Offshore Underground Hydrogen Storage in Support of Offshore Green Hydrogen Production

Case study: Depleted Gas Reservoir in Dutch North Sea

A Techno-Economic Analysis

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PREFACE

This thesis marks the completion of my journey as a Mechanical Engineering Bachelor student and subsequently, a MSc student in Sustainable Energy Technology at TU Delft. It has taken me eight years to reach this point, a journey filled with its fair share of challenges and setbacks. Nevertheless, I am incredibly proud of my achievement, particularly in contributing to research that informs policymakers on the feasibility of an important aspect of the future energy system.

During my time at Delft, I have learned an immense amount about technology. I arrived as a naive young student with little understanding of the field I had chosen, but my decision has ultimately proven to be the right one. This research has also provided many answers to the question of whether a technical direction is right for me. Realizing the energy transition and encouraging oil giants to adapt requires young talents to join organizations like Shell and institutions such as TU Delft. The tide can still be turned, and I have thoroughly enjoyed working on my research, knowing that it can make a significant impact.

I would like to express my sincere thanks to Hadi Hajibeygi for agreeing to be my head supervisor and for making it possible for me to conduct this research on underground hydrogen storage. Your endless support and kindness during my thesis made it much more bearable to withstand setbacks and to gain strength again. I am also grateful to Thijs Vlugt and Ad van Wijk for joining my thesis committee.

Several individuals provided exceptional guidance throughout my research. First, I would like to thank Mark Looijer for his outstanding mentorship, critical questions, and collaborative thinking on various concepts. Additionally, I am thankful to Sally Easton and Arjen van Benthem, who were always ready to explain complex issues when I was lost in the intricacies of the research. Karin de Borst, thank you for the opportunity to conduct my research at Shell; it was an honor to be part of the hydrogen storage team.

My gratitude extends to Ramona Nicolau and Stas Lundiak for their assistance with well performance questions and conducting simulations crucial to my research. I am also indebted to Sarah Hopkin, Huub Hillen, and Robert Timmerman for their help with hydrogen transport issues.

Finally, I want to thank the team at NAM: Harald Kingma, Esther Vermolen, and Ella van der Veer, for providing essential information about NAM's assets.

This thesis represents the final step in my journey as an MSc student, and I am thrilled to finally become an engineer.

Joost K.J. Westerhout
Delft, Juli 2024

EXECUTIVE SUMMARY

This study investigates the technical feasibility and economic viability of utilizing depleted offshore gas reservoirs in the Dutch North Sea for underground hydrogen storage (UHS) to buffer intermittent hydrogen production from offshore wind farms in the Dutch North Sea. The research aims to address the existing knowledge gap in integrating an offshore hydrogen storage platform while considering the maximum re-useability of existing natural gas infrastructure.

The study demonstrates that utilizing a depleted offshore gas reservoir for hydrogen storage presents significant technical and economic challenges. Although technically feasible under certain conditions, the high capital (CAPEX) and operational (OPEX) expenditures, mainly due to the isolated location and platform costs, hinder economic viability. The Levelized Cost of Hydrogen Storage (LCOHS) for hydrogen produced at wind area 7 (WA7) is \$3.6-\$3.8 per kilogram for offshore hydrogen storage in depleted gas reservoirs, considering an implementation time of 5 years between FID and start of operations. The LCOHS is \$4.6 per kilogram for offshore salt caverns, compared to an estimated \$3.0 per kilogram for onshore salt caverns. As 25% of the hydrogen produced at WA7 needs to be stored to generate a constant supply, the cost for offshore storage adds \$0.9-\$1.2 to the Levelized Cost of Hydrogen (LCOH) for the hydrogen produced at WA7, while onshore storage adds ~\$0.7-\$0.8/kg. These cost estimates highlight that storage costs are a significant component of the total hydrogen production cost, emphasizing the economic challenges of offshore UHS technology.

Key findings indicate that reusing NAM's offshore assets for the offshore hydrogen backbone holds potential, particularly for pipeline reuse. However, the proposed reservoir is unsuitable for UHS, and the existing natural gas platform is inadequate for housing UHS installations. The proposed offshore UHS platform is in the range of the biggest oil and gas platforms globally. Key design parameters for an offshore gas reservoir hydrogen storage platform include the size and weight of tail gas compressors, injection compressors, and PSA installations. Addressing fluctuation issues is critical, especially for efficient PSA operations and remains a challenge.

It was found that a depleted gas reservoir can potentially be used for UHS if the reservoir has a transmissivity >2,500 mDm, to obtain well withdraw rates of 5 million Nm^3/day. Drilling 9 5/8" wells in the Dutch North Sea, is found to be a serious challenge, due to the Zechstein layer and the corresponding need for extra strong casing. The integration of

purification systems and the management of tail gas remain to be significant challenges. Offshore UHS in depleted gas reservoirs with a PSA is only feasible if a significant portion of the tail gas of the PSA is re-injected in the reservoir using a dedicated tail gas well, as no other destination for the side stream has been identified besides blending hydrogen into natural gas for the blue hydrogen plant in Den Helder.

Other alternatives, such as utilizing an ultra-depleted gas reservoir for UHS to avoid purification or processing purification onshore, faces significant challenges. The former increases the need for cushion gas, while the latter approach complicates buffering offshore pipelines, potentially leading to fatigue crack growth. Onshore purification complicates buffering offshore pipelines, potentially leading to fatigue crack growth. A possible mitigation strategy involves pipeline packing for small fluctuations, using salt caverns for moderate fluctuations, and the depleted gas field for large fluctuations, thereby stabilizing PSA inflow operations. This further complicates the economic and technical viability of this storage method.

The impact of platform size on feasibility is particularly critical. The Pressure Swing Adsorption (PSA) system, the utility that purifies the contaminated hydrogen produced from the reservoir, is designed for constant flow, while it faces hourly fluctuations in UHS operations, leading to inefficiencies and operational issues. Additionally, the tail gas compressor, which needs to handle an inflow rate of approximately 4 million Nm^3/day and a compression ratio of 230, requires a deck space of 14,000 m^2. Given that the size of a deck space is around 4,000 m^2, this results in an impractically large footprint for offshore installation. The required platform size and weight, exceeding 27,000 m^2 and 30,000 tons, respectively, make the UHS platform one of the largest offshore platforms globally, significantly increasing costs and logistical challenges.

Despite these challenges, the research provides new insights, highlighting that building an offshore platform equipped with purification utilities and compressors is fraught with cost and logistical issues. The feasibility of this approach is less favorable compared to salt cavern or nearshore solutions, which have fewer technical uncertainties and lower associated costs. Moreover, the technical complexity of constructing such a platform is unprecedented, with additional issues such as safety, accessibility, and environmental impact further complicating the design process.

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NOMENCLATURE

Abbreviation	**Definition**
Am^3	Actual cubic meters
AQS	AquaSector Consortium
Bar(g)	Gauge Pressure
Bara	Absolute Pressure
BCM	Billion Cubic Meters
BH	Blue Hydrogen
BOP	Balance of Plant
CAPEX	capital expenditures
CCET	Capex Cost Estimation Tool
CCS	Carbon Capture and Storage
CM	Compression Module
CS	Carbon Steel
DG	Decision Gate
EZK	Dutch Ministry of Economic Affairs and Climate Policy
FCG	Fatigue Crack Growth
FID	Final Investment Decision
FID	Final Investment Decision
GHG	Greenhouse Gas
GW	Gigawatt
GWP	Global Warming Potential
HHV	Higher Heating Value
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
LCOGH	Levelized Cost of Green Hydrogen
LCOH	Levelized Cost of Hydrogen

LCOHS	Levelized Cost of Hydrogen Storage
LHV	Lower Heating Value
LOHC	Liquid Organic Hydrogen Carrier
MAOP	Maximum Allowable Operating Pressure
Mln	Million
MSF	Multistage Flash
MWh	Mega Watthours (10^6 Wh)
NA	Not Available / Not Applicable
NAM	Nederlandse Aardolie Maatschappij B.V.
NG	Natural Gas (CH_4)
NGT	Noordgastransport (pipeline)
Nm^3	Normal cubic meters (T = 0 °C & p = 1 bar(g) (atmospheric))
OD	Outer Diameter
OPEX	Operational expenditures
P2G	Power-to-Gas
PFCA	Pipeline Flow Capacity Assessment
PO	Partial Oxidation
PSA	Pressure Swing Adsorption
REE	Rotating Equipment Engineer
RFSU	Ready for start up
RO	Reverse Osmosis
SBC	System Boundary Conditions
Sm^3	Standard cubic meters (T = 15 °C & p = 1 bar(g))
SMR	Steam Methane Reforming
TNO	Dutch Organisation for Applied Scientific Research
TWh	Terra Watthour (10^9 Wh)
UGS	Underground Gas Storage

UHS	Underground Hydrogen Storage
UHSP	Underground Hydrogen Storage in Porous Reservoirs
WA7	Wind Area 7

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1 INTRODUCTION

It is expected that hydrogen will be an important feedstock in Dutch energy system according to the expert team of "Energy System NL 2050" [2]. At the request of the Dutch Cabinet, the Energy System 2050 expert team considered the issue of what the new energy system of the Netherlands and the path toward it will look like. According to their report, between 10 to 15% of the energy demand of the Netherlands should come from hydrogen in 2050. This is a minimum requirement to obtain flexibility in the Dutch energy system.

With the presence of abundant wind in the North Sea, green hydrogen can be produced in a sustainable manner using renewable electricity generated by offshore wind farms combined with offshore electrolysis system. Green hydrogen refers to hydrogen produced with renewable energy, where electrolysis is used to split H_2O into O_2 and H_2. This method ensures that no carbon is emitted, unlike other methods of producing hydrogen, such as steam methane reforming (SMR) or partial oxidation (PO), which result in carbon as a by-product. For green hydrogen production through electrolysis, the only by-product is oxygen (O_2).

Another significant benefit of hydrogen is its versatility across various industries. Climate experts emphasize that achieving climate neutrality hinges on green hydrogen. It features in each of the eight net-zero emissions scenarios for 2050 presented by the European Commission [3]. While the outlook for green hydrogen appears promising, there are still many uncertainties regarding the transformation of the current energy system into a robust, sustainable one that complies with the Paris Agreement of 2050.

Theoretically, green hydrogen can accomplish three things: store excess renewable energy when the grid is unable to handle it, assist in decarbonizing hard-to-electrify industries such as heavy industry and long-distance transportation, and replace fossil fuels as a zero-carbon feedstock in the manufacture of chemicals and fuels [4]. These advantages suggest that incorporating green hydrogen into the future energy system is a straightforward solution to tackle global warming. However, the intermittency of renewable energy sources like solar and wind leads to fluctuating energy production and, consequently, fluctuating production of green hydrogen. This results in a mismatch between demand and supply, generating periods where there can be either a surplus of hydrogen or a deficit in supply. Hydrogen can play a crucial role in stabilizing these fluctuations in energy production.

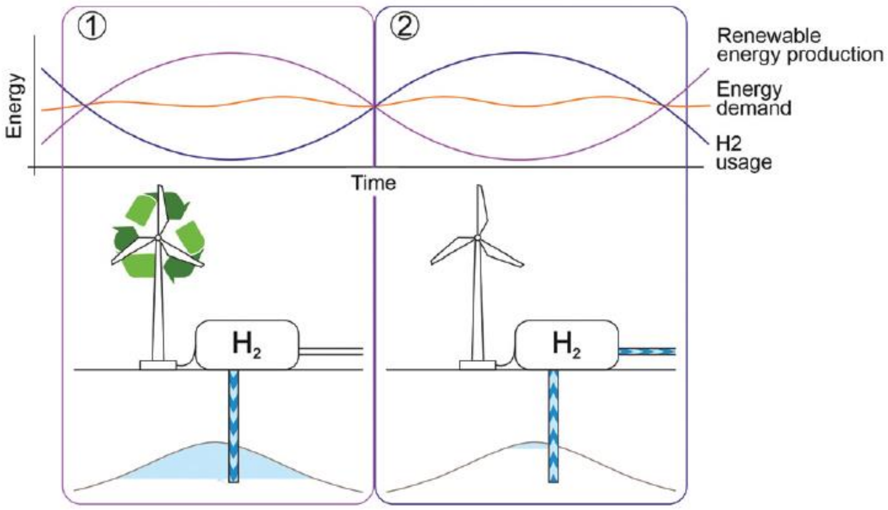


Figure 1-1: Hydrogen from renewable energy is stored during periods of high renewable energy production (1) to satisfy demand during times of high energy demand and low renewable energy production (2). [5]

Next to the problem of fluctuating production, the costs of green hydrogen are not competitive with grey and blue hydrogen. According to recent studies on the Levelized Cost of Green Hydrogen (LCOGH) in the Netherlands, green hydrogen will have a production cost between €6-€14, where grey and blue hydrogen are in the range of €2 and €2-4, respectively [6] [7].

It is therefore important to develop a green hydrogen infrastructure that is reliable in supply but also be cost-effective to compete with non-sustainable alternatives. Storage of hydrogen is an important aspect of this infrastructure to regulate the intermittency of supply and meet the ever-present demand. A large-scale energy storage system is therefore highly desirable to act as buffer to meeting the continuous energy demand [8].

With its extensive gas infrastructure and enormous wind energy potential near the North Sea, the Netherlands can become a pioneer in the transformation of the European energy system. The gas, electricity, and heating components of the Dutch energy system are currently separated. The goal of the Dutch climate policy is an increasingly integrated energy system for 2021–2030 and beyond, which should increase the efficiency of energy generation and delivery [9]. This report focusses on integrating offshore underground hydrogen storage in a depleted gas reservoir to buffer intermittent supply of far offshore green hydrogen production by exploring the re-useability of the natural gas infrastructure in the Dutch North Sea, to increase the efficiency of future energy generation and delivery.

The aim of this report is to better understand the technical implications when integrating offshore hydrogen storage in porous reservoirs in support of offshore green hydrogen production in the Dutch North Sea, while focusing on repurposing existing infrastructure to maximize cost-effectiveness.

2 THEORY

This chapter describes the theoretical background used for this research. The realization of an offshore subsurface hydrogen facility depends on three critical subsystems: the production, transportation, and storage subsystems of offshore green hydrogen (GH_2). In this chapter the fundamental theory that influences the design choices for this research is described. First, the production of hydrogen in an offshore environment is examined, followed by the transportation of gaseous hydrogen with a focus on re-useability of existing natural gas pipelines. Finally, the theory behind underground hydrogen storage and its implications are elaborated.

2.1 Green hydrogen production by offshore wind

In the quest for carbon neutrality within the energy industry, the generation of green hydrogen will play an important role. This is done through electrolysis, utilizing electricity sourced renewable energy, such as offshore wind. Offshore wind turbines convert kinetic energy from wind into electrical energy, which then powers the electrolysis process to split water into oxygen and hydrogen ($\Delta \boldsymbol{H}_{298K}$= +285.8 $\boldsymbol{kJ\ mol^{-1}}$). As the enthalpy of the reaction is positive, the reaction is endothermic. This means that external energy is needed for the reaction to occur. The electrons generated by the wind turbine are used to power the electrolyser to produce green hydrogen. The Power-to-Gas (P2G) process ensures that hydrogen is produced with no carbon emissions.

The chemical process of green hydrogen production through electrolysis is an oxidation-reduction (redox) reaction. An electrolysis cell consists of an anode, cathode, and electrolyte. The oxidation occurs at the anode, where water is oxidized to oxygen, protons (H^+), and electrons:

$$2H_2O(l) \rightarrow \ O_2(g) + \ 4H^+(aq) + \ 4e^- \quad (1)$$

Here, water acts as the reducing agent and loses electrons, which are then available for the reduction process at the cathode. At the cathode the second half reaction of the reduction-oxidation process takes place. This is the half-reaction where protons (H^+ ions) gain electrons (thus, are reduced) to form hydrogen gas. The reduction reaction at the cathode is:

$$4H^+(aq) + \ 4e^- \rightarrow \ 2H_2(g) \quad (2)$$

In this case, the protons act as the oxidizing agent and gain electrons, completing the redox process. The electrolyte transports the electrons, which were obtained at the oxidation reaction at anode, to the cathode. The overall redox reaction for the electrolysis of water can be represented by the sum of these two half-reactions, yielding hydrogen and oxygen gases as the final products, see Equation (3):

$$2H_2O(l) \rightarrow 2H_2(g) + O_2(g) \tag{3}$$

The equations show that no carbon is involved in the process and that pure H_2O is needed. Therefore, in a far offshore environment, the seawater needs to be demineralized and purified using a desalination plant and an electrodeionization unit. The dominant technologies for the demineralization of water are Multi Stage Flash (MSF) and Reverse Osmosis (RO). The former is a thermal-based and the latter membrane-based process. As MSF is an energy-intensive process, it is not considered a viable technology for implementation of green hydrogen in the North Sea. Therefore, only RO will be considered the purpose of this study.

While the production of hydrogen itself is out of the scope for this study, it is essential to understand the context in which green hydrogen is produced offshore. Notable projects in this area include the PosHYdon pilot project and the AquaSector Consortium (AQS) project.

At PosHYdon green hydrogen will be produced offshore on a hydrogen production platform in the North Sea near the coast of Scheveningen, the Netherlands. This pilot project consists of a 1 MW electrolyser which will produce a maximum of 400 kg of H_2 per day [10]. The first production of hydrogen on the platform is scheduled for the second half of 2024. The platform used for PosHYdon was formerly a natural gas production platform, now repurposed for green hydrogen production.

Another project that aims to produce offshore green hydrogen is the AquaSector Consortium (AQS) project a collaboration of Shell, RWE, Gasunie and Equinor. This feasibility study intends to construct offshore hydrogen park approximately 150 km offshore Germany with ~300 MW electrolyser capacity by 2028 to produce 20,000 tons of green hydrogen per year [10].

2.2 Transport of gaseous hydrogen

Hydrogen, as an energy carrier, holds significant potential in the quest for a sustainable energy future. Its versatility, ability to store and transport energy, and role in reducing carbon emissions make it a critical component of the global energy transition. Among the various methods of hydrogen transportation, pipelines are emerging as a viable and efficient option for large-scale energy distribution.

The growing interest in hydrogen transport through pipelines is driven by the need to integrate renewable energy sources, such as offshore wind farms, into the energy grid. Offshore wind farms generate electricity that can be used to power electrolysis, producing hydrogen from water. Given the remote offshore location of these wind farms, the transmission of this energy to the mainland presents unique challenges. This transmission can be accomplished either through electrical cables or steel pipelines for transporting electrons and gaseous hydrogen, respectively.

Electrical transmission can be handled by HVAC (High Voltage Alternating Current) cables or HVDC (High Voltage Direct Current) cables. While HVAC cables are favorable for short transport distances within wind farms, HVDC becomes more economically favorable for subsea electricity transport over distances typically exceeding 60 kilometers [11, 12].

Studies researched if offshore hydrogen production from wind power could ever compete with onshore hydrogen production from the same wind power, given the higher costs that are typically associated with offshore investments [13] [14, 15]. From a cost perspective the onshore hydrogen scheme is hampered by the high cost of power export for distances beyond 100 km. This implies that the energy of offshore wind farms that have distances beyond 100 kilometers from the coast is more efficient to be transported in the form of molecules.

This section explores the current state of hydrogen pipeline infrastructure, recent technological advancements, and opportunity of re-useability of natural gas pipelines and hydrogen initiatives that are paving the way for hydrogen transport. It also discusses the challenges for hydrogen gas transport, highlighting the role of hydrogen pipelines in achieving a sustainable energy future.

2.2.1 Current State of the Art

Pure gaseous hydrogen has been transported through carbon steel pipelines since the 1930s. Up to 2016 a total of 4,500 kilometers of dedicated and purpose-built H_2 pipelines were installed and operational, predominantly concentrated in the industrial areas of the USA (Texas/Louisiana), and north-western Europe, covering the Rhine/Ruhr area of Germany, the industrial areas near the harbours of Rotterdam (Netherlands) and Antwerp (Belgium), with connections into northern France [16].

Currently there are no examples of offshore transport of H_2, nor are there any available standards for design. Currently, DNV is developing a standard for offshore hydrogen gas transport, H2Pipe [17]. One pilot project that will provide knowledge about offshore transport of hydrogen is the Dutch PosHYdon project, scheduled for deployment before 2030. This project will retrofit an existing offshore carbon steel (CS) X60 pipeline to transport a blend of up to 10% H_2 in natural gas downstream of a 30 barg electrolyser [18].

Offshore pipelines do not differ significantly from onshore pipelines in steel grades, but they generally have a smaller diameter, thicker walls and they often operate at higher pressures (above 100 bar) without intermediate compression [19].

Research done by Bureau Veritas concluded that the NGT and NOGAT pipelines are suitable for hydrogen transportation. These pipelines are among the biggest natural gas pipelines of the Dutch North Sea and the hydrogen transport capacity of the NGT and NOGAT pipelines are 10-14GW and 10-12GW, respectively [20]. Scenarios are developed to free up one of the two pipelines for pure hydrogen prior to 2030. This would make it possible to export the green hydrogen produced at offshore wind parks in the North Sea.

2.2.2 Hydrogen Properties

From a transport and safety standpoint, it is critical to comprehend the physical characteristics of the hydrogen gas, including the effects of any related pollutants and impurities. Gaseous H_2 is odourless, non-toxic, non-corrosive, almost colourless, highly flammable, easily ignited, lighter than air, and heats up when the pressure is reduced due to the negative Joule-Thomson coefficient (i.e. JT heating) at typical pipeline pressures and temperatures.

Table 1 lists the physical characteristics of hydrogen and compares them with those of methane, which makes up the majority of natural gas (usually 70 to 98 mol%). These characteristics may set H_2 pipelines apart from natural gas transportation systems in terms of capacity, design, and operation.

Table 1 Comparison of physical properties of hydrogen and methane

Physical property	Hydrogen	Methane	Unit
Molecular weight	2.016	16.05	g/mol
Calorific Value (HHV)	12.7	55.5	MJ/m^3
Density at NPT (1 atm, 293.15 K, gas phase)	0.0838	0.668	kg/m^3
Dynamic viscosity at NPT (1 atm, 293.15 K, gas phase)	$0.761*10^{-5}$	$1.11*10^{-5}$	Pa s
Joule-Thomson coefficient (80 bara, 293.15 K, gas phase)	-0.013	0.38	K/bar
Molecular size [21]	2.89	3.80	Å
Limits of flammability in air	20.37	111.7	K
Limits of flammability in air	4–75	5.3–15.0	volume %
Minimum ignition temperature in air	500	537	°C
Ignition Energy	0.02	0.29	MJ

Because the calorific value content of hydrogen being four times lower than natural gas, a much larger volume of gas is needed to convey the same amount of energy as methane. Recognizing that hydrogen has a density $1/9^{th}$ of natural gas and, assuming the same levels of kinetic energy (ρV^2), the permissible velocity for H_2 gas pipelines can increase by a factor of three. Standard gas velocity in pipeline is 10 m/s, so she first order estimate of the maximum velocity in a pure H_2 pipeline is thus 30 m/s [19].

Compared to natural gas, hydrogen has a lower energy density: a cubic meter of hydrogen only holds a third as much energy as a meter of natural gas at the same pressure. However, this does not imply that three times as many pipes are needed to transfer the same quantity of energy. The maximum energy capacity of a hydrogen pipeline can reach a value of up to 80% of the energy capacity it possesses while transporting natural gas because the volume flow of hydrogen can be larger than for natural gas due to the flow velocity of hydrogen [22].

Furthermore, hydrogen diffuses far more readily through steel than natural gas does, which encourages the development of cracks (embrittlement) as a result of cyclic loads. By reducing cyclic stresses, employing a thicker pipeline wall, and using fewer high-grade steels, the effect can be reduced [23]. This implies the importance of offshore storage to buffer, to reduce the cyclic loading and the corresponding pressure differences.

The psychical and chemical properties of hydrogen (low molar mass and large volume flow) lead to compression challenges, as more efforts are needed compared to natural gas. This topic is further explained in section 2.5.

Due to the wider flammability limits in air, the lower ignition temperature and lower ignition energy of H_2 in comparison to natural gas, the risk of fire or explosion with H_2 increases. However, in open environments (not in confined spaces), H2 will disperse more quickly due to the greater diffusivity in air which decreases the risk of fire or explosion in the case of minor leaks [21].

2.2.3 Hazards Associated with Hydrogen Transport

As H2 is a smaller molecule and has a lower dynamic viscosity than methane, it permeates more easily through pipeline components and materials that are qualified as leak-proof for natural gas, such as elastomeric components (O-rings, gaskets, membranes) in flanges and valves, and polymer pipeline walls. H2 molecules are too large to diffuse easily through a carbon steel pipeline wall, and research has shown organic coatings as typically applied for external corrosion protection also limits hydrogen diffusion [24, 25]. However, some molecules will dissociate into hydrogen atoms and can then penetrate into the steel pipeline.

2.2.3.1 Hydrogen impurities and their impacts

Alkaline and proton exchange membrane (PEM) electrolysis produces H2 with purity levels >99.999%, whereas methane reforming produces H2 with purity levels between 97.5 and 98.5%. This is assuming that a water removal equipment is installed at the producing side to dry the H2 before it enters the pipeline. A basic risk assessment of the possibility and magnitude of the impact is provided by ISO 19880-8 [26] along with a summary of the contaminants that may arise as a by-product of H2 generation by SMR or electrolysis (on PEM fuel cells only).

Table 2 Possible impurities per hydrogen production method [26]

Method	Possible impurities	Improbable impurities
Steam Methane Reforming	CO, CH4, N2	Ar, CO2 & O2, H2O, NH3, hydrocarbons, HCOOH, Halogens, HCHO
Alkaline Electrolysis	O2, H2O	CO2, CO, CH4, He, N2, Ar, NH3, HCHO, hydrocarbons, HCOOH, Halogens
PEM Electrolysis	O2, H2O	CO2, CO, CH4, Ar, N2, NH3, HCHO, hydrocarbons, HCOOH, Halogens

2.2.3.2 Hydrogen Embrittlement

A variety of hydrogen-enhanced cracking mechanisms are covered by the collective name of hydrogen embrittlement (HE). Three critical factors must be present to give a high risk of HE: 1. Hydrogen at critical partial pressure, 2. Susceptible material, 3. Stress above threshold level.

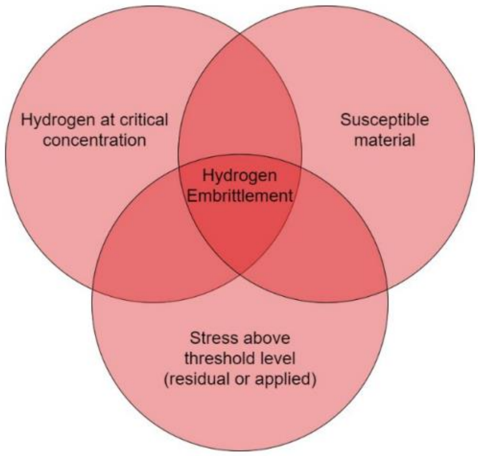


Figure 2-1 Conditions for hydrogen embrittlement [19]

Hydrogen embrittlement is a term referring to degradation of mechanical properties by hydrogen and can be a problem for structural materials. The hydrogen molecules adsorb on the surface of the metal, dissociates to atoms, and is diffused. This phenomenon normally occurs when there is lattice defect in the metal, so the hydrogen becomes trapped. The trapping is mainly due to a low solubility and diffusivity of atomic hydrogen [27] [28].

Figure 2-2 shows the energy diagram for hydrogen gas that adsorbed to the metal surface. The terms "energies of hydrogen in gas-metal equilibria" relate to the various energy states and interactions of hydrogen atoms within a metal. These energies help describe how hydrogen behaves when it enters and moves through the metal lattice.

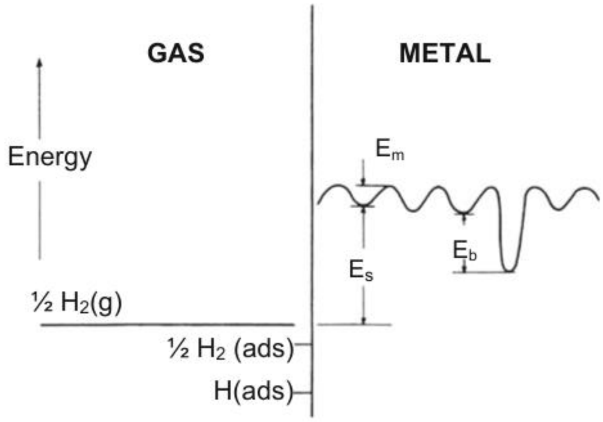


Figure 2-2: Energies of hydrogen in gas-metal equilibria. Es, energy of solid solution; Em, migration energy; Eb, trap binding energy [29]

E_s is the energy associated with hydrogen atoms being dissolved in the metal matrix to form a solid solution. When hydrogen atoms enter a metal, they occupy interstitial sites within the metal lattice, forming a solid solution. The energy of the solid solution (E_s) refers to the thermodynamic stability of hydrogen atoms in these interstitial positions. A lower Es indicates that the hydrogen atoms are more stable within the metal lattice, meaning they are more likely to dissolve and remain in the solid solution.

E_m is the energy barrier that hydrogen atoms must overcome to move or migrate from one interstitial site to another within the metal lattice. A lower E_m means that hydrogen atoms can more easily migrate through the metal, leading to higher diffusion rates. Conversely, a higher Em indicates that hydrogen atoms are less mobile.

E_b is the energy associated with hydrogen atoms being trapped at specific sites within the metal, such as dislocations, grain boundaries, or voids. A higher E_b means that hydrogen atoms are more strongly bound to these traps, making it difficult for them to leave and continue migrating through the metal [30]. This can lead to localized concentrations of hydrogen, contributing to phenomena like hydrogen embrittlement.

The likelihood of hydrogen embrittlement in offshore hydrogen pipelines can be minimized through several measures [23]:

- Choosing appropriate pipeline materials (High grade CS is more susceptible to HE)
- Implementing conservative design principles (such as maintaining low hoop stress)
- Reducing pressure fluctuations, for instance, by using storage solutions
- Maintaining a low partial pressure of hydrogen (<0.25 MPa) [31]
- Keeping temperatures low (<~200 °C), as temperature is a determining factor in hydrogen diffusivity and bulk hydrogen concentration [32, 33]

2.2.3.3 Fatigue Crack Growth (FCG) in Pipeline Steel

Carbon steel (CS) is the most common line pipe material, both for new H_2 pipelines and existing pipelines that could be repurposed for hydrogen. It is generally the most cost-effective pipeline material choice for long distance transport [34]

Natural gas pipelines are commonly constructed using carbon-manganese steels, which have relatively low yield strengths, typically between 173 and 414 MPa (25 to 60 ksi). There has been a shift towards using stronger microalloyed steels for newer pipelines. These microalloyed steels have yield strengths ranging from 414 to 483 MPa (60 to 70 ksi) and are produced with lower carbon content. They undergo specialized processing techniques, such as controlled rolling, and are alloyed with small amounts of elements like niobium, molybdenum, vanadium, or titanium to enhance their strength. Although these steels are generally resistant to hydrogen embrittlement under steady or gradually increasing loads due to their lower strength levels, they can still experience accelerated crack growth when subjected to cyclic loading, regardless of their strength [35].

These cyclic loading arises due to pressure fluctuations under normal operation conditions and shutdowns and startups of the flow, which is the case for intermittent produced renewable hydrogen. This leads to internal stress in the pipeline's material, consisting of normal and shear stress. Only the normal stress has a significant influence on the fatigue behaviour in offshore pipelines [36]

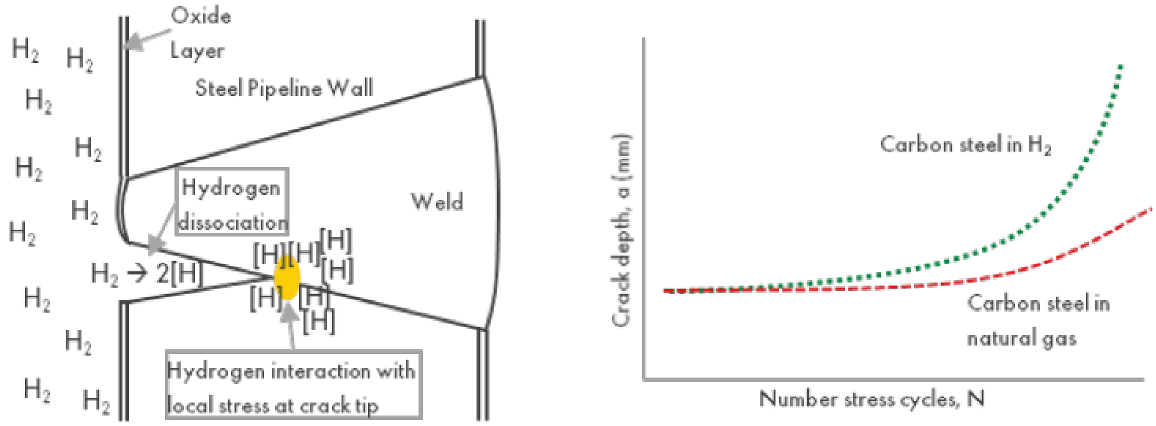


Figure 2-3: Mechanism of FCG in hydrogen, and a sketch of the impact on the crack growth rate compared to natural gas [37].

As brittle fracture risk rises with material hardness, ASME 31.12-2014 increases the necessary wall thickness for steel materials with rising hardness. An instance of brittle fracture connected to H2 resulting from the choosing of too hard steel material was the Kashagan sour gas export line failure [38]. Since carbon steel X52 is the least expensive material, it is the choice for new offshore pipeline material. The choice of standard X65 offshore pipeline carbon steel would lead to comparable or higher wall thickness specifications and higher steel expenses. The benefit of using X52 carbon steel is that it is sufficiently soft to enable operation at pressures over 104.4 bara (1500 psi) and up to 208.7 bara and temperatures as high as 121°C [13].

2.2.4 Energy Threshold Value: Comparison with Electricity Cables

While offshore wind parks are today located relatively close to the coast, new wind projects are being planned further out to sea. The cost of offshore power transmission for onshore hydrogen production increases relatively quickly with distance, whereas offshore hydrogen production and subsequent transport incurs fixed costs, such as platforms for the electrolyzers and AC/DC inverters, leading to higher transport costs for shorter distances compared to offshore power transmission and onshore hydrogen production. For an installed wind power and electrolyser capacity the threshold distance lays slightly above 100 km, see Figure 2-4.

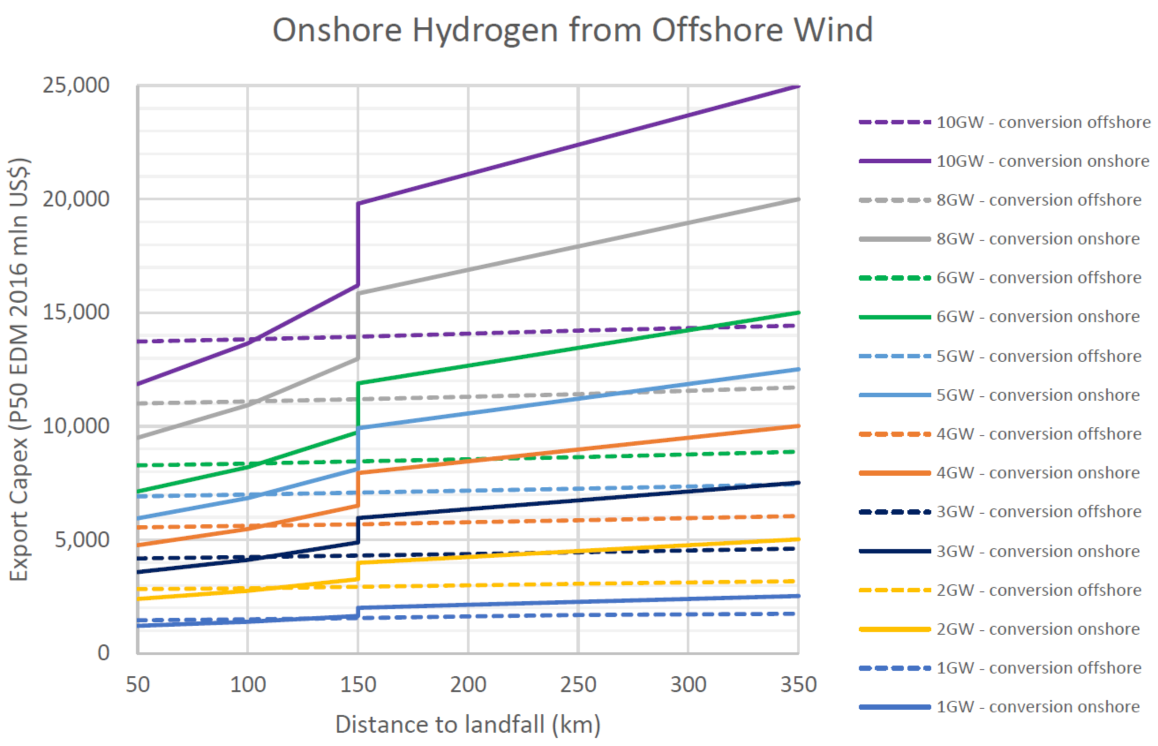


Figure 2-4: Overview of costs versus export distance for onshore and offshore hydrogen production for different installed wind powers [13].

For longer distances, offshore hydrogen production and transmission may become more cost-effective, especially if it can benefit from the economies of scale of pipelines. There are some uncertainties about the operating pressures of offshore hydrogen pipelines. While offshore natural gas pipelines operate at higher pressures, this could increase the risk of embrittlement with hydrogen and further research is needed. The costs of re-using a pipeline are estimated to be around 10% of building a new offshore pipeline [40, 41].

Evaluating natural gas pipelines for hydrogen transport is therefore an interesting alternative.

2.2.5 Natural gas pipeline re-useability

According to research done by DNV-GL and KIWA, in 2017 and 2018, respectively, the existing gas infrastructure can be relative easily adapted for hydrogen transport [42, 43]. Standards such as ASME B31.12 and EIGA guidelines provide frameworks for these conversions, including pressure de-rating factors to determine the maximum allowable operating pressure for hydrogen service, which is typically lower than for natural gas [44] [45].

The derating factor in ASME B31.12 determines the Maximum Allowable Operating Pressure (MAOP) for pipelines operating with hydrogen. This factor consistently leads to a lower allowable pressure compared to pipelines operating with natural gas.

According to the European Hydrogen Backbone research, refurbished onshore hydrogen pipelines have a capital cost per kilometer that is between 15 and 30 percent of the cost of new constructed hydrogen pipelines. This percentage is projected to be 10% for offshore pipelines, mostly because building offshore requires a comparatively larger investment in capital expenditure [40]. The amount of intervention, inspection, and testing necessary to repurpose for hydrogen use will have a significant impact on the offshore cost.

During a 2020 meeting of the HIPS-NET consortium, Gasunie (the natural gas grid operator in the Netherlands) presented an approach to deal with hydrogen-enhanced fatigue by calculating a crack growth rate of an assumed defect. Based on this, they concluded that 100% H2 can be transported in existing natural gas pipelines up to their design pressure (66 barg) without affecting the pipeline integrity [37].

Globally, there are few examples of onshore carbon steel pipelines repurposed for hydrogen. In the Netherlands, Gasunie operates a 12 km Dow-Yara pipeline, a combination of an 11.3 km converted natural gas pipeline and a 0.7 km newly installed section, both in carbon steel. This pipeline transports approximately 5,000 tons of hydrogen annually in an 80% hydrogen and 20% natural gas mix, demonstrating practical reusability [37].

Repurposing existing natural gas pipelines for hydrogen transport offers significant potential but involves several technical challenges. These include ensuring material compatibility, managing pressure requirements, and addressing the impacts of hydrogen embrittlement. Here, we explore these aspects along with their economic and environmental implications.

Earlier research indicates that pipelines intended for the transmission of natural gas might potentially be repurposed for the transfer of hydrogen. However, it will necessitate a few adjustments to the pipelines' operation and maintenance, most critical among them being the following [41]:

- valve replacement, due to higher permeability rate of H_2 compared to NG (~3x);
- complete cleaning of the pipeline (based on the needed level of purity);
- metering equipment replacement;
- new methods for operating the pipeline, such as pressure fluctuation control;
- new procedures for management and maintenance.

2.2.6 Hydrogen blending

Hydrogen blending into natural gas is an ongoing research topic aimed at integrating hydrogen into the existing energy infrastructure. This approach involves injecting hydrogen into natural gas pipelines to create a blended gas that can be used in conventional natural gas applications with minimal modifications to existing infrastructure. This strategy represents a transitional pathway towards a greater presence of hydrogen in the energy sector, leveraging existing assets while contributing to the decarbonization of the gas grid.

The primary advantage of hydrogen blending is the ability to utilize existing natural gas infrastructure, including pipelines and end-use appliances, with minimal modifications. This significantly reduces the need for substantial capital investments compared to developing a completely new hydrogen-specific infrastructure. Additionally, hydrogen blending helps scale up hydrogen production and integration, providing a demand signal for hydrogen producers and supporting the growth of the hydrogen economy. When using methane-hydrogen mixtures with low hydrogen content, the safety measures and risks are similar to those encountered when working with natural gas [46].

However, there are practical constraints and regulations that limit the extent to which hydrogen can be blended with natural gas. The current end-user equipment capabilities and regulatory standards for natural gas quality impose significant limitations. For instance, in the Netherlands, the main transmission line network and a regional transmission line network can only accommodate a maximum of 0.02 mol% of hydrogen [42] [47]. This stringent requirement is the primary restriction on mixing hydrogen in the natural gas system.

The biggest hurdles for increasing the hydrogen blend level are the tolerance levels of end-users of the blended gas. If a dedicated end consumer is capable of using all the volume of the mixed gas, an increased hydrogen amount could be considered. Gas mixtures containing up to 17 vol% of hydrogen should not cause difficulties [48]. However, current specifications for gas cylinders (e.g., type CNG1) limit hydrogen content to a maximum of 2% (ISO 11439 standard) [49]. Presently, only 0.5 vol% hydrogen can be blended into the natural gas grid, as per the Ministerial Regulation on Gas Quality [47]. However, when blending hydrogen, the value of hydrogen is downgraded as natural gas prices are lower compared the green hydrogen.

In the European Union, the REPowerEU Plan calls for careful consideration when blending hydrogen and suggests a potential blending level of 3%, equivalent to 1.3 million tons of hydrogen by 2023 [50].

Another benefit of hydrogen blending is associated with underground hydrogen storage in porous media. The contaminated side stream of the hydrogen purification process, necessary after withdrawing hydrogen from the reservoir, contains both methane and hydrogen. This stream can be tied into a natural gas pipeline, provided that the hydrogen content does not exceed allowable blend levels.

2.3 Underground hydrogen storage

To meet the ever-present demand for energy, it is crucial to develop storage facilities capable of absorbing the fluctuations caused by renewable energy sources and providing hydrogen during periods of low production. A possible solution for large-scale storage of hydrogen is to store the hydrogen in subsurface structures such as salt caverns, aquifers, or depleted gas reservoirs. Notably, depleted gas reservoirs exhibit immense storage capacities, reaching the scale of terawatt-hours (TWh), equivalent to one million megawatt-hours (MWh). To put this into perspective, consider the recent opening of the largest battery in the Netherlands, boasting a capacity of 48 MWh, which was attended by the Dutch Minister of Climate and Energy. By comparison, a two billion cubic meters (2BCM) gas reservoir, with an energy storage capacity of approximately 6 TWh, could store the energy equivalent of an astonishing 125,000 batteries with a capacity of 48 MWh each [1]. The utilization of such large storage facilities could prove highly advantageous in securing a reliable supply that aligns with energy demand.

2.3.1 Underground hydrogen storage in salt caverns

Salt caverns are the most suitable choice for UHS due to their integrity, inertness to H2, flexibility in withdrawal and injection rates, and cost effectiveness [51]. Salt caverns are already in use for UHS in UK and US. The largest salt cavern in the world, used for hydrogen storage, is located in the Spindletop Dome in Texas. It has an approximate capacity of 906,000 cubic meters. This cavern, situated onshore at a depth of about 1500 meters, is part of an underground storage facility operated by Air Liquide USA [52].

On the contrary, the development of offshore salt caverns entails considerable challenges. One of the biggest challenges is that implementing salt caverns to store hydrogen is a time-consuming process as the salt caverns are artificial and therefore must be built by leaching a salt layer in the subsurface. By leaching, a water flow is injected to a geological salt layer to dissolve the salts and the brine is extracted. By doing so, the salt cavern is shaped. HyStock, working on the first large-scale salt cavern UHS of hydrogen in the Netherlands, states that the entire process of permitting, drilling and leaching takes about 7 years for a cavern that can hold 6,000 tons of hydrogen, with an energy content of 237 GWh [53]. This timeline will prove to be difficult to meet if future demands for renewable power are to be satisfied. Besides the challenge of time, the brine, extracted from the leaching process of the salt caverns, could be harmful if it is dumped into the sea, as it is of extremely high salinity and therefore could affect the local ecosystem. Another challenge for building offshore salt caverns is that it is never been done before.

Moreover, public opposition and negative perceptions of UHS in salt caverns could arise. The public may not agree to UHS in onshore salt caverns due to fears of structural integrity issues, seismic shifts, or loss of containment.

On the other hand, gas reservoirs already exists, which could speed up the timeline for commencing offshore hydrogen storage operations. The storage capacity of salt caverns is in the order of 100-250 GWh, where depleted gas reservoirs have the potential to store in the order of TWh [54]. The Netherlands' depleted hydrocarbon reservoirs have a potential hydrogen storage capacity of 93 billion m^3 (or 277 TWh) for onshore fields and 60 billion m^3 (or 179 TWh) for offshore fields. In addition, they thought of storing hydrogen in caverns, predicting a working gas capacity of 14.46 billion m^3 (43.3 TWh) [55].

The challenges related to timeline, public opposition, brine disposal and the storage capacity increase the importance of exploring alternative large-scale storage options for hydrogen.

2.3.2 Underground hydrogen storage in depleted gas reservoirs

Since salt caverns have less energy storage capacity compared to gas reservoirs, exploring alternative storage options becomes of interest [54]. One alternative for storing hydrogen that is currently researched, it the use of depleted gas reservoirs. TNO reports that 80 depleted gas reservoirs in the Dutch North Sea were determined to be essentially suitable for short-cycle, seasonal, and/or strategic storage of hydrogen [56].

This research focusses on exploring the feasibility of an offshore depleted gas reservoir in support of offshore green hydrogen production. Installing an offshore storage facility makes it able to buffer the offshore pipelines to minimize pressure fluctuations and therefore fatigue crack growth.

The choice for an offshore gas reservoir is also since many research initiatives are already exploring the use of salt caverns for hydrogen storage. Globally, depleted gas fields are the most popular choice for storing natural gas, especially for sporadic or less flexible uses [53]. With existing technical uncertainties for UHS in a depleted gas reservoir, especially offshore ones, researching its technical and economic feasibility is crucial.

However, it should be noted that the use of depleted gas reservoirs presents its own set of challenges, most notably the risk of hydrogen contamination and the large volume of cushion gas required. Hydrogen stored in porous reservoirs may require purification steps to meet hydrogen quality standards before it can be exported to the onshore backbone. This post-treatment is essential to produce high-grade hydrogen that is compatible with the onshore hydrogen backbone infrastructure and to ensure that it does not compromise the integrity of pipeline systems.

The expectations for energy storage in depleted gas reservoirs are high, but the technology is still immature [5] [57]. While there is experience in storing hydrogen in salt caverns in the US Gulf Coast in Texas and Teeside, UK, there is no experience in storing hydrogen in a depleted gas reservoir [58]. In Austria, the first underground hydrogen storage of pure hydrogen in a depleted gas field became operational in April 2023 [59].

To achieve a zero-carbon energy system in the future, it is important to identify potential dealbreakers and scientific challenges and safety issues related to UHS in reservoirs. The key processes of UHS in depleted gas reservoirs are still poorly understood [5], such as the formation of the toxic hydrogen sulfide gas, loss of hydrogen content due to contamination in the reservoir with residual gasses and microbial processes. To better understand these challenges, multidisciplinary research, including reservoir engineering, chemistry, geology and microbiology is necessary. Another important aspect to better understand the challenges with UHS is the implementation into the future energy system. UHS is more complex than methane (CH_4) and carbon dioxide (CO_2) storage and requires other working principles.

Consideration must be given to a few special features of hydrogen. In the first place, hydrogen differs greatly from other geologically stored fluids such as CH4, air, or CO2 in terms of its physical and chemical characteristics. Second, hydrogen may react with fluids and minerals below the surface, which could have an impact on storage operations. Thirdly, bacteria that consume hydrogen can grow if there is hydrogen present below the surface. Last but not least, frequent injection and withdrawal cycles in hydrogen storage sites will alter the stress field, which could jeopardize the containment integrity.

CO2 sequestration, or long-term and permanent storage, aims to remove CO2 from the atmosphere. The process lacks a withdrawal step because CO2 storage is not cyclical. Therefore, the co-production of CO2 with other fluids already present in the porous media is not an issue [8].

Similar to the storage of natural gas, the safe storage of hydrogen in porous media (such as aquifers or depleted reservoirs) necessitates a suitable geological structure, such as a well-confined porous and permeable formation surrounded by impermeable cap rock or seal. Carbon dioxide only needs to be injected in the reservoir, where the hydrogen has to be extracted frequently, meaning more frequent pressure and temperature cycling, which can fatigue well components, and the near-well area of the reservoir. Hydrogen gas behaves very differently than natural gas when it comes to safety, much wider flammability range and much lower ignition energy compared to methane as stated in section 2.2.2.

In contrast to natural gas storage, the extraction of stored hydrogen must occur often and at a high pace in order to satisfy market demand [8]. Besides, hydrogen molecules are much smaller than natural gas, and the molecular weight of methane is almost 8 times as heavy as hydrogen (16.04 g/mol for methane versus 2.016 g/mol for hydrogen). Hydrogen can leak more easily compared to a natural gas molecule due to its high diffusivity and low viscosity. Another downside of hydrogen is the highly reactive property. This can induce microbial activity, causing microbially induced corrosion [55].

Globally there are 661 underground gas storage (UGS) sites, that contain a total of 422 billion m3 of natural gas, which reflects to 10% of the total annual consumption [60]. The majority of the UGS sites are in depleted gas fields (80%), but aquifers and caverns are also used, 12% and 8%, respectively.

2.4 Hydrogen Purification

A common issue for UHS in depleted gas reservoirs is the contamination of hydrogen, necessitating purification before it can be exported to the hydrogen backbone. This requirement is seen a potential dealbreaker for offshore underground hydrogen storage in porous media (UHSP), such as depleted gas reservoirs.

After hydrogen extraction from the wells, multiple purification steps are required to achieve the high purity levels necessary to meet backbone standards. This process is similar to UGS but involves different technological choices. The primary distinction is that hydrogen must be purifiedom other residual gases. The three prevalent methods for hydrogen purification are Pressure Swing Adsorption (PSA), polymeric membranes, and cryogenic separation [61]. In the case of UHS, it depends on the purity requirement, the composition of the injected gas, the inflow rate, temperature and pressure of the gas mixture {Yousefi, 2023 #103}.

The most used technology for hydrogen purification is Pressure Swing Adsorption (PSA), with proven alternatives including polymeric membranes and cryogenic separation. The required purity of the hydrogen grid can influence the choice of purification technology. For UHS, the optimal gas cleaning method is determined by end-users' needs (such as purity), the composition of the gas mixture extracted from the reservoir, the rate of withdrawal, and the temperature and pressure of the gas [62].

Cryogenic separation is a highly energy-intensive and costly process. The withdrawal rates for UHS are in the order of millions of Nm^3/day, which cannot be achieved with current membrane technologies [61]. Due to these drawbacks, PSA is often the preferred choice.

The working principle of PSA is based on an adsorbent bed that captures contaminants from the gaseous stream, allowing only hydrogen molecules to pass. The impurities adsorbed at higher partial pressure are desorbed at lower partial pressure. Since a relatively small amount of hydrogen is adsorbed compared to methane and other impurities, high pressure hydrogen is recovered [63]. The pressure-driven regeneration implies that no thermal energy contributions are necessary to carry out the gas separation process.

Silica gel can be used to remove heavy hydrocarbons, protecting other layers of the adsorbent bed [64]. Activated carbon and zeolite are the most dominant adsorbents for hydrogen purification. Activated carbon can remove CH_4 and CO_2, while zeolite can remove N_2 from the gas mixture and capture trace components at the end of the column [64, 65]. The sequence of layers is crucial to prevent the adsorption of certain components by specific materials (e.g., CO_2 or higher hydrocarbons by zeolite), as this would compromise the desorption process.

Commercially, PSA dominates hydrogen purification technology for high purity requirements above 98%. PSA systems can be designed to meet various purity ranges, with a trade-off in hydrogen recovery rates when deeper purity specifications are targeted. Achieving very high purity hydrogen results in a loss of hydrogen, which remains in the adsorbed stream and is designated as tail gas.

2.5 Hydrogen Compression

Generally speaking, hydrogen compression applications can be separated into two categories: pure (100%) hydrogen and hydrogen rich [67]. Compressing hydrogen often present unique technical challenges, that are not typically seen with other process gasses, such as methane or carbon dioxide. The mole weight of hydrogen, 2.016 g/mol, is the lowest of all elements. The density at atmospheric conditions is low (90 g/m^3) for hydrogen, which indicates that compression is often required to transport or store hydrogen. A unique characteristic of hydrogen is that it heats up when the gas expands from high pressure to lower pressure, when the temperature is above its inversion point of -73 °C, also known as the reverse Joule-Thompson effect.

Hydrogen compressors are essential components of the hydrogen energy system, serving multiple critical functions at various stages:

1. **H_2 Production Platform Compression**: At the hydrogen production platform, compression is required to export hydrogen through pipelines to the onshore backbone and the UHS platform. This involves compressing pure hydrogen.
2. **UHS Platform Injection Compression**: To store hydrogen in the depleted reservoir, compression is necessary at the UHS platform to inject hydrogen arriving from the production platform. This process also involves pure hydrogen compression.
3. **UHS Platform Tail Gas Compression**: If the decision is made to re-inject tail gas back into the reservoir, a compressor is needed for this purpose. This involves compressing non-pure hydrogen.
4. **UHS Platform Export Compression**: When hydrogen exits the PSA, it may require pressure boosting to meet the delivery requirement of 50 bar to the onshore backbone, as stipulated by Gasunie [68].

The compression of hydrogen is necessary as it has a low volumetric density. This makes compression essential for both storage and transportation, to decrease the volumetric flow rates. As hydrogen molecules differ from those of natural gas, compressing hydrogen usually takes more energy. Because hydrogen molecules are lighter and have a lower density, compressing them takes a greater amount of energy.

Calculations for compression work are typically made simpler by assuming an isothermal or adiabatic compression process [69]. Assuming an adiabatic process, the process proceeds at a constant entropy (isentropic) and without releasing heat into the environment. The less labor needed to compress hydrogen, the closer the process is near isothermal conditions [70]. In reality, compression is a polytropic process that requires cooling the compressed gas after each step to make it less adiabatic and more isothermal, indicating compression needs multiple stages [67].

The two conventional hydrogen compression technologies available to date are: 1) Reciprocating Compressors and 2) Centrifugal Compressors, both mechanical compression technologies [71]. Other compression technologies have a maximum flow capacity of less than 1000 Nm3/h and are therefore not suitable for UHS. Reciprocating and centrifugal compressor types are covered in the followings sections and the challenges associated with the required hydrogen compression duties. Figure 2-5 shows the discharge pressure range versus inlet volume flow in m3/h for centrifugal and reciprocating compressors, respectively. Reciprocating are suitable when higher pressure ratios are needed, where centrifugal compressors is the most common type for high flow rates {Yousefi, 2023 #103}.

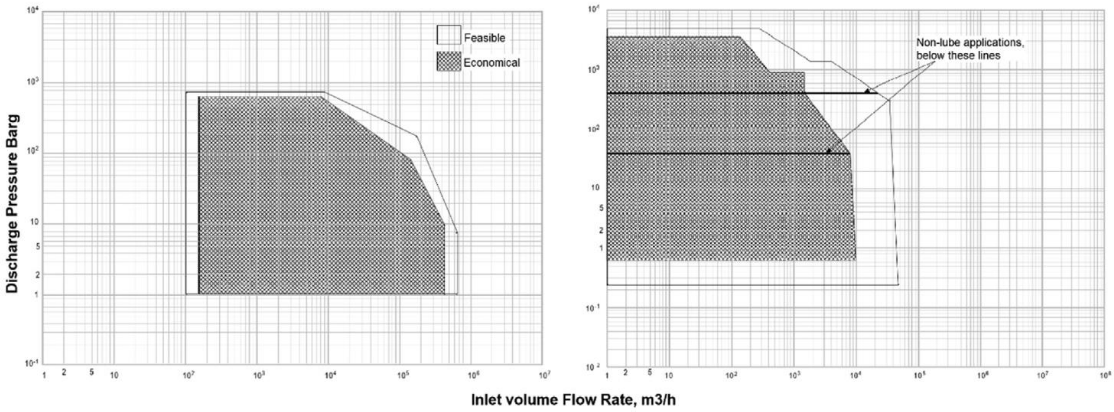


Figure 2-5: The left figure shows the application range chart for centrifugal compressor and the right chart the application rate for reciprocating compressors [72]

2.5.1 Reciprocating compressor

For pure hydrogen compression piston (reciprocating) compressors is the state-of-the-art technology [57] to gain better efficiencies and are more flexible in capacity and pressure range {Yousefi, 2023 #103}. They can typically be used for up to actual volumetric flow rates of ~ 30,000 m3/h (discharge pressures typically more than 400 bar for lubricated and up to 225 bar for non-lubricated compressors. The typical pressure ratio per stage is 1.6-2.5. Reciprocating compressors are relatively insensitive to intermittent operation, they have a strong history, also for processes with lots of start-stops such UGS [73].

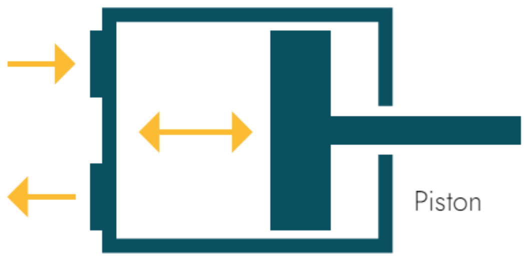


Figure 2-6: Working principle of a reciprocating compressor. Through reciprocating motion of the piston the gas is compressed [22].

The common risks for reciprocating solutions are the large size cylinders, the greater number of cylinders per compressor casing, hydrogen material compatibility, increased maintenance frequency. One of the disadvantages of a reciprocating compressor is that it generates pulsations and vibrations, which, without limitation and proper attention during design, manufacturing, installation and operation, can lead to fatigue failures, inefficiency, capacity limitations and unsafe situations [74].For offshore duty, dimensions, weight, and vibration management are important aspects to consider.

These units are characterized by high maintenance costs because of wearing components such as valves, rider bands, and piston rings [75]. These compressors are typically non-lubricated (oil-free) to reduce the risk of contaminating hydrogen with oil [76]. However, to compress hydrogen to high pressure levels, lube-oil might be necessary. This would require an extra process to remove the lube-oil out of the hydrogen before it is injected into the reservoir.

It should be mentioned that because of the complexity involved, reciprocating compression is not the standard compressor choice for an offshore platform. Vibration is a serious problem that necessitates more maintenance since it can lead to structural platform problems as well as faults inside the package, which increases operating expenditure (OPEX). Furthermore, more engineering design is needed when designing reciprocating compressors for offshore applications to properly account for the anticipated high vibrations in the pipework, baseplate, structural, and Anti-Vibrational Mount (AVM) designs. Usually, this has a negative effect on the footprint and weight.

2.5.2 Centrifugal compressor

Centrifugal compressors are well-suited for high volumetric flow rates but are currently achieving low pressure ratios per stage of hydrogen compression. Even at relatively high impeller tip speeds of 350 m/s, typical pressure ratios per stage seldom exceed 1.1 [77]. This implies that a lot of stages are needed to get an overall high pressure increase. In hydrogen centrifugal compression, the impeller imparts kinetic energy to the gas, significantly increasing its velocity. This kinetic energy is then converted into pressure energy in the diffuser, raising the gas pressure.

Because of the low molecular weight of hydrogen, hydrogen compressors need tip-speeds that are around three times higher than those used for natural gas to gain the same pressure difference [71]. These high-speed and purity requirements present challenges in the seal design, contamination, vibration, material selection, and rotor dynamics. Further, because of its low specific gravity, hydrogen tends to return to the inlet, thus decreasing the compressor's centrifugal efficiency.

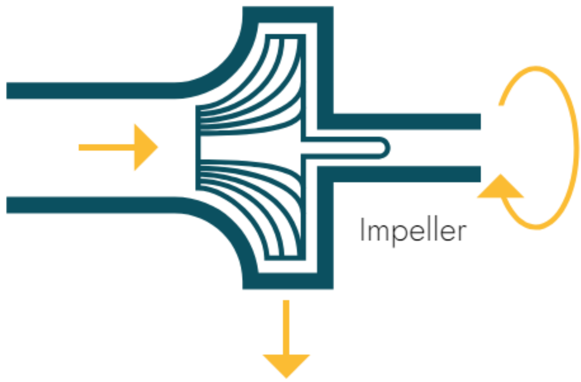


Figure 2-7: Working principle of a centrifugal compressor. Through centrifugal force of rotation, the gas is compressed [22].

Centrifugal compressors offer high flow capacity but have a relatively narrow operating window due to aerodynamic effects. Intermittent renewables cause variability in hydrogen production, leading to inconsistent flow rates into the compressor. Centrifugal compressors are designed for steady-state operation and can experience performance degradation under variable inflow conditions. Energy losses in these compressors are strongly related to internal friction and incidence losses, which increase when operating at non-ideal conditions. Therefore, careful engineering is required to minimize these losses and maintain efficiency [73].

Common risks associated with centrifugal compressors in hydrogen applications include operational flexibility, lateral stability, the effect of degradation of the material and its compatibility to avoid hydrogen embrittlement, managing high tip speeds which complicate rotor dynamics and stability, overcoming fabrication and manufacturing challenges, particularly regarding contamination, and addressing the heavy rotor weight which can pose material handling and maintainability issues. Testing challenges are also significant, as high-speed models require rigorous overspeed testing and balancing to ensure safety and performance.

Despite these challenges, centrifugal compressors remain an attractive option for hydrogen compression due to their ability to handle large volumes of gas. Companies such as Elliott Ebara, Baker Hughes, MAN Energy Solutions, Mitsubishi Heavy Industries, and Siemens Energy are at the forefront of developing solutions that address the unique challenges posed by hydrogen compression. These companies focus on innovative design and advanced materials to ensure reliable and efficient performance under demanding conditions.

By leveraging advanced materials and design techniques, these companies aim to overcome the inherent challenges in hydrogen centrifugal compression, paving the way for more efficient and reliable hydrogen infrastructure. This continuous development and optimization are critical as the demand for hydrogen as a clean energy source continues to grow.

2.6 HHV vs LHV

There is an ongoing discussion on whether to use HHV or LHV to express the energy content in hydrogen streams. The energy content of hydrogen can be expressed as the HHV (higher heating value) or LHV (lower heating value). For hydrogen, the HHV is 39.4 kWh/kg or 141.8 MJ/kg and the LHV is 33.3 kWh/kg or 120 MJ/kg. As water is released during the combustion of hydrogen by combining oxygen and hydrogen. This then evaporates, using up some of the energy that was previously available to "do work." Because the LHV accounts for this "loss," the Lower Heating Value (LHV), also known as the net calorific value, is lower [23].

The LHV is only relevant when a substance is burned and no heat is recovered from flue gases [78]. To determine the flow rate for the hydrogen in the system and its energy content it is therefore decided to use the HHV instead of LHV as it provides it is the actual energy content of the hydrogen.

3 RESEARCH APPROACH AND METHODOLOGY

In this chapter the reason behind the direction of this research is explained. It starts with section 3.1, where the academic knowledge gap and problem are stated, followed by the research question in section 3.2. Thereafter, the methodology of this research is described in section 3.3. that consists of phases A till F.

3.1 Academic knowledge gap and Problem statement

The expectations for large-scale energy storage are high but the testing of the feasibility using depleted gas reservoirs remains largely untested [5]. Accord to Heinemann et al. [5] most of the UHS research is focused on the subsurface performance, such as microbial and geochemical reactions, the flow of hydrogen within the reservoirs, the mixing with the in-situ gas and storage integrity. Less efforts have been put in better understanding the high-level overview of the feasibility of a subsurface hydrogen storage facility in the future energy infrastructure of the Dutch North Sea. According to Van Gessel et al. [56], 80 reservoirs in the Dutch North Sea, might be suitable for UHS. The research of Van Gessel et al. [56] only focused on static criteria of the reservoirs, but didn't encounter the dynamic criteria, such as the well performance, that are crucial to understand if these reservoirs are actually suitable as storage facility for the future energy system.

As large-scale energy storage options offer the important capability to balance the demand and supply, it is crucial to better understand the uncertainties and challenges of underground hydrogen storage in porous reservoirs. Especially the safety and economic impacts are of high importance to increase research budgets and close the knowledge gap. To close the knowledge gap, there is extensive research focusing on subsurface key processes that influence the predictability of hydrogen flow through the porous media, such as the impact of hydrogen sulfide (H_2S) in the reservoir, the microbe activities and permeability changes due to geochemical interactions with the hydrogen molecules.

While these processes are of high importance for the feasibility of implementing this technology, this research mainly focusses on bigger picture of implementing UHS in the future energy system, with a focus on re-useability of the present offshore infrastructure. This consists of the design choices that influence the system above the seabed instead of the processes occurring within the reservoir. For the processes occurring within the porous reservoirs, assumptions will be made as there are still many uncertainties due to the maturity of the research [57].

Besides the technological implications, there are also social challenges that can influence the outcome for UHS in the Netherlands. Issues such as public opposition and limited land availability for onshore renewable energy production and storage, as experienced in the Netherlands, underscore the need to explore offshore alternatives. Next to that, the Dutch government is tendering feasibility studies of offshore green hydrogen production facilities, which might require storage facilities close to the production facilities to buffer pipelines from the intermittent production cycles [79]. Buffering pipelines could increase lifetime of existing natural gas pipelines as pressure fluctuations are minimized leading to a constant flow and would therefore make it interesting to use these as hydrogen pipelines instead of installing new pipelines in the North Sea. As the North Sea has an extensive pipeline infrastructure it is interesting to see if a section of these pipelines can be re-used for hydrogen transportation.

The exploration of underground hydrogen storage has attracted large interest by academics and the industry, leading to increased amount of research in the last decade. For the industry it is of importance to evaluate the opportunity to re-purpose their infrastructure, such as pipelines, platforms, and hydrocarbon reservoirs. It is for these businesses, like Shell and NAM, of high interest to maintain a business in their expertise of subsurface engineering through the energy transition.

This report focusses on the implementation of offshore underground hydrogen storage in support of offshore green hydrogen production in the Dutch North Sea using depleted gas reservoirs as storage facility, to buffer intermittent production and ensure a constant supply of hydrogen to the onshore backbone.

The goal of this report is to outline the technical requirements for implementation of re-purposing present infrastructure for hydrogen storage in porous rocks in an offshore environment and identify potential deal breakers. The outcomes of this report should help the Dutch government and other decision makers to better understand the complexity of offshore hydrogen storage in porous media and the technical implications for hydrogen storage in a far offshore environment re-using existing infrastructures.

As this research focusses on a far offshore environment (>> 100 km), the idea is that all the installations necessary regarding hydrogen production and storage are situated on offshore platforms. This means that the compressors and purification installations are on a platform. The research focusses on a designing a platform that can inject, withdraw, and purify the hydrogen while using pipelines in the North Sea to transport the hydrogen from the offshore wind farm to the storage facility and export the hydrogen to the onshore backbone, while dealing with waste products of the involved processes in an offshore environment.

3.2 Research question & Objectives

The primary aim of this research thesis is to explore the potential of using a depleted gas reservoir in the North Sea for green hydrogen storage, situated within the larger context of advancing next-generation hydrogen energy infrastructure. Considering the extensive existing natural gas infrastructure in the North Sea and the ambitious target of achieving net-zero carbon emissions by 2050, repurposing these infrastructures for hydrogen storage presents a potentially economical solution that might also mitigate environmental impacts.

This study concentrates on the application of offshore subsurface hydrogen storage in a depleted gas reservoir located in the Dutch North Sea. This region, particularly Wind Area 7, has been identified for its potential to produce green hydrogen through electrolysis, which this storage solution would buffer against the variability of hydrogen production.

Given these premises, the overarching research question formulated for this thesis is:

"Does the utilization of an offshore depleted gas reservoir in the Dutch North Sea, for the purpose of buffering the intermittent hydrogen production at wind area 7, align with both technical feasibility and economic desirability?"

To thoroughly address this main question, the following sub-questions have been developed:

1. Is offshore gas reservoir hydrogen storage a feasible technical solution for maintaining a steady supply of green hydrogen to the hydrogen backbone?
2. Could there be merit in reusing NAM's offshore assets for offshore hydrogen production, storage, and transport in the future? If so, what are the key elements in achieving this?
3. What are the key design parameters for an offshore gas reservoir hydrogen storage platform in the Dutch North Sea?
4. What are the key cost drivers for developing the offshore UHS platform and the associated pipeline infrastructure?
5. How do the capital costs, operating costs, and maintenance costs of the offshore UHS platform compare with other underground hydrogen storage solutions?
6. Which destination is considered the most viable option for the contaminated rest stream that comes out of the gas reservoir next to hydrogen?
7. Is offshore gas reservoir hydrogen storage technically and economically more feasible than onshore storage alternatives and offshore salt caverns?

By answering these research (sub)questions, the objective is to identify if a depleted gas reservoir in a far offshore environment is technically and economical attractive solution to act as a buffer for hydrogen storage in the Dutch North Sea. The outcomes are compared to alternative storage options such as salt caverns offshore and onshore. Another objective is to see if there is merit for existing natural gas infrastructure to be transformed for hydrogen purposes. The outcomes of this research should lead to better understanding the technical implications for offshore UHS in a depleted gas reservoir and help the Dutch government and other decision makers to consult on the complexities of offshore hydrogen storage in a depleted gas reservoir.

3.3 Methodology

To come to the answers to the research questions, this research is divided into multiple phases. The research strategy will consist of six subsequent phases, and within each research phase, sub-questions are designated that are chronologic structured to solve the main research question. It starts with Phase A, where the literature is researched to understand the current state of art on UHS and the academic knowledge gap. This is followed by Phase B, that consists of the conceptual system design where the technical analysis of this research is described. This section is divided in multiple sub-phases focusing on the reservoir, transport routes and platform. Followed by Phase C, that described the economic analysis of implementation of the designed system. Hereafter, the methodology of the sensitivity analysis is presented. The research report ends with Phase E & F, where the Discussion and Conclusion & Recommendations are carried out, respectively.

3.3.1 Phase A: Literature Research / Theory

Phase A involves a comprehensive literature review to assess the current state of knowledge in UHS. The review focuses on identifying the academic and industrial gaps in subsurface hydrogen storage, particularly in porous rock formations under the sea. The literature review was conducted using online databases such as Google Scholar and the internal database of Shell reports. Key topics include:

- Previous studies on UHS (using depleted gas reservoirs).
- Technological challenges and solutions in subsurface hydrogen storage.
- Existing offshore infrastructure and its potential reusability for hydrogen storage and transportation.

3.3.2 Phase B: Technical Analysis

The technical analysis of the offshore underground hydrogen storage system begins with defining the system boundary conditions. This foundational step is critical as it sets the framework within which all further design and analysis are conducted. System boundary conditions ensure the scope of the system in terms of physical, operational, environmental, and technical parameters. Accurate definition of these boundaries ensures that the subsequent phases of the design process are focused and relevant, minimizing the need for revisions and recalibrations. With these boundary conditions, Phase B develops a conceptual design for the UHS system. This phase breaks down into three sub-phases:

- **Reservoir Suitability Analysis:** Evaluates the geological and geophysical characteristics of potential reservoirs in the Dutch North Sea to determine their suitability for hydrogen storage. This includes an evaluation of the well performance during injection and production cycles to understand if the reservoir can handle the flow rates needed for UHS. For this simulation the software Prosper was used. The flow within the reservoir and the distribution of the gasses in the reservoir are modelling using Shell's own simulator. Dynamic reservoir simulations were run to comprehend the depleted gas field's storage behavior during the injection-production cycle(s) and to ascertain the composition of the back-produced gas stream and the total hydrogen recovery.

- **Transport Routes Analysis:** Examines the existing pipeline infrastructure for its potential to transport hydrogen and side products from production sites to storage locations and eventually to onshore facilities. Block Flow Diagrams (BFDs) will be created to provide a simplified representation of the hydrogen transport process. These diagrams will illustrate the major processes involved in the transportation of hydrogen, including:
    - Points of hydrogen production (e.g., offshore wind farms where electrolysis occurs).
    - Pipeline sections used for hydrogen transport.
    - Storage facility location.
    - Onshore delivery points.

  Multiple scenarios for the implementation of a UHS facility in the Dutch North Sea are described and the thinking steps are clearly explained with comments on every design choice. At the end the most promising scenarios are compared and evaluated.

- **Platform Design:** Focuses on the modifications required for existing platforms or the design of new platforms to handle hydrogen injection, storage, withdrawal, and purification processes. This also includes the powering of the platform.

3.3.3 Phase C: Economic Analysis

Once the technical design phase of the offshore underground hydrogen storage (UHS) system is completed, the project proceeds to a high-level economic analysis. This critical phase is designed to establish a clear financial framework for the implementation and operation of the UHS system, focusing primarily on understanding the economic implications of the project.

The economic analysis begins by calculating both the capital expenditures (CAPEX) and operational expenditures (OPEX) associated with the UHS project. CAPEX includes all initial costs required to develop and install the UHS system, such as expenses related to retrofitting existing infrastructure, constructing new facilities, costs related to cushion gas, and installing necessary technologies for hydrogen handling. OPEX encompasses all ongoing costs needed to maintain and operate the system efficiently, including maintenance, energy costs and hydrogen loss.

A pivotal component of this economic analysis is the calculation of the Levelized Cost of Hydrogen Storage (LCOHS). The LCOHS is a metric that quantifies the additional cost per unit of hydrogen stored, effectively measuring the incremental price that is added to the cost of the green hydrogen produced in this specific use case. This calculation is essential for determining the economic viability of the storage system and helps in comparing the cost-effectiveness of UHS with other storage technologies or methods.

By integrating the LCOHS into the Levelized Cost of Hydrogen (LCOH), stakeholders can gain a deeper understanding of the financial performance of the UHS project and benchmark their projects against others. It allows for a more informed assessment of whether the additional costs incurred by storing hydrogen in this manner are justified by the benefits, such as enhanced energy security, improved utilization rates of renewable energy sources, and potential revenue generated from hydrogen sales.

The outcome of this economic analysis will not only highlight the direct costs and benefits associated with the UHS project but also provide critical insights into the broader economic impacts, including potential cost savings from extended asset utilization and contributions to achieving environmental and energy resilience goals. This comprehensive economic perspective is vital for decision-making and strategic planning, ensuring that the project aligns with financial, technical, and environmental objectives.

3.3.4 Phase D: Sensitivity Analysis

Sensitivity analysis is an integral part of the economic evaluation. This analysis assesses how sensitive the project's financial outcomes are to changes in key variables, providing insight into the potential risks and uncertainties associated with the project.

In this analysis, the best performing scenario is examined to understand the impact of various factors on the financial viability of the UHS system. These factors typically include fluctuations in market prices of hydrogen, changes in technological efficiency, and variations in CAPEX and OPEX. By altering these parameters within certain ranges, the analysis can identify which variables have the most significant influence on the project's economic outcomes. For example, the model might explore the effects of a 10% increase in hydrogen prices or a 20% reduction in CAPEX due to technological advancements.

This process not only highlights the variables that are most critical to the project's success but also helps in preparing risk mitigation strategies. For instance, if the analysis shows a high sensitivity to hydrogen market prices, the project team might consider strategies such as entering into long-term sales agreements to lock in prices or developing a more flexible operational model that can quickly adapt to market changes.

3.3.5 Phase E: Discussion - Comparison between different storage scenarios

In Phase E of the research, the discussion focuses on comparing different hydrogen storage scenarios to determine the most effective and efficient solution for integrating into the

Dutch North Sea infrastructure. This phase critically evaluates the offshore underground hydrogen storage in a depleted gas reservoir against alternative storage methods such as onshore and offshore salt cavern storage or near-shore storage. This phase informs stakeholders about the most suitable hydrogen storage approach, paving the way for informed decision-making in Phase F: Conclusion and Recommendations.

3.3.6 Phase F: Conclusion and Recommendations

In Phase F of the research, the methodology involves synthesizing all collected data and findings from the previous phases to assess the technical and economic viability of using offshore underground hydrogen storage in porous media in the Dutch North Sea. This phase focuses on integrating the insights related to system design, economic analysis, sensitivity impacts, and comparative assessments to formulate a cohesive conclusion about the project's feasibility. The approach ensures that all relevant factors are considered to answer the main research question comprehensively and provide a well-rounded view of the potential for implementing UHS to buffer an intermittent supply of green hydrogen. This consolidated analysis sets the stage for delivering informed and strategic recommendations for future research and policy development.

4 TECHNICAL PREMISE - CONCEPTUAL SYSTEM DESIGN

Chapter 4 outlines the process that led to the conceptual design for offshore hydrogen production and underground hydrogen storage. It aims to answer the sub-questions:

- Could there be merit in reusing NAM's offshore assets for offshore hydrogen production, storage, and transport in the future? If so, what are the key elements in achieving this?
- Which destination is considered the most viable option for the contaminated stream that comes out of the gas reservoir next to hydrogen?
- Is offshore gas reservoir hydrogen storage technically and economically more feasible than onshore storage alternatives and offshore salt caverns?

This research study embarks on the conceptualization of a high-level offshore underground hydrogen storage in a gas reservoir located in the Dutch North Sea, integrated with an offshore wind farm for hydrogen production and the export routes to the onshore backbone. The initial phase involves outlining the system's boundary conditions and formulating foundational assumptions regarding hydrogen production, transportation, and storage in an offshore depleted gas reservoir.

Subsequently, in Section 4.4, the infrastructure design choices for the hydrogen production, storage and transportation are outlined by interlinking the various subsystems via pipelines. Particular emphasis is placed on the potential repurposing of existing pipelines, operated by NAM, for the distribution of H_2 and tail gas to shore. Upon the identification of two scenarios with the most promising feasibility for future implementation, a deeper exploration into each is conducted by constructing block flow diagrams and defining essential hardware for UHS platforms for both scenarios. The latter consists of footprint, weight and power consumption of the significant utilities, such as compressors and the PSA.

In conceptualizing a UHS system for hydrogen derived from offshore wind energy, several critical steps are undertaken. Initially, the specifications of the hydrogen production plant are established, considering factors such as location, capacity, electrolyser type, and efficiency. The purpose of the storage facility is then identified, which could range from buffer storage to manage a constant supply to the onshore backbone, seasonal storage for long-term variations, or strategic reserves for unforeseen disruptions. The optimal location and geological formations for the UHS, such as salt caverns or depleted gas reservoirs, are determined next. Essential to the process is the selection of cushion gas and the adoption of a suitable purification technology, which could be Pressure Swing Adsorption (PSA), Membrane Separation, or Cryogenic Separation. As this choice is based on theoretical evidence as stated in section 2.4, it remains external of the infrastructural design process for this case study. The suitable purification technology depends on the hydrogen product specifications of the Dutch hydrogen grid. As there is no clear decision made yet, the higher purity grade of 99.99+% has been assumed. This emphases the choice for PSA again.

A pivotal aspect of the design process involves the examination of diverse pipeline pathways to bridge the offshore hydrogen wind farm with the UHS and from UHS to the onshore H_2 backbone. This exploration considers the optimal re-use of existing infrastructure to minimize costs and environmental impact, as well as the feasibility of transporting hydrogen and tail gas to shore.

The design steps are detailed in Table 3, progressing from left to right. Each step inherently impacts subsequent decisions. By the conclusion of this chapter, a comprehensive discussion clarifies the rationale behind the choices made throughout these design steps.

Table 3: Comparative Design Choices for Underground Hydrogen Storage (UHS) Systems: Evaluating Production, Transportation, and Storage Options in Relation to Offshore Wind Farms

			Hydrogen Production			
Windfarm Offshore Location	Windfarm Capacity	Windfarm Production	Electrolyser Location	Electrolysis	Electrolyser Efficiency	Energy Conversion (PtG)
Area 3 (2 GW)	2 GW	Electricity	Centralised / Platform	PEM	70%	70%
Area 7 (8 GW)	8 GW	Hydrogen	Decentralised	Alkaline	80%	75%
Area 6 (10 GW)	10 GW	Electricity & Hydrogen	Energy island	Solid Oxide	100%	80%
			Hydrogen Storage			
Purpose of Storage	Storage Location	Offshore Store type	Cushion Gas	Compressor	Purification Technology	Tail Gas Destination
Buffering pipelines	Offshore	Salt Cavern	H_2	Reciprocating	PSA	Reinjection into Reservoir
Seasonal	Onshore	Gas Reservoir	CO_2	Centrifugal	Polymeric Membrane	Export
Strategic		Aquifer	N_2		Cryogenic Separation	Reinjection & Export
			CH_4			
			Hydrogen Transport			
Pressure de-rating percentage of NG pipeline	Max H_2 Flow Velocity	H_2 Export Flow	H_2 Export Pipeline	Onshore Location (H_2 pipeline landing)	H_2 Export Pipeline	Tail Gas Export Pipeline
50%	10 m/s	1 GWh	Existing	Eemshaven	NGT	NGT
60%	30 m/s	2 GWh	New	Den Helder	WGT	WGT
80%	60 m/s	3.5 GWh	Both	Rotterdam	LoCal	LoCal
100%		10 GWh			New Pipeline	New Pipeline

4.1 Key Assumptions for Design

4.1.1 Wind farm

For the purposes of this research, Wind Area 7 (WA7) in the Dutch North Sea was appointed as the primary site for the establishment of a wind park for green hydrogen production, see Figure 4-1. This is a wind farm far offshore in the Dutch North Sea with an estimated installed wind power capacity of 8 GW. Wind Area 7 is part of the offshore wind development roadmap 2030+, present by the Dutch government [80], see APPENDIX 1.

For the wind turbine, the IEA 15-Megawatt Offshore Reference Wind Turbine data sheet has been used to simulate the energy yield, see APPENDIX 3 [81].

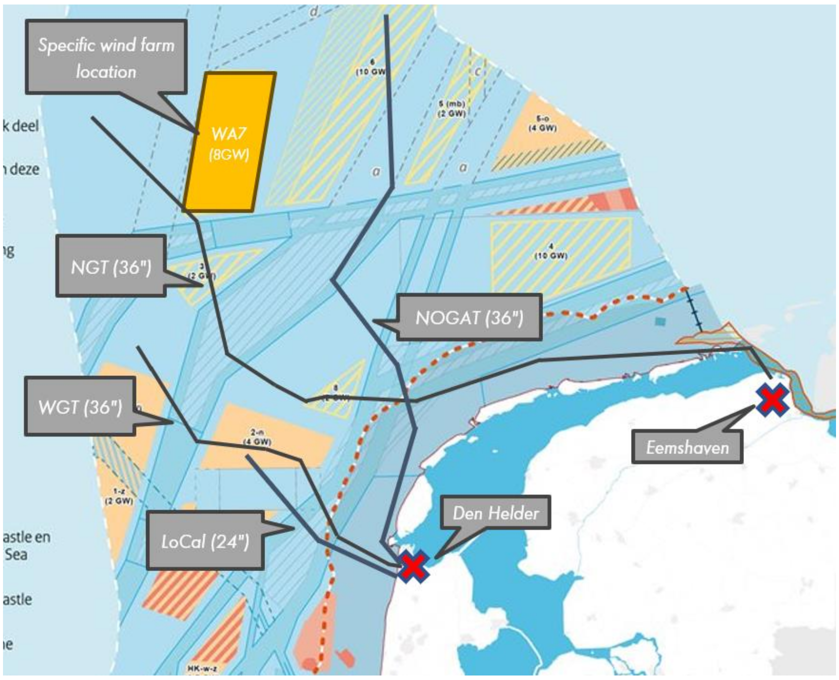


Figure 4-1 - Location of wind area 7 with respect to the main four trunklines to the Dutch shore

The choice for WA7 was influenced by a set of scientific considerations:

- **Geographic Positioning**: The main reason for favoring wind power export to shore via molecules rather than electrons, is that costs increase with distance is steeper for cables than pipelines. The tipping point lays between 100-150 km [13, 82]. The absolute distance from WA7 to Eemshaven and Den Helder are ~190 km and ~140 km, respectively. This indicates the incentive to transport the energy using molecules instead of electrons.
- Foremost, WA7's far offshore positioning yields a heightened capacity factor compared to wind areas near shore [83]. Farther offshore locations typically benefit from steadier and more potent wind speeds, thus guaranteeing a more dependable energy yield. Besides the higher capacity factor, the cables losses for electricity

transportation will be higher when going further offshore. Therefore, this wind area has a high probability of hydrogen generation compared to the other future wind development areas in the Dutch North Sea.

- **Size and Capacity**: This research primarily focuses on UHS within gas reservoirs, with an emphasis on storage capacities spanning multiple TWh. A critical aspect to consider is identifying a wind farm that can produce hydrogen, approximately aligning with the storage capacity. So, it is logical to choose a large producer of H_2, hence WA7.
- The WA7 wind farm emerges as a logical choice for this study due to its substantial power generation potential. Specifically, WA7 has the capability to generate up to 8 Gigawatts (GW) of power. Considering a capacity factor of 0.4, which is normal for offshore wind energy [83], this translates to an annual energy production of 28 TWh. Therefore, selecting a large-scale hydrogen producer like WA7 is rational for this investigation, ensuring that the production and storage capacities are corresponding. Since gas reservoirs have much larger sizes and capacities than salt caverns, it is logical to choose a large producer of hydrogen.
- **Strategic Proximity**: The site's location close to the existing NGT pipeline, which received its 'Certificate of Fitness' by Bureau Veritas makes it a strategically attractive location for the export of hydrogen to the onshore hydrogen backbone [20].

Collectively, these attributes underscore WA7's potential not just as a feasible, but as an optimal hub to address and significantly cater to the escalating demand for hydrogen.

Further bolstering the decision to choose for this site is the foundational research by D. Eradus [84]. Eradus used the wind profile from weather station, D15-FA-1. This weather station is next to F16-A, the closest to WA7. However, F16-A's weather data set extracted from KNMI is not sufficient as there are significant datapoints missing. Subsequently, it was decided to use the weather data of D15-FA-1. As a result, the storage sizing findings from D. Eradus's research, which relied on this wind data set, are directly applicable. Given that Eradus's research is a critical cornerstone of this study, it reinforces the rationale behind selecting WA7 as the most suitable location. The consistency in wind data ensures that the energy output for the wind farm, based on a rated wind power, is accurate, thereby validating the storage sizing recommendations from the research.

4.1.2 Electrolysis

The 8 GW of electricity generated from the offshore windfarm will be used for electrolysis to generate H_2 from seawater using offshore Polymer Electrolyte Membrane (PEM) electrolysis technique. PEM electrolyzers have a number of benefits, including significantly shorter start-up times, higher current densities that result in smaller electrolyzer footprints, higher hydrogen purity (>99.99%), functioning beyond nominal power, and higher output pressure compared to alkaline electrolysis [85]. PEM electrolysers are suitable for intermittent inputs like the power produced by offshore wind farms because they are highly flexible with considerable changes in operational parameters [11]. Besides the suitability for intermittent inputs, PEM electrolysers are lower in weight compared to Alkaline Electrolysers and that is preferred for offshore settings, to manage platform stability and structural integrity. Centralized electrolysis is assumed due to scale simplicities.

Shell is looking with industry partners at producing offshore green hydrogen from wind energy. Their proposed electrolyser platform is used as a reference case. The electrolysis platform has an installed electrolyser capacity of 300 MW. Figure 4-2 shows the block layout of the 300 MW centralized electrolysis platform at weather deck elevation. The dimensions of the platform are approximately 64 m x 64 m.

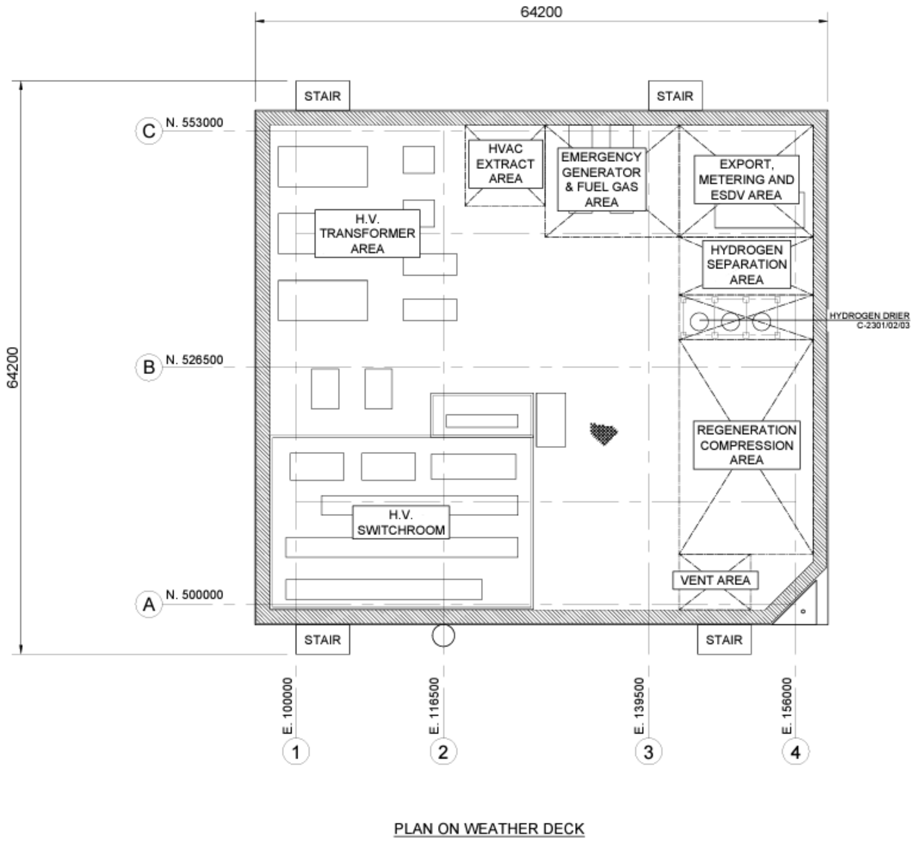


Figure 4-2: Block Layout of 300 MW Centralized Electrolysis Platform at Weather Deck Elevation

Taking into consideration the dimensions of the electrolysis platform, for a significantly smaller capacity than that being assessed in this study i.e., 300 MW vs 8 GW, it has been assumed that 16, individual electrolysis platforms, each with the capacity for hydrogen processing of 500 MW will be used in this study. The arrangement of these platforms can be seen in Figure 4-2, where the green diamonds present the electrolyser platforms. The dimensions of these 500 MW platforms are assumed to be the same as those shown in Figure 4-2. The reasoning for this is based on the assumption that with time, technological advancements will be such that a similar sized platform can process more H_2 in 2030+, according to Shell's Green Hydrogen Department and IRENA's report on green hydrogen cost reduction [86] [87].

PEM electrolyzers have theoretical efficiencies in the range of 80% to 90% [88]. An additional energy loss of 10% is used in this research due to electrical losses – in transmission, transformers, switch gear – and powering utilities on the hydrogen platform such as desalination plant, water intake system, de-oxygenation, compression, dehydration, and aftercooler powering. Therefore, the efficiency of the electrolysis platforms has been assumed to be 70%, which results in P2G conversion of 70%, so 5.6 GW of produced hydrogen at rated wind power. Of this 5.6 GW of hydrogen, 3.5 GW requires piping to shore and 2.1 GW that is a surplus requires injection to UHS. This is the similar ratio as the study of D. Eradus. This will be further elaborated in Section 4.2.

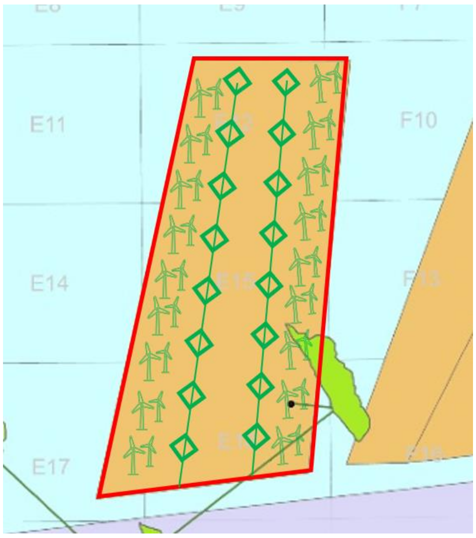


Figure 4-3 – Assumed electrolysis platforms arrangement in WA7, consisting of 16 500MW electrolysis platforms and an installed wind turbine capacity of 8GW

4.1.3 Storage type

The goal is to support offshore green hydrogen production in the North Sea, particularly far from the coast. The wind profile directly affects how much hydrogen gets produced at WA7, making the consistency of production a key concern. To provide a steady flow of hydrogen to the onshore backbone, a reliable storage system is essential. A buffer store will help maintain a smooth flow through the pipelines, which also helps to extend the pipelines' lifespan. To store the energy that is being produced at an 8 GW wind farm, large-scale energy storage facilities are required. UHS in a depleted gas reservoir will be evaluated for this research.

During the development of the UHS system, an offshore depleted gas reservoir, in the K8 region in the North Sea, was chosen instead of other storage options like offshore salt caverns. This gas reservoir is operated by NAM and located closest to WA7, see Figure 4-4. According to NAM, it possesses the potential to be aptly suitable for UHS applications [89].

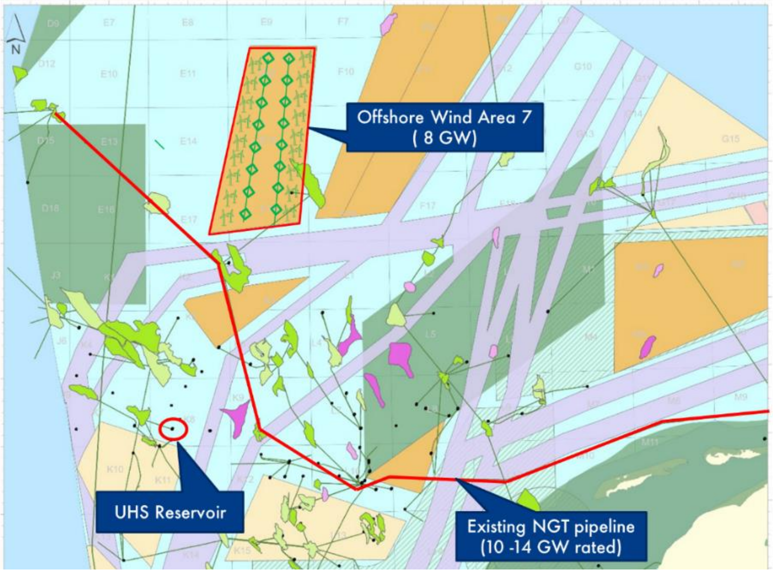


Figure 4-4 – Geographical position of WA7, the UHS reservoir and the NGT pipeline in the Northern quadrant of the Dutch North Sea. The orange blocks are 2030+ potential windfarm locations.

As there are still many uncertainties about the use of porous media for hydrogen storage in the subsurface, it is important to state the assumptions that have been made in this research for the offshore UHS facility and its capabilities. The following assumptions are applied in this research to an offshore UHS option:

- The offshore UHS option assumes 100% buffering of the intermittent production of renewable H_2 into the pipeline to generate a constant export of hydrogen to the onshore backbone.
- It is presumed that before initiating the storage operations, the storage facility will be pre-filled with H_2 cushion gas. Various types of gas can be used as cushion gas, including N_2, Methane or CO_2. For H_2 storage, using these types of cushion gases highlighted the requirement for implementing post-processing of the produced gas, as some cushion gas can produced along with the H_2, thereby affecting the quality of the hydrogen outflow. Cushion gas injection is further discussed in 4.6.1.1.
- The storage operations can start in October, as the reservoir will be topped up with cushion gas and in the winter months, generally there will be a surplus of green hydrogen and therefore the store can be filled. Therefore, it is of importance to fill the store with cushion gas in the months prior to October. To fill the store with cushion gas, hydrogen is needs to be injected before the store can act as buffer. Therefore, the first hydrogen that is produced is designated for filling up the reservoir with cushion gas. This process is further explained in section 4.6.1.1.
- It is assumed that the operations begin when the reservoir is topped up with hydrogen to 250 bar, which to energy content of 2782 GWh of H_2. This is equivalent to 100% of the fill level.
- It is assumed that the depleted reservoir pressure will be 40 bar(g) after gas production and decommissioning of the gas platform. This indicates that the reservoir

pressure will be 40 bar before conversion to UHS. This baseline pressure is considered while planning any storage activity and the amount of cushion gas necessary.

- The reservoir will undergo a pre-filling process before actual operations. The pre-fill will consist of H_2 cushion gas. Before the onset of hydrogen storage operations, it is assumed that the reservoir will be pre-filled or "topped up" to a pressure of 150 bar(g) using H2 cushion gas. This cushion gas serves to support system integrity and provide a pressure buffer for the working gas.
- The designated operating pressure range for the storage facility is between 150 bar(g) and 250 bar(g). The operating pressure range for the storage facility is presumed to be between 150 bar(g) and 250 bar(g). Within this range, the system is assumed to operate optimally in terms of both safety and efficiency. The upper limit of 250 bar(g) is considered the maximum safe operating pressure, beyond which the system's safety and integrity may be compromised.

The Zfactor of H_2 is 1.0731 at 150 bara and 20 °C and 1.1226 at 250 bara and 20 °C [90]. An average value of the Z-factor of 1.09785 is used to calculate the storage capacity for the working pressure range of 150–250 bara. Leading to the volumes presented in Figure 4-5.

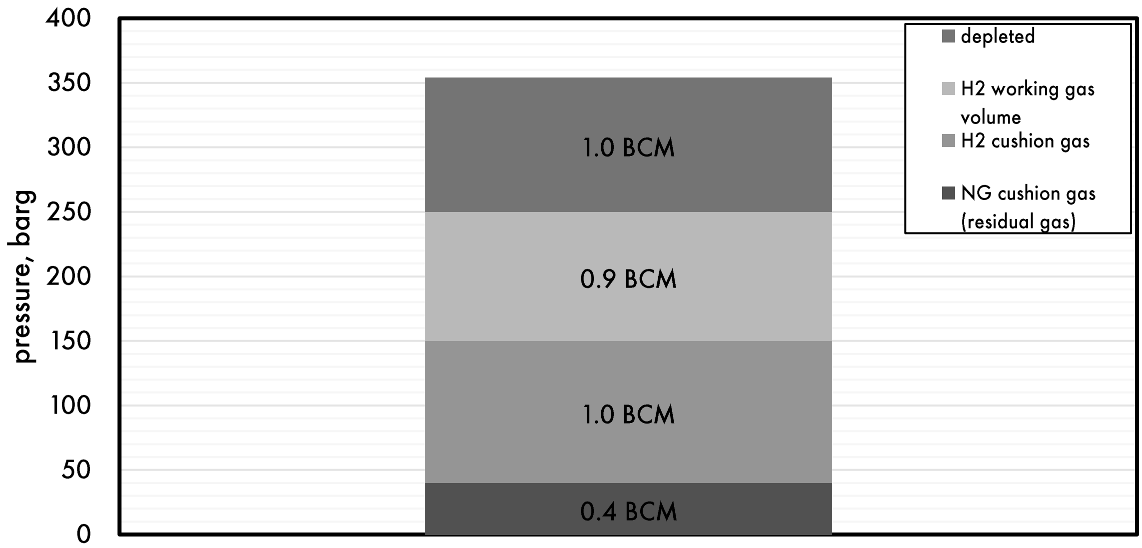


Figure 4-5: Reservoir Volume Information

4.1.4 Tail Gas Destination

As the hydrogen is stored in a depleted gas reservoir, the hydrogen needs purification to get rid of contaminants and to meet the hydrogen backbone purity spec of 99.5%, as stated in section 4.1.6. Therefore, the hydrogen is purified using a PSA. The side stream that comes out of the reservoir is at near-atmospheric pressure and varies in mole weight, large, intermittent and unreliable flow rate. Finding a dedicated customer for this stream, therefore becomes difficult. Two options were found to be the most realistic as destination for the tail gas, which are reinjection of the tail gas and partial export of the tail gas to a blue hydrogen plant in Den Helder. The research on the tail gas can be found in section **Error! Reference source not found.**.

4.1.5 Pipeline boundary conditions

Although there is currently no offshore hydrogen pipeline in operation, certain assumptions have been made for the potential operation of offshore hydrogen pipelines.

- Design Pressure:
  Especially for repurposing of natural gas pipelines the design pressures of these pipelines are of importance. For hydrogen transportation, it is crucial to adjust the traditional natural gas design pressures to ensure safe operations. Adjustments are necessary to prevent occurrence of hydrogen embrittlement, leading to more brittle metals and higher chance of cracking. According to an hydraulic study of the offshore LoCal pipeline (24" OD x 84 km), [91], a Maximum Allowable Operation Pressure (MAOP) of 62 barg is assumed when 4~5 GW of H_2 is transported. As the design pressure of the LoCal pipeline for natural gas is 100 barg, this leads to a de-rating percentage of 62%. For simplicity, in this study the design pressures for all repurposed natural gas pipelines are downscaled to 60% of the initial design pressure, to maintain safe gaseous H_2 transport. It is important to note that every pipeline need thorough evaluation before it could be possibly repurposed for H_2 transportation, as downscaling by 60% is a preliminary assessment.
  For new pipeline sections one can design a pipeline that withstands the capacity and the loads and therefore there are no restrictions on design pressures for new pipeline segments. For pipelines that are not operated by NAM, it was decided to work with a design pressure of 120 MPa, leading to MAOP of 72 barg for hydrogen purposes, which is similar to NP001 (24" OD x 31 km).
- Flow Velocities:
  Standard natural gas pipeline design practice is to limit the gas velocity to 10 m/s. Recognizing that hydrogen has a density 1/9th of natural gas and, assuming the same levels of kinetic energy (ρV^2), the permissible velocity for H_2 gas pipelines can increase by a factor of three. The first order estimate of the maximum velocity in a pure H_2 pipeline is thus 30 m/s. Although flow velocities above 30 m/s are not preferable, they are currently considered acceptable for this design phase. While the maximum acceptable velocity might extend between 30 m/s to 60 m/s, a conservative assumption sets it at 30 m/s to ensure safety.
- Flow Temperature:
  For the purposes of this conceptual design, the flow temperature of the hydrogen within the pipeline is assumed to remain constant at 20 degrees Celsius. It should be noted that this assumption is rather high for subsea pipelines but assumed to be true for now. This assumption simplifies preliminary calculations and models. However, it's essential to note

that in the later design phases and during real-world operations, temperature modelling, monitoring and control mechanisms might be necessary to ensure this consistency, especially if the flow passes through regions with significant temperature fluctuations.

- Wall Roughness:

  The wall roughness, which plays a pivotal role in deciding frictional losses and flow characteristics, is assumed to be 3.00×10^{-5} m. This value will serve as a standard for initial calculations. No distinctions were made between wall roughness of new and existing pipelines, although older pipelines likely have higher wall roughness.
- Pressure Drops:

  Significant pressure drops over short sections of the pipeline can indicate high energy losses and are therefore undesirable. Such issues depend on individual pipeline sections. Therefore, a thorough pressure drop evaluation of each section is necessary to determine if they can manage the projected flowrates. High pressure drops indicate high friction forces, which imply higher change of pipeline failure, and are therefore unfavourable.
- Reusability Considerations:

  The mentioned conditions serve as initial steps to ascertain the possible reusability of existing pipelines for hydrogen transportation. However, it is of paramount importance to conduct a more in-depth evaluation before concluding that re-purposing is practical. The repurposing assessment isn't solely an on-paper task; direct inspection and material testing are essential to guarantee safe and effective operations.
- Bathymetry: Detailed pipeline bathymetry is not available and not used in hydraulic calculation. Pipeline assumed to be straight pipelines (without bends, elevation changes).

4.1.6 Hydrogen Backbone

The purity of hydrogen produced at the windfarm is of extremely high purity, in the range of 99.999% as this is the purity of H_2 from PEM electrolysis [REF]. This will not be the case when the hydrogen is withdrawn from the reservoir. It is therefore of importance what the specifics are of the onshore hydrogen backbone to understand the requirements for purity. According to Gasunie, who will be the operator of the Dutch H_2 backbone, the Dutch Ministry of Economic Affairs and Climate Policy (EZK) will specify the minimum quality of hydrogen in the Dutch hydrogen network. EZK asked testing and certification institutions KIWA and DNV to prepare a report to establish quality requirements for the hydrogen in the network. These quality requirements focus on the minimum purity and maximum permissible concentration of trace elements and impurities. According to the latest update from HyNetwork Services, a subsidiary of Gasunie, there is no final statement on the purity spec [68]. Currently, June 2024, the policymakers are still deciding on 9~10%or 99.5% purity. This research assumes that the onshore backbone specification has the purity of 99.5%.

Besides the purity specifics of the hydrogen, another important parameter is the operational pressure regime and the minimum pressure at which the hydrogen should be delivered to the onshore network. The operating pressure envelope is between 30 and 50 bar(g). Therefore, it's important to deliver the hydrogen at least with 50 bar(g) to the shore without the need of an additional compressor onshore. For this research the starting point is to deliver the hydrogen at a pressure of at least 50 bar(g) at the end of the latest offshore pipeline, without intermediate compression stations between pipelines and no further onshore recompression. Compression will only be done on the offshore platform before the hydrogen is exported.

The 2040 onshore European hydrogen network, consisting of 39,700 km of pipelines, envisages 69% repurposed pipelines combined with 31% new pipelines at an estimated cost of between €43-81 billion [92]. Approximately 4,600 kilometers of pipeline form a widespread web of existing natural gas and oil pipelines on the Dutch Continental Shelf alone [93], but the length of the offshore hydrogen backbone is still unknown..

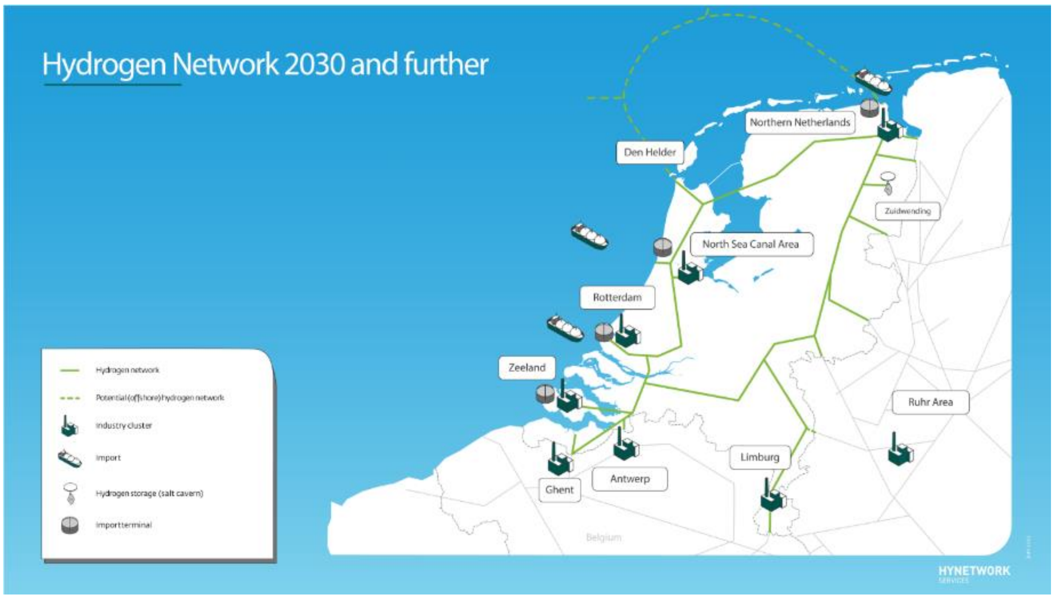


Figure 4-6 Hydrogen network Netherlands in 2030 [11]

4.2 Required storage capacity

A study by Deirdre Eradus, a fellow TU Delft MSc Sustainable Energy Technology student, investigated the storage capacity of an offshore UHS facility in the Dutch North Sea to maintain a steady supply of offshore green hydrogen production to the onshore backbone [84]. Her research focused on salt caverns as storage location, where this research focusses on depleted gas reservoir. For depleted gas reservoirs it is evident that the reservoir already exists, so the capacity is also known. However, the research of Eradus helps to understand the ratio between installed wind power and the hydrogen export rate. As mentioned in section 4.1.1, an 8 GW wind farm has been assumed. This assumption forms an initial building block, with a view that calculated values can be pro-rated. The research worked with an electrolyser efficiency of 80%, where this research will work with an overall power-to-gas conversion of 70%, due to an encountered energy loss of 10% for powering the H2 platform utilities.

An 8 GW wind farm has the capacity of producing 5.6 GW of H2 during rated wind speeds. By pro-rating the production/export ratio of the TU Delft report, an export capacity of 3.5 GWh of hydrogen for this use case is found. So, an 8 GW wind farm is able to produce a constant hydrogen output of 3.5 GW per hour if it can be stored during surplus of wind and withdrawn during periods of deficit.

Pro-rating the storage capacity found in the TU Delft report, The Techno-Economic Feasibility of Green Hydrogen Storage in Salt Caverns in the Dutch North Sea, an 8 GW wind farm, results in a required storage capacity of 2,782 GWh as shown in Table 4, reflecting to a working volume ~854 million Nm^3.

Table 4 - The outcomes of TUD 2022 report prorated for this research

Parameter	TUD 2022 [84]	Wind Area 7[1]	Units
Wind Output Power	19.80	8.00	GW
Electrolyser Feed	19.80	8.00	GW
Overall system efficiency	80	70	%
H_2 Produced from Electrolyser	15.84	5.60	GW
Export Pipeline Capacity	10.00	3.50	GW
UHS Injection Capacity at Time of Surplus	5.84	2.10	GW
Margin between store withdrawal rate and pipeline capacity	95	100	%
Production Capacity from UHS at Times of Deficit	9.50	3.50	GW
Hydrogen recovery rate	100	90	%
Store volume at pipeline capacity	36.00	33.12	Days
UHS Capacity	8640.00	2782.00	GW hours H_2
	2880.00	854.24	Million Nm3
	259,200	76,881	Tonnes H_2

[1] Zoekgebiedkaart Noordzee – Kaart 4 Programma Noordzee 2022-2027

Table 5 shows the annual hydrogen flow rate through the system simulated, together with the injection and production rates of the reservoir in GWh and Mton, respectively.

Table 5: Total hydrogen quantities flowing through the system simulated for the wind speeds of 2019.

Simulation Results	Year 2019 [GWh]	Year 2019 [Mton]
H_2 Production by WA7	28,985	0.735
H_2 Injected into reservoir	7,320	0.186
H_2 not buffered by UHS	21,665	0.550
H_2 withdrawn from reservoir	7,240	0.184
H_2 transported to shore	28,905	0.734

As reservoirs are in the range of BCM's, finding a reservoir that can handle this storage capacity, should be a problem. The required storage capacity has been confirmed and replicated using an in-house Shell Hydrogen Value Chain Model and this capacity is used in this research, see Figure 4-7. It shows the seasonal sinusoidal swing with daily and weekly variations in storage requirements. The storage is being at the highest fill level at the end of winter, so it can supply hydrogen during the summer, and is the lowest fill level in the beginning of autumn.

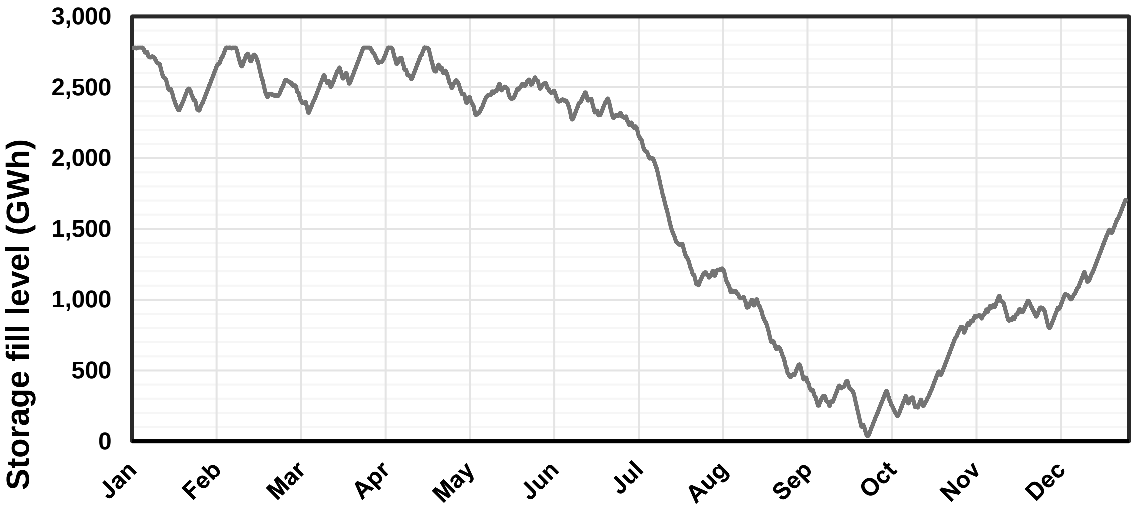


Figure 4-7 - Storage fill level in GWh simulated using Shell's Hydrogen Value Chain Model.

The input used for Shell's Hydrogen Value Chain model, can be found in Table 6.

Table 6 - Input Data for Shell's Hydrogen Value Chain Model

Name	Input	Unit
Wind Input Data	D15-FA-1 – year 2019	[-]
Turbine	IEA 15-Megawatt Offshore Reference Wind	[-]
Rated power	15	[MW]

Number of turbines	533	[-]
U_{Cut-in}	3 m/s	[m/s]
U_{Rated}	10.59 m/s	[m/s]
Wake effect	1	[-]
Electrolyser efficiency	70	[%]
Max input power	8	[GW]
Base load	3.5	[GWh]
Summer deviation	0	[-]
Winter deviation	0	[-]
Storage size	4000	[GWh]
Initial fill [1 jan]	2782	[GWh]
Cycle time	1	[hour]
Injection capacity	2100	[MW]
Production capacity	3500	[MW]

4.3 Injection and production rates

From an engineering perspective it is important to better understand the injection and production rates for the UHS facility. Due to the intermittent nature of wind power, the switching between injection and production modes happens rapidly and often. In some instances, switching as often as every hour, see Figure 4-8. The H_2 injection compressor is designed to respond quickly to these changes and is discussed in section 4.6.1.3. A detailed section dedicated to the hydrogen injection process and production process can be found in sections 4.6.1 and **Error! Reference source not found.**, respectively.

The purpose of the offshore UHS is to ensure a constant supply of H_2 to the onshore backbone while there is intermittent production of green hydrogen, so the store will act as cyclic storage. This minimizes pressure fluctuations in the offshore pipelines to increase lifetime and prevent the pipelines from fatigue crack growth. The injection and production rates are determined by estimating the total time required to fill and empty the required H_2 storage capacity of 854 million Nm^3 at the injection and production capacities listed in Table 7.

Table 7 Injection and Production Rates

Parameter	Value	Units
Required Storage Capacity	2782.00 (854)	GWh H_2 (Million nm^3)

Injection Capacity	2.10	GWh H_2
Injection Cycle at Full Capacity	60	Days
Production Capacity	3.5	GWh H_2
Production Cycle at Full Capacity	38	Days
Hydrogen recovery	92	%
Injection Rate	14.24 (2.1 GW)	Million nm^3 / day
H_2 Export Rate	23.72 (3.5 GW)	Million nm^3/ day

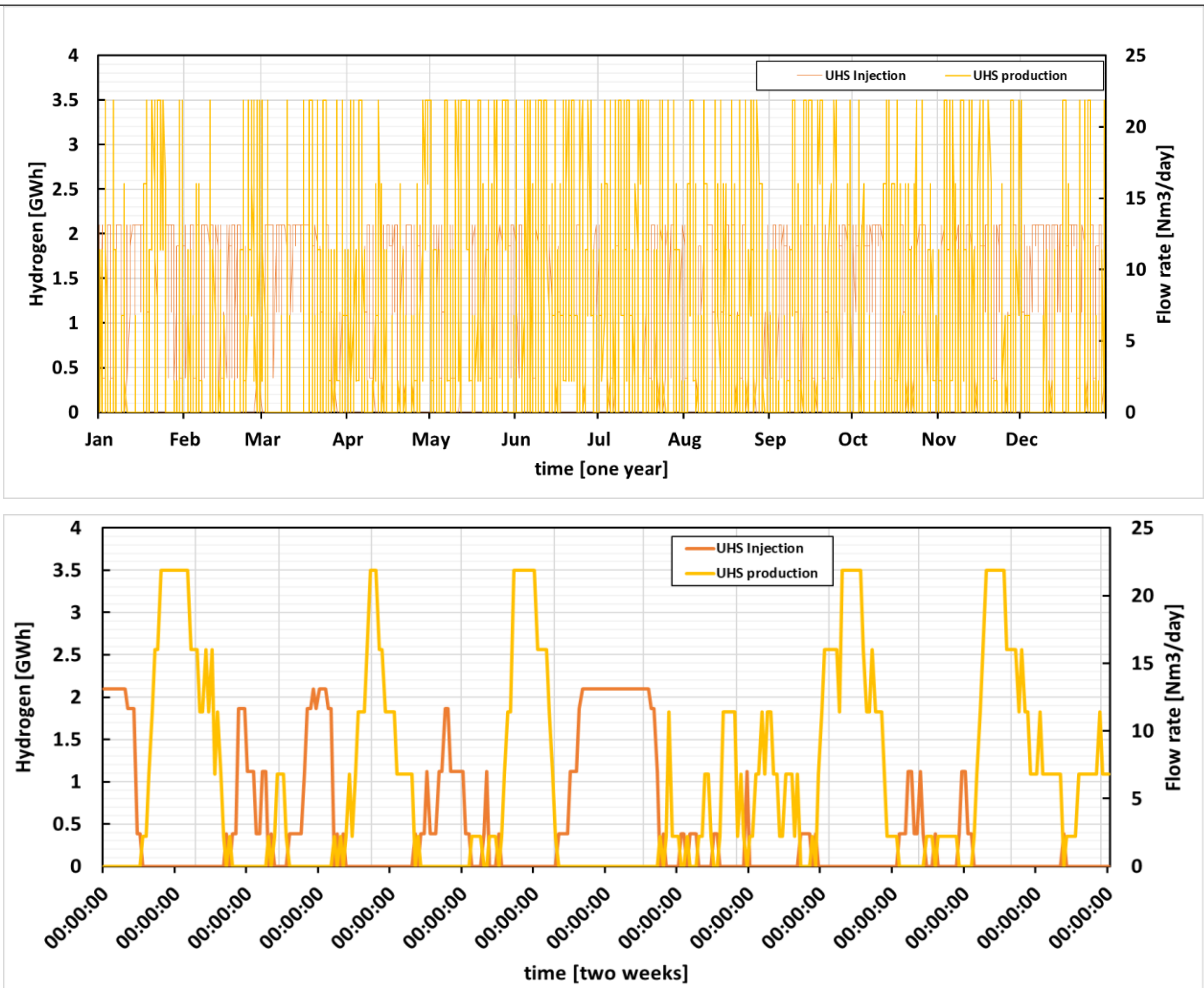


Figure 4-8: Simulated Injection & Production Flow Rates in Nm3/day and GWh over one calendar year and a 14-day period in January. Resolution is in hours.

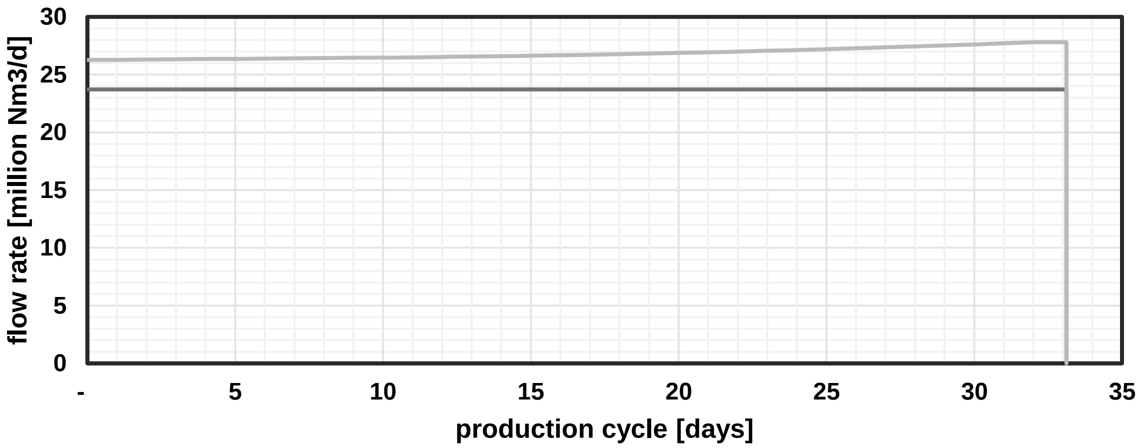


Figure 4-9: Withdrawal at full production capacity in 33 days @ constant 23.72 million Nm3/d send-in to hydrogen backbone. Well production 3-4 million Nm3/d higher rate to account for hydrogen loss due to ~90% recovery rate of hydrogen. Black denotes the hydrogen flow rate and grey denotes the total flow rate (hydrogen + tail gas (which also includes hydrogen)).

4.4 Different Conceptual scenarios

In this section, the diverse conceptual scenarios surrounding hydrogen production and the strategic placement of the UHS facilities are explored. An overview of all the current ONEgas facilities in the North Sea is provided, followed by an in-depth understanding of the state of the Dutch North Sea as of 2030+. Afterwards an evaluation of different scenarios for the use case of this research is presented coupled with a forward-looking analysis that will be instrumental for any offshore hydrogen storage system implementation. As one of the sub questions of this research is:

"Could there be merit in reusing NAM's offshore assets for offshore hydrogen production, storage, and transport in the future? If so, what are the key enables? "

It is important to understand the offshore infrastructure of NAM in the North Sea and how this could be re-purposed for hydrogen production, storage, and transport. Especially the latter is of high interest as this can connect future windfarms with depleted gas reservoirs and the energy hubs onshore, where the pipelines come to shore and where it is connected to the backbone. **Error! Reference source not found.** shows the JDA area of NAM facilities and pipelines together with other operators as in June 2018. This area is of high interest as this contains the facilities and pipelines that are connect to the gas reservoir that is used for hydrogen storage and the pipeline export routes to shore. This gives better understandings on how the pipelines are connected to the facilities and therefore what routes the hydrogen can take to be exported to shore. The locations of the platforms are not geographically correct, although it gives better sense on the number of facilities in the North Sea and how they are interlinked. Approximately 4,500 kilometers of pipeline form a widespread web of existing natural gas and oil pipelines on the Dutch Continental Shelf alone [93].

Based on insights from the "Programma Noordzee 2022-2027" [80] —a document focused on the governance and utilization of the Dutch North Sea—it becomes clear that certain areas have been pre-designated for the development of wind farms. For a detailed visual representation of future wind farm map of the Dutch North Sea, see APPENDIX 1.

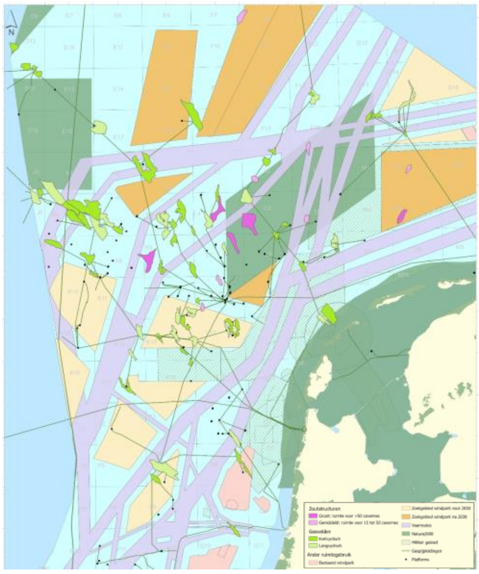


Figure 4-10 Infrastructure of pipelines in the Dutch North Sea [1]

Figure 4-10 showcases the wind park zones, highlighting in orange boxes the regions under consideration for future wind park tenders, where the yellow boxes present the windfarm locations that should be constructed before 2030 and the pink boxes present the established windfarms in 2023. After understanding the current state of the North Sea and its facilities, the hydrogen system designing process can start.

The process of designing various connection scenarios between WA7 and the UHS reservoir involves the following steps:

1. **Pipeline Route Design:** The first step is to map out all possible pipeline paths connecting WA7 to the reservoir. This involves listing both existing pipelines and new ones proposed for transporting hydrogen. A more detailed explanation on this topic is available in Section 4.1.4. After setting up the main transport path, the next task is to identify where the hydrogen will be exported to the main onshore system and where the impure stream from the PSA will be directed. This information is crucial to set the right pressure levels at important points, like where the pipeline from WA7 connects at NGT and where the purified gas exits near the reservoir. It's important to note that this process is intricately linked with assessing the pipeline's capacity. If the chosen routes can't manage the expected flow within safe limits, adjustments will be needed.
2. **Pipeline Flow Capacity Assessment (PFCA):** This hydraulic capacity assessment evaluates the pipeline route designs made in step 1. This evaluation is predicated upon the operational boundary conditions inherent to the pipelines and draws upon the specialized knowledge of Shell's H_2 transport team.
   The pressure drop is predicted based on the non-ideal gas law, factoring in a pressure-dependent compressibility coefficient, see Equation (4) [94].

$$Z(p,T) = \frac{p}{\rho RT} = 1 + \sum_{i=1}^{9} a_i \left(\frac{100K}{T}\right)^{b_i} \left(\frac{p}{1\ MPa}\right)^{c_i} \quad (4)$$

The energy flow through a pipeline is described by Equation (5) [48] :

$$Q = C * D^{2.5} * e * \sqrt{\frac{(p_1^2 - p_2^2)}{dZTLf}} \tag{5}$$

whereby Q is the normal flow rate, Nm3/h; C the proportionality constant=0.000129, dimensionless; D the inner diameter of the pipeline in mm; e the pipeline efficiency (assumed 1), dimensionless; p_1 the inlet pressure, kPa; p_2 the outlet pressure, kPa; d the relative density compared to air, dimensionless; Z the compressibility, dimensionless; T the gas temperature, K; L the length, km; f the friction factor, dimensionless; [Nm3/h] the normal cubic metre/hour.

The outcomes of this analysis might compel alterations to the preliminary scenarios, particularly if specific pipelines do not have the necessary capacity to accommodate the hydrogen and tail gas volume.

3. **Sub-Scenario Evaluation:** Each final scenario for interlinking and export is thoroughly evaluated, highlighting its respective advantages and disadvantages. This comparative analysis is instrumental in finding the optimal method of connecting all the aspects of the system to become operational.
4. **Final Decision:** A definitive choice is made to evaluate two specific scenarios, grounded on the collective advantages and drawbacks of the final scenarios.

4.4.1 Transport Route Analysis

To buffer the intermittent hydrogen production cycles with a storage facility, it is fundamental to connect the store to the windfarm and its electrolysis platforms using pipelines. Therefore, it is interesting to see whether these pipelines have the capacity for the transportation of the hydrogen to the store.

To connect the reservoir with the production platform, the four scenarios are presented in Figure 4-11. By outlining these scenarios, the aim is to supply a clear blueprint for optimal hydrogen transportation to the reservoir and understand the design choices. It is important to mention that there are more options to consider interlinking WA7 with the gas reservoir, but these scenarios were having the highest potential and were the most straight-forward.

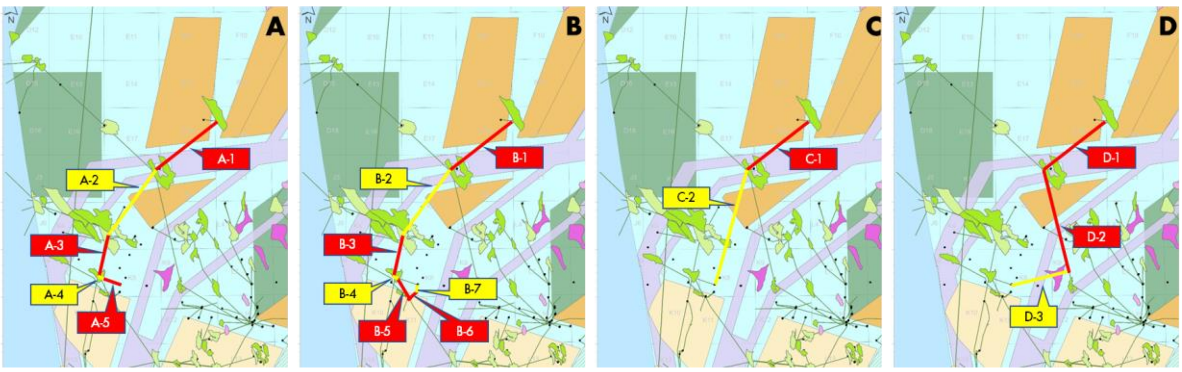


Figure 4-11: Four pipeline scenarios to connect the reservoir with WA7 that are evaluated in this research. The red lines represent existing pipelines that will be repurposed, where the yellow line denote proposed new pipelines. Note: The notations in the figure are not the official names of the pipelines.

4.4.1.1 Interlinking pipeline between NGT and WA7 (ABCD-1)

All scenarios (A, B, C, & D) utilize the same pipeline for exporting hydrogen from WA7 up to the NGT crossing. This pipeline is labeled as A-1, B-1, C-1, and D-1. Although this pipeline is, strictly speaking within the scope of green hydrogen production, and therefore not part of this research, it is still important aspect for the conceptual system as it influences the operating conditions of the UHS system. This 24-inch OD x 32 km pipeline, designated PL0168_PR at the North Sea Energy Atlas [95], was formerly operated by Wintershall. This pipeline is out of use since Q3 2020 [96]. The assumption is made that the pipeline was installed in 2004, as the F16-A platform that is connected to this pipeline, was installed in 2004. No information was found on the design pressure and therefore assumptions are needed to evaluate the capacity. The design pressure for H_2 was assumed to be 72 bar(g), as the NG design pressure is assumed to be 120 bar(g), as this is the same design pressure as the LoCal pipeline. The tie-in of the hydrogen produced at WA7 into PL0168_PR, will be at 25 km up north with respect to the NGT tie-in location. This implies that the 5.6GW of hydrogen is transported over 25 km and should not exceed 72 bar(g) in this pipeline. Post the NGT pipeline crossing, the scenarios diverge, therefore in all scenarios will use the pipeline between NGT and WA7.

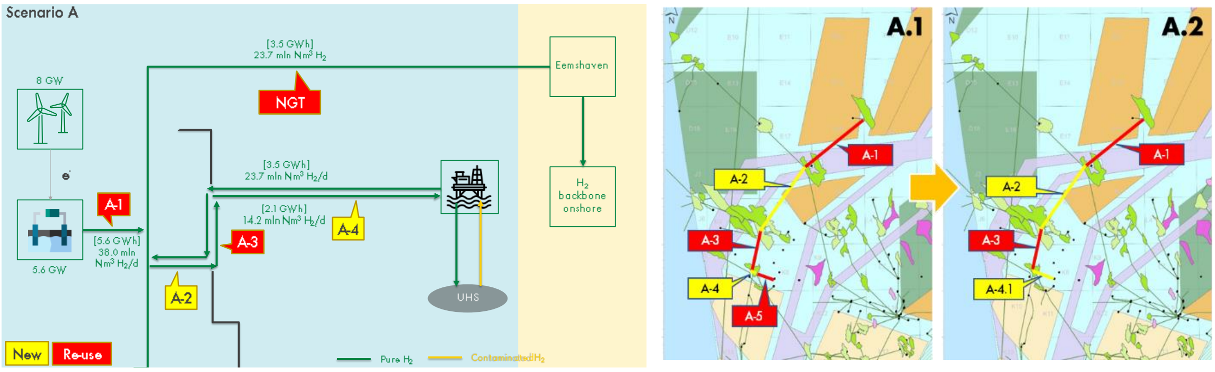
The initial assumption is that H2 will be transported to Eemshaven via the NGT pipeline. As NGT is closest to WA7 and has received the Certificate of Fitness from Bureau Veritas as presented in Section 4.1.1., it is seen as an obvious first choice. Given the requirement for the 3.5 GW of H2 to reach Eemshaven at a pressure of at least 50 bar(g), the pressure drop in the NGT can be determined over the distance between its tie-in point with A-1 and Eemshaven. This pipeline spans 254 km and boasts a nominal diameter of 36 inches. To meet the desired outlet pressure of 50 bar(g) at Eemshaven, the inlet pressure at the tie-in between NGT and A-1 should be 54.9 bar(g). From this data, the outlet pressure from A-1 is established, as it is the same as the inlet pressure of 54.9 bar(g). The export pressure of the green hydrogen platform will be 70 bar [97]. To calculate the pressure drop in A-1, using input 5.6 GW of H2 over 25 km in a 24” OD pipeline. Leading to an inlet pressure of 63.5 bar(g). So, there will be a pressure drop of 8.6 bar over 25 km. Next to that the maximum velocity at inlet and outlet were calculated, which are 26.4 m/s and 30.2 m/s for the inlet and outlet velocities, respectively. As stated in Section 4.1.4, the maximum velocity range for H_2 transport in pipeline was set at 30 m/s.
In case the pipeline is not suited for re-use to transport H_2, a new pipeline is designed that generated a flow velocity below 30 m/s. Therefore, the diameter could be increased from 24 to 26 inch to create maximum flow velocity of 25.8 m/s instead of 30.2 m/s when transporting 5.6 GWh of hydrogen to the NGT pipeline. This decision depends on economic optimization, costs, pressure losses/compression versus pipeline costs.

4.4.1.2 Interlink UHS with WA7 - Scenario A

The rationale behind this option was to pinpoint the shortest route from the NGT crossing to an existing natural pipeline capable of carrying a flow to the reservoir and handling a maximum H_2 withdrawal rate of 3.5 GW during windless periods.

Initial Configuration (Scenario A.1):

In this preliminary layout, pipeline WGT Extension (known as A-3), see Figure 4-12, is not connected directly to A-5. As a remedy, a new 800 m pipeline section, A-4, has been proposed to bridge these infrastructure segments. However, A-5 (also referred to as NP011) with an outer diameter (OD) of 12", lacks the capacity to transport the intended 3.5 GW of H_2 as it is only able to transport 1 GW of H_2 under the conditions. This limitation led to the development of Scenario A.2., see Figure 4-12.



a) b)

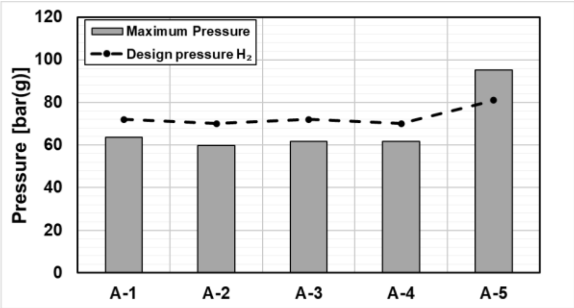
Figure 4-12 Modification from Scenario A.1 to A.2 results in using 4 pipelines, down from 5, to manage a 3.5 GWh H_2 flow as pipeline A-5 has a capacity limit of 1 GWh for H_2 flow.

Revised Configuration (Scenario A.2):

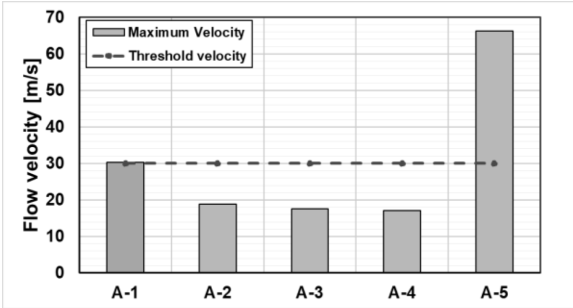
In Scenario A.2, the pipeline configuration largely mirrors that of Scenario A.1, utilizing segments A-1, A-2, and A-3. However, a significant modification is the extension of segment A-4. Instead of connecting to A-5 as in Scenario A.1, A-4 now directly links to the storage facility. A critical requirement for the pipelines is their bi-directional capability. Presently, only segments A-3 and A-1 operate in a one-directional mode, necessitating modifications. These changes will incur additional expenses.

For scenario A.2, the infrastructure will demand two new bi-directional pipelines, measuring 12 km and 34 km, respectively. This totals to an additional 46 km of new pipelines. Additionally, another 46 km of the existing pipeline network will require modifications to achieve bi-directional functionality. This gives a total of 92 km of pipelines that need adjustments or construction between tie-in at NGT and the reservoir.

Ownership and connected infrastructure also introduce complexities. The repurposed pipelines do not fall under the ownership of NAM or Shell, potentially complicating access and use negotiations. Moreover, the upstream part of the A-3 pipeline has multiple connections to other offshore infrastructure. If this connected infrastructure stays operational during the intended implementation period, it could pose significant challenges for the project's seamless execution.



a)



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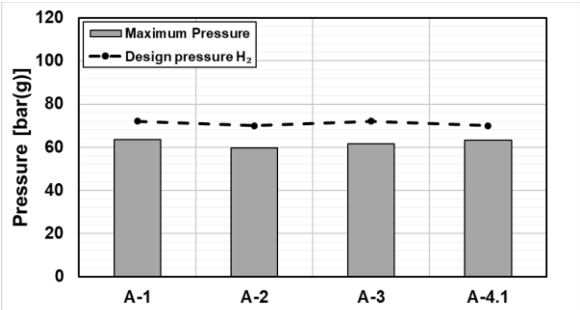
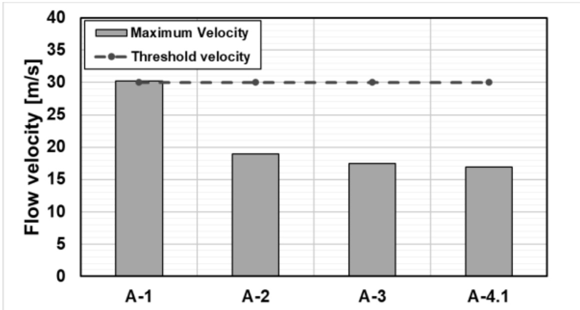


c)



d)

Figure 4-13: Comparative analysis of maximum pressure and flow velocity for Scenarios A.1 and A.2. Figure 4-13 a) & b) show that the design pressure and velocity for pipeline A-5 is exceeded in Scenario A.1. Evidently, A-5 cannot accommodate a 3.5 GWh H2 flow within its operational limits. For Scenario A.2, Figure 4-13 c) & d) show that the introduction of pipeline section A4.1 in Scenario A.2 effectively addresses this limitation.

4.4.1.3 Interlink UHS with WA7 - Scenario B

In Scenario B.1, the primary objective is to optimize the utilization of existing pipelines to bridge production and storage facilities. This scenario aligns with the trajectory of Scenario A.2 up to the point where the flow departs from pipeline B-3. Subsequently, the flow is redirected to capitalize on pre-existing NG pipelines, thereby reducing the need for new pipeline installations.

Upon evaluating the capacity of the pipelines, it was discerned that pipelines B.5 and B.6 are suboptimal for hydrogen flow. Notably, B.6 exhibited significant inefficiencies, with pressure levels exceeding 110 bar(g) and a peak velocity approaching 100 m/s. Such performance metrics raise concerns, necessitating the introduction of a supplementary pipeline, designated B-6.1, that leads to Scenario B.2.

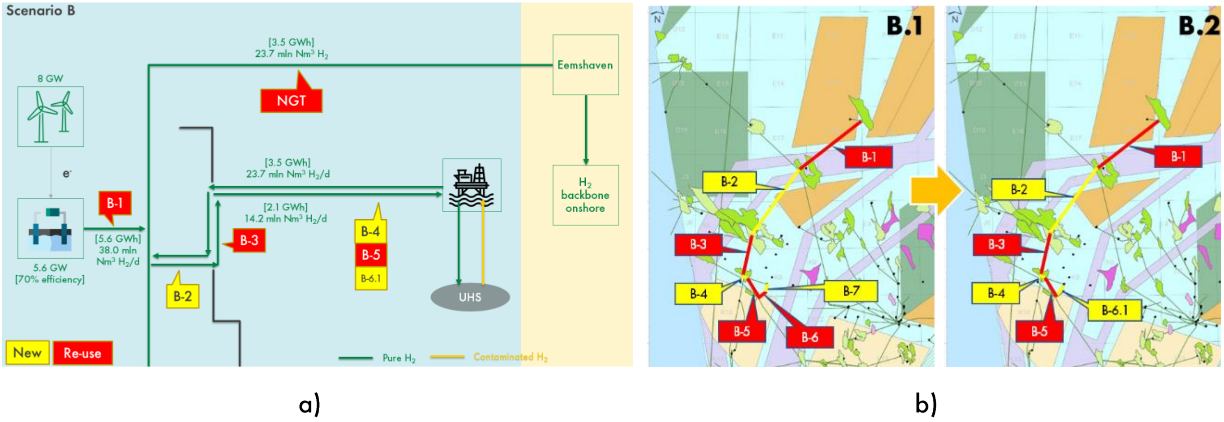


Figure 4-14 Modification from Scenario B.1 to B.2 results in using 6 pipelines, down from 7, to manage a 3.5 GWh H_2 flow, incorporating the reusability of 3 existing pipelines and the construction of 3 new pipelines.

Scenario B.2, while optimizing the reuse of existing NG pipelines, necessitates the introduction of three new pipeline sections. In contrast, Scenario A.2 requires only two. This implies that while B.1 might offer advantages in terms of reusing existing infrastructure, it does so at the potential cost of increased complexity and potential additional expenditure due to the need for an extra pipeline section.

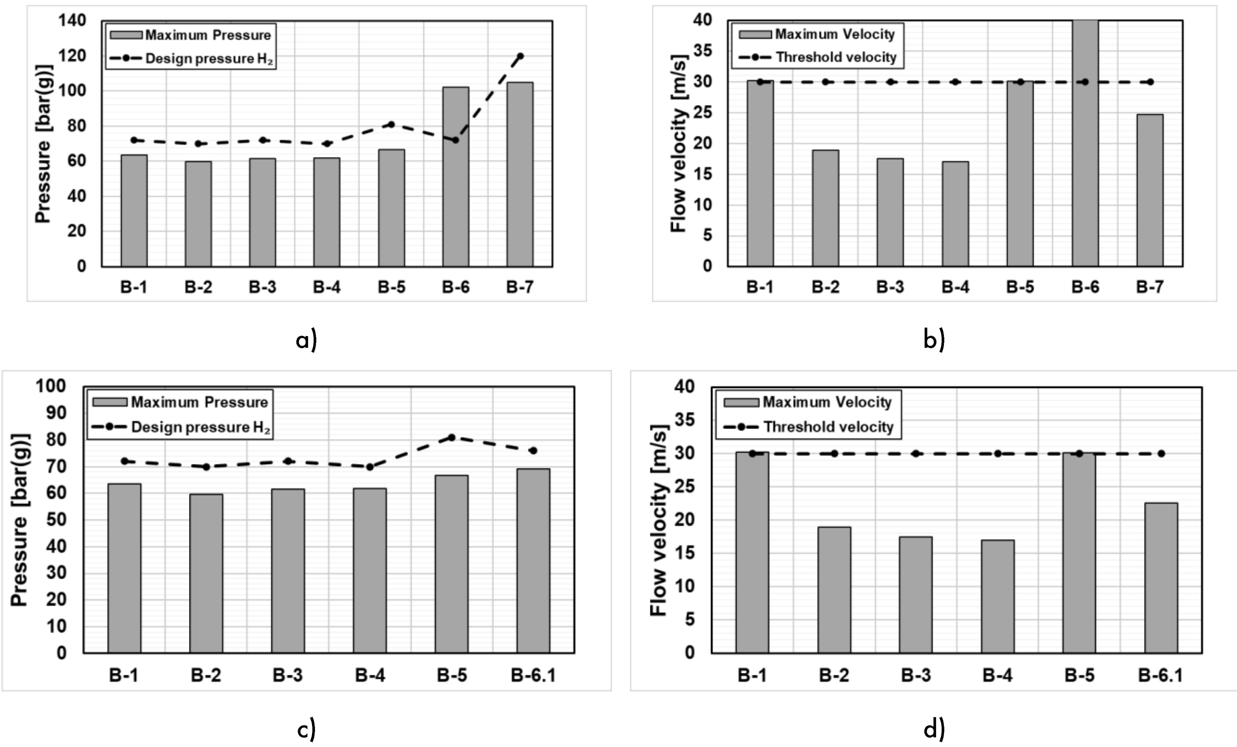
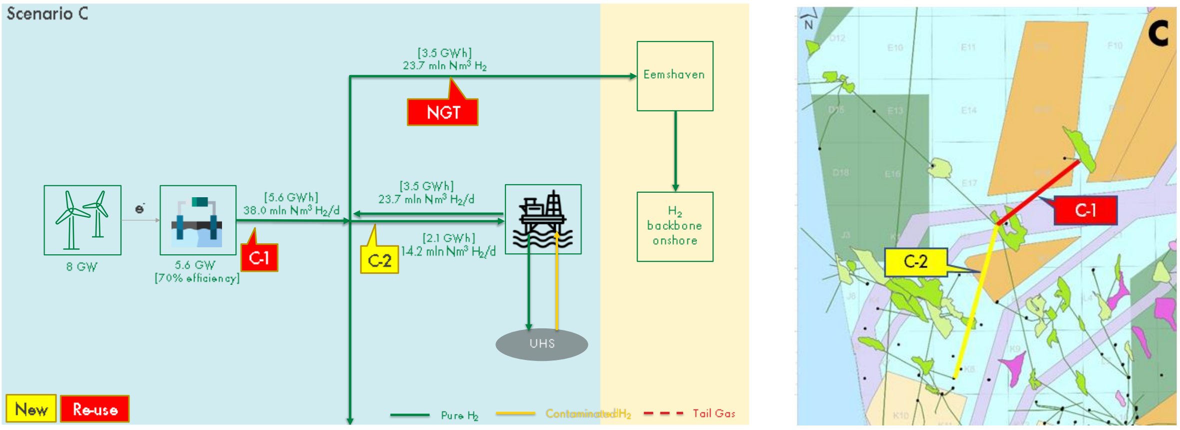


Figure 4-15: Comparative analysis of maximum pressure and flow velocity for Scenarios B.1 and B.2. Evidently, B-6 cannot accommodate a 3.5 GWh H2 flow within its operational limits. Introducing pipeline section B6.1 in Scenario B.2 effectively addresses this limitation.

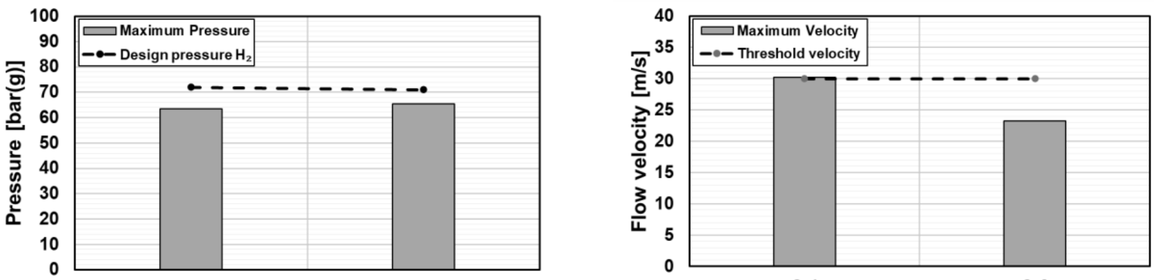
4.4.1.4 Interlink UHS with WA7 - Scenario C

Scenario C proposes the construction of a new bi-directional pipeline, labelled C-2, linking B-1 at the NGT junction directly to the reservoir. Spanning 46 km, C-2 is designed to link NGT directly with the reservoir from the tie-in location. This leads to 100% buffering of the NGT pipeline. The benefit of this scenario is that the complexity of the system is not there compared to Scenario A & B, where multiple pipelines are re-used and need adjustments before, they are operational, which could encounter difficulties and re-use feasibility studies are necessary, which come with additional costs. Another benefit is that a new pipeline can be designed specifically for this scenario and therefore the fluctuations that will be present in the pipeline can be taken care of during the designing process of C-2.



a) b)

Figure 4-16: Scenario C consists of 2 pipelines for transport the hydrogen from Wind Area 7 to UHS, installing a new bi-directional 46km pipeline with nominal diameter of 22".



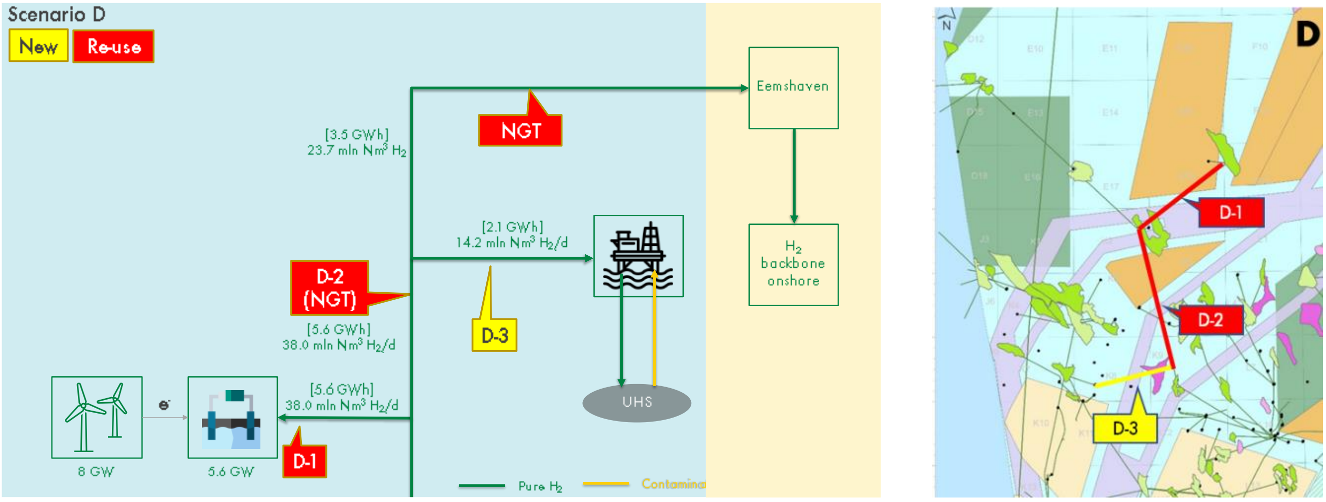
a) b)

Figure 4-17: Comparative analysis of maximum pressure a) and flow velocity b) for Scenario C

In case the NGT pipeline will be chosen to be the export route for H2, C-2 must become bi-directional.

4.4.1.5 Interlink UHS with WA7 - Scenario D

Scenario D, by contrast, was crafted with an emphasis on identifying the most direct route between NGT and the reservoir. To achieve this a perpendicular tie-in into NGT is designed, leading to a new pipeline D-3 of 24 kilometers. D-3 has to become bi-directional if NGT will become the export pipeline for hydrogen.



a) b)

Figure 4-18: Scenario D consist of 3 pipelines for the transport of hydrogen from WA7 to the reservoir. It is the shortest route from the NGT to the reservoir, by installing a new bi-directional pipeline, D-3, of 24 km between the reservoir and NGT.

In this scenario there are two sections, D-1 and D-2 that will experience all the flow fluctuations created by the intermittent production of hydrogen. As one of the major sub-goals of this research is to buffer existing natural gas pipelines to increase lifespan by limiting pressure fluctuations in pipelines and generate a constant H_2 flow through export pipelines, this scenario has a downside. However, this scenario makes to most use of existing pipelines and needs to shortest addition of new pipeline section. From sustainability perspectives, this can be a suitable option. However, the pipelines that are repurposed in this scenario are not operated by NAM.

Another downside of this scenario is that the distance the hydrogen has to travel before it reaches the reservoir is 95 kilometers, which is the highest compared to the other scenarios. This implies that it will be harder to switch between injection and production mode as the hydrogen has to travel a longer distance.

Error! Reference source not found. shows the PFCA of Scenario D, and it can be concluded that the scenario can become operational without any exceedance of operational boundary conditions.

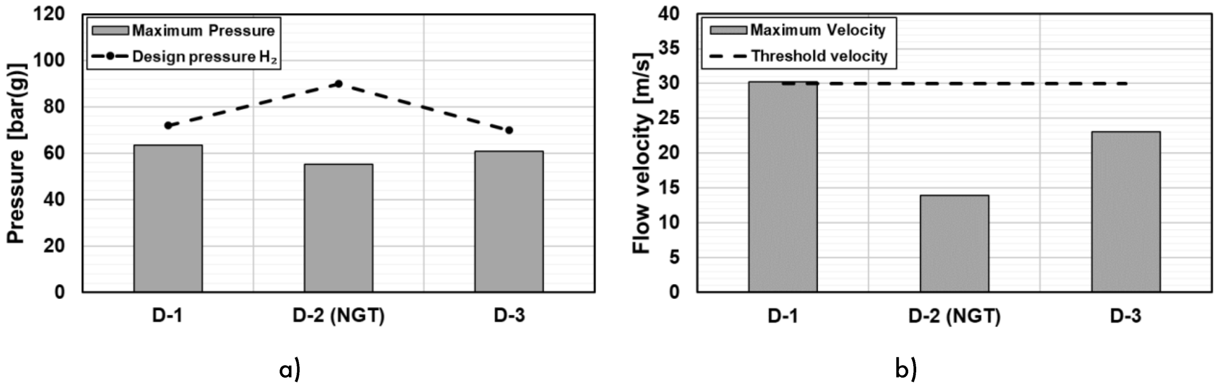


Figure 4-19: a) Maximum Pressure and b) Flow Velocities in Hydrogen Pipelines (D-1, D-2 NGT, and D-3) Under Interlinking Scenario D. The threshold pressures and velocities are indicated by the dashed line.

4.4.1.6 Interlinking UHS with WA7 - Scenarios Evaluation

The evaluation of the four pipeline scenarios for underground hydrogen storage in the Dutch North Sea has been conducted based on various criteria, including the number of pipelines, pipeline distance, reusability, complexity, and buffering. Each criterion was scored using a '+' to denote a positive aspect, '-' for a negative aspect, and '+/-' for a neutral or mixed aspect, see Table 8. Scenario A and B represent the adjusted scenarios, as the unfeasible scenarios A.1 and B.1 where not scored.

Table 8: Comparative Analysis of 4 Scenarios linking WA7 with Hydrogen Storage: Insights and Implications.

Scenario	A	B	C	D
Number of pipelines	4	6	2	3
- Re-used (NAM)	2(0)	3(1)	1(0)	2(0)
- New pipelines	2	3	1	1
Pipeline Distance [km]	85	91	71	95
Pipeline Distance	+/-	-	+	-
Reusability	+/-	+	-	+/-
Complexity	-	-	+	+
Buffering	+	+	+	-
Total	+/-	+/-	++	-

Scenario A presented a complex system, requiring adjustments to 92 km of pipelines. While it looked to utilize existing infrastructure, the need for new pipelines and the potential challenges posed by ownership and connected infrastructure complexities resulted in negative scores in terms of complexity. It also cuts out the natural pipelines that are downstream of the re-used pipelines, making it an unattractive solution.

Scenario B, although initially promising in its attempt to optimize the reuse of existing NG pipelines, introduced increased complexity with the need for three new pipeline sections. This scenario, while positive in terms of reusability, was negatively scored in terms of complexity due to the additional pipeline sections required. Another important aspect is that the pipelines downstream of the re-used pipeline become unavailable for natural gas transport, as the same is in Scenario A. This makes it an unattractive solution.

Scenario C emerged as the most favourable. By introducing a new bi-directional pipeline designed specifically for this scenario, it effectively reduced system complexity. The ability to address flow fluctuations during the design process of the C-2 pipeline offered significant advantages. No other pipelines downstream, are being cut out when introducing this scenario. This scenario received positive scores in terms of pipeline distance, complexity, and buffering. Its straightforward approach, reduced reliance on existing infrastructure, and design flexibility made it the most optimal choice from a technical perspective.

Scenario D, though offering a direct route, did not have the same advantages as Scenario C. The flow fluctuations in sections D-1 and D-2, combined with the lack of design flexibility inherent in a direct route, resulted in negative scores in terms of buffering capacity and pipeline distance that should handle the intermittent hydrogen flow.

After consideration of the four options to transport the hydrogen to the gas reservoir for storage using pipelines, Scenario C stands out as the most optimal option for this use case study. Its reduced system complexity, combined with the ability to design a new pipeline specifically tailored to the project's needs, offers significant advantages over the other scenarios. While Scenarios A and B might present potential reuse of existing infrastructure, they also introduce complexities that make them less favorable from a technical point of view as the downstream pipelines at both scenarios are cut out. Looking into complexity of scenario A & B, where 4 & 6 pipelines are needed, respectively, which need multiple new build pipelines and existing pipelines needs to be adjusted to be bi-directional, it was decided to drop these scenarios.

Scenario D, while offering a direct route, does not possess the buffering capabilities, resulting in an uncontrollable intermittent flow over a span of 78 km, in contrast to the 25 km observed in Scenario C. An additional advantage of Scenario C is its flexibility: should pipeline C-1 prove inadequate for managing the intermittent flows, modifications can be confined to C-1 alone. In contrast, Scenario D would necessitate a re-evaluation of the entire 46 km of the NGT, which would also be exposed to the intermittent flow. Given that a primary boundary condition for this study was to ensure complete buffering of the pipeline transporting hydrogen to the shore, Scenario C was selected as most viable possibility and is used in the remaining of this research.

Given that the interconnection between WA7 and the gas reservoir plays a pivotal role in determining export options, it's logical to commence by examining the various export scenarios.

4.4.1.7 Export routes for H_2 and Tail Gas from UHS to shore

Eemshaven and Den Helder stand out as two prominent onshore locations, serving as crucial import hubs for offshore hydrogen to the onshore hydrogen backbone. These hubs are under consideration as potential destinations for hydrogen. This section delineates the various export route options for these hubs. In Figure 4-20, four distinct scenarios are illustrated:

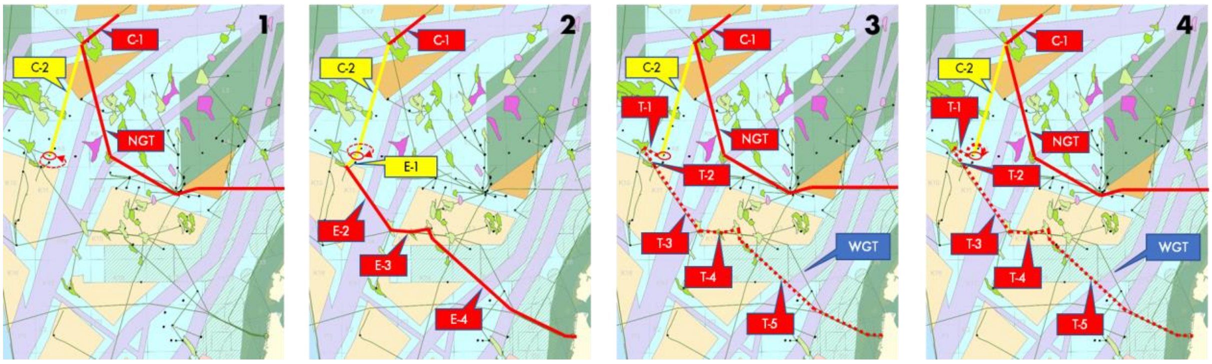


Figure 4-20 Different scenarios for export of hydrogen and tail gas to onshore backbone

In Figure 4-20, the solid lines present the H_2 routes, while dashed lines depict the tail gas streams. The red circle denotes the location of the gas reservoir. For scenario 1,2, and 3 the export destination is Eemshaven, which lays further in the Northeast of the Netherlands and is not presented here.

4.4.1.8 Export scenario 1

In the first export scenario, H_2 is transported to Eemshaven via NGT and the new-built C-2 pipeline as indicated in Figure 4-21b. The C-2 pipeline must be bi-directional since it is used to fill the reservoir during surplus periods and needs to export the purified H_2 to NGT during deficit periods. While the withdrawal capacity stands at 3.5 GW, there is a surplus of 2.1 GW, which causes design modifications to enhance capacity.

Figure 4-21 shows a schematic flow diagram for export scenario 1 together with interlinking scenario C. This gives a high level overview of the outlook of the most important aspects of the system, such as windfarm, electrolysers, pipelines, UHS platform, purification and export destination together with the maximum H_2 flow rates per pipeline. So during a day with maximum generated wind energy there is a flow of 5.6 GW (34.7 million Nm^3 H_2 per day) going through C-1. The NGT will export 3.5 GW to Eemshaven and in times of surplus the remaining flow will be exported via C-2 and injected in the gas reservoir.

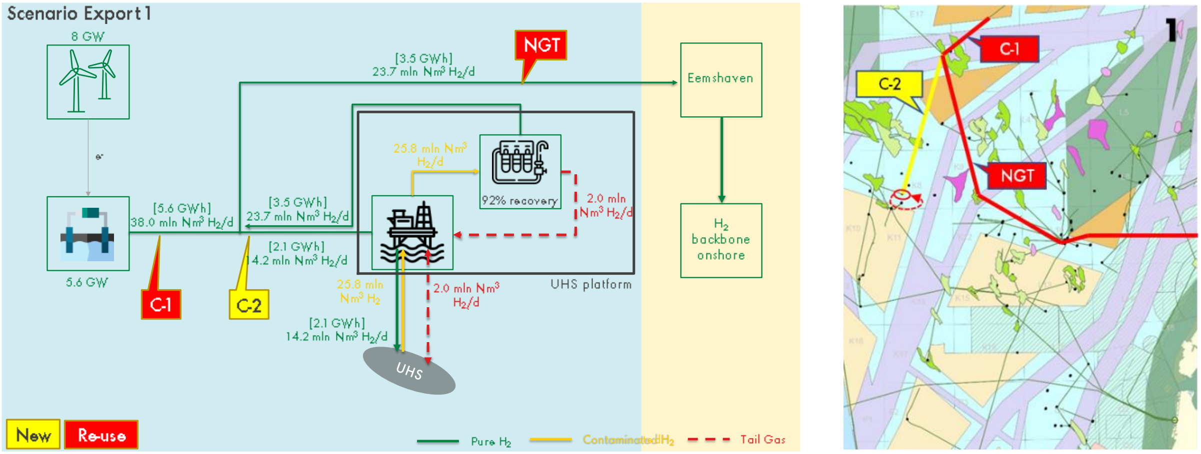


Figure 4-21 Flow diagram for Export Scenario 1's volumetric H_2 design flow rate per day and pipeline routes. a) Schematic Overview of Export Scenario 1. b) Overview of Export Scenario 1 in the Dutch North Sea.

The tail gas stream in scenario 1 is fully reinjected into the reservoir, as indicated by the dotted arrow circling it. This reinjection is facilitated by recompressing the stream emerging from the PSA through a dedicated tail gas well. The idea is to keep impurities away from hydrogen injection and production well as much as reasonably possible, by introducing a new well, dedicated to injecting the contaminated stream that comes out of the PSA back into the reservoir. The location of the well should be far away from the hydrogen well to decrease contamination of the purer hydrogen region. Given hydrogen's significantly lower density compared to methane (CH_4) and carbon dioxide (CO_2), purer hydrogen is more likely to be found in the reservoir's upper region. Since the tail gas stream exits the PSA at a pressure close to atmospheric (~0.30 bar(g)), multiple low-pressure, high-compression stages are required to elevate the tail gas to a suitable reinjection pressure that is in line with the pressure in the reservoir.

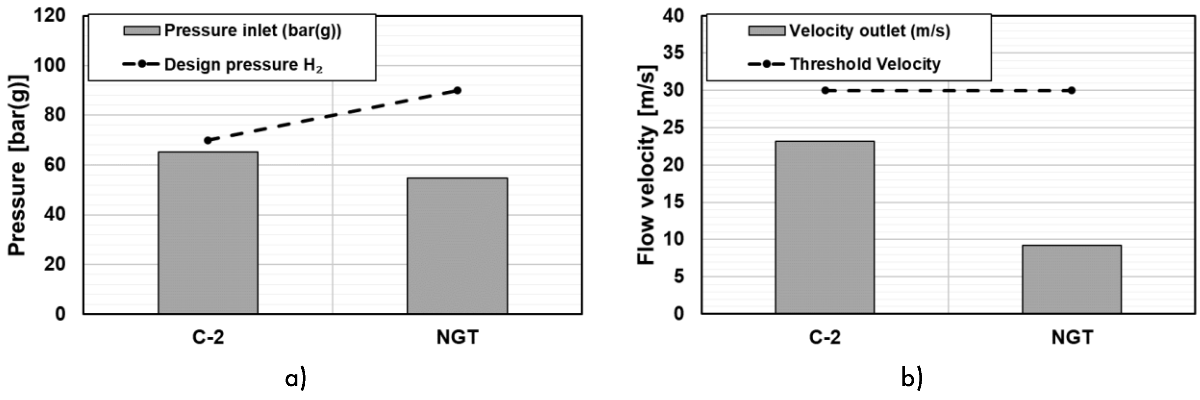


Figure 4-22: Scenario 1: Analysis of Maximum Pressure and Velocity in Export Pipelines with respect to MAOP and Maximum Flow Velocity of 30 m/s as stated in Section 4.1.4 - 23.72 million Nm3/d H2 Export via NGT & 100% Tail gas Re-injection

To ensure that the H_2 flow reaches Eemshaven at a pressure of at least 50 bar(g) and to avoid additional onshore recompression, it's essential to ascertain the pressure drop in the

NGT starting from the C-1 & C-2 tie-in point, see Figure 4-21b. The PFCA shows that there will be a pressure drop of 4.9 bar(g) over 254 kilometres, see APPENDIX 6. So, the output pressure of C-2 should be at least 54.9 bar(g), which is a design parameter to estimate the diameter of the C-2 pipeline and the operating pressure of the PSA, as that determines at what pressure the hydrogen will be feed into C-2. This will be further analysed in the hardware section 4.6.2. As the flow capacity for C-2 should be at least 3.5 GWh of H_2, it leads to a design diameter of 22". For a detailed PFCA, please access APPENDIX 6.

4.4.1.9 Export scenario 2

In scenario 2, H_2 is exported to Den Helder and the tail gas is reinjected. For Scenario 2 the LoCal pipeline is used for H2 export and for Scenario 2.1 the WGT pipeline is used. The LoCal pipeline is operated by NAM and is therefore favorable. However, the WGT pipeline, operated by Wintershall, has a diameter of 36", leading to higher capacity. If LoCal's pipeline capacity calculation shows exceeding values, WGT will be evaluated as export pipeline.

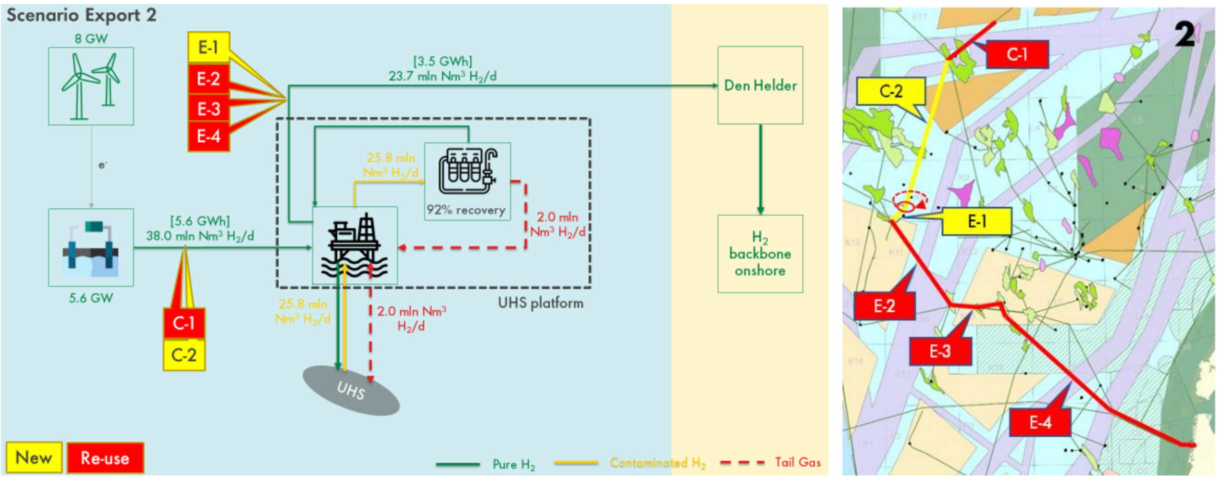


Figure 4-23 Flow diagram for Scenario 2's volumetric H_2 design flow rate per day and pipeline routes. a) Schematic Overview of Export Scenario 2. b) Overview of Export Scenario 2 in the Dutch North Sea.

Unlike scenario 1, the C-2 pipeline in this case operates with a unidirectional flow and only needs to handle a peak flow of 2.1 GWh H_2 instead of 3.5 GWh. This suggests a smaller diameter for the C-2 pipeline in scenario 2 compared to scenario 1. A disadvantage of this scenario is that it requires the establishment of an additional pipeline segment, E-1, to tie-in to E-2. This export route is made up of four pipelines, where 3 are existing and operated by NAM, for the export of H_2 to Den Helder.

Figure 4-24 shows the PFCA of Scenario 2, where the maximum pressure and maximum flow velocity were calculated to bring the hydrogen to shore without the need of extra step of recompression onshore. This means that the hydrogen arrives at the onshore backbone with 50 bar(g). Therefore, the output pressure of E-4, was set at 50 bar(g) and the corresponding flow velocities and pressure to obtain the 50 bar(g) onshore are presented in Figure 4-24. As LoCal has an OD of 24" and a design pressure of 10 MPa for natural gas, the pressure drop would be 12 bar(g) over 84 kilometers with a gas flow velocity of 20.7 m/s. The pressure drop leads to exceedance of the design pressure for H_2 of 6 MPa by 0.2 MPa. This could be further analyzed as the exceedance is not significant, but E-3 is an even bigger bottleneck as the gas flow velocity is 38 m/s and the pressure will be 77.4 bar, while the MAOP should be 60 bar for H_2. It can be concluded that the LoCal pipeline cannot handle the flow rate at the desired conditions as the MAOP is exceeded for the LoCal, E-3, and E-2. While the gas flow velocity is exceeded for E-3.

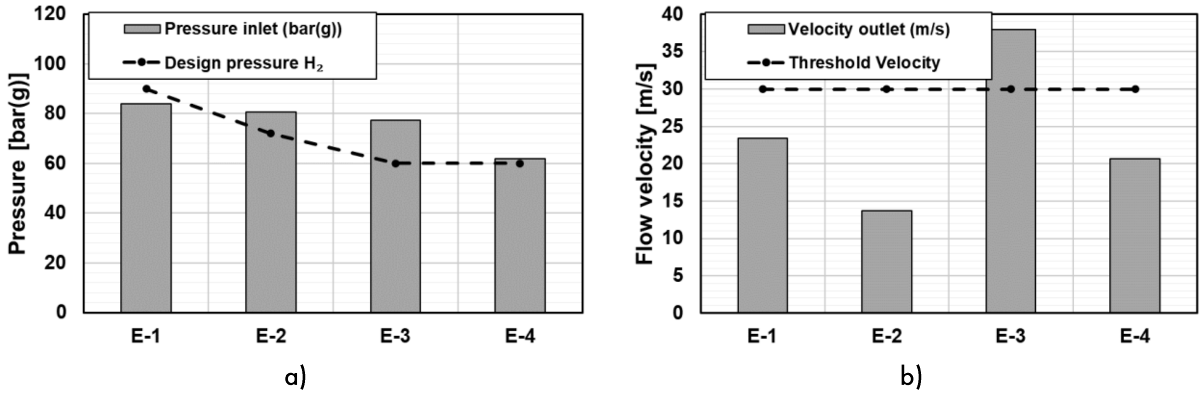


Figure 4-24: Scenario 2: Analysis of Maximum Pressure and Velocity in Export Pipelines with respect to MAOP and Maximum Flow Velocity of 30 m/s as stated in Section 4.1.4 - 23.72 million Nm3/d H2 Export via LoCal & 100% Tail gas Re-injection.

This leads to adjust Scenario 2 by replacing LoCal with WGT as tie-in point to Den Helder, leading to a subsequent change as WGT cannot be reached by E-3, so E3.1 is introduced, see Figure 4-25. This is a short section pipeline of ~200 m and 24", that connects platform K14-FA-1P/1C, so E-2 with WGT. WGT is a pipeline of 130 kilometers with an OD of 36", but the tie-in point with E3.1 is at 92 kilometers to shore. This scenario is denoted as Scenario 2.1. As WGT's diameter is 1.5 times larger than LoCal's pipeline and the design pressure is assumed to be the same as NGT, the operation conditions fall easily within the maximum design pressure and gas flow velocity. As the pressure drop in WGT is 1.8 bar, it makes it much easier for E-1, E-2 and E-3 to operate within their boundaries. Figure 4-26 shows the PFCA of Scenario 2.1.

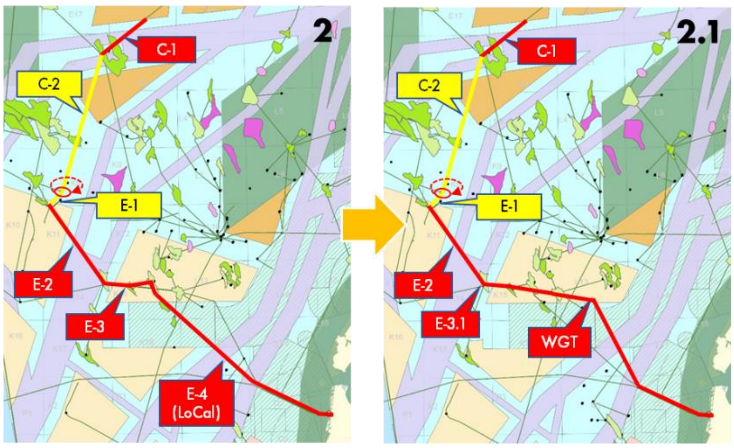


Figure 4-25: Modification from Scenario 2 to 2.1, to manage an export capacity 3.5 GWh H_2. Instead of re-purposing NAM's LoCal pipeline, it uses the WGT pipeline that is operated by Wintershall Noordzee.

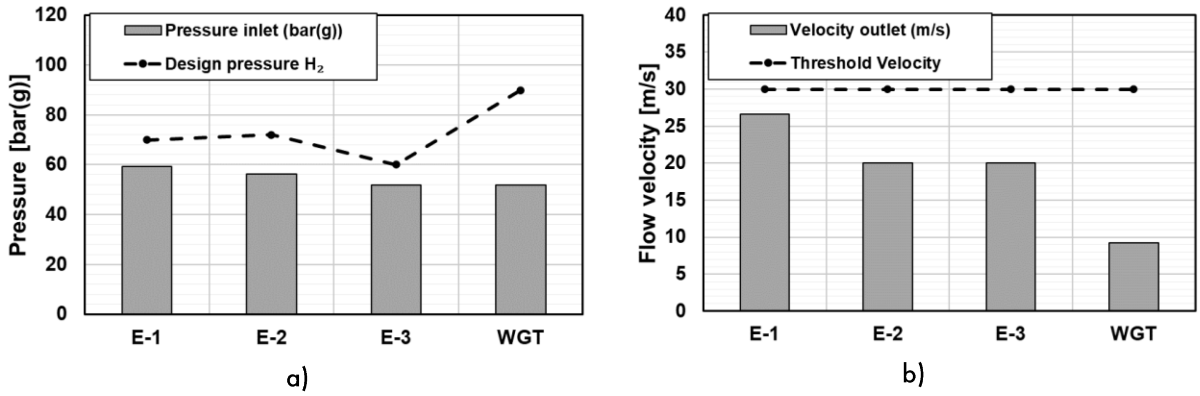


Figure 4-26: Scenario 2.1: Analysis of Maximum Pressure and Velocity in Export Pipelines with respect to MAOP and Maximum Flow Velocity of 30 m/s as stated in Section 1.1.4 - 23.72 million Nm3/d H2 Export via WGT & 100% Tail gas Re-injection.

As the tail gas is reinjected into the reservoir, this will be the same situation as for Scenario 1, you can find them in Section Export scenario 1.

4.4.1.10 Export scenario 3

As there are two tie-in destinations for the onshore hydrogen backbone, Eemshaven and Den Helder, that can be reached from the UHS platform by pipelines. This makes it an interesting opportunity to see if both routes can be used for export of the gases produced at the UHS platform. Scenario 3 makes use of these exporting routes mentioned in scenario 1 and 2. The NGT pipeline is used for H_2 export, and the LoCal pipeline is used to transport the tail gas to Den Helder. There are several reasons to export the tail gas.

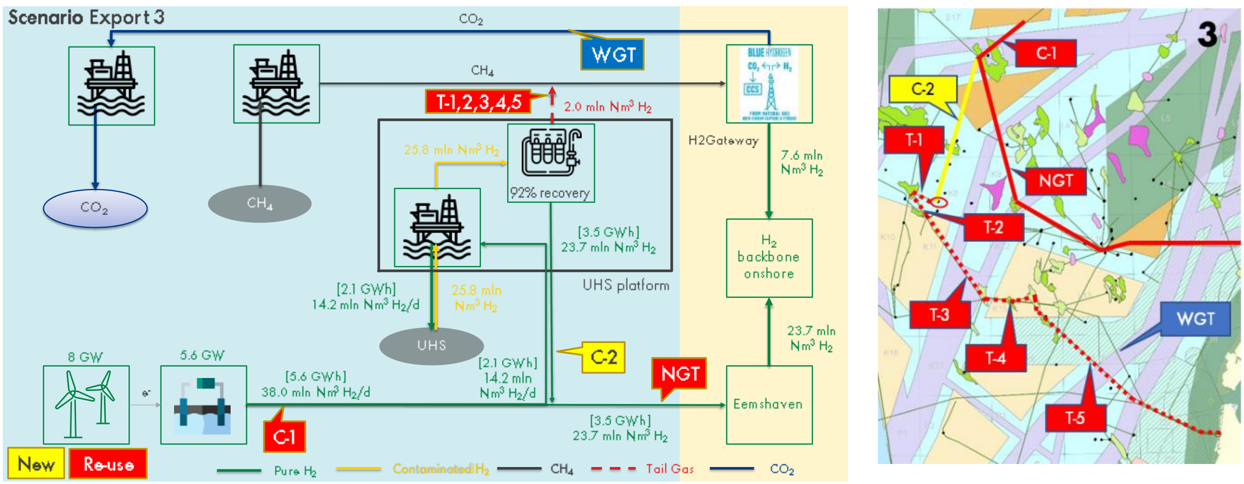


Figure 4-27 Flow diagram for Scenario 3's volumetric H_2 design flow rate per day and pipeline routes. a) Schematic Overview of Export Scenario 3. b) Overview of Export Scenario 3 in the Dutch North Sea.

When tail gas is reinjected, the contaminants will never leave the reservoir and the reservoir will not be 'cleaned'. By exporting the tail gas, you can decrease the impurities into the storage site, improving the hydrogen recovery rate, to the point where purification, tail gas compression and export will no longer be required.

Scenario 3's schematic flow diagram is displayed in Figure 4-27. The maximum flow rate, or design specifications, are referenced by the normalized volume of H_2 per stream at each direction of flow. Green lines show pure H_2 streams, yellow lines indicate contaminated streams, grey lines indicate CH_4 streams, and blue line indicates CCS stream containing CO_2. It's worth noting that only the quantity of H_2 is displayed, excluding the contaminated stream.

Tail gas from hydrogen PSA often contains valuable components, such as unadsorbed hydrogen and hydrocarbons. Exporting this tail gas can be a source of additional revenue if it can be sold or utilized elsewhere. In contrast, reinjecting it underground might represent a missed opportunity. However, as the tail gas is extracted, the volume needs to be replaced by H_2, to keep the store at the same pressure, and that H_2 needs to be procured as well. Exporting tail gas is a necessity rather than an economic opportunity, as the price of hydrogen is higher compared to natural gas.

Currently, H2Gateway, a consortium of businesses and public bodies, is evaluating the viability of establishing a blue hydrogen plant in Den Helder. It is estimated that this plant could be operational in 2027 [98]. Natural gas is used to make blue hydrogen, and this process results in the production of CO_2. The CO_2 is kept from entering the atmosphere by capturing and storing this CO_2 in depleted gas fields using CCS techniques. 'Blue hydrogen' is the name given to the hydrogen created in this manner. The blue hydrogen plant from H_2Gateway might encourage industry to move toward carbon-free manufacturing methods, as well as cut overall industrial carbon emissions from the Netherlands' key industrial clusters by about 14% and therefore significantly advance climate goals [98].

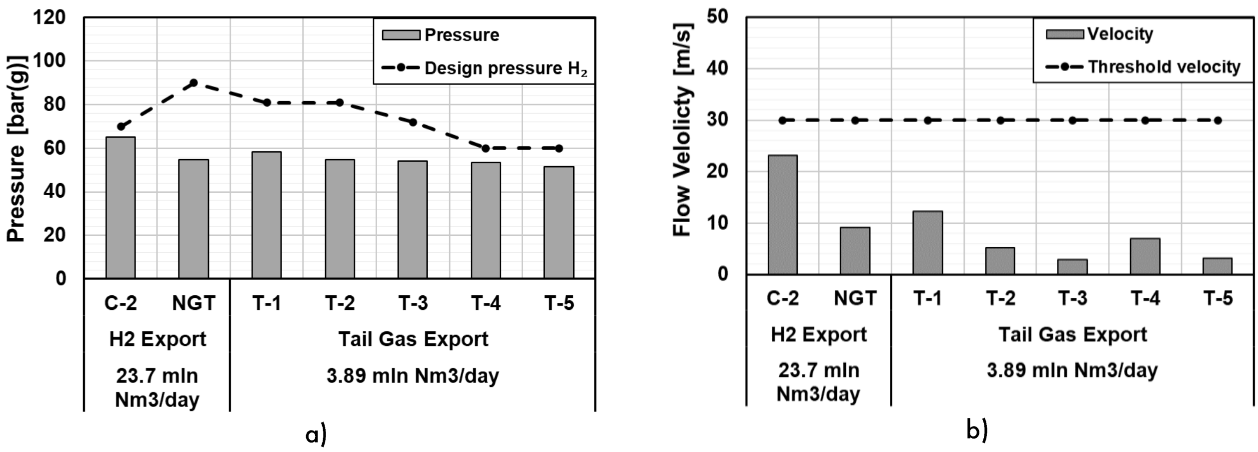


Figure 4-28: Scenario 3: Analysis of Maximum Pressure and Velocity in Export Pipelines with respect to MAOP and Maximum Flow Velocity of 30 m/s as stated in Section 4.1.4 - 23.72 mln Nm3/d H2 Export via NGT & 3.89 mln Nm3/d Tail gas Export via LoCal Pipeline

The natural gas used for blue hydrogen production can contain a specific mol%/mol ratio of hydrogen, provided it remains within an acceptable range. For the purposes of this study, a threshold value of 10 mol%/mol of H_2 in CH_4 has been assumed to be blend in.

To determine if the threshold value is exceeded when exporting all the tail gas to Den Helder, the tail gas composition and amount must be determined. This is done by reservoir modelling as mentioned in section 4.5.1. For this case study the worst-case scenario is evaluated to determine what the maximum amount of tail gas. The flow rate and composition of the tail gas during the worst-case scenario is presented in APPENDIX 3.

The maximum intake capacity for the H2Gateway blue hydrogen plant is estimated to be 3.8 million nm^3 per day. When considering the maximum of 10% H_2 in the CH_4 feed, one can conclude that the maximum acceptable H_2 flow to H2Gateway, should be 0.38 million nm^3 per day. Looking into Figure 4-27, the threshold value is exceeded as it is 1.96 million nm^3 H_2 per day instead of the maximum value of 0.38 million nm^3 H_2 per day. Therefore, this scenario is not feasible to implement as the H2Gateway project cannot accept this amount of hydrogen. It is overwritten with 516% of the maximum capacity of hydrogen that is acceptable. Even if one would consider an acceptable rate of 20 mol%/mol H_2, it still would be not possible. As the contaminated stream that comes out of the reservoir contains CH_4, C_2H_6, CO_2, N_2 and could contains some H_2S, there is no possibility to feed this into the hydrogen backbone. This leaves us no other option than finding an alternative destination for at least the 416% of H_2 that cannot be accepted by the blue hydrogen powerplant. As this stream is huge, 1.68 million nm^3 of hydrogen would be released in the atmosphere, together with CH_4, C_2H_6, CO_2, N_2. Besides the release of the GHG's hydrogen has indirect warming impacts as well. The oxidation of hydrogen in the atmosphere leads to increasing concentrations of greenhouse gases in both the troposphere and stratosphere, as described in Figure 4-29.

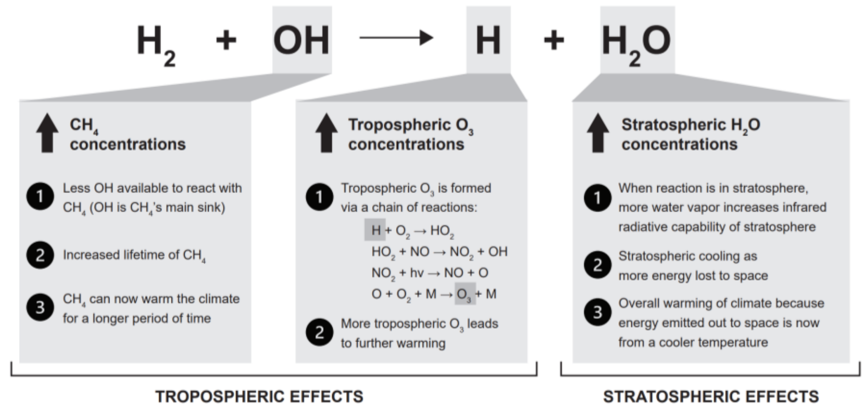


Figure 4-29 Effects of hydrogen oxidation on atmospheric greenhouse gas concentrations and warming [99].

Methane has a longer atmospheric lifetime because there is less OH available to react with it in the troposphere; as this is the principal sink for methane, methane's atmospheric duration accounts for around half of the total indirect warming effect of hydrogen. Moreover, the production of atomic hydrogen from hydrogen oxidation in the troposphere leads to a series of reactions that ultimately form tropospheric ozone, a greenhouse gas that accounts for about 20 % of hydrogen's radiative impacts [100]. In contrast with the Global Warming Potential (GWP) of CO_2, hydrogen has an estimated GWP20 of 37.3 and a GWP100 of 11.6 [101]. This implies that leakage of hydrogen into the atmosphere is 37.7 and 11.6 times more effective in trapping heat in the atmosphere and contribute to the greenhouse effect over 20 and 100 years, respectively. CH_4 has a GWP20 of approximately 84, over 20 years but a GWP100 of 28 [102]. This difference is because it breaks down faster in the atmosphere than CO_2, so its relative impact decreases over longer time frames.

The implications of releasing the contaminated stream from the reservoir into the atmosphere are profound. Not only would a significant volume of hydrogen be released, but it would also be accompanied by other greenhouse gases like CH_4, C_2H_6, and CO_2. The environmental ramifications of such a release are multi-faceted. Directly, there's the immediate contribution of these gases to the greenhouse effect. Indirectly, the oxidation of hydrogen can lead to increased concentrations of other greenhouse gases, further exacerbating the warming effect. The high Global Warming Potential (GWP) of both hydrogen and methane, especially over shorter time frames, underscores the urgency of finding alternative solutions for handling the contaminated stream. Simply releasing it into the atmosphere is not a sustainable or environmentally responsible option. As we move forward, it's imperative to prioritize solutions that mitigate these environmental impacts and promote a more sustainable use of Earth’s resources.

Burning or combusting the contaminated stream from the reservoir offers a potential alternative to releasing it directly into the atmosphere. By doing so, the primary components of the stream, namely CH_4, C_2H_6, and H_2, would be converted primarily into water vapor (H_2O) and carbon dioxide (CO_2), with smaller amounts of other byproducts depending on the combustion conditions. By burning the methane present in the stream, its direct release into the atmosphere is prevented. This combustion process converts methane into CO_2, which, while still a greenhouse gas, has a much lower GWP than methane. Combusting the stream will inevitably produce CO_2, especially from the methane (CH_4) and ethane (C_2H_6) components. While CO_2 is a less potent greenhouse gas compared to methane, its longer atmospheric lifetime means it will contribute to global warming for a more extended period. Burning the hydrogen present in the stream prevents its release and subsequent oxidation in the atmosphere, which can lead to increased concentrations of other greenhouse gases. This helps in avoiding the indirect warming impacts associated with hydrogen leakage. The combustion process, especially in the presence of nitrogen (N_2), can lead to the formation of nitrogen oxides (NO_x), which are pollutants that contribute to smog, acid rain, and can impair respiratory health. Their formation would need to be carefully managed and minimized.

From a sustainability perspective, burning the contaminated stream can be seen as a waste of potentially valuable resources. The hydrogen, in particular, is a clean energy carrier that could be utilized in various applications, from fuel cells to industrial processes.

While burning the contaminated stream can mitigate some of the direct environmental impacts associated with its release, it is not without its challenges and implications. The production of CO_2 and potential NOx emissions need to be weighed against the benefits of reducing methane and hydrogen's indirect warming effects. From a sustainability standpoint, the combustion of valuable resources, especially hydrogen, may not be the most optimal solution.

Although export scenario 3 seemed like the scenario with the most perspective, it can be concluded that it is too good to be true.

Reinjecting the contaminated stream back into the gas reservoir and exporting a portion of it to H2Gateway offers another potential solution to manage the stream. This approach would involve reinjecting 3.14 million nm^3 /day of the tail gas stream back into the gas reservoir while diverting a smaller "bleed" stream of 0.75 million nm^3 /day to H2Gateway, as this contains 0.38 million nm^3 H_2 per day and that is the maximum amount of H_2 that the powerplant can take. This leads to export scenario 4.

4.4.1.11 Export scenario 4

This scenario differs slightly from scenario 3. The NGT pipeline will be used for H_2 export to Eemshaven. However, there is a significant difference as the tail gas is exported but also reinjected to deal with the overflow of H2Gateway. This dual approach could be advantageous, particularly if amount of H_2 in the feedstock for the blue hydrogen plant exceeds the threshold value of 10 mol% per mol CH_4 as is the case in Scenario 3. A maximum of 0.75 million nm3/day of tail gas is accepted to be exported to H2Gateway, as it contains 0.38 million nm3/day H_2 in the stream. The other 3.14 million nm3/day of tail gas must be re-injected into the reservoir as no other suitable destination is found. This can be done by a dedicated tail gas well, which is placed at another location of the reservoir and deeper than the H_2 well, as the higher purity zones are at the upper regions of the reservoir due to the density of hydrogen, which is significantly lower than that of CO_2 and CH_4.

Since the tail gas stream exits the PSA at a pressure close to atmospheric (~0.30 bar(g)), multiple low-pressure, high-compression stages are required to elevate the tail gas to a suitable reinjection pressure that is in line with the pressure in the reservoir.

By reinjecting part of the contaminated stream back into the reservoir, it becomes feasible to export a bleed stream of the tail gas to be used as feedstock for another process.

Surely, one would not vent these gases into the atmosphere and therefore this is the most straightforward alternative. This approach helps in avoiding both the direct and indirect greenhouse effects associated with releasing these gases and still make it possible to repurpose a part of the tail gas.

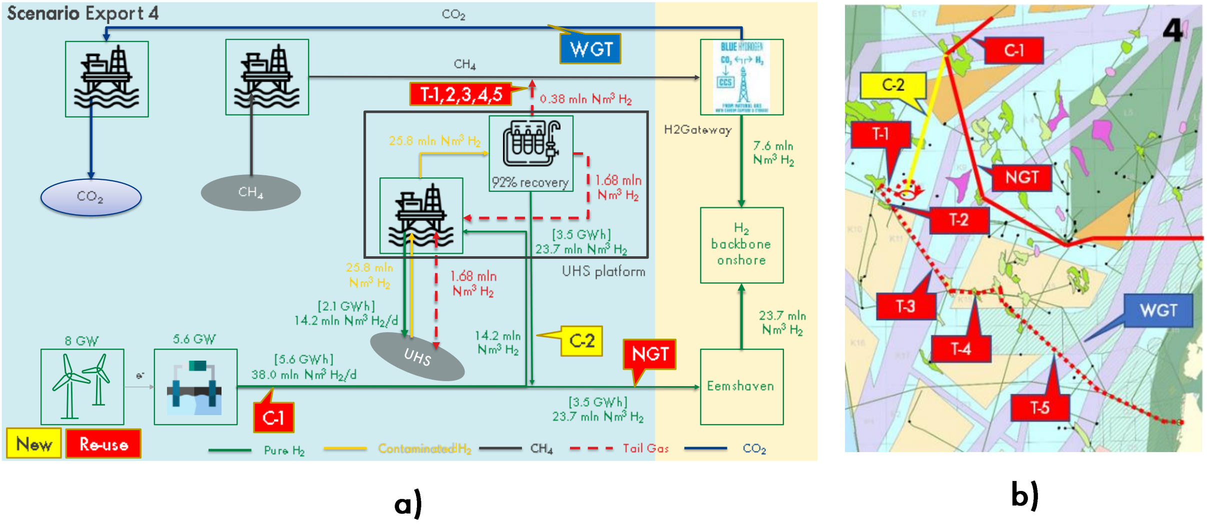


Figure 4-30 Flow diagram for Scenario 4's volumetric H_2 design flow rate per day and pipeline routes. a) Schematic Overview of Export Scenario 4. b) Overview of pipelines used in Export Scenario 4 in the Dutch North Sea.

Figure 4-30a shows the schematic overview of this export concept. When the hydrogen is withdrawn from the gas reservoir it goes into the PSA, where ~90% of the hydrogen is recovered and the other ~10% is captured in the tail gas. 80.7% of that tail gas is reinjected, where a maximum of 0.38 million nm^3 H_2 per day will be exported to H2Gateway, to 20% during the cycle that produces the most volume of tail gas.

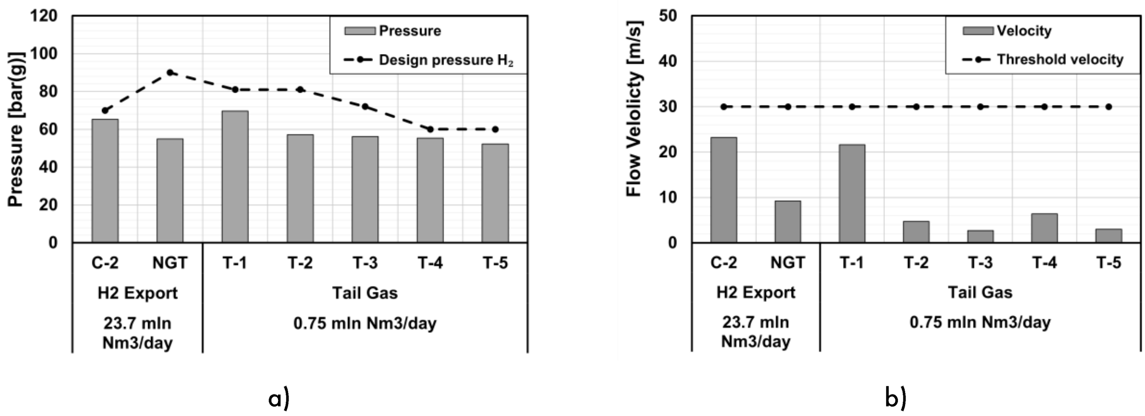


Figure 4-31: Scenario 4:– Analysis of Maximum Pressure and Velocity in Export Pipelines with respect to MAOP and Maximum Flow Velocity of 30 m/s as stated in Section 4.1.4 - 23.72 mln Nm3/d H2 Export via NGT & 0.75 mln Nm3/d Tail gas Export & 3.14 mln Nm3/d Re-injection into Reservoir.

Reinjection can be viewed as a form of resource conservation, but it also means that the reservoir will be 'cleaned' much slower, than when fully exporting the tail gas. The natural gas will slowly be removed as 80.7% of the tail gas will be reinjected during the cycle with the highest contamination grade. So partial reinjection of tail gas will lead to longer period where there is hydrogen contamination in the reservoir. Instead of burning or releasing the gases, they are stored for potential future extraction and use. Normally, the tail gas would only be produced during times of low wind, as the hydrogen is withdrawn from the gas reservoir. During these periods the hydrogen that is exported must be purified using PSA. The contaminated output of the PSA is the tail gas, so there will only be a flow of H_2 & natural gas to H2Gateway when there is a deficit.

However, in scenario 4, it is possible to extract tail gas from your dedicated tail gas well, so during surplus and deficit of wind energy. This option combines the storage reservoir with a partial export case to average out the production rate of the PSA tail gas over a full year, rather than having excessive peaks during the production cycles. This is possible as the tail gas well together with the PSA can operate independently of the H_2 well. This makes it possible to extract a constant flow of tail gas, and therefore decreasing the intermittency problem for the customer. Export scenarios – Evaluation

The Dutch North Sea, with its potential for underground hydrogen storage, offers a promising avenue for sustainable energy storage. The five proposed scenarios, each with its distinct pipeline export strategy, provide a comprehensive insight into the possible approaches to harness this potential. Table 9 provides a detailed comparison of these scenarios based on various parameters.

Table 9 Comparative Analysis of 5 Export Scenarios: Insights and Implications.

Scenario	**1**	**2**	**2.1**	**3**	**4**
H_2 Destination	Eemshaven	Den Helder	Den Helder	Eemshaven	Eemshaven
H_2 Export Pipeline	NGT	LoCal	WGT	NGT	NGT
H_2 Export [GW]	3.5	3.5	3.5	3.5	3.5
H_2 Export Flow [mln Nm^3/day]	23.7	23.7	23.7	23.7	23.7
No. H2 Export Pipelines	2	4	4	2	2
- Repurposed Pipelines	1	3	3	1	1
Proposed Tail gas Destination	Reservoir	Reservoir	Reservoir	Den Helder	Reservoir & Den Helder
Final Tail gas Destination	Reservoir	Reservoir	Reservoir	Not Feasible	Reservoir & Den Helder
No. Tail gas Export Pipelines	0	0	0	5	5
- Repurposed Pipelines	0	0	0	5	5

Tail gas Re-Inject Flow [mln Nm^3/day]	3.89	3.89	3.89	0	3.14
Tail gas Export Flow [mln Nm^3/day]	0	0	0	3.89	0.75
Store Clean-Up	-	-	-	+	+/-
Power Consumption	-	-	-	+	+/-
Pressure Drop	+	-	+	+	+
H_2 Pipeline Capacity	+	-	+	+	+
H_2 Flow Complexity	+	+/-	+/-	+	+
Tail gas Flow Complexity	+	+	+	+/-	-
Intermittency	+	+	+	-	+/-
End use of tail gas	-	-	-	-	+
Tail gas Customer	N/A	N/A	N/A	N/A	H2GateWay
Total	++	- - -	+	+++	+++
Total No. Pipelines	2	4	4	7	7
Total No. Repurp. Pipelines	1	3	3	6	6
Feasible	Yes	Not Feasible[1]	Yes	Not Feasible[1]	Yes

[1]Note: Not feasible means the proposed system design is not feasible or not optimal

Export Scenario 1 stands out for its operational resemblance to salt cavern Underground Hydrogen Storage (UHS) systems as the tail gas is reinjected. The scenario proposes transporting hydrogen to Eemshaven via the NGT pipeline, with a total of two pipelines, one of which is repurposed. The tail gas is entirely reinjected into the reservoir, ensuring no direct emissions to the atmosphere by releasing or burning the contaminated stream of the PSA. This approach, while environmentally sound, requires design modification of C-2 to handle the surplus of 2.1 GW and multiple compression stages for tail gas reinjection. Especially, recompression of the tail gas will require high power needs and will encounter a large footprint of the platform, making re-use of existing platforms very hard.

Export Scenario 2 leverages existing infrastructure, specifically pipelines operated by NAM, to transport hydrogen to Den Helder. However, the scenario's reliance on the LoCal pipeline poses significant operational challenges, particularly the exceedance of design pressure and gas flow velocity. Although the LoCal pipeline is evaluated for a 5-6 GW of hydrogen, these rates are only achieved when the pipeline sections upstream are replaced. The need for an additional pipeline segment, E-1, further complicates the design. Given these challenges, this scenario is deemed not optimal under the design conditions.

Export Scenario 2.1 addresses the limitations of Scenario 2 by utilizing the WGT pipeline, which offers a higher capacity. The operational conditions of this scenario comfortably fall within the maximum design pressure and gas flow velocity, making it a feasible alternative. However, there is a possibility that WGT will be used to export CO_2 to sea as it has large diameter and therefore has a high capacity for CCS of H2Gateway project.

Export Scenario 3 is ambitious in its attempt to utilize both available export routes, potentially maximizing export capacity and minimizing offshore compression needs. The scenario proposes using the NGT pipeline for hydrogen export and the LoCal pipeline for tail gas transport to Den Helder. While the economic allure of this scenario is evident in the potential for additional revenue streams from tail gas, the environmental and operational challenges overshadow its benefits. The exceedance of acceptable H_2 levels for the H2Gateway blue hydrogen plant and the profound environmental implications of releasing or burning the contaminated stream into the atmosphere render this scenario considered not optimal for the design case.

Export Scenario 4 offers a nuanced approach to tail gas management. By adopting a dual strategy of reinjecting and exporting tail gas, this scenario provides a level of flexibility that could be pivotal in dynamic operational conditions. The environmental footprint is minimized by the reduced direct emissions resulting from the reinjection of a portion of the tail gas. However, the partial reinjection implies a slower 'cleaning' process for the reservoir, potentially leading to extended periods of hydrogen contamination.

In conclusion, Scenarios 1, 2.1, and 4 emerge as feasible options, with Scenario 1 being particularly noteworthy as the idea behind this scenario is similar as salt cavern UHS systems, as no tail gas leaves the platform. There is a possibility that WGT will be used for CCS, and the idea was to evaluate 2 different scenarios for offshore hydrogen storage in gas reservoirs, it was decided to work out Scenario 1 and 4. The latter can be seen as Scenario 1 plus a bleed stream to cleanse the store at a pace that the tail gas user can handle.

4.4.2 Final Scenarios of WA7, UHS and Export

After conducting a comprehensive assessment of potential approaches to incorporate an offshore gas reservoir as a large-scale storage facility to facilitate green hydrogen production in wind area 7, two scenarios emerged as the most promising for stabilizing pipelines and ensuring a consistent supply of green hydrogen to the onshore backbone. Interestingly, these two scenarios share a fundamental similarity, involving the use of NGT as the export route for hydrogen, with the necessity to re-inject the tail gas into the reservoir. This commonality is not coincidental but rather a result of the absence of viable alternatives for exporting all the tail gas for repurposing. The primary reasons behind this choice are the highly intermittent nature of tail gas production, similar to the wind profile, and the challenge of finding a dedicated customer capable of accommodating the sporadic and high-flow rates associated with this process, akin to handling a firehose of intermittently produced gas containing hydrogen.

4.4.2.1 Final Scenario 1

Table 10**Error! Reference source not found.** shows the different design choices for the underground hydrogen storage system design indicated with green blocks. This has led to the scenario depicted in Figure 4-32.

Table 10: Design Options Table for Final Scenario 1 (Interlinking Scenario C + Export Scenario 1)

Hydrogen Production							Hydrogen Storage							Hydrogen Transport					
Windfarm Offshore Location	Windfarm Capacity	Windfarm Production	Electrolyser Location	Electrolysis	Electrolyser Efficiency	Energy Conversion (Wind to Produced H_2)	Purpose of Storage	Storage Location	Offshore Store type	Cushion Gas	Compressor	Purification Technology	Tail Gas Destination	Pressure de-rating percentage of NG pipeline	Max H_2 Flow Velocity	H_2 Export Flow	H_2 Export Pipeline	Onshore Location (H_2 pipeline landing)	H_2 Export Pipeline
Area 3 (2 GW)	2 GW	Electricity	Centralised / Platform	PEM	70%	70%	Buffering pipelines	Offshore	Salt Cavern	H_2	Reciprocating	PSA	Reinjection into Reservoir	50%	10 m/s	1 GWh	Existing	Eemshaven	NGT
Area 7 (8 GW)	8 GW	Hydrogen	Decentralised	Alkaline	80%	75%	Seasonal	Onshore	Gas Reservoir	CO_2	Centrifugal	Polymeric Membrane	Export	60%	30 m/s	2 GWh	New	Den Helder	WGT
Area 6 (10 GW)	10 GW	Electricity & Hydrogen	Energy island	Solid Oxide	100%	80%	Strategic		Aquifer	N_2		Cryogenic Separation	Reinjection & Export	80%	60 m/s	3.5 GWh	Both	Rotterdam	LoCal
										CH_4				100%		10 GWh			New Pipeline

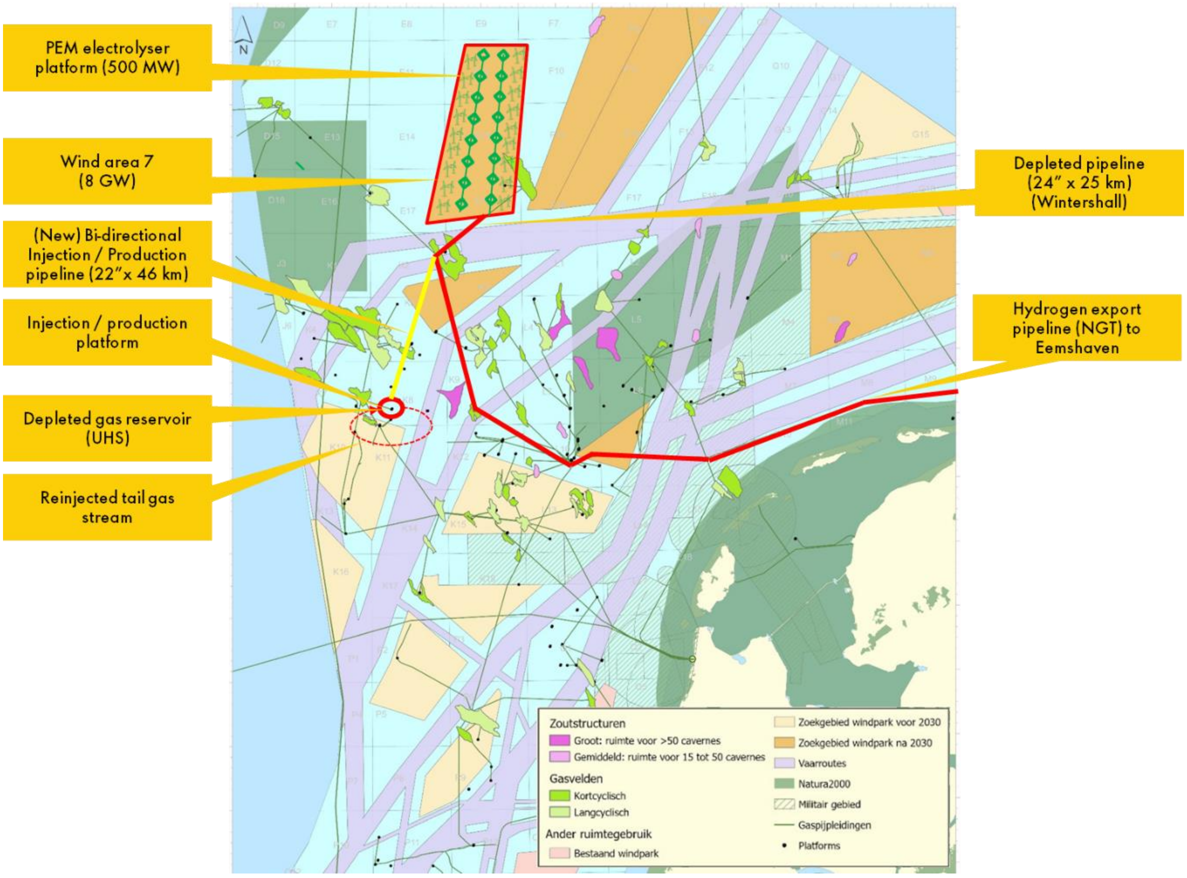


Figure 4-32 Overview of Final Scenario 1 with important aspects of the conceptual system design

4.4.2.2 Final Scenario 2

For Final Scenario 2, the difference lays in the export of the tail gas. As the reservoir lays close to pipelines that are connected with LoCal pipeline, it was decided to explore export routes for the tail gas. This led to a scenario where 19.3% of the tail gas will be exported during the dirtiest cycle, leading to the export of 0.38 million Nm^3 of H_2 per day to Den Helder for the blue hydrogen plant H2Gateway. Table 11 presents the different design choices for Final Scenario 2, that led to the conceptual design in Figure 4-33.

Table 11: Design Options Table for Final Scenario 1 (Interlinking Scenario C + Export Scenario 4)

Hydrogen Production							Hydrogen Storage							Hydrogen Transport						
Windfarm Offshore Location	Windfarm Capacity	Windfarm Production	Electrolyser Location	Electrolysis	Electrolyser Efficiency	Energy Conversion (Wind to Produced H_2)	Purpose of Storage	Storage Location	Offshore Store type	Cushion Gas	Compressor	Purification Technology	Tail Gas Destination	Pressure de-rating percentage of NG pipeline	Max H_2 Flow Velocity	H_2 Export Flow	H_2 Export Pipeline	Onshore Location (H_2 pipeline landing)	H_2 Export Pipeline	Tail Gas Export Pipeline
Area 3 (2 GW)	2 GW	Electricity	Centralised / Platform	PEM	70%	70%	Buffering pipelines	Offshore	Salt Cavern	H_2	Reciprocating	PSA	Reinjection into Reservoir	50%	10 m/s	1 GWh	Existing	Eemshaven	NGT	NGT
Area 7 (8 GW)	8 GW	Hydrogen	Decentralised	Alkaline	80%	75%	Seasonal	Onshore	Gas Reservoir	CO_2	Centrifugal	Polymeric Membrane	Export	60%	30 m/s	2 GWh	New	Den Helder	WGT	WGT
Area 6 (10 GW)	10 GW	Electricity & Hydrogen	Energy island	Solid Oxide	100%	80%	Strategic		Aquifer	N_2		Cryogenic Separation	Reinjection & Export	80%	60 m/s	3.5 GWh	Both	Rotterdam	LoCal	LoCal
										CH_4				100%		10 GWh			New Pipeline	New Pipeline

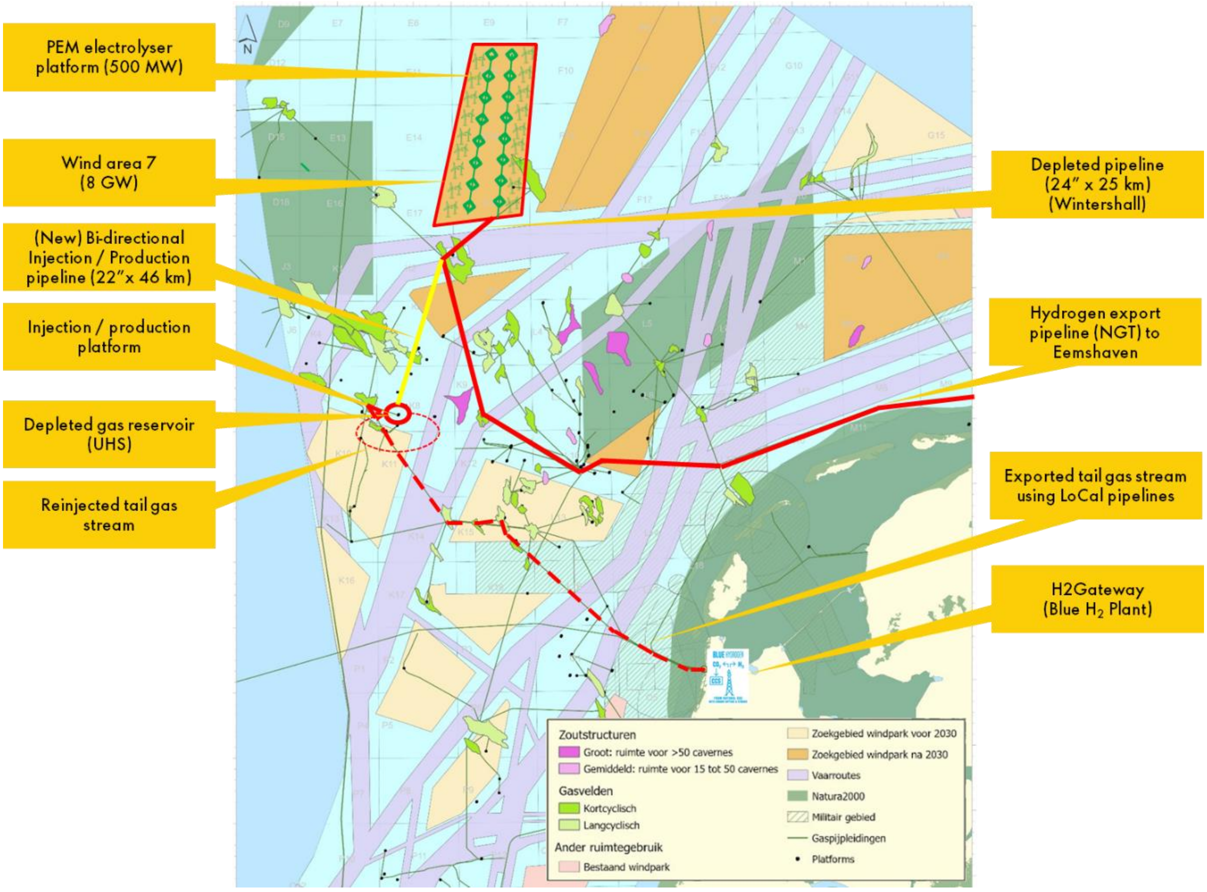


Figure 4-33: Overview of Final Scenario 2 with important aspects of the conceptual system design

4.5 Hydrogen Storage Performance

Utilizing a depleted gas reservoir for hydrogen storage presents unique challenges and advantages. Initially filled with natural gas, such reservoirs are advantageous due to their established geology and existing infrastructure. However, this same history introduces complexities, particularly concerning the purity of the stored hydrogen. As hydrogen is injected into the reservoir, it mixes with residual gases, leading to inevitable contamination. There is also possibility of geochemical and microbial reactions, decreasing the purity of the stored hydrogen. This contamination affects the amount and quality of hydrogen that can be subsequently withdrawn, necessitating careful management of the injection and extraction processes to optimize hydrogen recovery and maintain its usability for energy production.

The level of contamination in the hydrogen depends significantly on the duration the hydrogen remains stored and the dynamics within the reservoir. Longer storage periods typically result in higher contamination levels due to prolonged interaction with residual gases and the reservoir's geological features. Conversely, hydrogen withdrawn shortly after injection tends to retain a higher purity level because there is less time for it to mix with other gases or for reactions to occur that might degrade its quality.

To effectively manage this, a more substantial volume of hydrogen than is strictly needed for energy production must be withdrawn. For instance, to achieve an output of 3.5 GWh, it is necessary to extract a higher volume to compensate for the inevitable losses due to contamination and process losses.

4.5.1 Reservoir Modelling

To understand the storage behaviour during the injection-production cycles and to determine the composition of the back-produced stream, a detailed 2D box model was employed to simulate the reservoir's behaviour throughout these cycles. The model was provided by Shell and was used in another UHS feasibility study. Due to lack of time for dedicated reservoir modelling, the provided model was used for this research. Although it is not representative to the performance of the reservoir chosen for this use case, it give a first impression on the quality of the back-produced hydrogen stream and the distribution of the hydrogen in the reservoir.

This model incorporates several key parameters:

- 2D box model with Huff-n-Puff well (500x500x50m) and random permeability distribution. Huff n' puff is an enhanced oil recovery method in which one well alternates between injection, soaking, and production [103].
- Average Permeability: 100 millidarcies
- Heterogeneity (VDP): 0.9
- Ratio of Vertical to Horizontal Permeability (kv/kh): 0.1

- Homogeneous Porosity
- Dip of the reservoir: 10 degrees
- Component Slate: Comprising H_2, N_2, CO_2, C1, and C2 for the reservoir modelling.
- Reservoir's Abandonment Pressure: 44 bar

Reservoir modelling is based on a seasonal storage scenario:

- Injection Phase: From May to November, pressure is increased to 250 bar, followed by a 2-month idle period allowing for equilibrium and stabilization within the reservoir.
- Production Phase: From January to April, pressure is reduced to 150 bar, followed by a 1-month idle period.

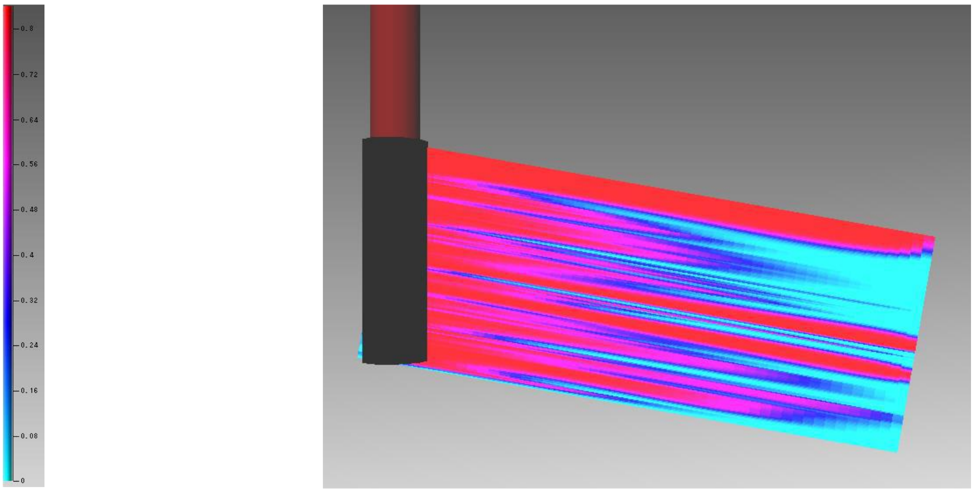


Figure 4-34 - Shows hydrogen saturation (mass fraction) distribution in the 2D model after the first injection cycle. The red areas indicate hydrogen gas, while the blue areas indicate contamination [104]

Figure 4-34 shows a snapshot of the 2D model after its first injection cycle. The red areas are referring to the hydrogen gas and the blue areas are referring to the contamination.

Modelling results have shown that:

- Initial Cycles: The purity of hydrogen decreases after a few cycles due to the superposition of cushion gas injections, which initially acts as a buffer. This decline in purity can be attributed to the increased presence of other gases that were initially meant to stabilize the reservoir environment.
- Long-Term Trends: Over time, the average hydrogen saturation within the reservoir tends to increase, leading to improved purity levels. This suggests that despite initial losses in purity, consistent operation and proper management of the injection and extraction processes enhance the overall quality of hydrogen available for withdrawal.

It is important to state that the current reservoir model is not aligned with the specific use case of this research, which focuses on buffering hydrogen production. In this use case, injection and production phases alternate continuously, unlike the seasonal storage system assumed in the model. Therefore, while the current model provides valuable insights into potential contamination levels and initial reservoir behavior, it does not accurately reflect the continuous injection-production cycles needed for buffering hydrogen production.

Future research should develop a reservoir model tailored to the specific use case of continuous alternation between injection and production phases. This tailored model would provide more accurate predictions of reservoir behavior, hydrogen purity, and contamination levels under the operational dynamics of hydrogen buffering. Understanding these aspects is crucial for designing effective storage and purification systems that ensure the hydrogen extracted meets the required standards for its intended use.

4.5.2 Reservoir Specifics

To accurately model and understand the behavior of the reservoir, it is essential to consider its specific characteristics. These parameters provide a detailed understanding of the reservoir's physical and chemical properties, which are crucial for designing effective storage and injection strategies. Table 12 outlines the key specifics of the reservoir:

Table 12 - Reservoir Specifics.

Parameter	Value	Unit
Porosity	~10	[%]
Permeability (Average)	5	mD
Reservoir depth	~3200	m
Well Depth	4235	mAH
Abandonment Pressure	40	Bara
Temperature	105	°C
Thickness	45	m
H_2S Presence[1]	100	ppm
Size (GIIP)	3.5	BCM
Caprock	Zechstein	[-]

[1]Note: This is an assumption made for this research to include H_2S removal. The actual data of the reservoir does not correspond to this value.

- **Porosity:** The reservoir has a porosity of approximately 10%, which indicates the proportion of void spaces in the rock that can store hydrogen. This moderate porosity suggests a reasonable capacity for hydrogen storage.

- **Permeability:** The average permeability of the reservoir is 5 millidarcies (mD). Permeability is a measure of the reservoir rock's ability to transmit fluids, which in this case is crucial for the efficient injection and withdrawal of hydrogen. The relatively low permeability may pose challenges for flow rates, making the reservoir unsuitable for large-scale energy storage.
- **Reservoir Depth:** The reservoir depth is ~3200 meters. This depth influences the pressure and temperature conditions in the reservoir, affecting the behavior and storage dynamics of hydrogen.
- **Well Depth:** The absolute well depth is 4235 meters. This depth provides insight into the pressure and temperature conditions encountered in the reservoir, which can affect the behavior of stored hydrogen and the efficiency of the storage process.
- **Abandonment Pressure:** The abandonment pressure of the reservoir is 40 Bara. This pressure is the baseline pressure of the reservoir after it was decommissioned from its previous use, and it forms the starting point for any new injection and storage operations.
- **Temperature:** The reservoir temperature is 105°C. This high temperature can influence the phase behavior of hydrogen and other gases within the reservoir, as well as the materials used in the construction of the storage facilities.
- **Thickness:** The reservoir has a thickness of 45 meters, providing a substantial vertical section for hydrogen storage and movement. This thickness, combined with the porosity and permeability, helps determine the total storage capacity of the reservoir.
- **H_2S Presence:** The presence of hydrogen sulfide (H_2S) at a concentration of 100 ppm is assumed and is a critical safety and operational concern. H_2S is a toxic and corrosive gas that requires careful handling and mitigation strategies to ensure safe operation of the storage facility. An assumption is made that the concentration of the H_2S is 100 ppm, as the influence on UHS on H_2S is not fully understood yet.
- **Size (GIIP):** The reservoir's gas initially in place (GIIP) is 3.5 billion cubic meters (BCM). This large volume indicates the potential scale of hydrogen that can be stored, making it a significant asset for large-scale hydrogen storage projects.
- **Caprock:** The caprock is identified as Zechstein, which is a geological formation known for its excellent sealing properties. The caprock's integrity is crucial for preventing the escape of stored hydrogen and ensuring the long-term viability of the storage operation.

These parameters influence the reservoir's ability to store and transmit hydrogen, the operational pressures and temperatures, and the necessary safety measures to handle potentially hazardous gases like H_2S. Future modelling efforts must incorporate these specifics to accurately simulate reservoir behavior and optimize storage operations.

4.5.3 Well performance

4.5.3.1 Hydrogen wells

For underground hydrogen storage projects, the role of wells is pivotal in both the injection and extraction of hydrogen. Wells are particularly designed and evaluated for their capability to handle specific compositions and pressures. For simplicity the End of Cycle (EOC) gas composition has been assumed to be 100% hydrogen for well performance modelling. It should be noted that this is not the case in the real world. This simulation gives a rough estimation of the production rates of the wells and if the desired rates are achievable by the end of the production cycle, utilizing the same wells for both injection and extraction processes.

In the case of reservoir, a well simulation was performed using the PROSPER software tool to assess well performance and determine feasible flow rates.

The well model is about IPR (Inflow Performance Relationship- what the reservoir can deliver) and VLP (vertical lift performance- what the well can deliver based on completion configuration, depth etc.). The intersection between IPR and VLP is the solution: the production rate the well can deliver based on both reservoir deliverability and well deliverability [105].

Given the demand for high flow rates, the largest available well sizes were used. Specifically, these wells feature a tubing size of 9 5/8” x 7” (ID 8.702” x 6.76”).

However, the well performance simulation results were not positive. The flow velocity in the wells during production for 9 5/8” are 50 m/s, while for natural gas the standard flow velocity is 10 m/s. The flow velocity for hydrogen is not yet defined, but considered to same as for hydrogen pipelines, so between 30 and 60 m/s. It should be noted that contaminants of the reservoir are in the flow, the high velocity could lead to serious erosion and safety issues. It is of importance that the well performance needs further research.

Another problem for the well installation is the Zechstein caprock. A thick casing is needed during drilling process as the Zechstein is difficult to pierce. Therefore, a very strong casing, having a thickness of 1 inch, would be necessary. However, this is not possible for 9 5/8” tubing, and therefore smaller tubing is necessary. This would mean that 7” tubing is necessary. If operating at 50 m/s, 12 wells would be necessary for 7” tubing. If operating at 30 m/s, an increase of 30% capacity is needed, leading to 16 wells [106].

During the simulation, it was noted that the designated well exhibited unstable flow characteristics when operated at a pressure of 150 bar. Consequently, the minimum operational reservoir pressure was determined to be 160 bar to achieve stable flow.

The well performance outcomes for pressures of 160, 200, and 250 bar are summarized in Table 13. At 160 bar, the production gas rate was approximately 0.5 mln Sm^3/d, requiring the installation of 49 wells to meet the production demands of the UHS project. However, at higher pressures of 200 and 250 bar, the required number of wells reduces to 28 and 17, respectively, due to improved flow rates and operational efficiencies.

Table 13 – Well Performance Calculation for Well Count done in PROSPER

Reservoir Pressure (bar)	FTHP (bara)	Production Gas Rate (1000Sm3/d)	Wellhead Superficial Gas Velocity (m/s)	Total No-Slip Velocity (m/s)	Erosion Rate (mm/year)	Number of required wells
150	N/A	N/A	N/A	N/A	N/A	N/A
160	70	542.47	2.68789	2.64493	0	49
200	70	946.84	5.06619	5.36907	0	28
250	70	1553.4	8.02744	9.02341	0	17

Despite the theoretical feasibility of achieving the required hydrogen production rates with increased reservoir pressures, practical challenges persist. Installing 49 vertical hydrogen wells, as necessitated at 160 bar, is technically not feasible due to spatial, environmental, and economic constraints. Moreover, the implications for well integrity and maintenance become significantly complex with an increasing number of wells.

4.5.3.2 Dedicated Tail Gas Well

To manage the tail gas produced during hydrogen extraction, a dedicated tail gas well is proposed. The tail gas, which includes residual gases and byproducts from hydrogen extraction, needs a reliable offtake solution. Without a designated offtake for the tail gas, the hydrogen cannot be fully withdrawn from the storage reservoir. The dedicated tail gas well will allow for the efficient re-injection of tail gas into a different section of the reservoir or its transport to a processing facility for further treatment.

The proposed design includes implementing the tail gas well in the lower area of the reservoir. This strategic placement prevents the upper part of the reservoir from becoming contaminated with hydrocarbons, CO_2, N_2, and H_2S. A study conducted by Shell examined the effect of a 10° dip into the reservoir for the well {Correnti, 2023 #163}. The results were positive, indicating minimal to no additional contamination of the hydrogen. This study supports the feasibility and effectiveness of the dedicated tail gas well design in maintaining the purity and integrity of the stored hydrogen. For simplicity of the case study, it is assumed that the well material is the same for hydrogen and tail gas well.

4.5.3.3 Influence of transmissivity on flow performance

The flow performance of the wells was notably poor, attributed primarily to the low reservoir thickness of 45 meters and the permeability (kH), leading to a low transmissivity of 225 millidarcies (mD.m), which is calculated by permeability times thickness of the reservoir.

A recent study conducted by TNO [60], explored the maximum theoretical withdrawal rate for UHS in the Grijpskerk reservoir, which has a permeability of 25 mD and uses 7-inch tubing. The study found that the maximum theoretical withdrawal rate is approximately 9 million Nm^3/day at a reservoir and wellhead pressure of 150 and 65 bar, respectively, equivalent to 25 GWh/day. Using 9-inch tubing would increase the withdrawal rate by 57% for the Grijpskerk UGS, yet also increase the bottom-hole drawdowns by 42%, which raises the risk of mechanical damage to the wellbore and significantly reduces flow performance.

Applying these theoretical rates to practical scenarios, the study suggests that 5 to 6 wells could be sufficient, instead of 49 wells, to achieve a total withdrawal rate of approximately 26 million Nm^3/day from a reservoir with these characteristics.

The low viscosity and density of hydrogen will lead to better flow properties during production compared to natural gas. Another study by TNO [107], evaluated the well performance of a UGS in Groningen. The key performance parameters for natural gas wells were identified as transmissivity and reservoir depth. These parameters are also crucial for UHS and are expected to remain unchanged.

According to Juez-Larré et al. [55] the screening parameters of candidate gas reservoirs, regarding permeability and transmissivity are:

- Permeability higher than 0.1 mD (i.e., no stimulation required)
- Transmissivity >100 mD.m,

Figure 4-35 illustrates the initial withdrawal rate for a single well for UGS versus the transmissivity for all onshore natural gas reservoirs in the Netherlands, using the Inflow Performance Relationship to estimate the wells production behaviour.

Reservoir simulations using PROSPER suggest that a transmissivity of 225 mD.m leads to an estimated well flow performance of 0.5 million Nm^3/day. These values for transmissivity and withdrawal rate are plotted in Figure 4-35, where the corresponding dark and light green colors represent these reservoir specifics.

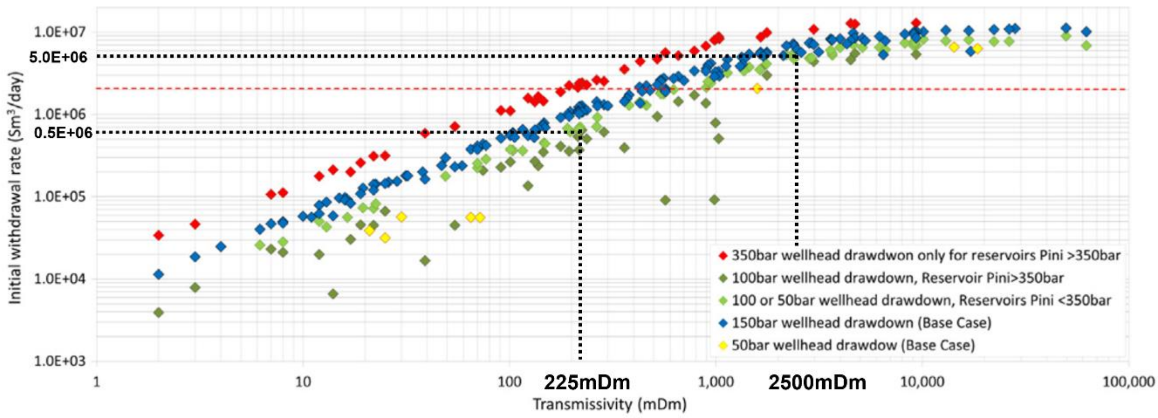


Figure 4-35: Initial single well withdrawal rate versus transmissivity for all onshore Dutch natural gas reservoirs. Adapted from [[107] and adjusted. The dotted lines present the transmissivity and initial withdrawal rate of the reservoir used in this research and the proposed new transmissivity for future research.

To achieve a well withdraw rate of 5 million Nm^3/day, the transmissivity should be ~2500 mD.m, according to Figure 4-35. This suggests finding reservoirs with a transmissivity >2,500 mD.m to obtain flow rate of at least 5 million Nm3/d.

This gives an associated withdraw rate of 5.0E6 Nm^3/day for natural gas. To minimize the wells and keep the number of well to a practical level, it was decided to propose the minimum level of transmissivity should be 2500 mDm as a screening parameter for UHS candidates to TNO.

It is expected that using a cut-off value for transmissivity greater than 2500 mD.m will be very restrictive, significantly reducing the number of candidate fields.

4.5.3.4 Improvement of well performance

To address the low withdrawal rate challenges for this reservoir, several strategies can be considered. One option is to change to another reservoir with better thickness and permeability, as the current reservoir's tightness makes it impractical for UHS storage.

However, this decision was not made in the current research due to the late stage of the study and the 150-bar operating limit. Another option is pressure management. Adjusting the operational strategies to maintain higher average reservoir pressures could decrease the number of required wells, as demonstrated by the lower well counts needed at pressures of 200 and 250 bar. However, higher pressures would lead to higher CAPEX due to the need for cushion gases, which is a significant cost item.

The pressure drops in the near well bore area and in the wells have been calculated using the software PROSPER. Significant pressure losses were observed, including a 52 bar loss around the wellbore and a 95 bar loss in the tubing, primarily due to the tight nature of the reservoir. With the working pressure ranging from 150 to 250 barg, the pressure at the inlet facilities is approximately 13 bar at the end of the cycle. Given the reservoir temperature of around 105°C and the negative Joule-Thompson coefficient of hydrogen, the temperature of the gas is expected to drop upon expansion, cooling the hydrogen stream as it decompresses.

The temperature of the reservoir is around 105 °C and the temperature of the hydrogen will drop when it is produced due to the negative Joule-Thompson coefficient, as the hydrogen decompresses. For hydrogen, the Joule-Thomson inversion temperature is around 200 K (-73°C) at atmospheric pressure. At temperatures above this inversion temperature, hydrogen will cool upon expansion (Joule-Thomson cooling). Since 105°C is significantly above -73°C, hydrogen is expected to cool under adiabatic expansion. According to the well simulations the wellhead temperature will be 8-12 °C.

4.6 Offshore Underground Hydrogen Storage Operations Platform

This section provides a comprehensive assessment of the critical infrastructure required for the offshore UHS operations platform. Serving as a strategic buffer, this infrastructure enables both the injection of hydrogen into the reservoir and its extraction as needed. The UHS platform plays a pivotal role in ensuring a continuous and reliable supply of hydrogen to the onshore energy grid, sourced from the offshore green hydrogen production site at Wind Area 7.

The analysis focuses on the design of the UHS operations platform within an offshore environment. Emphasis is placed on the critical utilities necessary for managing both compression and purification processes. These utilities, including hydrogen compressors and purification systems, are linked to the well systems, discussed in section 4.5.3 that connect the platform with the reservoir.

The section is organized as follows:

- **Operational Modes**: Description of the different operational modes, specifically hydrogen injection and production, highlighting the essential utilities for managing compression and purification processes including an evaluation of tail gas destination.
- **Pressure Waterfall Chart**: A detailed pressure waterfall chart to show the various pressure operation zones across the subsystems.
- **Power Requirements**: Examination of the power requirements for the UHS platform, along with the corresponding backup power systems.
- **Platform Layout Estimation**: Estimation of the platform layout based on the footprint and weight of the essential utilities, detailed in Section 4.6.6.

This structured approach ensures a clear and thorough understanding of the spatial and logistical considerations involved in the design and operation of the offshore UHS platform.

4.6.1 Hydrogen Injection

4.6.1.1 Cushion Gas Injection

Cushion gas is used to maintain pressure in the reservoir to allow the working gas to be withdrawn at the required production rate even if the level of working gas in the reservoir is low. Underground gas storage typically requires some form of cushion gas to help maintain the pressure within the reservoir as the gas is being withdrawn. Once injected, the cushion gas remains within the reservoir. The cushion gas used in this use case is hydrogen. Various types of gas can be used as cushion gas, including N_2, CH_4 or CO_2. For H_2 storage, using these types of cushion gases highlighted the requirement for implementing post-processing of the produced gas, as some cushion gas can produced along with the H_2, thereby affecting the quality of the hydrogen outflow. Not only does post-processing of the withdrawn H_2 introduce a lot of additional CAPEX as well as OPEX associated with equipment and its operation, but it is also counterintuitive.

Table 14: Cushion Gas and Working Gas Volumes and its Energy Content

Type	Volume (million Nm^3)	Energy content (GWh)	Volume % of Cushion Gas
Working Gas Volume (H2)	854.24	2,782	37%
Cushion Gas Volume	1,037.00	3,671	72%
Cushion Gas Volume (NG)	395.48	4,172	28%
Total Gas Volume	**2286.72**		**63%**

The cushion gas for this use case is sourced from Wind Area 7 (WA7) and its electrolysers. It is assumed that the maximum acceptable hydrogen flow will be utilized to fill the reservoir with cushion gas. However, this hydrogen flow is constrained by the injection compressor's design flow rate, which is 0.52 million Nm^3/h (equivalent to a surplus of hydrogen of 2.1 GWh). To fill the storage reservoir to 150 bar, 1 BCM (billion cubic meters) of hydrogen is required.

A percentage of the initial hydrogen produced from the PEM electrolysers at WA7 can be injected into the reservoir. If 100% of the initial hydrogen produced from WA7 is available for use as cushion gas, the only limitation is the capacity of the injection compressor, so the fastest injection rate is 2.1GWh. This scenario results in the cushion gas installation taking approximately 90 days (from January 1st to March 26th). If 50% of the hydrogen produced is exported, the installation time extends slightly, concluding around April 9th. For a 20% offtake, the process extends significantly, taking until August 30th to complete, see Figure 4-36.

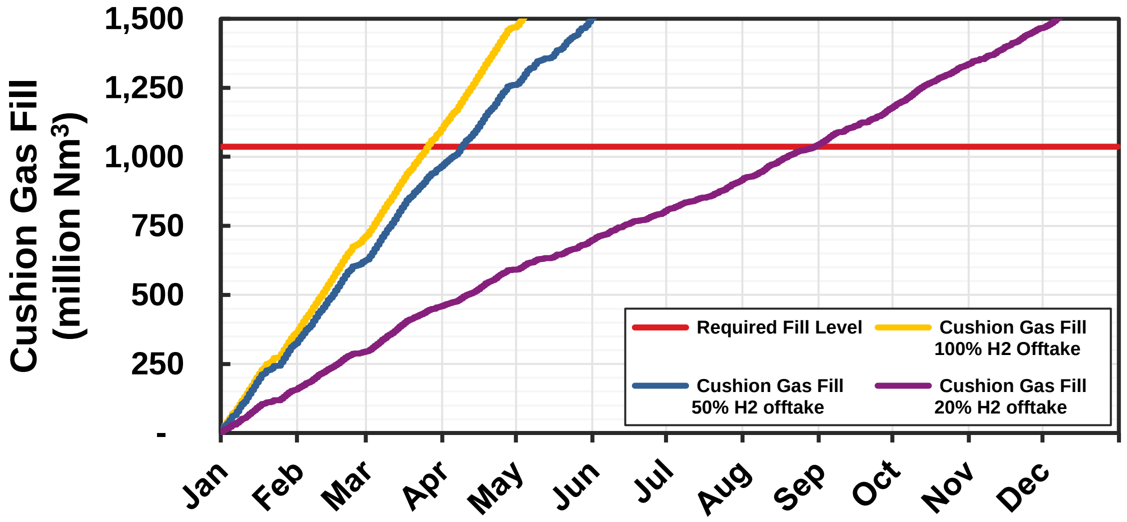


Figure 4-36: Duration Required to Fill the Reservoir with Cushion Gas at Various Hydrogen Offtake Percentages (20/50/100%). The injection compressor's maximum flow rate is capped at 0.6 million Nm³/h, while the maximum hydrogen production rate at WA7 is 1.6 million Nm³/h.

4.6.1.2 Injection Process

Periods of surplus of wind energy are dedicated as injection cycles, as there is more hydrogen produced at the offshore wind farm than the baseload of 3.5 GWh that should be exported to the onshore backbone. To determine the amount of hydrogen that will be injected a metering device will meter the amount of hydrogen that reached the platform. After metering the hydrogen is fed into the compressor module. As the surplus of H_2 is received at the UHS platform at a pressure range of 50barg – 55barg and the reservoir working pressure is between 160barg - 250 barg, compression of H_2 is required for injection process. As discussed in section 2.5, reciprocating compressors will be used, due to its flexible operations, large range in capacity and discharge pressure. As the typical pressure ratio per stage is 1.6 to 2.5 [73], with a suction pressure of 50 barg, the platform will need multiple stages to pressure the stream up to 300 barg as the overall pressure ratio is 6, leading to a multi-stage compressor module. Intermediate air coolers and KO drums will be necessary to maintain acceptable temperature (<130 degrees Celsius) and purity respectively, to compress the H_2 to the working pressure range of 150 barg – 250 barg. As most of the reciprocating compressors use lubricants, this could lead to contamination of the hydrogen. An oil separator should be used to extract the lube oil before the hydrogen enters the well and the reservoir.

4.6.1.3 Injection Compressor

The injection compressor plays a pivotal role in UHS platform's operation by facilitating the injection of surplus hydrogen into the storage reservoir during periods of wind energy abundance. This compressor is essential for maintaining the optimal pressure within the storage reservoir, ensuring efficient storage capacity utilization. It operates in tandem with wind energy availability, activating specifically during periods of surplus wind power to inject excess hydrogen into the reservoir. The hydrogen supplied to the UHS platform originates from WA7, where it undergoes compression before being transported. Upon arrival at the platform, the hydrogen has a pressure of 53 bara. Given that the working pressure range of the reservoir is chosen to be between 150 and 250 bar, the injection compressor must be designed to recompress the hydrogen to at least 250 bar. Additionally, to accommodate for losses incurred between the injection compressor and the reservoir, a margin is necessary. The losses are friction losses in the well tubing and the friction losses in the reservoir near the well bore area. To simplify this, a margin of 50 bar has been considered. Consequently, the injection compressor is designed to operate at a pressure of 300 bar, necessitating the compression of hydrogen from 53 bara to 300 bara.

Designing for intermittency requires keeping the injection compressor hot and ready to respond when idling. This can be achieved by recycling the minimum turndown flowrate through the compressors whilst doing no work. For a variable frequency drive compressor, a reasonable assumption for the minimum turndown has been assumed as 60% of the full capacity.

A benchmark was created by using a specialized tool designed by Baker Hughes [108], a specific model of reciprocating compressor was identified that meets the operational demands of this project. The selection was based on several key parameters which include capacity, suction pressure, discharge pressure, and the nature of the gas being compressed, which in this case is 100% hydrogen. The inputs and results from this tool are summarized in Table 15.

Table 15 - Input values & Results for reciprocating compressor tool of Baker Hughes

Input	Value	Results	Value
Capacity (Nm^3/h)	200,000	Adsorbed Power (kW) (per train)	15600
Suction Pressure (bara)	50	No. of trains necessary	3
Discharge Pressure (bara)	300	Dimensions per train (m^2) [1]	210
Stage 1 Temp (°C)	20	Weight per train (ton) [1]	274
Cylinder Lube	Lube	Dimensions BOP per train (m^2)	200
Component list	100% Hydrogen	Weight BOP per train (ton)	150
Compressor Model	API 618 6HG/2	Total Dimension Compressor (m^2)	1.230
Number of Cylinders	6	Total Weight Compressor (ton)	1.272

[1] The dimensions and weight of the injection compressor train include frame and motor of the compressor (13x10.5m & 245 ton), lube oil (5.5x3.1m & 11 ton) & cooling water console (7x4m & 18 tons), but exclude other balance of plant (i.e. piping, KO drums and coolers) For the footprint per train, it was chose to take an area of 20x10.5m, leading to 210 m2.

The desired injection flow rate for the project is 14.2 million Nm^3/day, equivalent to ~0.6 million Nm^3/hour. Initially, no existing compressor models were found capable of handling this entire flow rate in a single unit. Consequently, the capacity requirement was downscaled to 0.2 million Nm^3/hour to identify a suitable compressor model. To manage the full capacity, it was determined that three compressor trains would be necessary. Each train consists of a compressor unit capable of handling the reduced flow rate, thereby collectively achieving the required total flow rate.

The plot area for the compressors, as proposed by the Baker Hughes tool, will include three trains. Therefore, the total plot area will be three times 410 m^2, resulting in a total footprint of 1,230 m^2. The weight of the compressor typically corresponds to 25% of the CM. Another 25% is attributed to the driver, and the remaining 50% is due to the base plate. Thus, the total CM weight is estimated to be four times the total weight of the compressor, leading to an estimated weight of ~5,000 tons.

While centrifugal compressors are generally preferred for applications involving larger volumes of gas due to their efficiency in continuous flow conditions, they are less suited for applications requiring high-pressure differentials between the suction and discharge points. In this case, the high discharge pressure required for hydrogen injection into the UHS makes reciprocating compressors a more appropriate choice. Reciprocating compressors are particularly effective in applications where a significant increase in gas pressure is needed, as they are capable of achieving higher compression ratios compared to centrifugal compressors.

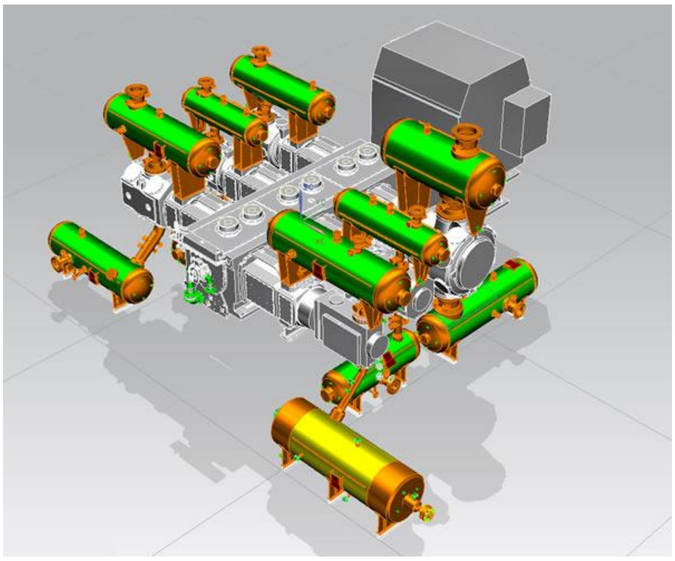


Figure 4-37 - API 618 6HG/2 reciprocating compressor model by Baker Hughes [108]

Table 16 - Prorating table for injection compressor

Injection Compressor	Baker Hughes	Use Case
Injection capacity (mln Nm^3/day)	14.2	14.2
Suction Pressure (bara)	50	50
Discharge Pressure (bara)	300	300
Power (MW)	46.8[1]	78.3
Dry Weight (tons)	5,088	5,088
Plot Area (m^2)	1,230	1,230
Configuration	3 trains recip	3 trains recip

The use case injection compressor is based on the output given by Baker Hughes tool for the weight and dimensions. This led to an injection compressor consisting of three trains, able to compress a flow rate of ~200.000 Nm^3/h each, leading to a daily flow rate of 14.2 million Nm^3. As the power of the compressor was given in absorbed power by the compressor, it was considered to give be lower than the actual power demand for the compressor.

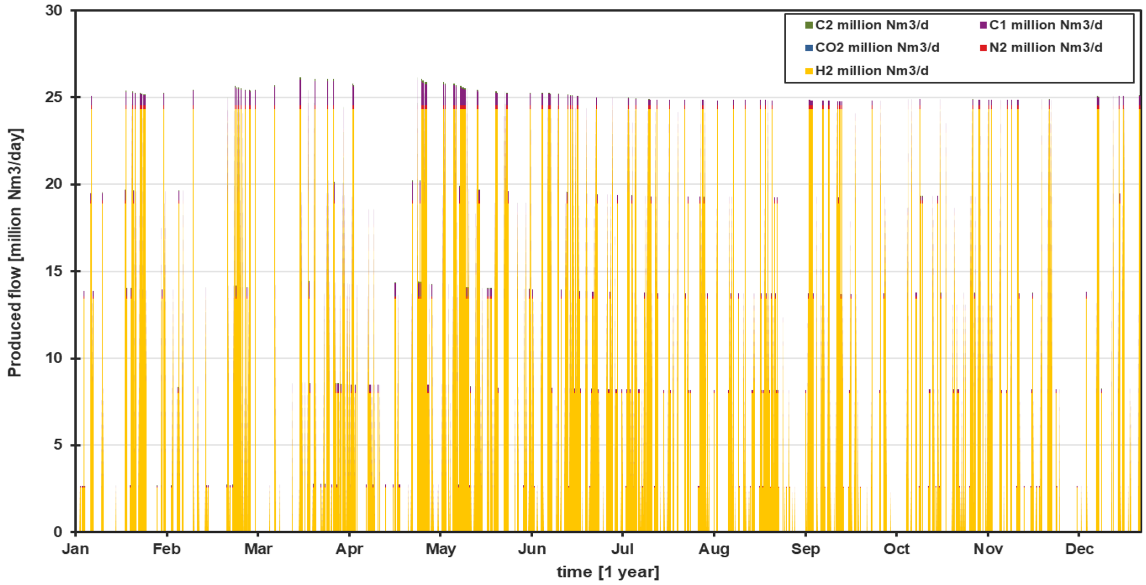
It must be noted that reciprocating compression for an offshore platform is not a default compressor option due to the complexities associated with reciprocating compressor. Vibration is a critical issue; this requires additional maintenance due to failures associated with vibration both within the package and structurally for the platform leading to increased Operating Expenditure (OPEX). In addition, the design of reciprocating compressors for offshore application requires increased engineering design to carry out due diligence in the piping, baseplate, structural and Anti-Vibrational Mount (AVM) design to cater to the expected high vibrations. This usually has an adverse impact on the weight and footprint.

4.6.2 Hydrogen Production

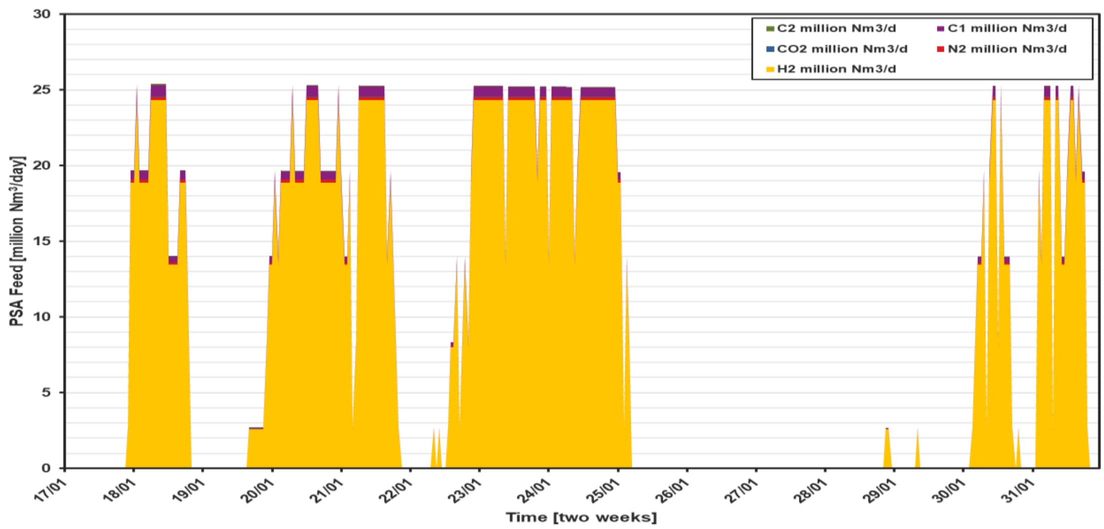
4.6.2.1 Hydrogen Purification - PSA

For hydrogen to be integrated into the energy grid, it must meet stringent purity requirements. For the Dutch hydrogen grid, a decision has to be made between 9~10%or 99.5%. Pressure Swing Adsorption is the most used technology to purify hydrogen streams that initially contain 60-90% hydrogen, enhancing their purity up to 99.99% with recovery rates between 70% and 90%. [109].

PSA is typically used in downstream process units having constant feed flow rates and the composition of the gas is constant. For UHS this will not be the case as the feed flow rate and feed composition vary continuously, which could lead to design problems for the suppliers of this technology. It is therefore important to visualize the fluctuations in the stream to inform the manufacturers of PSA installations. To do so, Shell's Hydrogen Value Chain Model is used and extend to better understanding of the flow fluctuations. Figure 4-38 shows the inflow of the PSA in million Nm^3 per day over a year and two-week period. The PSA feed includes 'over-production' to compensate for tail gas that is co-produced and includes hydrogen.



a)



b)

Figure 4-38 - PSA inflow feed shown over a) one calendar year and b) two-week period in January. Wind farm 8 GW [peak], electrolyser 5.6 GW [peak], pipeline 3.5 GWh [constant].

The data resolution in these figures is hourly, highlighting the frequent rate changes. For instance, in 2019, the system recorded 403 start/stop cycles. These frequent shifts between injection and production processes underscore the need for a PSA system that can rapidly adjust to changing inputs without significant losses. It is assumed that the switching between the modes can be done within an hour, and as the resolution of the feed is also in hours, it is assumed that there are no losses due to the switching periods.

To design a PSA system capable of handling this input effectively, it must be robust enough to adapt to variations in mole weight (ranging from 2 to 10 g/mol) and flow rate (ranging from 0 to 27.8 million Nm^3/day). The ability to swiftly transition between operational modes, potentially within an hour as per the resolution of the feed data, is also critical. Such capabilities will ensure the hydrogen produced meets grid standards consistently, even under the dynamic conditions typical of UHS operations.

To design the PSA system, benchmark systems are employed. These benchmarks are based on existing installations that have proven effective in similar applications. By comparing the new system against these benchmarks, designers can estimate the footprint and weight of the PSA system, which are critical factors in the layout and construction of the UHS facility.

The scaling is performed using a benchmark PSA system and a scaling exponent, which is commonly used in engineering to adjust for non-linear increases in equipment size and system capacity.

Based on this scaling, the calculated area for a single PSA train tailored to the UHS needs is approximately ~1,500 m^2. Given that the train represents about half the total area required for a complete PSA installation, this figure is doubled to account for comprehensive facility requirements, totalling ~3,000 m^2 for the complete plant.

Similarly, the operating weight is scaled up, resulting in an estimated total weight of ~6,000 tons for the entire PSA system. When withdrawing hydrogen from the UHS store and purifying it through the PSA system, about ~10% of the hydrogen ends up in the tail gas.

To further increase the hydrogen recovery rate, a vacuum PSA (VPSA) might be considered instead of the standard PSA. While VPSA for hydrogen purification has not been widely applied commercially due to higher operating costs, its potential to maximize hydrogen product yield makes it worth considering.

The operational principle of the PSA, which relies on adsorption processes, necessitates moderate power consumption. The power requirements for such systems are typically in the range of several kilowatts, depending on the specific configuration and operational parameters. This level of power consumption is very low within the context of the overall energy infrastructure of the UHS facility. The side stream, which is adsorbed by the PSA, defined as the tail gas, needs further attention.

4.6.2.2 Handling of Tail Gas

Tail gas is a byproduct stream that results from PSA. The stream containing most of the natural gas and impurities, plus the hydrogen that was captured by the adsorbent beds. In hydrogen purification via PSA, achieving very high purity hydrogen often leads to a higher proportion of hydrogen remaining in the tail gas. This occurs because the adsorbent materials capture trace amounts of hydrogen along with the contaminants. As a result, the efficiency of hydrogen recovery decreases as the purity specification increases.

The management of tail gas is an important consideration for industrial operations. While the primary goal is to maximize hydrogen recovery and purity, the tail gas still contains valuable components that can be recovered or utilized. Strategies for handling tail gas that needs further exploration are:

1. **Reinjection:** Tail gas can be reinjected into the hydrogen storage reservoir or another suitable geological formation for storage or enhanced recovery operations. This can be done in the same reservoir as the UHS reservoir, using a dedicated tail gas well placed in the lower area of the reservoir. Given that natural gas is significantly heavier than hydrogen, it will remain at the lower part of the reservoir. The amount of mixing would need detailed studying with specialist reservoir simulation input. Reinjection of the tail gas will need 7 compression stages to bring the pressure from 1.3 to 300 bara, according to a simulation done in UniSim Design, resulting in a compressor with large footprint and weight. In an offshore environment this is unfavourable due to associated costs and technical implications.
2. **Export to the NG grid**: The tail gas could be exported and blended into the natural gas grid if it meets the natural gas grid specifications. Therefore, the hydrogen content in the tail gas should not exceed 0.5 %vol [47]. It is expected that the amount of hydrogen that is accepted into the natural gas grid will increase in the coming decade, as for onshore equipment a limitation of 15 vol% hydrogen is expected [111].
3. **Export to dedicated customer:** If a customer can be found that is able to handle the tail gas and its specs a dedicated tail gas export pipeline can be used exporting the tail gas directly to the customer.
4. **Further Processing:** Tail gas can undergo additional processing steps to separate and recover individual components, such as hydrogen, methane, or carbon dioxide, for use in other industrial applications.

Effective management of tail gas is crucial for optimizing the overall efficiency and economic viability of hydrogen purification processes. By carefully considering the composition and potential uses of tail gas, industries can reduce waste, improve resource utilization, and enhance the sustainability of operations. Without a destination for all the tail gas, the hydrogen cannot be fully withdrawn from the store. It is a crucial step to find a destination for the tail gas.

4.6.2.3 Tail Gas Destinations

The management of tail gas presents unique challenges due to its intermittent production and variable composition. Tail gas is not a continuous output; it appears sporadically based on the operational cycles of hydrogen withdrawal from the UHS. When it does appear, it does so in large volumes with a composition that significantly varies, making it difficult to handle and utilize efficiently.

The difficulty with this so-called 'tail gas' is that it requires a destination that can accept a sporadic and variable stream than can suddenly appear which is not there for most of the year; that can suddenly appear; and, when it does, is very large and variable, both in flow rate and composition. The tail gas composition does not meet the NL natural gas grid specifications; and the stream is rather large and variable for any single user such as a nearby power plant or blue hydrogen facility.

This study indicates the need for a tail gas offtake during hydrogen withdrawal from the UHS. Without this, the full withdrawal of hydrogen is not feasible, necessitating (partial) reinjection of the tail gas. This challenge is likened to "drinking from a firehose," where the volume and rate of tail gas exceed any single facility's capacity.

To address this, the potential for utilizing part of the tail gas at the H2Gateway blue hydrogen production plant in Den Helder was investigated as mentioned in section 4.4.1.10. The blue hydrogen plant aims to produce 0.2 Mton/year of blue hydrogen, corresponding to a daily production of 7.6 million Nm^3 of hydrogen, requiring 3.8 million Nm^3/day of methane as feedstock [98]. It is assumed that the plant can accommodate up to 10% hydrogen in the feed, though this feasibility is yet to be confirmed by the technology licensor. For the purposes of this research, it is assumed to be feasible. The remaining tail gas that can't be accepted by the BH plant, needs to be reinjected into the reservoir as no other customer was identified according to research by Costain [112].

The tail gas consists of 5 components: H_2, N_2, CO_2, C1 and C2. The tail gas process parameters SOC and EOC can be found in **Error! Reference source not found.**.

In the SOC, relative pure hydrogen is withdrawn from the store and therefore low contamination which leads to a low concentration of contaminants in the tail gas, where at the EOC the concentration of contaminants is 50%. This has implications on the mole weight of the tail gas, as can be seen in Figure 4-39.

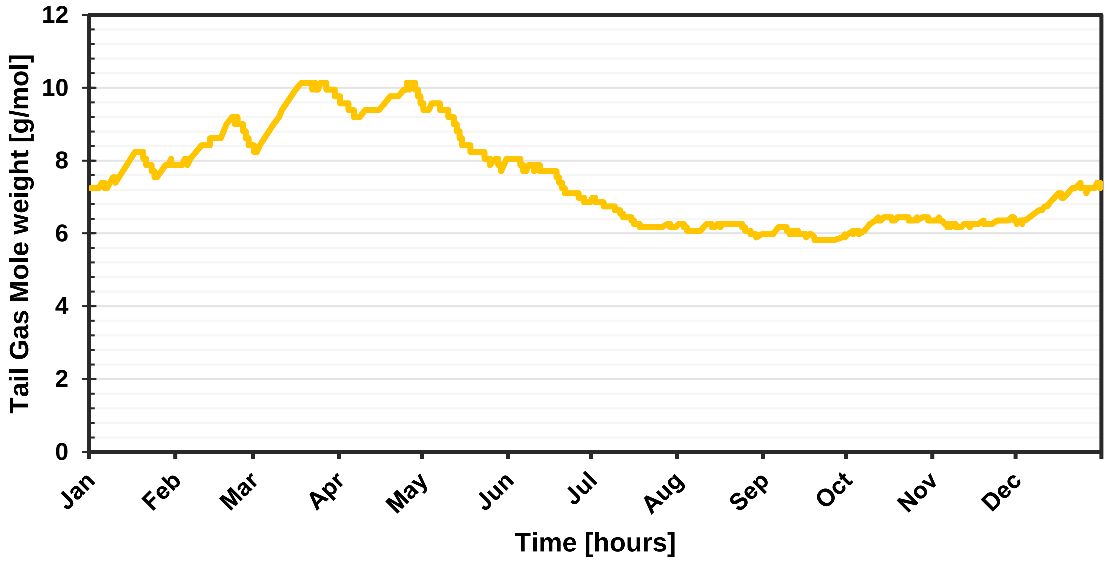


Figure 4-39: PSA tail gas mole weight (g/mol) differentiation shown over a calendar year.

Figure 4-40 and Figure 4-41 show the produced tail gas by the PSA for one calendar year and two weeks, respectively. The resolution of the data is in hours and is translated to Nm^3/day. Recalling that the blue hydrogen plant can only take up 0.38 mln hydrogen Nm^3/day, the yellow section (H2 in the graph shows this threshold value is almost always exceeded. The flow varies between 0-3.89 mln Nm^3/day and consists of 403 start/stops for the year 2019. The remaining tail gas that can't be accepted by the BH plant, needs to be reinjected into the reservoir.

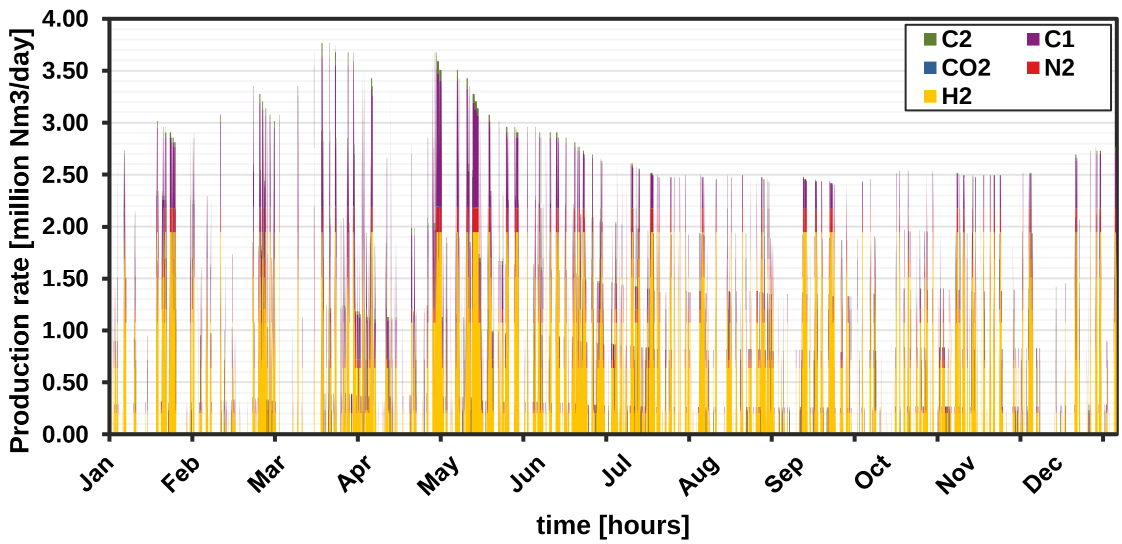


Figure 4-40: PSA Tail Gas Production Rate shown for one calendar year. The resolution of the production data is in hours (assuming ~90% H_2 recovery).

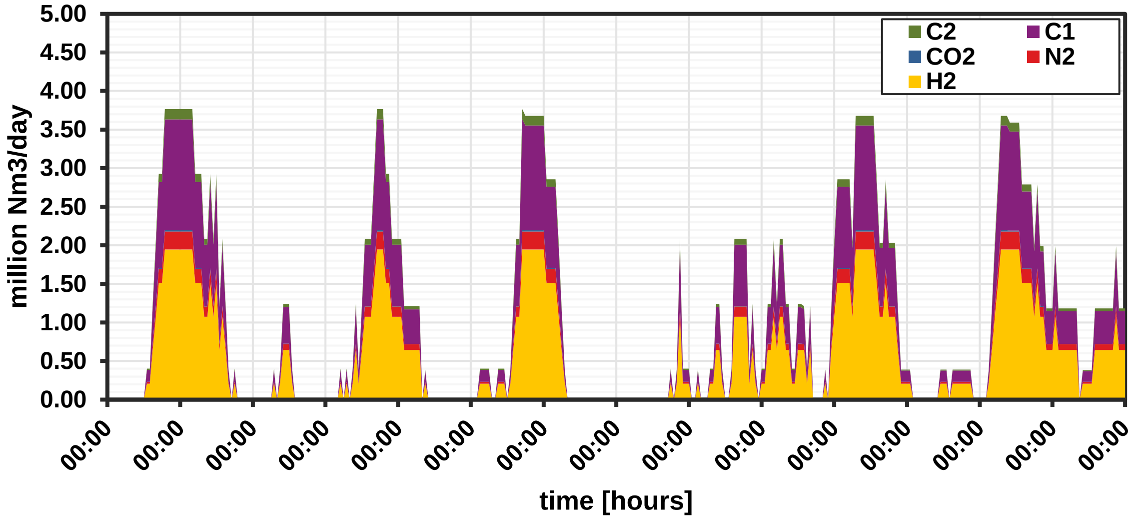


Figure 4-41: PSA Tail Gas Production Rate (assuming H_2 ~90% recovery rate) shown for two-week period (March 18-31). The resolution of the production data is in hours.

In summary, effective tail gas management from the PSA process focuses on two primary strategies: 100% reinjection into the reservoir and partial reinjection combined with a bleed stream exported to the H2Gateway blue hydrogen production facility. Reinjection requires significant compression, posing challenges in offshore environments due to the large compressor footprint and weight. Exporting a bleed stream to H2Gateway leverages its capability to handle hydrogen in the feed, with the remaining tail gas reinjected into the reservoir. These strategies optimize hydrogen recovery and ensure a destination for the tail gas. The tail gas leaves the PSA at 0.3 bara and therefore needs to be compressed to be exported or reinjected. This leads us to the next essential step in the process: tail gas compression.

4.6.2.4 Tail Gas Compressor

After PSA, the purified hydrogen stream experiences a ~1 barg pressure drop to 59 bara, while the tail gas drops to 1.3 bara. For reinjection, the tail gas needs to be compressed to 300 bara, requiring an approximate overall pressure ratio of 230. Multi-stage tail gas reciprocating compressors with intermediate air-coolers will be provided to raise the tail gas pressure. Dew-pointing of tail gas will be carried out by a dehydration unit, and the tail gas will be supplied to H2Gateway through blending into the BH plant inflow stream.

It is important to investige the tail gas production from the PSA. As the PSA has a recovery rate has been conservatively estimated to 90%%, ~10% of the hydrogen is closed-in by the tail gas. The tail gas leaves the PSA at 1.3 bara, so it needs compression for reinjection and export. For reinjection, the hydrogen needs to be compressed to 300 bar, as this is the maximum working pressure of 250 bar with an assumed 50 bar margin of pressure losses due to well tubing and near well bore area. The tail gas needs to be compressed for export and it is assumed that the exported hydrogen should reach the coast at 50 bar, leading to 5 stages of compression, while for reinjection the injection pressure is 300 bar, requiring eight compression stages. So, the tail gas that will be exported, will be extracted after the 5^{th} stage.

The pressure swing adsorption system used for purification of the back-produced hydrogen generates a tail gas stream close to atmospheric pressure. Combined with the large normal flow rate of up to 3.9 million Nm3/d for the case study, this results in an actual volumetric flow rate of ~142,000 Am3/h. The initial stage volumetric flow rate ranges from 65,000 m^3/h to 142,000 m^3/h. Recent quotations for standard reciprocating compressors typically restrict suction volumetric flow rates to 3,000 m^3/h per cylinder [112]. To increase the suction volume, more cylinders can be added, and the suction duty can be performed in parallel. For the first compression stage 48 cylinders are necessary. The number of cylinders decreases over the compression stages as the actual flow rate decrease due to increased pressure (PVT). With a pressure ratio of 2, the overall cylinder count is ~96 divided over 7 stages. More cylinders indicate high operational downtime, which is very unfavorable for a high cyclic system. To deal with the high overall cylinder count for the reciprocating compressors a high-speed centrifugal compressor can be used for the first stages to increase the suction volume and therefore decrease the amounts of trains necessary. This is not further looked into but could be an option to reduce the overall cylinder count.

The 96 cylinders and 7 stages of compression with inter-cooling comes with a cost in terms of power, size, and weight. The benchmark tail gas compressor has a power of 33 MW, assuming 80% efficiency. The benchmark compressor has a EOC flow rate of 109,300 m^3/hour while the volumetric flow EOC for this use case is 142,00 m^3/hour. The inflows of both compressors are used to pro-rate the power needs for this use case, leading to a tail gas compressor with rated power of 35.5 MW. The benchmark compressor's layout 157m X 73m (Length x Width) so the area is 11,461 m^2. When pro-rating again this leads to a footprint of 14,628 m^2, approximately the size of two football fields. This will become a challenge in the offshore environment, with an estimated weight of 17,000 tons.

4.6.3 Salt Cavern in Support of Reservoir

To deal with the fluctuations in the inflow of the PSA, it is worth to explore the possibility to damp the fluctuations. As PSA's are designed to have a continuous inflow, the fluctuations could make it difficult to operate the PSA efficiently, potentially leading to malfunction of the PSA. By integrating a small fast store that can deal with the hourly fluctuations, such as a salt cavern, the PSA inflow rate can be managed.

In this approach, constraints were applied to the injection and production rates, as well as to the switching time between these operations. The peak rates required were set higher than initially projected: capped at 8 million Nm^3/day for injection and 16 million Nm^3/day for production instead of 14 million Nm^3/day and 24 million Nm^{3-}/day. Furthermore, the minimum switching time between injection to production and production to injection was limited to a minimum of 24 hours, based on hourly data.

These constraints on rates and switch times resulted in the gas reservoir storage being unable to handle sudden or steep fluctuations in demand. Consequently, the system requires additional buffering mechanisms, such as a salt cavern, to manage these fluctuations. The peak rates for the salt cavern would need to be close to the original peak rates, approximately 18 million Sm^3/day for injection and 24 million Sm^3/day for production in this scenario. However, the required volume for the salt cavern would be almost an order of magnitude smaller than that of the gas reservoir.

Thus, the gas reservoir serves as a large, slow storage facility primarily catering to seasonal variations, while the salt cavern functions as a small, fast storage option to accommodate short-term weather fluctuations. This dual-storage approach ensures a stable and efficient hydrogen storage system capable of handling varying demand patterns.

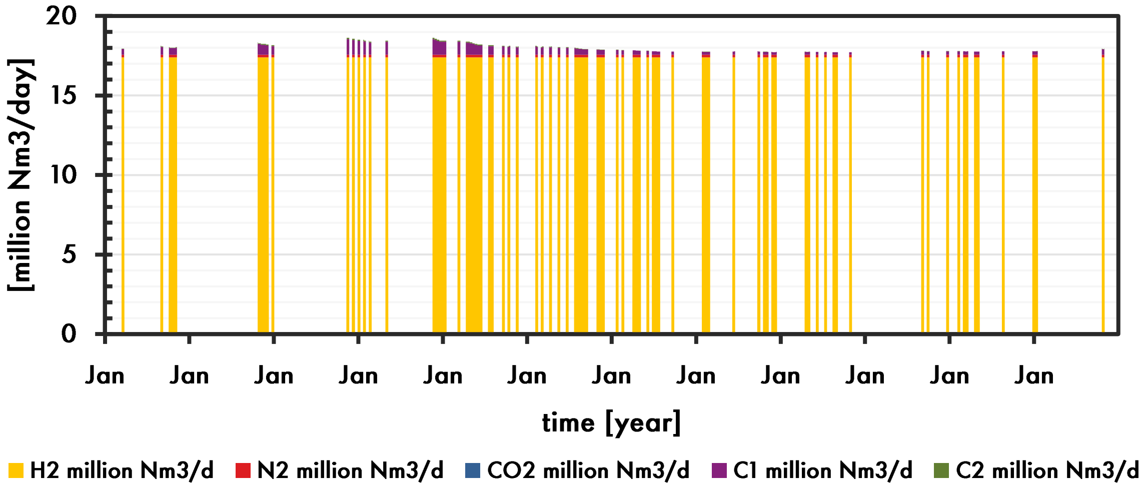


Figure 4-42: Inflow Rates for the PSA with Additional Buffering by a store that is able to respond quickly, like a salt cavern.

This graph illustrates the inflow rates for the Pressure Swing Adsorber (PSA) system, highlighting the impact of additional buffering provided by a salt cavern. The salt cavern effectively manages sudden and steep fluctuations, resulting in more stable and constant inflow rates to the PSA, thus ensuring optimal operational performance.

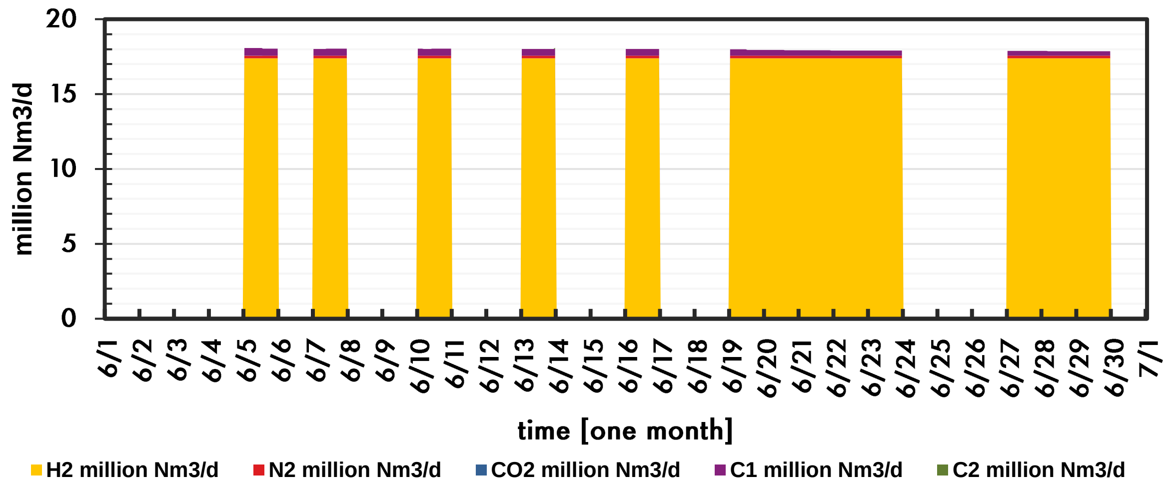


Figure 4-43 shows the different UHS fill levels for the depleted gas reservoir when the injection and production rates are capped at 8 mln Nm^3/day and 16 mln Nm^3/day, respectively.

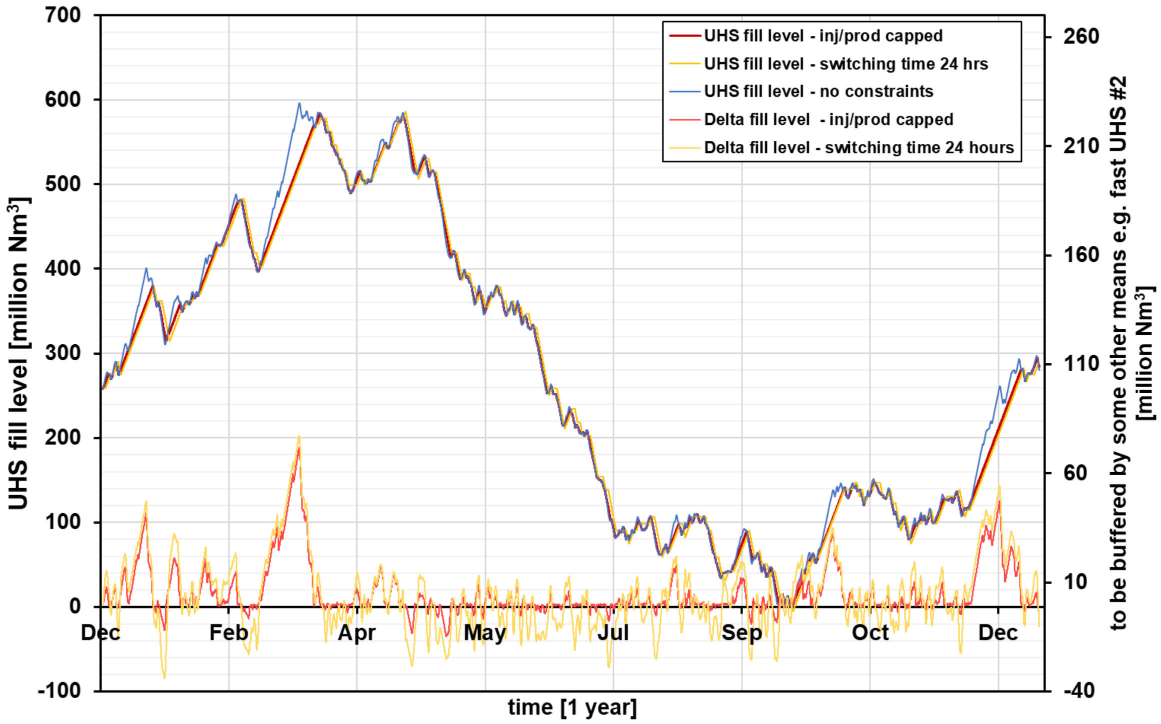


Figure 4-43: Influence on UHS fill level by implementing a salt cavern to flatten fluctuations for UHS in depleted gas reservoir. The hydrogen that needs to be buffered by the other store is plotted on the secondary axis and represent the difference in the storage fill level compared to no buffering and it plotted on the secondary vertical axis.

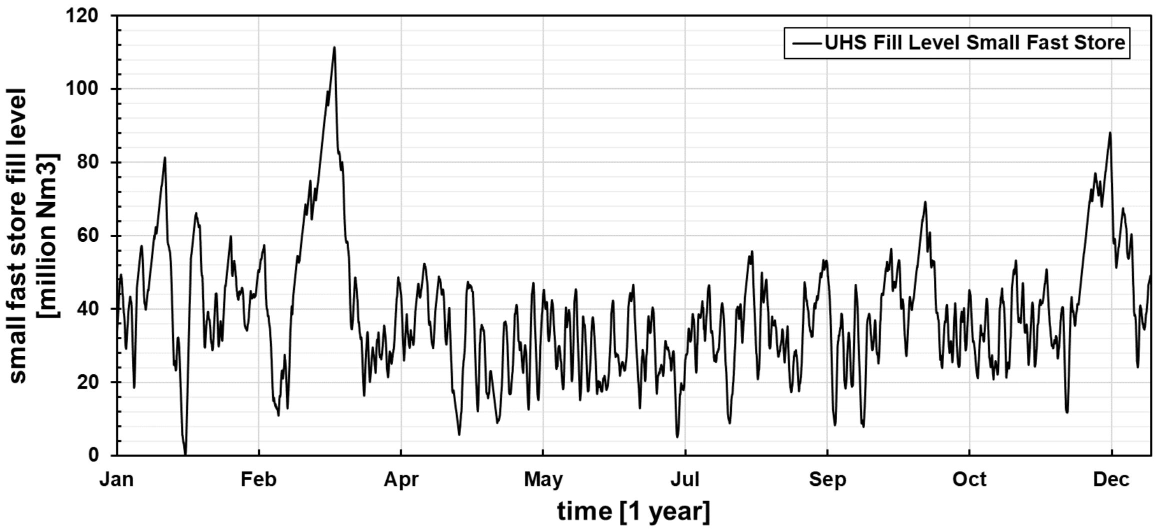
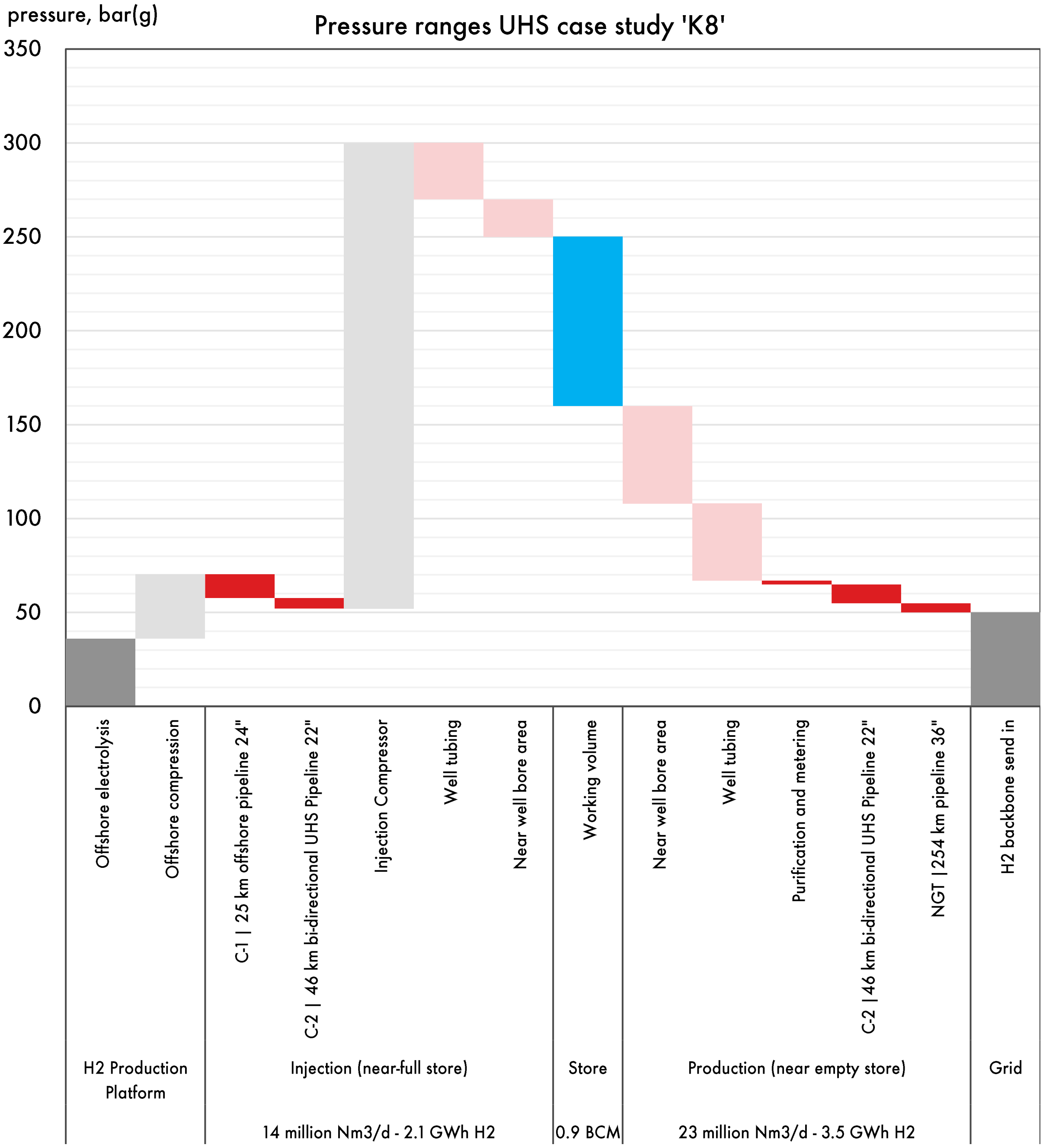


Figure 4-44: The storage fill level of the small fast store that operates to dampen the fluctuation for the depleted gas reservoir UHS.

If the salt cavern is not able to handle peak moments, curtailment of hydrogen production can be another option to deal with fluctuations.

4.6.4 Pressure Profile

Given the significance of compression and operating pressures across various subsystems in this UHS case, a pressure waterfall profile provides a comprehensive overview of these pressures. This profile effectively maps out the pressure dynamics of each subsystem, offering valuable insights into the overall performance of the system.



Offshore electrolysis produces hydrogen at an initial pressure of 50-55 barg, necessitating compression for export. After compression, the hydrogen is transported via pipelines C-1 and C-2 to the storage facility, experiencing pressure losses due to internal friction as detailed in section 0. The hydrogen arrives at the UHS facility at 53 bara. To inject hydrogen into the reservoir when it is nearly full, the pressure must be increased to 300 bara to overcome the reservoir pressure of 250 bar. This process assumes a pressure drop of 50 bar in the well tubing and near-wellbore area. Further research is required to calculate the precise pressure drop.

The initial lower bound of 150 bar resulted in unstable flow characteristics in the near-wellbore area and the well during the production cycle, necessitating an increase in the lower bound hydrogen storage pressure to 160 bar. Thus, the storage facility operates between 160 and 250 bar. Significant pressure losses have been observed, including a 52-bar loss around the wellbore and a 95 bar loss in the tubing, primarily due to the reservoir's tight nature. As noted in section 4.5.3, the reservoir’s permeability renders it unsuitable for large-scale UHS. Despite this recent finding, for the sake of simplicity, other calculations regarding the reservoir will maintain the initial lower bound of 150 bar.

The hydrogen is therefore assumed to reach the UHS facility at 70 bar. If the actual pressure losses in the wells and near-wellbore area were considered, the hydrogen would reach the platform at approximately 13 bara. However, since pressure drops within the wells are typically not that high, it is assumed that the hydrogen reaches the platform at 70 bar. The purification steps result in some additional pressure loss, but the hydrogen exiting the PSA can be exported to the onshore backbone via pipelines C-2 and NGT without the need for additional compression, reaching the backbone at 50 bar.

4.6.5 Electrical Power Consumption

This section describes a simplified calculation of the energy demand for UHS operations in section 4.6.5.1, followed by configuring a back-up power system in section 4.6.5.2 and at section 4.6.5.3 the round-trip efficiency of the UHS facility is calculated.

4.6.5.1 Energy demand of platform

Electrical power is required for UHS operations. The major power consuming items for the UHS operations are the injection and tail gas compressors. Electrical power for the cycle with the lowest purity of hydrogen extracted is used to calculate the electrical energy demand for the platform’s operations. A margin of 30% is considered to account for power consumption by other utilities of the UHS platform.

The operations are design with a working volume pressure range of 150-250 bar. To account for losses in the wellhead and near well bore area a margin of 50 bar is included. Hence the compressors output pressures vary between 200 and 300 bar. To compress the hydrogen to 300 bar at maximum flow rate a rated power of 78 MW is considered, which is maximum power of the compressor. The actual power consumption of the compressor is estimated by pro-rating the inflow rate for an annual average flow rate. 0.84 GWh is the mean flow rate, so the actual power consumption becomes 28.5 MWh for the injection compressor. This leads to an annual energy consumption of 249 GWh.

Hence, compression of the hydrogen from 50-55 bar when the hydrogen arrives at the platform to 150 bar is needed when injecting to a reservoir with no to little amount of working gas left (EOC) and power is required to inject the reservoir with hydrogen when the store is close to 250 bar (SOC). Hence power consumption in the injection compressor is determined as following:

Table 17: Power Balance for Injection Compressor

Power Requirement during EOC (production) of H2 Injection (Injection against a backpressure of 150bara)	
Compression	50-300 bara
Flowrate	14.24 Mil Nm3/d | 2.10 GWh H2
Annual average injection flow rate	5.70 Mil Nm^3/d | 0.84 GWh H2
Rated Power Compressor	78 MW
Power Rated for Usage	28.5 MW
Total Power Required for H2 Injection Annually	**249 GWh**

The tail gas stream produced from PSA has a variable maximum flow rate between 2.55-3.89 mln Nm^3/day and the mole weight varies between 5.8 and 10.15 g/mol. As the composition is mixed hydrogen, the power for compression is lower, although a higher pressure ratio needs to be achieved. The tail gas needs compression from 1.3 bara to 200-300 bara. The same method used for the injection compressor is used.

Table 18: Power Balance for Tail Gas Compressor

Power Requirement of Tail Gas	
Compression	1.3-300 bara
Flowrate full store (SOC)	2.55 Mil Nm3/d | 300 bar
Flowrate empty store (EOC)	3.89 Mil Nm^3/d | 200 bar
Rated Power Compressor (EOC)	35.5 MW
Power Rated for Usage (SOC)	16.8 MW
Total Power Required for Tail Gas Injection Annually	**147 GWh**

Hence the total power consumption is:

Table 19: Total Power Consumption of UHS Platform

Description	Value	Unit
Injection Compressor	249,546	MWh
Tail Gas Compressor	147,396	MWh
Margin (10%)	39,694	MWh
Total	**409,636**	**MWh**

The UHS platform needs 409 GWh of energy annually to operate the UHS facilty for the injection-production cycles. Decisions needs to be made on how this is achieved. Given the intermittent nature of wind power, extracting the energy from the wind farm can give problems as there might be periods of no wind. During days of little to no wind, H_2 is required to be withdrawn from the reservoir to make up for a H_2 deficit. Therefore, equipment associated with the withdrawal of H_2 from the caverns require power even when this cannot be supplied by wind energy. This results in the requirement for a backup energy source.

4.6.5.2 Back-Up Power System

If there wouldn't be a back-up system to power the utilities on the platform such as the compressors and PSA, it could lead to undesired downtime of the UHS storage. To deal with this problem multiple back-up systems were evaluated as potential solution:

- Photovoltaic System
- Lithium-ion Batteries
- H_2 Fuel Cells with Topsides H_2 Storage
- H_2 Gas Turbine Generators

To evaluate the different back-up options the power usage of the platform needs to be investigated. Electrical power is required for the UHS operations. As WA3 is the closest to the storage location, is assumed that power will be available from WA3 and that a percentage of this power can be drawn upon to power UHS operations. During an injection cycle, there is lots of wind, hence the need to inject surplus H_2 into the reservoir. It is assumed that electrical power from WA3 will be used to power the injection compressor. Please note that the injection compressor is operational only during times of wind surplus and therefore it as assumed that it will be powered by wind energy and its power requirements don't have to be considered when designing the back-up system.

It has been found that for transmission distance shorter than 60 km subsea or 200 km overhead HVAC has better economics performance [12] [113]. As the distance between the store and WA3 is ~25 km, it was decided to used HVAC cables.

Table 20 - High Voltage Power Cable Properties

Parameter	Value
Cable Material	Copper Cable
Type	HVAC
Voltage	66,000 V
Length	6 km
Cable Starting Location	WA1 (Nederwiek Noord)
Cable End Location	UHS Platform

Back-Up Power Demand

It is assumed that the equipment for UHS operations is powered by electrical power, so the hydrogen that is stored in the reservoir is not used to power the operations. The back-up power needs are assumed to be the power usage of the PSA and tail gas compressor. A margin of 30% for the other equipment on the platform has been considered.

Table 21 - Equipment that needs back-up power

Equipment	Power (MW)
PSA	0.01
Tail gas compressor	35.5
Margin (30%)	10.65
Total	46.16

This leads to a total power requirement of 46 MW. A very high-level sizing estimate of each of the above options has been undertaken using an average of the 2017 – 2020 wind profiles from the nearest weather station to WA7, D15-FA-1 to determine their feasibility. It was determined from these wind profiles that on average, there is no wind for 11% of the year, with no wind for periods as long as 36 hours. This acts as the sizing basis for the 4 back-up options.

H_2 Gas Turbine Generator

The use of a gas turbine generator (GTG) for generating back-up power, using a H2 feed stream has been considered as back-up power option. Although this is not the most efficient way of utilising H_2 in this case, it is the most feasible, due to the footprint and weight. The decarbonization tool of Siemens Energy was used to calculate the hydrogen mass required for yearly operations [115]. The results can be found in Table 22.

Table 22 - Hydrogen Consumption for H_2 Gas Turbine

Parameter	Value	Unit
Turbine Power Requirement	46.11	MW
Expected Annual Operating Hours of GTG	1124	Hours
Energy requirement	47	Days
H_2% of Fuel	100	%
Hydrogen Fuel Load	4220	Tonnes/year
Maximum withdraw rate from store	2026	Tonnes/day
% of produced H_2 used for back-up system	4	%
Footprint	152	m^2

The footprint of the GTG is 20.8x7.3x6.6m and has a weight of 285 ton. The efficiency of a GTG is low with a gross efficiency of around 39%, although the footprint and weight compared to the other options, make it the most viable option.

4.6.5.3 Round-Trip Efficiency of UHS

Round-trip efficiency is a critical metric for evaluating the performance of energy storage systems. In the context of batteries, it is typically calculated by dividing the amount of energy discharged from the battery by the amount of energy required to charge the battery. This straightforward calculation, however, is not directly applicable to underground hydrogen storage systems.

For UHS, round-trip efficiency can be assessed by determining the annual energy consumption required to operate the storage facility and comparing this to the total energy content of the hydrogen stored in the reservoir. This approach provides insight into the efficiency of the storage process, accounting for the energy losses associated with hydrogen injection, storage, and extraction.

Based on the calculations presented in section 4.6.5.1, the annual energy consumption by the UHS utilities on the platform is estimated to be 409 GWh. Since the energy injected per annum differs from the energy that is produced, the round-trip efficiency is calculated using Equation (6).

$$Round\ Trip\ Efficiency\ (\eta) = \frac{Energy\ Retrieved}{Energy\ Input} * \ 100\% \qquad (6)$$

As the hydrogen produced in the simulated year is 7240 GWh, the round-trip efficiency of the UHS facility in that year is ~0.94. It should be noted that this round-trip efficiency is rather optimistic as it doesn’t account for microbial and geochemical reactions in the reservoir. The actual round-trip efficiency will therefore be lower, although this gives a good first impression of the round-trip efficiency.

4.6.6 UHS Platform Concept

The design of an offshore UHS platform involves various critical aspects, including dimensions, weight, utilities, and load limits. This section provides a high-level overview of these elements. In this section the most important utilities for UHS which are estimated to have the largest footprint and highest weight are described because footprint and weight are an important aspect in offshore constructions are lower footprint and weight are desired. The most important utilities tend to be the heaviest and largest, which are the injection compressor, tail gas compressor and PSA.

4.6.6.1 Utilities on the Platform

The UHS platform relies on several critical utilities to facilitate its operation effectively. Among these, three stand out as particularly vital and are discussed for footprint and weight estimation: the injection compressor, tail gas compressor, and Pressure Swing Adsorption (PSA) unit.

- **Injection Compressor**: With a power requirement of 78 MW, the injection compressor's dimensions are approximately 30x41 meters per train, leading to a footprint of 1,230 square meters and a weight of 5,088 tons.
- **PSA Unit**: The PSA unit, essential for hydrogen purification, occupies a footprint of 3,073 square meters with dimensions of 54x54 meters and weighs 6,135 tons.
- **Tail gas Compressor**: The tail gas compressor, necessary for recompressing and managing tail gas, has a significant footprint of 14,628 square meters with dimensions of 157x73 meters and a weight of 17,000 tons.
- Other Essential Equipment: Assumed to occupy 2 decks, leading to an additional 8,192 square meters.

4.6.6.2 Platform Footprint and Dry Weight

The dimensions of the injection compressor, PSA, tail gas compressor, and assumption on other equipment are shown in Table 23.

Table 23 - Dimensions of key facilities on the platform

Utility	Power [MW]	Footprint [m^2]	Decks	Weight [tons]
Injection Compressor	78	1,230	0.3	5,088
PSA	0.01	3,073	0.8	6,135
Tail gas Compressor	35.3	14,628	3.6	17,000

Other equipment	NA	8,192	2.0	4,915
Total	**NA**	**27,123**	**6.9**	**33,138**
Existing platform	NA	2,130	3.0	NA

The platform currently used for natural gas production by NAM, comprises three decks: main, cellar, and tween. The main deck, being the largest, has a gross area of 872.4 m². The cellar deck measures approximately 30x21 meters, giving a gross area of 672 m², and the tween deck offers 585.6 m², totalling 2,130 m² across all decks.

The UHS platform's total estimated footprint is approximately 27,100 m², equivalent to 13 present natural gas platforms. Consequently, the existing platform must be dismantled to make way for a new, larger platform. For simplicity, dimensions of the hydrogen production platform are used for the new UHS platform, measuring 64x64 meters, with a floor area of 4,096 m² per deck. Given the total footprint required, the platform will need seven decks, which aligns with the largest offshore platforms globally. This configuration is simplified, and the actual floor plan may vary significantly, but it gives a first impression of the size of the platform.

4.6.6.3 Load Limits & Weight Implications

The platform design must account for various load limits, including operational, environmental, and dynamic loads. Dynamic loads include the weight of fluids/gasses flowing through equipment, personnel, and daily activities. Environmental loads consider the impact of wind, waves, and currents, which the platform must withstand to ensure stability. Dry weight corresponds to the weight of the utilities without any fluids or gasses.

Industry structural density norms for integrated decks tend to fall between 0.35 ton/m2 and 0.6 t/m2 [97]. Whilst the determination of deck areas is still at a preliminary stage, it can be seen from Table 24 that the structural densities that are currently being reported are exceeding the expected industry range. This means that the size of the platform will increase to not exceed the load limits.

4.6.6.4 Platform layout

In general, a layout shows the minimum space requirement of an overall structure based on footprint and weight. The goal is to show the total size of an UHS platform. Center of Gravity and specific weight are therefore not considered for this layout. Typical, the placement of heavy equipment is on lowest deck.

The offshore UHS platform is a large, multi-deck structure designed to accommodate all necessary equipment and operations. It should be able to house the equipment for UHS operations. The dimensions of the platform are considered to be 64x64m , based on the floorplan of the Aquasector Consortium Hydrogen Production Platform [97]. That platform consists of 3 decks with a height of around 10 meters. To house all the equipment for UHS, 7 decks would be demanded, see Figure 4-45.

Table 24: Platform sizing

Utilities	Injection compressor	PSA	Tail gas compressor	Other equipment	TOTAL
Case 1 (no load limit)					
Area (m²)	1,230	3,073	14,628	8,192	**27,123**
Weight (tons)	5,088	6,135	17,000	4,915	**33,138**
Decks	0.3	0.75	3.57	2	**7**
Load (ton/m²)	4.14	2	1.16	0.6	**N/A**
% of industrial norm	689%	333%	194%	100%	**N/A**
Case 2 (load limit 0.6 t/m²)					
Area (m²)	8,480	10,224	28,333	8,192	**55,230**
Weight (tons)	5,088	6,135	17,000	4,915	**33,138**
Decks	2.1	2.5	6.9	2	**13**
Load (ton/m²)	0.6	0.6	0.6	0.6	**N/A**
% of industrial norm	100%	100%	100%	100%	**N/A**

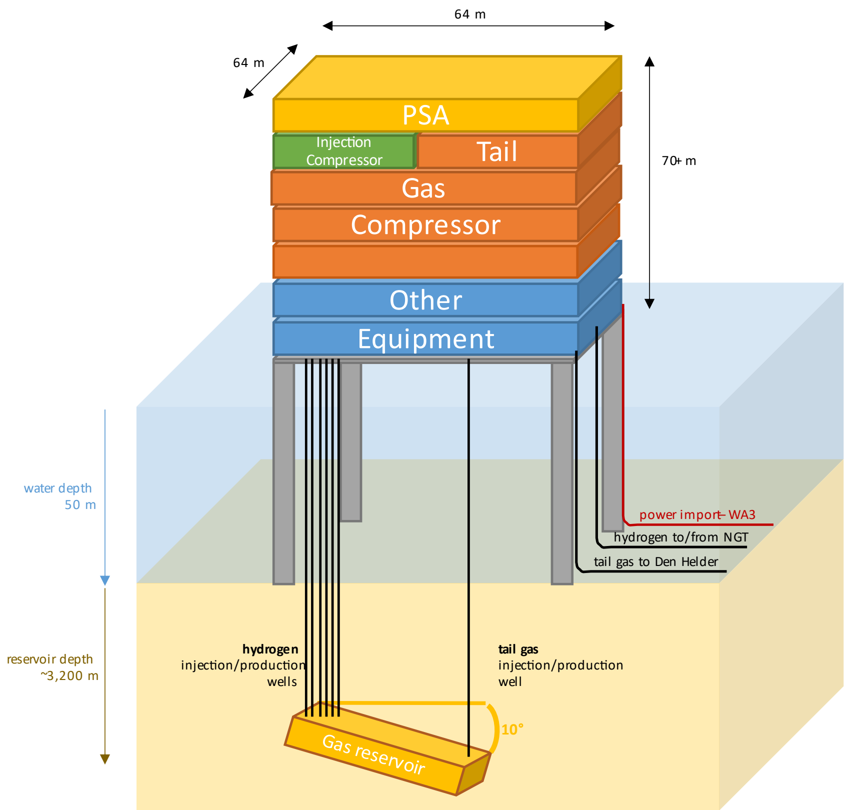


Figure 4-45: Platform design neglecting industry density load limit of 0.6 ton/m2.

The platform design must also consider industry structural density norms, which typically range between 0.35 ton/m² and 0.6 ton/m², to ensure it does not exceed load limits. Heavy equipment is typically placed on the lowest deck to maintain stability. This approach ensures that the platform can support the operational, environmental, and dynamic loads while maintaining structural integrity. The increase in footprint for the different utilities when integrating the industrial structural density norm of 0.6 ton/m² is shown in Figure 4-46.

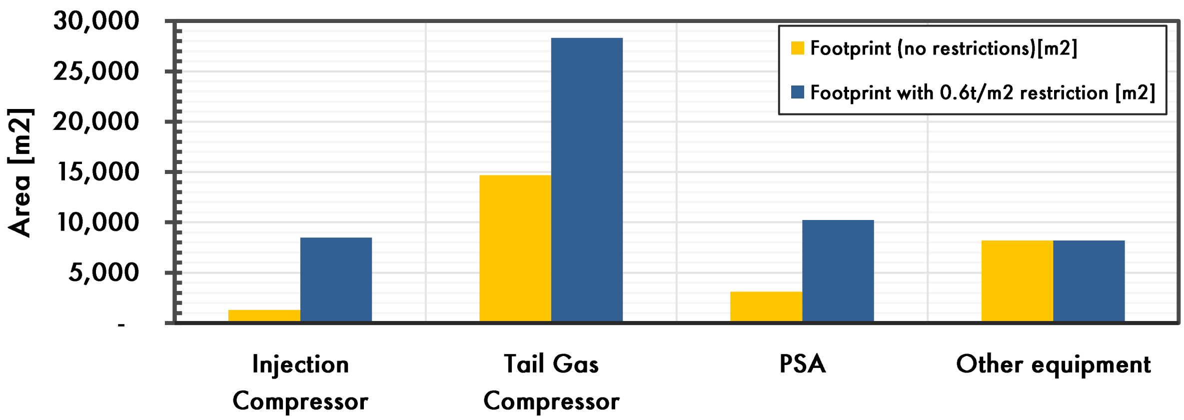


Figure 4-46: Footprint of equipment on the UHS platform and the influence of the load limit

Another primary design consideration is avoiding excessive topside weight, which could restrict the choice of installation vessels. The Pioneering Spirit, with a lifting capacity of 48,000 tonnes, is currently the only vessel capable of handling extremely heavy topsides [116]. Other notable vessels include the Sleipnir, with a maximum lifting capacity of 20,000 metric tons, and the Thialf, with a capacity of 14,200 metric tons [117]. If the topside weight exceeds these capacities, it significantly limits the installation options and increases costs and complexity.

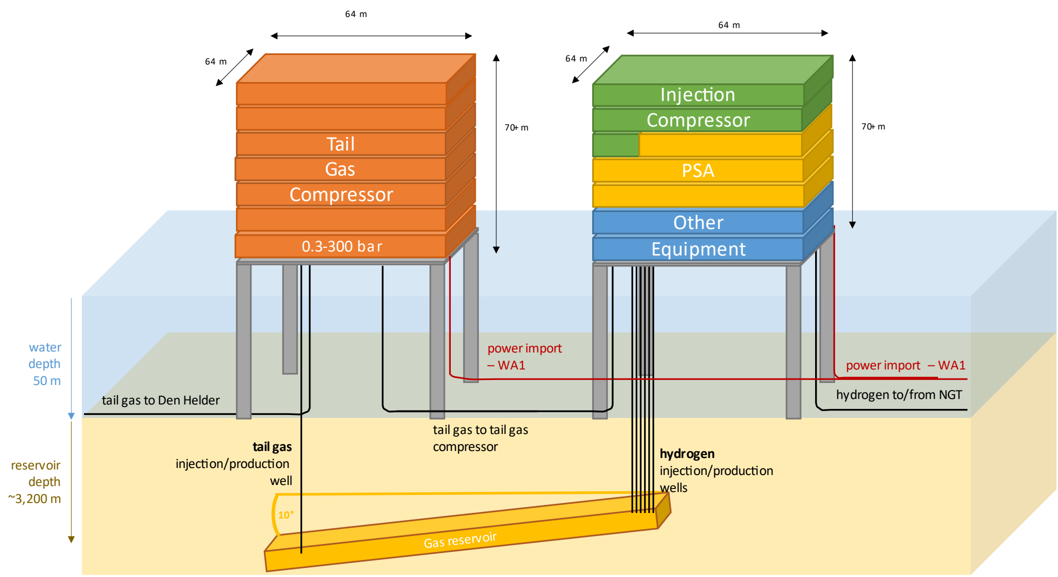


Figure 4-47: Platform design considering industry density load limit of 0.6 ton/m²

The water depths in the Dutch sector pose additional challenges for installation. The shallower waters require precise clearance management for float-over and catamaran lift operations, making the design and execution more intricate compared to installations in deeper waters.

The technical complexity of designing and constructing a UHS platform is unprecedented. No UHS platform of this kind has ever been built, and the challenges extend far beyond footprint and weight considerations. While these factors alone present significant difficulties, additional issues such as safety, accessibility, and environmental impact further complicate the design process. Developers must seriously consider whether far-offshore hydrogen purification is the most viable solution, given the immense technical hurdles. Alternative solutions may need to be explored to achieve efficient and safe hydrogen purification and storage.

4.6.6.5 Summary of UHS platform concepts

The proposed platform dimensions are 64x64 meters per deck, providing 4,096 square meters per deck. This size is considered the largest feasible for construction. To house all the necessary equipment, the platform would need seven decks, each approximately 10 meters in height, based on the footprint of the utilities. However, when weight considerations are included, the industrial load limits of 0.35 ton/m² to 0.6 ton/m² are exceeded. To comply with a load limit of 0.6 ton/m², 14 decks would be required, making such a design technically impractical for a far-offshore environment. Consequently, at least two platforms with seven decks each would be necessary. Constructing a platform with seven decks of 64x64 meters is considered feasible but remains an optimistic scenario.

Key utilities on the platform include the injection compressor, PSA unit, and tail gas compressor. The injection compressor, essential for injecting hydrogen into the reservoir during high production periods, has an estimated power requirement of 46.8 MW, a footprint of 1,230 square meters, and a weight of 5,088 tons. The PSA unit, crucial for purifying hydrogen before export or reinjection, has a footprint of 3,073 square meters and weighs 6,135 tons. The tail gas compressor, necessary for managing the tail gas produced during the PSA process, requires 35.5 MW of power and occupies a footprint of 14,813 square meters, with a weight of 17,000 tons.

The design must also consider various load limits, including operational, environmental, and dynamic loads. These include the weight of equipment, personnel, wind, waves, and machinery movement. Industry structural density norms, typically ranging from 0.35 ton/m² to 0.6 ton/m², present a significant challenge, as preliminary calculations indicate that all utilities exceed these norms. This necessitates the construction of an additional platform to house all utilities without exceeding the load limit.

Safety and load limits are critical in the platform design. Adequate safety distances are implemented to minimize risks associated with hydrogen storage and handling, ensuring sufficient spacing between equipment to prevent hazardous interactions. Integrating critical utilities within the platform's limited space poses significant engineering challenges, making it crucial to optimize layout and design to fit all equipment within the available decks.

Moreover, the technical complexity of constructing such a platform is unprecedented. No platform of this kind has ever been built, and the challenges extend far beyond footprint and weight considerations. Additional issues such as safety, accessibility, and environmental impact further complicate the design process. Developers must seriously consider whether far-offshore hydrogen purification is the most viable solution, given the immense technical hurdles. Alternative solutions may need to be explored to achieve efficient and safe hydrogen purification and storage.

In conclusion, the UHS platform concepts are designed to leverage existing offshore infrastructure for hydrogen production and storage. Both design scenarios—one focusing on complete tail gas reinjection and the other employing a hybrid approach with partial tail gas export—aim to balance operational efficiency, environmental sustainability, and safety. Ensuring stable PSA inflow and addressing space and weight constraints are critical challenges that require careful consideration in the platform design.

5 ECONOMIC ANALYSIS

The CAPEX estimation is based on business case-level cost estimates for the offshore and onshore scope described in previous sections. The CAPEX for cushion gas cost was estimated assuming a (green) hydrogen cost of 4.00 USD/kg. It is important to note that the replenishment of the H_2 cushion gas over time to maintain a constant operating pressure range has not been accounted for. This is because part of the remaining natural gas will be co-produced and not replaced in the tail gas export scenario.

The goal is to determine if this UHSP system can compete in terms of its Levelized Cost of Hydrogen Storage (LCOHS) with other UHS options. Therefore, it will be compared with alternative storage options, such as offshore and onshore UHS in salt caverns.

5.1 Overall cost estimation

This section describes the CAPEX and OPEX estimations for integrating an underground hydrogen storage facility in the Dutch North Sea for the offshore hydrogen infrastructure. The costs for the case were worked out. The total CAPEX and OPEX were:

- CAPEX: ~$3,000 million
- OPEX: ~$160 million per year for 30 years

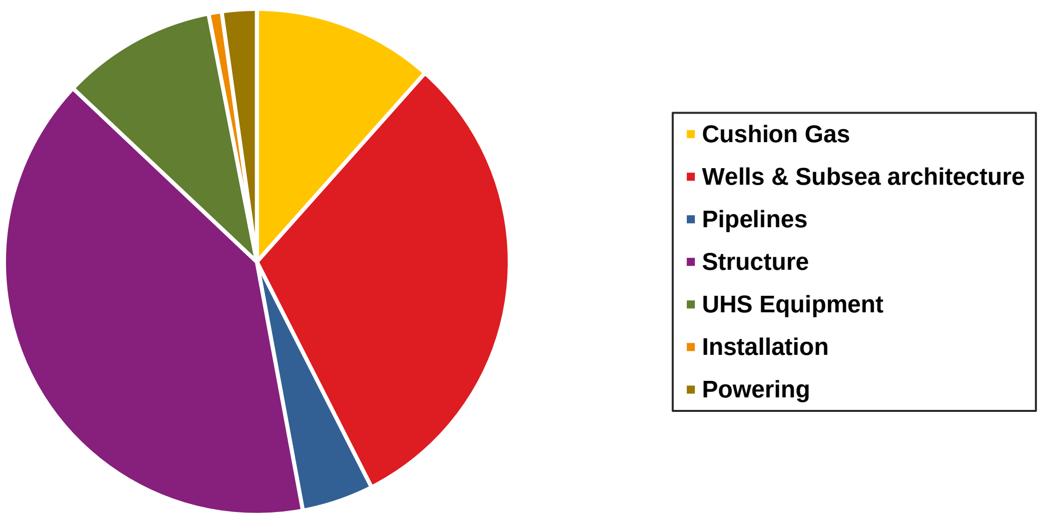


Figure 5-1: Cost breakdown of CAPEX - $3,000 Million USD

5.2 Levelized Cost of Hydrogen Storage

The Levelized Cost of Hydrogen Storage (LCOHS) is a critical metric used to evaluate the economic viability of hydrogen storage facilities. It represents the cost per unit of hydrogen stored, considering all relevant expenses over the lifecycle of the storage facility. This section discusses the LCOHS for an underground hydrogen storage project and its influence on the Levelized Cost of Hydrogen (LCOH) for offshore green hydrogen production by WA7. To calculate the LCOHS, it is essential to determine the total annual storage costs per kg of hydrogen, which include both the annual CAPEX and the OPEX and a discount factor, see Equation (7)

$$\boldsymbol{LCOHS} = \frac{CAPEX + \sum_{t=1}^{n} \frac{OPEX}{(\mathbf{1}+\boldsymbol{i})^{t}}}{\sum_{t=1}^{n} \frac{\boldsymbol{m_{H2}}}{(\mathbf{1}+\boldsymbol{i})^{t}}} \tag{7}$$

Where:

- **CAPEX**: Total investments made prior to operations.
- **OPEX**: Annual operating expenses required to operate the storage facility, including power costs and maintenance.
- $\boldsymbol{m_{H2}}$: Total mass of hydrogen withdrawn from the reservoir over the lifetime of the UHS facility.
- ***i*** : Discount factor used to discount future cash flows to their present value.
- ***n*** : Lifespan of the facility.
- ***t*** : Year in which OPEX is incurred relative to the initial capital expenditures (CAPEX). When t=1, the facility is in operation in the same year the initial investments are made, assuming operations begin immediately. This is assumed in the LCOHS calculations for depleted gas reservoirs.

This discount factor (i) used for the initial LCOHS is 10% and the project lifespan (n) of the storage facility is assumed to be 30 years. Table 25 shows the results for the LCOHS with and without a discount factor. The hydrogen stored per year (m_{H2}) is in kilograms and is assumed to be constant every year for the simplicity of the calculations. The inputs are based on Table 5.

Table 25: LCOHS Calculations

Cost Item	Value	Unit
CAPEX	3,279	Million USD
OPEX	162.2	Million USD / year
Discount Factor	10%	[-]
Hydrogen stored per year	184	Million kg
Lifespan of system	30	years
% of $H2_{produced}$ into UHS	25	%

LCOHS	2.8	USD/kg

In summary, the LCOHS for 100% reinjection of tail gas in the reservoir is calculated to be 2.8 USD/kg. It should be remarked that in the calculations it is assumed that the store becomes operational in the same year as the FID. The influence of this decision is further described in section 6.2.

This cost includes the CAPEX and OPEX, over the storage facility's 30-year lifespan with a discount factor of 10%. The LCOHS adds 0.7 USD/kg to the LCOH, as 25% of the H_2 produced at WA7 needs to be stored in the reservoir according to the simulations discussed in section 4.2. This analysis underscores the economic considerations essential for the viability of large-scale hydrogen storage projects, influencing the broader hydrogen economy's cost structure.

6 SENSITIVITY ANALYSIS

In the context of a techno-economic analysis, sensitivity analysis plays a crucial role in evaluating both the technical and economic performance of the case studies. This method assesses the influence of various key parameters on the LCOHS, helping to identify which factors have the most significant impact on the economic feasibility of the underground hydrogen storage project. Sensitivity analysis provides valuable insights into how different parameters contribute to uncertainties in model outcomes. Given that the storage facility is part of the operating infrastructure and does not generate revenue, it is imperative to focus on the LCOHS as the primary parameter for evaluation, instead of NPV and IRR. This approach ensures a comprehensive understanding of the factors driving costs and supports informed decision-making to enhance the understanding of the project's financial viability.

It is crucial to acknowledge that the individual components of the UHS design exhibit varying degrees of volatility. For instance, the price of cushion gas can fluctuate easily with a factor four, depending on the choice between grey and green hydrogen. Platform costs are another highly volatile component, as currently only the cost of one platform is considered, while having a load of 1.2 ton per m^2. There is high possibility that the load is too much, and that another platform is necessary and therefore the cost for the platform is doubled. As the platform has a significant influence in the LCOHS, the platform costs are highly volatile. Pipelines are another highly volatile component, as the assumption that all potential pipelines will be reused could change dramatically; the necessity of installing new pipelines could increase cost of re-used pipelines by a factor of ten. In contrast, an increase or decrease in the power tariff is not expected to be a highly volatile factor.

6.1 Volatility of the most critical technical parameters

To illustrate the volatility of the most critical parameters, their influence was evaluated at increments of +20%, +10%, -10%, and -20%. The sensitivity analysis involved varying each parameter by ±20% and ±10% from their base case values and observing the corresponding changes in the LCOHS. The base case LCOHS was calculated to be $2.8 USD/kg with a discount rate of 10%. The parameters analyzed include power tariff, lifespan, cushion gas cost, H_2S removal technology cost, maintenance cost, wells cost, platform cost, contingency on opex and capex, discount factor, pipelines and H_2 recovery rate. The assumption that all the hydrogen is reinjected and therefore can be recovered, this parameter was not considered. Each parameter's impact on the LCOHS was calculated by adjusting both the CAPEX and OPEX, where applicable.

The results of the sensitivity analysis are summarized in Figure 6-1. Each parameter's variation shows its effect on the LCOHS, providing insight into the project's cost drivers and economic robustness. The chart gives a better understanding which variables are more important for decision-making for cost-reduction and uncertainties in the future.

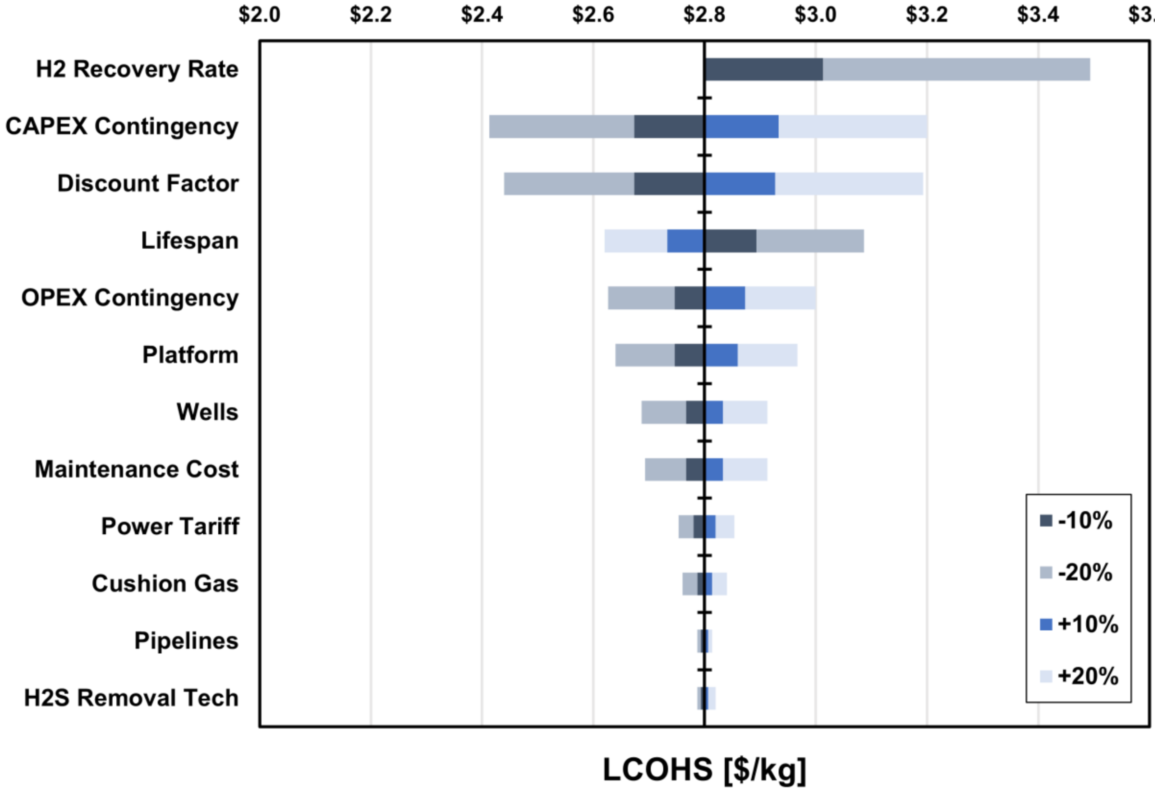


Figure 6-1: Results of the sensitivity analysis show the impact of ±10% and ±20% changes in key parameters on the Levelized Cost of Hydrogen Storage (LCOHS). The base case LCOHS is $2.8 USD/kg with a discount factor of 10%.

The sensitivity analysis indicates that the most influential parameter on the Levelized Cost of Hydrogen Storage is the hydrogen recovery rate. The assumption in the base case design is that all the hydrogen can be recovered, so the recovery rate is already at its maximum (100%). Therefore, only a decrease in the recovery rate was considered in the sensitivity analysis. The most striking finding is the paramount importance of the H2 recovery rate, which can swing the LCOHS dramatically from $2.8 to $3.5/kg, which is a 25% increase on a decrease of 20% of the recovery rate. This seems impossible, but it is due to the LCOHS formula, see Equation (7). This underscores the critical role of recovery efficiency in determining the economic viability of hydrogen storage projects. Equally impactful is the CAPEX contingency, reflecting the uncertainty in capital expenditures, which can cause the LCOHS to fluctuate significantly. The discount factor also emerges as a crucial parameter, affecting the present value of future costs and highlighting the importance of favorable financing conditions.

Lifespan and OPEX contingency are also notable, as they shape the cost distribution over the project's lifetime and account for unforeseen operational expenses, respectively. Interestingly, while platform and well costs are essential, their influence is moderate compared to the top-tier factors. The same applies to maintenance costs and power tariffs, which, despite their role in operational efficiency, have a less pronounced effect on the

LCOHS. Cushion gas, although necessary for system integrity, exhibits minimal impact on the overall costs. While cushion gas is often seen as one of the biggest contributors to the LCOHS for depleted gas reservoirs, this is not the case for this specific use case. This is mainly due to the size of the reservoir, as approximately 1 BCM of cushion gas is needed. The other big influence is that the other costs for installing the UHS facility offshore comes with high costs. The choice between different types of hydrogen for cushion plays an important role, albeit to a lesser extent compared to other parameters.

6.2 Effect of t, n, and discount factor on LCOHS

When analyzing the LCOHS using Equation (6), the values for t, n, and the discount factor (i) play crucial roles in determining the overall cost. This section elaborates on the effect of different values in the equation and demonstrates how varying these parameters can significantly impact the LCOHS.

Table 26: Influence of discount factor, t and n on LCOHS

Discount factor	t	n	LCOHS [$/kg]
0%	1	30	1.47
10%	1	30	2.76
10%	5	35	3.61

The LCOHS increases significantly when the discount factor changes from 0% to 10%. For instance, the LCOHS rises from $1.47/kg to $2.76/kg with a discount factor of 10% and t=1 and n=30. This highlights the importance of financing costs in the overall economic viability of the project.

When assuming a delay of 5 years between FID and the start of operations (i.e., t=5 and n=35), the LCOHS increases further. Tthe LCOHS increases from $2.76/kg to $3.61/kg. This demonstrates the adverse effect of delayed operations on the economic performance of UHS projects.

The analysis underscores the sensitivity of LCOHS to changes in the discount factor, time to operation (t), and the operational lifespan (n). Higher discount rates and delays in the start of operations significantly increase the cost of hydrogen storage, emphasizing the need for efficient project planning and financing. By carefully managing these variables, the economic viability of UHS projects can be optimized, ensuring a more sustainable and cost-effective solution for hydrogen storage.

7 DISCUSSION

7.1 Comparison with other storage options

In this section, describes a comparison of the use of depleted offshore gas reservoirs for cyclic underground hydrogen storage with other prevalent hydrogen storage methods, specifically offshore salt caverns, onshore salt caverns, and nearshore storage. The comparison focuses on technical feasibility and economic viability.

Offshore salt caverns offer a promising alternative for hydrogen storage due to their high flexibility and scalability. The creation of salt caverns involves leaching process, which forms large, stable underground cavities suitable for hydrogen storage. The integrity of salt formations provides an excellent seal, minimizing the risk of hydrogen leakage. However, storage capacity is in the order of GWh, where the storage capacity of gas reservoirs is in the order of TWh. The timeline for construction of salt caverns, is another downside as construction of a cavern, that can hold 6,000 tons of hydrogen, with an energy content of 237 GWh, takes 9 years from FID to start of storage operations, as is artificial and no salt caverns are constructed in the Dutch North Sea yet. Therefore, final investment decision should be done way in advance before the store becomes operational. In this comparison it is assumed that for reservoirs, there is a period of 5 years between FID and the start of operation. The cost for storing the hydrogen offshore to generate a constant supply of hydrogen to the backbone were estimated to be:

- CAPEX: ~$3,000 million
- OPEX: ~$160 million per year for 30 years
- LCOHS: $3.6-$3.8/kg H2

For comparison, the LCOHS for other UHS options are:

- Offshore salt cavern: $4.6/kg H_2
- Onshore salt cavern: $3.0/kg H_2
- Nearshore storage (seasonal): $2.1/kg H_2

What can be concluded is that offshore hydrogen buffering comes with a cost and that the time between FID and start of operations have a significant influence on the LCOHS.

The capital expenditure (CAPEX) for implementing an offshore UHS facility is substantial. The reason that offshore hydrogen storage cost is higher is mainly due to the isolated location and the related platform costs. Another major OPEX and CAPEX item is the well construction for offshore operations.

The high CAPEX and OPEX for the offshore UHS facility are driven by the extensive infrastructure needed to overcome technical challenges associated with the significant space and weight demands of compression and purification systems. These costs are higher compared to alternative storage solutions like salt caverns, highlighting the economic and technical feasibility challenges of offshore UHS in depleted gas reservoirs. Integrating the cost of hydrogen storage into the overall production cost significantly impacts the Levelized Cost of Hydrogen (LCOH).

The onshore UHS option assumes that the pipelines from WA7 to shore and from shore to the salt caverns will have to deal with both flow and pressure fluctuations as no buffering of hydrogen into the export pipeline is available, due to the intermittent nature of wind power and subsequently hydrogen generation. The pipeline must, therefore, be prepared to accept maximum flowrates during peak H_2 production. Secondly with no buffering, the integrity of the pipeline must be considered, with fluctuating flowrates of H_2 potentially having a negative impact on the integrity of the pipeline over time. The diameter of the NGT pipeline is 36", although not fully defined in this phase of the study, it is likely that with no H_2 buffering upstream of the pipeline, that the diameter of the pipeline could be too small to fully buffer maximum H_2 production.

The near-shore case assumed to import hydrogen from the onshore backbone, instead from offshore green hydrogen production. The functionality of the storage is seasonal, so during winter the store is filled and the flow rates are lower compared to buffering offshore green hydrogen production.

Hydrogen storage in depleted gas reservoirs is at a relatively immature technology. This immaturity introduces higher risks and uncertainties, likely resulting in additional costs for further research, development, and unexpected issues during implementation. As a result, the overall expenses for this storage option may escalate as the project progresses towards the final investment decision, making it a riskier and potentially more expensive choice compared to more developed and better understood storage technologies like salt caverns.

7.2 Technical Feasibility

The selected reservoir's low permeability of 5 mD and transmissivity of 225 mD.m necessitate an impractically high number of wells –up to 49– with an EOC flow rate of 0.5 Nm^3/day. The permeability is an important aspect for hydrogen storage performance and the proposed limit for screening parameter by Juez-Larré et al. [55], should be thoroughly evaluated at as their screening parameter for permeability and transmissivity are >0.1 mD and >100 mD.m, respectively. Addressing the permeability issue by selecting a different reservoir could alleviate some production rate problems. Repurposing of existing natural gas wells becomes a challenge. Where a reservoir is normally depleted in multiple decades, it is now depleted is several weeks. This increases the needs for more wells and larger tubing.

A detailed geological analysis is essential for selecting appropriate geological structures for underground hydrogen storage, considering geological and engineering criteria. The permeability and well performance are crucial factors in determining the suitability of a depleted gas reservoir for UHS. The choice of geological structures for underground hydrogen storage should be based on a detailed geological analysis, taking geological and engineering criteria into account.

One of the most significant technical challenges associated with offshore UHS is the management of tail gas produced during the hydrogen purification process. When hydrogen is purified through a Pressure Swing Adsorption (PSA) system, about ~10% of the hydrogen ends up in the tail gas. Efficient management of this tail gas is crucial to maintaining the overall system's efficiency and minimizing hydrogen loss.

The destination of the tail gas poses real challenges in an offshore environment. Ideally, the tail gas should be either utilized or reinjected into the reservoir. However, finding a suitable customer for the tail gas offshore is difficult. In this study, it is assumed that only ~10% of the tail gas can be off taken by a customer, necessitating the partial reinjection of the remaining side stream of the PSA into the reservoir.

Reinjecting the tail gas requires a substantial infrastructure, including a tail gas compressor. The specifications of this compressor are critical, as it needs to handle high inflow rates and operate under challenging conditions. The tail gas compressor must compress the gas from low pressure (around 0.3 bar) to the high pressures required for reinjection (up to 300 bar). This process demands significant energy and space, resulting in a substantial footprint and weight for the offshore platform.

The platform's size and weight are directly influenced by the tail gas compressor's requirements. The compressor and its auxiliary systems necessitate a deck space of over 17,000 m^2 and add considerable weight, estimated to exceed 30,000 tons. Given that the maximum feasible deck space for offshore platforms is typically around 4,000 m^2, accommodating such a large compressor system presents significant logistical and engineering challenges.

Additionally, a small, fast storage option could manage the inflow of tail gas effectively. However, this only solves the problem for the inflow rates for the PSA. The necessary deck space and associated weight of the UHS purification facilities comes with significant costs and technical complications regarding installation of the platform.

To increase the recovery rate of hydrogen, vacuum PSA (VPSA) may be applied instead of the standard PSA. During VPSA, the last depressurisation step is carried under vacuum conditions. VPSA for hydrogen purification has practically not been applied commercially because of the higher operating costs, however with the metric to maximise hydrogen product yield, it may be worth consideration.

In summary, the technical feasibility of offshore UHS is heavily influenced by the reservoir's characteristics and the effective management of tail gas. Addressing these challenges requires careful planning and consideration of alternative solutions, such as onshore purification processes and the use of ultra-depleted reservoirs. The implications of tail gas management on platform size and weight highlight the need for innovative engineering solutions to optimize offshore hydrogen storage systems.

7.3 Uncertainties and Knowledge Gaps

The research presented is based on numerous assumptions, making the outcomes susceptible to variations in the design parameters. This section highlights the most critical aspects that can influence the design, along with the knowledge gaps that must be addressed to achieve a higher level of certainty in the proposed design.

1. H_2S concentration
    - H2S formation due to biological, chemical processes is still not well understood. This remains a key knowledge gap.
    - Reliable predictions of H2S content in the produced hydrogen are lacking. A high H2S concentration of 100 ppm is considered, leading to increased CAPEX and OPEX for the chosen H2S scavenger option.
2. Power requirement
    - Power requirements significantly influence the round-trip efficiency and the Levelized Cost of Hydrogen Storage (LCOHS).
    - The exact power requirements for the proposed system need further investigation to refine efficiency and cost estimates.
3. Compressors
    - The proposed compressors have never been manufactured before; therefore, it is uncertain if compressors can be designed to meet the specific operating conditions required for this application.
4. Bi-directional pipeline

- The bidirectional flow of pipelines results in a wide range of operating pressures.
- The impact on pipeline material selection and design life needs further understanding. Therefore, detailed analysis of pipeline materials and longevity under varying pressures is required.

5. Reservoir Performance
    - The study's reservoir performance analysis is limited to H2, C1, C2, CO2, and N2 and it based on a simplified 2D box model.
    - Influence of reinjecting the tail gas in the reservoir using a dedicated tail gas well is not encountered in the simulation used for this research.
    - The behaviour of H_2 in the reservoir is an area of ongoing research.
    - Therefore, more comprehensive reservoir modelling is necessary.
6. Wells for offshore UHS
    - Drilling 9 5/8" wells in Zechstein layer can become a challenge, so other options for well drilling should be investigated.
7. Pipelines re-useability and export scenario's
    - The reuse of existing pipelines and the feasibility of various export scenarios need thorough evaluation.
    - In-depth studies on pipeline integrity and export logistics are required.
8. Onshore backbone purity spec
    - The purity of the hydrogen for the onshore backbone is not certain. In this research the purity spec of 99.5% is assumed. This has led to the requirement of a PSA Separation technology separation of contaminants from H_2. Other separation technologies can also be explored in future phases of the study as they progress through the technology readiness funnel.
9. Onshore backbone 50 bar
    - It is assumed that the hydrogen needs to arrive at the shore with at least 50 bar. It is uncertain if the requirement will stay at 50 bar or is decreased to 30 bar.
10. Hydrogen recovery from tail gas
    - Separation technologies for the tail gas can also be explored in the next phase of the study to improve H_2 recovery.
11. Exporting tail gas
    - Export of tail gas to H2Gateway is the destination selected in current concept for tail gas export. This tail gas stream can contain considerable number of contaminants, next to hydrogen and methane.
12. Flow velocity hydrogen
    - The maximum flow velocity for gaseous hydrogen transport is still uncertain. Ongoing research should create clarity of the maximum hydrogen velocity in pipelines and wells to prevent erosion.

13. HSSE Aspects
    - HSSE aspects are not investigated in the current study. HSSE standards for H2 service such as safety distances, dispersion behaviour etc. need to be investigated and incorporated in the next phases of the study.

These uncertainties highlight the areas requiring further research to enhance the reliability and efficiency of UHS systems. Addressing these knowledge gaps is critical for advancing the technical and economic feasibility of underground hydrogen storage in depleted gas reservoirs.

8 CONCLUSION AND RECOMMENDATIONS

This objective of the research was to address the existing knowledge gap in academic research on integrating an offshore hydrogen storage platform in the Dutch North Sea to buffer intermittent offshore green hydrogen production, while considering maximum re-useability of existing natural gas infrastructure. The research demonstrated that utilizing a depleted offshore gas reservoir for underground hydrogen storage to support offshore green hydrogen production power by a far offshore 8GW wind park presents significant technical and economic challenges.

While it is technically feasible under certain conditions, the economic viability is hindered by high CAPEX and OPEX, mainly due to the isolated offshore location and the associated platform costs. This results in LCOHS of $3.6-$3.8/kg for offshore hydrogen storage in depleted gas reservoirs, and $4.6/kg for offshore salt caverns, where onshore salt caverns have an estimated LCOHS of $3.0/kg. As 25% of the hydrogen that is produced at WA7 needs to be stored in the UHS, the LCOHS adds ~$0.9/kg to the LCOH for UHS in offshore depleted gas reservoirs, compared to $1.1/kg and $0.8/kg for offshore and onshore salt caverns, respectively.

These cost estimates highlight that storage cost is a significant component of the total hydrogen production cost, underscoring the economic challenges of offshore underground hydrogen storage solutions. Additionally, the feasibility of the offshore UHSP cases presents larger uncertainties compared to alternatives like salt caverns or nearshore storage. Addressing these uncertainties will undoubtedly incur further costs, meaning there is a higher risk of escalating expenses for this case when considering progression to final investment decision.

8.1 Main Findings

Reusing NAM's offshore assets for the offshore hydrogen backbone may hold potential, particularly for pipeline reuse. However, the proposed reservoir is unsuitable for UHS and the corresponding existing natural gas platform is inadequate for housing UHS installations. Key design parameters for an offshore gas reservoir hydrogen storage platform include the dimensions and weight of tail gas compressors, injection compressors, and PSA installations. Addressing fluctuation issues remains critical, especially for efficient PSA operation. To deal with inflow challenges for the PSA, a salt cavern could be installed to deal with the short-term weather fluctuations and the reservoir acts a seasonal store.

It was found that a depleted gas reservoir can potentially be used for UHS if the reservoir has a transmissivity >2,500 mDm, to obtain well withdraw rates of 5 million Nm^3/day. Installing wells with a 9 5/8" tube in the Dutch North Sea, is found to be a serious challenge, due to the Zechstein layer and the corresponding need for extra strong casing. This can imply challenges for future offshore UHS well installation.

The integration of purification systems and the management of tail gas remain significant challenges, especially in an offshore environment. Purification in an offshore environment is the biggest dealbreaker due to the size and weight of the utilities and fluctuations challenges at inflow for PSA.

Numerous technical implications remain, particularly finding a customer for the side stream (tail gas) of the purification process required. This is due to hydrogen contamination from residual natural gas and the purification processes required. Offshore UHS in depleted gas reservoirs is considered only feasible if a significant portion of the side stream is re-injected using a dedicated tail gas well, as no dedicated other destination for the side stream has been identified beside blending in hydrogen to natural gas for the blue hydrogen plant in Den Helder. Consequently, re-injecting the contaminated rest stream appears to be the most viable option, though its impact on storage performance requires further investigation.

Future research could explore reinjecting the tail gas another depleted gas reservoir with a lower pressure, which could decrease the need for the large tail gas compressor. Other alternatives, such as finding an ultra-depleted gas reservoir for UHS to avoid purification or processing purification onshore, faces significant challenges. The former increases the need for cushion gas, while the latter approach complicates buffering offshore pipelines, potentially leading to fatigue crack growth. A possible mitigation strategy for using a depleted gas reservoir for UHS to buffer offshore green hydrogen production involves pipeline packing for small fluctuations, using salt caverns for moderate fluctuations, and the depleted gas field for large fluctuations, thereby stabilizing PSA inflow operations.

This further complicates the economic and technical viability of this storage method. The Pressure Swing Adsorption system, designed for constant flow, faces hourly fluctuations in UHS operations, leading to inefficiencies and operational issues. Additionally, the tail gas compressor, which needs to handle an inflow rate of ~4 million Nm^3/day and a compression ratio of 230, requires a deck space of over 17,000 m^2. Given that the maximum feasible deck space is around 4,000 m^2, this results in an impractically large footprint for offshore installation, needing multiple levels to install the tail gas compressor.

The UHS platform will be among the biggest offshore oil & gas platforms in the world and that comes with a cost.

Despite these challenges, the research offers new insights. It highlights that building an offshore platform equipped with purification utilities and compressors is fraught with cost and logistical issues. The feasibility of this approach is currently less favourable compared to salt cavern or near-shore solutions, which have fewer technical uncertainties and lower associated capital costs. Therefore, this study has added new insights on the technical challenges and cost level of offshore UHS in depleted gas reservoirs. While the LCOHS is competitive with offshore salt caverns, there is high uncertainty in the cost estimation and the technology related to hydrogen storage in porous reservoirs.

Moreover, the technical complexity of constructing such a platform is unprecedented. No platform of this kind has ever been built, and the challenges extend far beyond footprint and weight considerations. Additional issues which were not enclosed in this research, such as safety, accessibility, and environmental impact further complicate the design process. Developers must seriously consider whether far-offshore hydrogen purification is the most viable solution, given the immense technical hurdles. Alternative solutions may need to be explored to achieve efficient and safe hydrogen purification and storage.

Ultimately, offshore gas reservoir hydrogen storage is neither technically nor economically more feasible than onshore storage alternatives and offshore salt caverns, unless combined buffering strategies are employed. This study underscores the need for continued research and innovation to overcome the identified barriers and optimize offshore hydrogen storage solutions.

8.2 Recommendations

Following the conclusion of this research, and in addition to addressing the knowledge gaps identified in section 7.3, six key recommendations are presented to tackle the identified challenges and optimizing future efforts in this domain.

Firstly, the proposed reservoir near Wind Area 7 was found unsuitable for UHS operations due to its low permeability (5 mD) and shallowness, resulting in a transmissivity of 225 mDm and a maximum flow rate per well of only 0.5 million Nm^3/day. It is recommended to find another reservoir in the proximity of Wind Area 7 that meets higher reservoir screening parameters. Specifically, look for reservoirs with transmissivities greater than 2,500 mDm, which can achieve flow rates of 5 million Nm^3/day per well. This will reduce the number of required wells, thus decreasing related costs and improving overall technical feasibility and efficiency.

Secondly, it is advised to explore the use of ultra-depleted gas reservoirs for UHS to minimize the need for extensive purification processes. Ultra-depleted gas reservoirs have significantly lower residual hydrocarbons, which reduces the contamination of stored hydrogen and minimizes the purification requirements. This approach can mitigate technical challenges associated with hydrogen purity and lower the overall operational costs.

Thirdly, it is recommended to evaluate the implications of intermittent flow fluctuations through offshore pipelines, as onshore storage is more cost effective than offshore storage solutions.

Fourthly, it is recommended to investigate the feasibility of conducting hydrogen purification processes onshore rather than offshore. Onshore processing of hydrogen purification can drastically reduce the costs and complexities associated with offshore platform installations, allowing for easier maintenance, scalability, and more robust infrastructure, thereby overcoming significant logistical and economic hurdles.

Fifthly, it is recommended to investigate if the tail gas can be reinjected in another reservoir that has lower operating pressures, as that decreases the size for the tail gas compressor significantly and could therefore improve the economic performance. However, the cost for replacing the tail gas could have a negative effect on the economic performance.

Lastly, it is suggested to investigate the feasibility of combined storage strategies that utilize both salt caverns and depleted gas fields to manage hydrogen storage and buffering more effectively. Combining storage methods can mitigate the issues related to fluctuating hydrogen production and purification processes. Salt caverns can handle moderate fluctuations, while depleted gas fields can be used for larger fluctuations, ensuring a stable and efficient storage system.

8.3 Implications for Society and the Energy Transition

By adhering to these recommendations, future efforts in offshore hydrogen storage can be significantly improved, enhancing both technical and economic feasibility. The research showed the importance of gaining practical insights and data on the feasibility of offshore hydrogen storage and transportation. It is suggested to implement pilot projects for UHS to close knowledge gaps related to UHS in depleted gas reservoirs.

The findings of this research have significant implications for the future of green hydrogen storage and the broader energy transition. By identifying the technical and economic barriers to offshore UHS, this study informs policymakers, industry stakeholders, and researchers about the practical considerations of integrating hydrogen storage into future offshore energy infrastructure.

By enhancing the understanding of the technical and economic feasibility of offshore hydrogen storage, this study contributes to the development of more effective energy storage solutions. These solutions are vital for balancing supply and demand, ensuring energy security, and facilitating the large-scale integration of renewable energy into the grid. Successfully addressing these challenges can lead to more robust and reliable energy systems that support the global shift towards renewable energy sources.

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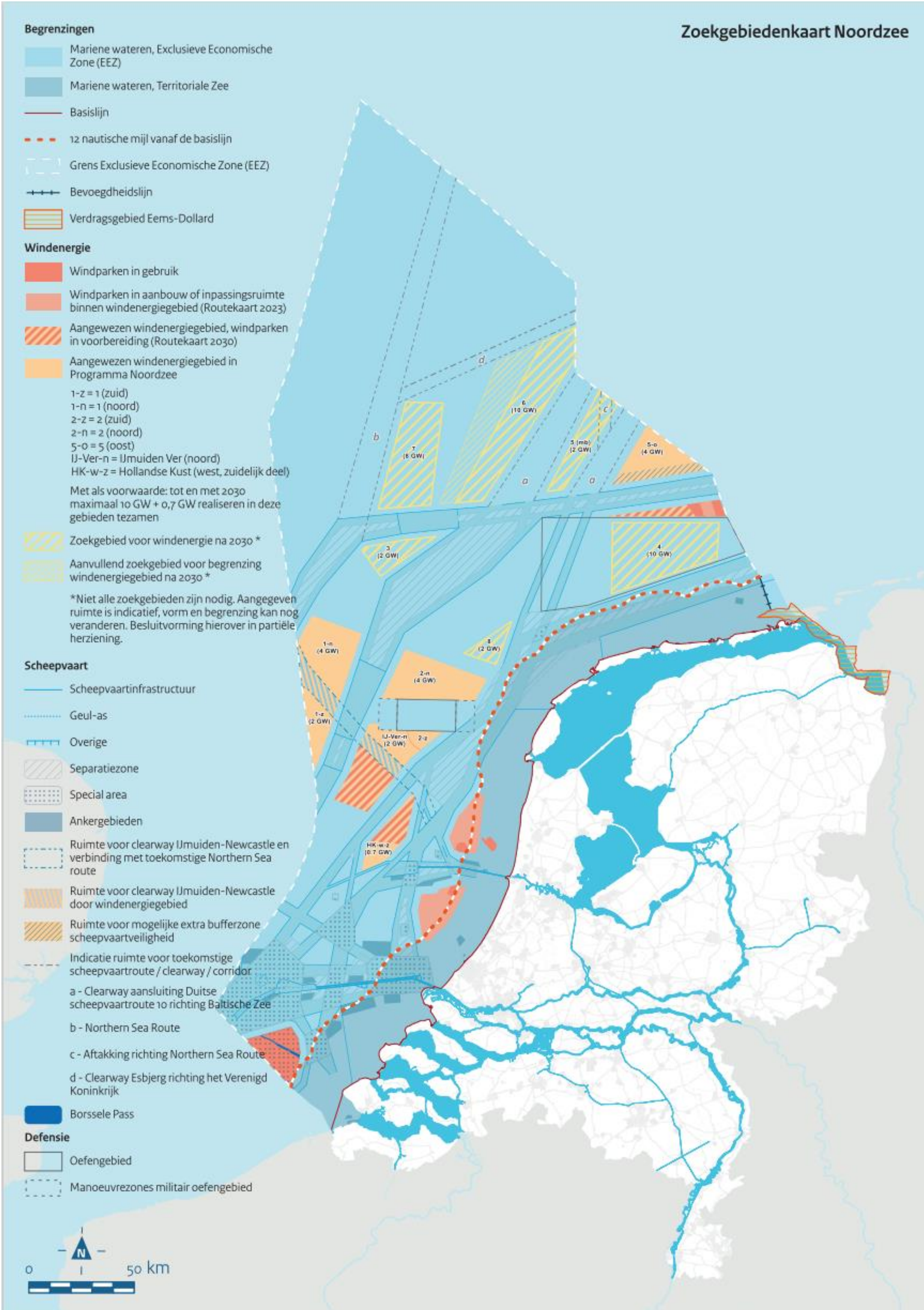
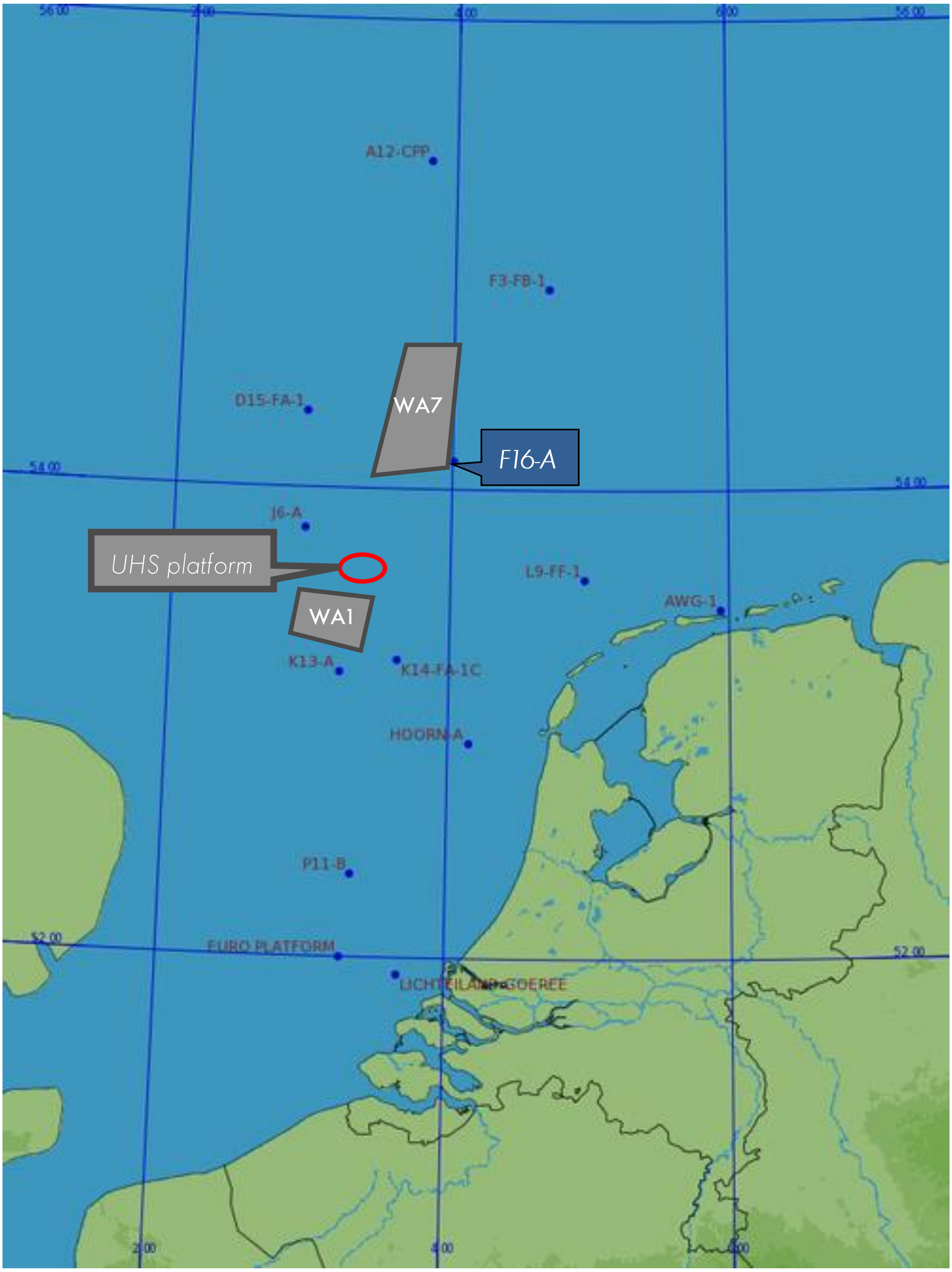
APPENDIX 1. Map of future wind farms [80]

Appendix 1 shows the "Zoekgebiedenkaart Noordzee" extracted from Programma Noordzee 2022-2027, a program that is part of the Dutch National Water Program 2022-2027, which is a governmental report dedicated to outline the future outlook of the Dutch North Sea.



APPENDIX 2. Offshore KNMI weather stations



APPENDIX 3. IEA Reference Wind 15-MW Turbine [81]

Table ES-1. Key Parameters for the IEA Wind 15-MW Turbine

Parameter	Units	Value
Power rating	MW	15
Turbine class	-	IEC Class 1B
Specific rating	W/m^2	332
Rotor orientation	-	Upwind
Number of blades	-	3
Control	-	Variable speed Collective pitch
Cut-in wind speed	m/s	3
Rated wind speed	m/s	10.59
Cut-out wind speed	m/s	25
Design tip-speed ratio	-	9.0
Minimum rotor speed	rpm	5.0
Maximum rotor speed	rpm	7.56
Maximum tip speed	m/s	95
Rotor diameter	m	240
Airfoil series	-	FFA-W3
Hub height	m	150
Hub diameter	m	7.94
Hub overhang	m	11.35
Rotor precone angle	deg	-4.0
Blade prebend	m	4
Blade mass	t	65
Drivetrain	-	Direct drive
Shaft tilt angle	deg	6
Rotor nacelle assembly mass	t	1,017
Transition piece height	m	15
Monopile embedment depth	m	45
Monopile base diameter	m	10
Tower mass	t	860
Monopile mass	t	1,318

deg	degrees	rpm	revolutions per minute
m	meters	t	metric tons
m/s	meters per second	W/m^2	watts per square meter

APPENDIX 4. Tail Gas Composition Table

Table 27: Tail gas Flow Rate & Composition EOC Scenario 3

Parameter	Value	Units
Tail gas Flow Rate	3.890	Million nm^3/day
Fraction H_2	1.960	Million nm^3/day
Fraction N_2	0.237	Million nm^3/day
Fraction CO_2	0.018	Million nm^3/day
Fraction CH_4	1.528	Million nm^3/day
Fraction C_2H_6	0.144	Million nm^3/day

Table 28: Tail gas Flow Rate & Composition EOC Scenario 4

Parameter	Value	Units
Tail gas Flow Rate	3.89	Million nm^3/day
- re-injected into UHS	3.14	Million nm^3/day
- to H2Gateway	0.75	Million nm^3/day
Fraction H_2 to H2Gateway	0.38	Million nm^3/day
Fraction N_2 to H2Gateway	0.046	Million nm^3/day
Fraction CO_2 to H2Gateway	0.003	Million nm^3/day
Fraction CH_4 to H2Gateway	0.296	Million nm^3/day
Fraction C_2H_6 to H2Gateway	0.028	Million nm^3/day

APPENDIX 5. Pipeline capacity assessment to connect WA7 with UHS (HHV)[1]

Scenario	Pipeline	Official Name	Design pressure NG [MPa]	Design pressure H_2 [MPa]	OD (")	Length (km)	Velocity outlet (m/s)	Maximum Pressure (bar(g))	Mass Flow Rate [kg/s]	H2 Capacity (GW)*	Design pressure H_2	Target flow
A	A-1	PL0168_PR	12*	7.2	24	25	30.22	63.5	39.5	5.6	72	30
	A-2	N/A	N/A	7	24	34	18.9	59.7	24.7	3.5	70	30
	A-3	PL0098_PR	12*	7.2	24	14	17.5	61.6	24.7	3.5	72	30
	A-4	N/A	N/A	7	24	0.8	17	61.7	24.7	3.5	70	30
	A-4.1	N/A	N/A	7	24	12	16.9	63.2	24.7	3.5	70	30
	A-5	NP011	13.5	8.1	12	8.9	66.2	95.3	24.7	3.5	81	30
B	B-1	PL0168_PR	12*	7.2	24	32	30.22	63.5	39.5	5.6	72	30
	B-2	N/A	N/A	7	24	34	18.9	59.7	24.7	3.5	70	30
	B-3	PL0098_PR	12*	7.2	24	14	17.5	61.6	24.7	3.5	72	30
	B-4	N/A	N/A	7	24	0.8	17	61.7	24.7	3.5	70	30
	B-5	NP006	13.5	8.1	18	9.3	30.1	66.8	24.7	3.5	81	30
	B-6	NP003	12	7.2	10	4	91.1	102.2	24.7	3.5	72	30
	B-7	N/A	N/A	12	16	4	24.7	104.8	24.7	3.5	120	30
	B-6.1	N/A	N/A	7.6	20	8	22.6	69.2	24.7	3.5	76	30
C	C-1	PL0168_PR	12	7.2	24	32	30.22	63.5	39.5	5.6	72	30
	C-2	N/A	N/A	7.1	22	46	23.2	65.3	24.7	3.5	71	30
D	D-1	PL0168_PR	12	7.2	24	32	30.22	63.5	39.5	5.6	72	30
	D-2 (NGT)	NGT	15	9	36	46	13.9	55.3	39.5	5.6	90	30
	D-3	N/A	N/A	6.1	22	24	23.1	60.9	24.7	3.5	70	30

[1]This was done using the H_2 Pipeline Pressure Drop Calculator tool of Shell's Hydrogen Transport Team using the following parameters: T = 20[°C], wall roughness = 3.00E-05 [m], dynamic viscosity = 8.69E-06 [Pa s] and the HHV to determine mass flow rate.

APPENDIX 6. Capacity assessment for export scenarios

Scenario	Pipeline	Transport	Mole fraction CH_4	Official Name	Design pressure NG [MPa]	Design pressure H2 [MPa]	OD (")	Length (km)	Velocity outlet (m/s)	Pressure inlet (bar(g))	Mass Flow Rate [kg/s]	H2 Capacity (GW)*
1	C-2	H2	0.00	N/A	N/A	7	22	46	23.2	65.3	24.7	3.5
	NGT	H2	0.00	NGT	15	9	36	254	9.2	54.9	24.7	3.5
2	E-1	H2	0.00	N/A	N/A	7	20	8	26.6	59.2	24.7	3.5
	E-2	H2	0.00	NP001	12	7.2	24	31	20.0	56.4	24.7	3.5
	E-3	H2	0.00	NP002	10	6	24	0.2	20	51.8	24.7	3.5
	WGT	H2	0.00	WGT	15	9	36	84	9.2	51.8	24.7	3.5
2.1	E-1	H2	0.00	N/A	N/A	9	18	8	23.4	84.0	24.7	3.5
	E-2	H2	0.00	NP001	12	7.2	24	31	13.7	80.5	24.7	3.5
	E-3	H2	0.00	NP035	10	6	16	16.7	38	77.4	24.7	3.5
	E-4	H2	0.00	LoCal	10	6	24	84	20.7	62.0	24.7	3.5
3	C-2	H2	0.00	N/A	N/A	7	22	46	23.2	65.3	24.7	3.5
	NGT	H2	0.00	NGT	15	9	36	254	9.2	54.9	24.7	3.5
	T-1	TG	0.41	NP011	13.5	8.1	12	8.9	12.24	58.2	15.3	0.3
	T-2	TG + NG	0.48	NP006	13.5	8.1	18	9.4	5.14	54.8	17.5	0.3
	T-3	TG + NG	0.48	NP001	12	7.2	24	31	2.92	54.1	17.5	0.3
	T-4	TG + NG	0.48	NP035	10	6	16	16.7	6.9	53.6	17.5	0.3
	T-5	TG + NG	0.48	LoCal	10	6	24	84	3.13	51.4	17.5	0.3
4	C-2	H2	0.00	N/A	N/A	7	22	46	23.2	65.3	24.7	3.5
	NGT	H2	0.00	NGT	15	9	36	254	9.2	54.9	24.7	3.5

	T-1	TG	0.39	NP011	13.5	8.1	12	8.9	21.6	69.6	2.9	0.06
	T-2	TG + NG	0.90	NP006	13.5	8.1	18	9.4	4.7	57.1	28.8	0.06
	T-3	TG + NG	0.90	NP001	12	7.2	24	31	2.7	56.2	28.8	0.06
	T-4	TG + NG	0.90	NP035	10	6	16	16.7	6.4	55.4	28.8	0.06
	T-5	TG + NG	0.90	LoCal	10	6	24	84	3	52.2	28.8	0.06