Delft University of Technology

Master thesis - Sustainable Energy Technology

THE TECHNO-ECONOMIC FEASIBILITY OF GREEN HYDROGEN STORAGE IN SALT CAVERNS IN THE DUTCH NORTH SEA

Rotterdam, January 25, 2022

By D.S. Eradus
Student number: 4373693

First supervisor:
Prof.dr. A.J.M. van Wijk

Thesis committee:
Prof.dr. A.J.M. van Wijk
Prof. Dr. Ir. Z.(Zofia) Lukszo
Dr. H. (Hadi) Hajibeygi

Nomenclature

Abbreviations

AF	Annuity factor
CCS	Carbon capture and storage
CV	Cushion volume
DRI	Direct reduced iron
EAF	Electric arc furnace
H2	Hydrogen
HHV	Higher Heating Value
KNMI	Koninklijk Nederlands Meteorologisch Instituut
IRENA	The International Renewable Energy Association
LHV	Lower Heating value
OBP	Overburden pressure
NC	number of caverns
PEM	Proton Exchange Membrane
RDS	Royal Dutch Shell
PtG	Power-to-Gas
PtH2	Power-to-Hydrogen
RoR	Rate of return
TOTEX	Total Expenditures
UGS	Underground Gas Storage
VC	Volume of caverns
WACC	Weighted average cost of capital
WV	Working volume

Preface

From an early age I have been interested in the concept of sustainability and renewable energy. This has led to the decision to complete my education with a master's degree in Sustainable Energy Technology at the Delft University of Technology. This thesis was written as part of the final stage of obtaining my master's degree and it marks the end of my educational career.

I would like to express my gratitude towards a number of people who contributed to this project as it would not have been possible to achieve this result without their help. First of all, I would like to thank my first supervisor, Ad van Wijk for introducing me to the topic; an ideal combination of my background in Applied Earth Sciences and my current field of study in renewable energy. Our conversations prevented me from getting off track and Ad's endless enthusiasm for the topic kept me motivated throughout the process. Furthermore, I would like to thank the members of my committee, Hadi Hajibeygi and Zofia Lukszo, for their ideas and suggestions that allowed me to focus my research, especially in the final stage of the project. In addition, I want to thank Royal Dutch Shell for allowing me to use their software, which has been of great help. Moreover, I would like to thank Mike Illingworth, who provided me with loads of useful cost information on offshore operations which I would otherwise not have had access to. It has added a lot of value to the final result of the project and I really appreciate the time and effort Mike took to help me. Finally, I would like to thank to Robert Kleibergen for mentoring me on a pro bono basis, out of intrinsic motivation and enthusiasm for the energy transition and this project in particular. Rob has helped me enormously with defining the scope of my project and his countless ideas and enthusiasm never failed to motivate me.

Abstract

The Dutch government aims to drastically reduce their greenhouse gas emissions. To this end, immediate and effective measures must be taken to transition from the fossil fuel-based system we have today to a renewable energy-based system. Green hydrogen could play an important part in this by aiding in the decarbonization of the industry sector; a substantial contributor to the Dutch energy consumption. Among other industries, the steel industry is working towards renewable energy based operation. Tata Steel Nederland B.V. is planning to replace the traditional blast furnace steel making process by a direct reduced iron (DRI) process, eventually powered by green hydrogen. The industry sector will require a constant hydrogen supply to run their operations to adhere to their obligation of emission reduction to a certain level. This cannot be realized with solely an offshore green hydrogen production system (i.e. electrolysis powered by wind energy) due to the intermittency of available wind energy. A storage facility must therefore be integrated in the system to level out the intermittency. Potentially, a salt cavern storage system can be created in the Dutch part of the North Sea for this purpose.

The aim of this thesis is to analyze the techno-economic feasibility of integrating an offshore salt cavern storage system into a green hydrogen production system in the Dutch North Sea, with the objective to provide a constant green hydrogen supply to the industry sector. To this end, the potential for creating salt caverns in the North Sea was examined and the prospected theoretical storage capacity was evaluated and compared to the required storage capacity. By means of simulation of hydrogen production from offshore wind speed data, the storage capacity required to fill a 10 GW pipeline with baseload green hydrogen was approximated. Based on this storage capacity, the boundary conditions for creating this system in the Dutch part of the North Sea were established to identify feasible locations. To assess the economic feasibility of the concept, the costs for the storage system and the associated increment to the levelized cost of hydrogen (LCOH) for offshore green hydrogen production were assessed.

The simulations reveal that a 19.8 GW wind park in combination with an 8.65 TWh salt cavern storage system would be sufficient to provide a constant hydrogen supply to a 10 GW pipeline. In the first year of simulation, the total hydrogen production by the system amounted to 85800 GWh (2.18 Mton), of which 23300 GWh (0.59 Mton) was injected into the storage system and 62500 (1.59 Mton) was inserted directly into the pipeline.

Four locations in the Dutch North Sea were identified where a group of adjacent salt caverns could be created with a collective storage capacity of at least the required 8.65 TWh. At least two of these locations are not obstructed by existing or planned wind parks, hydrocarbon fields and associated surface structures. Although further research is required, from this analysis it is concluded that creating a salt cavern storage system of sufficient magnitude may indeed be technically feasibly.

Figure 1 shows a schematic image of the conceptual system design, with the capacities of the different components in the system. Shown in the yellow frame is the part of the system considered in the cost analysis.

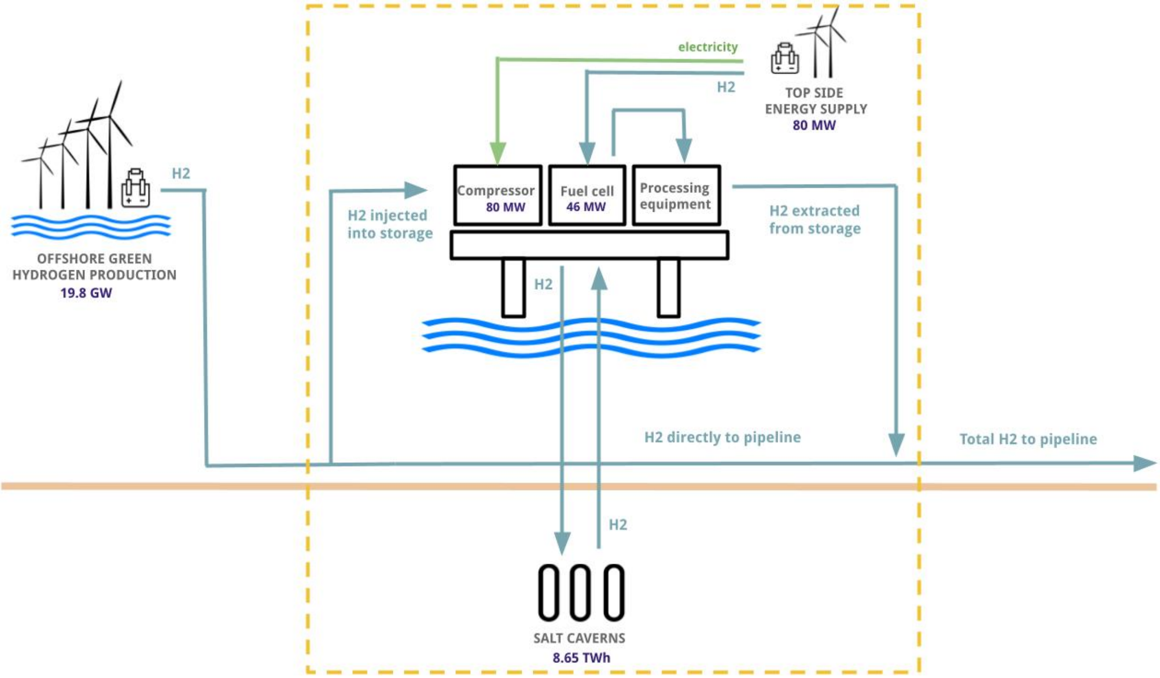


Figure 1: Schematic image of the system designed in this study.

The incremental costs of adding to offshore hydrogen production a storage system with the components and capacities shown in figure 1 would translate to an addition of 0.17 €/kg to the LCOH for offshore green hydrogen production. Optimization of system design and the financial state of affairs may reduce costs for the storage system and thereby the total LCOH for offshore hydrogen production and storage. The economic feasibility of this concept will depend on the price of alternatives and the amount of subsidy required and received.

In conclusion, the results of the analysis speak in favour of the techno-economic feasibility of integrating a salt cavern storage system into offshore green hydrogen production. It is therefore recommended to further develop and optimize the configuration and mode of operation of the system, and to calculate the costs with increased accuracy to provide a better outlook on the practical feasibility of the concept.

Contents

Chapter 1

Introduction

In 2013, on behalf of 886 Dutch citizens the Urgenda Foudation brought on the Climate Case and filed a lawsuit against the Government of The Netherlands “for not taking sufficient measures to reduce greenhouse gas emissions that cause dangerous climate change” [1].
On 20 December 2019, after 6 years of legal proceedings, the Supreme Court of the Netherlands upheld the decision of the District Court of The Hague on 24 June 2015 as well as the decision of the Court of Appeal on 9 October 2018, affirming the order that the Netherlands need to reduce its emissions by a minimum of 25% before 2020 compared to 1990 levels. The ruling urged the Dutch government to take immediate and effective measures on climate change.

The Dutch climate plan for 2021-2030 describes that the Dutch government aims to reduce their greenhouse gas emissions by 49% by 2030 and by 95% in 2050, compared to 1990 levels [2]. The European Union (EU) has committed to adjusting emission reduction from 40% to 55% in 2030 [3]. The European aim of 55% is estimated to raise the Dutch emission reduction goal to 52% by 2030 [4]. These are ambitious goals, for which drastic changes are required in all fields and industries.

According to climate experts, green hydrogen is indispensable in the journey towards net zero emissions[5]; Not only can green hydrogen be used to decarbonize the industry and transport sector, but it can also serve as a solution to the intermittent availability of renewable energy.
Europe has great potential for developing a hydrogen economy. Especially the Netherlands, with its gas infrastructure and great potential for wind energy at the North Sea, could well be a frontier. Currently in the Dutch energy system the different components: gas, electricity and heating, are segregated. The climate policy for 2021-2030 aims at an increasingly integrated energy system, which should lead to more efficiency in the distribution and generation of energy [6].

An example of such system integration may be the combination of offshore wind energy and hydrogen production. By employing the abundant offshore wind energy to power the process of electrolysis, large amounts of so called ’green hydrogen’ can be produced; hydrogen generated by renewable energy instead of energy from fossil fuels. This hydrogen can be transported to shore to be used as feedstock or fuel.
However, there is the problem of intermittency; hydrogen production from offshore wind energy varies with wind conditions and therefore a constant supply cannot be guaranteed. Like all other sectors, the steel industry is under pressure to reduce their carbon emissions. Dutch steel producer Tata Steel Nederland B.V. is working on a strategy to meet the Paris agreement and they see departing from coal based technologies as an indispensable element in becoming fossil free by 2050. The company aims to replace their traditional blast furnaces by direct reduced iron (DRI) units, a mature technology which would initially run on natural gas but can be converted to use green hydrogen in a later stage [7]. To allow the steel producing units to run 24/7, a constant hydrogen supply is required.

Like steel producers, other industry players will also have to make the switch to renewable energy in the near future. Hence, the industry sector will at some point require a constant hydrogen supply to run their operations, which cannot be generated solely from an offshore green hydrogen production system due to the intermittency of available wind energy. To be able to provide a constant energy supply, a hydrogen 'buffer' must be available to use in times of poor wind conditions and corresponding low hydrogen production. An opportunity lies in the subsurface: salt caverns in the North Sea can be used for storing excess hydrogen in times of abundant hydrogen production, to be used at times of little or no production. Thus, integrating a storage system into an offshore green hydrogen production system could be a way of ensuring a constant green hydrogen supply for the industry sector.

In this thesis, the techno-economic potential of providing a constant green hydrogen supply by integrating a salt cavern storage system into an offshore green hydrogen production system (i.e. hydrogen production by electrolysis powered by offshore wind energy) is analyzed. In this chapter, first of all a general introduction into the production and storage of green hydrogen in salt caverns is presented in section 1.1. Subsequently, the problem definition and scope are defined in section section 1.2 and the objectives of the study are given in section 1.3. Finally, the research questions are presented in section 1.4 and the approach for answering them is discussed in section 1.5.

1.1 Background information

This section presents background information on green hydrogen production and storage in salt caverns to aid understanding of the technology, i.e. the boundary conditions for successful implementation thereof. Furthermore, the significance of the study is demonstrated by discussing the role a salt cavern storage system could have in the decarbonization of the industry sector.

1.1.1 Green hydrogen production

renewable energy can be stored by converting the renewable energy to chemical energy in the form of gas. This process is referred to as Power-to-Gas (PtG), or in the case of hydrogen Power-to-hydrogen (PtH2), where hydrogen serves as the energy carrier [8].
Hydrogen gas is created by means of electrolysis; a process where water molecules are decomposed into hydrogen molecules (H_2) and oxygen (O_2) molecules. This is an oxidation-reduction (redox) reaction. Combining the half reactions at the anode and the cathode yields the following overall reaction:

$$2H_20(l) \longrightarrow 2H_2(g) + O_2(g) \tag{1.1}$$

The decomposition of water into oxygen and hydrogen is an endothermic reaction, requiring an electrical power source for it to occur. When the electrical power is obtained from renewable energy, the produced hydrogen is referred to as green hydrogen. Hydrogen produced with energy from fossil fuels is known as grey hydrogen and renamed blue hydrogen in case the CO_2 emitted in the process is captured, a process referred to as carbon capture and storage (CCS).

A renewable energy technology of accelerating maturity, wind energy can be an excellent energy source for green hydrogen production. Considering wind speeds are generally higher with increasing distance from shore, the energy price for wind energy from turbines located far offshore are generally lower than for energy from onshore wind parks. Therefore the potential for large-scale green hydrogen production from offshore wind energy in the North Sea is currently being studied, not only by scientists [9] but also by industry players like Shell and Gasunie, who are cooperatively investigating the opportunities for large scale green hydrogen production at the North Sea as part of the NortH2 consortium [10].

1.1.2 Underground hydrogen storage in salt caverns

Underground storage of green hydrogen is thought of as the only feasible option in Europe for large scale renewable energy storage since it allows storage of large amounts (TWh-scale) of hydrogen gas for a relatively low price per unit power compared to other storage technologies [8]. Different geological formations can be used for underground gas storage (UGS). Among the UGS techniques are storage in porous media, where gas is stored in the interconnected voids of a formation, and storage in man-made cavities in impermeable rock formations, such as rock salt. The latter can occur either as bedded salt deposits or salt structures in the form of salt domes, salt pillows or salt walls [11]. In salt bodies, large cavities can be created by means of dissolution of the salt. Depending on the geology, the volume of these engineered salt caverns can range from a few 100 000 m^3, and up to 1 000 000 m^3 [12].
Although UGS was practiced already in 1915, the first salt cavern UGS facility was authorized only in 1961 in the USA. In 1964 the first salt cavern for gas storage purposes was commissioned in Canada, followed by the first facility in France in 1970 [13].

Among the several techniques for hydrogen storage, salt cavern underground gas storage (UGS) is likely promising for fast cycle large scale purposes for a number of reasons. First of all, underground storage facilities can accommodate much larger volumes than for example surface gas tanks [14]. Large burial depth , associated with high overburden pressure, allows for high operating pressures, thereby enabling a large storage capacity [8] since the energy density is proportional to the pressure [15]. Furthermore, UGS requires a relatively small amount of land area and is less liable to external influences than above-ground storages [14]. The specific costs for salt cavern UGS are relatively low and the operational safety is higher than for other, above-ground storage methods. [8].

Rock salt has specific material properties that make it a superior medium for storing hydrogen. Unlike in porous rock formations, no mineralogical or microbiological reactions are expected between hydrogen gas and rock salt. Furthermore, rock salt permeability is very low; most laboratory measurements give permeabilities below $10^{-20}m^{-2}$ and field measurements still give values below $10^{-18}m^{-2}$, despite inhomogeneities and local disturbances [16]. With this low permeability comes the benefit of little to no leakage of hydrogen. Moreover, the required amount of cushion gas in salt caverns is modest compared to storage in porous rock formations [8].
Another important advantage salt caverns as a storage medium for hydrogen produced from highly intermittent renewable energy sources such as wind or solar energy is the fact that salt caverns allow flexible operation; injection- and withdrawal rates are high and switching between injection mode and withdrawal mode can be done in short time intervals [14].

Construction of salt caverns

Salt caverns are artificially created caverns in subsurface salt deposits, constructed by means of solution mining. In solution mining, water is pumped into a salt deposit, thereby dissolving the salt and leaving a cavity in the formation after the produced brine is retrieved. The first phase of the solution mining process is the leaching phase. A well is drilled in the subterranean salt deposit and the outer casing, often referred to as the surface casing is placed in the well and fixed in place to prevent seepage. Inside this casing a leaching system of two concentric tubes is placed. Feed solvent (either fresh water of undersaturated brine) is circulated in the salt deposit through one of the tubulars and the produced brine is collected through the other tubular [13]. the void between the outer leaching tube and the well casing is filled with a lighter density, inert 'fluid blanket' to avoid leaching of salt above the bottom of the casing, thereby securing the cavern roof and avoiding calamities such as roof collapse. In the past, hydrocarbon products such as diesel or crude oil were used as fluid blanket, but today nitrogen and sometimes compressed air are preferred as these are safer and more environmentally friendly to use for this purpose. The thickness of the fluid blanket can be controlled by a tube right inside the outer casing [17].

The leaching of the salt can be done by either direct or indirect circulation. In the former, fresh water or undersaturated brine flows out a leaching string at the well bottom and, due to it having a lower density than the brine, migrates up towards the blanket, gradually *saturating* in the process. In case of indirect leaching, the feed solvent flows out the annulus, gradually *mixing* with the brine whilst travelling downward, where it flows into the leaching tube. The direct leaching method favors expansion of the bottom of the cavern, while indirect leaching will enlarge the upper part of the cavern. Impurities in the salt causes the presence of insoluble materials, such as dolomite-anhydrite residues or shattered roof blocks in the salt cavern. These insolubles will not dissolve in the feed solvent during the leaching process but will sink to the bottom to form a slump.
Figure 1.1 shows a schematic overview of the leaching phase in the solution mining process, displaying both direct and indirect leaching [17]. Generally, a combination of the two techniques is used depending on the desired cavern shape[14].

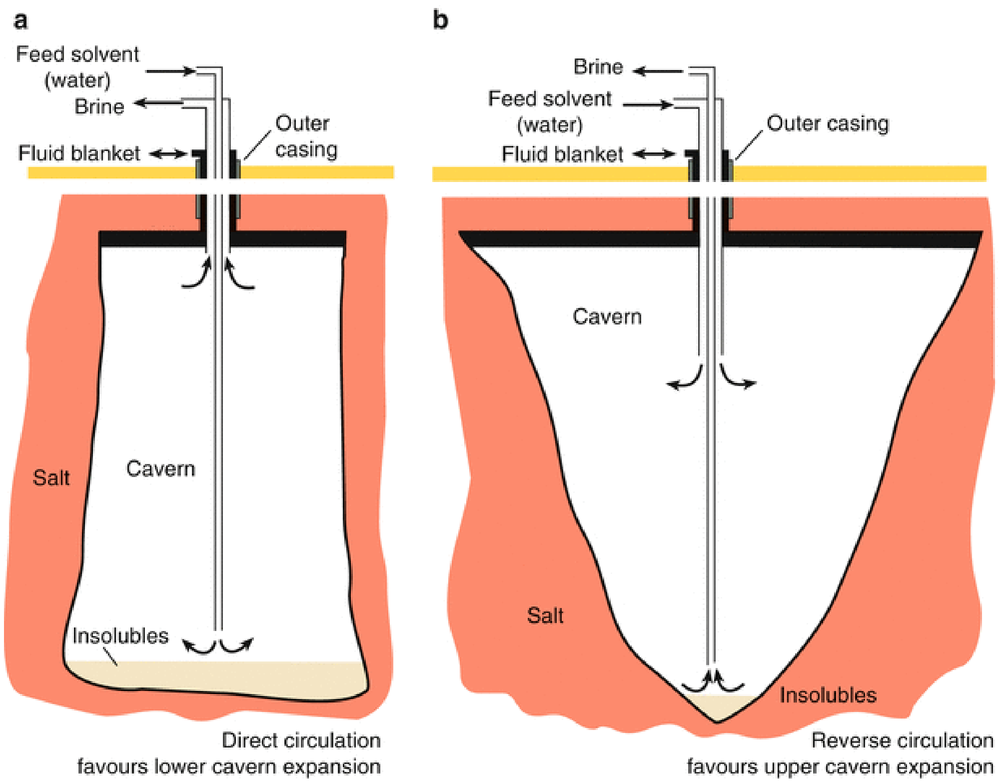


Figure 1.1: Overview of solution mining process

After the cavern has reached the desired volume and shape, the leaching process is terminated and the cavern must be depleted of the brine. To this end, the leaching tubes are removed and instead a gas injection string and a brine string are inserted. The cavern is then depleted from the brine by injecting hydrogen gas at high pressure, pushing out the brine. After all brine has been removed, the brine string is taken out. The salt cavern is now filled with pressurized hydrogen and can serve as a gas storage [14]. The cavern will initially be loaded up to a certain minimum pressure for stability reasons and to enable delivery of the working gas volume [14]. The volume of gas required to achieve this minimum pressure is referred to as cushion gas or base gas.

Operation of salt caverns

The operation of salt caverns is comprised of a number of processes. In this section, the practices required for gas injection into and gas withdrawal out of salt caverns is explained. The proceedings described in this section are based on the underground natural gas storage Zuidwending in Groningen, the Netherlands. It is assumed that the process of storing hydrogen in salt caverns is similar to that of storing natural gas in salt caverns; the main difference between natural gas storage and hydrogen storage are the materials used in the subsurface installation (see figure 1.2) and transmission infrastructure [11].

Gas injection
After hydrogen is produced by electrolysis it is transported towards the storage facility through pipeline. Before it enters the facility, the gas must be filtered to prevent any (solid) particles present from damaging the facility. The gas then enters a metering station which measures the exact amount of gas that is injected and withdrawn from the storage facility. To be able to insert it in the salt cavern, the hydrogen gas must be compressed from the pressure in the pipeline, to cavern pressure, generally ranging approximately from 80 up to 180 bar [18]. Pressure regulating stations are used to control the gas pressure. Due to the compression the gas experiences an increase in temperature. Therefore, heat exchangers are used after compressing the gas in order to cool it down. The gas can then be safely inserted in the salt cavern through the master valve. Figure 1.2 shows a schematic overview of the subsurface installation of an operating salt cavern [8].

Gas withdrawal
To withdraw hydrogen from the gas cavern, the master valve is opened and hydrogen is allowed to flow out. Before it can be inserted into the pipeline, the hydrogen needs to be purified as it could be polluted with moisture and other impurities present in the slump in the cavern. The solid particles are extracted using sludge catchers. To meet the pressure in the gas network, the gas must be decompressed, which is encompassed by a decrease in temperature. For that reason the gas is pre-heated using boilers prior to decompression, as it needs to have a temperature of 15 °C when entering the gas network. To eliminate any moisture in the gas it is dried using a drying column. In the drying column, moisture is extracted by mixing the gas with a hydrophylic substance called glycol. Afterwards, the glycol is separated from the gas to be used again. Finally, the gas is metered to measure the amount of gas flowing out of the storage facility, after which it is inserted into the gas grid [18].

Successful cases and prospects

Gas storage in subterranean salt formations is a proven technology. Several salt cavern UGS facilities have been constructed and are successfully being operated to date; by the end of 2016, out of the 672 underground gas storage facilities in the world 97 were salt caverns [19]. An example of natural gas storage in salt caverns in the Netherlands is the Zuidwending facility in Groningen mentioned previously in section 1.1.2, consisting of five large salt caverns at a depth between 1000 and 1500 metres.In this facility, hydrogen can be injected and withdrawn very rapidly, switching from injection to withdrawal within fifteen minutes [18], allowing high performance conditions. Apart from that, a number of salt cavern hydrogen storage facilities are currently operative. In Teesside, UK, a salt cavern storage facility has been successfully used for storing hydrogen since 1972[12]. Furthermore, in the US salt caverns are being used for hydrogen storage in Clemens Dome and Moss Bluff since 1983 and 2007 respectively [11]. From these cases the technical feasibility of hydrogen storage in onshore salt caverns is demonstrated.

As of 2019, no offshore salt caverns were used [20]. However, the potential and feasibility is being researched in several projects. The first license for offshore gas storage was obtained by

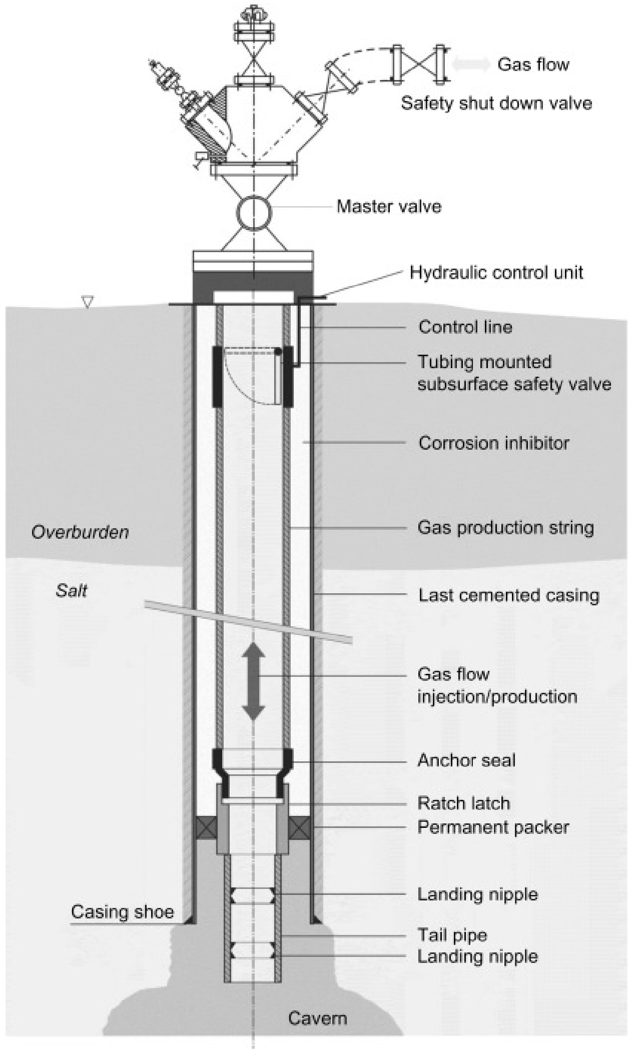


Figure 1.2: Schematic overview of the subsurface installation of an operating salt cavern for gas storage

the Gateway project by Stag Energy in 2010 [21]. In this project, extensive data acquisition was performed to identify the most suitable salt structure for offshore gas storage in the UK.
Moreover, the potential for an offshore salt cavern UGS facility in Brazil for CCS purposes is currently being studied. Before constructing the first ever offshore salt cavern with a height and diameter of 450 m and 150 m, respectively, an experimental salt cavern was developed in a study by Costa et al in 2017 [22], to simulate the geomechanical behaviour over time and to calibrate parameters, which can then be used to assess the structural integrity [20]. The study concludes that the designed cavern will remain within an acceptable stress- and strain region during operation over its lifetime, and using it for natural gas storage would be feasible in light of the logistics of natural gas in Brazil [22].

The technical feasibility of offshore salt cavern UGS for CCS purposes in Brazil is trusted; according to [23] there is "no doubt this shall be performed". It should be noted though that hydrogen storage differs greatly from CCS in terms of cycle frequency, and hence the stress conditions and creep-strain rate will differ. Hence, this study does not provide a conclusion on the technical feasibility of offshore salt caverns for high performance hydrogen storage purposes as is aimed at in this thesis. However, from the simulation it can be concluded that safe construction and lower frequency cycling of offshore salt cavern storages could be possible.

1.1.3 Potential for hydrogen production and storage in the North Sea

The North Sea holds ample opportunity for green hydrogen production and storage. The North Sea subsurface contains salt bodies originating from the Permian age. In the south, central and northern North Sea, members of the Zechstein formation Z1 and Z2 have been identified, containing halite units of significant thickness [13]. Caglayan et al [11] have investigated the technical potential for salt cavern UGS in Europe. In this study, technical potential is defined as the storage potential without taking into account ecological and social limitations. An analysis of the geology was performed to identify suitable locations for salt caverns. The technical potential was then determined from the potential storage volume. Figure 1.3 shows a map of all identified salt bodies (bedded salt formations as well as salt structures) in Europe. Clearly, the North Sea accommodates numerous salt bodies potentially suitable for salt cavern UGS.

Apart from the geological setting, the North Sea accommodates an extensive gas infrastructure as a consequence of the exploitation of offshore hydrocarbon sources. Moreover, the Dutch coast can serve as a hydrogen distribution hub; Groningen, with its gas fields is an essential node in the European gas network, and the port of Rotterdam, with its already widespread pipeline network of over 1500 km [24], seeks to develop a hydrogen network in order to boost the development of a hydrogen economy throughout Europe [25]. Therefore the North Sea in combination with the Dutch coast has outstanding potential for developing a high performance hydrogen production and storage system.

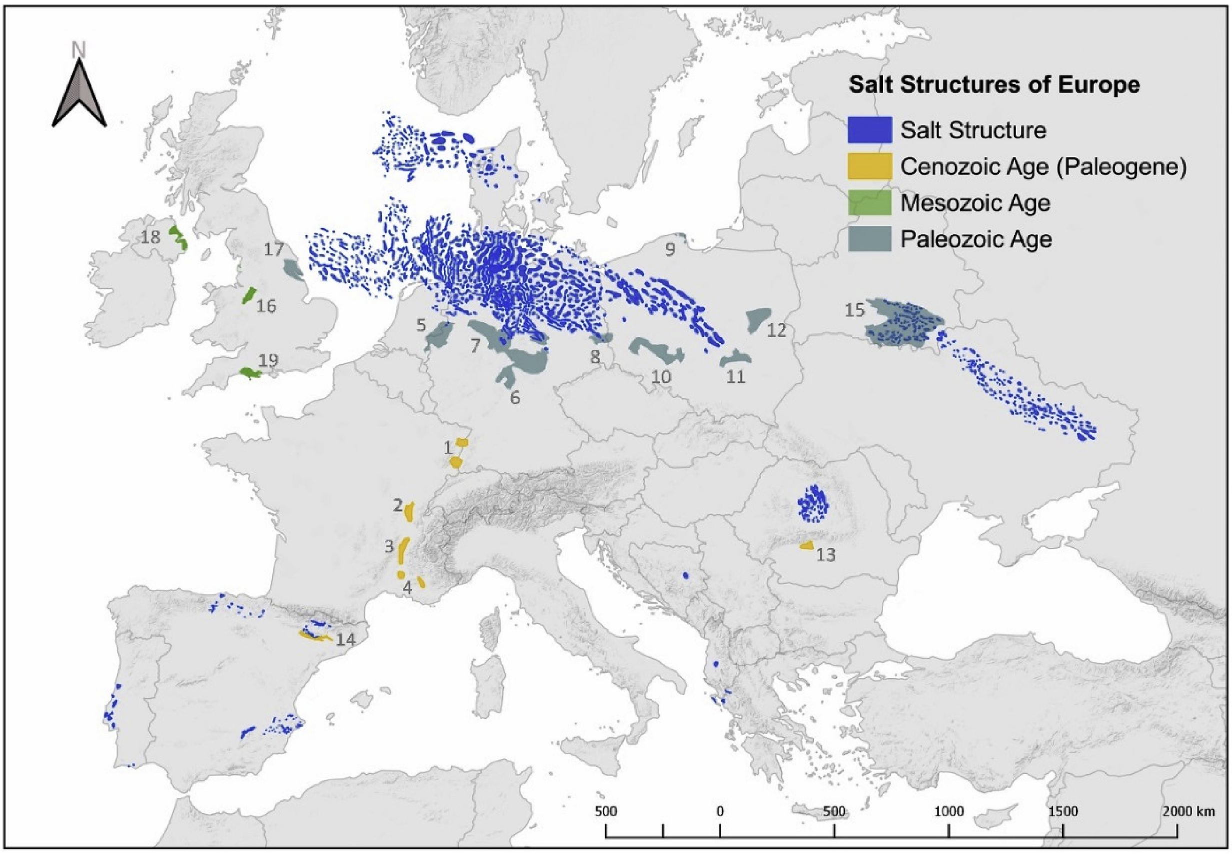


Figure 1.3: Map of salt depositions in Europe

1.1.4 The role of hydrogen in decarbonization of the industry sector

The industry sector is responsible for a large share of the total national energy consumption. in 2019, the industry sector was amenable for 42%[26] of the total Dutch energy consumption, which amounted to 2000 PJ in that year [27]. Hence enormous gains in reduction of national CO2 emissions could be made if the industry sector would switch to renewable energy.

An example of an industry player working towards renewable energy based operation is Tata Steel Nederland B.V., henceforth referred to as Tata Steel. Like all other industries, the steel industry is required to act to meet the Dutch climate goals set by the Paris agreement. To this end, Tata Steel has been working on a strategy for a greener, more sustainable future of the company. Several strategies for decarbonization have been considered and analyzed. For example, CCS has been considered as a means to reduce the net carbon emissions from steel making. More promising in the long term is the replacement of the traditional blast furnace steel making process by a direct reduced iron (DRI) process. In this process, iron ore (Fe_2O_3) is reduced to iron (Fe) in the solid state, where a reducing agent removes the oxygen from the iron ore. Subsequently, the iron can be converted to steel using an electric arc furnace (EAF)[28].

In the direct reduction of iron, CO (obtained from coal or natural gas) can be used as a reducing agent. The overall chemical reaction is as follows:

$$Fe_2O_3 + 3CO \longrightarrow 2Fe + 3CO_2 \tag{1.2}$$

The final reaction products of the direct reduction reaction in case carbon monoxide is used as a reducing agent are iron and CO2. The CO2 emissions from this process can be mitigated by using hydrogen as a reducing agent instead of carbon monoxide. In that case only iron and water are produced and the overall reaction is as follows:

$$Fe_2O_3 + 3H_2 \longrightarrow 2Fe + 3H_2O \tag{1.3}$$

Seeing as Tata Steel's IJmuiden plant produces roughly 12.5 million tonnes of steel per year, of which 63% comes from the blast furnaces [7], replacing the blast furnaces by DRI production units would have significant impact on CO2 emission reduction.
The DRI production units would initially run on natural gas, but could in a later stage switch to green hydrogen. To this end, a constant green hydrogen supply would have to be provided.

Apart from Tata Steel, also other industries will once require a constant hydrogen supply to run their operations to adhere to their obligation of emission reduction to a certain level. This cannot be realized with merely an offshore hydrogen production system (i.e. electrolysis powered by wind energy) due to the intermittency of wind energy. A storage facility should therefore be incorporated in the system to level out the intermittency, in order to guarantee a constant hydrogen flow to the steel production location.

1.2 Problem definition

Ever since the discovery of the largest gas reserves in Europe in 1959 [29] the Netherlands has benefited from it in terms of welfare and energy security. The discovery of natural gas sparked an energy transition; that of a coal-based system to one of predominant natural gas utilization. Nowadays, an energy transition is again approaching, albeit on different grounds this time. With the increasing pressure on governments to reduce carbon emissions, a transition from a fossil fuel-based energy system to a renewable, zero-emission energy system is imperative. Hence, options replacing fossil fuels should be and currently are being explored.

The industry sector is one that still heavily relies on fossil fuels and in this lies an opportunity for drastic change. Considering the sector's large contribution to the national energy consumption, if the use of fossil fuels in the industry sector could be toned down or even phased out entirely, this would greatly benefit the goal of becoming a net-zero emissions country. In order to decrease or

eliminate the use of fossil fuels, a renewable equivalent is demanded. The solution could be found in green hydrogen: hydrogen produced by electrolysis powered by renewable energy, for example from (offshore) wind energy.
A system producing green energy from offshore wind energy is in itself not competent in replacing fossil fuels; a wind energy powered electrolyzer is not able to provide a constant supply of hydrogen because of the intermittency of the energy source. In order to ensure a constant hydrogen supply, a storage facility would have to be incorporated in the green hydrogen production system to balance out the intermittency of wind conditions and inherently the hydrogen production. Potentially, a storage system of sufficient capacity can be created from salt caverns in the North Sea subsurface.

Although salt cavern storage is proven technology and economically feasible, it has not yet been applied offshore in the Netherlands. There are a number of major unknowns that will determine whether or not a system as described above will provide a feasible alternative to fossil fuels. Although the salt cavern storage capacity of Europe has been studied ([11],[14]), it is unclear whether the North Sea could accommodate a storage system with the purpose of providing a constant hydrogen supply to the industry sector, let alone what such a system would cost and inherently the price of the produces hydrogen.
To assess the feasibility of integrating a storage system into an offshore green hydrogen production system, these unknowns must be addressed. Seeing as both the technical and the economic feasibility for the system are of crucial importance, the problem definition of this thesis is twofold:

1. To determine the requirements on a green hydrogen production and storage system that complies to the demand for a constant hydrogen supply by the industry sector, and to assess the possibility of creating this in the Dutch North Sea.

2. To determine the costs associated with creating this system and inherently the levellized hydrogen to see if the system could be financially viable

1.3 Objectives

The objective of this thesis is to shed light on the techno-economic feasibility of integrating an offshore salt cavern storage facility into a green hydrogen production system in the Dutch North Sear. With regards to the technical feasibility of this concept, the aim is to develop a conceptual system design, providing insight in the required capacities and dimensions of the different system components to allow for constant hydrogen production of sufficient volume. The subsurface conditions needed for creating the conceptual system are compared to the subsurface conditions in the Dutch North Sea to determine the theoretical potential for accommodating this system.

To assess the financial viability of integrating a storage system into a hydrogen production system, an analysis of the costs of the system is performed. The objective of this part of the study is to give an indication of the incremental cost of the storage system, and inherently the addition to the price of hydrogen. In this way the costs of the system can be compared to the costs for alternatives and an indication of required subsidies can be given.
Another objective of the cost analysis is to pinpoint the main cost drivers and most crucial elements in the system, which will enable further optimization of the system in future research.

1.4 Research question

Based on the problem description presented above, which describes on the one hand the unknowns in system capacity and dimensioning and the possibility of construction in the North Sea, and on the other hand the yet unexplored financial picture, the research question is defined as follows, encompassing both facets of the problem:

"Under what conditions would it be technically possible and financially feasible to store green hydrogen in salt caverns in the North Sea, to supply baseload green hydrogen to the industry sector?"

The research question grasps different facets of the topic, and in order to direct the thesis in these different directions, the following sub-questions were defined:

1. What hydrogen production capacity and salt cavern storage capacity would be required to provide a baseload hydrogen supply of sufficient magnitude?
2. Which location(s) in the North Sea would be suitable for creating a salt cavern storage system of sufficient capacity?
3. What would be the cost of this storage system and how much would this add to the price of hydrogen?

Based on these sub-questions, a comprehensive (preliminary) conclusion on the technical and economical feasibility of integrating salt cavern storage into an offshore green hydrogen production can be drawn.

1.5 Research approach and methodology

In this section, the approach and methodologies are described. The research question is divided into three sub-questions. The first two sub-questions concern the technical feasibility, whereas the third question addresses the economic feasibility. The thesis will be subdivided in a technical feasibility analysis, in which the first two sub-questions are discussed, and an economic feasibility analysis which will answer the third research question. For each sub question a research approach and methodology was defined, which are separately discussed in this section.

sub-question 1: What hydrogen production capacity and salt cavern storage capacity would be required to provide a baseload hydrogen supply of sufficient magnitude?
To determine the required storage capacity, hydrogen production from offshore wind energy will be simulated from offshore wind speed data. The desired capacity of the hydrogen production system will be scaled to the hydrogen demand, and based on the mismatch between production and demand the storage capacity required to balance the intermittent hydrogen production with the constant hydrogen demand is approximated. The simulation is done by means of a MATLAB model using wind speed data obtained over a time span of several years. The product of this part of the thesis will be an approximation of the required wind park capacity and the required storage capacity, represented by a number of fictional caverns with predefined characteristics.

sub-question 2: Which location(s) in the North Sea would be suitable for creating a salt cavern storage system of sufficient capacity?
Based on the targeted storage capacity and the associated number of salt caverns required for the system, the boundary conditions on the location for successful creation and operation of the system can be defined. By comparing these boundary conditions to the subsurface conditions in the North Sea, potentially suitable locations can be identified.
The boundary conditions on the subsurface are obtained from literature. To assess the suitability of the North Sea, we use software that integrates information on the salt formations in the North Sea to estimate the potential for creating salt caverns. Based on the dimensions and depth of the salt bodies, the software plots potential salt caverns and provides information on their prospected (theoretical) storage capacity. In this way, locations with sufficient storage capacity can be identified and checked for interference with any obstacles. The product of this part of the thesis is a selection of potential sites for the storage system.

sub-question 3: What would be the cost of this storage system and how much would this add to the price of hydrogen?
The third and final part of the thesis will be a cost analysis. This requires an analysis of all expenses involved in the integration of a salt cavern storage in an offshore green hydrogen production system. Based on the capacity and size of the storage system as established in part 2, the capacity and corresponding costs of all system components can be estimated/determined, which will provide an insight in the total costs of the system. From there, the additional cost per amount of delivered hydrogen can be determined, which will shed light on the financial viability. In addition, a sensitivity analysis is conducted to identify the primary cost drivers. Hence, the products of this part of the thesis are the incremental cost of the storage system to the offshore green hydrogen production system, the amount this would add to the levelized cost of hydrogen and an indication of the largest influences to the total system cost.

Chapter 2

Technical feasibility

In order to determine the technical feasibility of constructing a salt cavern storage system with the purpose of supplying a constant hydrogen supply of sufficient magnitude, the required storage capacity of the system must be compared to the available salt cavern storage capacity in the Dutch part of the North Sea. To this end, we must first define the targeted hydrogen production, i.e. the 'hydrogen supply of sufficient magnitude' which in turn governs the 'required storage capacity'. These boundary conditions are presented in section 2.1. Subsequently, the methodology for determining the required storage capacity is described in section 2.2 and the procedure for assessing the salt cavern storage potential in the North Sea is presented in section 2.3. The results of the assessments are presented in sections 2.4 and 2.5, respectively. Finally, the fundamental conclusions of this chapter are presented in section 2.6.

2.1 System boundary conditions

Subject of this study is a salt cavern storage system with the purpose to balance out green hydrogen production and demand, enabling a continuous supply. The storage system will be fed by an offshore hydrogen production system, i.e. offshore wind turbines that power in situ electrolyzers. When wind speeds are high, large amounts of hydrogen will be produced and transported to shore via pipelines. Due to the intermittency of wind energy, hydrogen production will fluctuate and production will sometimes exceed demand, while at other times production will be lower than demand. The salt cavern storage system will function as a buffer; excess hydrogen can be injected into the caverns when production exceeds demand, to be extracted again at times of insufficient production. In this way, the system can provide a continuous green hydrogen supply to constantly meet the demand.

Definition of hydrogen demand

The hydrogen 'demand' in this case is defined as the objective to provide a constant hydrogen supply into a pipeline to shore, to provide baseload green hydrogen to the industry sector. In this study, a 10 GW gas pipeline is adopted. This translates to the objective to constantly generate 10 GW of power in the form of hydrogen gas; at each hour the system should inject 10 GWh of hydrogen into the pipeline. Hence, a 'hydrogen supply of sufficient magnitude' is defined as a continuous production of 10 GWh of hydrogen gas per hour.

Definition of required storage capacity

The storage capacity should be such that the system can meet the objective of supplying sufficient hydrogen quantities at all times. This implies an obligation of guaranteeing security of supply to the consumer. In case of 100% security of supply, the system should at all times be able to adequately supplement the hydrogen stream from the electrolyzers to the pipeline at times of insufficient production by the electrolyzers. In other words, it cannot occur that the storage system is 'empty', i.e. cannot supply hydrogen, while demand exceeds production by the electrolyzers.

Hence, the required storage capacity is defined as the storage capacity that will prevent such events from occurring. In this study, the required storage capacity is determined by simulation and therefore the required storage capacity in this study is defined as the storage capacity required to ensure the storage system can always provide supplementary hydrogen to the pipeline to shore. The simulations are predicated on wind speed data deemed representative for offshore weather conditions in the North Sea. It should be noted that the required storage capacity will be case-specific and will in practice vary to a certain degree with wind conditions, time frame and demanded hydrogen production. That being said, in this study the storage capacity determined from simulations will be regarded as representative for the system analyzed in this study.

2.2 Method for assessment of the required storage capacity

In this section, the methodology for determining the targeted salt cavern storage capacity is presented. By means of simulation, the wind energy capacity and salt cavern storage capacity needed to generate an adequate hydrogen supply are determined. First of all, a description of the data used in the simulation is given in section 2.2.1, after which the methodology for simulating the hydrogen production is described in section 2.2.2. Section 2.2.3 explains the approximation of the minimum required storage capacity of the system, and section 2.2.4 describes how the possibility of installing less than the minimum required storage capacity is explored.

2.2.1 Description of data used for simulations

The hydrogen fed into the system is produced by electrolyzers powered by offshore wind energy. Consequently, the capacities of the system components are partly governed by the wind conditions at the envisioned location of the wind park. Although identifying the most optimal location for this wind park is outside the scope of this study, the general notion is that it will be placed far offshore to benefit from higher wind speeds and inherently lower electricity costs. For this reason, wind speed data from a weather station location far offshore in the North Sea is used for simulation of the wind energy production.

Koninklijk Nederlands meteorologisch Instituut (KNMI) is responsible for archiving all weather measurements in the Netherlands and wind speed data of its weather stations is publicly available on their website. Figure 2.1 shows a plan view of all offshore KNMI Weather stations. Visible in figure 2.1 is that the stations located furthest offshore are D15-FA-1, F16-A, J6-A, F3-FB-1 and A12-CPP. From the first four weather stations, wind speed data is available from 2011-2020, whereas for A12-CPP this data set is incomplete. For this reason, only stations D15-FA-1, F16-A, J6-A and F3-FB-1 will be considered. Out of this selection, D15-FA-1 and F3-FB-1 are located furthest offshore. After a first exploratory data analysis it was decided to use weather station D15-FA-1 for the calculations, since the analysis revealed that the 2011-2020 wind speed data from weather station F3-FB-1 gave unrealistically high wind speeds for majority of the last year of measurements (366.8 m/s).

To verify that the wind speed data from weather station D15-FA-1 is indeed representative for wind conditions far offshore and is therefore suitable for determining the required capacities for the hydrogen production and storage system, the data from weather station D15-FA-1 will be further analyzed and compared to data measured over the same time period from stations F16-A and J6-A. The data sets contain hourly 10 minute average windspeed measurements collected from 2011 to 2020. The outcomes of this data analysis are compared to the long term average values published by KNMI and can be found in Appendix B. The analysis reveals that the wind speed data from weather station D15-FA-1 is indeed representative for far offshore conditions and will henceforth be used for calculations.

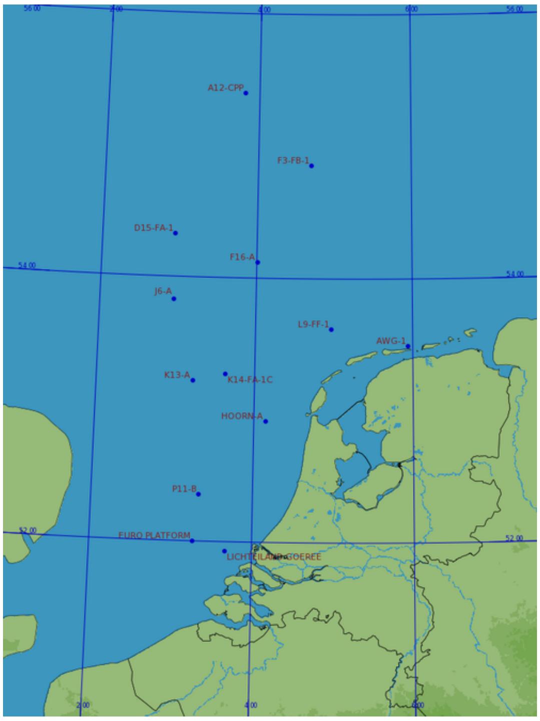


Figure 2.1: KNMI weather stations in the Netherlands and the Dutch North Sea

2.2.2 Simulation of hydrogen production

To determine the required storage capacity, the quantity of hydrogen injected into and withdrawn from the storage system at each time instant must be simulated. The first step in this process is the simulation of wind power production from wind speed measurements. Wind speed is measured at 10 m elevation and must be converted to wind speed at the turbine hub height to calculate the wind energy production. This is done by first translating the wind speed at reference height to the wind speed at blending height using the logarithmic law[30]:

$$U(h) = U(h_{ref}) * \frac{ln(\frac{h}{z_0})}{ln(\frac{h_{ref}}{z_0})} \tag{2.1}$$

Where U is wind speed in m/s, h is blending height (60 m), h_{ref} is the measurement height (10 m), and z_0 is the surface roughness. The surface roughness for open sea is 0.0001 [31]. Next, wind speed at blending height is translated to wind speed at hub height using the power law[30]:

$$U(h) = U(h_{ref}) * (\frac{h}{h_{ref}})^{\alpha} \tag{2.2}$$

Where the power law coefficient α is between 0.064 and 0.08 for the Dutch part of the North Sea. In the calculations a value of 0.07 for α will be used [32].

From the wind speed variations at hub height, the wind power production can be simulated. Wind turbines produce power only between a certain (turbine-specific) minimum and maximum wind speed, referred to as cut-in and cut-out wind speed, respectively. For wind speeds below cut-in wind speed or above cut-out wind speed, the turbine rotor is idling at low rotational speed and there is no electricity production. For wind speeds between cut-in and cut-out wind speed, power production can be described by a power curve. This curve is divided in two regions based on wind speed: the partial load region and the full load region. The partial load region is the power production for wind speeds between cut-in wind speed and rated wind speed. Power production in the partial load region is described by equation 2.3:

$$P = \frac{1}{2} * \rho * c_p * \eta_g * \eta_b * A * U^3 \tag{2.3}$$

Where P is the produced wind power [w], ρ is the air density 1.225 kg/m3, c_p is the power coefficient of the turbine, $\eta_g$and η_b are the generator efficiency and gearbox efficiency, respectively, A is the rotor swept area (π*r^2) and U is the wind speed [m/s].
For wind speeds between rated wind speed and cut-out wind speed, the turbine produces rated power. This is referred to as the full-load region.

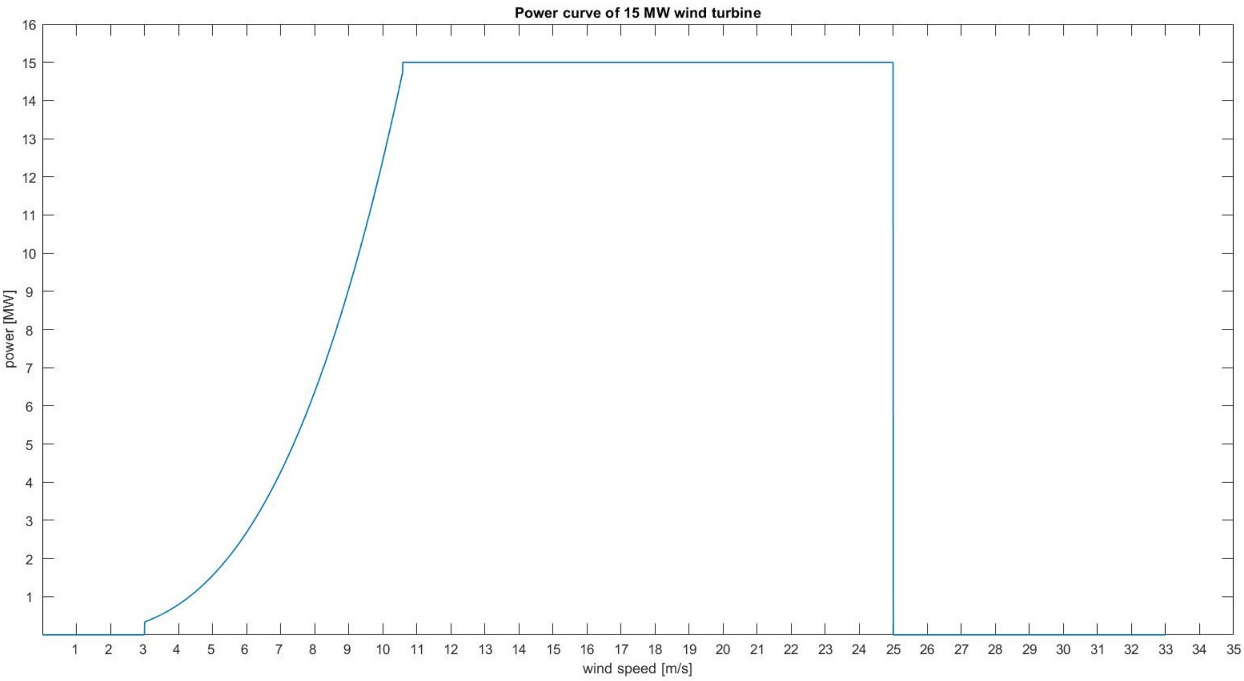


Figure 2.2: Power curve for the wind turbine used for calculations

In the simulation of power production, 15 MW wind turbines with built-in electrolyzers are assumed. This kind of turbine is currently being developed by Siemens Gamesa and a full scale offshore demonstration is expected by 2025/2026 [33]. The design parameters of a 15 MW offshore reference turbine [34] are used for calculations. Table 2.1 shows the specifications of this turbine that are relevant for calculation of the power production. With these parameters and using equation 2.3 the power curve can be plotted. Figure 2.2 shows the power curve for the reference turbine used for calculations. The power curve shows that below cut-in wind speed, the power production is zero. Between cut-in windspeed and rated wind speed, power production satisfies the v^3 relation. For wind speeds ranging from rated wind speed and cut-out wind speed, the turbine produces at rated power. When wind speed exceeds cut-out wind speed, power production is zero again.
From the power curve and wind speed data the power production of a wind turbine can be computed. The total power production of the wind park is determined by multiplying this power production by the number of wind turbines in the wind park. In this evaluation of the power production of the wind park the effect of interference between turbines is neglected.

Initially, the wind park capacity is established based on the demanded hydrogen production. The purpose of the system in this study is to provide baseload hydrogen through a 10 GW pipeline. This means that the system is demanded to deliver 10 GWh per hour in the form of hydrogen.

Turbine parameter	**Value**
Hub height [m]	150
Power rating [MW]	15
Cut in windspeed [m/s]	3
Cut out wind speed [m/s]	25
Rated wind speed [m/s]	10.59
Design Cp [-]	0.489
Generator efficiency [%]	96.5
Gearbox efficiency [%]	n.a.

Table 2.1: Design specifications of the wind turbine used in calculations, obtained from the reference turbine as specified in[34]

Producing hydrogen from wind energy through electrolysis is a process consisting of multiple steps. The focus of this study lies on the storage system, and a detailed analysis and simulation of the hydrogen production process would be out of scope. Therefore a simplified approach is employed, meaning the hydrogen production is approached as a (fixed) percentage of the wind energy production. Current electrolyzer efficiencies are in the range of 70-90% [35]. The turbine developed by Siemens Gamesa will employ a proton exchange membrane (PEM) electrolyzer. This technology currently has an electrical efficiency of 80-90% [36] on the higher heating value (HHV). In this study, an overall conversion efficiency from wind energy to hydrogen of 80% is adopted. That is: the total energy in terms of HHV of the hydrogen produced from a certain quantity of wind energy is assumed 80% of that amount of wind energy. Accordingly, the hydrogen production (quantified in units of energy, GWh) will be approximated as 80% of the simulated wind energy production; a linear relation between wind energy production and hydrogen production is assumed in this study.

2.2.3 Evaluating the required storage capacity

To determine the required storage capacity, the hydrogen production at each hour needs to be compared to the demanded hydrogen supply of 10 GWh per hour to fill the 10 GW pipeline. Following the simplified approach for translating wind energy production to hydrogen production presented in section 2.2.2 a total wind park capacity of 12.5 GW would be required to generate 10 GWh of hydrogen per hour if the turbines would run at rated power at all times. However, due to varying wind conditions the latter is not the case.
The wind park capacity and storage capacity must be chosen such that neither a decreasing nor an increasing trend in the hydrogen content is observed in the salt cavern system system in the long term. Ultimately, the hydrogen production over the simulated period should equal the cumulative hydrogen demand to achieve long term steady state in the system.Accordingly, the fluctuations in hydrogen content of the salt caverns must be simulated to find the minimal storage capacity that can still fulfil the H2 demand on an hourly basis.

To find the most optimal configuration of system capacities, the mismatch between hydrogen production and demand is determined for each time instant. The cumulative sum of this mismatch is used to simulate the amount of hydrogen inserted into or extracted from the storage system for each time instant. From the cumulative sum of hydrogen insertion and extraction the quantity of hydrogen present in the system is simulated over time. The minimum required storage capacity is then established as the capacity which ensures that the integrated hydrogen production and storage system is able to meet demand throughout the entire simulation. The wind park capacity and storage capacity combination that ensures a long time balance in the system is found by iteration.

The storage capacity is chosen such that the system will not fall short in meeting demand throughout the entire simulation. In other words: a boundary condition for the system is that the simulated

hydrogen content in the salt caverns cannot go below zero.
That being said, hydrogen content exceeding the storage capacity is *not* a limiting factor; the storage system is allowed to be full, meaning it can occur that hydrogen cannot be inserted without cavern pressures exceeding the upper boundary condition (80% of overburden pressure). In that event it is assumed that the excess hydrogen can be sidetracked to a different storage medium or curtailed. A detailed investigation of strategies for these circumstances are outside the scope of this study.

Using the methodology described in this section, the system's storage capacity demanded by the local wind conditions and demanded hydrogen supply can be approximated. The storage capacity determined in this way would in theory guarantee security of supply; a system with this storage capacity would not fail to provide the demanded hydrogen supply for the simulated wind conditions. However, in reality wind conditions vary and the circumstances will deviate from this simulation, meaning that chances are that while the storage capacity as determined in this section would in theory (i.e. according to this simulation) ensure security of supply, in reality this might not be true. Furthermore, the system will not be able to operate at full capacity at all times due to maintenance or otherwise caused temporary downtime of one or several components of the system. For that reason 100% security of supply cannot be guaranteed. Nevertheless, the storage capacity as determined from the simulation as described in this section will be regarded as a sufficient storage capacity for the purpose and will henceforth be regarded as the 'minimum required storage capacity'.

In light of the economic feasibility it would be interesting to assess the system's performance in case of installing less storage capacity than the minimum required capacity. After all: less storage capacity requires less salt caverns which decreases the investment costs for the storage system. Therefore apart from the scenario where 100% of the minimum required storage capacity would be realized, three more scenarios are defined where the storage system will have only 90%, 75% and 50% of the minimum required storage capacity.

2.2.4 Assessment of security of supply and potential back-up strategies

As explained in the previous section, the minimum required storage capacity is defined such that the system would not fall short in meeting demand. In designing this system, it is important take into account the interests of the stakeholders involved. The demand side of the storage system is comprised of multiple parties in the industrial sector, each claiming their share of the hydrogen supply fed into the pipeline by the system. For parties that require a constant energy supply to run their operations, the system's failure to deliver sufficient hydrogen could have significant consequences and consequently, security of supply is of vital importance. However, demanding a high level security of supply may be costly. Potentially, parties would be willing to trade in part of the security of supply for a reduction in cost. For this reason an assessment of the performance of different storage capacities is carried out. Evaluating the consequences of having a system with less than the minimum required storage capacity will shed light on the effect on the security of supply.

A storage system with less than the minimum required storage capacity will encounter moments at which the storage system cannot deliver the demanded quantity of hydrogen, *if* the boundary conditions on cavern pressure for safe operation are obeyed. That is: if all salt caverns can only be operated within the recommended pressure range of 24% to 80% percent of overburden pressure, i.e. the pressure at the depth of the top of the cavern resulting from the weight of the overlying rock material. In other words, if the boundary conditions for cavern pressure are to be respected, there will be moments when no hydrogen can be extracted from the storage system while hydrogen production from the electrolyzers is insufficient to meet demand. These instances are henceforth called periods of shortage.

To assess the severity of these occurrences, the frequency, duration and magnitude of these hydrogen shortages are determined for multiple percentages (90, 75 and 50 %) of the minimum storage capacity, based on which the security of supply of each storage capacity can be approximated. The security of supply is defined in this study as the theoretical percentage of time the system is able to meet demand hence is determined by the following:

$$Security of supply = \frac{t_{sim} - t_{shortage}}{t_{sim}} \cdot 100\% \tag{2.4}$$

Where t_{sim} represents the total duration of the simulation in hours, and $t_{shortage}$ refers to the total amount of hours the system encounters hydrogen shortage. As mentioned previously, the capacity for which, based on the simulation, no hydrogen shortages occur is regarded as the capacity with 100% security of supply. Following the logic presented here, for a system with less than 100% of the determined capacity the security of supply will be less than 100%. Depending on the cost reduction resulting from the decrease in storage capacity, the associated level of security of supply might be acceptable.

That being said, even when aiming for maximum security of supply, it is still interesting to investigate the option of decreasing the required storage capacity. Possibly, demand could still be met with a smaller storage capacity when combined with a back-up strategy, i.e. maximum security of supply could be achieved with a smaller storage capacity. This could be an financially fruitful concept if the reduction in investment costs achieved by creating less salt caverns exceeds the costs for the back-up strategy. In this study we explore the possibility of exploiting the cushion gas in the caverns as a back-up strategy.

As mentioned previously, a system with less than 100% of the minimum required storage capacity will encounter moments when the system is empty; hydrogen cannot be extracted without disobeying the boundary condition for a safe minimum cavern pressure.
Nevertheless, when reaching the lower boundary for cavern pressure, the storage system is not literally 'empty'; at that point, the caverns still contain a considerable amount of hydrogen due to the necessity of cushion gas being present for stability reasons. Hence, in theory there is more hydrogen to be extracted from the caverns, albeit in violation with the safe limit for minimum operating pressure in the caverns.

It could be considered to install less storage capacity than what is required to prevent shortages, and to extract hydrogen beyond the advised minimum cavern pressure the salt caverns when needed. In this way, demand could be met by a smaller and hence less costly storage system. This however poses issues from a stability perspective, seeing as exceeding the advised pressure boundaries can jeopardize safe and stable operation of the system. Hence, the effect of temporarily extracting cushion gas from the caverns must be addressed to judge the feasibility of this concept.

In the simplest approach, during shortages hydrogen would be extracted from all caverns collectively, with the advantage that the resulting pressure drop would be relatively low since the load is carried by all caverns cooperatively. However, considering the heterogeneity of the subsurface, irregularity in cavern shapes, fractures in the rock material and more dissimilarities in subsurface conditions, some caverns are likely to be less stable than others and are therefore less suitable to be operated below their recommended minimum pressure with regards to the risk of collapse. For this reason it could also be considered to select a group of caverns that are in the most optimal conditions from a stability perspective (i.e. the caverns that are not in the vicinity of faults, salt body boundaries, et cetera) to handle the periods of shortage. By analyzing the subsurface conditions and shape of each cavern, the caverns that are the most suitable to be operated beyond the minimum pressure boundary condition could be identified. This selection could potentially serve as a back up system to provide the required hydrogen at times the system cannot provide a sufficient amount in itself. Both approaches for exploiting the cushion gas as a strategic reserve will be studied for systems with different shares of the minimum required storage capacity. By analyzing the duration, frequency and magnitude of shortages, we can shed light on the associated effects on cavern pressures in case of shortages to determine if these affects could be acceptable.

Although the concept is being studied for economic reasons, this assessment is not only relevant in case less than the minimum storage capacity is installed; seeing as the storage capacity is determined from simulation of historic wind speed data, this storage capacity cannot guarantee security of supply in practice because weather conditions cannot be predicted with 100% accuracy. For that reason shortages could occur even in case the system has the minimum required storage capacity and therefore analysis of the pressure variations is relevant in any case.

To assess the potential of exploiting the cushion gas in case of shortages, the magnitude, duration and frequency of the hydrogen shortages will be assessed for three storage capacities: 90%, 75% and 50% of the minimum required storage capacity. To determine for each of these capacities the effect of the shortages on cavern pressures, the resulting pressure variations are simulated. For calculation purposes, all salt caverns are assumed to have a volume of 750.000 m3, a height of 300 m and a diameter of 58 m as described in [11]. The depth of all caverns, i.e. the depth of the cavern bottom, is assumed to be 1500 m, hence the burial depth is 1200 m. For each storage capacity, the number of required caverns is approximated using the Capacity Calculator by specifying the inputs for cavern depth, height and diameter according to the assumptions mentioned above.

As described in section 2.3, a safe operating range for cavern pressure is between 24% and 80% of overburden pressure. Hence, the initial minimum cavern pressure is determined as 24% of overburden pressure, which can be determined from equation 2.11 presented in section 2.2. For each scenario, the maximum drop in cavern pressure is estimated from the maximum amount of hydrogen that is extracted consecutively from the caverns, whereby the minimum boundary condition for cavern pressure is exceeded. For many gases, pressure can be approximated with reasonable accuracy by the ideal gas law:

$$PV = nRT \tag{2.5}$$

Hydrogen behaviour deviates from ideal gas behaviour, and to account for the deviation a compressibility factor Z is included to determine hydrogen pressure using the real gas law:

$$\rho_{h2} = \frac{PM}{zRT} \tag{2.6}$$

Where P is the cavern pressure [Pa], M is the molar mass [kg/mol], R is the universal gas constant (8.314), z the compressibility factor and T is the average gas temperature, determined as follows: [11]:

$$T = 288 + 0.025(depth - cavernheight/2) \tag{2.7}$$

In these calculations, the gas temperature T is assumed to be constant throughout the pressure variations and *depth* refers to the depth of the bottom of the cavern. In reality, the temperature will decrease with decompression. The relation between the mass of hydrogen extracted from the caverns and the resulting change in hydrogen density is described by the following equation:

$$m = (\rho_{h2,max} - \rho_{h2,min}) * V \tag{2.8}$$

with m the hydrogen mass [kg] and V the cavern volume [m^3].

The compressibility factor is estimated from experiments. Figure 2.3 shows the compressibility factor of hydrogen for a range of pressures and temperatures [37]. As mentioned previously, a cavern depth of 1500 m is adopted in these calculations. At this depth, the average gas temperature is 322 K according to equation 2.7 and assuming an average overburden density of 2300 kg/m3,

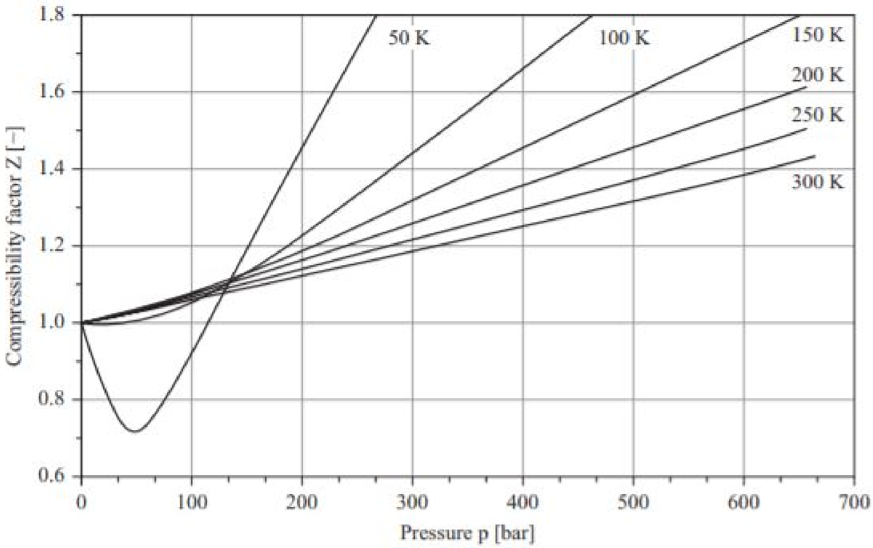


Figure 2.3: Compressibility factor Z for hydrogen

the overburden pressure would be 271 bar at a burial depth of 1200 m. At 24% of overburden pressure, the minimum advised cavern pressure would be 65 bar. Visible in figure 2.3 is that for pressures between 0 and 65 bar at T = 300 K, the compressibility factor for hydrogen will remain below 1.025. Hence, the real gas law will predict a pressure drop that is at most 2.5% higher than what follows from the ideal gas law.

For each storage capacity the maximum pressure drop the resulting new minimum cavern pressure is estimated using the method described in this section. This is done for approach 1, where all caverns will be operated below their advised minimum pressure in case of shortage, as well as for approach 2, where only a selection of the caverns are to be operated below the minimum boundary condition for cavern pressure. In the latter it is assumed that in each scenario fifteen caverns are identified that are especially stable and fit for this purpose.

The results of this analysis will provide a preliminary outlook on security of supply in case of decreasing the storage capacity. In addition, the potential for a system with less than the minimum required storage capacity in combination with a strategic reserve in the form of exploiting the cushion gas is assessed from the resulting pressure variations.

2.3 Method for assessment of the technical feasibility of creating a salt cavern storage system in the Dutch North Sea

The potential for creating salt caverns in rock salt formations depends primarily on the geological structure; the burial depth, thickness and longitudinal and lateral extent determine the number and size of potential salt caverns. Hence, in order to assess the technical potential of creating salt caverns in the Dutch part of the North Sea, the characteristics of salt formations have to be compared to the boundary conditions for salt cavern construction. Section 2.3.1 presents the prerequisites for salt cavern construction. Subsequently, section 2.3.2 presents the method for identifying suitable salt formations in the North Sea.

2.3.1 Evaluation of salt cavern storage potential

Paramount for creating salt caverns is the presence of a suitable geological salt deposit. As a result of significant periods of salt depositions due to marine transgression during the Paleozoic, or Permian, and Mesozoic ages, many bedded salt deposits and diapiric structures were formed in central Europe [11]. The structures and deposits in the Dutch part of the North sea are represented by the Zechstein (or Upper Permian) formation [38].

Evidently, the North Sea accommodates salt formations. However, not all salt bodies are suitable to accommodate salt caverns. A suitable salt deposit can be selected based on a set of conditions for safe construction and operation of salt caverns. Taking into account the short term and long term stability of salt caverns limitations on the salt cavern design and inherent requirements on the formation have been defined. In this section, the theory behind these design limitations and subsurface prerequisites is explained.

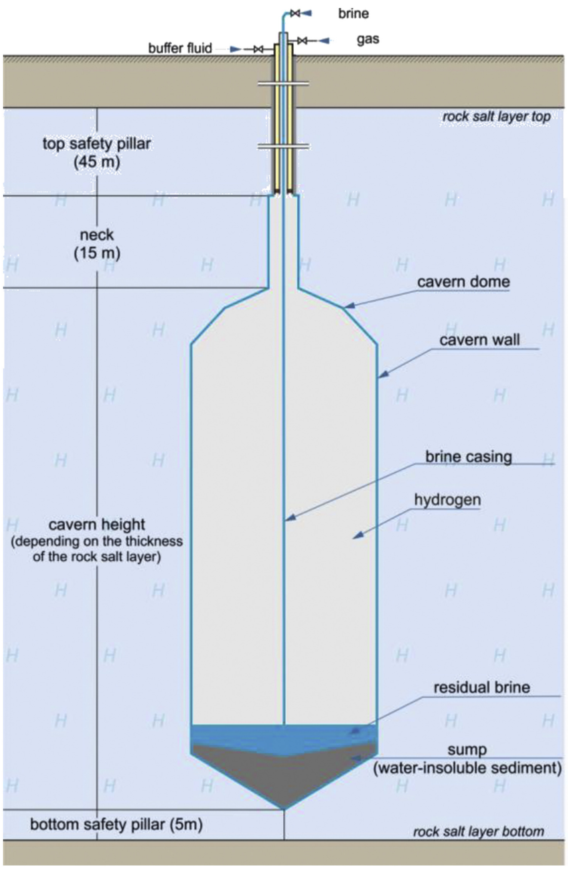


Figure 2.4: Simplified cavern shape

To establish the requirements on salt formations to accommodate salt caverns, the dimensions of salt caverns need to be specified. The targeted shape for salt caverns is generally either elliptical, cylindrical or capsuled shaped, the latter of which was found to be the most stable [14]. Figure 2.4 shows a simplified representation of a capsule shaped cavern.

The dimensions and volume of salt caverns are limited by the characteristics of the targeted salt formation. In other words, the allowed cavern height, diameter, offset between cavern boundaries and deposit boundaries and distance between adjacent caverns are all governed by the burial depth, thickness and extent of the salt body. Based on previous studies on salt cavern storage potential ([11],[14]) a number of boundary conditions for cavern construction were defined. First of all, the relation between the maximum cavern height H and diameter $\varnothing$ of a salt cavern in a salt deposit or structure with thickness M can be approached by the following equation [11]:

$$H = M - 0.20\varnothing - 0.75\varnothing \tag{2.9}$$

The second and third term in this equation represent the safety boundaries in the form of the minimum distance between the bottom of the cavern and the lower limit of the salt layer, known as the bottom safety pillar, and the minimum distance between the rock salt layer top and the roof of the salt cavern, the top safety pillar. To ensure safe operation, the minimum thickness of the bottom and top safety pillars should be at least 20% and 75% of the cavern diameter $\varnothing$, respectively [11]. Theoretically, the target diameter of the cavern $\varnothing$ could be as large as 2/3 of the cavern height H provided the deposit is axially symmetric and has homogeneous leaching properties [39]. In reality the target diameter is generally defined by regarding a minimum height-to-diameter ratio of 0.5. Assuming a capsule-shaped cavern shape as depicted in 2.4, with a cylindrical mid section, a dome-shaped top section with height 1/6 cavern diameter and a cone-shaped bottom with height 1/3 cavern diameter, the cavern volume V can be approximated by the following equation [14]:

$$V = \frac{\pi}{12}\varnothing^2(3H - \varnothing) \tag{2.10}$$

Another property that depends on the geological conditions is the cavern storage capacity. The amount of hydrogen that can be stored in a salt cavern is governed by the upper and lower boundary conditions for cavern pressure. These pressure limits are derived from the overburden pressure and for this reason the allowed cavern pressure, and inherently the storage capacity of the cavern, depends on the burial depth of the cavern [39]. The overburden pressure is obtained by equation 2.11:

$$P_{overburden} = \rho_{rock} g(D - H) \tag{2.11}$$

Where ρ_{rock} refers to the (average) rock density of the overburden, which is assumed to be 2300 kg/m^3 as is done in the study by Ozarslan [14], g is the gravitational acceleration which is 9.81 m/s^2, D is the depth of the bottom of the salt cavern in m and H represents the cavern height in m. To ensure geotechnical safety, cavern pressure should remain between 24% and 80% of the overburden pressure according to Caglayan et al.[11]. Exceeding these limits could jeopardize cavern integrity; surpassing the upper pressure limit could induce fracturing, while the lower pressure limit is imposed to enable gas injection and withdrawal and to secure stability by preventing the cavern from collapsing.

The limitations on minimum and maximum operating pressures determine the range of allowed pressure ranges and inherently the range of densities that hydrogen can adopt during operation. The minimum and maximum hydrogen density are determined from the minimum and maximum cavern pressure using the real gas law:

$$\rho_{H_2} = \frac{PM}{ZRT} \tag{2.12}$$

Which uses the minimum or maximum pressure P in pa, the molar mass of hydrogen M in $kg * mol^{-1}$, the universal gas constant, 8.314 $JK^{-1}mol^{-1}$, the compressibility factor Z and temperature

T in K [11].
In determining the gas temperature at a certain depth, it is assumed that the gas has the same temperature as the rock mass at that depth. Moreover, a geothermal gradient of $25°Ckm^{-1}$ is assumed for depths until 5 km. Assuming a surface temperature of 288 K, the average gas temperature in K can be determined by the following relation:

$$T_{average} = 288 + 0.025(D - H/2) \tag{2.13}$$

Where D and H represent the cavern depth and -height in m, respectively.
From the hydrogen density range obtained from equation 2.12, the mass of the working gas $m_{WorkingGas}$ can be determined from equation 2.14 which uses, apart from the minimum and maximum hydrogen density which are determined from equation 2.12, the volume of the cavern V_{cavern} and a safety factor θ_{safety}, assumed 70%, attributed to the loss of storage volume due to the slump and brine that remains in the cavern [11].

$$m_{WorkingGas} = (\rho_{H_2,maximum} - \rho_{H_2,minimum})V_{cavern}\theta_{safety} \tag{2.14}$$

From the mass of hydrogen that can be stored, the energy storage capacity of a salt cavern can be derived using the higher heating value (HHV, 39.4 kwh/kg for hydrogen [40]); multiplication of the stored hydrogen mass with the HHV gives the theoretical cavern storage capacity in GWh:

$$Capacity = m_{WorkingGas}HHV \tag{2.15}$$

From the principles described in this section, the requirements on the subsurface to be suitable for salt cavern construction can be established. Based on a predetermined cavern design; desired cavern height, diameter and corresponding volume, and the desired storage capacity, i.e. a desired pressure range, the minimum thickness and burial depth of a deposit to be suitable for this salt cavern design can be established. Potential locations for salt cavern storage in the North Sea were determined by comparing the geological setting of the salt formations with the boundary conditions as described in this section.

2.3.2 Identification of potential locations for the storage system

After salt structures and deposits that are suitable for salt cavern storage have been located in the North Sea, their suitability for housing a storage system of the required storage capacity must be evaluated. The suitability of a location depends on a number of concerns. First and foremost, the potential storage capacity of the location, i.e. the amount and capacity of prospective caverns, must equal or exceed the required storage capacity of the system. Additionally, the location should have no interference with existing or planned physical obstacles (to be defined later in this section), and therefore these should also be identified.

Consequently, site selection for the storage system will consist of examination of the suitability of the salt body itself in terms of storage capacity, as well as analysis of the eligibility of the location with regards to interference with obstacles. In other words: suitable locations for the system are identified based on suitability, i.e. sufficient storage capacity, and availability, i.e. no interference with other matters.

Software has been developed within Royal Dutch Shell (RDS, henceforth referred to as Shell), to assess the salt cavern storage potential of North-West Europe. The software is called "H2 Cavern Storage Capacity Calculator" (henceforth called "Capacity Calculator") and it was made available to use in this study. The Capacity Calculator follows the methodology as presented in the study by Caglayan et al. [11] to assess the storage capacity of salt formations from publicly available GIS data on salt depth and salt isochore. From this data the Capacity Calculator plots potential locations for salt caverns and computes their theoretical storage capacity. Additionally, the capacity calculator has integrated GIS data on the locations of existing and planned wind parks, hydrocarbon fields and affiliated platforms and gas infrastructure and can therefore be used to examine possible interference of caverns with existing or planned physical obstacles. Non-physical obstacles such as licenses for hydrocarbon exploration and extraction, sailing routes and military operations are not considered in this study but should be addressed in a later stage since these too could have implications for the availability of a location.

The capacity calculator asks for a number of values and allowed ranges for the input parameters. To assess the effect of the boundary conditions on the prospected storage capacity, three sets of input values were defined. The first input set is based on the study by Caglayan et al.[11]. Considering that both the methodology employed in the capacity calculator and this set of input values are based on the same study, this input set is deemed as the 'base scenario', also referred to as the 'reference scenario'.

A second set of input values was defined to demonstrate the difference in prospected storage capacity in case the input values would be more conservative with regards to stability; i.e. by restricting the allowed cavern pressure to a smaller range and by decreasing the diameter-to height-ratio. The second set of input values hence represents a more conservative scenario and the parameters are derived from a study by Ozarslan [14] and from a study by Lankof [39].

A third set of input values was defined to determine if restricting the cavern depth range would still give locations with satisfactory storage capacities. The aim of restricting the allowed depth range to a maximum depth would be to constrain the initial investment costs for the salt caverns; the costs for cavern construction typically increase with depth. Imposing a minimum depth would ensure a certain minimum pressure (range) and corresponding capacity, ensuring that the created caverns would have sufficient capacity for them to be economical. In brief, the third input set serves to demonstrate if restricting cavern depth to benefit the economic feasibility would still lead to identification of suitable locations. All input parameters and values are shown in table 2.2 and a detailed explanation of the three input scenarios is presented in appendix A.

	Input set 1	**Input set 2**	**Input set 3**
Geothermal gradient [degrees C/km	25	25	25
Overburden density [kg/m3]	2300	2300	2300
H2 heating value [MJ/kg]	141.8	141.8	141.8
H2 surface temperature [degrees C]	15	15	15
Min. thickness above and below cavern [m]	63	65	65
Diameter-height ratio [-]	0.5	0.4	0.4
Cavern spacing [-]	4	4	4
Safety factor [-]	0.7	0.7	0.7
Operating pressure range [%]	0.24-0.80	0.30-0.70	0.24-0.80
Cavern height range [m]	120-300	80-287.5	100-350
Cavern depth range [m]	500-2000	max 1800	1000-1500

Table 2.2: Three different sets of input values and -ranges for the capacity calculator software. Input set 1 is derived from the study by Caglayan et al, input set 2 is derived from studies by Ozarslan and Lankof, and input set 3 is a modified version of input set 1.

After entering the input values and obtaining the storage capacities of the salt formations, the Capacity Calculator will output preliminary locations for salt caverns and their theoretical storage capacity. Keeping in mind cost and ease of construction and operation of the storage system, it would be convenient to create the salt caverns as close together as possible. Therefore we used the

Capacity Calculator to identify locations where adjacent caverns would have a combined theoretical capacity equal to or larger than the minimum required storage capacity.

the locations with sufficient storage capacity will be regarded as potential locations. Existing and planned wind parks, gas infrastructure, hydrocarbon fields and the associated surface facilities and licenses for hydrocarbon exploration and exploitation are plotted to check for interference with the salt caverns in the locations that are thus far deemed suitable. Based on this analysis it is decided which of the potential locations are in theory available to use for the storage system analyzed in this study.

2.4 Results of assessment of required storage capacity

This section presents the findings on the required storage capacity of the system. First of all, a minimum required storage capacity is introduced in section 2.4.1, after which the effects of decreasing the storage capacity are revealed in section 2.4.2.

2.4.1 Minimum required storage capacity

To determine the required storage capacity, first of all the hydrogen production was simulated from wind speed data. By comparing the hydrogen production with the demanded hydrogen to be inserted in the pipeline, the hydrogen quantities injected into the storage system, extracted from the storage system and transported directly from the electrolyzers to the pipeline, i.e. bypassing the storage system were simulated. When hydrogen production exceeds demand, 10 GWh of hydrogen per hour is carried directly from the electrolyzers to the pipeline. The excess is injected into the storage system. In case demand exceeds production, the entire hydrogen quantity produced at that time is carried directly to the pipeline, and an additional amount of hydrogen is obtained from the storage system so that a total of 9.5 GWh of hydrogen is fed into the pipeline. The reason for inserting less than the total pipe capacity of 10 GW is that it allows for some room in the pipeline so that a safe pressure in the pipeline can be maintained. Figure 2.5 shows the hydrogen streams in the system for an arbitrary period of 48 hours to demonstrate the different hydrogen streams in the system. The average annual hydrogen production is 85000 GWh or $2.16 * 10^9$ kg, of

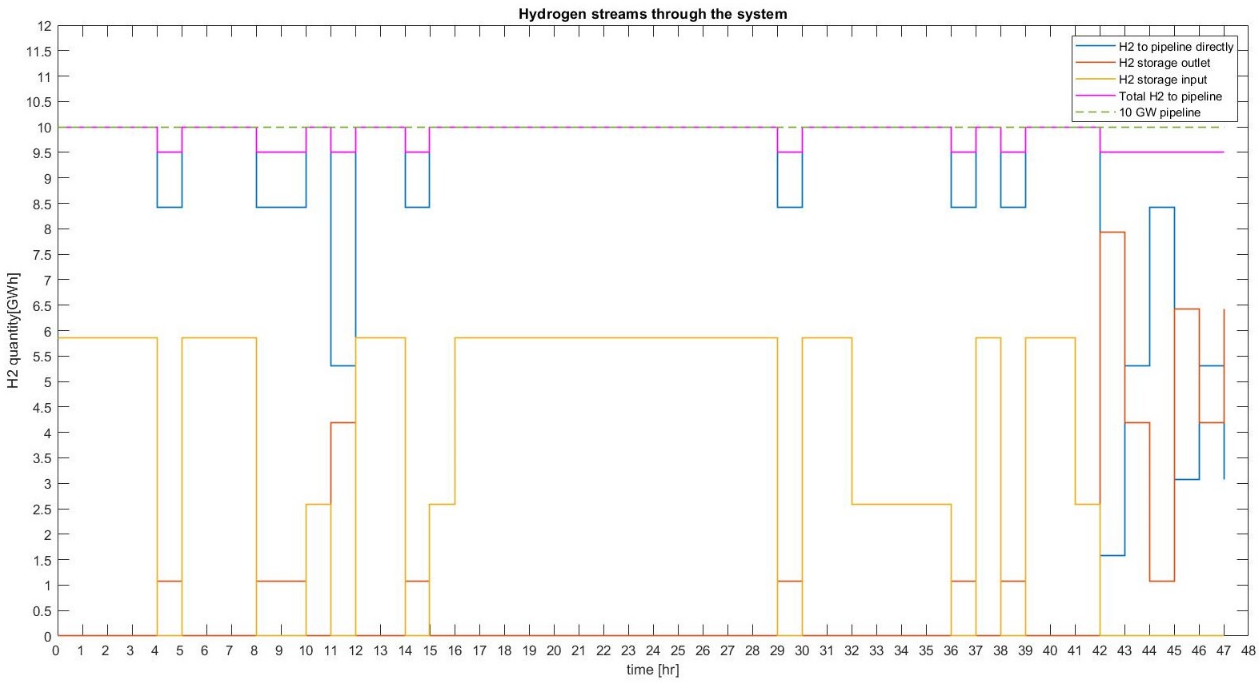


Figure 2.5: Hourly hydrogen quantities inserted directly into pipeline, inserted into salt caverns or extracted from salt caverns

which 26% passes through the storage system before being fed into the pipeline. To demonstrate the relative share of each hydrogen stream, the total amounts were determined for the first year of simulations. Table 2.3 shows the total hydrogen quantity produced by the system, as well as the amount transported directly to the pipeline, the amounts injected into and withdrawn from the storage system and the total amount of hydrogen transported to shore through the pipeline.

	Year 1 quantity [GWh]	Year 1 quantity [Mton]
H2 production by electrolysis	85800	2.18
H2 inserted in storage	23300	0.59
H2 directly to pipeline	62500	1.59
H2 extracted from storage	23000	0.58
H2 transported to shore	85500	2.17

Table 2.3: Total hydrogen quantities flowing through the system in year one of simulation

The correlations between the different hydrogen streams presented in table 2.3 are defined by the following two balancing equations:

$$H2_{productionbyelectrolysis} = H2_{insertedinstorage} + H2_{directlytopipeline} \tag{2.16}$$

$$H2_{transportedtoshore} = H2_{directlytopipeline} + H2_{extractedfromstorage} \tag{2.17}$$

From the hydrogen quantities injected into and withdrawn from the storage system, the minimum required storage capacity could be determined. This was done by simulating the hydrogen content in the storage system from the cumulative net sum of injected and withdrawn hydrogen. The most optimal combination of hydrogen production capacity and hydrogen storage capacity was found in a system with 19.8 GW wind capacity and 8.65 TWh storage capacity, the latter referring to the minimum required storage capacity as defined in section 2.3.1. In the simulation of wind energy production, wake effects are not taken into account. For that reason, the practical wind energy production might be less than what is presented by the simulation, meaning that the required wind capacity obtained from the simulation might be an underestimation. However, since this study focuses on the storage system and assumes that a sufficient hydrogen input is a given, this will not be elaborated on in this study.
In the simulations it was assumed that the storage system would be full prior to operation, i.e. the initial storage content is equal the total storage capacity. Figure 2.6 shows the hydrogen content of a storage system with this capacity over the simulated period. Figure 2.7 shows the hydrogen surpluses and shortages experienced by the system for this capacity, the figure reveals that for this capacity there are indeed no periods of shortage, yet surpluses do occur.

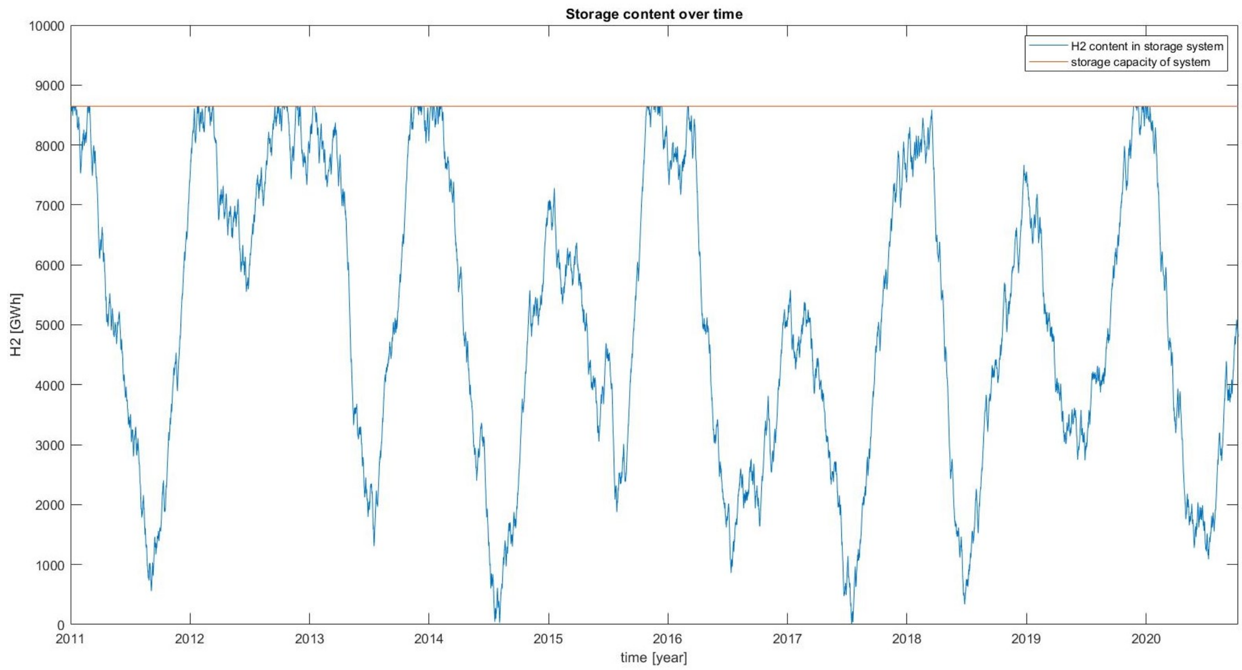


Figure 2.6: Simulated hydrogen content in a system with a storage capacity of 8.65 TWh

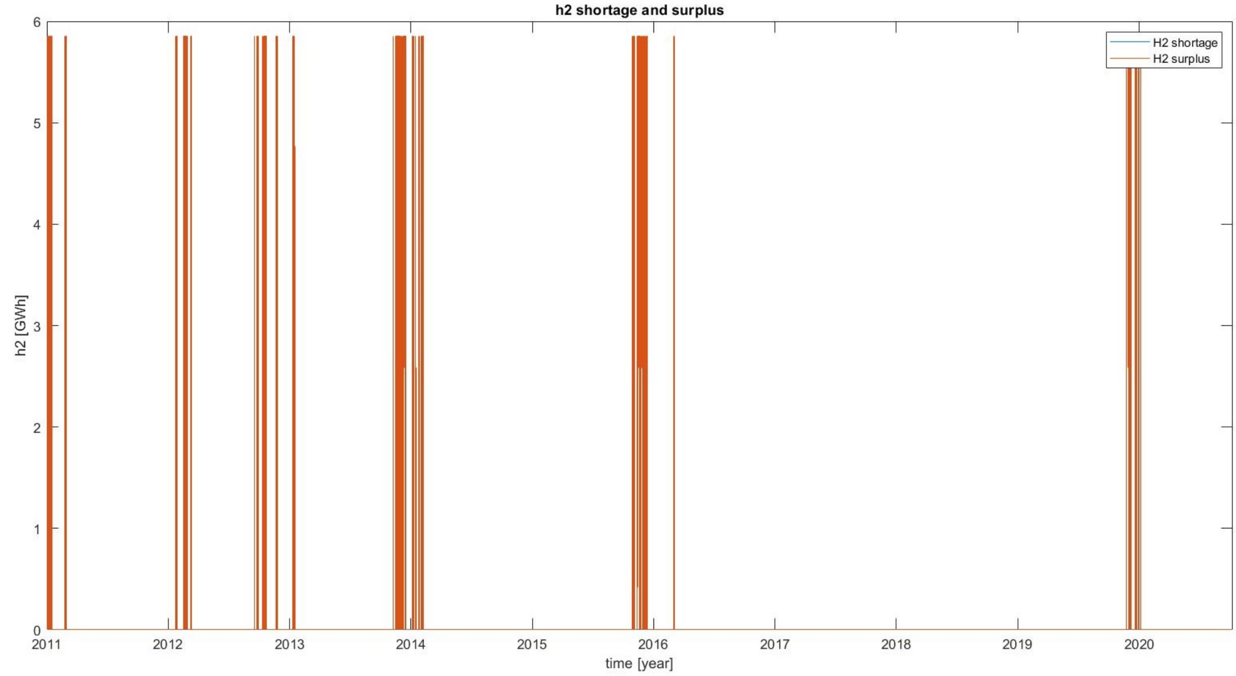


Figure 2.7: Simulated hydrogen surpluses and shortages for a storage capacity of 8.65 TWh

2.4.2 Performance of alternative scenarios for storage capacity

Apart from the minimum required storage capacity, three other scenarios were assessed in which the storage capacity would be 90%, 75% and 50% of the required capacity. For each scenario the storage capacity and associated number of caverns and autonomous time (i.e. time a storage system, completely full initially, could provide the demanded H2 quantity to the pipeline without H2 influx). Furthermore, the frequency, magnitude and duration of the hydrogen shortages was determined. Table 2.4 shows for each share of the required minimum storage capacity the most relevant results of this analysis.

	100% capacity	**90% capacity**	**75% capacity**	**50% capacity**
Storage capacity [TWh]	8.65	7.78	6.49	4.32
Number of salt caverns [-]	48	44	36	28
Autonomous time [days]	36.0	32.4	27.0	18.0
Average annual shortage [GWh]	0	251	972	2496
Average annual surplus [GWh]	1559	1810	2422	3728

Table 2.4: Specifications for storage system presented in case of 100%, 90%, 75% and 50% of the minimum required storage capacity

As expected and predicted, decreasing the storage capacity will result in periods of shortage; i.e. hydrogen cannot be extracted from the salt caverns without the cavern pressure surpassing the lower boundary, yet hydrogen production from the wind park is not sufficient to provide baseload hydrogen into the pipeline. For each share of the minimum required capacity the hydrogen content over time as well as the surpluses and shortages were simulated. Figures 2.8-2.13 show the hydrogen content and the simulated shortages and surpluses for 90%, 75% and 50% of the minimum required storage capacity, respectively.

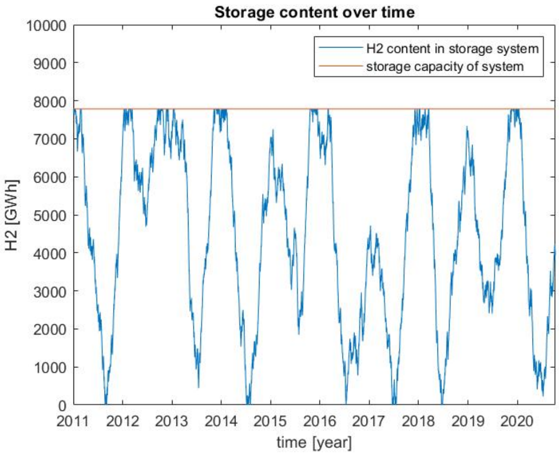


Figure 2.8: Simulated hydrogen content in a system with 90% of the minimum required storage capacity of 8.65 TWh

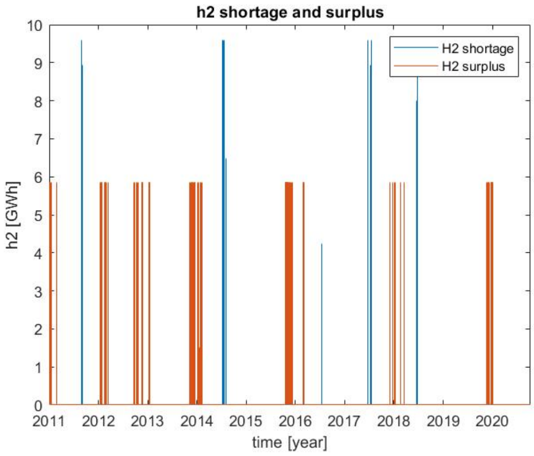


Figure 2.9: Simulated hydrogen surpluses and shortages for a system with 90% of the minimum storage capacity of 8.65 TWh

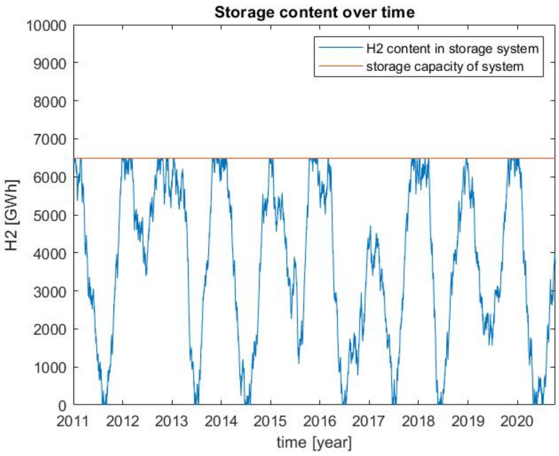


Figure 2.10: Simulated hydrogen content in a system with 75% of the minimum required storage capacity of 8.65 TWh

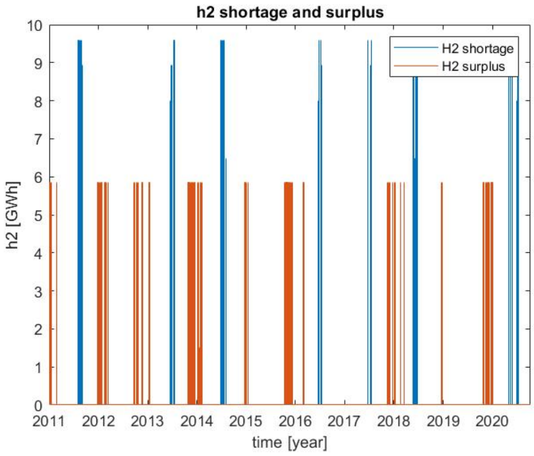


Figure 2.11: Simulated hydrogen surpluses and shortages for a system with 75% of the minimum storage capacity of 8.65 TWh

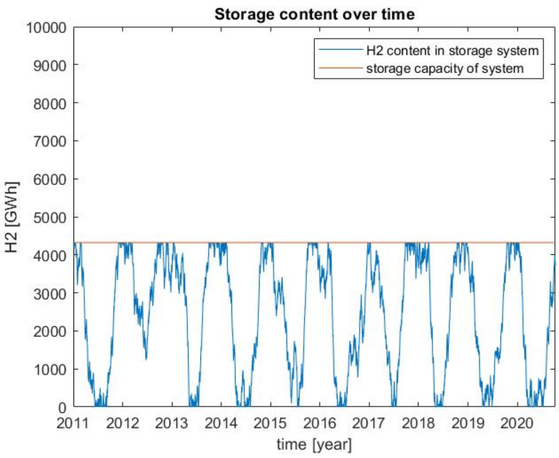


Figure 2.12: Simulated hydrogen content in a system with 50% of the minimum required storage capacity of 8.65 TWh

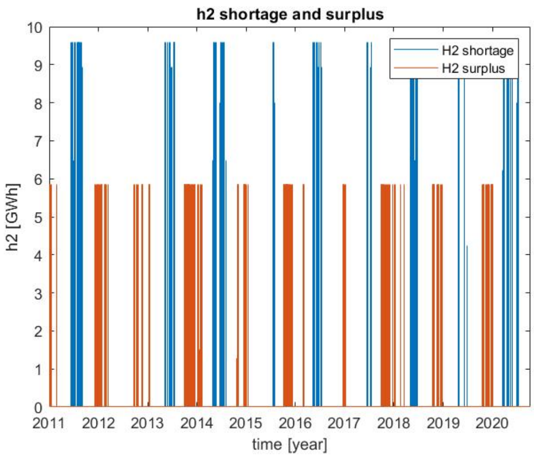


Figure 2.13: Simulated hydrogen surpluses and shortages for a system with 50% of the minimum storage capacity of 8.65 TWh

To evaluate the performance of each share of the minimum required storage capacity, the periods of shortage were analyzed. The security of supply was determined from the amount of total hours the system would be in shortage. Table 2.5 shows for each share of the capacity the security of supply in case no back up strategy would be established.

	100% capacity	**90% capacity**	**75% capacity**	**50% capacity**
Instances of consecutive shortfall [-]	0	25	79	173
Total shortfall time [hrs]	0	417	1571	3929
Security of supply [%]	100	99.51	98.16	95.41

Table 2.5: Security of supply in case of a system with 100%, 90%, 75% or 50% of the minimum required storage capacity

Clearly, when aiming for maximum security of supply, a back up strategy is imperative in case the storage capacity is reduced to 90% 75% or 50% of the minimum required storage capacity. As explained in section 2.2, the cushion gas in the caverns could serve as a strategic reserve in case boundary conditions for cavern pressure are disobeyed. To assess the feasibility of this strategy, the effect of this concept on cavern pressure was analyzed. Table 2.6 shows for each fraction of the minimum required storage capacity the maximum and mean magnitude and duration of the hydrogen shortages the system encounters over the entire simulated time span of ten years. In addition, the average annual frequency of such periods is given.

	100% capacity	**90% capacity**	**75% capacity**	**50% capacity**
Max. shortage [GWh]	0	379	502	1108
Max. duration of shortage [hrs]	0	52	82	147
Mean shortage [GWh]	0	99	121	142
Mean duration of shortage [hr]	0	17	20	23
Avg. occurrence [per year]	0	2.5	7.9	17.3

Table 2.6: Maximum and mean magnitude and duration of periods of hydrogen shortage in the system.

Using the cushion gas in the caverns as a strategic reserve will cause cavern pressures to surpass the minimum boundary condition of 24% of overburden (OBP) pressure. For the caverns at a depth of 1500 m, the overburden pressure is 271 bar following equation 2.11 and assuming cavern height to be 300 m, hence the theoretical safe minimum operating pressure is 65 bar. To evaluate the effect on safety and stability, for each capacity the maximum decrease in cavern pressure and the resulting minimum pressure in the caverns was approximated for both strategies as described in section 2.2. The results are presented in table 2.7.

		100%	**90%**	**75%**	**50%**
Strategy 1: Use all caverns as strategic reserve	Max. pressure drop [bar]	0	3.9	6.3	18
	New min. pressure [bar]	65	61	59	47
	New min. pressure [% of OBP]	24%	23%	22%	17%
Strategy 2: Use 15 of the most stable caverns as a strategic reserve	Max pressure drop [bar]	0	11	15	33
	New min. pressure [bar]	65	54	50	32
	New min. pressure [% of OBP]	24%	20%	18%	12%

Table 2.7: Effects on cavern pressure when using the cushion gas in the caverns as a strategic reserve

Visible in the table is that decreasing the storage capacity to 50% of the minimum required capacity will decrease cavern pressures to 17% of overburden pressure in case strategy 1 is applied. Strategy 2 even reduces the pressure in the selected caverns to a minimum of 12%. Installing 90% or 75% of the storage capacity will, as can be expected, have a less severe effect on cavern pressure, with cavern pressures remaining above 20% of overburden pressure for both capacities and strategies, except when using strategy 2 with 75%. For example, decreasing the storage capacity to 90% of the minimum required capacity and applying strategy 1 would merely cause cavern pressures to decrease from 24% to 23% of overburden pressure. Even applying strategy 2 with 90% capacity would not decrease cavern pressures below 20% of overburden pressure.

The results of this analysis imply that reducing the storage capacity to 90% might be a feasible way of cutting costs, provided it is proven that exploiting the cushion gas as a strategic reserve will not jeopardize cavern stability. Decreasing storage capacity to 75% seems more questionable a concept since cavern pressures could in this case drop to only 17% of overburden pressure. A storage capacity of 50% in combination with exploiting the cushion gas is deemed unlikely to be feasible since cavern pressures could drop to 12% of overburden pressure; only half the recommended minimum cavern pressure.

However, before concluding on the feasibility of decreasing the storage capacity to 90%, 75% or 50% and employing strategy 1 or 2 as a strategic reserve, extensive analysis of the stability of the caverns would have to be conducted. The cavern shape, homo- or heterogeneity of the rock salt material as well as impurities and faults all influence cavern stability and each should be studied ad hoc to assess which caverns, if any, could withstand pressures outside of the safe operating range. This would require knowledge of the exact location of the caverns and the viability of this concept can therefore only be determined after or during construction of the caverns.

Apart from finding a strategic reserve in the cushion gas, different back up strategies could be applied to supplement the hydrogen supply in case less than 100% of the required storage capacity is created. For instance, imported green hydrogen or a blue hydrogen production system could provide an additional hydrogen supply to the pipeline when needed. The feasibility of these concepts would require information about the potential cost reduction by scaling down the storage capacity as compared to the costs for applying these strategies. Therefore, even though no conclusion on the feasibility of installing less than the minimum required storage capacity is drawn, it is still interesting to assess the cost reduction achieved by installing less than 100% of the required storage capacity. Accordingly, cost calculations are performed for scenarios with 100%, 90%, 75% and 50% of the minimum required storage capacity.

2.5 Results of assessment of the technical feasibility of creating a salt cavern storage system in the Dutch North Sea

In this section, the potential of creating a salt cavern storage system of sufficient capacity in the Dutch North Sea is presented. First of all a general outlook on the technical potential of creating salt caverns in the North Sea is provided in section 2.5.1, offering a first insight in the scale of the storage potential. Subsequently the results of a more elaborate evaluation of the storage potential of salt formations in the Dutch part of the North Sea is presented in section 2.3.2. In this section, potential locations for the system are proposed based on the methodology presented in section 2.3.

2.5.1 Storage potential of the North Sea

The technical potential of salt cavern storage in Europe has been studied by Caglayan et al [11]. In this study, bedded salt deposits with a minimum thickness of 200 m and a burial depth between 500 and 2000 m were considered suitable for constructing a cavern of 500.000 m^3 with a height of 120 m and diameter of 84 m. In this study, the separation distance between caverns was assumed to be four times the cavern diameter, i.e. 336 m in this case. For caverns in salt domes or diapirs, a standard cavern volume of 750.000 m^3 (height 300 m, diameter 58 m) was adopted in the analysis. Due to higher salt thickness in salt domes, the limitation on cavern height and the requirements on hanging wall and foot wall are less important and therefore a minimum thickness of 300 m is assumed for salt domes. The inter-cavern distance for caverns in salt domes is assumed 4 times the diameter, i.e. 232 m. Based on these requirements potential locations for salt caverns were found. The theoretical storage capacity of the caverns was determined given the depth and corresponding in situ cavern pressure and temperature. In this way, the potential for salt cavern storage in Europe was assessed. Figure 2.14 shows the salt deposits that were deemed suitable for salt cavern storage as a result of this assessment.

The total theoretical storage capacity in Europe was quantified at 84.8 PWh ($305 * 10^3$ PJ) of hydrogen, of which 10.4 PWh ($37.4 * 10^3$ PJ) belongs to the Netherlands. The storage potential was classified as onshore, offshore but within 50 km of the shore, and offshore. figure 2.15 shows the distribution of the storage potential between these three classes in European countries considered in the analysis. The image reveals that more than half of the storage potential of the Netherlands is located offshore (>50 km away from the coast).

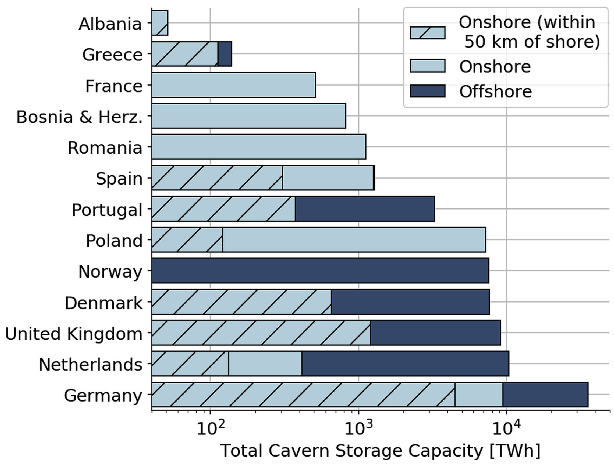


Figure 2.15: Storage potential of European countries, classified as onshore, onshore (<50 km from the coast) and offshore [11].

Evidently, the Dutch North sea carries ample salt cavern storage potential of more than 5.2 PWh ($18.7 * 10^3$ PJ) of hydrogen according to this analysis. This speaks in favour of the technical

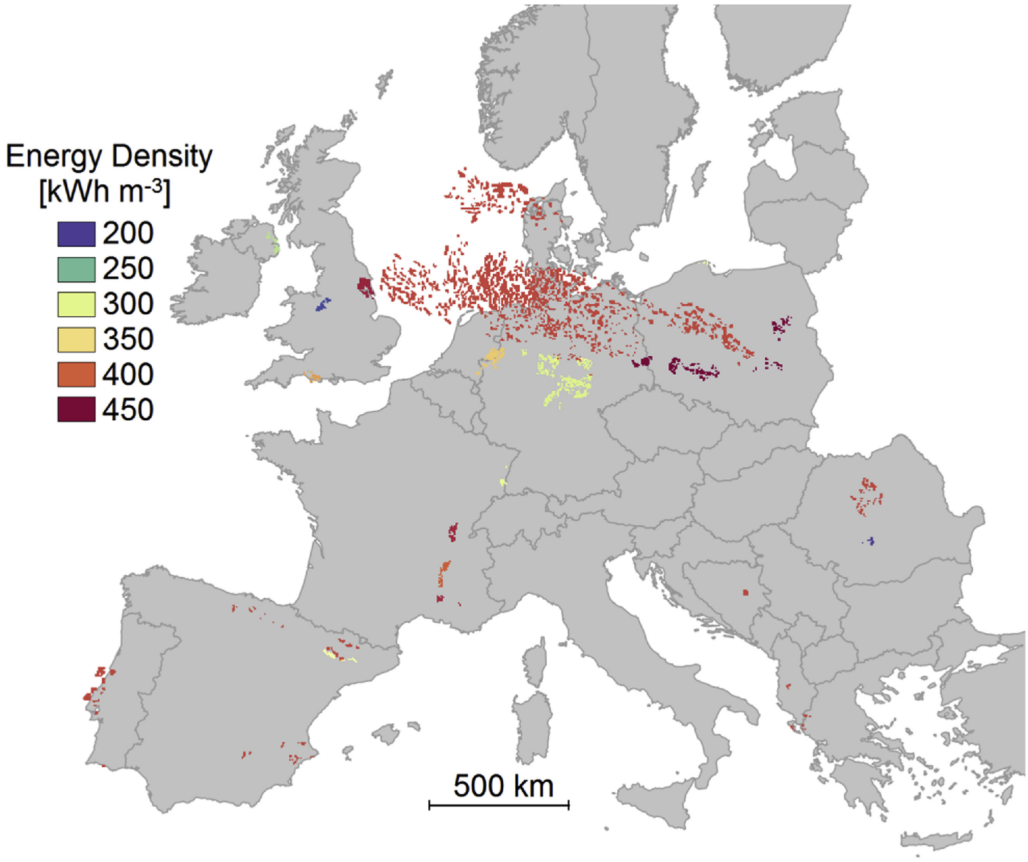


Figure 2.14: Potential salt cavern storage capacity in Europe [11]

potential of creating a salt cavern storage system in the Dutch North Sea. To determine whether a system with sufficient storage capacity for the purpose of our system could indeed be created in the North Sea, the storage capacity of the salt formations deemed suitable by the study discussed in this section must be compared to the minimum required storage capacity of the system (see section 2.4) and the availability of the locations must be assessed and confirmed. The latter will be clarified in the upcoming section.

2.5.2 Site selection

As explained in section 2.3, the Capacity Calculator was used to determine possible locations for salt caverns and their theoretical storage capacities. The three sets of input parameters as presented in section 2.3.2 were entered in the Capacity Calculator to assess for each set of boundary conditions the potential locations and storage capacities of the salt caverns. In this way it was possible to identify groups of adjacent caverns with sufficient cumulative storage capacity to create the system. In addition, the availability of the locations as defined in section 2.3 was assessed.

First of all, for each set of input parameters presented in section 2.3, the total storage capacity of all potential caverns in the Dutch part of the North sea was assessed. Figure 2.16, 2.17 and 2.18, show the prospected cavern locations for input set 1, 2, and 3, respectively. In the figures, the storage capacity of the caverns is represented by the color gradient from yellow (small capacity) to purple (large capacity). Table 2.8 shows the total estimated offshore storage capacity of the Netherlands for each input set as derived from the output of the capacity calculator.

	Input set 1	Input set 2	Input set 3
Dutch North Sea storage capacity	550 TWh	155 TWh	100 TWh

Table 2.8: Storage capacity of the Dutch North Sea for input sets 1, 2 and 3.

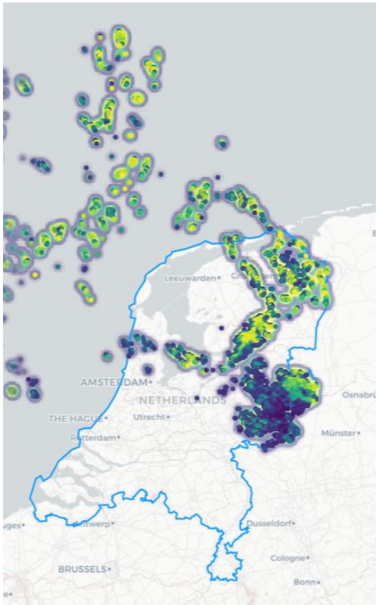


Figure 2.16: Potential locations for salt caverns in the Dutch part of the North Sea for the input parameters described by input set 1.

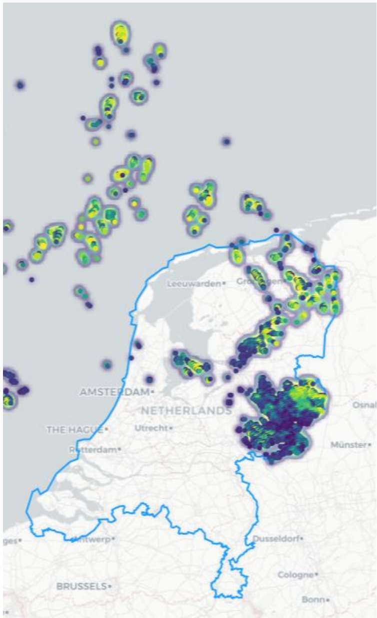


Figure 2.17: Potential locations for salt caverns in the Dutch part of the North Sea for the input parameters described by input set 2.

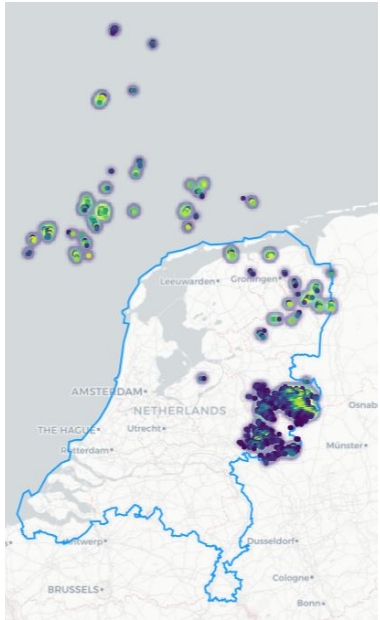


Figure 2.18: Potential locations for salt caverns in the Dutch part of the North Sea for the input parameters described by input set 3.

From the output of the Capacity Calculator it appears that the total storage capacity of the Dutch part of the North Sea ranges from 100 TWh to 550 TWh depending on the input parameters. Hence, there is a large discrepancy between the storage capacity as estimated by previous study [11] versus the output. This discrepancy can at least be partly explained by the application of different boundary conditions, which is clearly demonstrated by the difference in storage capacity estimated by the Capacity Calculator for the three different input sets. The main difference between input set 1 and 3 is the allowed depth range of the caverns, which is clearly of high influence considering the factor five difference in potential storage capacity between the results of the two input sets. Evidently, the potential storage capacity varies a lot with the imposed boundary conditions and hence the discrepancy between the findings in this study versus what was found in previous study.

As mentioned previously in section 2.4, the required capacity of the storage system was determined to be 8.65 TWh. Hence, according to the output of the software, based on the imposed boundary conditions the Dutch North Sea has in theory sufficient salt cavern storage capacity to accommodate the minimum required storage capacity.

Zooming in on the map allowed for identification of groups of adjacent caverns. For each group of caverns plotted by the Capacity Calculator, the combined storage capacity of the caverns was determined and compared to the minimum storage capacity of 8.65 TWh. This was done for all three sets of input values. After checking the capacity of each group of caverns, four promising groups were selected, each with a total storage capacity larger than 8.65 TWh for at least two out of the three sets of input values. Figure 2.19 shows the locations of these four groups, denoted with A, B, C and D, henceforth called location A, location B, location C and location D.

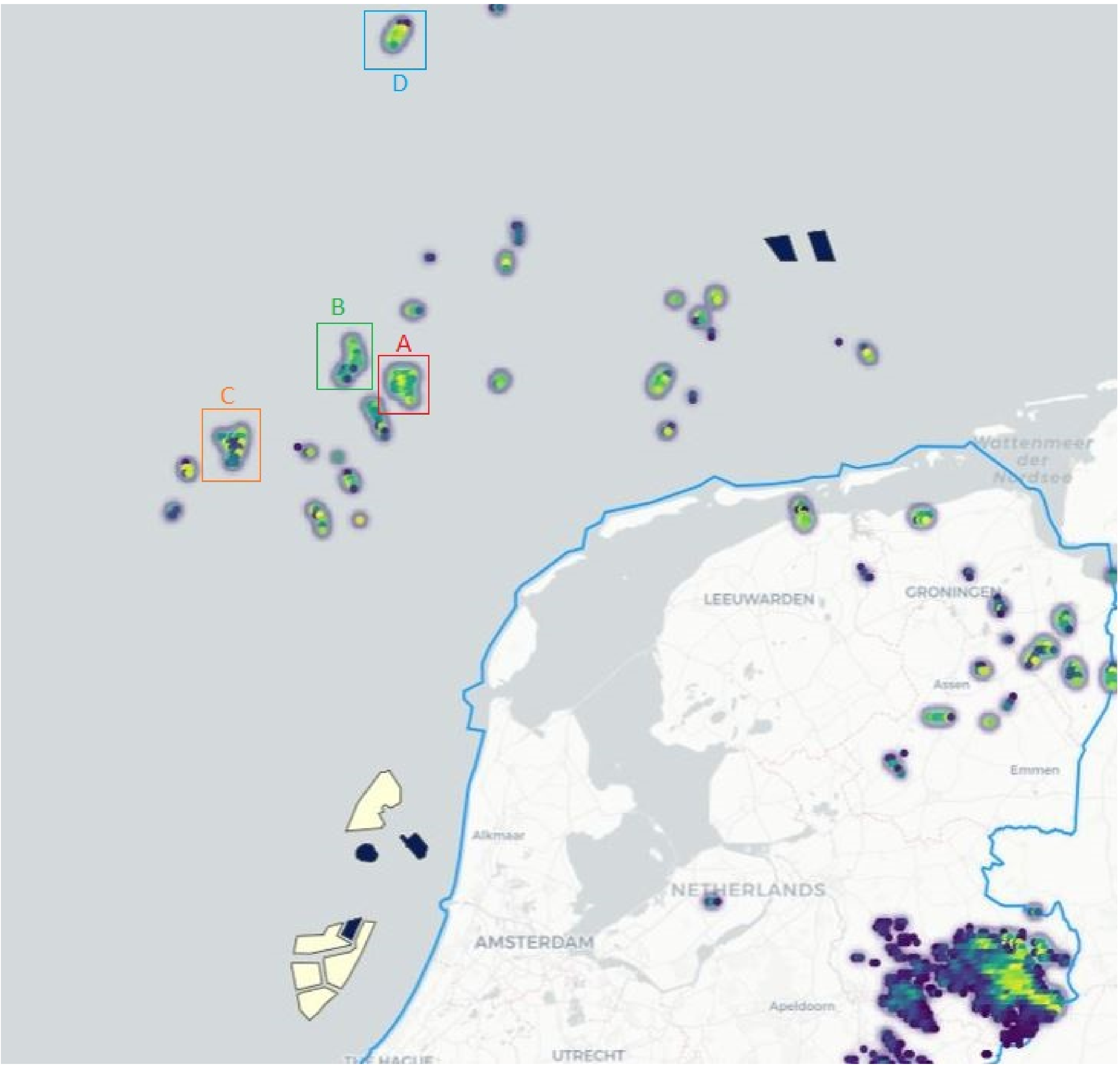


Figure 2.19: Locations in the Dutch North Sea with sufficient salt cavern storage capacity to house the hydrogen storage system. The locations are denoted with A, B, C and D

Table 2.9 shows the total storage capacity for each location in each input scenario. Location A, B, C and D all have sufficient capacity for creating a system with 100% of the minimum required storage capacity, for the boundary conditions specified by Input set 1. For input set 2, only location A, C and D would have sufficient capacity. In the third scenario, i.e. the scenario with the more stringent depth restriction to benefit system costs, all four locations would have sufficient storage potential for the system.

	Input set 1	**Input set 2**	**Input set 3**
Location A	19.63 TWh	10.44 TWh	19.87 TWh
Location B	17.17 TWh	8.27 TWh	11.04 TWh
Location C	30.51 TWh	12.88 TWh	11.81 TWh
Location D	57.06 TWh	10.27 TWh	8.84 TWh

Table 2.9: Total summed storage capacities of the salt caverns located in location A, B, C and D

Location A, C and D have sufficient storage capacity for all of the assessed conditions, and location B has enough capacity for input set 1 and 3, and nearly enough for input set 2, the more conservative scenario. Keeping in mind the stakeholders and their interest in keeping system costs to a minimum, it would be wise to select a location where the caverns could be placed in an economical depth range, i.e. a depth range that would allow substantial storage capacity (i.e. high operating pressures) while also keeping construction costs below acceptable levels. In this study this depth range is defined as 1000 to 1500 m depth. Therefore the locations will henceforth be assessed based on their capacities according to the boundary conditions defined by input set 3.

To determine whether the selected locations are actually available to use, the locations of existing and planned offshore structures, i.e. wind parks, hydrocarbon sources, production platforms and other surface facilities and pipelines were inspected to check for interference with location A, B, C and D. Figure 2.20 shows location A, B, C and D as well as existing structures in this part of the North Sea.

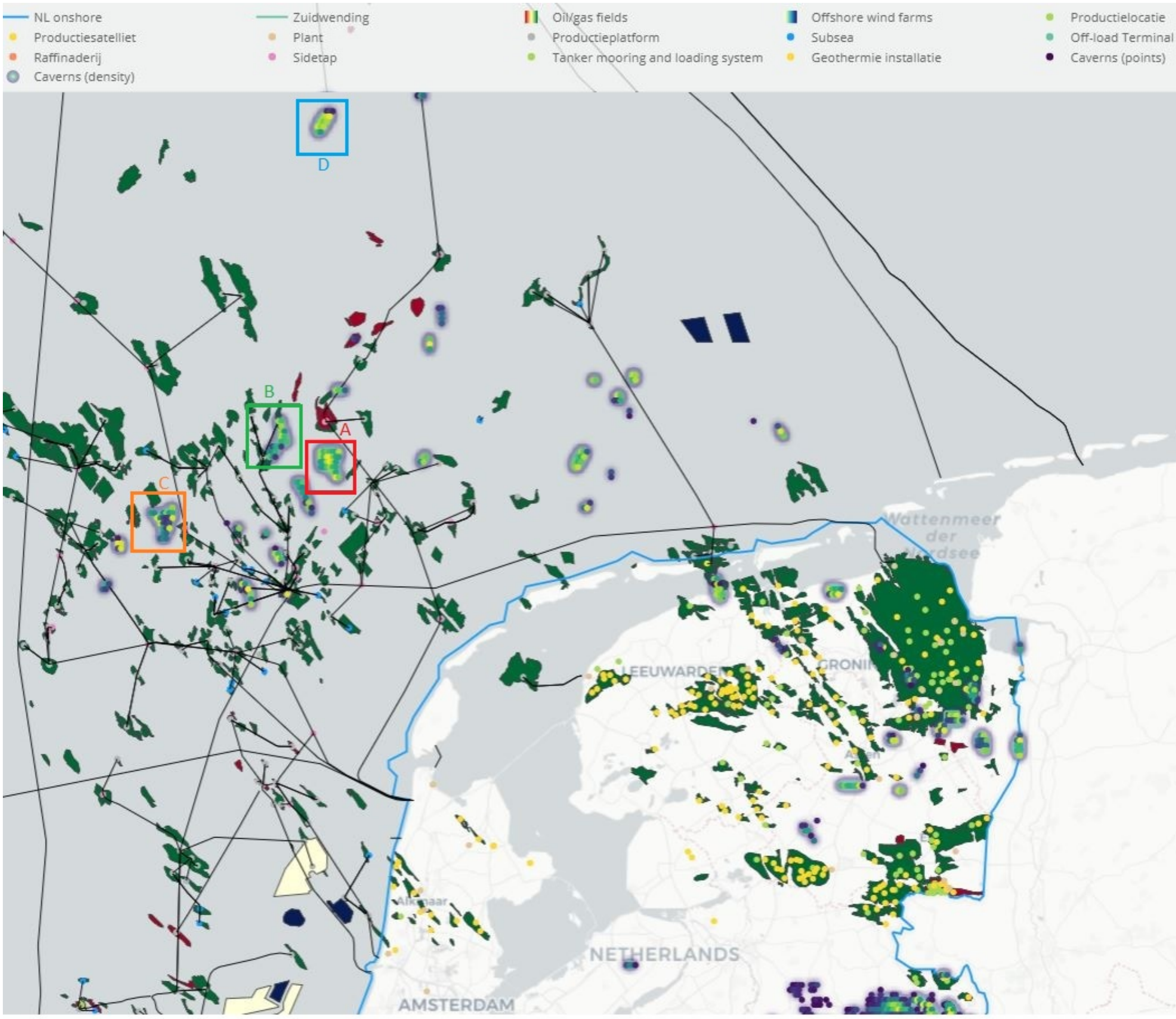


Figure 2.20: Plan view of the North Sea showing Locations A, B and C as well as hydrocarbon sources, platforms and other surface facilities, pipelines, and wind parks.

Figure 2.21 shows a zoom view of location A, B and C and their interference with existing structures and licenses for hydrocarbon exploration and/or extraction. Figure 2.22 shows the same for location D, located more remotely to the north.

Location A
Visible in figure 2.21 is that the salt caverns in location A, although close to gas field L05b-A, do not interfere with any hydrocarbon sources or structures. Hence, in theory all the storage capacity identified in location A could be used. Furthermore, in figure 2.21 one can see that a large part of location A lies in an area with a license for hydrocarbon exploration or extraction. However, since location A does not interfere with hydrocarbon bodies it seems unlikely that the availability of this location would be hindered by hydrocarbon exploration or extraction. Therefore this is not deemed as a limitation on location availability.

Location B
As can be seen in figure 2.21 some of the salt caverns in Location B interfere with gas fields L04-G and L04-A, and with a sub-sea production installation. The gas fields and sub-sea production installation all lie in areas with a license for hydrocarbon extraction or exploration. The caverns that do not interfere with structures or hydrocarbon fields in licensed areas have a collective storage capacity of 7.48 TWh, which would be insufficient considering the minimum required storage capacity of 8.65 TWh. However, as considering hydrogen storage may be prioritized over hydrocarbon exploitation in the future, location B will not be disregarded.

Location C
Figure 2.21 shows that none of the caverns in location C interfere with existing structures or hydrocarbon sources and licensed areas, although some of the caverns would be located rather close to gas field K08-FE. Hence, all the plotted salt caverns in location C are available and therefore all of the hypothetical capacity could be installed.

Location D
Visible in figure 2.22 is that the caverns in location D are not obstructed by any structures or licenses. Therefore all caverns as plotted by the Capacity Calculator could be created without interference and thus all prospected storage capacity is theoretically available.

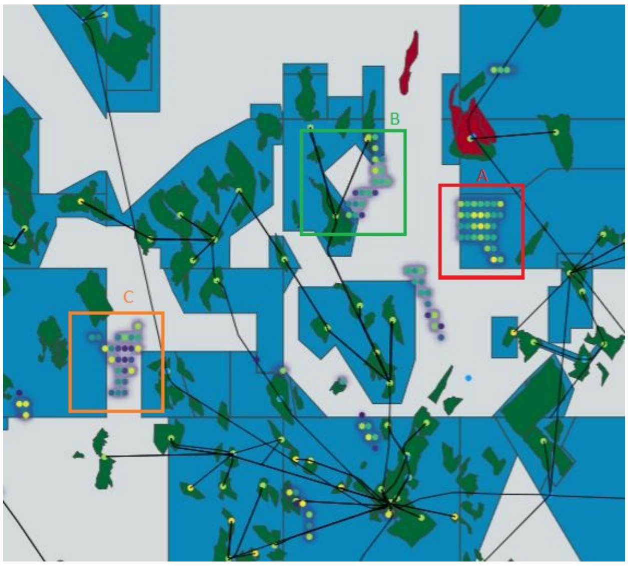


Figure 2.21: Plan view of part of the Dutch north sea showing Location A, B and C and existing offshore structures and pipelines, and licenses for hydrocarbon extraction and/or exploration.

Figure 2.22: Plan view of part of the Dutch north sea showing Location D and existing offshore structures and pipelines, and licenses for hydrocarbon extraction and/or exploration.

The analysis shows that location A, B, C and D are, in theory, suitable locations for the constructing the storage system following the boundary conditions described by input set 3. In each of these locations a group of salt caverns can be created with a total storage capacity that would be sufficient for a system with the purpose described in this study. Locations A, B and C lie in the vicinity of a gas field, however considering the fact that the total storage capacity in both locations exceeds the demanded capacity, the salt cavern locations plotted close to the gas field could be expelled from the system in case constructing salt caverns close to gas fields would pose (legal or stability) issues. locations A, B and C lie in the vicinity of branches of the yet existing gas infrastructure (see figure 2.21), which is favorable in the sense that only short distances would have to be covered from the storage system to the pipeline. Location D is located farther away from existing gas pipelines, however with regards to prospected new wind parks in this area this location is appealing too.

In conclusion, there are multiple locations in the Dutch part of the North Sea that could, in theory, accommodate a group of adjacent salt caverns to create a storage system of sufficient capacity. For the three sets of input values and boundary conditions that were assessed in this study, at least four locations can be identify as theoretically suitable for constructing the storage system investigated in this thesis, namely location A, B, C and D. Location D is completely free of interference with any physical or non-physical obstacles, whereas some of the caverns in location A, B and C interfere with hydrocarbon sources or licences for hydrocarbon exploration and/or exploitation. However, considering the ambitions to transition to a more renewable energy system, hydrocarbon exploration will likely not be prioritized in the future and therefore interference with licenses is not perceived as a rigid constraint. Hence, all four locations are deemed theoretically suitable and available for constructing the storage system.

It should be noted that in this analysis, a boundary condition for site selection was that it should be possible to create one group of adjacent cavern with a cumulative storage capacity equal to or larger than the minimum required storage capacity. This boundary condition was imposed from an economic perspective. Relaxing this boundary condition would allow for more freedom in site selection, since in that case we could combine several locations with smaller storage capacities that were initially disregarded in this study and more locations than just location A, B, C and D could be considered.

For further analysis we select location A. As mentioned previously, for input scenario 3, location A has a total storage capacity of 19.87 TWh. According to the Capacity Calculator, this capacity would be distributed over 120 caverns with an individual storage capacity ranging from 146 to 250 GWh. If we assume identical cavern volume (750.000 m^3) and depth (1500 m), the minimum required storage capacity of 8.65 TWh would require 48 of these salt caverns. Decreasing the storage capacity to 90%, 75% or 50% reduces the required number of caverns to 44, 36 and 28, respectively. Hence, location A holds ample opportunity for creating a storage system of sufficient capacity.

2.6 Conclusion on technical feasibility

In this section, the primary results and conclusions of this chapter are summarized. First of all, the findings on the required storage capacity are summarized, after which the storage potential of the North sea is discussed. Subsequently, the results of the two sub-analyses are combined to form a conclusion on the technical feasibility of creating a salt cavern storage system of sufficient capacity in the Dutch North Sea.

Conclusions on the required storage capacity

- The minimum required storage capacity was found to be 8.65 TWh. Assuming identical caverns, each with a volume of 750.000 m3 and a depth of 1500 m, 48 caverns would be required.
- In light of economic feasibility, it could be decided to reduce the storage capacity to shares of the storage capacity, for instance 90%, 75% or 50%. These capacities would require 44, 36 and 28 standard salt caverns, respectively. In these cases, security of supply as it is defined in this study decreases from 100% to 99.5%, 98.2% and 95.4%, respectively.
- Especially in the case of less than 90% of the minimum required storage capacity, a reduced storage capacity would have to be combined with a back up strategy in order to still meet the objective of supplying a constant hydrogen supply of sufficient magnitude at all times.
- The option of exploiting the cushion gas of all or a selection of the caverns was explored as a potential back-up strategy. The analysis shows that this concept might be viable in case of a system with 90% of the minimum required storage capacity, but is more debatable in case of installing only 75% or 50% of the required storage capacity.
- Although for a system with 90% of the minimum required storage capacity the security of supply and effect on cavern pressure seems reasonable, the practical feasibility of this concept requires analysis of cavern stability and can hence only be concluded on after or during cavern construction.

Conclusions on the storage potential of the North Sea

- Four locations, denoted location A, B, C, and D, were identified as being suitable for the system designed in this study based on their potential storage capacity being larger than the required 8.65 TWh.
- Location D shows no interference with physical or non-physical obstacles and is hence regarded as available.
- locations A, B, and C interfere either with hydrocarbon sources or licences for hydrocarbon exploration and/or exploitation. However, considering hydrogen storage may be prioritized over hydrocarbon exploitation, this is not perceived as a rigid constrained and therefore location A, B and C are also deemed available for the system.
- If the boundary condition of having all caverns in one place would be relaxed, locations with smaller storage capacities could be combined to form a system of sufficient capacity, allowing for more freedom in choosing the location.

In conclusion: A salt cavern storage system with the purpose to balance out on one hand the hydrogen supply from an offshore green hydrogen system, and on the other hand a demanded constant 10 GWh of hydrogen to be fed into a pipeline, could indeed be constructed in the North Sea. The North Sea houses several salt formation with sufficient storage capacity to accommodate a salt cavern system with a storage capacity of 8.65 TWh, i.e. the minimum required storage capacity to safeguard security of supply as assessed in this study.

Chapter 3

Economic feasibility

This chapter presents an analysis of the economic feasibility of integrating an offshore salt cavern storage system into offshore green hydrogen production. To determine the incremental costs of the storage system, all expenditures to do with its construction and operation must be quantified. A conceptual design for the system is presented in section 3.1 to give an overview of the scale and an overview of the different elements that contribute to the costs. Subsequently the methodology for evaluating the costs is presented in section 3.2 and the results of the calculations are presented in section 3.3. Finally, the most important conclusions of the economic feasibility analysis are presented in section 3.4.

3.1 Conceptual system design and dimensioning

In order to estimate the total costs of the system, the dimensions of the system components need to be known. To this end, a conceptual system design was made for all four storage capacity scenarios. This section describes the elements that are considered in the cost calculations, framing the scope of the economic feasibility analysis accordingly.

Apart from the salt caverns required for hydrogen storage, various other components are needed to successfully operate the storage system. First of all, a compressor is required to compress the hydrogen from pipeline pressure to cavern to allow insertion. Moreover, several types of processing equipment are required for the processing of hydrogen extracted from the caverns before it can be inserted into the pipeline, namely equipment for cooling after compression and heating after decompression, metering systems, multiple types of filtering equipment, and equipment for decompression and dehydration.

The compressor and processing equipment are placed on a surface platform. To transfer the hydrogen from compressor down to the caverns and back up to the processing equipment, the equipment on the platform is connected to the salt caverns via pipelines. Furthermore, an energy supply is required to power the compressor and other equipment on the platform. The energy for compression can be delivered by wind turbines, whereas the energy for the other processing equipment (for the extraction of hydrogen) can be obtained from the hydrogen output of the system.

In this study, the incremental costs of the storage system are analyzed. In the analysis we consider everything from the point where the hydrogen, arriving from the production system, enters the compressor for injection into the caverns, to where the hydrogen is inserted into the pipeline to shore. Hence, Considered in the cost analysis in this study are the salt caverns, the entire top side including compressor and additional processing equipment, platform to accommodate these, personnel and facilities, and infrastructure from compressor to caverns and from caverns to top side equipment. Figure 3.1 shows all system components considered in the cost analysis.

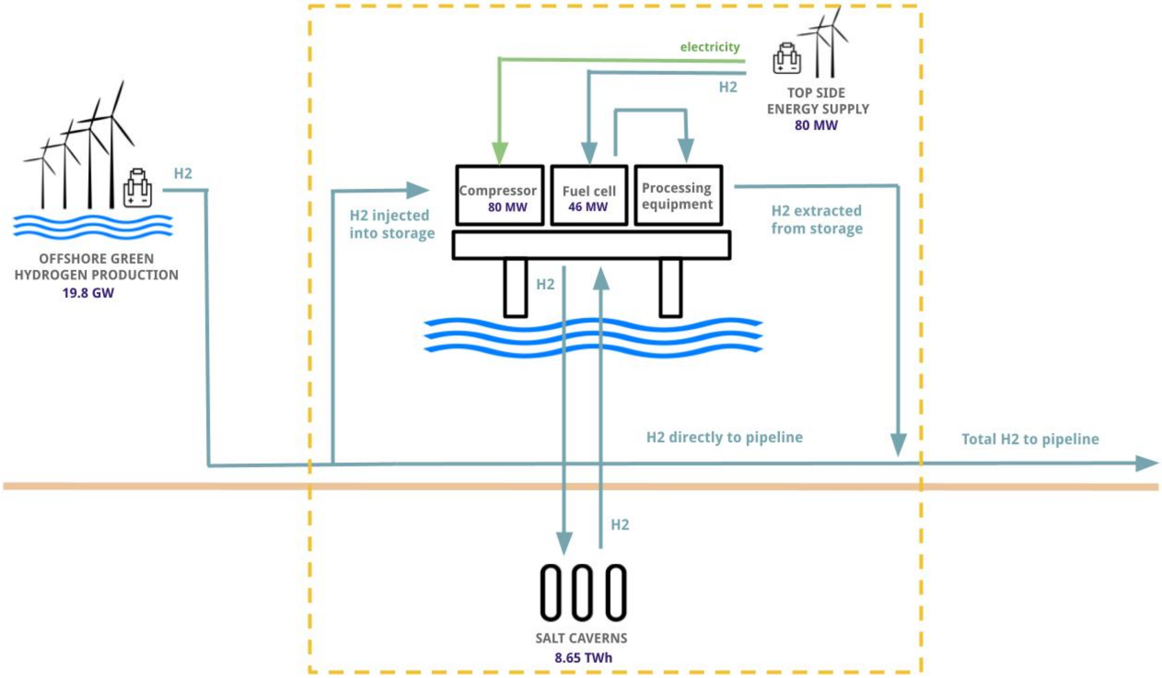


Figure 3.1: Shown in the yellow frame is the part of the system considered in the cost analysis.

3.1.1 Salt caverns

The minimum required storage capacity for this system was determined to be 8.65 TWh, and this is defined as 100% capacity. As described previously in section 2.4, it is assumed that all caverns are identical in shape and size, with height 300 m, diameter 58 m and volume 750.000 m^3. The depth of all caverns (i.e. bottom of cavern) is assumed to be 1500 m. From these assumptions it follows that 48 of such caverns are required to create 8.65 TWh of storage capacity.

Keeping in mind ease of construction and the objective to minimize construction costs, it might be favourable to construct the caverns as close to each other as possible in a raster pattern, in a square-like shape The minimum safe distance between caverns is defined as 4 times the cavern diameter [11], hence would be 232 m in this case. Conceptual plan views of the caverns for the scenario with 100%, 90%, 75% and 50% of the storage capacity are shown in figures 3.2, 3.3, 3.4 and 3.5, respectively. The green square in the figures represents the platform, which serves as a basis for well boring towards the locations of the prospected caverns and accommodates all top side equipment and facilities.

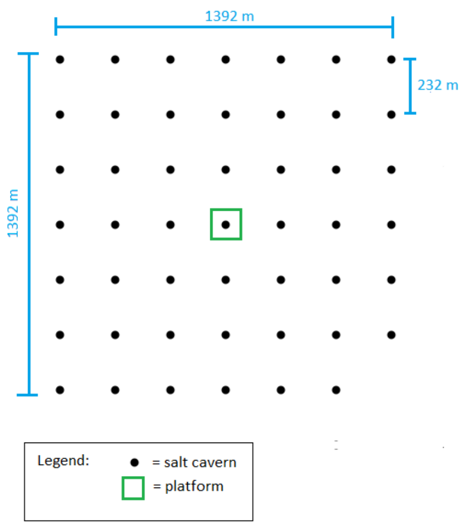


Figure 3.2: Conceptual plan view of cavern field for scenario with 100% storage capacity, i.e. 48 caverns.

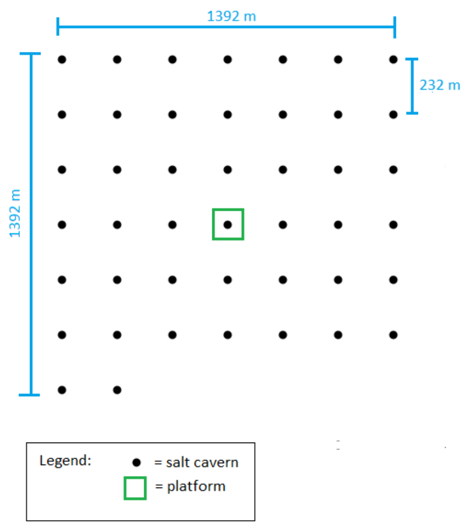


Figure 3.3: Conceptual plan view of cavern field for scenario with 90% storage capacity, i.e. 44 caverns.

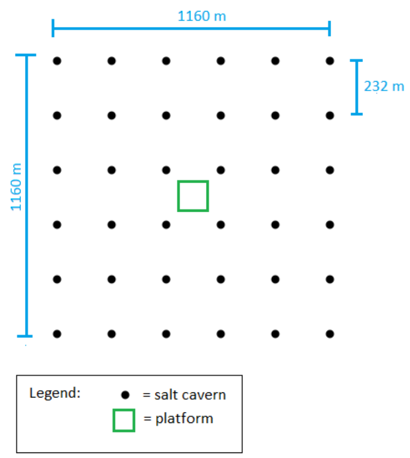


Figure 3.4: Conceptual plan view of cavern field for scenario with 75% storage capacity, i.e. 36 caverns.

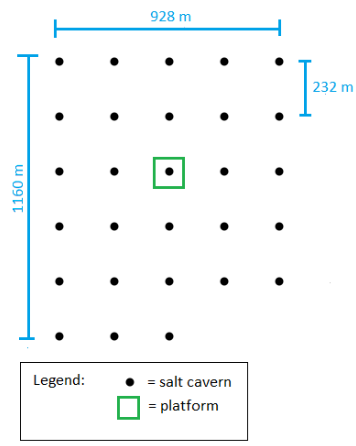


Figure 3.5: Conceptual plan view of cavern field for scenario with 50% storage capacity, i.e. 28 caverns.

3.1.2 Pipeline

The hydrogen infrastructure considered in this analysis is the pipeline transporting hydrogen from the compressor to the caverns and from the caverns to the processing equipment. Considering hydrogen will not be inserted and extracted from the salt caverns simultaneously, one pipeline can be used to transport hydrogen from the compressor at the platform down to the caverns, and back from the caverns to the processing equipment, assuming processing equipment and compressors are placed on the same platform. To approximate the total costs for the infrastructure, an average distance to be covered per cavern is determined. The total length of pipeline is then taken as this average distance times the number of caverns.

Under the assumption that the platform will be placed in the center of the cavern field, the distance to be covered is the square root of the lateral distance squared plus the depth of the top of the cavern squared. The minimum distance is determined from the distance of the cavern closest to the platform. likewise, the maximum distance is determined from the distance of the cavern furthest away from the platform. The average of these two values is regarded as the average distance of pipeline required per cavern. Table 3.1 shows the required pipeline length per cavern and the total distance to be covered in the system for each the four defined storage capacity scenarios.

Scenario	**100%**	**90%**	**75%**	**50%**
number of caverns	48	44	36	28
minimum pipeline length per cavern	1.20 km	1.20 km	1.53 km	1.20 km
maximum pipeline length per cavern	2.36 km	2.36 km	1.97 km	2.01 km
average pipeline length per cavern	1.78 km	1.78 km	1.75 km	1.60 km

Table 3.1: Information about distances between caverns and platform for scenario with 100%, 90%, 75% and 50% of the minimum required storage capacity.

3.1.3 Top side

The top side is defined in this study as an offshore platform in the midst of the conceptual cavern field, accommodating the compressor and all other required equipment, as well as personnel and accommodation. In this analysis it is assumed that one platform, placed in the centre of the cavern field, will hold all top side facilities. Another assumption is that all leaching wells for cavern construction can and will be drilled from that same platform. Considering the relatively shallow depth of the North Sea at the prospected locations (where it does not exceed 40 m depth) a floating platform is deemed not necessary and consequently a fixed platform is assumed. Moreover, in this study it is assumed that all caverns are operated simultaneously and in the same pressure range, following from the assumption that all salt caverns in the system display identical characteristics and find themselves in the same geological conditions. For this reason we assume that one processing system is required, i.e. one compressor for compression and one 'set' of additional processing equipment.

The requirements on the platform and inherently the costs are to a large extent governed by the weight of the top side. Considering the large difference between pipeline pressure and maximum cavern pressure and the large amounts of hydrogen to be compressed per hour, it is clear that a large compression capacity is required and the compressor weight is therefore a major constituent in the total weight of the top side. Compressor weight depends on compressor capacity, which can be derived from the required pressure increase and the mass of hydrogen to be compressed per time instant. The practical work required for the compression of hydrogen lies somewhere in between the isothermal work and the adiabatic work [41], both plotted in in figure 3.6. Taking the average of the isothermal and adiabatic work to approximate the practical work required for compression could lead to underestimation of the required practical work for compression, and inherently underestimation of the required capacity and price of the compressor. For that reason the adiabatic work will be used to determine the compressor capacity in this study. The work required for adiabatic compression of hydrogen can be determined by the following formula[41]:

$$w = \frac{\gamma}{\gamma - 1} p_0 V ln[(\frac{p_1}{p_0}^{\frac{\gamma-1}{\gamma}} - 1] \tag{3.1}$$

With p_0 the initial pressure, p_0 the final pressure, V the volume and γ the ratio of specific heats (Cp/Cv), 1.41 for hydrogen. Assuming ideal gas behaviour, equation 3.1 can be rewritten as

$$w = \frac{\gamma}{\gamma - 1} nRT_0 ln[(\frac{p_1}{p_0}^{\frac{\gamma-1}{\gamma}} - 1] \tag{3.2}$$

From which the adiabatic work to compress 1 kg of hydrogen is determined, with n the number of moles in 1 kg hydrogen (determined from the molar mass of hydrogen), R the universal gas

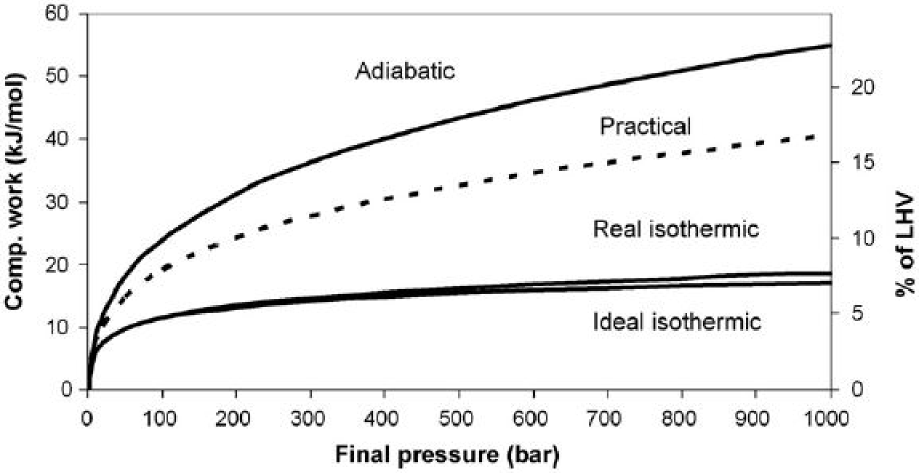


Figure 3.6: Isothermal, adiabatic and practical work for compression of hydrogen

constant (8.314), T_0 the average gas temperature, P_0 the pressure in the pipeline leading to the compressor, assumed 100 bar, and P_1 the maximum cavern pressure as described in section 2.4. In this study, the average temperature of the hydrogen arriving at the compressor is assumed $15°C$. The reasoning behind this assumption is that although the gas initially undergoes compression to 100 bar after electrolysis for transportation purposes, which is accommodated by an increase in temperature, the temperature will decrease again due to the gas migrating through the subsea pipeline and losing its heat by convection. The monthly average water temperature in the North Sea varies between $4.5°C$ and $20°C$ and based on this an average temperature of hydrogen arriving at the compressor of $15°C$ is assumed. The total work to be delivered by the compressor is determined by multiplying the work required to compress 1 kg of hydrogen to the desired pressure with the maximum mass of hydrogen to be compressed. Finally, a factor for efficiency is incorporated to arrive at the required compressor capacity.

The compressor capacity required for this system is determined based on the maximum compression work it should be able to deliver. That is: the work required to compress hydrogen from pipeline pressure to maximum cavern pressure, at the maximum injection rate. Pipeline pressure is assumed 100 bar, and the maximum cavern pressure was determined to be 217 bar for cavern specifications assumed in this study (i.e. at a depth of 1500 m and operating pressure range between 24% to 80% of overburden pressure). From the simulation of hydrogen streams in the storage system it was derived that the maximum injection rate is 148486 kg/hr. Therefore the compressor should be able to compress 148486 kg/hr from 100 to 217 bar. Table 3.2 shows all relevant parameters for approximating the work required for compression and the corresponding compressor capacity. The adiabatic work to compress 1 kg of hydrogen from p_0 to p_1 in the conditions as described was found to be 0.29 kwh/kg. Taking into account the efficiency, the energy required from the compressor would be 0.44 kwh/kg. Compressing 148486 kg/hr from 100 bar to 217 bar would therefore require 65 MW of compression capacity.

Seeing as pipeline pressure exceeds the minimum cavern pressure, when the hydrogen content in the storage system is low, cavern pressures could become inferior to pipeline pressure, which implies that compression for inserting the hydrogen into the pipeline may be needed. The compression capacity for this purpose is determined from the maximum compression work it should be able to provide, i.e. for compression from the minimum cavern pressure: 65 bar, to pipeline pressure: 100 bar. Following the same methodology as presented above, the adiabatic work required to compress 1 kg from 65 bar to 100 bar was found to be 0.15 kwh/kg. Taking into account the efficiency of 65%, the compression energy to be delivered would be 0.23 kwh/kg, demanding 35 MW compres-

Parameter	**Value**	**Unit**
Processing capacity	148486	kg/hr
P_0	100	bar
P_1	217	bar
Efficiency	65	%
T_0	288	K
gamma	1.41	-
MH2	2.016	g/mol

Table 3.2: Relevant parameters for approximating compressor capacity

sion capacity.

Since hydrogen insertion into and extraction from the storage system does not happen simultaneously, one compressor could be used both for the insertion and extraction of hydrogen. The previous analysis reveals that 65 MW of compression power would be sufficient to deliver the maximum required compression energy for insertion into the caverns, as well as the maximum compression energy needed for injection into the pipeline.

Considering the obligation to provide a constant hydrogen supply to industry, it would be wise to have multiple compressors, possibly each running at a lower rate of say 75% of their maximum capacity, instead of having just one compressor running at 100%. In that way, in case maintenance is required or failure occurs the system is still able to supply hydrogen and (at least partly) comply with its legal commitment of providing baseload hydrogen instead of the hydrogen supply shutting down entirely. For that reason it is decided to include two compressors in the system, each running at a fraction of their maximum capacity, for instance 75%.

3.1.4 Top side energy supply

To power the top side equipment, an energy supply needs to be established. For the compression of hydrogen for injection into the storage facility, wind energy can be used; hydrogen is only inserted into the storage system at times when production exceeds demand, hence at times of high wind speeds and inherently a lot of wind energy production. On the other hand, it may not be possible to power the equipment required for extraction of hydrogen solely with energy directly from wind turbines since hydrogen is extracted from the storage system when demand exceeds production, when wind speeds are low. For that reason, a fuel cell could be included in the system. When wind speeds are high, hydrogen is compressed by a number of extra turbines installed especially for this purpose. Excess wind energy can be used for hydrogen production, and this hydrogen production can then be used to charge a fuel cell, which can supply energy to the processing equipment (and if required, the compressor) when hydrogen needs to be extracted from the storage system due to low hydrogen production.

3.2 Methodology for system cost calculation

To assess the economic feasibility of integrating a salt cavern storage system into an offshore green hydrogen production, the levellized cost of hydrogen (LCOH) of the storage system is used as an indicator for the incremental cost of an offshore salt cavern storage system to the cost of offshore green hydrogen production. The LCOH gives a measure of the revenue required to induce a rate of return (RoR) on the investment that is equal to the Weighted average cost of capital (WACC) over the total lifetime of the system; hence it gives the average cost of the produced hydrogen over the total lifetime, given in current prices.

Combining system costs and hydrogen production in one metric, The LCOH is determined from the average annual total expenditures of the hydrogen production per year. Hence the costs of each component in the system must be quantified and compared to the annual hydrogen production. The latter is determined from the wind park capacity and the capacity factor determined from simulations as described in section 2.4. With a wind park capacity of 19.8 GW and a capacity factor of 60% (determined from the simulations) and assuming 8000 baseload hours per year, the system produces on average 95040 GWh of wind energy annually, which translates to $2.41 * 10^9$ kg or 2.41 million ton of hydrogen per year using the HHV and assuming a direct conversion rate from wind energy to hydrogen of 80% as was explained in section 2.2.2. The total overall expenditure (TOTEX) of the system is approximated by the methodology presented in a study by Reuß et al [42] and can be calculated using the following formula:

$$TOTEX = CAPEX + fixOPEX + varOPEX \tag{3.3}$$

Where CAPEX refers to the total capital expenditures and fixOPEX and varOPEX concern the fixed and variable operational expenditures, respectively. In this study, the variable operational expenditures that are considered are the costs for the energy required to power the compressor and the topside equipment. As explained in section 3.1, in the conceptual system design presented in this study the compressor and other top side equipment are powered by extra wind turbines and a fuel cell installed for this purpose. Hence, varOPEX are integrated in other cost elements, namely in the investment costs and OM costs for the additional wind turbines and fuel cell, and therefore varOPEX is not added to TOTEX separately in this study. Consequently, the TOTEX of the system is approached by a modification of 3.3:

$$TOTEX = CAPEX + OPEX \tag{3.4}$$

Where OPEX represents only the fixed operating costs. The system LCOH are determined from the TOTEX per year and the amount of hydrogen produced by the system per year:

$$LCOH = \frac{TOTEX/year}{H2production/year} \tag{3.5}$$

To arrive at the system LCOH, TOTEX/year is determined for each component separately from CAPEX/year and OPEX/year:

$$TOTEX/year = CAPEX/year + OPEX/year \tag{3.6}$$

For each component, CAPEX/year is determined by multiplying investment cost by the annuity factor (AF) to arrive at the capital expenditures per year:

$$CAPEX/year = Investment * AF \tag{3.7}$$

Where Investment represents the total investment costs and AF is the annuity factor, which is determined from the weighted average cost of capital (WACC):

$$AF = \frac{(1 + WACC)^n * WACC}{(1 + WACC)^n - 1} \tag{3.8}$$

With n the depreciation period in years. In the absence of information about the WACC for salt cavern storage, the value for WACC is approximated in this study by the WACC for offshore wind energy. Multiple values for the latter are presented in literature. Based on historic observations, a WACC of 7.5% for offshore wind energy was found by The International Renewable Energy Association [43], while Catapult suggest a predicted 6% [44]. Seeing as the system has yet to be developed, a predicted value is deemed more accurate than a value based on historic observations and therefore in this study the latter value will be adopted. The annual operational and maintenance costs OPEX/year are determined as a percentage of CAPEX/year:

$$OPEX/year = CAPEX/year * OM \tag{3.9}$$

Where OM represents the annual expenditures on operation and maintenance as a fraction of CAPEX/year.
In this way, the overall expenditures of each system component are quantified and based on this the total system costs and inherently the incremental LCOH of the storage system can be approximated. In addition, the monetary significance of the elements can be determined from their weight in the total LCOH, based on which the cost drivers can be identified.
In the succeeding subsections, the (prospected) costs of each component as described in section 3.1 are presented.

3.2.1 Salt caverns

Although specific costs are relatively low compared to other (large scale) storage technologies, salt caverns are costly; Investment costs for a 500.000 m3 salt cavern are estimated at 81 M€ [45] which includes construction costs (i.e. all labour and materials required for creating the salt caverns), the borehole costs and the costs for the cushion gas. These costs do not include top side facilities such as the compressor. The relative shares of construction costs, borehole costs and cushion gas are 73%, 15% and 12%, respectively [46]. The investment costs for 750.000 m3 caverns can be approximated by scaling to volume through the following equation [42]:

$$Investment = invest_{base}(\frac{capacity}{Invest_{compare}})^{invest_{scale}} \tag{3.10}$$

Where capacity denotes the cavern volume in m3, $Invest_{compare}$ denotes the cavern volume for which investment costs are given, $invest_{base}$ represents the investment costs for this cavern volume and $invest_{scale}$ is a scale factor. Table 3.3 shows all relevant parameters for calculation of the investment costs and inherently CAPEX/year and OPEX/year for salt caverns by the methodology described above. The study by reußet al [42] gives a depreciation period of 30 years. However, it is expected that the lifetime of salt caverns could reach 50 years, provided they are operated well. This is demonstrated by the salt cavern in Teesside, the United Kingdom, which was constructed in 1971 and is still operational [12]. Therefore in this study a lifetime of 50 years is adopted.

As mentioned previously, the salt caverns in the system are assumed to be uniform in volume, depth and shape and therefore the total expenditures for the salt caverns will be determined by multiplying cavern CAPEX and OPEX by the number of caverns in the system.

Parameter	**Value**	**Unit**
$Invest_{base}$	107	M
$Invest_{compare}$	500.000	m3
$Invest_{scale}$	0.28	-
Capacity	750.000	m3
n	50	years
OM	2	%

Table 3.3: Relevant parameters for calculation of investment cost, CAPEX and OPEX of salt caverns.

3.2.2 Pipeline

As indicated in figure 3.1, the infrastructure considered in this analysis consist of the required pipeline to connect the compressor and the salt caverns, and the pipeline between salt caverns and the top side processing equipment. To approximate the cost of hydrogen infrastructure per salt cavern, the average distance between compressor and cavern and between cavern and top side equipment is taken as the total length of pipeline required per cavern, as previously presented in table 3.1.

The costs for hydrogen pipelines were estimated in a study by reußet al [47] by the following equation obtained from an empirical cost analysis for 100 bar natural gas pipelines by Mischner et al [48]:

$$Investment = 1.05 \cdot 278.24 \cdot e^{1.6 \cdot D_{pipe}} \tag{3.11}$$

Where a factor 1.05 represents an additional 5% in the costs as a conservative estimate to account for adjustment of the pipeline to allow utilization for hydrogen transport. However, in our case the pipelines are newly built and therefore the 5% is disregarded in this study. Accordingly, the costs for pipeline are approximated in this study by equation 3.12.

$$Investment = 278.24 \cdot e^{1.6 \cdot D_{pipe}} \tag{3.12}$$

Which relates the pipeline diameter D_{pipe} in [m] to the pipeline investment costs in [€/m]. The pipeline diameter D_{pipe} can be derived from the following formula [49]:

$$D_{pipe} = 2 \cdot \sqrt{\frac{P_{GW}}{\pi \cdot v_{H2} \cdot \rho \cdot HHV \cdot 3.6}} \tag{3.13}$$

Where P_{GW} gives the pipeline capacity, v_{H2} describes the velocity, assumed 25 m/s as is done in previous research [50]. The density ρ was determined to be 8.2 kg/m3 (from the real gas law given by equation 2.6 and assuming T = 288.15, P = 100 bar and z = 1.025) and HHV is 39.4 MJ/kg. The system should be able to deliver 10 GW of hydrogen. Assuming 48 identical caverns each connected to the top side equipment through an individual pipeline, each of these pipelines should have a capacity of 0.21 GW. Inserting these numbers in equation 3.13 gives a pipeline diameter of 5 inch. In case only 50% of storage capacity were installed, i.e. 28 salt caverns, the capacity per pipeline would be 0.36 GW, corresponding to a pipeline diameter of 6 inch. In this study we adopt the latter value to use in the cost calculations.

From equation 3.12 the costs of pipeline per meter are determined to be 360 €/m. From this price per meter, the average length of pipeline required per cavern as presented in section 3.1.2 and the number of caverns in the system, the investment costs and based thereon annual CAPEX and OPEX are determined for the pipeline in the storage system. Table 3.4 shows all relevant parameters for calculation of investment costs, CAPEX and OPEX of hydrogen pipelines in the system.

Parameter	Value	Unit
Investment	360	€/m
n	40	years
OM	4	%

Table 3.4: Relevant parameters for calculation of investment cost, CAPEX and OPEX of pipeline.

3.2.3 Top side

As described in section 3.1.3, the top side of the operation is defined in this study as the above ground portion of the operation: the platform, top side equipment and personnel (labour + accommodation). The primary cost driver in the top side costs is weight since this determines the requirements on the jacket, which accounts for a majority of the total costs. The weight of the top side can be approximated from the capacity of the compressor and corresponding weight.

The compressor capacity as presented in section 3.1.3 was used to make an estimation of the total weight of the top side and inherent costs [51]. By means of a computative tool used for calculation of the compression energy required for industrial centrifugal compressors, the capacity required for compression from pipeline pressure to maximum cavern pressure, i.e. from 100 bar to 217 bar, was estimated between 70 and 80 MW, depending on the number of stages, which is slightly higher than the 65 MW that followed from the calculations presented in section 3.1 due to the fact that the tool also includes the capacity required for the driver. A more detailed description of the calculations obtained from the aforementioned tool can be found in appendix D. The required capacity for a one stage compressor, i.e. 80 MW, is assumed henceforth. As described in section 3.1.3, the system is assumed to have two of these compressors.

Based on the weight of two 80 MW compressors, the total weight of the top side, an estimation of the additional equipment, export facilities, personnel and accommodation facilities was made. The total weight of the top side was estimated at 11000 ton, and based on this weight a high end estimation of the total expenditures on the top side of the operation was made.

A conceptual budget for the top side operation was made, the details of which can be found in appendix C. The total top side expenditures are estimated at 480 M€, including labour and materials, with an accuracy of ±50%. This estimation includes all top side equipment, as well as accommodation for twenty people.

Based on this estimation for overall top side investment costs and assuming an overall depreciation period for the entire top side of 30 years and operation and maintenance to account for 4% of annual CAPEX [51], the annual CAPEX and OPEX for the top side are approximated using the parameters presented in table 3.5.

Parameter	Value	Unit
Investment	480	M€
n	30	years
OM	4	%

Table 3.5: Relevant parameters for calculation of investment cost, CAPEX and OPEX of top side.

Top side energy supply

As described in section , it is assumed that the compressor is powered by a number of additional wind turbines, placed especially for this purpose. A fuel cell will serve to power the other processing equipment required to prepare the hydrogen extracted from the caverns for injection into the pipeline. The fuel cell can be powered by hydrogen produced from (excess) wind energy from the additional wind turbines. Hence, the costs for top side energy consumption are approximated by the costs of additional turbines and a fuel cell.

As mentioned in section 3.1.3, the system requires an 80 MW compressor. The compressor could be powered by four 20 MW wind turbines. This is based on the maximum compression energy required, i.e. for compression from pipeline pressure (100 bar) to maximum cavern pressure (217 bar). However, since the average cavern pressure over the simulated time period is only 127 bar, the compressor will mostly not run at full capacity and therefore the excess wind energy produced can be used to produce hydrogen to charge the fuel cell. To determine the required capacity for the fuel cell, a high end estimation of the total energy consumption by the processing equipment was made. The energy consumption of the additional top side equipment required for hydrogen processing is approximated based on the energy consumption of one of the instruments: the cyclone filter. A cyclone filter for industrial purposes consumes 0.25-1.5 kWh/1000 nm^3 [52]. In this study we will assume an average consumption of 1.5 kWh/1000 nm^3 as a conservative approach which corresponds to 0.017 kWh/kg.

A rough estimation of the total energy consumption of the processing equipment is made by multiplying the energy consumption of a cyclone filter by the number of different types of processing equipment required for hydrogen storage in salt caverns. At the Zuidwending facility, there are seven types of machinery to serve the purposes described in section 3.1.3, namely equipment for cooling and heating, two metering systems (for hydrogen import and export), sludge catchers for filtering, a choke train for decompression, a glycol contracter for dehydration, and finally a cyclone filter for filtering. In this study the same equipment for processing is assumed and consequently the energy consumption of the cyclone filter is multiplied by seven. Hence, the processing equipment energy consumption is estimate at 0.12 kwh/kg.

The fuel cell should be able to deliver 0.12 kwh/kg. From simulations it was determined that the maximum mass of hydrogen to be extracted from the storage system in one hour is 241049 kg. Assuming an efficiency of 56% [53], the fuel cell should have a capacity of 46 MW. The investment costs for this type of fuel cell are estimated at 250 €/kw by 2030. Therefore the investment costs for the fuel cell for this system are estimated at 12 M€.
The costs for 20 MW wind turbines are estimated at 462 M€/GW by 2035. Costs for installation and assembly costs are estimated at 276 M€/GW and 39.3 M€/GW [9]. These figures lead to a total investment costs of 15.5 M€ for a 20 MW turbine and thus the investment costs for the four extra wind turbines would amount to 62 M€.

The costs for the fuel cell are added to the estimated investment costs for the top side (see table 3.5). Hence, the total investment for the top side used in the cost calculations is 492 M€. The costs for the extra wind turbines are incorporated separately by calculating the annuity factor, CAPEX and OPEX from the investment costs as presented here, the lifetime and the OM percentage as given in table 3.6.

Parameter	**Value**	**Unit**
Investment	492	M€
n	30	years
OM	4	%

Table 3.6: Relevant parameters for calculation of investment cost, CAPEX and OPEX of the additional wind turbines.

3.2.4 Uncertainty

The values presented in this section for investment costs are estimations. To indicate the accuracy of the result and thereby express its value, it is essential to acknowledge the uncertainty in the parameters used in calculations.

The top side investment costs are estimated at 480 M€, with an uncertainty of ±50%. The investment costs for a 500.000 m3 salt cavern is assumed to be 81 M€ in this study. However, other publications suggest investment costs of 107 M€ for a cavern of equal size [8], indicating a large uncertainty. Moreover, these estimations are based on onshore salt caverns and might be an underestimation of the actual investment costs for offshore salt caverns, considering potential increased complexity of sub-sea construction. On the other hand, considering the large amount of caverns to be constructed, the costs could possibly decrease during the construction process due to increased maturity of the technology.

As for the pipeline; pipeline costs are estimated based on empirical relations and are not studied in detail. Moreover, the length of pipeline required in the system is a crude estimate which could vary significantly from the length required in practice. An important question to answer in light of the pipeline budgeting is: how are the caverns operated and what does this mean for connection to one another and equipment? At this point the modus operandi of the salt cavern storage system is not known, and on behalf of the cost calculations an average length of pipeline required per cavern is assumed in this study since determining the actual required infrastructure requires further studies into the connections between individual caverns and system components, which is outside the scope of this study. Furthermore, further study into the design of the infrastructure is required to determine the actual required pipeline capacity and corresponding diameter. Hence, the length and diameter of pipeline are crude estimations, and therefore the estimation of the practical costs for the infrastructure is highly uncertain at this point.

For the reasons mentioned above, an uncertainty of ±50% is assumed for the capital costs for pipeline and salt caverns, as is done for the top side expenditures. The costs of each system component are determined for three cases; a base scenario, using the cost parameters as presented in this section, and in addition an optimistic and a conservative scenario with the investment costs plus 50% and minus 50%, respectively. In this way a range of costs for the system can be given.

3.2.5 Additional costs

To account for unforeseen costs, a percentage contingency is added to the CAPEX. In this study, a contingency of 10% is assumed and this is added to the CAPEX of each system component.

In addition to the direct costs, i.e. CAPEX and OPEX, operations like these also encounter indirect costs often given as a percentage of the total costs. These indirect costs are partly represented by the owners' costs: the costs made by the owner to set up all systems required to run the operation. Examples are operator training courses, costs for permitting, insurances, all pre-engineering costs (i.e. location analysis, pipeline routing studies, UXO ground penetration radar testing, et cetera), licenses fees, capital spare parts, and, if required, working capital) [51]. A study into the costs for CAES in salt caverns assumes the owners' cost as 15% over the total expenditures [54] and therefore this value is adopted in the cost analysis.

In the cost calculations, the owners cost is added after the CAPEX and OPEX of all individual components is added. Therefore the LCOH is determined over the total of direct costs, i.e. the sum of CAPEX + contingency and OPEX, plus a percentage of owners' cost.

3.3 Results of system cost calculation

In this section the results of the analysis of the system costs are presented. The input values used in calculations can be found in appendix E. Figure 3.7 shows the CAPEX (including 10% contingency), CAPEX/year, OPEX/year, TOTEX/year, TOTEX/year including the indirect cost (i.e. 15% owners cost) and the LCOH calculated from this final value for the total expenditures by the methodology presented in section 3.2 for the individual components and for the system as a whole, for the scenario with 100% of the required storage capacity, i.e. 8.65 TWh distributed over 48 caverns.

		Base scenario	Investment+50%	Investment-50%	Unit
TOTAL SALT CAVERNS EXPENDITURES					
	CAPEX	4791	7186	2395	M€
	CAPEX/year	304	456	152	M€/year
	OPEX/year	12	18	6	M€/year
	TOTEX/year	316	474	158	M€/year
	LCOH	0,13	0,20	0,07	€/kg
TOTAL PIPELINE EXPENDITURES					
	CAPEX	34	51	17	M€
	CAPEX/year	2	3	1	M€/year
	OPEX/year	0	0	0	M€/year
	TOTEX/year	2	4	1	M€/year
	LCOH	0,001	0,001	0,000	€/kg
TOTAL TOP SIDE EXPENDITURES					
	CAPEX	540	809	270	M€
	CAPEX/year	39	59	20	M€/year
	OPEX/year	2	2	1	M€/year
	TOTEX/year	41	61	20	M€/year
	LCOH	0,02	0,03	0,01	€/kg
TOTAL ADDITIONAL WIND TURBINES EXPENDITURES					
	CAPEX	68	102	34	M€
	CAPEX/year	5	7	2	M€/year
	OPEX/year	0	0	0	M€/year
	TOTEX/year	1	2	3	M€/year
	LCOH	0,0005	0,0008	0,0011	€/kg
TOTAL SYSTEM EXPENDITURES					
	CAPEX	5433	8149	2716	M€
	CAPEX/year	350	526	175	M€/year
	OPEX/year	14	21	7	M€/year
	TOTEX/year	361	541	182	M€/year
	TOTEX/year incl. indirect	415	622	210	M€/year
	SYSTEM LCOH	**0,17**	**0,26**	**0,09**	**€/kg**

Figure 3.7: Results of the economic analysis for a system with 100% of the minimum required storage capacity

Similarly, the costs were determined for the scenarios with 90%, 75% and 50% of the minimum storage capacity. Figure 3.8, 3.9 and 3.10 respectively show CAPEX, CAPEX/year, OPEX/year, TOTEX/year, TOTEX/year including indirect costs and the LCOH for the system as a whole in case of 90%, 75% and 50% capacity, respectively.

		Base scenario	Investment+50%	Investment-50%	Unit
TOTAL SALT CAVERNS EXPENDITURES					
	CAPEX	4392	6588	2196	M€
	CAPEX/year	279	418	139	M€/year
	OPEX/year	11	17	6	M€/year
	TOTEX/year	290	435	145	M€/year
	LCOH	0,12	0,18	0,06	€/kg
TOTAL PIPELINE EXPENDITURES					
	CAPEX	31	47	16	M€
	CAPEX/year	2	3	1	M€/year
	OPEX/year	0	0	0	M€/year
	TOTEX/year	2	3	1	M€/year
	LCOH	0,001	0,001	0,000	€/kg
TOTAL TOP SIDE EXPENDITURES					
	CAPEX	540	809	270	M€
	CAPEX/year	39	59	20	M€/year
	OPEX/year	2	2	1	M€/year
	TOTEX/year	41	61	20	M€/year
	LCOH	0,02	0,03	0,01	€/kg
TOTAL ADDITIONAL WIND TURBINES EXPENDITURES					
	CAPEX	68	102	34	M€
	CAPEX/year	5	7	2	M€/year
	OPEX/year	0	0	0	M€/year
	TOTEX/year	1	2	3	M€/year
	LCOH	0,0005	0,0008	0,0011	€/kg
TOTAL SYSTEM EXPENDITURES					
	CAPEX	5030	7546	2515	M€
	CAPEX/year	325	487	162	M€/year
	OPEX/year	13	19	6	M€/year
	TOTEX/year	334	501	169	M€/year
	TOTEX/year incl. indirect	384	576	194	M€/year
	SYSTEM LCOH	**0,16**	**0,24**	**0,08**	**€/kg**

Figure 3.8: Results of the economic analysis for a system with 90% of the minimum required storage capacity

Clearly, the number of caverns makes a large difference in the total costs of the system and inherently the system LCOH; decreasing the number of caverns from 48 to 28 decreases the LCOH from 0.17 /kg to 0.11 /kg (in the base scenario); a decrease of 35%. The caverns make up the largest part of the total system expenditures, followed by the top side and lastly the pipeline. Table 3.7 shows for 100%, 90%, 75% and 50% the contribution to the overall TOTEX/year.

	100% capacity	90% capacity	75% capacity	50% capacity
Salt caverns	81%	80%	80%	77%
Pipeline	9%	8%	7%	7%
Top side	10%	12%	13%	16%

Table 3.7: Contribution of each component to the (direct) total costs of the system

		Base scenario	Investment+50%	Investment-50%	Unit
TOTAL SALT CAVERNS EXPENDITURES					
	CAPEX	3593	5390	1797	M€
	CAPEX/year	228	342	114	M€/year
	OPEX/year	9	14	5	M€/year
	TOTEX/year	237	356	119	M€/year
	LCOH	0,10	0,15	0,05	€/kg
TOTAL PIPELINE EXPENDITURES					
	CAPEX	25	37	12	M€
	CAPEX/year	2	2	1	M€/year
	OPEX/year	0	0	0	M€/year
	TOTEX/year	2	3	1	M€/year
	LCOH	0,001	0,001	0,000	€/kg
TOTAL TOP SIDE EXPENDITURES					
	CAPEX	540	809	270	M€
	CAPEX/year	39	59	20	M€/year
	OPEX/year	2	2	1	M€/year
	TOTEX/year	41	61	20	M€/year
	LCOH	0,02	0,03	0,01	€/kg
TOTAL ADDITIONAL WIND TURBINES EXPENDITURES					
	CAPEX	68	102	34	M€
	CAPEX/year	5	7	2	M€/year
	OPEX/year	0	0	0	M€/year
	TOTEX/year	1	2	3	M€/year
	LCOH	0,0005	0,0008	0,0011	€/kg
TOTAL SYSTEM EXPENDITURES					
	CAPEX	4226	6339	2113	M€
	CAPEX/year	274	411	137	M€/year
	OPEX/year	11	16	5	M€/year
	TOTEX/year	281	421	142	M€/year
	TOTEX/year incl. indirect	323	484	164	M€/year
	SYSTEM LCOH	**0,13**	**0,20**	**0,07**	**€/kg**

Figure 3.9: Results of the economic analysis for a system with 75% of the minimum required storage capacity

As explained in section3.2, an uncertainty of 50% was assumed for the investment costs of all three components. Figures 3.7, 3.8, 3.9 and 3.10 show at the bottom row the system LCOH for the base scenario, the conservative scenario (investment costs of all system components +50% and the optimistic scenario (investment costs of all system components -50%). In case of 100% storage capacity, the LCOH for the base scenario is 0.17 €/kg, while the optimistic estimate is 0.09 €/kg and the worst case scenario would be 0.26 €/kg. Although it is unlikely that either the costs of all system components are at their lower boundary, or all at their upper boundary (i.e. it would be more likely that some costs are overestimated and some are underestimated), the conservative and optimistic scenario provide an indication of the range of possible values for the LCOH of this system.

		Base scenario	Investment+50%	Investment-50%	Unit
TOTAL SALT CAVERNS EXPENDITURES					
	CAPEX	2795	4192	1397	M€
	CAPEX/year	177	266	89	M€/year
	OPEX/year	7	11	4	M€/year
	TOTEX/year	184	277	92	M€/year
	LCOH	0,08	0,11	0,04	€/kg
TOTAL PIPELINE EXPENDITURES					
	CAPEX	18	27	9	M€
	CAPEX/year	1	2	1	M€/year
	OPEX/year	0	0	0	M€/year
	TOTEX/year	1	2	1	M€/year
	LCOH	0,001	0,001	0,000	€/kg
TOTAL TOP SIDE EXPENDITURES					
	CAPEX	540	809	270	M€
	CAPEX/year	39	59	20	M€/year
	OPEX/year	2	2	1	M€/year
	TOTEX/year	41	61	20	M€/year
	LCOH	0,02	0,03	0,01	€/kg
TOTAL ADDITIONAL WIND TURBINES EXPENDITURES					
	CAPEX	68	102	34	M€
	CAPEX/year	5	7	2	M€/year
	OPEX/year	0	0	0	M€/year
	TOTEX/year	1	2	3	M€/year
	LCOH	0,0005	0,0008	0,0011	€/kg
TOTAL SYSTEM EXPENDITURES					
	CAPEX	3420	5130	1710	M€
	CAPEX/year	223	334	111	M€/year
	OPEX/year	9	13	4	M€/year
	TOTEX/year	228	342	116	M€/year
	TOTEX/year incl. indirect	262	393	133	M€/year
	SYSTEM LCOH	**0,11**	**0,16**	**0,06**	**€/kg**

Figure 3.10: Results of the economic analysis for a system with 50% of the minimum required storage capacity

3.4 Conclusion on economic feasibility

In accordance with the results of the cost analysis presented in this chapter, the following conclusions were drawn on the economic feasibility:

- The estimated costs for an 8.65 TWh salt cavern storage system translate to a LCOH of 0.17 €/kg for the storage system.
- Reducing the storage capacity to 90%, 75% or 50% of the storage capacity would reduce the LCOH to 0.16 €/kg, 0.13 €/kg or 0.11 €/kg, respectively. This could be a way to decrease cost, provided a proper backup strategy can be established, and the incremental costs of this backup strategy would be smaller than the absolute change in LCOH.
- Although further studies are required to define the costs for the storage system with higher accuracy, the results imply that integrating a storage system into an offshore green hydrogen production system is a financially viable concept.

Chapter 4

Sensitivity analysis

This chapter presents an overview of assumptions made in the modeling and calculations for this study. The assumptions deemed most significant are studied further in an uncertainty analysis. In this way this chapter aids in identifying the most crucial elements and circumstances to consider in a salt cavern storage system, which allows us to pinpoint possible bottlenecks and to give useful recommendations for further studies.

First of all, the assumptions used in the modeling and calculations are described in section 4.1. Based on the assumptions deemed most significant, three scenarios are defined. In each scenario, one of these assumptions is relaxed to determine the consequences for system design choices and the associated change in system costs. A sensitivity analysis is performed for each scenario, which is presented in section 4.2. Finally, the most important conclusions of this chapter are presented in section 4.3.

4.1 Assumptions in modeling and calculations

In the analysis of the technical and financial feasibility of the storage system in this study, certain assumptions were made. In this section, the most prominent assumptions are discussed. The assumptions are grouped in (1) assumptions in hydrogen production (2) assumptions in the system design, (3) assumptions regarding salt caverns and (4) assumptions made in cost calculations. Finally, the most significant assumptions are selected to be investigated further in a sensitivity analysis.

4.1.1 Assumptions in Hydrogen production

In this study, the hydrogen production is regarded as a given; it is assumed that a wind park of sufficient capacity can be constructed and that the wind conditions are conform to the simulated wind conditions (see appendix B) However, wind conditions form an external factor that we can not influence and it differs per location. Moreover, the effect of wake in wind parks has not been incorporated in this study. For that reason the practical capacity factor is presumably lower than the value obtained from simulations.

Furthermore, in this study the hydrogen production is simulated linearly to wind energy production; it is assumed that 80% of the wind energy production is translated to hydrogen. However, in reality the ratio between wind energy production and hydrogen production is less linear due to the fact that the electrolyzers cannot scale up or down, or switch on or off, their hydrogen production capacity promptly with increasing or decreasing wind energy. Although due to stacking scaling up or down the electrolyzers can scale up or down their production rate following the wind energy production pattern from the wind to a degree, the assumption of a linear relation between the two is questionable in practice.

What happens when wind conditions are worse/better than expected? what happens when wind conditions change over time, what does that mean for the system? does climate change have an effect?

4.1.2 Assumptions in System design and operation

The level of project definition in this study allows for a significant degree of freedom in system design choices; seeing as the exact location and layout of the cavern field is not defined in this study, design choices made in terms of the location of the platform, the number of platforms required, the equipment required and the required infrastructure are assumptions rather than decisions. For example, in this study it is assumed that all wells required for creating the caverns can be drilled from one platform, based on the conceptual field development plans presented in section 3.1 from which it was determined that the maximum lateral distance between cavern and platform is still within an acceptable range for drilling[51].
If however it turns out that the cavern field cannot be created in the coveted shape and consequently the distance between certain caverns and the platform becomes too large, an extra platform might be required for drilling. Moreover, the required infrastructure (i.e. length of pipeline required in the system) depends on the actual field development plan. The pipeline diameter in turn depends on the configuration of the system and the way the different system components are interconnected; this determines the flow rate and hence capacity required of the pipelines, parameters that govern the pipeline diameter.

In this study, it is assumed that all system components can switch promptly between hydrogen insertion and extraction. That is: it is assumed that the compressor can switch on and off, and can adjust its capacity to the current input pressure right away, cavern wellheads can switch from hydrogen insertion to hydrogen extraction instantaneously, and the processing equipment can be switched on and off instantaneously. Although injection and withdrawal rates and switching rates are high in salt cavern storage [14], assuming instantaneous switching might not be entirely just. In practice, there might be a delay in the hydrogen streams inserted into the caverns and extracted from the caverns and the simulation with respect to the hydrogen stream carried directly from the production system to the pipeline, hence the simulated hydrogen streams per time instant might not be entirely in-sync. The effect of this has not been incorporated in this study but should be investigated to more accurately simulate the different hydrogen flows in and around the system, and inherently the required production- and storage capacity.

4.1.3 Assumptions regarding salt caverns

First of all, all salt caverns in the system are assumed to be equal in shape, volume and depth, implying that all caverns have the same storage capacity. In reality, however, this will not be the case since the shape of the caverns can only partly be controlled by the leaching process as it is also governed by external factors like heterogeneity of the salt rock. In this study, the geological setting is assumed to be the same for all caverns, implying equal stability in all caverns.

The above implies that all caverns in the system can be operated in the same pressure range; i.e. between 24% and 80% of overburden pressure as is applied in this study. In reality, some caverns will be more stable and hence be better equipped to withstand pressure variations (and higher frequency thereof) than others. Thus, it might be the case that some of the caverns can be operated between 24% and 80% of overburden pressure, while others may only able to withstand pressures between for example 35% and 70% of overburden pressure. In an even worse scenario it could be the case that not even one cavern can withstand pressures below 35% nor above 70% of overburden pressure.

If analysis of the cavern stability shows that the latter is the case, this would have serious consequences for the number of caverns that would have to be created to provide sufficient storage capacity. Not only would this lead to higher costs, it could also mean that the location chosen initially does not have enough storage capacity after all, if not all additionally required caverns can be constructed in that location.

Another important assumption regarding the salt caverns is the lifetime. In the cost calculations, it is assumed that the lifetime of caverns is 50 years, provided they are well operated. However, the exact lifetime is not known and might be shorter in practice. Considering their large contribution to the total system costs, the salt caverns having a shorter lifetime of say 30 years is expected to have a significant influence on the LCOH.

4.1.4 Assumptions in cost calculations

In the cost calculations, some of the input values were obtained from literature and are based on empirical evidence, while others are estimated values. The level of accuracy differs substantially between input parameters; the pipeline costs as a function of diameter and length can be approximated with reasonable certainty based on the costs of previously constructed gas infrastructure. On the other hand, other parameters are less obvious, either due to a lack of maturity of the technology or due to large uncertainties in the design and operation of the system. For example, the investment costs for salt caverns are derived from studies on the economic feasibility of (onshore) salt cavern storage. In the cost calculations, it is assumed that these investment costs are representative for offshore salt caverns, while in reality the increased complexity in the construction process might add to the investment costs. Moreover, it is assumed that the investment costs for the caverns incorporate the entire construction process; i.e. the drilling of the well and installing the well head, the entire leaching process, and finally the disposal of the brine by inserting the cushion gas. Decommissioning is not mentioned [42] and is thus assumed to be integrated in the investment costs.

Another important assumption in the cost calculations is the value taken for WACC. As explained in section 3.2, WACC is assumed to be 6% in this study. WACC is not known for salt cavern storage and it is a parameter that is difficult to grasp, seeing as it depends not only on maturity of technology but also on the ratio between equity and debt capital. Determining the WACC for salt cavern storage would hence require information about the financial structure of the project, which is outside the scope of this study. The WACC partly determines the annuity factor which in turn governs the average annual CAPEX, the value obtained for WACC is expected to significantly influence the total system costs.

4.1.5 Most significant assumptions

The assumptions that the salt caverns all have equal spatial characteristics and are in the same geological setting lead to the assumption that all caverns can be operated in the same pressure range. Relaxing this assumption would imply that some or even all caverns would have to be operated in a more conservative pressure range, meaning that the practical storage capacity would have to be larger than the theoretical storage capacity. This would have severe consequences for the dimensioning of the system since this demands either an increased amount of caverns or a larger individual cavern volume. Especially considering the high investment costs for salt caverns and their large contribution to the total system costs (see table 3.7) this could add substantially to the overall LCOH and therefore the authority of this assumption is studied in an uncertainty analysis.

Apart from the uncertainty in the practical storage capacity of the caverns, another important uncertainty lies in the expected lifetime of the caverns. Should the lifetime of the caverns be less than the 50 years assumed in this study, this would lead to higher annual average expenditures on the salt caverns. Again, due to the large contribution of the salt caverns to the total costs, this could considerably increase the LCOH.

Less an assumption on physical circumstances than the previous two, the assumption for WACC is an important indicator for the financial situation and can have significant impact on the LCOH as it authorizes the entire cost calculation through the annuity factor. Following the value predicted for offshore wind energy could either be an under- or overestimation and quantifying the effect of this is important to demonstrate the need for further research into the prospected and desired financial state of affairs.

4.2 Sensitivity analysis

To determine the effect of relaxing the three assumptions presented in the previous section, a sensitivity analysis is performed for three cases. The cases are compared to the base case: a storage system with 8.65 TWh storage capacity divided over 48 identical caverns. The input parameters for the base case are given in appendix E.
In case 1, the assumption that all caverns can be operated in a range 24-80% of overburden pressure is relaxed and it is assumed instead that a more conservative pressure range applies. As discussed previously, as a consequence either the number of caverns or the size of the caverns should then increase to counterbalance the lost storage capacity. We therefore define a case 1A and case 1B; in the former the number of caverns is increased while in the latter the cavern volume is enlarged to compensate for the increased confinement on cavern pressure. In case 2, the cavern lifetime (n) is changed while all other parameters are left unchanged. Lastly in case 3 the WACC is changed, again leaving the other parameters untouched.

For each of the cases, the LCOH was determined. Table 4.1, shows the change in input parameters as described above and the resulting change in the LCOH for case 1A, 1B, 2 and 3. Visible in the table is that the LCOH calculation is highly sensitive to the value chosen for WACC (case 3): a 2% increment in WACC raises the LCOH by 24%, from 0.22 €/kg to 0.27 €/kg. Likewise, decreasing WACC by 2% lowers the LCOH from 0.22 €/kg to 0.17 €/kg, a reduction of 22%.

CASE 1A		**base case**		**No. caverns + 10%**		**No. caverns + 20%**	
		value	change	value	change	value	change
No. caverns	[-]	48	0%	53	+10%	58	+20%
LCOH	[€/kg]	0.22	0%	0.24	+9%	0.25	+13%

CASE 1B		**base case**		**cavern vol. + 10%**		**cavern vol. + 20%**	
		value	change	value	change	value	change
Cavern volume	[m3]	750.000	0%	825.000	+10%	900.000	+20%
LCOH	[€/kg]	0.22	0%	0.22	+2%	0.23	+4%

CASE 2		**base case**		**n - 20**		**n - 20**	
		value	change	value	change	value	change
n	[years]	50	0%	40	-20%	30	-40%
LCOH	[€/kg]	0.22	0%	0.23 €/kg	+4%	0.24	+12%

CASE 3		**base case**		**WACC + 2%**		**WACC - 2%**	
		value	change	value	change	value	change
WACC	[%]	6	0%	8	+2%	4	-2%
LCOH	[€/kg]	0.22	0%	0.27	+24%	0.17	-22%

Table 4.1: Results of sensitivity analysis for case 1A, case 1B, case 2 and case 3, showing for each case the change in the subject of the case and the resulting change in LCOH.

4.3 Conclusions

In the economic feasibility analysis multiple assumptions were made. The assumptions deemed most significant in the cost calculations are the following:

- All caverns can be operated in a pressure range of 24-80% of overburden pressure.
- The lifetime of all salt caverns is 50 years.
- The WACC for offshore salt cavern storage is 6%.

The effect of these assumptions was assessed by means of a sensitivity analysis, which led to the following conclusions:

- Increasing the storage capacity by increasing the number of caverns is much more costly then increasing the individual cavern volume.
- The value of WACC greatly impacts the outlook on total expenditures and LCOH for the storage system. Hence, to get an accurate prediction of the financial viability, further research into the real value for WACC is imperative.
- The expected cavern lifetime has high impact on the LCOH for the storage system. Hence taking precautions to extend cavern lifetime would be beneficial in terms of costs.

In conclusion: multiple assumptions were made in this study which call for further study. The results of the sensitivity analyses show that the LCOH is sensitive to cavern-related parameters, which was expected considering the caverns are the major cost driver in this system. Moreover, the WACC is of great authority in the financial prospects for this system and better understanding of this parameters is demanded for more accurate prediction of the financial viability.

Chapter 5

Discussion

In this chapter, a reflection on the results of the analyses of the technical and economical feasibility of the storage system. First of all, the limitations in the method and the results of the technical feasibility analysis are addressed in section 5.1. Although part of the technical feasibility analyses, a separate section is devoted the required storage capacity. This is section 5.2. Subsequently, the methods and results of the economic feasibility analysis are discussed in section 5.3. Finally, the importance of the time frame is discussed in section 5.4.

5.1 Technical feasibility Analysis

An important outcome of the technical feasibility analysis is that there are several locations in the North Sea that seem suitable for constructing a salt cavern storage system of sufficient capacity. Sufficient capacity refers to the minimum required storage capacity, which was determined to be 8.65 TWh by simulation. This storage capacity can be realized with 48 caverns, each with a volume of 750.000 m3 and at a depth of 1500 m.
These caverns are to be created by means of leaching, requiring large amounts of fresh water. As the operation is located offshore, most likely the fresh water will be obtained in the form of purified seawater. For that reason a desalinating system is required, which is not yet included in the cost calculations. The leaching process produces enormous amounts of brine; 48 caverns with a volume of 750.000 m3 will produce 36 million cubic meters of salt, or 78 billion kg, extracted from the caverns in the form of brine. For onshore salt caverns, the costs for brine disposal are to be attributed to the costs for installing a pipeline from the cavern to the ocean, implying that the brine will be disposed of in the ocean. Doing this for one cavern might not pose too much of an environmental hazard, but could become an issue when not one but 48 caverns are being leached. Releasing large amounts of brine in one location will likely change the salinity of the water which could pose all sorts of problems for biodiversity and ecosystems. This may likely induce social and political resistance and therefore a proper strategy for brine disposal should be established to serve serve public acceptance and thereby facilitate implementation of the system. For example, the brine could be spread out over a large part of the ocean, potentially via ships passing by the facility. Alternatively, depending on the chemical substance of the salt rock, the salt in the brine may be used to extract compounds to use in industry.

Four suitable locations in the North Sea were selected based on their storage capacity, determined from the amount, size and depth of the salt caverns that could be created in that (part of) the salt body. In this selection sailing routes, military operations, fishing areas and other intangible obstacles are not taken into account and it might be that the selected locations interfere with one or more of these intangible barriers. However, considering the urgency of transitioning to a renewable energy system, hydrogen storage may be prioritized over other functionalities and therefore interference with the aforementioned barriers would not necessarily be a harsh constraint for practical system implementation. Therefore further study into this matter is required to assess the actual social, political and legal circumstances at the prospected location and their effect on the availability of locations.

Another decision criterion in the selection of the locations was the possibility to create all caverns 'in one group'. That is: the distance between adjacent caverns should be the minimum inter-cavern distance, i.e. four times the cavern diameter, at maximum. This restriction was only applied to favour ease of construction and operation and to minimize cost; relaxing this restriction would suggest many more potential locations for the system, the caverns would merely be constructed in multiple 'groups'. Although it might be preferred to have the caverns as close to one another as possible, if further analysis proves that the four selected groups of cavern are not suitable for this system after all, it could be considered to combine multiple, smaller groups of caverns.

In this study the system is assumed to be operated in unison; all caverns are operated simultaneously under the assumption that all caverns display identical characteristics and find themselves in the same geological conditions, each cavern endures the same pressure variations. This assumption is merely made for simplification; the optimal modus operandi for the storage system has not been studied. Potentially cavern stability, system efficiency, the financial affairs or perhaps all three would benefit from operating the system in multiple clusters. For instance, this would enable us to unburden weaker caverns, employing the more stable caverns more often, which could extend the total lifetime of the system. This concept is discussed further in section 5.2. Moreover, having separate sub-systems operating independently would improve the security of supply since failure or maintenance would only affect part of the system, allowing the rest of the system to remain operational.

5.2 Storage capacity and security of supply

The effect of installing less than the minimum required storage capacity of 8.65 TWh was assessed by means of a simulation of cavern pressures. An estimation of the cavern pressures was made in case of installing 90%, 75% or even only 50% of the minimum required storage capacity was made (see table 2.7. The assessment was done for two strategies; either to use all caverns as a strategic reserve (strategy 1) or to use only a selection of the 'strongest' caverns (strategy 2). Although of course the cavern pressures for strategy 1 are more favourable in terms of stability, it is unlikely that this strategy could be applied in reality.

The characteristics and geological conditions are assumed equal for all caverns. In reality however, cavern shapes, their sizes and the stability of surrounding rock vary due to heterogeneity, impurities, and faults in the rock salt. Therefore it is unlikely that all caverns can be operated beyond the advised operation pressure range of 24-80% of cavern pressure. In fact, it might even be that some caverns cannot even withstand these pressures and some will have to be operated in more conservative ranges, as discussed in section 4.1.
Hence, strategy 2 seems like a more realistic scenario. Employing strategy 2 would lead to cavern pressures occasionally decreasing to 20%, 18% and 12% in case of decreasing the storage capacity to 90%, 75% and 50% of the minimum, respectively. Depending on the stability of the caverns, 20% and 18% of overburden pressure might be acceptable for some, in which obviously the frequency and rate of the pressure variations must be considered. Reducing the storage capacity by 50% would cause cavern pressures to reach 12% of overburden pressure, which seems alarmingly low considering this is is only half the advised minimum cavern pressure. It is deemed unlikely that a strategic reserve can be found in the cushion gas in case strategy 2 is applied and the storage capacity is only 50% of the minimum required 8.65 TWh.

The results of the costs calculations show that a significant cost reduction can be realized by decreasing storage capacity. The results of the sensitivity analysis support this by showing that the caverns are the primary cost driver in the system. The analysis also revealed that increasing the number of caverns would add relatively more to the cost than increasing cavern volume. This implies that from a cost perspective it would be better to realize the required storage capacity with fewer, larger caverns. However, in light of security of supply and the strategy discussed above, fewer caverns could reduce the number of caverns that would be suitable to be operated beyond the advised pressure range to in that way serve as a back-up hydrogen reserve.

Using the cushion gas as a back-up energy supply might prove to be a viable way of providing security of supply in some cases. As there will be uncertainty in subsurface conditions, the stability under prospected circumstances cannot be fully guaranteed. Furthermore, the 'prospected circumstances' are not set in stone either and might be more stringent than expected, which could induce failure. It could be argued that this strategy be too hazardous with regards to cavern stability. However, if brine would be injected while extracting hydrogen beyond the lower pressure boundary (i.e. from the cushion gas), a safe minimum cavern pressure could be maintained while the cushion gas would function as a strategic reserve. In this way, all cushion gas, i.e. the remaining 24% of overburden pressure, could effectively be extracted from the caverns. Accordingly, the storage capacity would increase, and therefore less caverns be required to realize the needed storage capacity. This concept could be employed not only when cavern pressures approach the lower boundary condition, but any time. This would be beneficial for cavern stability since in this way pressure variations in the caverns would be mitigated.
Whether this is an option to safely use the cushion gas as a back-up hydrogen reserve, information about the systems required to insert brine back into the caverns and the added complexity to the system is required. In any case, assessment of the feasibility of this concept requires further study.

Furthermore, a comparison to other back up strategies would be required; a strategic reserve could also be found in imported (green) hydrogen or in a blue hydrogen production system. In addition, there is storage capacity in the pipeline which could be employed as a back-up hydrogen supply. Especially considering the distance to be covered from the offshore salt cavern system to shore and the large pipeline diameter, the pipeline can embody a considerable storage volume. Under normal conditions, when insertion into the pipeline and consumption are balanced the pressure in the pipeline will remain (roughly) at the targeted pressure, in this study assumed 100 bar. If however the pressure were allowed to drop below the targeted pipeline pressure, more hydrogen can be extracted from the pipeline. This concept is referred to as line-packing.

Hence, apart from the back-up strategy investigated in this study, several other possibilities could be explored. Studies into the technical feasibility, costs and the non-financial (i.e. social and political) benefits of each concept will have to show which would be the preferred strategy.

5.3 Cost calculations and economic feasibility

As mentioned previously, the parameters used in the cost analysis were derived from historic observations. No offshore salt caverns exist, and no salt cavern storage system of the capacity targeted in this study was created. The cost parameters used in this study were obtained from smaller, onshore salt cavern systems, which may not be representative for larger, offshore salt cavern systems. For instance, drilling sub-sea adds complexity to the construction process, likely accompanied by higher costs. Furthermore, drilling all caverns from one, central location, as is assumed in this study, would require (a higher degree of) directional drilling, which is known to be more expensive than vertical drilling.
Also, costs might be underestimated as the maturity of the technology may develop during the construction process. In this study, no learning rates were applied for investment costs, i.e. investment

costs were assumed to remain the same over time, regardless of future technology developments. In reality, costs are likely to decrease with growing maturity of the technology, as is the case for example with (offshore) wind energy [9].

For the reasons mentioned above, the practical cost parameters could deviate (in both directions) from the values used in this study. The indication of the system costs should be therefor perceived as an approximate value, indicating the order of magnitude, rather than high accuracy. After all, the objective of the economic feasibility analysis was to get an idea of the costs of the storage system with respect to the costs for offshore green hydrogen production, to assess the feasibility of integrating the former into the latter and to identify the primary cost drivers.
Considering the level of project definition and the large uncertainties in investment costs and fundamental unknown parameters in the design, and keeping in mind the objective of the economic analysis, an estimation of the LCOH for the storage system was made by approximating the average annual expenses from the investment costs using the annuity factor. Such methodology is often used by industry players because it allows for comparison of the costs of different technologies.

In more advanced stages of project development, this methodology will not provide sufficient accuracy and a more detailed cost analysis is demanded. Once the timeline for the development of the project is established, the annual expenditures can be approached in more detail through information on phasing of the investments of the different components and prospected start of construction and operation of the system. Based on this information, net present values and cash flows can be determined, which will be relevant for investing parties to determine the profitability of the project.

5.4 Time frame for development

The system subject to this study is still in a conceptual stadium and the most optimal design and strategy for operation are yet to be defined. Once the latter is accomplished, a time frame for the construction process may be developed, allowing for a detailed indication of the annual and total expenditures and cash flows. As mentioned previously, this time frame is important since parameters like learning rates and WACC, proven a crucial factor in cost calculations in this study, make that the manner of phasing the investments can majorly impact the total and annual expenditures and thereby the prospected profitability.

Once the system design phase is completed and the economic feasibility is indicated, the social and political angles need to be addressed. Permitting needs to be arranged for placing the wind turbines, the platform and creating the salt caverns. To obtain these permits, all potential hazards and difficulties need to be addressed and a proper strategy for mitigation needs to be in place. For example, a plan for disposal of the brine created in cavern construction needs to be established and approved of, making sure that this will not jeopardize the environment. This could be of crucial importance in acquiring the necessary permits, since the lack of an appropriate procedure for this mitigating this hazard could cause a lot of social and political resistance.

Considering the magnitude of the system and associated complexity and risks, the social, economic and political arrangements might take considerable time. Bearing in mind the objective of a party like Tata Steel to transition to green hydrogen soon, it might be decided to start construction as soon as legally possible, and start operation already when a share of the hydrogen production capacity and storage capacity is created. When part of the wind park and a number of salt caverns are available, operation could begin on a smaller scale provided that the platform with top side equipment and required infrastructure should at that moment be ready for operation. In this phase, it could be decided to temporarily supply less than 10 GW (potentially through a smaller, temporary pipeline), or to supplement the system production with grey (or preferably blue) hydrogen. This would require establishment of a grey/blue hydrogen production system, which could in a later stage serve as a strategic reserve.

Another crucial time element is the number of hours the storage system can autonomously supply the demanded hydrogen quantity, i.e. the number of days the system can provide sufficient amounts of hydrogen in case of no hydrogen production and hence the absence of hydrogen injection into the storage system. This duration of autonomous hydrogen production for a storage system of 8.65 TWh was determined to be 36 days. This is important with regards to the choice for a back up strategy. If future study reveals that the strategy of operating a share of the caverns below their minimum pressure boundary in times of shortage is not an option, a strategic reserve would have to be found elsewhere. For example, hydrogen may be imported from a neighbouring country such as Belgium, which has the ambition to become a hub for renewable hydrogen. Important questions are: can hydrogen import be arranged in 36 days in case of extremely poor wind condition prospects? Or in case the storage system is only half full at that point, could it be arranged in 18 days? What if, for external reasons, importing hydrogen from that country is not possible at that moment, would there be enough time to set up a fall-back emergency grey hydrogen production facility in that time frame? If not, should this be in place in any case for emergencies? These are questions left unanswered for now which are vital to investigate further for successful development of the system.

Furthermore, in the cost calculations performed in this study a certain depreciation period was assigned to each system component to determine the spread of investment costs over time. For example, the depreciation period for caverns was assumed to be 50 years. For some of the system components, such as the compressor, pipeline network and top side facility, the depreciation period may be equal to the actual lifetime of that component, meaning that these components need to be replaced after the depreciation period/lifetime is exceeded. For salt caverns however, the depreciation period actually being equal to the lifetime would have serious consequences, since this would imply that after 50 years, the caverns would have to be dismantled and abandoned and an entirely new salt cavern storage system would have to be created. Considering the size and amount of salt caverns required for this system, this would be an enormous, recurring investment and a project of increasing complexity considering the limited suitable locations i the North Sea. In the end this would mean that after repeatedly creating new salt cavern storage systems, the number of suitable locations would run out, meaning that this would not be a sustainable, long term solution. For that reason it is crucial to further investigate cavern lifetime and to develop a long-term (100+ years) plan for the system.

Chapter 6

Conclusion

The aim of this study was to assess the techno-economic feasibility of integrating a salt cavern storage system into an offshore green hydrogen production system consisting of offshore wind turbines and in-situ electrolysis. The research question was formulated as follows:

"Under what conditions would it be technically possible and financially feasible to store green hydrogen in salt caverns in the North Sea, to supply baseload green hydrogen to the industry sector?"

To answer the research question, three sub-questions were formulated. In this chapter, the most important results and conclusions are addressed for each sub-question separately, after which a general conclusion is given to answer the principal research question.

Sub-question 1: What hydrogen production capacity and salt cavern storage capacity would be required to provide a baseload hydrogen supply of sufficient magnitude?
The hydrogen production capacity and the salt cavern storage capacity required to deliver the desired hydrogen supply were determined by means of simulation. Hydrogen production was simulated from wind speed data obtained from a far-offshore weather station in the North Sea. Hydrogen demand was defined as the objective to constantly fill a 10 GW pipeline. This was simulated as a constant hourly hydrogen demand in energy units of 10 GWh. From the mismatch between production and demand, the required storage capacity was approximated.

The simulation reveals that the objective of the system demands a 19.8 GW wind park in combination with an 8.65 TWh storage system. For the simulated wind conditions, these capacities would ensure an ever-sufficing hydrogen supply to the pipeline while respecting the imposed boundary conditions on cavern pressure. Assuming identical cavern dimensions and subsurface conditions (750,000 m^3 volume and 1500 m depth) and considering an allowed operating pressure range between 24% to 80% of overburden pressure, an 8.65 TWh storage system would consist of 48 caverns.

Furthermore, the possibility of decreasing the storage capacity was explored to determine if in this way the system costs could be minimized. The concept was to create a storage system of smaller theoretical storage capacity, and to exploit the cushion gas at times when the theoretical storage content reached the bottom limit. A crude simulation of cavern pressure was used to evaluate possibility of exploiting the cushion gas by operating either all caverns or a selection of the strongest caverns below the recommended minimum pressure. The aim was to get an idea of the variations in cavern pressures resulting from applying either strategy to shed light on the consequences for stability and inherently the technical feasibility of the concept.

The simulation revealed that for either strategy, reducing the storage capacity to 90%, i.e. from 48 to 44 caverns, cavern pressures would not drop below 20% of overburden pressure. Furthermore, exploitation of the cushion gas would occur with low frequency (on average less than 3 times per year). This speaks in favour of the technical feasibility of this concept and implies that a system with a system with only 90% of the minimum required capacity could be considered.

It was concluded that the strategy of using the cushion gas of all caverns is unrealistic seeing as it is unlikely that all caverns could withstand pressures below 24% of overburden pressure due to dissimilarities in cavern shape and geological conditions. Employing a selection of the most stable caverns is deemed more realistic and could be an option if stability analysis reveals that these caverns could temporarily withstand the prospected pressure drops. Applying the latter strategy, reducing the storage capacity to 75% or 50% would lead to very low cavern pressures of 17% and 12%, respectively. Considering the effect of these low pressures on cavern stability as well as the increased frequency of occurrence, reducing the storage capacity to 75% or 50% of the required capacity might be too hazardous with respect to cavern stability.

In conclusion, the judgement of the practical feasibility of this concept demands analysis of the stability of each cavern, prediction of their tolerable pressure ranges and a prediction of the magnitude, frequency an duration of the variations in cavern pressures. Hence, the true viability of this concept can only be judged after cavern construction.

Sub-question 2: Which location(s) in the North Sea would be suitable for creating a salt cavern storage system of sufficient capacity?
Potential locations for the storage system were selected by comparing the required storage capacity to the theoretical storage capacity of salt bodies in the North Sea. Software developed by Royal Dutch Shell was used to determine prospective locations for salt caverns and their storage capacity. Locations where groups of caverns could be created with a collective storage capacity equal to or larger than 8.65 TWh were considered feasible. Each location identified as feasible was checked for interference with existing physical and non-physical obstacles to assess their practical availability.

The results of the analysis reveal that at least four locations in the Dutch North Sea would be suitable for creating a salt cavern storage system of sufficient capacity. In one of these locations, the prospected cavern locations do not interfere with any of the physical or non-physical obstacles considered in this study. In the other three locations, some of the prospected caverns interfere with hydrocarbon sources or licenses for exploration and/or extraction thereof. However, considering hydrogen storage may be prioritized in the future, this is not perceived as a rigid constraint and therefore these three locations may also be available for the system.
If the boundary condition of having all caverns in one place would be relaxed, locations with smaller storage capacities could be combined to form a system of sufficient capacity, increasing the number of potential locations.

Sub-question 3: What would be the cost of this storage system and how much would this add to the price of hydrogen?
The financial viability of integrating a salt cavern storage system into an offshore hydrogen production system was evaluated by assessing the related increment to the LCOH. Through estimation of the expenditures related to system construction and operation,the average annual total expenditures were approximated and translated to LCOH.

The results of the cost analysis indicate that the incremental cost of the storage system is minor compared to the costs for the hydrogen production system. An 8.65 TWh salt cavern storage system was estimated to contribute 0.17 €/kg to the LCOH for offshore green hydrogen production. Reducing the storage capacity to 90%, 75% or 50% of the storage capacity would reduce the incremental cost to 0.16 €/kg, 0.13 €/kg or 0.11 €/kg, respectively. Salt caverns are the primary cost driver and the financial viability of the operation could therefore benefit considerably from longer cavern lifetimes and larger cavern volumes. Hence, optimization of the system could decrease the LCOH for the storage system.

Main research question: Under what conditions would it be technically possible and financially feasible to store green hydrogen in salt caverns in the North Sea, to supply baseload green hydrogen to the industry sector?
The results of the technical feasibility analysis indicate that integrating a salt cavern storage system into an offshore hydrogen production system in the Dutch North Sea appears to be technically feasible for multiple sets of boundary conditions. For each of the assessed combination of boundary conditions on cavern design parameters and subsurface conditions, multiple locations were identified where, in theory, clusters of salt caverns of sufficient cumulative storage capacity could be created. Although this advocates for the technical feasibility of the concept, there are still many uncertainties and unknowns about the construction and operation of an offshore salt cavern system of this scale. Consequently, further study is required to confirm the practical viability of this concept.

The costs of the storage system and the corresponding incremental cost to the levelized cost of hydrogen speak in favor of the economic feasibility of integrating a salt cavern storage system into an offshore green hydrogen production system. Implementation of this concept can thus be considered as a realistic option for providing a baseload green hydrogen supply to the industry sector in the future. Optimization of system configuration and operation, as well as increasing maturity of technology, could further reduce the contribution of the storage system to the LCOH. Ultimately, the economic feasibility of this concept will depend on external matters, i.e. the price of alternative ways of providing baseload green hydrogen and the amount of subsidy granted.

Chapter 7

Recommendations

Based on the outcomes of this study and the discussion of the results, a number of recommendations for further research are given in this chapter.

First of all, the storage capacity of the system should be optimized. As part of the technical feasibility analysis, the concept of creating a storage system with less than the minimum required storage capacity in combination with a back-up strategy was explored. The results of the economic analysis and the sensitivity analysis revealed that caverns are the major cost driver and hence a significant yield in financial feasibility could be made by reducing the number of salt caverns. It is therefore recommended to further investigate the feasibility of a storage system with less storage capacity in combination with a strategic reserve.

Furthermore, the results of the sensitivity analysis indicate that increasing the number of caverns results in a larger increase in LCOH than increasing the cavern volume. This implies that costs could be reduced by creating the targeted storage capacity with fewer, but larger caverns. Therefore it is recommended to study the limits to cavern volume to optimize the configuration of the storage capacity.

In addition, A prominent assumption was made about the prospected lifetime of caverns; a depreciation period of 50 years was adopted in cost calculations. Seeing as the sensitivity analysis proves that the depreciation period has considerable effect on the LCOH, it is recommended to investigate if a lifetime of more than 50 years (and thus a depreciation period of more than 50 years) for offshore salt caverns is realistic and if and how it could be extended. Moreover, it would be interesting to specify what happens when a cavern's lifetime is exceeded. Other than from a cost perspective, further analysis of cavern lifetime is of crucial importance since it determines if the system analyzed in this study will be a sustainable solution in the long term. If caverns become unusable at some moment after being used, that means that in the long term the salt cavern storage capacity in the North Sea will run out and this should be considered in the long-term development plan of the system. For the reasons mentioned above, it is recommended to analyze cavern lifetime and to contemplate what happens after cavern lifetime is exceeded. Questions that arise are: Is the cavern decommissioned right at that moment? Does that mean that after the lifetime of the caverns is exceeded, an entirely new storage system must be created? What does that mean for choosing the location for the system? These questions are important to address in light of designing a long-term renewable energy system.

In the cost calculations, assumptions were made regarding system design and configuration. For example, required pipeline length was estimated based on assumptions on platform positioning, cavern field layout and connections between caverns and equipment. For a more accurate indication of these costs the configuration of the system should be developed in more detail. To this end, it is imperative to define the modus operandi of the system. Questions to address are: will all caverns be operated simultaneously or parallel, in clusters? What does this mean for the interconnection between caverns and the configuration of the top side? Also interesting to consider would be the effect different operational strategies would have on cavern lifetime.

Moreover, the results of the cost calculations are subject to many uncertainties due to a lack of historic data. For instance, cavern costs are derived from offshore operations which could in practice be an underestimation. Especially Considering the large contribution to total system costs, it is recommended to investigate the costs for large scale offshore salt cavern construction in more detail.

The results of the sensitivity analysis indicate that the value used for WACC in cost calculations significantly affects the LCOH. For better judgement of the economic feasibility of the concept, it is imperative to increase the accuracy of the value chosen for WACC. Therefore it is recommended to investigate the prospected financial state of affairs of the operation as well as the predictions on price developments, if possible.

Finally, the elephant in the room must be addressed. In this study, the disposal of the brine produced through cavern leaching was neglected. However, one can imagine that the construction of 48 large salt caverns produce enormous amounts of salt which cannot simply be ignored; creating 48 750.000 m3 caverns produces 36 million cubic meters, or about 78 million tons, of salt, all dissolved in brine. As it is deemed unlikely that these quantities of brine can be discarded in sea without disturbing ecosystems, a proper strategy for brine disposal must be established to prevent social and political resistance. In the discussion a number of suggestions were presented for dealing with the brine and it is recommended to study this matter further.

List of Figures

List of Tables

Bibliography

[1] S. Urgenda, “Dagvaarding Urgenda Klimaatzaak 2013,” Dec. 2013. [Online]. Available: https://www.urgenda.nl/wp-content/uploads/DagvaardingUrgendaKlimaatzaak19-11-13.pdf

[2] L. e. I. Ministerie van Economische Zaken, “Climate policy - Climate change - Government.nl,” Feb. 2019. [Online]. Available: https://www.government.nl/topics/climate-change/climate-policy

[3] M. van Economische Zaken en Klimaat, “Klimaatnota 2021,” 2021.

[4] Klimaatakkoord, “Voorjaarsbrief Voortgangsoverleg Klimaatakkoord,” Sep. 2021.

[5] S. van Renssen, “The hydrogen solution?” *Nature Climate Change*, vol. 10, no. 9, pp. 799–801, Sep. 2020. [Online]. Available: https://www.nature.com/articles/s41558-020-0891-0

[6] M. of Economic Affairs and Climate Policy, “Klimaatplan 2021-2030,” Apr. 2020. [Online]. Available: https://www.rijksoverheid.nl/onderwerpen/klimaatverandering/documenten/beleidsnotas/2020/04/24/klimaatplan-2021-2030

[7] W. Zeester, “Naar een toekomstbestendige staalindustrie IJmuiden - Strategisch plan 2020 - 2050,” TATA Steel, Tech. Rep. 201201, Dec. 2020.

[8] U. Bünger, J. Michalski, F. Crotogino, and O. Kruck, “7 - Large-scale underground storage of hydrogen for the grid integration of renewable energy and other applications,” in *Compendium of Hydrogen Energy*, ser. Woodhead Publishing Series in Energy, M. Ball, A. Basile, and T. N. Veziroğlu, Eds. Oxford: Woodhead Publishing, Jan. 2016, pp. 133–163. [Online]. Available: https://www.sciencedirect.com/science/article/pii/B9781782423645000075

[9] C. Hellinga and K. Rodewijk, “Working document H2@NorthSea (Draft 7-11-2021),” Nov. 2021.

[10] “NortH2 | Kickstarting the green hydrogen economy.” [Online]. Available: https://www.north2.eu/

[11] D. Gulcin Caglayan, N. Weber, H. Heinrichs, J. Linben, M. Robinius, P. Kukla, and D. Stolten, “Technical potential of salt caverns for hydrogenstorage in Europe,” *International Journal of Hydrogen Energy*, vol. 45, no. 11, pp. 6793–6805, Feb. 2020. [Online]. Available: https://www.sciencedirect.com/science/article/pii/S0360319919347299

[12] S. Donadei and G.-S. Schneider, “Compressed Air Energy Storage in Underground Formations,” *Storing Energy*, pp. 113–133, Jan. 2016. [Online]. Available: https://www.sciencedirect.com/science/article/pii/B9780128034408000063

[13] D. Evans and R. Chadwick, *Underground Gas Storage - Worldwide Experiences and Future Development in the UK and Europe*. Geological Society of London, 2009. [Online]. Available: https://app.knovel.com/hotlink/toc/id:kpUGSWEFD1/underground-gas-storage/underground-gas-storage

[14] A. Ozarslan, “Large-scale hydrogen energy storage in salt caverns,” *International Journal of Hydrogen Energy*, vol. 37, no. 19, pp. 14 265–14 277, Aug. 2012. [Online]. Available: https://www.sciencedirect.com/science/article/pii/S0360319912017417

[15] P. T. Moseley and J. Garche, *Electrochemical Energy Storage for Renewable Sources and Grid Balancing.* Elsevier, Oct. 2014. [Online]. Available: https://ebookcentral-proquest-com.tudelft.idm.oclc.org/lib/delft/detail.action?docID=1826797

[16] O. Schulze, T. Popp, and H. Kern, “Development of damage and permeability in deforming rock salt,” *Engineering Geology*, vol. 61, no. 2, pp. 163–180, Aug. 2001. [Online]. Available: https://www.sciencedirect.com/science/article/pii/S0013795201000515

[17] J. K. Warren, “Solution Mining and Salt Cavern Usage,” in *Evaporites: A Geological Compendium*, J. K. Warren, Ed. Cham: Springer International Publishing, 2016, pp. 1303–1374. [Online]. Available: https://doi.org/10.1007/978-3-319-13512-0_13

[18] EnergyStock, “Our facility.” [Online]. Available: https://www.energystock.com/about-energystock/our-facility

[19] Cedigaz, “Underground Gas Storage in the World – Part 1: Current capacity,” Jul. 2017. [Online]. Available: https://www.cedigaz.org/underground-gas-storage-world-part-1-current-capacity/

[20] A. M. da Costa, P. V. Costa, A. C. Miranda, M. B. Goulart, O. D. Udebhulu, N. F. Ebecken, and Azevedo, “Experimental salt cavern in offshore ultra-deep water and well design evaluation for CO2 abatement,” *International Journal of Mining Science and Technology*, vol. 29, no. 5, pp. 641–656, Sep. 2019. [Online]. Available: https://www.sciencedirect.com/science/article/pii/S2095268618305822

[21] “Gateway | Stag energy.” [Online]. Available: https://www.stagenergy.com/gateway/

[22] P. V. M. Costa, A. M. Costa, A. Szklo, D. C. Branco, M. Freitas, and L. P. Rosa, “UGS in giant offshore salt caverns to substitute the actual Brazilian NG storage in LNG vessels,” *Journal of Natural Gas Science and Engineering*, vol. 46, pp. 451–476, Oct. 2017. [Online]. Available: https://www.sciencedirect.com/science/article/pii/S1875510017303153

[23] A. M. Costa, P. V. M. Costa, A. C. O. Miranda, N. F. F. Ebecken, K. Nishimoto, J. R. Meneghini, S. M. de Eston, G. de Tomi, F. Ruggeri, C. Brandão, and A. Breda, “Salt Rock: a Strategic Geomaterial in Brazil,” *Polytechnica*, vol. 3, no. 1, pp. 66–77, Dec. 2020. [Online]. Available: https://doi.org/10.1007/s41050-019-00020-3

[24] J. H. S. B. M. Chemicals and D. B. S. message, “Pipeline network,” Jun. 2015. [Online]. Available: https://www.portofrotterdam.com/en/doing-business/logistics/connections/intermodal-transportation/pipeline-network

[25] “Port of Rotterdam steps up hydrogen economy drive,” May 2020. [Online]. Available: https://www.porttechnology.org/news/port-of-rotterdam-steps-up-hydrogen-economy-drive/

[26] CLO, “Energieverbruik per sector, 1990-2019 | Compendium voor de Leefomgeving,” May 2021. [Online]. Available: https://www.clo.nl/indicatoren/nl0052-energieverbruik-per-sector

[27] C. B. voor de Statistiek, “11 procent energieverbruik in 2020 afkomstig uit hernieuwbare bronnen,” May 2021. [Online]. Available: https://www.cbs.nl/nl-nl/nieuws/2021/22/11-procent-energieverbruik-in-2020-afkomstig-uit-hernieuwbare-bronnen

[28] V. Vogl, M. Åhman, and L. J. Nilsson, “Assessment of hydrogen direct reduction for fossil-free steelmaking,” *Journal of Cleaner Production*, vol. 203, pp. 736–745, Dec. 2018. [Online]. Available: https://www.sciencedirect.com/science/article/pii/S0959652618326301

[29] "Alles over aardgas." [Online]. Available: https://www.onsaardgas.nl/alles-over-aardgas/

[30] S. Emeis and M. Turk, "Comparison of Logarithmic Wind Profiles and Power Law Wind Profiles and their Applicability for Offshore Wind Profiles," in *Wind Energy*, J. Peinke, P. Schaumann, and S. Barth, Eds. Berlin, Heidelberg: Springer Berlin Heidelberg, 2007, pp. 61–64. [Online]. Available: http://link.springer.com/10.1007/978-3-540-33866-6_11

[31] "Fundamentals." [Online]. Available: https://www.wind-energy-the-facts.org/fundamentals.html

[32] KNMI, "Power law coefficient for 10-100m and 10-200m | Atlas | Dutch Offshore Wind Atlas." [Online]. Available: https://www.dutchoffshorewindatlas.nl/atlas/image-library/image-library/power-law-coefficient-2

[33] S. Gamesa, "Green hydrogen." [Online]. Available: https://www.siemensgamesa.com/products-and-services/hybrid-and-storage/green-hydrogen

[34] E. Gaertner, J. Rinker, L. Sethuraman, B. Anderson, and G. Barter, "Definition of the IEA Wind 15-Megawatt Offshore Reference Wind Turbine," IEA, Technical report NREL/TP-5000-75698., 2020. [Online]. Available: https://www.nrel.gov/docs/fy20osti/75698.pdf

[35] V. Nguyen Dinh, P. Leahy, E. McKeogh, J. Murphy, and V. Cummins, "Development of a viability assessment model for hydrogen production from dedicated offshore wind farms," *International Journal of Hydrogen Energy*, Jun. 2020. [Online]. Available: https://www.sciencedirect.com/science/article/pii/S0360319920316438

[36] S. Shiva Kumar and V. Himabindu, "Hydrogen production by PEM water electrolysis – A review," *Materials Science for Energy Technologies*, vol. 2, no. 3, pp. 442–454, Dec. 2019. [Online]. Available: https://www.sciencedirect.com/science/article/pii/S2589299119300035

[37] S. Makridis, "Hydrogen storage and compression," Jun. 2016. [Online]. Available: https://arxiv.org/ftp/arxiv/papers/1702/1702.06015.pdf

[38] N. Smith, D. Evans, and I. Andrews, "The geology of gas storage in offshore salt caverns," British Geological Survey, Confidential Report to the Department of Trade and Industry GC05/11, Oct. 2005. [Online]. Available: https://itportal.ogauthority.co.uk/information/papers/BGS_Report1.pdf

[39] L. Lankof and R. Tarkowski, "Assessment of the potential for underground hydrogen storage in bedded salt formation," *International Journal of Hydrogen Energy*, vol. 45, no. 38, pp. 19 479–19 492, Jun. 2020. [Online]. Available: https://www.sciencedirect.com/science/article/pii/S0360319920317523

[40] "Fuels - Higher and Lower Calorific Values." [Online]. Available: https://www.engineeringtoolbox.com/fuels-higher-calorific-values-d_169.html

[41] J. O. Jensen, A. P. Vestbø, Q. Li, and N. J. Bjerrum, "The energy efficiency of onboard hydrogen storage," *Journal of Alloys and Compounds*, vol. 446-447, pp. 723–728, Oct. 2007. [Online]. Available: https://www.sciencedirect.com/science/article/pii/S092583880700864X

[42] M. Reuß, T. Grube, M. Robinius, P. Preuster, P. Wasserscheid, and D. Stolten, "Seasonal storage and alternative carriers: A flexible hydrogen supply chain model," *Applied Energy*, vol. 200, pp. 290–302, Aug. 2017. [Online]. Available: https://www.sciencedirect.com/science/article/pii/S0306261917305457

[43] IRENA, "Future of wind." [Online]. Available: https://www.irena.org/publications/2019/Oct/Future-of-wind

[44] Catapult, "Wind farm costs – Guide to an offshore wind farm." [Online]. Available: https://guidetoanoffshorewindfarm.com/wind-farm-costs

[45] P.-M. Heuser, D. Severin Ryberg, T. Grube, M. Robinius, and D. Stolten, "Techno-economic analysis of a potential energy trading link between Patagonia and Japan based on CO2 free hydrogen," *International journal o f hydrogen energy*, vol. 44, pp. 12 733–12 747, 2019. [Online]. Available: https://www.e-bridge.de/wp-content/uploads/2021/05/Heuser-et-al._Techno-economic-analysis-of-a-potential-energy-trading-link-between-Patagonia-and-Japan-based-on-CO2 pdf

[46] R. Tarkowski, "Underground hydrogen storage: Characteristics and prospects," *Renewable and Sustainable Energy Reviews*, vol. 105, pp. 86–94, May 2019. [Online]. Available: https://www.sciencedirect.com/science/article/pii/S1364032119300528

[47] M. Reuß, L. Welder, J. Thürauf, J. Linßen, T. Grube, L. Schewe, M. Schmidt, D. Stolten, and M. Robinius, "Modeling hydrogen networks for future energy systems: A comparison of linear and nonlinear approaches," *International Journal of Hydrogen Energy*, vol. 44, no. 60, pp. 32 136–32 150, Dec. 2019. [Online]. Available: https://www.sciencedirect.com/science/article/pii/S0360319919338625

[48] J. Mischner, H. Fasold, and J. Heymer, "Gas2energy. net: Systemplanerische grundlagen der gasversorgung inkl. ebook." Deutscher Energie Verslag, 2013.

[49] R. Roobeek, "Shipping Sunshine A techno-economic analysis of a dedicated green hydrogen supply chain from the Port of Sohar (Oman) to the Port of Rotterdam (The Netherlands)," Ph.D. dissertation, Delft University of Technology, Apr. 2020.

[50] A. Van Wijk and C. Hellinga, "Hydrogen - The key to the energy transition," May 2018. [Online]. Available: https://d2k0ddhflgrk1i.cloudfront.net/Websections/Energy_Initiative/Hydrogen%40Sea/Technical%20Report%20Hydrogen%20-%20the%20key%20to%20the%20energy%20transition.pdf

[51] M. Illingworth, "E-mail correspondence," Dec. 2021.

[52] "Cyclone | EMIS." [Online]. Available: https://emis.vito.be/en/bat/tools-overview/sheets/cyclone

[53] D. Ferrero, M. Gamba, A. Lanzini, and M. Santarelli, "Power-to-Gas Hydrogen: Techno-economic Assessment of Processes towards a Multi-purpose Energy Carrier," *Energy Procedia*, no. 101, pp. 50–57, Nov. 2016.

[54] K. Mongird, V. Viswanathan, J. Alam, C. Vartanian, and V. Sprenkle, "2020 Grid Energy Storage Technology Cost and Performance Assessment," Pacific Northwest National Laboratory, Technical Report DOE/PA-0204, Dec. 2020. [Online]. Available: https://www.pnnl.gov/sites/default/files/media/file/CAES_Methodology.pdf

[55] M. L. Harper, "Approximate Geothermal Gradients in the North Sea Basin," *Nature*, vol. 230, no. 5291, pp. 235–236, Mar. 1971. [Online]. Available: https://www.nature.com/articles/230235a0

Appendix A

Shell storage capacity calculator

This appendix presents an explanation of the software used for determining the salt cavern storage potential of the Dutch North Sea, as well as a rationale for decisions made regarding the input values for the Shell capacity calculator. Three sets of input values were used for the analysis, of which the first two are based on information found in literature, while the third one is a combination of these two and aimed at decreasing the costs of the system. The first five input parameters are the same for each input set and are described below.

Onshore / N-W Europe
First of all, the software gives the option to select either the Netherlands or the entire North-West Europe. In order to get results for the North Sea, the latter is selected.

Geothermal gradient
By default, the geothermal gradient is set to 25°C/km since this is the value assumed by the reference paper [11]. Harper [55] reports an average geothermal gradient of 29.7 °C/km for the entire North sea basin, hence 25°C/km is regarded a reasonable approximation.

Overburden density
The software's default overburden density is 2300 kg/m3, which seems slightly low considering the density of sandstone is more towards 2650 kg/m3. In a paper by [14] calculations are also performed with an overburden density of 2300 kg/m3. Since no better value was found, this value will also be used in this analysis.

H2 heating value
For the heating value of hydrogen, the higher heating value (HHV) is used. The HHV of hydrogen is 141.8 MJ/kg.

Surface Temperature
A surface temperature of 288 K or 15°C is assumed by Caglayan et al [11] in their study, and considering the software is based on this paper this value will be attained.

Safety factor
A safety factor is incorporated to account for the "loss of storage capacity to the sump and brine at the bottom of the cavern, as well as unplanned construction circumstances during the leaching of the cavern" by [11]. In their paper a safety factor of 70% is used, hence a value of 0.7 is used in the software.

Cavern spacing
The spacing between caverns is taken as 4 times the cavern diameter, as is done in the study by Caglayan et al [11].

Apart from these parameters that were assumed the same for each scenario, the software asks for five more parameters. These input parameters are what distinguishes the three input sets. Below, the decisions for these input parameters are described per input set.

INPUT SET 1: optimistic scenario, based on [11]

Minimum salt thickness above and below cavern
For stability an intact layer of salt is desired below and especially above the cavern to prevent collapse of the roof. As stated in [11], the minimum thickness of the hanging wall and foot wall should be at least 75% and 25% of the cavern diameter, respectively, to ensure geomechanical safety. In their paper, Caglayan et al discuss two cavern sizes; one 500.000 m3, 120 m height and 84 diameter one and one 750.000 m3, 300 m height and 58 m diameter one. If we take the min. salt thickness as 75% of the largest cavern diameter we would get 63 m. Hence this value will be used in input set 1.

Cavern D/H ratio
To ensure geomechanical safety, a minimum diameter-to-height ratio of 0.5 is assumed for bedded salt deposits [11]. Since this is the limiting factor (out of bedded deposits and structures) this is the value that will be used to ensure safe operation under all conditions.
Operating pressure range
to ensure stability and geotechnical safety, the operating pressure inside the caverns should be kept between certain fractions of the overburden pressure. According to [11], operating pressures should be kept between 20% and 84% to safeguard stability and geomechanical safety. Hence, these limits will be applied in this scenario.

Cavern height range
The cavern height range can be varied from 100 to 500 m. Caglayan et al assumes for bedded salt deposits caverns of 500.000 m3 with a height of 120 m, and for salt diapirs 750.000 m caverns with a height of 300 m are assumed. Hence the range for this input set will be 120 to 300 m.

Cavern depth range
In the software, the depth range can be varied from 0 to 3000 meter. Seeing as the storage capacity depends on overburden pressure, which in turn depends on burial depth, a certain minimum depth is required to allow for the desired allowed pressure range within the salt caverns. With increasing depth, the (construction) costs increase which limits the maximum burial depth. [11] use a depth range of 500-2000 in their analysis, as will be done for input set 1.

INPUT SET 2: Conservative scenario, based on [39] and [14]

Min. salt thickness above and below cavern
In the study by Lankof [39], a minimum salt thickness above and below the cavern of 65 meter is assumed. Since this set of input parameters is based on this study, this value is adopted in input set 2.

Cavern D/H ratio
In [39] the diameter to height ratio is not given as a fraction, but for a cavern with height 150 m a maximum diameter of 60 m is used. for that reason the fraction for this input set is taken as $60/150 = 0.4$.

Operating pressure range
The operating pressure is not given as a percentage in [39]. Since all other parameters of scenario 2 are more conservative than in scenario 1, it was decided to also use a more conservative operating

pressure range. [14] uses a pressure range of 30-70% of overburden pressure, and this range will be used for this scenario.

Cavern height range
A cavern height range of 85-278.5 is used in [39] and is therefore adopted in this input set.

Cavern depth range
A depth range of up to 1800 is considered in [39]. No minimum depth is mentioned. Therefore a depth range of 0-1800 m is adopted in input set 2.

Input set 3: restricted depth range to benefit financial viability

Min. salt thickness above and below cavern
The minimum salt thickness of 65 m used in input set 2 will be applied for safety reasons.

Cavern D/H ratio
Like the previous input parameter, the diameter to height ratio is obtained from input set 2 for safety.

Operating pressure range
In this input set, the operating pressure range is based on the study by Caglayan et al[11], which is the more optimistic approach. Hence, in input set 3 we apply an operating pressure range of between 24% and 80% of overburden pressure.

Cavern height range The allowed cavern height in this input set is 100 to 350 m, a slightly broader range than is done in the study by Caglayan et al[11] to allow for more storage capacity in the more restricted depth range.
Cavern depth range For economic reasons, the depth range is restricted to 1000 to 1500 m.

After entering the input values and obtaining the storage capacities of the salt formations, the availability of the salt bodies is assessed by plotting existing structures and hinders on the map. The software can plot existing and planned wind parks, hydrocarbon sources, platforms, et cetera. after plotting it can be seen what formations can be used, and their storage capacity can be checked to see if they could hold enough capacity for our system.

Appendix B

Eligibility analysis of data set used for calculations

To assess the suitability of the data set that is used for calculations, the wind speed distribution as well as a number of other characteristics are determined. These are compared to the other data sets and to predictions on wind conditions published by KNMI, and based on the similarities and/or discrepancies the eligibility of the data set to be used are verified. All calculations are performed through a MATLAB script written for this purpose.

After removal of outliers caused by NaN values in the data, the wind speed measurement distributions were plotted for each weather station and a Weibull fit was performed. figure B.1, figure B.2 and figure B.3 show the wind speed distribution and corresponding Weibull curve for the measurements from weather station D15-FA-1, F16-A and J6-A, respectively.

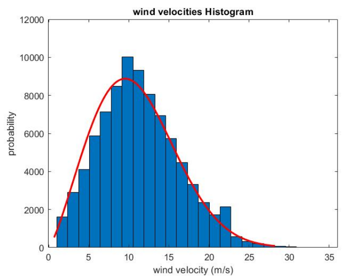


Figure B.1: Wind speed distribution weather station D15-FA-1

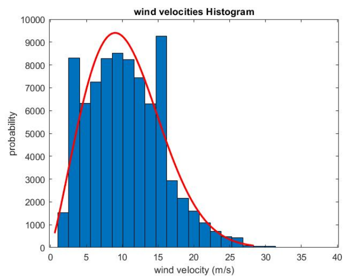


Figure B.2: Wind speed distribution weather station F16-A

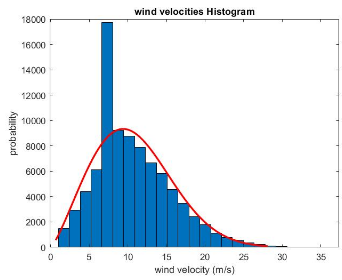


Figure B.3: Wind speed distribution weather station J6-A

The Weibull parameters, i.e. shape parameter k and scale parameter a, were determined for each data set, as well as the minimum, maximum and average wind speed. Then the wind speed measurements, measured at 10 m elevation, are converted to wind speed at turbine hub height (see section 2.2.2) since the latter governs the wind energy production. The weibull parameters and mean, maximum and minimum wind speed were determined again for the wind speeds at hub height. The results of the analysis were compared to the long term average values for these parameters as published by KNMI. Table B.1 shows the results of the analysis both for wind speed measurements at reference height and for converted wind speeds at hub height.

Relevant to characterize is the worst case scenario in terms of wind conditions; the system should ultimately be able to supply sufficient hydrogen even in the poorest circumstances. The poor wind conditions that are assessed are periods where the wind speed is below a certain 'critical' wind speed. The critical wind speed is chosen to be 4 m/s, which is typically the cut-in wind speed for offshore wind turbines. First of all, the longest consecutive period where the 10 minute average

	D15-FA-1	**F16-A**	**J6-A**	**long term average**
Mean wind speed (10 m)	8.14 [m/s]	7.89 [m/s]	8.05 [m/s]	8-8.5 [m/s]
Mean wind speed (150 m)	10.90 [m/s]	10.56 [m/s]	10.78 [m/s]	10.0-10.8
Shape parameter k (10 m)	2.27	2.18	2.25	2.1-2.3
Shape parameter k (150 m)	12.3	11.92	12.18	11.2-12.0
Scale parameter a (10 m)	2.27	2.18	2.26	2.1-2.3
Scale parameter k (150 m)	9.19	8.91	9.10	9-9.5

Table B.1: Average wind speed and Weibull scale and shape parameters for wind speeds at reference height (10 m elevation) and wind turbine hub height (15 m elevation) for data from weather stations D15-FA-1, F16-A and J6-A. The last column shows the long term average values for these parameters as published by KNMI for verification

wind speed is below the critical wind speed was determined. In addition, the longest consecutive periods where the average wind speed over 12 and 24 hours was assessed. In this way the poor wind conditions the system could encounter and have to be able to withstand can be pinpointed, and it be established if the data sets show similar patterns in this respect, revealing whether the result is representative. Table B.2 shows the wind conditions that were analyzed with for each data set the outcomes of the analysis as well as the mean value and standard deviation.

	D15-FA-1	**F16-A**	**J6-A**	**Mean**	**Std. dev.**
Longest consecutive period where hourly 10 min. average is below critical wind speed [hr]	44	34	42	40	5.29
Longest consecutive period where 12 hr average is below critical wind speed [hr]	104	106	76	95.33	16.77
Longest consecutive period where 24 hr average is below critical wind speed [hr]	105	109	86	101.33	13.28

Table B.2: Analysis of wind speed data (hourly 10 minute averages) measured at KNMI weather stations D15-FA-1, F16-A and J6-A from 2011 to 2020

Appendix C

Top side cost estimation

Estimating Summary - Topside only

CLIENT : TU Delft
PROJECT NO :
PROJECT TITLE : Offshore Hydrogen Storage - incl. export compression
UNIT NAME : Topsides
SUBJECT : Feasibility Estimate
LOCATION : North Sea
CAPACITY :
ACCURACY : +/- 50%

ALL COSTS EUR x 1,000
All Contingencies Excluded

PRINT DATE : 16-dec-21
ISSUE DATE : Dec 2021
FILENAME : H2 Compressor TS FE v1.
CURRENCY : EUR x 1,000
ORIGINATOR : CMI
REVISION : 1
Exchange Rate Used EUR 1.00 = USD 1,12

RESPONSIBILITIES	DESCRIPTION SUMMARY SHEET	% or Wgt	GROSS WEIGHTS - TE EQUIP.	STRUCT STEEL	BULKS	SYSTEM TE	CONSTR'N HOURS	SUBCON COSTS	LABOUR	MAT'LS	BASE COST	CONT'CY %	TOTAL COST	Remarks
	Topside Equipment	22.8%	2.495			2.495				161.000	161.000		161.000	
	Topside Structural steel	49.5%		5.414		5.414	676.800		30.500	9.700	40.200		40.200	
	Architectural	1.4%			150	150	30.000		1.400	1.500	2.900		2.900	
	Piping	18.7%			2.046	2.046	675.200		30.400	28.600	59.000		59.000	
	HVAC	0.1%			12	12	2.500		100	100	200		200	
	Electrical	2.3%			250	250	147.300		6.600	4.700	11.300		11.300	
	Instruments & Controls	3.4%			374	374	228.300		10.300	15.000	25.300		25.300	
	Insulation/paint	0.5%			55	55	87.900		4.000	300	4.300		4.300	
	Safety	0.5%			50	50	30.500		1.400	2.000	3.400		3.400	
	Miscellaneous Systems													
	Transformer / Switchgear													
	Module Transportation to Hull Integration Yard								2.900		2.900		2.900	
	Topside integration						219.000		9.900		9.900		9.900	
20	Dockside Pre-Commissioning Topside						59.900		2.700		2.700		2.700	
people	FPSO Hull													
10 ea	Living Quarter					100	20.000		900	1.000	1.900		1.900	
	Utilities													
	Storage Tanks													
	LNG/LPG Offloading system													
	Turret & Mooring System													
	Transport & Installation to Site								8.700		8.700		8.700	
	Pipelines													
	SUB-TOTAL	99%	2.495	5.414	2.937	10.946	2.177.400		109.800	223.900	333.700		333.700	
	CONCEPT / BASIC ENG & FEED	3%							14.000		14.000		14.000	
	TOPSIDE ENGINEERING	20%							66.700		66.700		66.700	
	CONSTRUCTION MANAGEMENT	10%							33.400		33.400		33.400	
	CERTIFICATION	1.5%								5.000	5.000		5.000	
	START UP & COMMISSIONING SPARES	1.5%								2.400	2.400		2.400	
	VENDORS REPS	2.5%							4.000		4.000		4.000	
	MAT'L TRANSPORT TO YARD	8%								17.900	17.900		17.900	
	LINCENSE FEE									3.000	3.000		3.000	
	COMMISSIONING & HOOK UP													
	SUB-TOTAL								118.100	28.300	146.400		146.400	
	GRAND TOTAL								227.900	252.200	480.100		480.100	EUR x 1,000

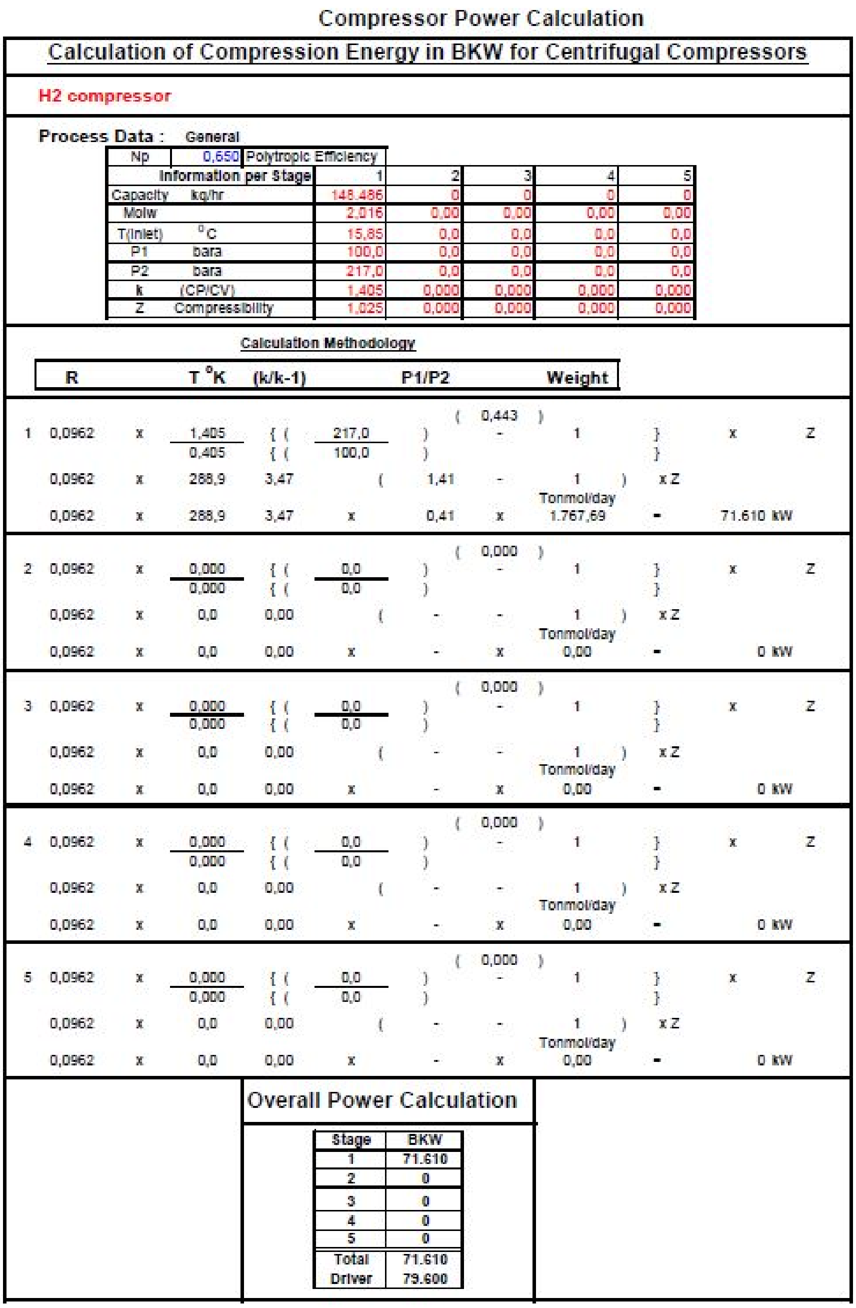
Note: *Based for Fabrication Yards & Integration Yard : South East Asia Labor Rate (EUR/hr) 45*

Prepared by: CMI Date: Dec 2021
Reviewed by: CMI Date: Dec 2021
Approved by: Date: Dec 2021

Figure C.1: Estimation of costs for top side of the operation, including platform, top side equipment and personnel

Appendix D

Compressor capacity estimation



Compressor Power Calculation

Calculation of Compression Energy in BKW for Centrifugal Compressors

H2 compressor

Process Data : General

Np	0,650	Polytropic Efficiency				
Information per Stage			1	2	3	4	5
Capacity	kg/hr		148.486	0	0	0	0
Molw			2,016	0,00	0,00	0,00	0,00
T(Inlet)	°C		15,85	0,0	0,0	0,0	0,0
P1	bara		100,0	0,0	0,0	0,0	0,0
P2	bara		217,0	0,0	0,0	0,0	0,0
k	(CP/CV)		1,405	0,000	0,000	0,000	0,000
Z	Compressibility		1,025	0,000	0,000	0,000	0,000

Calculation Methodology

R T °K (k/k-1) P1/P2 Weight

1 0,0962 x 1,405 / 0,405 { (217,0 / 100,0) (0,443) - 1 } x Z
0,0962 x 288,9 3,47 (1,41 - 1) x Z
0,0962 x 288,9 3,47 x 0,41 x Tonmol/day 1.767,69 = 71.610 kW

2 0,0962 x 0,000 / 0,000 { (0,0 / 0,0) (0,000) - 1 } x Z
0,0962 x 0,0 0,00 (- - 1) x Z
0,0962 x 0,0 0,00 x - x Tonmol/day 0,00 = 0 kW

3 0,0962 x 0,000 / 0,000 { (0,0 / 0,0) (0,000) - 1 } x Z
0,0962 x 0,0 0,00 (- - 1) x Z
0,0962 x 0,0 0,00 x - x Tonmol/day 0,00 = 0 kW

4 0,0962 x 0,000 / 0,000 { (0,0 / 0,0) (0,000) - 1 } x Z
0,0962 x 0,0 0,00 (- - 1) x Z
0,0962 x 0,0 0,00 x - x Tonmol/day 0,00 = 0 kW

5 0,0962 x 0,000 / 0,000 { (0,0 / 0,0) (0,000) - 1 } x Z
0,0962 x 0,0 0,00 (- - 1) x Z
0,0962 x 0,0 0,00 x - x Tonmol/day 0,00 = 0 kW

Overall Power Calculation

Stage	BKW
1	71.610
2	0
3	0
4	0
5	0
Total	71.610
Driver	79.600

Figure D.1: Compression capacity required for compression from 100 bar to 217 bar, assuming a one stage compressor

Compressor Power Calculation

Calculation of Compression Energy in BKW for Centrifugal Compressors

H2 compressor

Process Data : General

Np	0,650	Polytropic Efficiency

Information per Stage		1	2	3	4	5
Capacity	kg/hr	148.486	148.486	0	0	0
Molw		2,016	2,016	0,00	0,00	0,00
T(Inlet)	°C	15,85	15,85	0,0	0,0	0,0
P1	bara	100,0	160,0	0,0	0,0	0,0
P2	bara	160,0	217,0	0,0	0,0	0,0
k	(CP/CV)	1,405	1,405	0,000	0,000	0,000
Z	Compressibility	1,025	1,025	0,000	0,000	0,000

Calculation Methodology

R	T °K	(k/k-1)	P1/P2	Weight

1 0,0962 x 1,405/0,405 { (160,0/100,0) (0,443) - 1 } x Z
0,0962 x 288,9 3,47 (1,23 - 1) x Z
0,0962 x 288,9 3,47 x 0,23 x 1.767,69 Tonmol/day = 40.480 kW

2 0,0962 x 1,405/0,405 { (217,0/160,0) (0,443) - 1 } x Z
0,0962 x 288,9 3,47 (1,14 - 1) x Z
0,0962 x 288,9 3,47 x 0,14 x 1.767,69 Tonmol/day = 25.270 kW

3 0,0962 x 0,000/0,000 { (0,0/0,0) (0,000) - 1 } x Z
0,0962 x 0,0 0,00 (- - 1) x Z
0,0962 x 0,0 0,00 x - x 0,00 Tonmol/day = 0 kW

4 0,0962 x 0,000/0,000 { (0,0/0,0) (0,000) - 1 } x Z
0,0962 x 0,0 0,00 (- - 1) x Z
0,0962 x 0,0 0,00 x - x 0,00 Tonmol/day = 0 kW

5 0,0962 x 0,000/0,000 { (0,0/0,0) (0,000) - 1 } x Z
0,0962 x 0,0 0,00 (- - 1) x Z
0,0962 x 0,0 0,00 x - x 0,00 Tonmol/day = 0 kW

Overall Power Calculation

Stage	BKW
1	40.480
2	25.270
3	0
4	0
5	0
Total	65.750
Driver	73.100

Figure D.2: Compression capacity required for compression from 100 bar to 217 bar, assuming a two stage compressor

Compressor Power Calculation

Calculation of Compression Energy in BKW for Centrifugal Compressors

H2 compressor

Process Data : General

Np	0,650	Polytropic Efficiency

Information per Stage		1	2	3	4	5
Capacity	kg/hr	148.486	148.486	148.486	0	0
Molw		2,016	2,016	2,016	0,00	0,00
T(Inlet)	^{0}C	15,85	15,85	15,85	0,0	0,0
P1	bara	100,0	135,0	165,0	0,0	0,0
P2	bara	135,0	165,0	217,0	0,0	0,0
k	(CP/CV)	1,405	1,405	1,405	0,000	0,000
Z	Compressibility	1,025	1,025	1,025	0,000	0,000

Calculation Methodology

R	T ^{o}K	(k/k-1)	P1/P2	Weight

						(0,443)					
1	0,0962	x	1,405 / 0,405	{ ({ (	135,0 / 100,0	))	-	1	} }	x	Z
	0,0962	x	288,9	3,47	(	1,14	-	1)	x Z		
								Tonmol/day			
	0,0962	x	288,9	3,47	x	0,14	x	1.767,69	=	24.860 kW	
						(0,443)					
2	0,0962	x	1,405 / 0,405	{ ({ (	165,0 / 135,0	))	-	1	} }	x	Z
	0,0962	x	288,9	3,47	(	1,09	-	1)	x Z		
								Tonmol/day			
	0,0962	x	288,9	3,47	x	0,09	x	1.767,69	=	16.260 kW	
						(0,443)					
3	0,0962	x	1,405 / 0,405	{ ({ (	217,0 / 165,0	))	-	1	} }	x	Z
	0,0962	x	288,9	3,47	(	1,13	-	1)	x Z		
								Tonmol/day			
	0,0962	x	288,9	3,47	x	0,13	x	1.767,69	=	22.560 kW	
						(0,000)					
4	0,0962	x	0,000 / 0,000	{ ({ (	0,0 / 0,0	))	-	1	} }	x	Z
	0,0962	x	0,0	0,00	(	-	-	1)	x Z		
								Tonmol/day			
	0,0962	x	0,0	0,00	x	-	x	0,00	=	0 kW	
						(0,000)					
5	0,0962	x	0,000 / 0,000	{ ({ (	0,0 / 0,0	))	-	1	} }	x	Z
	0,0962	x	0,0	0,00	(	-	-	1)	x Z		
								Tonmol/day			
	0,0962	x	0,0	0,00	x	-	x	0,00	=	0 kW	

Overall Power Calculation

Stage	BKW
1	24.860
2	16.260
3	22.560
4	0
5	0
Total	63.680
Driver	70.800

Figure D.3: Compression capacity required for compression from 100 bar to 217 bar, assuming a three stage compressor

Appendix E

Input values for cost calculations

GENERAL			
	WACC	6,0%	%
	Wind Capacity	19,8	GW
	Capacity factor	60%	%
	Annual H2 production	2,41E+09	kg
	FLH	4800	h/year
	Annual storage throughput	26%	%
	HHV	141,80	MJ/kg
	HHV	39,41	kwh/kg
	γ	1,41	
	R	8,314	J/(K*mol)
	MH2	2,016	g/mol
	Owners costs	15%	%
	contingency	30%	%
SALT CAVERNS			
	Capacity	750.000	m3
	invest compare	500.000	m3
	invest base	81	M€
	invest scale	0,28	[-]
	n	50	years
	OM	4%	% of capex
PIPELINE			
	diameter	36	inch
	Material and installation	67,57	k€/"km
	n	40	years
	OM	4%	% of capex
TOP SIDE			
	Investment cost	480	M€
	n	30	years
	OM	4%	% of capex

Figure E.1: Input parameters used in cost calculations