage users.

Table 3.6: Range of mass of hydrogen stored by the 2 pathways:new and retrofitted caverns according to pressure swings 75-180 bar

	$mass_{minH_2}$ for p =75 [bar]	$mass_{maxH_2}$ for p=180 [bar]
Retrofitted cavern [tons H_2]	2 000	4 558
Newly built cavern [tons H_2]	3 700	8 598

3.5.3. Cost breakdown

As literature points out the main costs regarding the capital expenditures of a salt cavern include: site preparation, cushion gas, compressor and well costs. As for the operational costs they include: compressor energy bills and the O&M of cavern and wells. Each of these cost components will be analyse in a dedicated section. Furthermore, it will be outlined in each section the contribution costs will have on each of the cavern pathways.

Site Preparation CapEx

It is the cost of constructing the cavern, namely, mining it and the overall process as described in section 2.2.2. It has a variable component related to the mining costs dependant on the cavern´s volume of $23[\$/m^3]$ and a fixed component associated with the leaching plant costs of \$10M [34], the exact cost breakdown of each of these components was not detailed in the respective source. Moreover, the total cost was converted from USD to EUR with a conversion rate of 1 USD = 0.85 EUR.

$$SitePrep_{CapEx} = (23 \cdot CavernVolume + 10.000.000) \cdot 0.85[€] \tag{3.7}$$

This cost component is only considered for the pathway which plans to build a new cavern. For the pathway that plans to use the existing caverns, this cost is avoided. Thus, the volume considered is 684 000 m^3 as detailed in the previous section.

Cushion Gas CapEx

The cushion gas represents the minimum amount of gas the cavern needs to have in order to maintain it's adequate pressure operational safety. In practice this cost component will represent the cost spent on the hydrogen that will be inside the cavern and can never be used during its' operation. To calculate it, one only needs to multiply the minimum mass of hydrogen the cavern needs to have - the lower limits exposed in table 3.6 of $mass_{minH_2} forp = 75[bar]$- by the cost of producing the hydrogen.

$$CushionGas_{CapEx} = mass_{minH_2} \cdot CostH_2[€] \tag{3.8}$$

Regarding the cost of hydrogen, the Portuguese government expects to create a mechanism to support hydrogen production. The mechanism intends to pay producers the difference in cost between natural gas and hydrogen production. The hydrogen produced in Sines is expected to fall under this category, thus the cost considered will be the cost of natural gas [35]. As of 2019 the cost of natural gas in Portugal for non-household consumers was of 0.0239€/kWh [16], then by considering a conversion factor of 1 kg_{H2} = 0.039 MWh (HHV), a subsidized cost of hydrogen can be determined: $0.9€/kg_{H2}$.

It is important to note the cushion gas will have a residual value at the end of the analysis period. Thus, it was assumed that at the end of the period, the gas would be *sold* and have a positive impact on the cost accounting. A 60% hydrogen cost drop [23] out of the current average price of hydrogen for Europe according to the [26] of 2.5€/kg was assumed to be the selling price. The remaining factors such as WACC and number of periods essential to calculate the present value, will be later discussed in this report. This cost will be considered for both retrofitted or new cavern.

Cavern Compressor CapEx

To calculate the CapEx of the compressor a cost function as described in the Hydrogen Delivery Scenario Analysis elaborated by Argonne was used [5]. It is a function of power that calculates the CapEx of the terminal storage compressor. Additionally, as suggested, a 1.3 installation cost factor was considered [4] as well as a conversion factor of 0.85 USD to EUR. The cavern compressors' power, in kW, has already been determined in section 3.4, and has a power of 748 [kW]. It is important to mention that this cost will also be considered for both retrofitted or new cavern.

$$CavernCompressor_{CapEx} = 1.3 \cdot 0.85 \cdot 40528 \cdot Power_{CavernCompressor}^{0.4603} [€] \qquad (3.9)$$

Well CapEx

The well acts as an effective conduit for hydrogen flows between cavern and surface. It has an important role in delivering the necessary flow rates and in maintaining and ensuring the integrity of seal. The use of retrofitted natural gas wells is discarded as [6] found it not to be suitable to use natural gas wells for a hydrogen based operation, thus, this cost component will also be considered for both retrofitted or new cavern pathways. The cost was extracted from literature which was found to have a fixed cost per well of: \$1.15M [34]. The monetary conversion factor is the same as previously used.

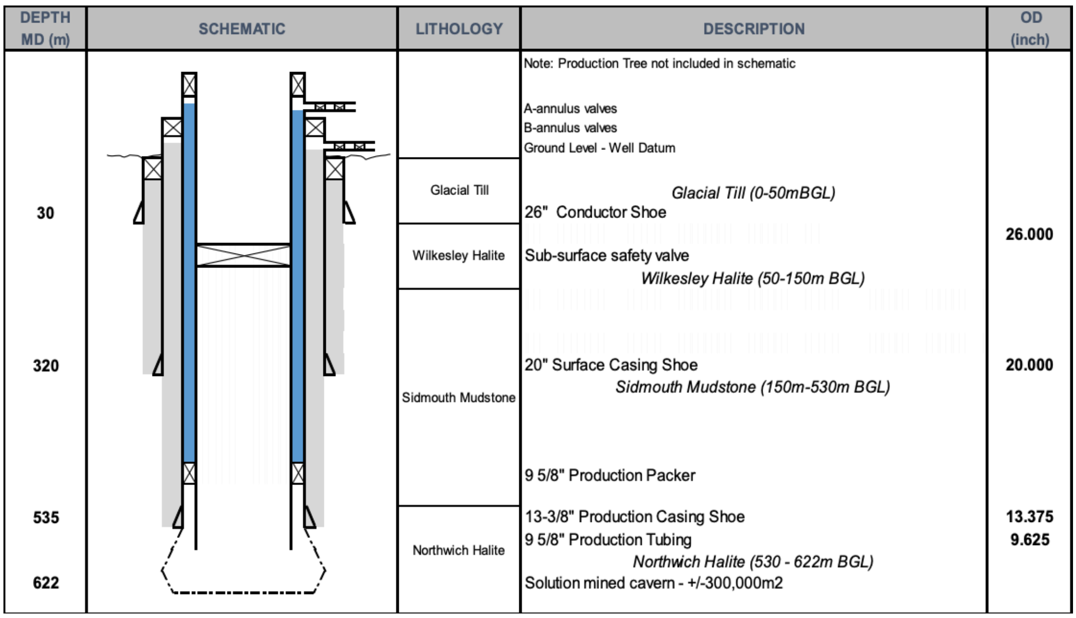


Figure 3.10: East Yorkshire conceptual well design proposal, [6]

Figure 3.10 presents a well design proposed to build a salt cavern in East Yorkshire, UK. On the first column one can note the depths; on the second the proposed scheme; on the third the lithology; on the fourth the equipment description used in the several parts of the well along with the depth of each lithology segment; and on the fifth column the well's outer diameter in inches. It is important to note that this example does not necessarily apply to a cavern built in Carriço, the lithology will likely be different and the equipment used as well. Nevertheless, it presents a clear picture of what a salt cavern well can look like.

Cavern Compressor OpEx

The operational expenditures of the cavern compressor considered are the energy bills in the form of electricity input to feed the compressing work. These bills were determined based on three parameters: electricity price in [€/kWh], compressor's maximum energy intensity in [kWh/kg] and total mass stored over 1 year in [kg], exposed in the following equation:

$$CavernCompressor_{OpEx} = Electricity_{Price} \cdot MaxEnergyIntensity \cdot TotalMass \quad [€/year] \tag{3.10}$$

The first, electricity price, is assumed to be the same as 2019's throughout the years. The value of 0.056 [€/kWh] for non-household consumers with a consumption in the given range: 2 000 MWh - 19 999 MWh (range in which electricity demand of total compression will fall) was retrieved from [17]. Please note, that as previously seen in figure 2.9, this value is above the EU average. Furthermore, other options such as cheap solar power instead of a power supply from the grid, could be considered, thus further reducing the energy bill. Having this said, one can point out that the electricity price will likely overestimate the compressors' OpEx.

The second input, compressor's maximum energy intensity, was determined in section 3.4 and found to be 0.50 for the cavern compressor. Please note that this factor is calculated based on the assumption that the compressor is working at maximum power compressing hydrogen from 55 to 180 bar. In practice such will not end up happening, for example: if the gas arrives to Carriço via pipeline at 84 bar and the cavern is at 85 bar, there will be very little compressing needs, however this assumption will consider they will be maximum (55 to 180 bar). And lastly, the third factor is the total mass of hydrogen throughput over one year, given in table 3.2 and with a total value 3 038 191 kg.

Well & Cavern OpEx

As for the well and cavern O&M, this research based itself on the report elaborated by [6]. The report collected cost data from several salt caverns out of which two can be comparable to the ones in Carriço. It's OpEx data include:

1. annual wellhead maintenance;
2. 5 yearly sonar surveys of caverns;
3. 10 yearly calliper surveys of the wells.

The two mentioned caverns have 30 years OpEx costs of £9.3M and £8.4M. Thus, as suggested by one of the authors in a private note [38], the annual OpEx considered was 1/30 of the average of the two values: £295 000. Then the value was converted to EUR by considering a 1.1 GBP to EUR rate.

$$Well\&Cavern_{OpEx} = 295000 \cdot 1.1 [€/year] \tag{3.11}$$

3.5.4. *Sines* H_2 *Hub* cost allocation

One must have in mind that the costs calculated are the overall costs for implementing and operating the caverns. As one can note, namely in table 3.6, the infrastructure is oversized for the *Sines* H_2 *Hub* so that third parties can also make use of it, thus, creating economies of scale.This section will allocate the costs of the complete infrastructure to the *Sines* H_2 *Hub* . To do so the main cost drivers, which are summarized in table 3.7, will be identified and then used to proportionally allocate the costs.

The **Site preparation CapEx and Cushion gas CapEx** cost components are considered highly dependant on the volume. If only a small share of the total potential volume of the cavern is used, the smaller the respective allocation to the *Sines* H_2 *Hub* and the more volume left for third parties to use. Thus, the share of volume the project will use will be calculated for both new and retrofitted caverns 3.7 in the following manner:

$$VolumeAllocationFactor = \frac{VolumeNeeds}{Cavern'sGeometricVolume} \quad [\%] \tag{3.12}$$

The calculation of the *volume needs* for the *Sines* H_2 *Hub* will be based on the Ideal Gas Law. As both pathways will operate with the same temperature and pressure conditions, it is reasonable to consider that the *volume needs* will be the same for both pathways.

$$VolumeNeeds = \frac{Mass_{maxstored} \cdot R \cdot T \cdot Z}{p \cdot M} \quad [m^3] \tag{3.13}$$

The mass considered is the maximum mass to store over 1 cycle as described in table 3.2, thus 24 089 kg_{H2}. The temperature assumed was 45°C and the pressure of 75 bar, the minimum cavern pressure, so that the volume needs are maximized and the most conservative approach followed. Then, the volume needs were calculated and determined to be: 4 366 m^3. After this, by considering the caverns' geometric volumes and equation 3.12, the volume allocation factor for both pathways was calculated: 1.20% for the new cavern and 0.64% for the retrofitted one.

The main cost driver considered for the **Cavern Compressor CapEx, Well CapEx and Well OpEx** was the share of time the equipment was operating due to the *Sines* H_2 *Hub* hydrogen flows. It is a simplistic approach because additional volumes of hydrogen, not relative to the project, could also flow through such equipment during those periods, thus making the equipment run at full capacity. Such share is 27.4%, the equivalent load factor calculated in section 3.3 and exposed in table 3.2.

As for the **Cavern Compressor OpEx**, there is no need to allocate the energy bill costs to the *Sines* H_2 *Hub* since such allocation has already occurred when determining the cost component itself. As one can note, the component depends on the Maximum Energy Intensity and Total Hydrogen Mass over 1 year. Since the total mass considered was only the total throughput of the *Sines* H_2 *Hub* , this will act as cost allocation factor. Therefore, this part of the research does not need make any allocation as it would be double accounting.

Furthermore, one must have into consideration that after the gas is stored in Carriço, it needs to travel back to Sines. Since the same equipment will be used, the method to consider such *extra* costs will be made through the cost allocation factors. The costs that need to be considered are only from the point the gas is started to be withdrawn from the cavern onwards.

Table 3.7: Storage cost drivers & project allocation for each cost component

Cost Component	Identified Cost Driver	Retro Allocation	Retro Final Cost	New Allocation	New Final Cost
Site Prep CapEx	Cavern's volume	n/a	0	1.20%	139 k€
Cushion Gas CapEx	Cavern's volume	0.64%	19 k€	1.20%	19 k€
Cavern Compressor CapEx	Load Factor Equivalent	27.4%	258 k€	27.4%	258 k€
Well CapEx	Load Factor Equivalent	2x27.4%	535 k€	2x27.4%	535 k€
Cavern Compressor OpEx	(already allocated on energy bill)	(100%)	85 k€/year	(100%)	85k €/year
Well & Cavern OpEx	Load Factor Equivalent	2x27.4%	177 k€/year	2x27.4%	177 k€/year

Thus, the costs upstream such as Site Prep CapEx, Cushion Gas CapEx, Compressor CapEx and OpEx do not need to be accounted - check figure 3.2. Having this said, in order to consider the hydrogen flows from Carriço to Sines in the storage infrastructure, one only needs to account for the Well CapEx and OpEx. To do so, since the allocation factor is a time based load factor, i.e., based on the number of hours the equipment is operating for the *Sines* H_2 *Hub* , one only needs to consider that the Well will be operating the double of the time: what was previously calculated to store the gas + that same amount of time needed to withdraw the gas, thus the multiplication by 2, exposed in table 3.7. It is important to note that this simplification will assume that the injection and withdraw rates will be the same, something that does not correspond to practice.

3.6. Gas pipeline

This section will expose the methodology on the calculation of the transmission cost in the context of the *Sines* H_2 *Hub* . Firstly, subsection 3.6.1 will expose the information collected on the existing gas pipelines. Secondly, subsection 3.6.2 will outline the method which was considered to be the most suitable to design the transmission system. Thirdly, the costs of such designs will be exposed over several cost components. And lastly, on subsection 3.6.4 the total cost of transmission will be allocated to the *Sines* H_2 *Hub* project.

3.6.1. Data collection

The gas pipeline is part of the national natural gas grid operated by the TSO: REN Gasodutos. Several approaches have been made to directly collaborate with the company in order to have the most updated and realistic data. Nevertheless that was not possible, thus, this research collected the required information directly from the TSO's publicly available reports or other sources which have the TSO as direct reference.

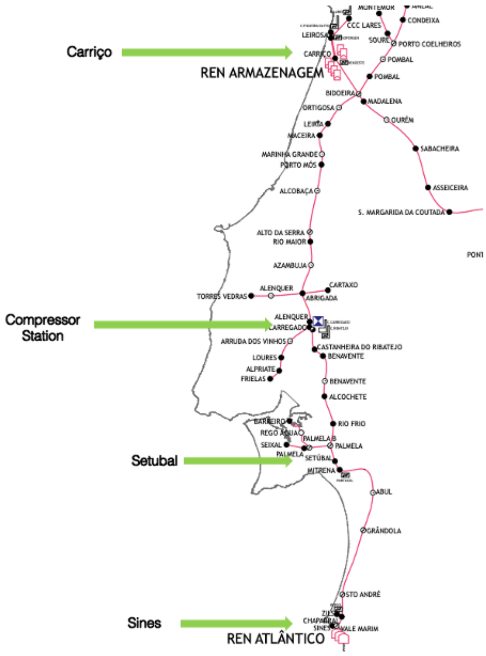


Figure 3.11: Partial map of natural gas network outlining valves, compressor station and relevant points [46]

Figure 3.11 presents a map of part of the gas network. Outlined by green arrows are important points to consider: Sines - the region in which hydrogen will be produced, converted to ammonia and shipped. Setúbal - city in which the gas pipeline changes diameter from 800mm (Sines-Setúbal) to 700mm (Setúbal-onwards). Carregado - point at which the compressor station is located. And lastly, Carriço - where the gas will be stored.

Currently transporting natural gas, the pipelines are at a depth of 0.8m, which has an average soil temperature of 10°C. Thus, it will be assumed throughout the report that whenever the gas is transported from Sines to Carriço, it will experience significant cooling down to this 10°C temperature [3].Please note that cooling depends on the flow speed of the gas and the energy dissipation per time unit to the surrounding, thus, only considering that the energy (up to 10°C) will be dissipated without further calculations will be a very rough simplification. Summarized in table 3.8 one can find all the parameters collected on the gas pipelines relevant for this research.

Table 3.8: Key data on Sines-Carriço gas pipeline

Parameter	Value	Source
Pressure range [bar]	55-84	[50]
Temperature [°C]	10	[50]
Depth [m]	0.8	[50]
Diameter Sines-Setúbal [mm]	800	[45]
Length Sines-Setubal [km]	87.31	[45]
Diameter Setúbal-Carriço [mm]	700	[45]
Length Setubal-Carriço [km]	192.88 km	[45]
Average diameter weighted on length [mm]	730	
Compressor station	Yes. In Carregado (mid-way)	[45]

3.6.2. Design of 2 pathways: new or retrofitted pipeline

Similarly to the approach followed in the salt cavern and given the fact that there is limited data available from the TSO: a two pathway approach will also be followed. This will mean that both options of retrofitting the existing pipeline to a hydrogen operation or building a new dedicated pipeline will be considered. Along with the 2 pathways possible for storage, now there will be 4 combinations for the final infrastructure outline: retrofitted pipeline and cavern; retrofitted pipeline and new cavern; new pipeline and retrofitted cavern; and new pipeline and cavern. The cost for each of these 4 combinations will be calculated and presented in the results chapter.

For sake of simplicity, the temperature, pressure, length, depth and weighted average diameter of the existing pipeline was assumed to be the same for the retrofitted pipeline. Therefore, when diving into the cost model of the transmission system the differentiating factor will be related to the unitary costs of building or retrofitting the respective infrastructure.

Furthermore it is of interest to confirm that the existing pipeline - and consequently, due to the previously made assumption - the new one, have the capacity to accommodate the maximum hydrogen flows determined by the storage needs on table 3.2. This analysis will be made using the Panhandle A equation, an elaboration of the *General Gas Flow Equation* used to relate the gas flow with its' operating conditions [37]. Given the fact that the *General Gas Flow Equation* requires the calculation of a friction factor, a highly nonlinear variable, this value needs to be read from tables or calculated iteratively. Alternatively, the gas flow can be given by four widely accepted friction factor approximations: Panhandle A, Panhandle B, Weymouth and IGT. Each of these equations is appropriate for a given set of conditions, thus, it is only of interest to elaborate on the Panhandle A equation: relevant for pipeline diameters ranging 305-1520mm and pressure ranges of 55-100 bar [37] - which covers the *Sines H_2 Hub* transmission conditions - and is given by:

$$Q_{sc} = \frac{a_1 \cdot (\frac{T_b}{P_b}) \cdot E \cdot (P_1^2 - P_2^2)^{0.5} \cdot D^{a2}}{\gamma^{a3} \cdot (T_a \cdot Z_a \cdot L)^{a4} \cdot \mu^{a5}} \tag{3.14}$$

Where Q_{sc} is the gas flow rate in $[ft^3/day]$, T_b is the gas temperature at base conditions, 519.6 [°R], P_b is the gas pressure at base condition, 14.7 [psia], E is the flow efficiency factor, dimensionless [-], P_1 is the pressure at the inlet, in [psia], P_2 the pressure at the outlet, in [psia], D is the pipeline internal diameter, in [inc], T_a is the average temperature inside the pipeline, in [°R], Z_a is the average compressibility factor, dimensionless [-], L is the pipeline length, in [miles], γ is the gas specific gravity, dimensionless [-], μ is the gas viscosity, in [cp], a_1 a Panhandle A constant of 403.09, a_2 a Panhandle A constant of 2.619, a_3 a Panhandle A constant of 0.4603, a_4 a Panhandle A constant of 0.5397, a_5 a Panhandle A constant of 0.0793.

Table 3.9: Inputs considered for maximization of flow using Panhandle A equation

Input	Value	Units	Units Conversion	Source
D	730	[mm]	1 mm = 0.0393701 inc	Based on previous assumptions
T_b	15	[°C]	$°R = ° Cx9/5 + 491.67$	Given
P_b	1	[atm]	1 atm = 14.7 psia	Given
E	0.92	[-]	n/a	Same as in [5]
P_1	84	[bar]	1 bar = 14.5 psia	Maximum pressure drop to maximize equation
P_2	55	[bar]	1 bar = 14.5 psia	Maximum pressure drop to maximize equation
T_a	10	[°C]	$°R = ° Cx9/5 + 491.67$	Assumed to be the same as the soil's throughout the transmission
Z_a	1.0359	[-]	n/a	Calculated for average pressure of 75 bar and temperature of 10°C
γ	0.0696	[-]	n/a	As found in [24]
μ	0.008779	[cp=miliPa/s]	same unit	Based on interpolations from the Hydrogen viscosity tables found in [41]

To calculate the maximum hydrogen flow possible that can run through the given pipeline(s), Q_{sc}, the inputs and assumptions found in table 3.9 were used in equation 3.14 having in mind the given conversion factors found in the 4th column. It is important to note that to maximize the equation, thus, calculate the maximum flow possible, the largest possible pressure drop was considered: from 84 bar to 55 bar - which are the limits that the pipeline can support.

Then, to determine if the pipeline can accommodate the required hydrogen flows, one must convert the Q_{sc} given in $ft^3_{H_2}/day$, to a Pipeline Gravimetric Capacity given in kg_{H_2}/h so that it can be compared to the *Sines H_2 Hub* maximum flow of 1 483kg_{H_2}/h. This will be done using the *Ideal Gas Law*, and applying some conversion factors:

$$PipelineGravimetricCapacity = \frac{Q_{sc} \cdot (\frac{0.028}{24}) \cdot M \cdot p_a}{R \cdot T_a \cdot Z_a} \cdot \frac{1}{1000} = 1.715 \cdot 10^5 \quad [kg_{H_2}/h] \tag{3.15}$$

Where Q_{sc} is the volumetric pipeline capacity in $ft^3_{H_2}/day$, 0.028 is the conversion factor from ft^3 to m^3, 24 is the conversion factor from days to h, M is the hydrogen molecule molar mass of 2 [g/mol], p_a is the average pressure, which is assumed to be the median value of the pipeline's operational range, thus, 75 [bar, then converted to Pascal], R is the universal gas constant of 8.3145 [J/mol/K], T_a is the average temperature of 10[°C, then converted to K], Z_a is the average compressibility factor, dimensionless [-] and the 1000 factor is to convert from grams to kg. As expected, one can conclude that the existing pipeline system or a possible newly built system under the same conditions, will have enough capacity $(1.715 \cdot 10^5 kg_{H_2}/h)$

to transport the maximum capacity the *Sines H_2 Hub* will require for its' storage needs management ($1.483 \cdot 10^3 kg_{H_2}/h$).

For sake of comparison against alternative hydrogen pipelines, one can convert the Pipeline Gravimetric Capacity from kg/h to GW by multiplying it by the conversion factor of 1 kg_{H2} = 0.039 MWh (HHV). Thus, it can be concluded that the pipeline will have a hydrogen capacity of 6.7 GW (HHV). Please note that [54] outlines that a 36-inch pipeline can transport around 9 GW (LHV). Therefore, it can be pointed out that the 6.7GW (HHV) capacity found for the Sines-Carriço pipeline of 730mm (28.7-inc) diameter, is aligned with literature.

3.6.3. Cost breakdown

The transmission infrastructure has two main capital expenditures: the cost of retrofitting the existing pipeline or building a new one (dependant on pathway selected) and the capital cost of the transmission compressor. As for the operational expenditures, it is interesting to look into the electricity bills of compressing the gas and the operation and maintenance costs (excluding electricity bills) of the infrastructure. This subsection will elaborate on each of these cost components.

Pipeline CapEx

As previously noted, the European Hydrogen Backbone report collected data from several TSO's and other relevant sources. Several cost parameters were computed, including unitary costs of transmission as it can be seen in table 3.10. It is important to note that the pipeline diameter is a key aspect when determining the cost and that the values presented are for a 48-inch pipeline. For sake of coherence with other parts of this report and also to build on the most updated values presented, the pipeline CapEx will be calculated based on such parameters (for 48-inc diameter = 1200mm) and then a diameter-cost adjustment factor will be applied to scale it down to the 730mm pipeline diameter of this project.

Table 3.10: Pipeline CapEx unitary costs, for a 48inc pipeline, [54]

Cost parameter	Unit	Low	Medium	High
Pipeline (incl. gas metering) CapEx, new	M€/km	2.5	2.75	3.36
Pipeline (incl. gas metering) CapEx, retrofit	M€/km	0.25	0.5	0.64

As noted by [48], [36] relates the pipeline diameter with hydrogen pipeline investment costs - based on the investment costs of natural gas. This relation is given by equation 3.16, where D is the pipeline diameter, in [m]:

$$PipelineCapEx = 1.05 \cdot 278.24 \cdot e^{D} [€/m] \tag{3.16}$$

Directly using such equation could also have been a possibility, but as stated, it was considered that the best approach would be to use the same and more updated source [54] as in other parts of the report and then apply the diameter-cost adjustment factor to scale it to the given diameter of 730mm. Such scaling factor was determined using equation 3.16 by making the cost ratio of 730mm and 1200mm pipeline diameters:

$$DiameterCostAdjustmentScalingFactor = \frac{1.05 \cdot 278.24 \cdot e^{0.73}}{1.05 \cdot 278.24 \cdot e^{1.20}} = 0.625 \tag{3.17}$$

Having this said, it is now possible to elaborate the CapEx of both pipeline infrastructures for the given diameter of 730mm. To do so, the medium scenario exposed in table 3.10 was chosen for this research and the diameter scaling factor just determined was applied.

$$PipelineRetrofitted_{CapEx} = Length \cdot 0.5 \cdot 10^6 \cdot 0.625[€] \tag{3.18}$$

$$PipelineNew_{CapEx} = Length \cdot 2.75 \cdot 10^6 \cdot 0.625[€] \tag{3.19}$$

Pipeline Compressor CapEx
To determine the CapEx spent on the pipeline compressor, two main cost factors will be considered: the unitary cost and the compressors' power. The first will be €3400 €/kW as determined by [54] and considered to be the same for both pathways. The second factor, has been determined in section 3.4, and has a total power of 774 [kW]. Thus, the final equation considered will be:

$$PipelineCompressor_{CapEx} = 3.4 \cdot 10^3 \cdot Power_{PipelineCompressor} \quad [€] \tag{3.20}$$

Pipeline Compressor OpEx
Similarly to the cavern compressor OpEx calculation, this cost component will be based on the same inputs: electricity price, in [€/kWh], compressor's maximum energy intensity, in [kWh/kg] and total mass stored over one year, in [kg]. Where the only distinct value will be the compressor's maximum energy intensity, which was found in section 3.4: 0.52 [kWh/kg]. As for the electricity price, it will be assumed the same value as previously assumed in section 3.5 of 0.056 [€/kWh]. Regarding the total mass stored over 1 year, the value considered will be the 3 038 191 kg, as previously calculated and exposed in table 3.2.

$$PipelineCompressor_{OpEx} = Electricity_{Price} \cdot MaxEnergyIntensity \cdot TotalMass \quad [€/year] \tag{3.21}$$

Since the methodology is the same as the one seen in section 3.5, further elaboration on each input and it's impact on the cost component can be found in that section.

Transmission O&M excl electricity
This cost component includes the operation and maintenance costs that the transmission system will have other than the compressor's energy bills. The approach proposed by [54] was followed: calculating this factor as a percentage of the overall transmission CapEx costs.

The transmission CapEx will be given by the sum of the pipeline and compressor CapEx's of the respective pathway. As for the percentage factor, [54] present a range of 0.8-1.7%. Thus, the median value of 1.25% was assumed to be a reasonable fit and considered as presented in the following equation:

$$TransmissionO\&M = (Pipeline_{CapEx} + PipelineCompressor_{CapEx}) \cdot 0.0125[€/year] \tag{3.22}$$

3.6.4. *Sines* H_2 *Hub* cost allocation
Similarly to the section on salt caverns, the costs calculated are for building and operating a complete infrastructure (exception for compressors energy bills) oversized for the *Sines* H_2 *Hub* . As it would not be reasonable to design and operate an infrastructure only for these storage needs, it will be used by other parties in their transmission needs. Thus, it is important

to allocate the overall transmission cost, on a beneficiary-pays principle, to the *Sines H_2 Hub*.

A relevant component will be the allocation of the **Pipeline CapEx**. A relatively small hydrogen flow will run through the pipeline, thus the allocation will be based on the ratio between the maximum *Sines H_2 Hub* hydrogen flow and the absolute maximum possible hydrogen flow the pipeline can operate. These values are given in the transmission design section 3.6.2. As previously determined, the *Sines H_2 Hub* maximum flow will be of $1.483 \cdot 10^3 kg_{H_2}/h$, while the absolute pipeline maximum possible flow will be of: $1.715 \cdot 10^5 kg_{H_2}/h$. By calculating the ratio of the two, it was found that the allocation factor will be of 0.86%.

The cost components: **Pipeline Compressor CapEx and Transmission OpEx** were allocated on the basis of the time they were operating for the *Sines H_2 Hub* . As noted in section 3.3, equivalent share of time over a complete year needed to process the hydrogen mass throughput at maximum capacity is 27.4%, thus, this will be the factor assumed to determine the allocation factor. It is important to note that this is a significant simplification as, for example, the different compressing efforts are not considered, i.e., it is still assumed that the compressor is running at full capacity and pressure differences. As for the **Pipeline Compressor OpEx** cost component, there is no need for allocation as this is already considered when multiplying the energy intensity by the mass of hydrogen throughput of the *Sines H_2 Hub* only.

Table 3.11: Transmission cost drivers & project allocation

Cost Component	Identified Cost Driver	Allocation	Retro Final Cost	New Final Cost
Pipeline CapEx	Pipeline capacity	0.86%	756 k€	4 163 k€
Pipeline Compressor CapEx	Load Factor Equivalent	27.4%	721 k€	721 k€
Pipeline Compressor OpEx	(already allocated on energy bill)	(100%)	88 k€/year	88 k€/year
Transmission OpEx (excl electricity)	Load Factor Equivalent	2 x 27.4%	2 k€/year	0.73 k€/year

Similarly to the section on the cost allocation of salt caverns, the way back from Carriço to Sines will also be considered in the transmission infrastructure. In practice, all the equipment that hydrogen will pass through on the way back, needs to be accounted for. To do so, it is important to have figure 3.2 in mind. After the gas is withdrawn from the cavern, the equipment it will pass through in the transmission infrastructure is the pipeline, thus the compressor cost components do not need to be considered. In other words, no compressors are needed to transport the hydrogen from the salt cavern back to Sines (as the gas will be at a already high enough pressure, the opposite will be necessary: pressure reduction).

As for the Pipeline CapEx cost component, the allocation previously considered via the maximum possible flow, is not a time based allocation. Therefore, if the gas needs to travel back from Carriço to Sines, the cost accounting should not be impacted - it is already considered.

On the other hand, the Transmission OpEx (excl electricity) is allocated based on the equivalent load factor - a time based factor. This means that given the total cost of Transmission OpEx over one year, the share allocated to the *Sines H_2 Hub* was determined based on the amount of time the equipment would be operating for the project: 27.4%. As this allocation factor was only calculated for one directional flow (Sines-Carriço), if one intends also to account for the flow Carriço-Sines, the allocation factor needs to double. Meaning that the amount of time the equipment is dedicated to the project will be the double: time spent on the way

Sines Carriço (initially allocated) plus the time spent from Carriço back to Sines (considered by multiplying initial by 2).

3.7. Final cost

This section is split in two subsections. The first will outline how the transmission and storage CapEx and OpEx costs were consolidated in a final levelized cost of hydrogen transmission and storage - this is considered to be the main scope of the research. Then, the second subsection will expose how to have a better understanding of such value by considering the whole stabilized supply to the hydrogen conversion facility.

3.7.1. Levelized Cost of Hydrogen Transmission & Storage

After computing and allocating to the *Sines H_2 Hub* the overall costs of retrofitting or building new infrastructures - storage and transmission - and operating them, this section will focus on the calculation of its' levelized cost. To do so, the CapEx costs will be spread over the project's lifetime using the annuity method - usually applied in Europe for preliminary assessments [21]. Then, along with the yearly OpEx costs the total cost over 1 year will be divided by the hydrogen throughput over 1 year, hence, calculating the final levelized cost of hydrogen transmission and storage of the proposed *Sines H_2 Hub* .

An overview of every cost component and their impact on the CapEx or OpEx is given in figure 3.12. In yellow one can note the components associated to the storage infrastructure and in blue the ones related to the transmission infrastructure. The calculation will be executed four times given the different pathways combinations.

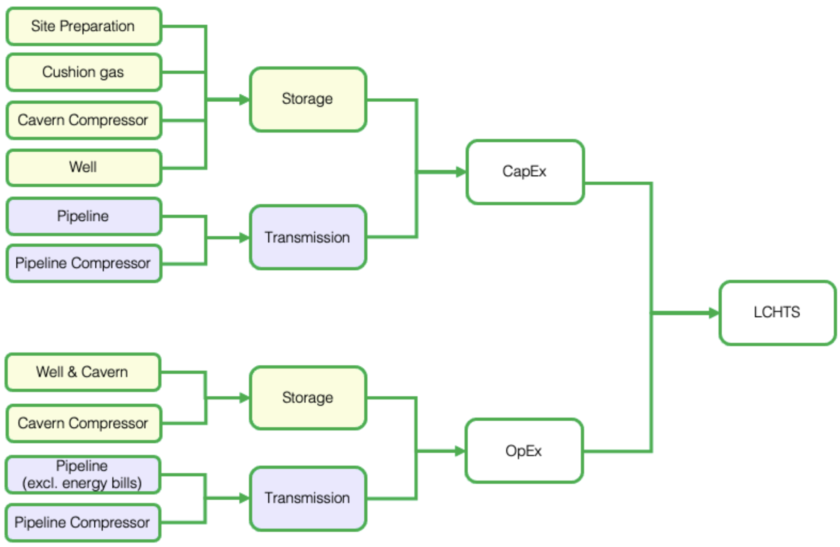


Figure 3.12: Cost model composition

As previously mentioned the overall CapEx cost is calculated via the annuity method. To allocate the cost throughout the years the annuity factor, which will then be plugged into each cost component, is based on a depreciation period (n) and a WACC. The first, n, summarized in table 3.12 will be set for each cost component by literature. The second, WACC, will be 6% which is the median value of the range considered by [54].

Table 3.12: Depreciation period, n, for the different CapEx cost components, in years

Cost component	n [years]	Source
Site Prep CapEx	30	[34]
Cushion Gas CapEx	30	[34]
Cavern Compressor CapEx	24	Assumed the same as Pipeline Compressor
Well CapEx	30	[34]
Pipeline CapEx	42.4	Median point considered by [54]
Pipeline Compressor CapEx	24	Median point considered by [54]

Then, for each cost component an annuity based on the same 6% WACC and respective depreciation period will be calculated as follows:

$$Annuity = \frac{(1+WACC)^n \cdot WACC}{(1+WACC)^n - 1} \tag{3.23}$$

And lastly to calculate the total yearly CapEx, firstly, each annuity will be multiplied by each CapEx cost component and secondly, all will be summed:

$$TotalYearlyCapEx = \sum_{i=1}^{i=6} CostComponent_i \cdot Annuity_i \tag{3.24}$$

Where the $CostComponent_i$ refers to the CapEx cost components, outlined in table 3.12. Since they are 6 items, the i will range from 1 to 6. And where the $Annuity_i$ refers to the annuity respective to cost component i.

As for the total yearly OpEx, each cost component, outlined in figure 3.12 is already given on a per year basis. Thus, these value do not need to be annualized and only need to be summed, as follows:

$$TotalYearlyOpEx = \sum_{j=1}^{j=4} CostComponent_j \tag{3.25}$$

Where the $CostComponent_j$ refers to each of the OpEx cost components. Since there are 4 items, j will range from 1 to 4.

Lastly to calculate the levelized cost of hydrogen transmission and storage - also referred to as $LCoH_{Transmission\&Storage}$ - the total annualized CapEx and OpEx's will be summed and divided by the hydrogen throughput. This value will be given by the storage needs summarized in table 3.2, which will be the maximum total mass of hydrogen transported and stored: 3 038 191 kg_{H_2}, (maximum is used for sake of coherence, since all previous simplifications were maximizations):

$$LCoH_{Transmission\&Storage} = \frac{TotalYearlyCapEX + TotalYearlyOpEx}{MassThroughput_{Transmitted\&Stored}} \quad [€/kg_{H_2}] \tag{3.26}$$

3.7.2. Added cost of stabilizing production

After having calculated the $LCoH_{Transmission\&Storage}$, it is relevant to put in perspective why the hydrogen was transmitted and stored: to provide a stable supply to a hydrogen conversion facility, f.e., ammonia plant. Thus, there will be two supply flows to this plant: a direct supply during the times that the hydrogen production matches the stabilized target, and a supply which had to be transmitted and stored so that the stabilized production would be fulfilled. The calculated $LCoH_{Transmission\&Storage}$ exposes the latter.

In order to have a comprehensive understanding of the added cost that a stabilized production will have after leaving the hydrogen production plant, one must consider both costs. To do so, one needs to weight the respective added costs (direct and transmitted & stored) on the mass throughput of each supply mode as follows:

$$
\begin{aligned}
LCoH_{StableSupply} = {} & LCoH_{Transmission\&Storage} \cdot \frac{MassThroughput_{Transmitted\&Stored}}{MassThroughput_{Total}} \\
& + LCoH_{DirectSupply} \cdot \frac{MassThroughput_{DirectSupply}}{MassThroughput_{Total}} \quad [€/kg_{H_2}]
\end{aligned}
\tag{3.27}
$$

Where, $LCoH_{StableSupply}$ is the added levilized cost of having a hydrogen stable supply. $LCoH_{DirectSupply}$ is the levelized cost of hydrogen direct supply. $MassThroughput_{DirectSupply}$ is the total mass of hydrogen over one year that was spplied directly from hydrogen production to conversion plant. And $MassThroughput_{Total}$ is the total mass of hydrogen produced over a year. Please note that the sum of the direct supply and the transmitted and stored supply equals the total stable supply. Furthermore, in this analysis, it will be assumed that the hydrogen conversion facility will be located next to the production plant, therefore, not generating any significant transportation costs. In practice, this assumption will consider that the $LCoH_{DirectSupply}$ is zero, thus the second term of the equation will be cancelled.

4

Results

This chapter will present the results of the model developed to calculate the levelized cost of hydrogen transmission and storage. Firstly, section 4.1 will present the results of each pathway broken down by cost component and also an average of the 4 possible combinations. Then, section 4.2 will investigate the impact that varying certain parameters will have on the overall cost. And lastly, section 4.3 will interpret the results in light of the added cost of stabilizing production.

4.1. Levelized Cost of Hydrogen Transmission & Storage

The four possible infrastructure pathway combinations: new or retrofitted transmission and new or retrofitted storage, differ on the equipment which will be used, and consequently have different impacts on the cost. Thus, the levelized cost of hydrogen transmission and storage for the *Sines H_2 Hub* will depend on the infrastructure pathway selected. Figure 4.1 presents the results of the different cost breakdowns for the possible pathway combinations. One can note that the cost for the pathway of retrofitting both storage and transmission infrastructure will be $0.17€/kgH_2$. Whereas for a completely new infrastructure will be of $0.25€/kgH_2$.

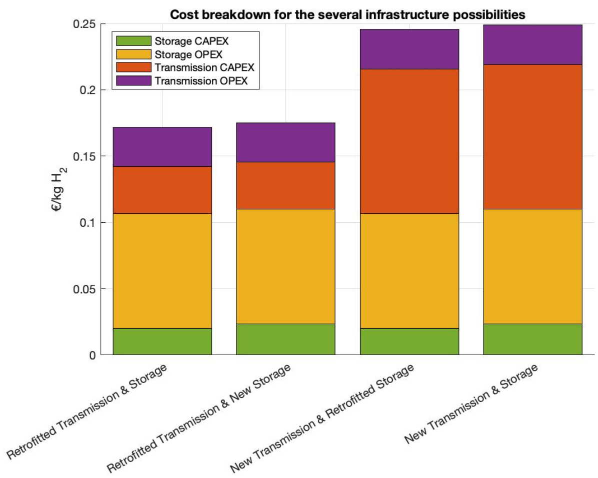


Figure 4.1: Cost breakdown for the 4 different pathways

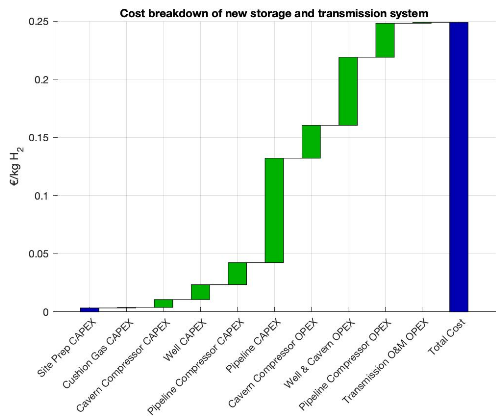
The other pathway combinations have a cost ranging in the between $0.17 - 0.25€/kgH_2$, yet, it is important to note that the largest cost difference between the pathway combinations will come due to the Transmission CapEx - in red. The total cost of transmission, for the retrofitted pathway will be of $0.06€/kgH_2$ for the transported 560.4km (2x280.2km). While for the new hydrogen dedicated infrastructure will be of $0.13€/kgH_2/580.4km$. As expected, such difference will come from the transmission CapEx costs (since the OpEx will be the same for both pathways).

Also interesting to note is the little impact that the pathway combinations had on storage, when compared to the gap transmission pathways had. Both pathways present a cost of $0.11€/kgH_2$ with a negligible difference. This difference, attributed only to the CapEx variation, is related to the fact that the only cost component that varies between the two pathways will be the Site Preparation. This component has a total CapEx allocated to the *Sines H_2 Hub* of 139 k€, which is less than 15% of the total *Sines H_2 Hub* storage CapEx. For a retrofitted final levelized cost of hydrogen storage CapEx (first green bar only) of $0.02€/kgH_2$, a 15% variation will have little impact on the overall cost. Thus, the total storage cost should practically be considered the same for both pathways.

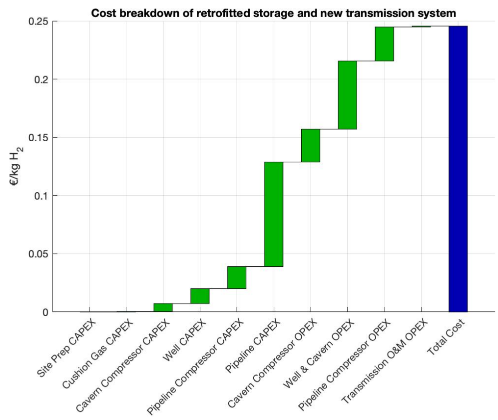
It is important to compare the results with the indications previously seen in literature. Despite not existing a study on cost the cost analysis of a hydrogen project with the combined transmission and storage characteristics as the *Sines H_2 Hub* , one can compare the storage cost and the transmission cost independently. The total transmission costs obtained in the model can be compared to the values outlined in the literature review - section 2.4.2 - if converted to a $€/kg_{H_2}/1000km$ basis. One can note that the results of this research present a cost of $0.06€/kgH_2/560.4km$ for the retrofitted infrastructure and $0.13€/kgH_2/560.4km$ for the new infrastructure. Thus, by converting it to the same 1000km basis, they are: $0.11€/kgH_2/1000km$ and $0.23€/kgH_2/1000km$, respectively. When comparing these values with the cost determined by [29] of $0.10€/kgH_2/1000km$ (using the conversion factors outlined in the literature review), it is possible to conclude the retrofitted value is aligned with the reference while the new infrastructure value is above the cost presented by [29]. As for the costs presented by [54], a comparison for new or retrofitted is possible. For the first, the value of $0.23€/kgH_2/1000km$ is completely aligned with the *high* scenario presented in the reference. As for the calculated retrofitted cost of $0.11€/kgH_2/1000km$, it is completely aligned with the *medium* scenario presented by the authors.

As for the storage infrastructure, the result of $0.11€/kg_{H_2}$ is on the lower range of values presented in literature $0.10 - 1.4€/kg_{H_2}$. However it is important to note that the values there presented are not directly comparable between each other as they have operations with different cycles. Thus, one can affirm that the storage cost is accurately aligned with literature but no direct comparison is possible.

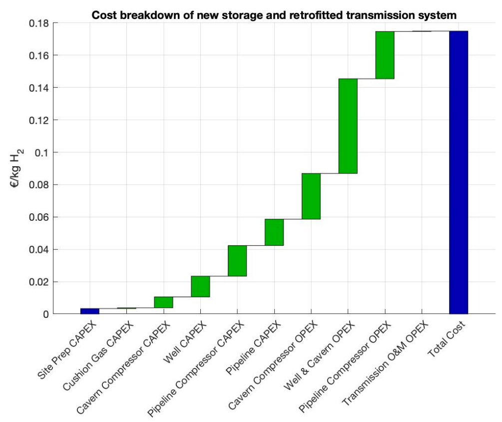
In order to better understand the exact impact each cost component had on the overall cost for the different pathway combinations, figure 4.2 is presented. One can note that for the retrofitted storage pathways there is no site preparation cost and that the cushion gas cost will be extremely little - certainly the residual value outlined in section 3.5.3, had a play: in practice, due to the hydrogen production subsidies, the price of hydrogen is assumed to cost $0.9€/kg_{H_2}$ now and $1€/kg_{H_2}$ in 30 years. Also interesting to point out is the cost difference of Pipeline and Pipeline compressor CapEx's: for the retrofitted transmission pathways, the Pipeline CapEx will be smaller than the Pipeline Compressor CapEx, while for a new transmission infrastructure it will be more than the double. Contributing to this, is the fact that the Pipeline compressor CapEx will be the same regardless of the pathway - a new compressor



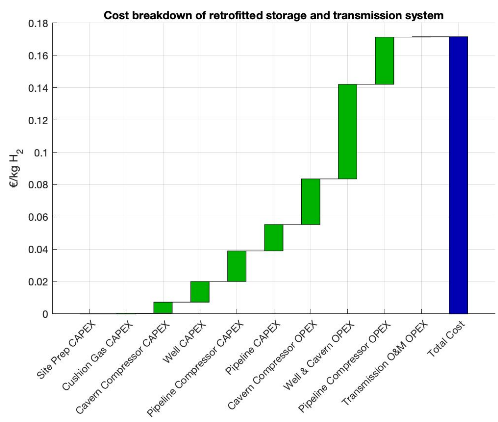
(a) New transmission, New storage



(b) New transmission, Retrofitted storage



(c) Retrofitted transmission, New storage



(d) Retrofitted transmission, Retrofitted storage

Figure 4.2: Cost breakdown per pathway

would be needed for any hydrogen operation.

To make a better assessment of the most relevant factors throughout the report, it is also important to analyse the 4 pathway combinations under the same scope. Figure 4.3 presents the cost breakdown of the average of the 4 possible pathway combinations, which has an overall average cost of $0.21€/kg_{H_2}$. At first sight the Well & Cavern OpEx cost component seems to be the most relevant cost factor accounting for 28% of costs. As outlined in the respective methodology, this cost component was calculated based on the average cost of two reported salt caverns. Thus, as this is a significant share of the costs, future research should focus on further diversify these reported values.

It is interesting to point out that the compressor's OpEx (of both cavern and pipeline) followed a similar methodology, only had different pressure and temperature inputs and when combined have a total share of 27%. The methodology of these cost components was based on 3 parameters: 1. Electricity price - which considered a value more expensive than the EU's average. 2. Total hydrogen mass throughput over 1 year and 3. the Maximum Energy Intensity - which is based on the compressors' power and on the maximum hydrogen flow $\dot{m}$. Since all the 3 parameters followed conservative approaches, the Compressor's OpEx is likely overestimated. Therefore, and given the fact that this is the second largest cost component but has a more complex approach than the one followed by the Well & Cavern OpEx, the impact analysis will focus on this component.

Also important to note is the impact the Pipeline CapEx has overall: 25%, nevertheless, one must be critical with this factor, because as previously seen it had significant variations for the different pathways. Thus, conclusions on this aspect for the overall system should be avoided. As for the rest of the cost components, all have shares less than 10% of the average cost, thus, no further focus will be put in analysing their results.

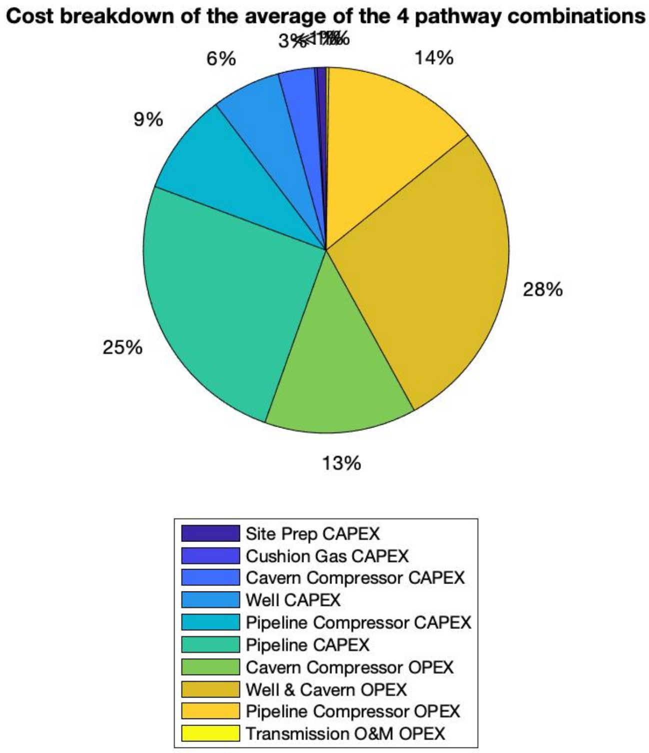


Figure 4.3: Cost breakdown of average of the 4 different pathways

4.2. Parameters impact analysis

As previously noted, the most relevant and interesting cost components to analyse are the Pipeline and Cavern Compressors OpEx, responsible for almost one third of the total cost. For both equipment the same methodology and same vast majority of inputs were considered. This impact analysis plans to vary some inputs considered and assess its' influence on the overall average of the levelized cost of hydrogen storage and transmission.

By looking back at the methodology described over the respective Compressors OpEx components, one can note that the parameters considered are: 1. Electricity price, 2. Total hydrogen mass throughput over 1 year, 3. Maximum Energy Intensity - which is based on the compressors' power and on the maximum hydrogen flow $\dot{m}$ - and 4. WACC. Regarding the total hydrogen mass throughput and the maximum hydrogen flow $\dot{m}$, these parameters are extracted from the *Sines H_2 Hub* expected production. Thus, as no significant variations are expected to occur, these parameters will not be considered variables in the impact analysis.

It is interesting to analyse the parameters: electricity price, compressors' power and WACC in dedicated sub-sections to assess the impact that variations between -25% to +25% will have on the overall $LCoH_{Transmission\&Storage}$. To do so it is appropriate to recap the values considered for each parameter:

- Electricity Price of 0.056€/kWh;
- Compressor Power of 774kW for pipeline and 748kW for cavern
- WACC of 6%.

4.2.1. Electricity price

When comparing the considered price of electricity to the EU's average electricity price, outlined in the literature review, one can note that the 0.056€/kWh used is greater than the EU's average of 0.050€/kWh. Thus, to make the variation of this parameter, the EU average price will be considered as the median value and then varied up to 25%. This way, one can be confidant one the middle value and expect a negative price variation to be as likely as a positive variation. Please note that by following this approach, the value considered in the research model roughly equals the median value (EU´s average) with a 10% increase.

Figure 4.4 presents the changes in the average $LCoH_{Transmission\&Storage}$ for several variations of the electricity price ranging from -25% to +25%. For example, the used electricity price of 0.0506€/kWh led to a $LCoH_{Transmission\&Storage}$ of $0.20€/kgH_2$. By reducing the electricity price in -25%, the $LCoH_{Transmission\&Storage}$ would be $0.19€/kgH_2$, which represents a -6.3% cost variation over the initial $0.20€/kgH_2$. On the other hand, if the electricity price increased +25%, the $LCoH_{Transmission\&Storage}$ would be $0.22€/kgH_2$, a +6.3% higher cost. From these variations, one has the indication that this variable will have a linear behaviour impacting the total cost.

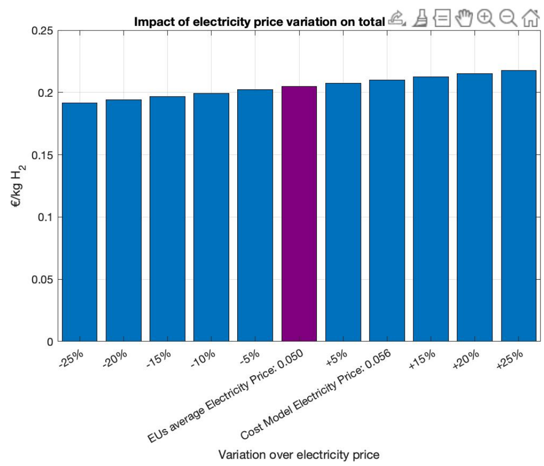


Figure 4.4: Impact analysis, electricity price

4.2.2. Compressors power

The compressor's power is also an important parameter to analyse. Given the fact that there are two compressors, for sake of simplicity, the given powers used throughout this report will be considered to have a scale factor of 1. Then, to expose for example a 20% variation over both compressor's power, it will only be mentioned that the scale factor increased to 1.2. Given the methodology used for the compressor's power calculation, at first sight it is not possible to determined if they are more likely to be oversized or undersized, thus, the median value will be the current power.

Figure 4.5 presents the cost variation of the $LCoH_{Transmission\&Storage}$ for the several variations over the compressors' scale factor of 1. For a compressor power variation of -25% the $LCoH_{Transmission\&Storage}$ reduced to $0.19€/kgH_2$, a 9.5% cost reduction. Whereas for an increase of the scale factor up to 1.25, the $LCoH_{Transmission\&Storage}$ increased to $0.23€/kgH_2$, also a +9.5% variation. This reveals a linear behaviour between compressor power and final cost.

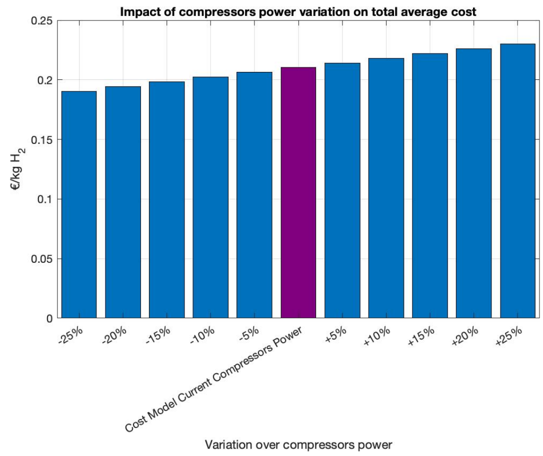


Figure 4.5: Impact analysis, compressors power

4.2.3. Weighted Average Cost of Capital

And lastly, the WACC was also analysed. This assessment is important given the broad range of this parameter can have in literature. During this study, most of the times the different sources analysed presented different WACC's. It was determined that the 6% was suitable given the fact that it was the median value of the range presented by [54], a reference used throughout the report.

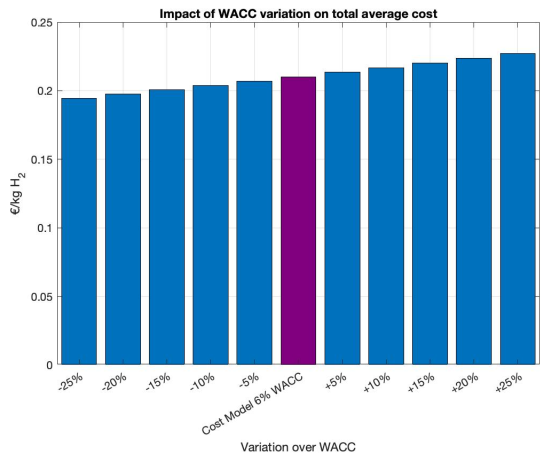


Figure 4.6: Impact analysis, WACC

This assessment was made considering the same methodology as the previous analyses. Several variations over the WACC parameter were made from -25% to +25% and the $LCoH_{Transmission\&Storage}$ calculated for each. Figure 4.6 presents the cost for each parameter variation. One can note that a -25% variation on the WACC led to a cost reduction of -7.5% on the $LCoH_{Transmission\&Storage}$. Whereas for a WACC increase by +25%, the $LCoH_{Transmission\&Storage}$ will be impacted by +8%, a non linear behaviour.

4.2.4. Comparison of parameters variations

It is interesting to compare the different impacts that the maximum variations on the inputs analysed (-25% and +25%) had on the average levelized cost of hydrogen transmission and storage. Table 4.1 presents the percentage changes on the $LCoH_{Transmission\&Storage}$ that those maximum input variations induced where one can note that the compressor's power is the most impactful parameter.

The ranges in which the parameters varied (-25 to +25%) were: WACC 4.5-7.5% ; Cavern Compressor Power 561-935 kW; Pipeline Compressor Power 582-968 kW; and Electricity Price 0.037-0.063 €/kWh, all of which present reasonable and possible variations. Furthermore, one can note that no 25% variation led to impacts greater than 10% on the levelized cost.

Having this said, one can highlight that the cost model developed to determine the OpEx of both cavern and pipeline compressors was based on assumptions and inputs that if varied between reasonable intervals, do not compromise the final levelized cost. As no parameter is expected to vary more than 25%, one can expect the levelized cost not to be impacted by more than 9.5%, which strengthens the research approach and final conclusions.

Table 4.1: Comparison of percentage variation of the $LCoH_{Transmission\&Storage}$ due to the -25% & +25% variation of the given parameters

		x-25%	x (no parameter variation)	x+25%
Electricity price, x = 0.05	[%]	-6.3	0.0	+6.3
Compressor's Power (scale factor), x = 1	[%]	-9.5	0.0	+9.5
WACC, x = 0.06	[%]	-7.5	0.0	+8.0

4.3. Added cost of stabilizing production

The total hydrogen production over one year is expected to be 5 338 928 kg. This research developed a model which according to table 3.2, the total mass that would need to be transmitted and stored would be 3 038 191 kg - around 57% of the complete production. Thus, the remaining 2 300 737 kg will be directly supplied from the hydrogen production plant to the hydrogen conversion facility at zero cost. The added cost of stabilizing the complete hydrogen production can be found on table 4.2 for each of the pathway combinations:

Table 4.2: Added cost of stabilizing production for each of the pathway combinations

[$€/kg_{H_2}$]	$LCoH_{Transmission\&Storage}$	$LCoH_{DirectSupply}$	$LCoH_{StableSupply}$
Retrofitted transmission and storage	0.17	0	0.10
Retrofitted transmission and new storage	0.18	0	0.10
New transmission and retrofitted storage	0.25	0	0.14
New transmission and storage	0.25	0	0.14

In line with the methodology exposed in 3.7.2, the table presents the costs that were considered for both Transmission & Storage and Direct Supply, which led to the final added cost of stabilizing production, outlined in the last column. One can note that the costs now range between $0.10 - 0.14€/kg_{H_2}$ dependant on the pathway combination.

It is important to question the values determined, thus, look back into the main variable that impacted this calculation. The mass considered for either direct supply or transmission & storage system is a critical input. As previously noted, this research considered that 57% of the mass produced in Sines would be transmitted and stored. This value comes from a conservative approach followed at the beginning of the research - section 3.3.2 - which selected the maximum mass of the 3 different stabilization scenarios.

In order to assess the impact of a different but also credible share of mass transmitted and stored, one can consider other mass throughput breakdowns. Namely, the ones that were not considered in order to follow that conservative approach. Both the monthly and daily stabilization scenarios (scenarios not previously considered) have roughly the same share of mass transmitted and stored of 54%. By considering this new mass breakdown, the $LCoH_{Transmission\&Storage}$ would range between $0.18-0.26€/kg_{H_2}$ which would lead to a slight and negligible cost reduction of the $LCoH_{StableSupply}$ still ranging between $0.10-0.14€/kg_{H_2}$.

5 Discussion

This chapter will discuss the results and methodology considered throughout the report. The final costs and most relevant cost component results will be summarized. Then, a review of the overall methodology will be exposed and comments on it's limitations and assumptions made. The comparison of the results to literature will also be approached along with some final considerations on the contribution of this research for future research and practical implementation.

It is important to recap the main question this investigation focused on: *"In the context of the Sines green hydrogen hub, what is the cost of transitioning to hydrogen and operating the Carriço salt caverns and its' supply infrastructure?"*. In a nutshell, the answer to this question could be given by stating the cost range presented in the results section: $0.17 - 0.25€/kg_{H_2}$. Nevertheless, it is also relevant to point out the cost breakdown: $0.11€/kg_{H_2}$ can be attributed to the storage infrastructure, while $0.06 - 0.13€/kg_{H_2}$ to the transmission, dependant on whether a retrofitted or new infrastructure is selected. Furthermore the most relevant cost component of the study stood out to be the operational expenses related to the energy bills of pipeline and cavern compressors, it represented 27% of the total cost. The most relevant parameter that contributed to this cost component (compressors' OpEx) ended up being the compressor's power.

Throughout the investigation, several assumptions and limitations were exposed. Just in the system design & boundaries section, the decision to only focus the research on the main equipment, i.e., pipeline, compressors, cavern and well, had an impact on the final cost. Not that the CapEx of heater and pressure reduction equipment are substantial, but due to the fact that its' impact on the OpEx was not considered. To recuperate the energy dissipated in the pressure reduction from cavern to pipeline, a turbine could have been included in the system. This was not the case from the beginning because the decision to draw the boundaries not including such equipment was made before retrieving the data outlining the large pressure difference between cavern and pipeline. Thus, if this aspect had been considered the $LCoH_{Transmission\&Storage}$ could have been reduced.

Building the whole research over the assumption that due to ammonia shipping, the complete hydrogen production had to be stabilized was also bold. In reality, there could have been other uses for the same hydrogen production: only a smaller share could have been converted to ammonia and still use the transmission ans storage system for other purposes. The whole storage needs chapter was based on such which replicated in the system design and cost allocation in other parts of the report. This aspect was minimized by only considering the maximums of the three stabilization scenarios, in order to keep the most flexible system possible. On the other had, this will mean that the system will be oversized for certain uses. The gain in flexibility meant losses in achieving the most cost-efficient solution.

Furthermore, it is important to note the quality of the data used. As for the hydrogen production, it was collected from Resilient Group - the consortium coordinating the project - thus one can be confidant on its' validity. As for the data on gas pipelines and salt caverns, a significant part was retrieved directly from public reports from REN, the TSO, nevertheless, critical values such as temperature and pressure ranges, were collected from third parties, which had the TSO as a direct reference. This means that despite being credible sources, not always the most clear and updated values were considered.

When designing the storage and transmission infrastructures a two pathway approach was proposed for each system. These pathways, which suggest either a retrofitted or new infrastructure, are considered because no significant data is available to determine which of the two is the best solution for the *Sines H_2 Hub* and other third parties. Technical parameters on the possibility of conversion to hydrogen would need to be collected. Nevertheless, this aspect makes the research interesting to assess from the techno-economic point of view which solution is more suitable and serve as input in that decision making process.

Literature points out that not much varies between a natural gas and hydrogen operation. Therefore, at the system design of the new dedicated infrastructure, the same conditions, namely pressure and temperature (for storage and transmission) and pipeline diameter (for the later only), were assumed to the the same as the ones of the retrofitted. This assumption disregarded any technological advancements on system design and applicability to a hydrogen-based operation. These parameters were initially decided more than 20 years ago for a natural gas operation with a different consumption pattern, thus, considering that a hydrogen operation has the same specifications is audacious, despite broad literature assessments. For example, the pipeline diameter of the new transmission infrastructure is considered to have the same 730mm as the existing pipeline. By comparing this diameter with other EU hydrogen projects, pointed out by [54], one can note that it will be significantly smaller than its' European peers. Certainly the current pipeline has more than enough capacity for the current flow of hydrogen related to the *Sines H_2 Hub* . Nevertheless, if an even larger diameter was considered (in line with EU peers), future demand possibly larger than current capacity, could be accommodated. Therefore, generating economies of scale and further reducing the cost allocated to this project in particular.

Over the cost model, the most pivotal assumption made relates to Maximum Energy Intensity which impacts the OpEx of the pipeline and cavern compressors (both followed the same methodology).The calculation assumed that the compressors, whenever in operation, would be working at full power was made. This, did not have into account that the pressure differences (inlet and outlet of compressors) will not always be equal to the maximum difference considered when designing its' power. For example, the cavern compressor was (well) designed so that in the case of the largest pressure difference, it would have enough power to compress it: from 55 to 180 bar. Nevertheless, that will not always be the case, thus this assumption is not an accurate representation of reality. In practice, other compressing needs can occur and be a tiny fraction of the maximum difference: for example, if the gas runs through the pipeline at a pressure of 85 bar and the cavern is at 86 bar, the compression power will be very limited. As noted in the results section, the Compressor's OpEx ended up representing 27% of the average $LCoH_{Transmission\&Storage}$. As noted in the impact analysis the compressor's power was the parameter that among the 3 assessed for a given 25% variation, had the largest impact on the final $LCoH_{Transmission\&Storage}$.

Additionally, over the cost model, the 6% WACC could have been elaborated in more depth. The research considered it to be a suitable value because it was the median value of the range given by [54] - a reference used throughout the report. However, currently record low interest rates along with typical power sector debt to equity rates of 80:20 [27], the WACC could be lower. By considering the just mentioned debt to equity factor, along with: a 3% cost of debt [27] and a 5.94% cost of equity of sustainable energy projects [18], the WACC pre tax is estimated to be 3.59%. If such value would have been used and included in the impact analysis, the $LCoH_{Transmission\&Storage}$ could have been further reduced to $0.16 - 0.21€/kg_{H_2}$. Please note that such low WACC is mostly dependant on the monetary policy regarding interest rates. As the current historically low interest rates are expected to increase in the medium to short term, so is the WACC.

As stated in the results section, it is important to compare the results with the indications previously seen in literature. Over that section it was concluded that: the retrofitted transmission cost is aligned with literature while the new transmission is also aligned but on the upper range of the intervals. As for storage, the values are on the lower range of the broad ranges found in literature but no direct comparison is possible to make as there is no reference with a similar large number of cycles. Furthermore, as noted in the impact analysis the assumptions and limitations previously pointed out do not radically affect the quality of the results presented. Having this said, one be confident that the results are consistent with literature and that the possible cost over-estimations related to the high electricity price and maximum energy intensity parameters, i.e., compressors' power assumption, impact the results in controlled manner - by no more than 10%.

Furthermore, it is important to understand the results of the added cost of stabilizing production. In practice this value will outline the extra cost on top of the production cost that had to be spent on stabilizing the hydrogen production - at expense of a direct supply and a transmitted & stored supply. The given range of $0.10 - 0.14€/kg_{H_2}$, dependant on the pathway combination, considers that 57% of the mass produced had to be transmitted and stored in order to achieve a yearly stable production of 609.5 kg/hour. If the hydrogen stabilization supplying the ammonia facility becomes more flexible, i.e., with more stabilization periods, the mass needed to store will be less. On one hand this will slightly increase the $LCoH_{Transmission\&Storage}$ - as the denominator becomes smaller - but will reduce the added cost of stabilizing production - as more mass is assumed to be supplied at cost zero. Nevertheless, other mass breakdowns which consider other variables, for example, different weather patterns (which impacts hydrogen production) should be further studied. Apart from those research improvements, if one considers a competitive hydrogen production cost of $1 - 1.5€/kg_{H_2}$, it is possible to estimate that a production stabilization solution such as the one exposed in this work, will cost roughly an extra 10%.

Generalizing the final results to other projects must be made with a critical mindset. The outputs of this research are given for the *Sines H_2 Hub* . Nevertheless, they can be used for projects that have similar hydrogen flows and cycles as well as cavern and pipeline dimensions. One can expect that finding a project with so much characteristics in common is hard, however, if only the transmission or storage infrastructure match, it is possible to still make sense of the results using the cost breakdowns. Furthermore, the whole research approach proposed - from the 3 stabilization scenarios up to the elaboration on each cost breakdown - is possible and encouraged to replicate.

One can sum up that future research should focus on investigating alternatives to the assumptions made on: the compressors power and it's impact on OpEx; the system design of pipeline diameter; and conduct a more comprehensive study that includes a broader range of equipment, such as a pressure reduction equipment capable of recover energy. The research results will serve academia to have a better understanding of the costs of transmission and storage involved in a project of these characteristics. But also for practical implementation by project developers, such as Resilient Group under the *Green Flamingo* project or EDP, Galp, REN, Engie, Martifer and Vestas, under the *H2Sines* project, which will be able to use the results to estimate aspects such as the projects' financial feasibility, price competitiveness and help on the decision process of using retrofitted or new infrastructure.

6 Conclusions and recommendations

The purpose of this research was to determine the levelized cost of hydrogen transmission and storage in the context of the *Sines H_2 Hub* . To do so, a cost model which considered the CapEx and OpEx's of the most relevant cost components, was elaborated in Matlab.

Initially, the literature review outlined the state of the art of the technologies considered, as proposed in the first sub-question. Then, it was collected data on the expected hydrogen production and traced the storage needs profile for three possible hydrogen stabilization scenarios. From these scenarios, the overall maximum parameters were fed into other parts of the research. Moreover, data on the existing transmission and storage system was collected, thus answering the second research question. This was followed by a proposed design for both infrastructure possible pathways (new or retrofitted), which answered sub-question 3. Then to answer sub-question 4, the cost model focused on elaborating the CapEx and OpEx cost components for both transmission and storage infrastructures. Then the CapEx costs were combined via the annuity method and along with the OpEx and total hydrogen throughput, calculated the Levelized Cost of Hydrogen Transmission and Storage ($LCoH_{Transmission\&Storage}$) for the *Sines H_2 Hub* , thus answering the research main question.

As one can note in table 6.1, the final results present a $LCoH_{Transmission\&Storage}$ between $0.17-0.25€/kg_{H_2}$. When broken down, $0.11€/kg_{H_2}$ can be attributed to the storage infrastructure, while $0.06-0.13€/kg_{H_2}$ to the transmission infrastructure (dependant on the pathway). If the average of pathways is analysed, it will be of $0.21€/kg_{H_2}$ and 27% of its' cost relates to the compressors' OpEx, 28% to the Well & Cavern OpEx and 25% to the Pipeline CapEx.

Table 6.1: Final results

Result	**Cost** [$€/kg_{H_2}$]
Retrofitted transmission cost	0.06
New transmission cost	0.13
Retrofitted or new storage	0.11
Total cost range	0.17-0.25
Average of the 4 pathways	0.21

When looking into the parameters that drove the compressors' OpEx, the most important will be: electricity price, compressors' power and WACC. It is important to note the results were strengthened in the impact analysis of these parameters as no 25% variation (among the reasonable range) impacted more than 10% the final cost. Furthermore, given the conservative approach followed when elaborating the maximum energy intensity (used to calculate the compressor's OpEx), one can expect an even lower $LCoH_{Transmission\&Storage}$ than the one previously exposed.

Furthermore, it was calculated an added cost of stabilizing the hydrogen production, which was determined to range: $0.10 - 0.14€/kg_{H_2}$, dependant on the pathway combination. Put into perspective, if a competitive green hydrogen production cost is considered, the cost of stabilizing production will be of roughly 10% on top production.

Recommendations for future research

It is important to address some of the main limitations and assumptions outlined during this study. Further research is encouraged in order to have a more accurate result and to determine the most cost-effective technological option capable of transporting and storing the hydrogen produced in the context of the *Sines H_2 Hub* . Therefore, one can summarize the recommendations to have in mind for further research on the topic:

- Design a dynamic energy intensity factor that translates the varying pressure differences that compressors face. This can have a significant effect in achieving a smaller $LCoH_{Transmission\&Storage}$;
- Consider a pipeline capacity increase, in line with other EU projects. In the future this can lead to even lower unitary costs of transmission due to economies of scale;
- Expand the system's boundaries in order to include other equipment. Such as the pressure reduction equipment, capable of recovering the energy currently lost in the decreasing pressure from cavern to pipeline;
- Consider other options such as line packing as alternatives to store such little hydrogen flows;
- Elaborate the impact analysis for other variables and assumptions. Other than the ones considered, it would be of interest to assess the changes in weather patterns and it's impact on the added cost of stabilized production, for example;

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