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Renewable hydrogen storage and supply options for large-scale industrial users in Finland

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Uusiutuvan vedyn varastointi- ja jakeluteknologiat suuren mittakaavan teollisille toimijoille Suomessa

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Kiinnostus uusiutuvaa vetyä kohtaan on ollut kasvussa viime vuosina, ja vaihtelevan uusiutuvan energian (VRE) kapasiteetin kasvun myötä myös vetyvarastokapasiteetin tarve kasvaa. Demonstraatioita Suomen olosuhteisiin sopivista suuren mittakaavan vetyvarastoteknologioista ei vielä ole, ja aihe on toistaiseksi kohtalaisen tuntematon.

Tämän diplomityön tavoitteena oli käydä läpi vedyn varastointiteknologioita, jotka ovat toteuttamiskelpoisia suuressa mittakaavassa Suomessa. Teknologioita vertailtiin ensin kvalitatiivisesti, jonka jälkeen kehitettiin dynaaminen malli Python-ohjelmointikielellä kuvaamaan suljetun maanalaisen kalliovaraston (LRC) toimintaa osana teräksenvalmistusprosessia. Työn tavoitteena oli tutkia, pienentääkö varasto vedyntuotannon kokonaiskustannusta.

LRC:n toimintakykyä arvioitiin luomalla skenaarioita ja vertailemalla niiden kustannuksia LCOH-menetelmällä. Muuttujista erityisen kiinnostuksen kohteena olivat varaston koko, käyttötunnit sekä sähkön hinta. Lisäksi tässä diplomityössä tutkittiin vedyn siirtoputkiston kustannuksia sekä ylijäämälämmön myyntituottoja.

Simulointitulokset osoittivat, että varaston käyttäminen voi pienentää tuotantokustannuksia suurimmillaan 0.64 €/kg_{H2} verrattuna konfiguraatioon, jossa varastoa ei ole, joskin sähkön hinnan vaihtelevuudella oli merkittävä vaikutus taloudelliseen kannattavuuteen. Varastokoon kasvattaminen johti referenssiskenaariota pienempiin LCOH-arvoihin vain suuremman vaihtelevuuden hintadatan kohdalla. Hintadatan, jossa sähkön hinnanvaihtelu oli vähäisempää, johti useimmissa skenaarioissa suurempiin LCOH-arvoihin, jossa suurin LCOH-nousu oli 0.13 €/kg_{H2}. Merkittävin osuus

tuotantokustannuksista muodostui sähkönkulutuksesta, kun taas pääomakustannusten osuuden havaittiin olevan pieni riippumatta sähkön hintatason vaihtelusta tai investointikustannusten herkkyytyksestä. Valuuttamuunnokset Yhdysvaltain dollarista euroon tehtiin käyttäen huhtikuun 2022 muuntokerrointa. Jatkoselvityksen aiheiksi ehdotetaan laajemman varastokapasiteettien joukon tutkimista sekä sähkön hintakehityksen ja erilaisten sähkönhankintasopimusten huomioimista. Tässä diplomityössä kehitetty malli oletuksineen ei ole räätälöity teräksenvalmistusprosessia varten, vaan sitä voidaan pitää yleisenä kuvauksena teollisuudenaloista, jotka käyttävät vetyä syötteenä jatkuvatoimisessa prosessissa.

Asiasanat: vetyvarasto, mallintaminen, LRC

ABSTRACT

Renewable hydrogen storage and supply options for large-scale industrial users in Finland

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The interest in renewable hydrogen has been on the rise in recent years, and with the increase in variable renewable energy (VRE) capacity, hydrogen storage capacity is needed. However, large-scale hydrogen storage applications viable in Finland are yet to be demonstrated, and the topic is rather unexplored. This thesis aimed to present the technology options for large-scale hydrogen storage applications viable in Finland. The technologies were first compared qualitatively after which a model to simulate the operating performance of a lined rock cavern (LRC) as a part of the steelmaking process was created using Python programming language. The aim was to study if the storage can reduce the overall cost of delivered hydrogen.

The performance of LRC was assessed by establishing different scenarios and comparing the Levelized cost of hydrogen (LCOH) of the scenarios. The variables of particular interest were the effect of storage size, operational hours of the storage, and electricity price. Additionally, the cost of the transmission pipeline and the benefit of surplus heat sales were included in this thesis.

The simulation results show that with the assumptions and price data used in this thesis, integrating storage can decrease LCOH up to 0.64 €/kg$_{H2}$ compared to a configuration with no storage, but the electricity price volatility had a substantial effect on the economic viability. Increasing the storage capacity led to lower LCOH only when price data with higher price volatility was used. Using price data with less volatility resulted in increased LCOH, up to 0.13 €/kg$_{H2}$, in most scenarios. Electricity cost was found to constitute the largest part of the LCOH, while CAPEX was found to have a small contribution regardless of the variation of electricity prices or investment cost estimations. Conversions from USD to EUR were conducted using exchange reference rates of April

2022. Future research including a broader set of storage capacities as well as focusing more in detail on the development of electricity prices and contract alternatives is suggested. The simulation and assumptions are not tailored for steelmaking but can be deemed as generalized descriptions for the industry that uses hydrogen as a feedstock in continuous operation.

Keywords: hydrogen storage, modelling, LRC

FOREWORDS

This thesis was done at VTT Technical Research Center of Finland between February and June 2022. The focus of this thesis was to map potential technologies for large-scale hydrogen storage and conduct a closer examination of the most promising concept.

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ABBREVIATIONS

BF	blast furnace
CAPEX	capital expenditure
CCUS	carbon capture, utilization, and storage
DBT	dibenzyltoluene
DRI	direct reduced iron
EBC	electrolyzer base capacity
EC	European Commission
EU	the European Union
EOC	electrolyzer overcapacity
GHG	greenhouse gas
HHV	higher heating value
IC	investment cost
LCOE	levelized cost of energy
LCOH	levelized cost of hydrogen
LHV	lower heating value
LOHC	liquid organic hydrogen carrier
LRC	lined rock cavern
NEC	N-ethylcarbazole
OPEX	operational expenditure
PEM	polymer electrolyte membrane
PPA	power purchase agreement
RES	renewable energy source
SMR	steam-methane reforming
TOL	toluene
TRL	technology readiness level
VRE	variable renewable energy
WACC	weighted average cost of capital

1 INTRODUCTION

The mechanization of the textile industry started the first industrial revolution over two hundred years ago. It was a significant turning point and set humanity on a path of growth unforeseen in history. Alongside the economies, the global atmospheric greenhouse gas (GHG) concentrations started growing due to the extensive use of fossil fuels to power societies (Martinez 2005). Since the start of the first industrial revolution, the CO_2 concentration in the atmosphere has grown by over 40%, accompanied by an increase of approximately 1°C in average global surface temperature (National Research Council 2020). However, the economic growth enabled by fossil resources is ending, as the efforts to mitigate climate change grow larger. Renewable energy capacity, mainly solar photovoltaic (PV) and wind energy is forecast to grow more than 60% between the years 2020 and 2060, surpassing the current global combined capacity of fossil fuels and nuclear power (IEA 2021a). The fundamental difference, in addition to zero CO_2 emissions, between wind, solar, and fossil fuels is that the two first mentioned sources of energy are not dispatchable, i.e., they cannot be turned on whenever needed. This change in the availability of electricity invites us to rethink the prevailing inelastic custom in consumption. In other words, more flexibility is required from the energy systems and processes.

The increasing share of variable renewable energy (VRE) creates more volatility in electricity production. If the VRE penetration is high in the power system, it is argued to increase the volatility of electricity market prices. However, the significance and magnitude of the ability of VRE to alter wholesale electricity prices is disputable and depends on the actions of other market participants (Rai and Nunn 2020). Another feature of VRE is that the output is not only variable but may also be poorly correlated with electricity demand. The variation in the availability of electricity may suit poorly especially industries such as the metal and petrochemical industry, as the processes are traditionally continuous (Ge et al. 2013). Hence, technologies to store electricity to be used on-demand are required by processes with limited flexibility.

Hydrogen has a strong role in the industry, where it is being used, pure or in a mixture of gases, as a feedstock in, e.g., oil refining, ammonia production, and steel production (IEA 2019). Although being mostly produced from fossil fuels for the moment, hydrogen produced from renewable energy sources is seen as one of the key enablers of the sustainable energy future for several reasons: it releases no air pollutants when used, it is suitable for long-term storage, and it can be produced from a broad set of low-emission energy sources (IEA 2019). The numerous roadmaps and investment plans announced highlight the interest in hydrogen. For example, the European Commission's REPowerEU Plan published in May 2022, includes setting a target of 10 million tonnes of hydrogen produced in the European Union (EU), as well as announcing additional €200 million additional funding for hydrogen research (European Commission 2022). In Finland, well-established hydrogen production and use as a feedstock in the industry are already in place, facilitating the shift towards a low-emission industry (Laurikko et al. 2020). While electrolyzer technologies and their related costs are well-researched, hydrogen storage, especially in the Finnish context, remains rather unexplored.

The publications concerning large-scale hydrogen storage principally focus on underground technologies, more precisely on salt cavities, depleted gas fields, and aquifers. For example, (Kruck et al. 2013) present an overview of underground storage technologies for hydrogen. Studies about potential business cases for hydrogen storage in Europe, such as (Michalski et al. 2017) and (le Duigou et al. 2017), mention salt caverns as the technically preferred option. However, the applicability of the technologies is limited to areas where these natural formations occur. In Finland, no geological formations suitable for hydrogen storage can be found (Laurikko et al. 2020). The rock mass, however, is stable and strong, possibly enabling applications based on excavating rock caverns, such as lined rock caverns (LRC). Hydrogen storage studies conducted in Sweden, such as (Johansson et al. 2018; Andersson and Grönkvist 2019, 2021), provide a good reference in the Finnish context due to similar geological conditions and economy.

This thesis aims to present the principles and different technology options for hydrogen storage, focusing on potential large-scale applications in Finland. Hydrogen uses in the industry as well as the regulatory framework focusing on EU legal acts will be presented in Chapter 2, followed by the principles and selected technology options of hydrogen storage and transportation in Chapter 3. Chapter 4 presents the methodology of the study, including technical and economic parameters and equations used, as well as a description of the simulation scenarios and the simulation model created. Using historical electricity price data, this thesis aims to study how much storage can decrease the operation cost of hydrogen production in comparison with the cost of producing hydrogen without storage, as well as compare the overall cost of delivered hydrogen between different scenarios. To gain an understanding of the effect of operating strategies on the overall cost, different rules for the operating logic are used in the simulations. Furthermore, this thesis tries to address the role of pipeline transmission and revenues from waste heat utilization on the overall cost by studying the storage economics between on-site production and storage, and production and storage located near a city, so that the excess heat can be sold to the district heat network.

Chapter 5 presents the results of the simulation model, as well as the levelized cost of hydrogen (LCOH) for the different scenarios. Interpretation and discussion of the results are provided in Chapter 6, and lastly, the conclusions of this thesis are provided in Chapter 8.

2 HYDROGEN IN INDUSTRY

Nearly all hydrogen production is fossil-based, and as such, replacing fossil raw materials or energy sources with hydrogen does not contribute to decarbonizing the industry by default, but it is determined by the source of energy used to produce hydrogen. To indicate the hydrogen generation technology, hydrogen is codified based on colors: grey hydrogen is produced by fossil fuels, blue hydrogen abates emissions from fossil fuels by carbon capture, utilization, and storage (CCUS), while green hydrogen uses energy supplied by renewable sources (Gerhardt et al 2020)

In 2020, the global hydrogen demand was approximately 90 Mt, of which 70 Mt was used as pure hydrogen, and 20 Mt mixed with other gases. The largest hydrogen user was the industry sector, where hydrogen is used as feedstock, followed by chemical production. These sectors consumed 50 Mt and 45 Mt of hydrogen in 2020, respectively. Approximately 5 Mt of hydrogen was used in steelmaking in direct reduced iron (DRI) process. In 20 years, the demand for hydrogen has increased by 50%, but the distribution between end-users has remained unchanged. (IEA 2021b)

The largest user of hydrogen is oil refining with a share of 33%, where hydrogen is used for hydrocracking and hydrotreating. Ammonia and methanol production consumes 27% and 11% of the hydrogen globally (IEA 2019). The main pathway for hydrogen production is steam-methane reforming (SMR), where hydrogen atoms are separated from carbon atoms into methane (IEA 2019). Methane, in turn, is supplied in form of natural gas. Other major processes for hydrogen production from fossil sources are partial oxidation of heavy oil and coal gasification (Kato et al. 2005). The distribution of global hydrogen production by energy source in the year 2020 is presented in Figure 1.

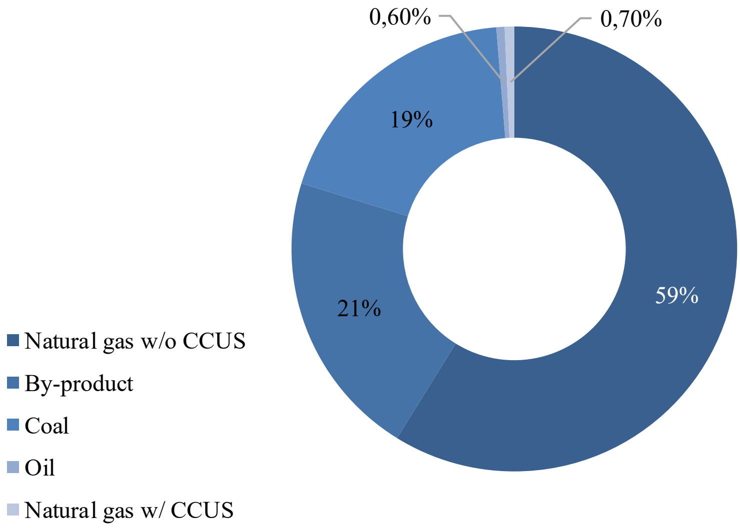


Figure 1. Energy sources in hydrogen production globally in 2020 (IEA 2019). Dedicated hydrogen plants account for 79% of the production and the remainder (21%) was formed as a by-product in facilities dedicated to other products, mainly oil refineries.

Hydrogen production via water electrolysis, invented in the 18th century by van Troostwijk and Deiman, is by no means a new concept (de Levie 1999). In the process, water is split into oxygen and hydrogen through the application of electrical energy, as in Reaction 1:

$$H_2O_{(l)} \rightarrow H_{2(g)} + \frac{1}{2}\,O_{2(g)} \tag{R1}$$

Commercially available electrolyzer technologies are alkaline water electrolysis and polymer electrolyte membrane (PEM) electrolysis, the first of which is fed with water and using caustic solutions as an electrolyte, while the latter is fed with pure deionized water. In comparison with alkaline electrolysis, the PEM electrolyzers are characterized by a simpler process, fast ramp rates, higher current density, and the possibility to operate under differential pressure, generally from 20 to 40 bar. (IRENA 2020)

As mentioned earlier in this chapter, virtually all the dedicated hydrogen produced globally is made from fossil sources. In total, 98% of all hydrogen produced globally comes from methane and coal. Consequently, the share of electrolytic hydrogen in dedicated hydrogen production is minor, 0.1% (IEA 2019). The reason for the domination of natural gas as a feedstock is due to its favorable economics: the production cost of hydrogen via SMR is 1.0 USD/kg$_{H2}$ in the United States, and even less in the Middle East.

In Europe, the cost is approximately 1.7 USD/kg$_{H2}$ (IEA 2019). The difference between the continents stems from the different costs of natural gas acquisition. The production cost of electrolytic hydrogen, in turn, ranges between 2.5 and 7.0 USD/kg$_{H2}$ (Vickers et al. 2020). Despite not producing emissions while being used, the production of hydrogen emits approximately 830 million tons of CO_2 per year (IEA 2019), as the main pathways for hydrogen production, such as SMR, produce carbon dioxide as well. Hence, the hydrogen used today in the industry is all but clean, and as the targets to reduce emissions get more ambitious, hydrogen production via electrolysis has gained significant interest. The contribution of green hydrogen in the net-zero future is tripartite: it can store surplus power generated by renewable energy sources (RES) when the power grid cannot absorb it, replace fossil fuels in fuel and chemicals production, and facilitate decarbonization of hard-to-abate sectors. However, some hurdles are yet to be solved for the hydrogen economy to properly set off.

Based on a survey conducted by a Finnish consultancy company, where 8 infrastructure and private equity funds were interviewed, certain conditions in the market are expected. To green hydrogen projects to become more appealing to investors, stable incentives, such as long-term supporting mechanisms and far-reaching policymaking, are required. A predictable and stable reputation as a legislator is expected from the government of the country in which the projects would be executed. In addition, direct demand for the produced hydrogen is desirable, which makes industry appear as the most appealing sector for investments. (AFRY 2021)

2.1 Regulatory framework

In November 2018, the European Commission adopted a strategic long-term vision A Clean Planet for All, which includes eight net-zero emissions scenarios for the year 2050 (European Commission 2018). Green hydrogen features in all scenarios, underlining the essential role of hydrogen in climate neutrality. In December 2019, the European Commission presented the European Green Deal, setting the framework for policies to reach carbon neutrality by 2050. The document identifies clean hydrogen as one of the priority areas of breakthrough technologies in industry by 2030 (European Commission 2019). Guided by the European Green Deal, a recovery instrument named Next Generation EU gives priority to jumpstarting a clean hydrogen economy in post-COVID-19 Europe (European Commission 2020).

The above mentioned are some of the several strategies and roadmaps that underline the ambition to deploy a hydrogen economy in Europe, but at the core of it is legislation. From the perspective of EU legislation, Directive 2012/18/EU of the European Parliament and of the Council of 4 July 2012 on the control of major accident hazards involving dangerous substances affects the storage of hydrogen. The Directive establishes obligations, e.g., to deploy a major accident prevention policy, as well as to produce safety reports and internal emergency plans for establishments exceeding 50 t (2012/18/EU). Directive 2014/34/EU of the European Parliament and of the Council of 26 February 2014 on the harmonization of the laws of the Member Stater relating to equipment and protective systems intended for use in potentially explosive atmospheres (recast) establishes the safety measures, equipment, and protective systems to be applied and used in potentially explosive atmospheres. The Directive requires companies to classify areas where explosive atmospheres may occur, and the manufacturers to design their equipment so that they are suitable in such areas (2014/34/EU). Additionally, hydrogen production and storage projects may be subject to Directive 2011/92/EU of The European Parliament and of the Council of 13 December 2011 on the assessment of the effects of certain public and private projects on the environment. The Directive defines the procedure for environmental impact assessment (EIA), and Annex II lists chemical industry projects for which the Member States shall determine whether the project shall be made subject to an assessment or not (2011/92/EU). Annex I in "Laki ympäristövaikutusten arviointimenettelystä (5.5.2017/252)" lists the chemical industry and integrated chemical manufacturing units subject to EIA in section 6c. However, according to the decision made by the Centre for Economic Development, Transport and the Environment in 25.5.2022 (UUDELY/1288/2022), a renewable hydrogen production unit is not considered an integrated chemical manufacturing unit and thus, is not subject to EIA. Section 8a classifies gas transmission pipelines with a diameter exceeding DN 800 and a length of more than 40 km to be subject to EIA, and section 8c classifies chemical storages with a volume of 50 000 m^3 or more to be subject to EIA (5.5.2017/252).

Commission directive 2009/73/EC concerning common rules for the internal market in natural gas, together with Regulation 715/2009/EC on conditions for access to the natural gas transmission networks establish the basis for the European gas market. The legislative framework for EU gas markets has changed little since the adoption of the third energy package in 2009. To reflect the changes in the market environment, as well as react to the increasing need for decarbonization, the European Commission published a proposal in

December 2021 to revise the Directive 2009/73/EC and Regulation 715/2009/EC. The revision seeks to extend the scope of the legal framework to cover renewable and low-carbon gases, including hydrogen (Tenhunen and Eggers 2021). The proposals can be traced back to the target of reducing GHG emissions by 55% by 2030 and reaching climate neutrality by 2050 as announced in the European Green Deal. The goal of the revision is to facilitate the shift from fossil fuels towards renewable and low-carbon gases by promoting the creation of a hydrogen market, investments, and infrastructure developments. From the consumer's perspective, the revision aims to empower consumers by enabling them to choose the gas supplier more easily as well as get better access to information, similarly to the electricity market (European Commission 2021). At the time of writing this thesis, the revisions were yet to be adopted.

The instrument that strongly dictates how the future of the hydrogen economy will develop is the revision of Directive 2018/2001/EU (2018) on the promotion of the use of energy from renewable sources (RED II), which is the main instrument to promote the shift towards renewable energy generation in EU. Directive 2018/2001/EU is a revised version of Directive 2009/28/EC (2009), and it established a binding target to increase the share of renewable energy to at least 32% by 2030, and part of that target was to increase the target for the share of renewable fuels in transport to 14%. In July 2021, the European Commission proposed a second revision (COM/2021/557) of the directive to align the targets with the objectives set in the European Green Deal. The key updates include increasing the EU-level target for renewable energy to 40% by 2030 and introducing a sub-target of 2.6% for renewable fuels of non-biological origins (RFNBOs), which includes green hydrogen, proposed also to apply in industry. Another key reform that applies to industry specifically is the target to increase renewable energy by 1.1 % annually from 2030, and the binding target of 50% for RFNBOs as a feedstock or as an energy carrier.

If the target of RFNBOs is extended to cover also other sectors than transport as proposed by the European Commission, the definition of RFNBOs is essential for green hydrogen in the industrial context: one requirement for RFNBOs is that it must be produced using renewable energy. Furthermore, according to recital 90 in RED II, hydrogen is considered renewable if there is a temporal and geographical correlation between the electricity production unit and the fuel production, and a requirement of additionality is complied. The requirement of temporal correlation denotes that power generation and consumption both must occur within a certain timeframe. Geographical correlation is fulfilled when the power is purchased, for example, from the same bidding zone where the consumption takes place. Finally, the element of additionality means that the fuel producer must add to the financing or use of renewable energy (2018/2001/EC). The potential implications of the proposals for hydrogen (storage) projects are discussed in Chapter 6.

3 HYDROGEN STORAGE TECHNOLOGY OPTIONS

Production of hydrogen via electrolysis is energy intensive. In hydrogen production, the raw materials are water and electricity, which means that the production cost of hydrogen is highly dependent on the price of electricity. Furthermore, the electricity price is expected to fluctuate more as the share of VRE increases in the power grid, resulting in more fluctuation in the hydrogen production cost. To control the production costs, constructing hydrogen storage interconnected with production might be sensible. This chapter aims to introduce the basic principles of hydrogen storage, as well as elaborate on selected state-of-the-art technologies with a focus on the large-scale viability of the technologies in Finland.

Historically, there has been little need to store hydrogen, as the main raw materials used to produce hydrogen are fossil-based, coal, oil, and natural gas, each of which is easily storable. As a result, only a handful of large-scale hydrogen storage exists worldwide. Following the categorization by (Andersson and Grönkvist 2019), hydrogen storage technologies can be divided into physical and chemical storage, in first of which hydrogen is stored in its elemental form, whereas chemical storage of hydrogen includes bonding hydrogen with other substances. It is also possible to store hydrogen by adsorption, where van der Waals bonding between hydrogen and applicable material is being utilized. However, this thesis focuses on storage technologies that have been demonstrated on an industrial level or deemed potential for near-future large-scale applications. Thus, adsorption will not be covered in this thesis due to the immaturity of the technology outside the laboratory scale.

Hydrogen storage technologies can vary in design, as well as utilize different physical or chemical phenomena, but the main conjunctive attribute they have is that in each technology, hydrogen requires some degree of pre-processing before it can be stored. The means to process hydrogen are, for example, compression, liquefaction, or hydrogenation. Thus, the charging state of storage operation requires energy, which has a diminishing effect on the hydrogen storage profitability. Furthermore, the release of hydrogen from the storage can be complicated and require an external source of energy in some technologies.

The applicability of a storage technology depends on the requirements of the storage and must be defined for each case. For example, storage with slow hydrogen release is not viable for short-term frequency control of the power grid, and again storage with considerable losses during hydrogen storing might not be a sensible application for long-time storage. Two metrics to characterize storage are charge and discharge durations, and the number of charge cycles. Duration of discharge refers to the amount of time that the storage can supply energy at its nominal output rate. The action of discharging the storage from a certain level and then charging it back to the initial fill level is called a cycle (Kiessling 2021). The number of charge cycles over a year indicates the usage of the storage: seasonal storage, stores energy during one season and discharges it later during another season, resulting in one full storage cycle per year. Storage with high injection and withdrawal rates in relation to working gas capacity is called short-term storage and is associated with a high number of charge cycles per year (Uniper SE 2022).

3.1 Physical storage

The gravimetric energy density of hydrogen is outstanding, approximately 33 kWh/kg_{H2} (Teichmann et al. 2012). However, the volumetric energy density is not. At atmospheric pressure, 1 kg of hydrogen has a volume of 1 Nm^3. Thus, storing massive quantities of hydrogen requires increasing the density to achieve lower storage volumes. This can be achieved by either compressing the gaseous hydrogen or cooling it down below its boiling point.

3.1.1 Liquefied hydrogen

Liquefied hydrogen is a promising storage technology in terms of hydrogen density. At atmospheric pressure, liquefaction of hydrogen can achieve a remarkably high hydrogen density of 70 kg/m^3. Additionally, liquefied hydrogen is considered with high purity (Aziz 2021). The technology readiness level (TRL) of liquefied hydrogen is between 7 and 9, the first one linked with large-scale applications (> 1000 t H_2/d) and the second value for small-scales (< 50 t H_2/d) (IRENA 2022). However, the temperature required to liquefy hydrogen is -253°C, which makes the process extremely energy-intensive. Currently, modern hydrogen liquefaction plants have an energy demand of approximately 10 kWh_{el}/kg_{H2}, and reductions down to 6 kWh_{el}/kg_{H2} are expected (Andersson and Grönkvist 2019). Furthermore, liquid storage of hydrogen requires that the heat transfer between the storage tank and environment is minimal and even so, a fraction of hydrogen evaporates nevertheless as no insulation can eliminate heat transfer. Minimizing the boil-off thus requires a well-insulated storage tank that is constantly cooled. Additionally, evaporated hydrogen must be vented off from the storage to prevent pressure build-up. Due to the extremely low temperature of liquid hydrogen, careful treatment is of foremost importance. Despite the high energy demand of liquefaction and the requirement to maintain the storage vessel temperature, liquefied hydrogen is seen as a fair option when high priority is given to storage density, e.g., overseas transportation, but less appealing for mid-to-long-term stationary storage for industrial purposes.

Instead of liquid hydrogen storage, the most typical technique to store pure hydrogen is to compress it (Barthelemy et al. 2017). Compressed hydrogen can be stored either above or below ground, of which underground storage is more suitable for large volumes: constructing the storage below ground level, the surrounding rock mass acts as a supporting element, whereas in above-ground applications the only supporting element is the storage tank. Thus, aboveground storage tends to have higher investment costs (Andersson and Grönkvist 2019). Most of the pure hydrogen storages in use today are belowground salt cavities filled with compressed gas (Kruck et al. 2013).

3.1.2 Salt cavern

The most demonstrated and mature technology to store large volumes of gas is to utilize salt caverns. The mechanical properties of rock salt make it an excellent storage material for gases: under compressive stress, the visco-plastic deformation of rock salt creates an airtight structure that does not require any additional sealing. Furthermore, stress from the construction and operation is redistributed in rock salt due to this deformation, diminishing the need for artificial reinforcement. Because of these properties, salt caverns have been used for natural gas storing since the 1970s, the number of caverns exceeding 300 in Europe only. At the moment, five salt caverns are used as hydrogen storage, all of them located in the USA. Three of them have been operating since 1972, and two since 1983. The experience of storing hydrogen thus reaches far. (Kruck et al. 2013)

As for safety, salt caverns are associated with large geometrical volumes, up to 1 million m^3, and the common depth for the cavern top is 1 000 m. This compiled with the tight structure of the cavern enables safe storage of large volumes. The safety hazards associated with hydrogen salt cavern storages are the same as natural gas caverns. Large gas leaks are unlikely due to underground safety valves and the natural tendency of rock salt to tighten under pressure. In the cavern, no oxygen is present, thus removing the risk of the formation of a combustible mixture. In comparison with other underground storage technologies, salt caverns have low investment costs as the excavation of caverns can be performed from aboveground by leaching. (Kruck et al. 2013)

Although the purity of withdrawn hydrogen from salt caverns is high, microbial activity during hydrogen storage cannot be ruled out. Part of the leaching water can remain at the bottom of the salt cavern, providing a living environment for microbes. As a result, traces of undesired side products may form in the cavity (Dopffel et al. 2021). However, the greatest limitation in salt cavern technology is geological; only a few salt deposits are in Northern Europe and none in the Nordics, except for Denmark (Kruck et al. 2013). In Finland, no salt caverns exist.

3.1.3 Lined rock cavern

In areas where salt caverns are not available and the geological conditions of the bedrock are stable enough, one potential means of storing hydrogen underground is to construct lined rock caverns (LRC). A LRC storage consists of a cylindrically mined cavern that is lined using a gas-impermeable material, further secured with a pressure-transferring layer of concrete between the lining and rock mass. (Sofregaz U.S. Inc and LRC 1999). The concept and the first industrial-sized LRC storage were developed in Sweden. In Skallen, Southern Sweden, a 52 m high cavern with a diameter of 35 m has been in operation since 2002, storing natural gas (Glamheden and Curtis 2006). The technical properties of the Skallen facility will be used as a reference later in this thesis.

The LRC storage system includes facilities both above- and underground. Compressor station, piping, equipment for heating and cooling, valves, metering, and a control system are located above ground, while the underground facility consists of a cavern or a set of caverns and access tunnels (Johansson et al. 2018). The components of the gas storage lining are presented in Figure 2. Starting from the innermost element, the storage consists of a steel lining (1), which creates a gas-tight environment inside the storage, followed by a sliding layer (2). The sliding layer between the lining and concrete (3) protects the lining from friction and, to some extent, corrosion. The purpose of the concrete is to even out the roughness of the excavated rock mass (7) surface, as well as transmit and distribute the pressure to the rock mass. To strengthen the concrete and further distribute the strain, the concrete is reinforced with a welded mesh structure (4). Between concrete and rock mass, a layer of shotcrete (5) is added. This layer is permeable, allowing water to percolate into the drainage system (6). When the gas pressure in the cavern is low, the pressure from surrounding groundwater might damage the lining without the presence of drainage pipes. The presence of groundwater in the porous shotcrete serves as a protective layer that keeps oxygen from reaching the steel lining, preventing corrosion. Furthermore, the drainage system can detect gas leakages, as leaking gas increases the pressure in the system. In case of a leakage, the drainage system collects the gas in the pipes, where it is then vented to the surface. (Johansson 2003)

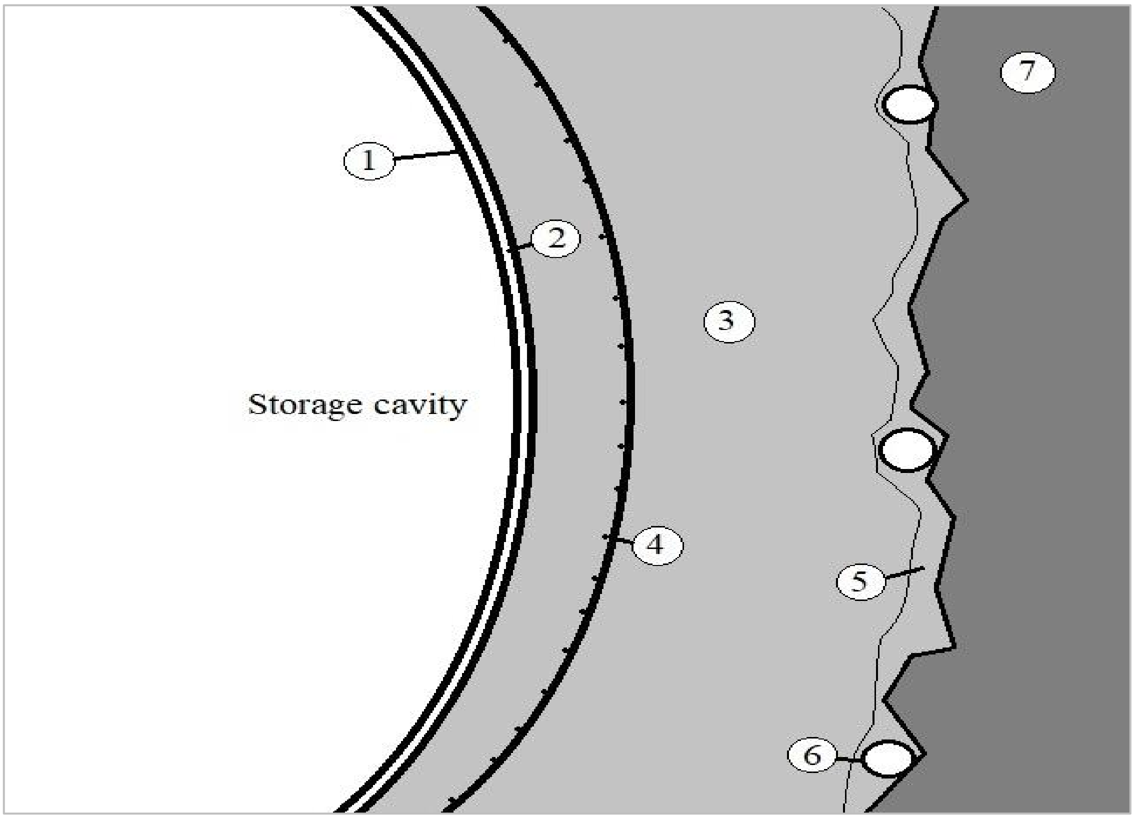


Figure 2. The structure of a LRC consists of steel lining (1), sliding layer (2), concrete (3), welded mesh structure (4), shotcrete (5), drainage system (6), and the surrounding rock mass (7) (adapted from Johansson 2003).

Geological conditions for cavern excavation require a homogeneous texture of the rock mass with little or no structural weaknesses, and sufficient mechanical stability. Hard crystalline rock, such as gneiss or granite, has been demonstrated to comply with these prerequisites. The bedrock of the Nordics, belonging to the Baltic shield, largely consists of these crystalline rocks. (Kruck et al. 2013).

As mentioned earlier in this chapter, the first and, for the time being, the only LRC in operation is located in southwest Sweden as a part of the natural gas grid. The storage has a geometrical volume of 40 000 m^3, with an operating pressure range of 20-200 bar and an estimated lifetime of over 30 years (Johansson et al. 2018). Of the total gas capacity, approximately 10% serves as cushion gas (Mansson and Marion 2003). Initially, the main purpose of the Skallen facility was to strengthen the security of supply in Sweden, as natural gas is imported to Sweden from Denmark via pipeline. Furthermore, the storage has contributed to transport cost reductions: during peak demands, the import level can be set lower as the storage can function as a buffer. In the same manner, imbalances between supply and demand are leveled out. (Tengborg et al. 2014)

3.1.4 LRC as a hydrogen storage

The maximum pressure to be used in the cavern varies depending on the depth of the cavern and the quality of the surrounding rock mass (Papadias and Ahluwalia 2021). As the cavern lies at a relatively shallow depth, approximately 100-150 meters below the ground surface, the rock mass must be rather strong to withstand the uplift forces applied to the rock mass by the gas. The technology is possible to be applied for lower quality rock masses as well, albeit with lower maximum pressures. Generally, the maximum operating pressure within the storage is estimated to range between 150 and 300 bar. (Tengborg et al. 2014) In addition, with withstanding high pressures, the minimum pressure requirement of LRC is low compared to other underground storage technologies, resulting in a small amount of cushion gas needed. The term cushion gas refers to a gas that cannot be retrieved from storage. The purpose of keeping a certain amount of gas always present in the storage is to keep a minimum pressure to ensure the structural integrity of the storage as well as allow for adequate withdrawal rates. The share of the total gas capacity that is available for use is called working gas. If the storage is used to store hydrogen, the estimated working gas capacity of a Skallen-sized LRC is 0.64 M kg, of which 1 300 kg and 3 600 kg of hydrogen could be injected into and withdrawn from the storage hourly (Kruck et al. 2013). Based on (Kruck et al. 2013), a single cavern with a volume of 120 000 m^3 and pressure up to 220 bar is technically feasible. Such a cavern is estimated to require a cushion gas volume of approximately 10% of the total volume. In addition to complying with minimum and maximum pressure rates, LRC also has limitations in safe pressure change rates. To avoid excessive temperature changes, hydrogen can be injected or withdrawn at a certain mass flow rate, which is approximately one-tenth the natural gas rate. (Kruck et al. 2013)

The suitability of LRC as large-scale hydrogen storage is yet to be demonstrated, but a successful pilot to integrate a LRC as a part of the natural gas grid in Skallen suggests that technology could be applied for other gases, as the design principles between different gases do not differ substantially. However, hydrogen is capable of embrittling steel, potentially reducing the lifetime of the steel lining (Johansson et al. 2018). As the tightness of the lining is of great importance to ensure safe operation and avoid losses, thorough testing to find the most suitable lining materials for hydrogen is necessary.

First-ever LRC storage with the purpose to store hydrogen is being built in Luleå, Sweden, by the HYBRIT initiative, owned by three companies: SSAB, LKAB, and Vattenfall. The construction work began in May 2021, and the operation is planned to commence in the summer of 2022 until 2024. The facility will be a pilot plant with a cavern volume of 100 m^3 and a designed operational pressure of up to 250 bar. The cavern is being constructed 30 m below ground in rock mass that consists mainly of amphibolite, pegmatite, and red granite. The LRC storage is a continuation of a pilot plant for direct reduced iron (DRI) production commissioned in August 2020, and it will be sited next to the DRI pilot plant. (HYBRIT 2022)

3.2 Compression

As mentioned in Chapter 3.1, storing pure gaseous hydrogen is challenging due to its low density. Hence, to achieve practicable storage volumes, hydrogen must be pressurized. The apparent drawback of hydrogen compression against other gases used as fuel is the required compression energy. When compared to natural gas, compressing hydrogen requires more energy because of the lower relative density, which is 0.089 kg/m^3. For reference, the gas density of methane, the main component of natural gas, is 0.72 kg/m^3. (Prachi R. et al. 2016) Figure 3 presents the amounts of energy required to compress hydrogen to certain pressures. In this thesis, the energy consumption to compress hydrogen between 20 bar and 250 bar is assumed to be 1 kWh/kg_{H2} (Gardiner 2009).

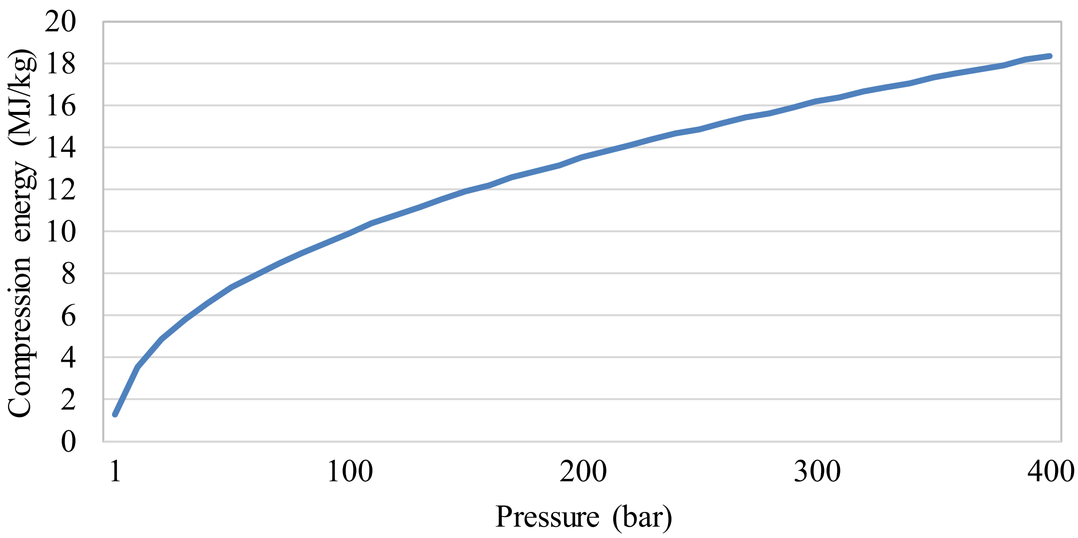


Figure 3. Hydrogen compression energy as a function of pressure (adapted from Elberry et al. 2021).

Large storage volumes translate into high investment costs, while increasing the storage pressure requires more compression work, leading to higher operating costs (Andersson and Grönkvist 2019). For a LRC storage with a capacity of 500 t H_2 and a maximum pressure of 150 bar, the compressor accounts for 77% of the aboveground equipment capital costs, and approximately 16% of the overall capital costs of the whole storage system (Papadias and Ahluwalia 2021). Expressed in another way, compression to, e.g., 350 bar requires an amount of energy corresponding to approximately 12% of the lower heating value (LHV) of hydrogen (Eberle et al. 2009).

3.3 Liquid organic hydrogen carriers

Physical methods for storing hydrogen require either high pressure or low temperature. Furthermore, underground storage applications are not always feasible due to geographical constraints. Although being well known and widely used in the chemical industry, for example, the handling and distribution of gaseous hydrogen require large upfront investments in constructing a new infrastructure to utilize hydrogen to the same extent as natural gas (Teichmann et al. 2012). Moreover, the safety aspect related to a pressurized gas, the low density and thus, large storage volumes in addition to the cost of compression tempts to seek alternative options for storing hydrogen. Instead of compression or liquefaction of pure hydrogen, it can be covalently bound with applicable compounds. Liquid organic hydrogen carriers (LOHCs) refer to a set of organic compounds, typically aromatic or heteroaromatic, that are capable of reversibly storing hydrogen. This carrier medium chemically binds hydrogen in an exothermic process called hydrogenation. When the hydrogen is released from the compound during dehydrogenation, little additional matter besides hydrogen is released, i.e., the purity of hydrogen is relatively high, and the LOHC returns to the state where it can be re-hydrogenated. (Aakko-Saksa et al. 2018) The working principle of the LOHC concept is shown in Figure 4.

Hydrogenation and dehydrogenation of LOHC take place at elevated temperatures, aided by a catalyst (Aakko-Saksa et al. 2018). Hydrogenation is an exothermic process, i.e., it releases heat, while dehydrogenation is endothermic, thus, the process requires an energy input (Teichmann et al. 2012).

Hydrogenation is a well-established and widely used technology in the chemical industry, where hydrogen is added to organic compounds by the formation of a chemical bond between hydrogen and the hydrogen carrier. The reaction enthalpy of prominent cyclic hydrocarbons varies between 64–69 kJ/mol$_{H2}$ (He et al. 2015; Aakko-Saksa et al. 2018). The presence of a catalyst enables lower operating temperatures for hydrogenation and dehydrogenation; for example, the temperature required to hydrogenate benzene without a catalyst is approximately 320 °C, while with a catalyst, the temperature can be lowered down to 100–250 °C, pressure being within the range of 10–50 bar (Cooper et al. 2006; Aakko-Saksa et al. 2018). For technically similar hydrogenation of organic compounds, nickel, palladium, or platinum is often used as catalyst material (Teichmann et al. 2012).

Dehydrogenation in turn requires energy input equal to the amount of heat released in hydrogenation. This is deemed the main negative attribute in storing hydrogen in LOHCs. The reaction enthalpy of 65 kJ/mol$_{H2}$, for instance, corresponds to 27% of the LHV of hydrogen (242 kJ/mol). As the heat required to release hydrogen from the LOHC is significant, approximately 180–350 °C, the source of the heat used for dehydrogenation becomes an important factor defining the costs of LOHC technology. The reaction being reversible, there is no need to produce a new batch of hydrogen carrier after dehydrogenation (Aakko-Saksa et al. 2018).

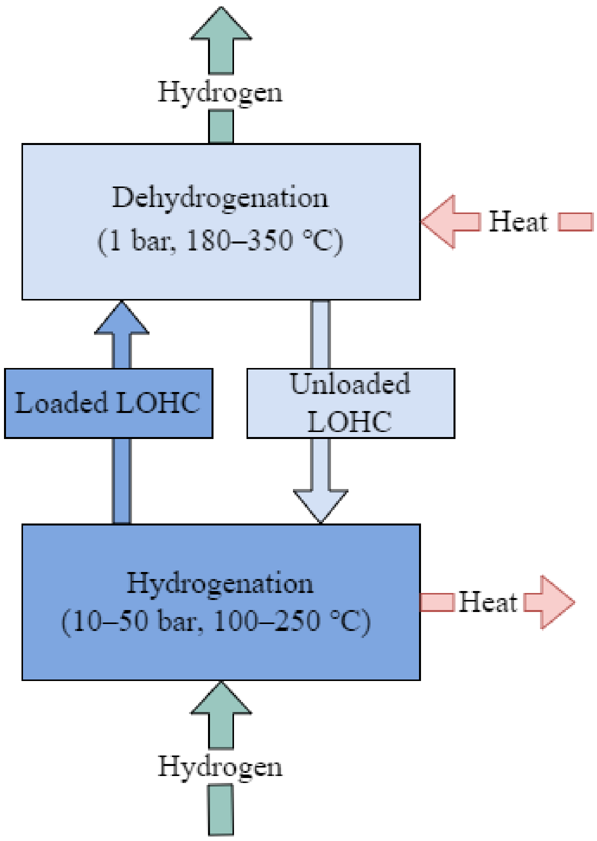


Figure 4. The working concept of LOHC technology (adapted from Hurskainen 2019).

The attributes to consider when selecting a hydrocarbon to be used as LOHC include, but are not limited to, safety and ease of handling, cost and availability of the material, thermodynamics, the safety of hydrogen release, and material stability (degradation). A variety of substances, such as cycloalkanes and N-heterocycles, have been identified as potential LOHC candidates. An ideal LOHC has a high hydrogen storage density and sufficiently low reaction enthalpy to ensure acceptable dehydrogenation temperature. The carrier should have a low degradation rate, i.e., it can go through several loading cycles, so that the replacement cost of carrier material is minimized. The attributes to consider when selecting a hydrocarbon to be used as LOHC include, but are not limited to, safety and ease of handling, cost and availability of the material, low flammability, the safety of hydrogen release, sufficiently mild reaction conditions, and material stability (degradation). Currently among the most prominent and researched LOHC pairs are toluene/methylcyclohexane (TOL–MCH), dibenzyl toluene/perhydrodibenzyltoluene (DBT–H18-DBT), and N-ethylcarbazole/dodecahydro-N-ethylcarbazole (NEC–H12-NEC). (Aakko-Saksa et al. 2018) Table 1 presents the key properties related to the beforementioned three LOHC pairs.

Table 1. Comparison of the physical properties of TOL, DBT, and NEC.

Property		**Unit**	**TOL**	**DBT**	**NEC**
Enthalpy		kJ/mol$_{H2}$	68.3[1]	65.4[4]	53.0[5]
H_2 storage capacity		% wt	6.2[2]	6.2[2]	5.8[2]
Melting/boiling point	Unloaded	°C	-95/110[3]	-39/390[7]	69/378[5]
	Loaded	°C	-127/100[3]	-50/370[7]	84[6]/281[2]
Hydrogenation	pressure	bar	10–50[8]	30–50[8]	70[8]
	temperature	°C	50–100[8]	150[8]	150–170[8]
Dehydrogenation	pressure	bar	3[8]	1[2]	1[2]
	temperature	°C	350[8]	320[8]	180–260[8]
Price		€/kg	0.3[9]	4.0[9]	40.0[9]

[1] (He et al. 2015)
[2] (Aakko-Saksa et al. 2018)
[3] (Rumble et al. 2021)
[4] (Sung et al. 2008)
[5] (Teichmann et al. 2012)
[6] (Stark et al. 2016)
[7] (Peters et al. 2019)
[8] (Schneider 2015)
[9] (Niermann et al. 2019)

Dibenzyltoluene (DBT) is a cycloalkane that is used as a heat transfer oil in the industry. Demonstrated by (Brückner et al. 2014), the hydrogenation of DBT takes place in 150 °C and 50 bar. Benzyltoluene (BT) resembles DBT with similar applications in industry, reaction enthalpy (63.5 kJ/mol$_{H2}$), thermal stability, and price. The main advantage of DBT is a higher boiling point and lower vapor pressure, which sets higher temperature limits for liquid-phase dehydrogenation temperature for DBT: boiling points for BT and DBT are 270 °C and 370 °C, respectively (Aakko-Saksa et al. 2018). However, BT possesses properties that make it possibly more suitable for storage in low-temperature storage applications: the benefit of using BT is low viscosity and thus, ease of handling (Aakko-Saksa et al. 2018). Moreover, the hydrogen release using Pt/Al_2O_3 catalyst at 270 °C is faster for perhydro-BT than perhydro-DBT (Rao and Yoon 2020). Commercial applications of BT as LOHC already exist on a small and industrial scale: for example, Hydrogenious LOHC Technologies GmbH provides LOHC storage plants exceeding 12 t H_2/day. In their process, hydrogenation takes place at approximately 250 °C and 25–50 bar, generating around 10 kWh/kg$_{H2}$ of heat. Dehydrogenation requires approximately 12 kWh/kg$_{H2}$ of heat at 300 °C. With BT, a storage density of 54 kg$_{H2}$/m^3 LOHC is reached. (Hydrogenious LOHC Technologies 2022)

As for compatibility with the existing infrastructure, LOHCs have several physico-chemical features resembling diesel fuel (Teichmann et al. 2012). For near-future applications, this can be considered one of the main advantages of LOHCs (Aakko-Saksa et al. 2018). However, the LOHC technology to store and transport hydrogen is relatively young, and only some small-scale applications are taking their first steps in the market (Aakko-Saksa et al. 2018). The TRL of LOHC hydrogenation and dehydrogenation for large scale is 5, and 7 for small scale (IRENA 2022). (Kiessling 2021) compiled literature sources covering costs related to LOHC storage, pointing out the large variation in cost estimations. The cost of the hydrogenation plant varied from 5 200 €/(kg_{H2}/h) to 12 600 €/(kg_{H2}/h), and for the dehydrogenation plant, the estimations were 1 420–17 800 €/(kg_{H2}/h).

3.4 Transportation of hydrogen via pipeline

Hydrogen pipelines can be constructed essentially the same way as natural gas pipelines today. The diameter of the pipeline typically would vary between 500 mm and 1200 mm at the transmission level, with pressure being within the range of 50 bar to 80 bar (Wang et al. 2021). At a smaller scale, the diameter of existing pipelines is typically within a range of 250 and 300 mm, and operating pressures are 10–20 bar (Gupta et al. 2016). As with LRC, hydrogen embrittlement necessitates additional planning in pipeline construction and operation to ensure structural integrity. To prevent embrittlement, as a solution the pipeline system can be, e.g., coated to protect the inner layer, or keep the operational pressure steady to avoid the formation of cracks. As a result, the investment cost for a newly built hydrogen pipeline is estimated to be 10-50% more expensive in comparison with a similar pipeline for natural gas. It should be noted, however, that methane, the main component of natural gas, carries three times more energy per unit of volume in comparison with hydrogen. The higher heating value of methane is 39.8 MJ/m^3, and for hydrogen the value is 12.7 MJ/m^3 (Engineering ToolBox 2003). The range variation depends on the pipeline diameter: the larger the pipe diameter, the lower the range. Alternatively, existing natural gas pipelines can be retrofitted for hydrogen transmission with little modification, as pipeline materials generally are already suitable for hydrogen transport. This way, repurposing natural gas pipelines are estimated to correspond to 10-25% of the investment cost of newly built dedicated hydrogen pipelines (Wang et al. 2021).

Gas flow in the pipeline is the result of pressure difference. The required pressure depends on characteristics such as elevation, friction loss, required pressure on the demand side, and properties of the gas transported. To keep the pressure at the required level, the gas is compressed periodically along the pipeline. Like required pressure, compressor capacity and compressor station distance are dependent on pipeline characteristics. Two currently used compressor types in gas transmission are reciprocating and centrifugal compressors. The reciprocating compressor injects gas into a cylinder, where the gas volume is reduced by compressing the gas with a piston. A centrifugal compressor utilizes the centrifugal force of rotation to convert the kinetic energy of radial blades into pressure, which compresses the gas flowing through the compressor. As discussed in Chapter 3.3, hydrogen compression requires more energy than natural gas due to its low density. In comparison with natural gas, a three times greater volume of hydrogen is required to deliver the same energy content. Consequently, the cost of compression has a greater role in the overall cost of the pipeline transmission system when the transport medium is hydrogen. Hence, careful compressor sizing is crucial in the overall system cost-optimization. (Wang et al. 2021). Generally, the distance between two compression stations is 80-100 km (Gupta et al. 2016).

Current hydrogen pipelines in Europe vary in length, pipe diameter, and operating pressure. For example, in Belgium, a pipeline of 80 km with a diameter of 150 mm operates at 100 bar, while in Germany, 220 km long and one of the oldest hydrogen pipelines has a diameter of 100–300 mm with an operating pressure of 2 bar. Like power lines, gas pipelines are divided into transmission and distribution networks, where the first-mentioned is characterized by larger pipe diameter and higher operating pressure (Gupta et al. 2016). Moving from transmission to distribution network, the gas pressure must be regulated in a pressure reduction station to meet the required equipment pressure of the end-user (Gasgrid Finland Oy 2022a). Besides conveying hydrogen from the producer to the supplier, a gas pipeline can also provide storage capacity by utilizing the operating pressure range within the pipeline. When the production of gas exceeds demand, surplus gas can be injected into the pipeline by increasing the pressure. This process is called line packing. (Gupta et al. 2016)

A substantial share of the costs related to a hydrogen pipeline is associated with the complexity of the installment and the securing of land access rights, rather than the pipe and its composition per se (Gupta et al. 2016). The costs of a hydrogen pipeline with the same length and diameter can differ substantially depending on the location it is constructed.

3.5 Technology summary

Among the technologies presented in this chapter, liquid hydrogen, salt cavern, LRC and LOHC were chosen for qualitative comparison. The result of the comparison is presented in Table 2. Salt cavern can be considered as a technology with full maturity, and it is also the most used technology both in this comparison but also globally among all hydrogen storage technologies. Salt is naturally inert to hydrogen, and it forms an air-tight structure when exposed to pressure. Additionally, salt cavern is linked with high hydrogen purity, albeit microbial side effects cannot fully be ruled out, especially in long-term storage. In this sense, LRC is likely to sustain higher hydrogen purity due to the thorough sealing of the cavern. LOHC is also considered to release hydrogen with high purity, although some purification may be required depending on the end-use of the released hydrogen. Among the technologies, liquefied hydrogen is linked with the highest hydrogen purity and the second-highest TRL for large-scale applications after salt caverns.

Liquefied hydrogen was deemed to be more suitable for transportation applications, where high priority is given to storage density. For stationary storage purposes, liquefied hydrogen is likely to be too energy-intensive with the requirement of constantly cooling the storage, as well as high losses compared to the other technologies due to boil-off.

Underground storages are associated with high upfront investment costs and low operational costs, whereas operational cost has more significant weight in the lifetime cost of LOHC technology. As salt caverns can be constructed from above ground by leeching, salt cavern is associated with lower investment cost than LRC. A clear hindrance for both salt cavern and LRC are the geological restrictions: salt formations are not uniformly distributed throughout the globe, and LRC requires a stable and strong rock mass. However, construction of salt caverns is strictly restricted to areas where salt formations occur, while LRC has slightly more degrees of freedom in locating as the thickness of the concrete wall, sealing and operational pressure range can be tailored to some extent depending on the rock mass properties. As the storage cavity is deep underground, both underground technologies are considered safe, salt cavern slightly more due to simpler construction.

The main drawback of LOHC technology is the high costs related to the technology, as mentioned in Chapter 3.4. Although hydrogenation is a well-known process in the chemical industry, dehydrogenation and the LOHC concept are yet to be demonstrated at a large-scale level. Thus, due to the incompleteness of the technology and multiple options for system setup (e.g., LOHC material, number of tanks, sourcing of heat for dehydrogenation), detailed cost estimation is difficult. Due to the relatively high hydrogen density of loaded LOHC and having no storage losses, but at the same time, the complexity of the technology and high reaction enthalpy, the main application for LOHC could be in long-distance transportation and import/export of hydrogen rather than on-site stationary storage. Nevertheless, LOHC technology possesses certain features, such as infrastructure compatibility, the ability to use cheap storage tanks, and the release of high-grade heat during hydrogenation, it is deemed an interesting storage option with future potential.

Table 2. Comparison of selected hydrogen storage technologies.

	Liquid H_2	**Salt cavern**	**LRC**	**LOHC**
Maturity	++	++	-	--
Safety	-	++	+	+/++
Investment cost	--	+	-	--
Operational cost	--	++	++	--
Purity of withdrawn hydrogen	++	+	++	+
Storage losses	--	+	++	++
Site limitations	+	--	-	++

Among the compared technologies, salt cavern is the most competitive option. However, when considering storage technologies feasible in Finland, salt cavern is not a possible application due to the lack of salt formations. Between the two technologies left, LRC was chosen for further assessment. The reasoning for choosing LRC over LOHC is that LRC possesses fewer uncertainties in technology development and thus, is expected to scale up for industry-level applications at a faster rate in near future. Additionally, literature sources provided more consistent information about the costs of LRC than LOHC, where price estimations varied greatly. Thus, more experience would be needed for LOHC for a sensible techno-economic assessment.

4 HYDROGEN STORAGE SELECTION CRITERIA

4.1 Rationale

The ambition to reduce GHG emissions suggests larger adoption of electrolysis in hydrogen production. Additionally, with an increasing share of VRE in the energy mix, power regulation becomes more challenging due to inaccuracies to forecast VRE production. Consequently, electrified - either directly or indirectly - industrial processes are exposed to variation in both availability as well as the value of electricity. For the latter problem, power purchase agreements (PPA) of renewable electricity can provide predictability to the electricity price levels. Although being possibly a sensible option against grid-only electricity sourcing, PPAs are not studied in this thesis. Storing hydrogen at off-peak times may potentially improve the economic feasibility of hydrogen production and consequently, hydrogen-using processes. On the other hand, during times of a low electricity price, it is feasible to produce hydrogen in excess to charge the storage. By storing excess hydrogen during the off-peak period and using it later instead of operating electrolyzers with a constant output, the average operational expenditure (OPEX) of hydrogen production may be lowered. In this connection, the primary objective of hydrogen storage is to decrease the Levelized cost of hydrogen (LCOH).

Based on the technology comparison in Chapter 3.6, LRC was believed to have the greatest potential to serve as hydrogen storage in near future in Finland. To assess the functionality and economic impact of the storage on the LCOH, a model to simulate the dynamic behavior of a LRC was established. In the model, the storage performance is compared to a hydrogen consumption scenario where no storage exists. The premise of the assessment is that hydrogen production and consumption exist, whether there is a storage facility associated with the system, and thus, the evaluation is done in relation to the baseline scenario. The variables of particular interest were the effect of storage size, operational hours of the storage, and electricity price data used. The scenarios are established in Chapter 4.2, followed by the description of the methods and parameters used for economic assessment in Chapter 4.3. Chapter 4.4 describes the principles and technical parameters of the simulation model.

4.2 Scenario definition

To assess the economic feasibility of hydrogen storage in industrial processes, the starting point was to establish a consumption scenario. The consumption scenario aims to imitate a prospective near-future industrial use of hydrogen, for which the storage and its operating model were then designed. The activities are assumed to take place in the year 2030. This thesis uses the steel mill in Raahe, Finland, owned by SSAB AB, as the end-user of hydrogen. SSAB has set up a target of decarbonizing its steel production, and one means for decarbonization is to replace the blast furnace (BF) process with hydrogen direct reduction (H-DR). The H-DR process uses hydrogen to reduce iron ore to sponge iron, from which steel can be produced in an electric arc furnace. The production of direct reduced iron (DRI), which is the product of the H-DR process, is estimated to be 1.3 Mt/a. This in turn requires hydrogen flow of approximately 116 000 Nm^3/h, or 10 541 kg/h. Assuming the PEM electrolyzer power demand to be 55 kWh/kg_{H2}, including both water electrolysis and other electricity consumption of the plant, the required electrolyzer capacity is 580 MW (Lappalainen 2020). In this thesis, this electrolyzer capacity is referred to as electrolyzer base capacity (EBC). The electrolysis process is assumed to be operational 8760 h/a. Given that all hydrogen required by the process is supplied by water electrolysis, the operational cost of hydrogen is dictated by the cost of electricity. This thesis assumes that the H-DR process is operated continuously with fixed hydrogen demand, for which the demanded hydrogen is supplied by continuously operating EBC, which produces hydrogen on-site. This constitutes the base scenario in this thesis. To assess the economic impact of hydrogen storage, this base scenario is modified so that in addition to the EBC, a LRC storage is integrated with the production. Consequently, with hydrogen storage in the system, ramping down hydrogen production must be compensated by delivering an equivalent amount of hydrogen from the storage. To charge the storage while still delivering a constant amount of hydrogen to the process, the system requires electrolyzer capacity that is higher compared to a situation without hydrogen storage. Hence, the storage is associated with electrolyzer overcapacity (EOC) that is dedicated to charging the storage. An additional matter of interest in this thesis is the benefit of utilizing the heat produced by the electrolysis. Thus, the location of the storage and electrolyzers are varied between Raahe and Oulu, a major city in Northern Finland with a population of nearly 210 000 (City of Oulu 2022), approximately four times the population of Raahe. A summary of these variable options as well as their descriptions is presented in Table 3. Figure 5 presents the locations of both cities and consequently, the storage location options, as well as the 440 kV and 110 kV electricity transmission grid lines. The purpose of selecting SSAB and H-DR process as the consumer is to simulate a possible use case for hydrogen in the future.

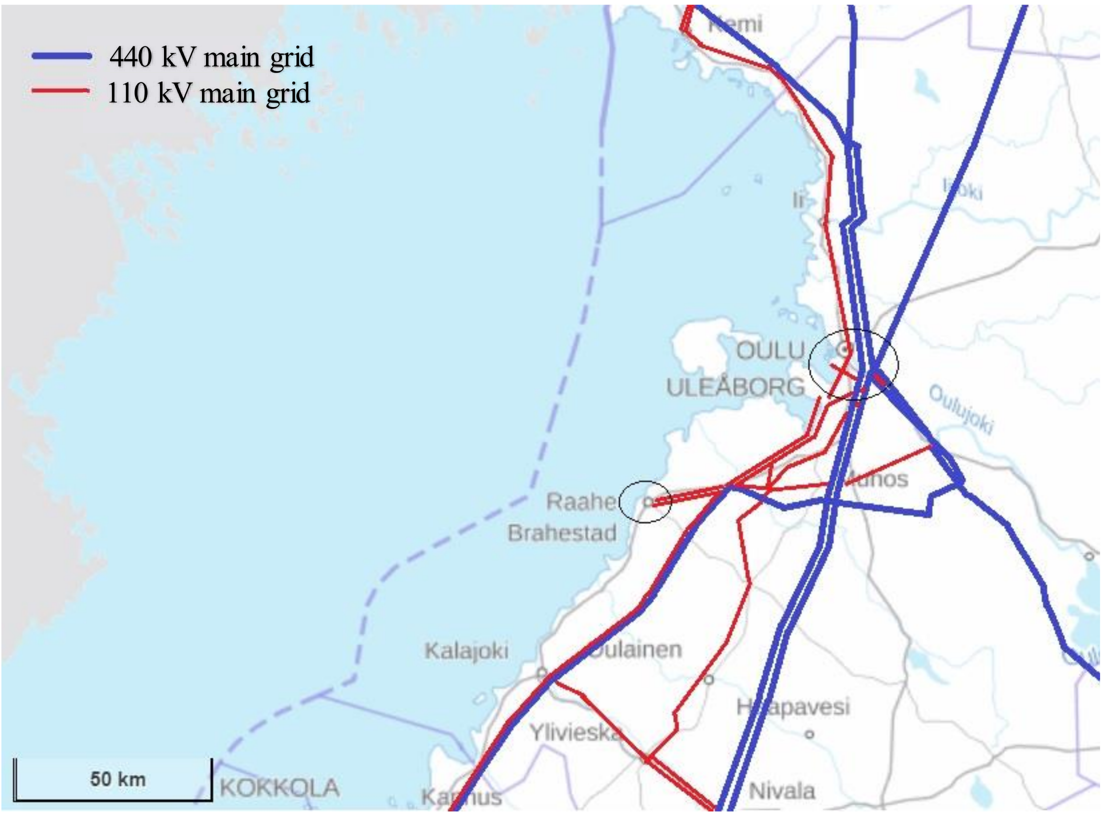


Figure 5. Storage locations (circled) illustrated with approximate lines of 440 and 110 kV main grid (adapted from Fingrid 2022; Maanmittauslaitos 2022).

Table 3. A summary of scenario variables. EBC and EOC denote electrolyzer base capacity and electrolyzer overcapacity.

Scenario	Description
Base	- Constant hydrogen production and supply with 580 MW EOC in Raahe - No storage
Production and storage in Raahe	- Constant hydrogen supply, production from EBC and EOC - Part of EOC ramped down when hydrogen is withdrawn from storage - Both EBC and EOC are operating during storage injection
Production and storage in Oulu	- Constant hydrogen supply, production from EBC and EOC - Part of EOC ramped down when hydrogen is withdrawn from storage - Both EBC and EOC are operating during storage injection - Hydrogen transported to Raahe via pipeline
Production and storage in Oulu, heat sold	- Constant hydrogen supply, production from EBC and EOC - Part of EOC ramped down when hydrogen is withdrawn from storage - Both EBC and EOC are operating during storage injection - Hydrogen transported to Raahe via pipeline - Generated heat sold to district heat network

4.3 Economics of hydrogen storage

The costs related to hydrogen storage consist of the investment cost of the storage, costs related to charging, and costs related to releasing the hydrogen from the storage. To assess the investment cost to build the storage system, an annualized capital expenditure (CAPEX) [€/a] is calculated as in Equation 1:

$$CAPEX = (IC_{Storage}) * a_{n,Storage} + (IC_{EOC}) * a_{n,EOC} + (IC_{EBC}) * a_{n,EBC} \quad (1)$$

where $IC_{Storage}$, IC_{EOC} and IC_{EBC} refer to investment costs (IC) of building a hydrogen storage and the electrolyzer capacity divided into EOC and EBC. Factors $a_{n,Storage}$, $a_{n,EOC}$, and $a_{n,EBC}$ represent annuity factors, also called capital recovery factors, which are used to amortize the investment costs over the lifetime of the plant (Kobos et al. 2020). The annuity factor is calculated in Equation 2 by using the weighted average cost of capital (WACC) and the plant lifetime (n) as in (Decker et al. 2019):

$$a_n = \frac{(WACC + 1)^n * WACC}{(WACC + 1)^n - 1} \tag{2}$$

As the storage technology is LRC, the investment cost is calculated based on (Papadias and Ahluwalia 2021), where the investment cost was estimated for a LRC with a storage capacity of 500 t H_2 The breakdown of costs of an LRC with a maximum pressure of 250 bar and volume of 30 925 m^3 is presented in Table 4. For storage volumes considered in this thesis, each cost component was scaled using Equation 3 (Moore 1959)

$$IC_i = IC_0 * \left(\frac{S_i}{S_0}\right)^k \tag{3}$$

where IC_i denotes the investment cost of the unit, IC_0 the known investment cost of the reference unit, S_i and S_0 denote unit capacities of the new and known units, and k is the scaling factor. The k values used for cost components are presented in Table 4. For liner, concrete, cushion gas, and land cost, no economies of scale were assumed.

Table 4. Capital costs of LRC with maximum pressure of 250 bar broken down (Papadias and Ahluwalia 2021). The cost components are scaled according to scaling factor k.

Component	USD/kg_{H2}	k
Shaft	11.2	0.6
Dome	15.6	0.6
Liner	3.9	1
Concrete	3.6	1
Total underground costs	**34.3**	
Engineering	5.1	0.6
Contingency	3.4	0.6
Permitting	1	0.6
Geological survey	2.3	0.6
Total other costs	**11.8**	
Compressor	8.5	0.9
P&I, valves	2.7	0.6
Cushion gas	0.3	1
Land cost	0.6	1
Total aboveground costs	**12.1**	
Total costs	**58.2**	

For the compressor, the value of k was assumed to be 0.9 as in (Yang and Ogden 2007), and for the rest of the cost components, a generic k value of 0.6 was assumed based on (Moore 1959). The costs were converted into euros by using an USD/EUR exchange rate of 0.92 from April 2022 (European Central Bank 2022).

An alternative approach to estimate the investment cost of an LRC based on storage dimensions is presented by (Žlender and Kravanja 2011) as in Equation 4:

$$IC_{LRC} = L_t \cdot \left(C_{t,exc} + C_{t,prot}\right) + V_{cav,exc} \cdot C_{cav,exc} + A_{cav} \cdot \left(C_{cav,prot} + C_{cav,drain}\right) + A_{steel} \cdot C_{steel} + V_{conc} \cdot C_{conc} + C_{ag} + C_{ug} \tag{4}$$

where C_{ag} and C_{ug} together form a constant sum that includes engineering, gas pipeline, gas station, compressor station, project management, design and control (Žlender and Kravanja 2011). The abbreviations are explained in Table 5.

Table 5. Explanation of variable abbreviations from Equation 4.

Cost variable	Abbreviation
Aboveground works [€]	C_{ug}
Underground works [€]	C_{ag}
Tunnel excavation cost [€/m]	$Ct_{,exc}$
Tunnel protection cost [€/m]	$Ct_{,prot}$
Cavern excavation cost [€/m^3]	$C_{cav,exc}$
Cavern protection cost [€/m^2]	$C_{cav,prot}$
Cavern drainage cost [€/m^2]	$C_{cav,drain}$
Cavern wall concrete cost [€/m^3]	C_{conc}
Steel lining cost [€/m^2]	C_{steel}

The investment costs calculated based on Equation 4 and the values of Table 4 are 35.3 M€ and 19.3 M€ for a LRC with the volume of 40 000 m^3. If the two approaches are compared, the approach by Papadias and Ahluwalia (2021) communicates aboveground costs in a more detailed manner, while Žlender and Kravanja (2011) present the same costs as a fixed sum without further detail. Additionally, the latter does not mention land cost or costs of cushion gas in underground costs. Figure 6 presents the breakdown of comparable LRC underground costs of the two approaches. The columns do not include all costs related to the LRC construction, but the components that can be compared. The approach by Papadias and Ahluwalia (2021) emphasizes the cost of cavern excavation, tunnel, and cost of concrete, while Žlender and Kravanja (2011) give more weight to the cost of steel lining. The results of the LRC investment cost calculation are shown in more detail in Appendix 1.

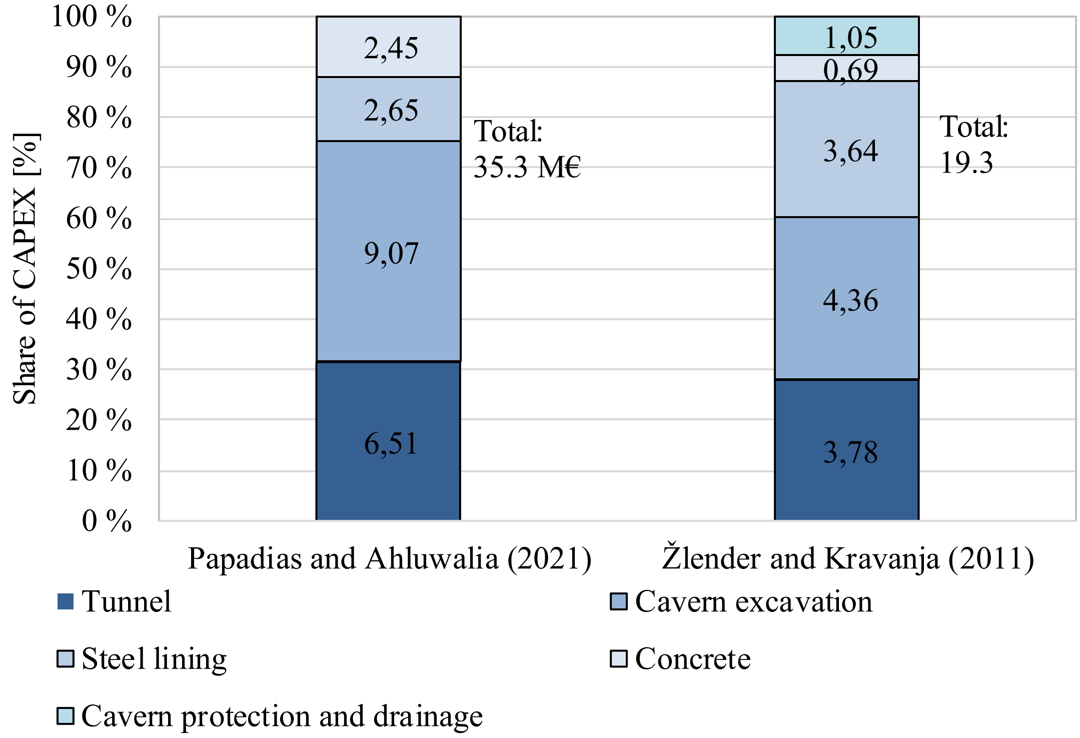


Figure 6. Breakdown of LRC underground costs of two calculation methods. The costs (in M€) of different components are displayed inside the columns, while proportional shares can be read from the y-axis. Note that the columns do not include all costs related to LRC construction, but components comparable between the two approaches. Total costs are displayed on the right side of the columns.

The feasibility of hydrogen storage can be assessed by comparing the system investment and operating costs with hydrogen storage to the situation where no storage exists. A higher storage capacity and larger EOC generally increase the investment cost, but on the other hand, they reduce the production cost of hydrogen more efficiently (Andersson and Grönkvist 2021). A hydrogen storage is considered profitable if it can reduce the hydrogen production OPEX so that it at least makes up for the CAPEX of the storage and EOC, fixed OPEX costs, as well as storage OPEX (Andersson and Grönkvist 2021).

Changing the hydrogen production and storage location from Raahe to Oulu necessitates implementing a transportation mode in the system. Gas transmission via pipeline was chosen as the method to be applied in this thesis. As mentioned in Chapter 3.5, the construction location may substantially affect the investment cost of the hydrogen pipeline. Due to the great influence of location, accurate cost estimation without comprehensive knowledge of the construction location characteristics is not possible. However, some cost estimation methods based on the pipe diameter and operating pressure can be found in the literature. To determine pipe diameter, the flow model of Equation 5 is used as in (Baufumé et al. 2013):

$$Q_{mass} = \rho \cdot v \cdot \frac{\pi \cdot D^2}{4} \tag{5}$$

where Q_{mass} is hydrogen flow in kg/s, ρ is the density of hydrogen in kg/m^3, v is the fluid velocity in m/s and D is the pipe diameter in m. Furthermore, (Baufumé et al. 2013) presented the pipeline IC as a second order polynomial function of the transmission pipe diameter as in Equation 6:

$$IC(D) = 4\ 000\ 000 \cdot D^2 + 598\ 600 \cdot D + 329\ 000 \tag{6}$$

A lower investment cost estimation for the pipeline can be found in Appendix 1. According to project manager M. Simola and development engineer V. Partanen from Gasdrid Finland Oy (Personal communication, 10 May 2022), an assessment of capital costs of a hydrogen pipeline is accompanied by several uncertainties and site-specific variables, thus the final costs are a joint effect of several factors. The cost effect of routing, for example, can be significant, if the route has other infrastructure, such as undercrossings of roads, buildings, and high-voltage power lines. Furthermore, the need for recompressing stations is dictated by the transferable gas capacity and pressure fluctuation. Thus, a capital cost estimation based on pipe diameter is likely to have a considerable margin of error.

As the hydrogen production and storage system components mentioned in this chapter and Chapter 4.1 are varied and included in different manners to comprise various configurations, the cost structure and components between the configurations vary. To allow for a systematic comparison between the configurations, a levelized cost method was applied. Levelized cost of energy (LCOE) represents the average revenue per unit of generated energy that is required to cover the costs of building and operating the plant considering all the costs during the plant lifetime, as well as the total system output (Lai and McCulloch 2017). The general method to calculate LCOE is given in Equation 7:

$$LCOE = \frac{Costs\ over\ lifetime\ [€]}{Energy\ output\ over\ lifetime\ [kWh]} \tag{7}$$

In this thesis, the LCOE is modified and referred to as levelized cost of hydrogen (LCOH), expressed as in Equation 8

$$LCOH = \frac{CAPEX + OPEX - R_{Heat}}{\dot{m}_{H2}} \tag{8}$$

where, depending on the system configuration, CAPEX includes annualized investment costs of LRC, EBC, EOC, and pipeline, while OPEX includes variable and fixed operating costs of EBC, EOC, pipeline, and LRC. R_{Heat} denotes revenues from selling the heat generated in water electrolysis, and $\dot{m}_{H2}$ refers to the annual mass flow of hydrogen to the process in kilograms. LCOH is used as the metric to compare the scenarios in Chapter 5.

The values and intermediate results used in economic calculations described in chapter 4.4 are presented in Table 6. The approach based on (Papadias and Ahluwalia 2021) was used to determine the investment costs of LRC for five capacities presented in the table. Calculations related to storage, EOC, and pipeline dimensioning are presented in Appendix 1.

Table 6. Key numbers related to the economic assessment.

LRC		40 000	60 000	80 000	100 000	110 000 m³
Storage capacity	t_{H2}	740	1 110	1 480	1 850	2 030
Cushion gas	% of total gas	8				
IC	M€	35.3	47.2	58.2	68.6	73.6
Fixed OPEX	% of IC	0.5[1]				
Lifetime	a	30				
Electrolyzers						
EBC	MW	580				
EOC	MW	76	114	152	190	209
IC	€/kW	644[2]				
Fixed OPEX	% of IC	3[3]				
Lifetime	a	20[3]				
Pipeline						
IC	M€	59.5[4]				
	M€/km	0.74				
Fixed OPEX	% of IC	2[1]				
Length	km	80				
Pipe diameter	m	0.25				
Lifetime	a	40				
Operation						
H_2 demand	kg/h	10541				
Electrolyzer power demand	kWh/kg_{H2}	55				
Compressor power demand	kWh/kg_{H2}	1				
Heat selling price	€/MWh	21				
Other financial						
WACC	%	8[1]				
Grid service fees	€/MWh	3.47				

[1] (Sofregaz U.S. Inc and LRC 1999)

[2] Investment cost estimation in 2030 based on (IEA 2019)

[3] Chosen based on estimation of fixed OPEX between 2% and 5% and lifetime of 10-30 years in 2030 (Brynolf et al. 2018). Assumed to include one stack replacement.

[4] Includes 1 M€ pressure reduction station investment cost

4.4 Simulation model

To evaluate the operation of the LRC as well as the costs in the settings portrayed in Chapter 4.2, 46 scenarios in total were created and simulated in Python. The flowchart of the simulation model related to the storage operation is described in Figure 7, and the logic of the flowchart converted to Python code can be found in Appendix 2.

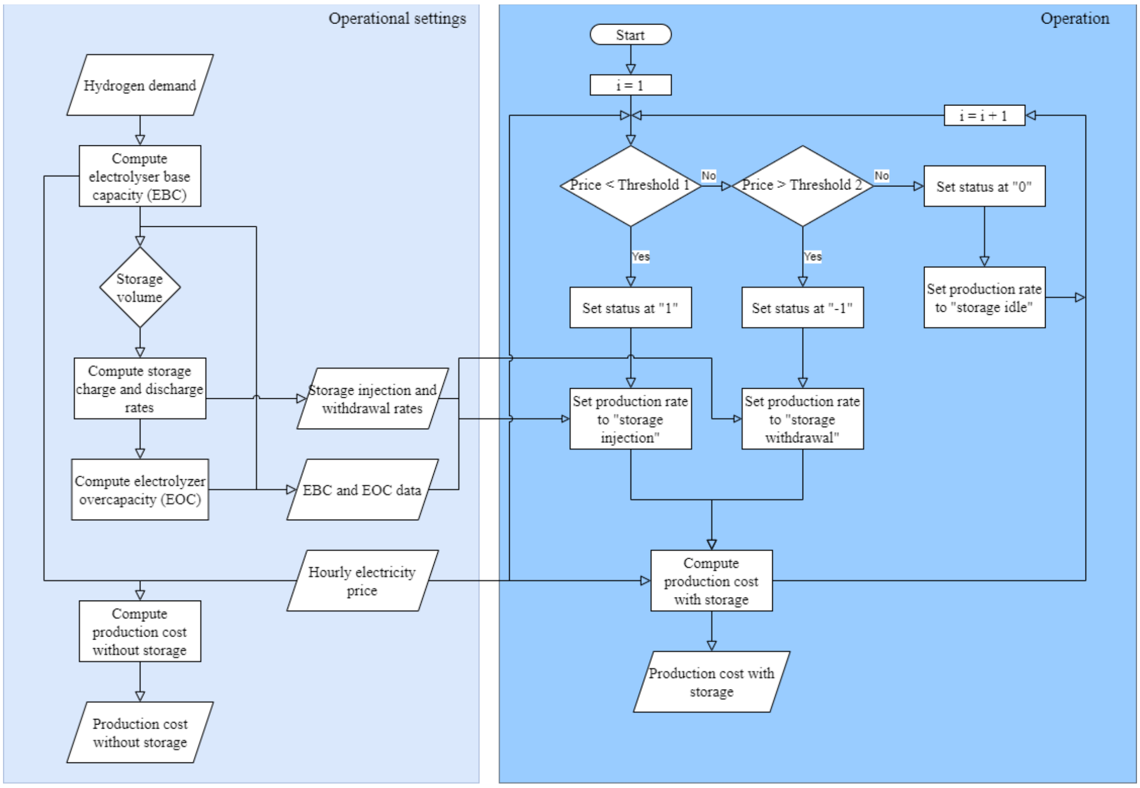


Figure 7. The flowchart of the simulation model.

The simulated hydrogen storage is LRC with storage volume ranging between 40 000 m^3 and 110 000 m^3. The storage is associated with EOC, for which the capacity is calculated by the injection and withdrawal rates of the storage. Assuming the mass flow rate of one-tenth of that of methane, the injection and withdrawal rates of hydrogen are estimated to be 1 300 kg/h and 3 600 kg/h for a Skallen-sized LRC, which is assumed to scale linearly with the storage volume (Kruck et al. 2013). From the relation between working gas capacity, which is assumed to be 640 t kg$_{H2}$ for Skallen-sized LRC, and injection and withdrawal rates in 40 000 m^3, the corresponding rates were derived for other volumes by multiplying the working gas capacity by 0.00203 and 0.00563. These injection and withdrawal constants were assumed to apply also in 250 bar, resulting in an injection rate of 1 380 kg/h and a withdrawal rate of 3 830 kg/h, when the working gas capacity of a 40 000 m^3 storage is 680.2 t kg$_{H2}$. Thus, one cycle lasts for 670 h, resulting in maximum number of charge cycles of 13.1/a.

The underlying operational principle for the storage operation is to define price threshold values based on set percentiles from the used hourly electricity price data. A limited foresight method over the production plan intervals is applied to the electricity prices. With the price data and defined threshold values, a production plan is created. The price threshold values are defined for a set time frame at a time, after which new threshold values are defined. For example, with monthly update mode, the price threshold values are updated every 730 hours. Depending on where the hourly price of electricity falls in relation to the price threshold values, every hour in the production plan gets assigned one of three different statuses: "1", "0" and "-1", which refer to "storage injection", "storage idle", and "storage withdrawal", respectively. Furthermore, based on the status of the hour, the EBC and EOC are set as active or inactive. In the basic situation, where the hourly price does not exceed the upper threshold nor fall below the lower threshold, only EBC is operating, and the storage fill level remains unchanged. When the hourly price falls below the lower threshold, i.e., the price of electricity is inexpensive enough, EOC activates and produces hydrogen to fill the storage. Interconnected with storage injection, electricity is consumed to compress the produced hydrogen. On the contrary, when the price exceeds the upper threshold, a capacity corresponding to the storage withdrawal rate is deactivated from the EBC, i.e., part of the hydrogen demand is supplied by the storage. As the withdrawal rate is nearly threefold in comparison with injection, consequently nearly three times higher rate of EBC is shut off compared to EOC and storage injection. Consequently, the lower price threshold value is set higher, including more storage injection hours.

Figure 8 presents an illustration of how the injection and withdrawal hours are determined based on the price of electricity within the set time frame. Hours on the left of the upper threshold are categorized as "storage withdrawal", whereas hours on the right of the lower threshold are categorized as "storage injection". By shifting the production weight towards the right side of the duration curve instead of operating with a constant output, the production cost of hydrogen decreases. The number of cycles is calculated from the production plan as well as injection and withdrawal rates. Thus, the threshold setting translates directly to the annual cycles of the storage, which is used as a measure of the operational activity of the storage in this thesis. The steps described above constitute OPEX related to the storage. The OPEX of EBC is calculated by multiplying EBC by the sum of the hourly price of electricity in the data. In addition to the hourly price of electricity, fees for transmission grid consumption (2.55 €/MWh) and output (0.92 €/MWh) are added to the operating cost (Fingrid Oyj 2022b). The price data used for the simulations are hourly prices in the day-ahead market for the years 2019 and 2021 in Finland. Figure 9 presents the day-ahead prices in the Finnish bidding area in years 2019 and 2021, and price duration curves plotted from the day-ahead data are shown in

Figure 10. As it can be observed from the figures, the years 2019 and 2021 represent two relatively different years in near history. The hourly price averages in the years 2019 and 2021 were 44.04 €/MWh and 72.34 €/MWh, respectively. In addition to the greater average price, prices were more volatile in 2021: the standard deviation was 15.28 €/MWh in 2019, while in 2021 the standard deviation was 65.99 €/MWh.

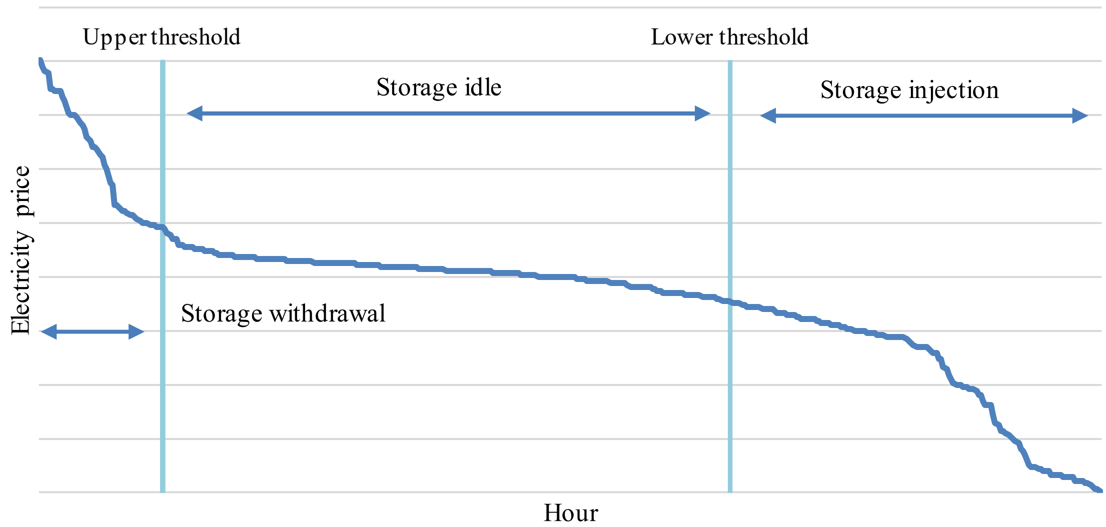


Figure 8. An illustrative example of how the price threshold values are defined using a price duration curve.

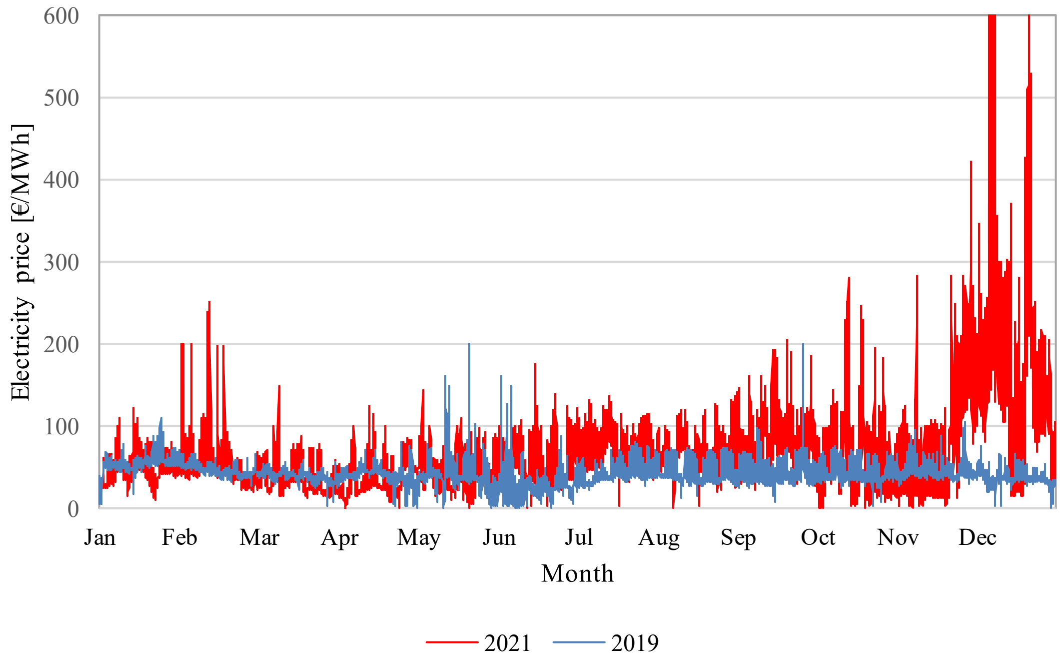


Figure 9. Day-ahead market prices for the years 2019 and 2021 in Finland. It should be noted that the y-axis is limited to 600 €/MWh for the sake of readability, which leaves out 18 hours when the price exceeded 600 €/MWh in 2021. The price data is acquired from (ENTSO-E 2022).

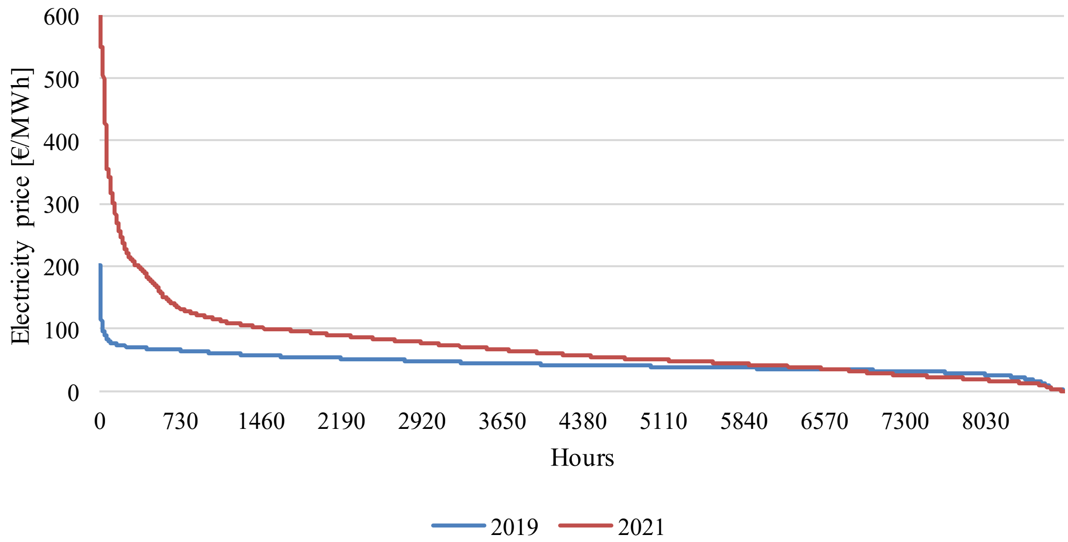


Figure 10. The historical price data of the years 2019 and 2021 expressed as price duration curves. The y-axis is limited to 600 €/MWh for the sake of readability.

Additionally, this thesis discusses the benefits of integrating electrolytic hydrogen production with heat production. The heat generated by electrolysis is calculated on an hourly basis, and assuming that all excess heat is sold to the return side of a district heat network for 21 €/MWh, the model calculates the revenue. The purchase price is derived from a Finnish energy company, based on the purchase price of heat fed to the return side of district heat network (Fortum 2022). The purchase price depends on the outside temperature so that higher price is paid for the heat during cold temperatures. The average outside temperature in Oulu is assumed to fall in the category "-0.9 – 4" °C. The return water temperature in the district heat network varies from approximately 30 to 55 °C depending on outside temperature, while the outgoing temperature ranges between 75 and 110 °C (Rämä and Klobut 2020). The increasing utilization of waste heat in the district heating network might decrease the outgoing temperature down to approximately 65 °C or below in the future (Rämä and Klobut 2020), which might denote higher revenues for waste heat sources. In this thesis, the heat is assumed to be sufficient for the return side, and the current purchase price for the appropriate temperature range is selected. The equations associated with heat calculations can be found in Appendix 2. Considering the possibility to sell the excess heat produced in the water electrolysis, it could potentially be viable to locate the electrolyzers near a heat sink. Thus, the potential economic impacts of locating the electrolyzer capacity in Oulu instead of Raahe are examined. For transmission between Oulu and Raahe, a pipeline with a diameter of 0.25 m calculated as in Equation 5 is implemented in some of the simulation scenarios. The diameter of the pipeline is sized for the throughput of all hydrogen consumed in the H-DR process.

The two locations, heat selling options, as well as production with or without storage constitute the parameter combinations, with the limitation that the location of storage is always the same as that of EBC's, along with the assumption that heat is only sold in Oulu. As a result, the overall costs of the systems are acquired. Table 7 presents how the variables are compiled to produce four different scenario configurations.

Table 7. Combinations considered in the simulation.

EBC location	Heat sold	Pipeline	Storage	Storage location
Raahe	0	0	0	No storage
Raahe	0	0	1	Raahe
Oulu	0	1	1	Oulu
Oulu	1	1	1	Oulu

To assess the effect of pipeline construction and selling of heat, storage is excluded from the first configuration. Within the combinations including a storage, three different annual number of cycles combined with five storage capacities yield 46 scenarios in total.

5 RESULTS

This chapter presents the results of the simulations. Chapter 5.1 presents the annualized CAPEX values of the hydrogen production and storage components, as well as their share of the LCOH. In Chapter 5.2, the operational results of the simulation are presented. The operational performance results are presented as OPEX values, first total annual OPEX results, followed by OPEX reduction compared to the base scenario. Additionally, the annual electricity consumption of the components is presented together with the total heat produced. Chapter 5.3 compiles the results from Chapters 5.1 and 5.2 and presents the weight of different cost components in LCOH. Chapter 5.3 also presents the difference in LCOH values between the scenarios. The contribution to transmission pipeline and heat sales is displayed in Chapter 5.4, followed by a sensitivity analysis, where electrolyzer investment cost and storage utilization rate are examined on a broader scale.

5.1 CAPEX of the system

The investment costs of the system are comprised of the storage, electrolyzers (divided into EBC and EOC), and pipeline. Annual CAPEX together with fixed OPEX for these components was calculated based on Table 6 in Chapter 4.3, and the contributions of these cost components per kg of hydrogen produced over a year are presented in Table 8. The table presents the costs for the smallest and largest storage considered in the simulation and shows that the cost structure is dominated by electrolyzer CAPEX. Even though underground storage technologies are characterized as having large upfront investment requirements (Teichmann et al. 2012), they are overshadowed by electrolyzer costs. It should be noted that EBC is present in all scenarios and is a separate investment from the storage. The annualized CAPEX for LRC for 40 000 m^3 and 110 000 m^3 storages are 3.1 M€/a and 6.5 M€/a, respectively, while EOC CAPEX are 4.9 M€/a and 13.7 M€/a. The increasing dominance of electrolyzers as the storage size increases is due to the less favorable scaling of the electrolyzers compared to LRC. For a LRC of 40 000 m^3, the cost of the pipeline is 50% higher than costs related to LRC. When the LRC capacity is 110 000 m^3, which has a withdrawal rate high enough to satisfy the whole hydrogen demand for approximately one week, the annual cost of LRC is 40% higher than that of pipeline.

Table 8. CAPEX of LRC, electrolyzers and pipeline, as well as the heat selling revenue per produced hydrogen kilogram for storages with capacities of 40 000 m^3 and 110 000 m^3, respectively.

Component	40 000 m^3	110 000 m^3	Unit
Pipeline	0.05	0.05	€/kg$_{H2}$
LRC	0.03	0.07	€/kg$_{H2}$
EOC	0.05	0.15	€/kg$_{H2}$
EBC	0.41	0.41	€/kg$_{H2}$

5.2 Operational performance of the storage

Figures 11 and 12 present the operation of the storage with the hourly electricity price over the simulation period. In the figures, the storage operation is presented as a percentage of the maximum fill level. The figures show how the storage reacts to electricity price signals by charging during low prices and discharging during high prices. The effect of limited foresight is visible; as the model only calculates the price thresholds for the following 730 hours at a time, looking at the storage operating over a year, the storage seems to make decisions that contradict the objective of taking advantage of low electricity prices. This type of decision-making logic does not lead to maximal cost reductions in the simulation and omits strategic decisions, but it is deemed to represent a more realistic operation in comparison with the perfect foresight model. The attributes of the model are discussed more in detail in Chapter 6.

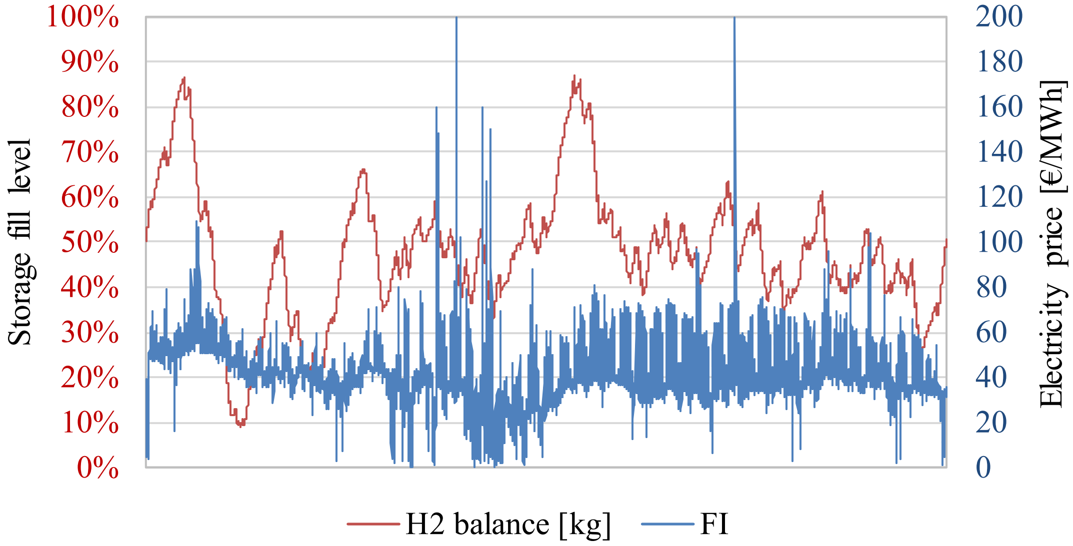


Figure 11. Storage balance with 55% utilization rate and day-ahead prices in 2019. The only parameter affecting the fill rate in the simulations is the utilization rate, thus the storage profile applies to all scenarios with the utilization rate of 55 %.

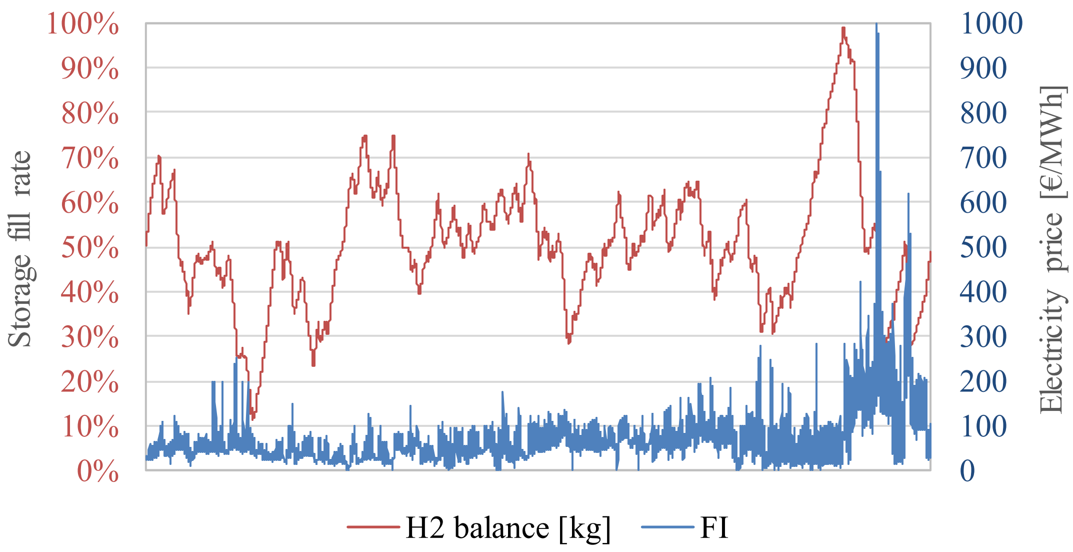


Figure 12. Storage operation with 55% utilization rate and day-ahead prices in 2021.

The OPEX values for different scenarios using price data for 2019 and 2021 are presented in Tables 9 and 10, where increasing utilization rate together with larger storage capacity can be observed to lead to decreasing OPEX. The left half of the tables display OPEX when the heat formed in electrolysis is not sold, and the right side shows the net OPEX, where the revenue from heat selling is included. It should be noted that the heat generation between scenarios over a year is constant and does not depend on other variables in the model. This is due to the fixed hydrogen demand in the model.

To allow for comparison between the two years, the absolute costs were converted to percentual reductions from the base OPEX, displayed as stacked columns side by side in Figures 13a and 13b, the first of which displays the reductions when the heat is not sold, while the latter includes heal selling revenues. The percentage related to the 19% utilization rate, i.e., the lowest bars on the chart, represents the absolute percentual reduction from the base OPEX, while bars displaying the reductions related to 38% and 55% utilization rates are additional reductions in OPEX. The figure shows that the decrease in OPEX is substantially greater in the year 2021, supporting the hypothesis that higher volatility in electricity prices increases the benefits of storage.

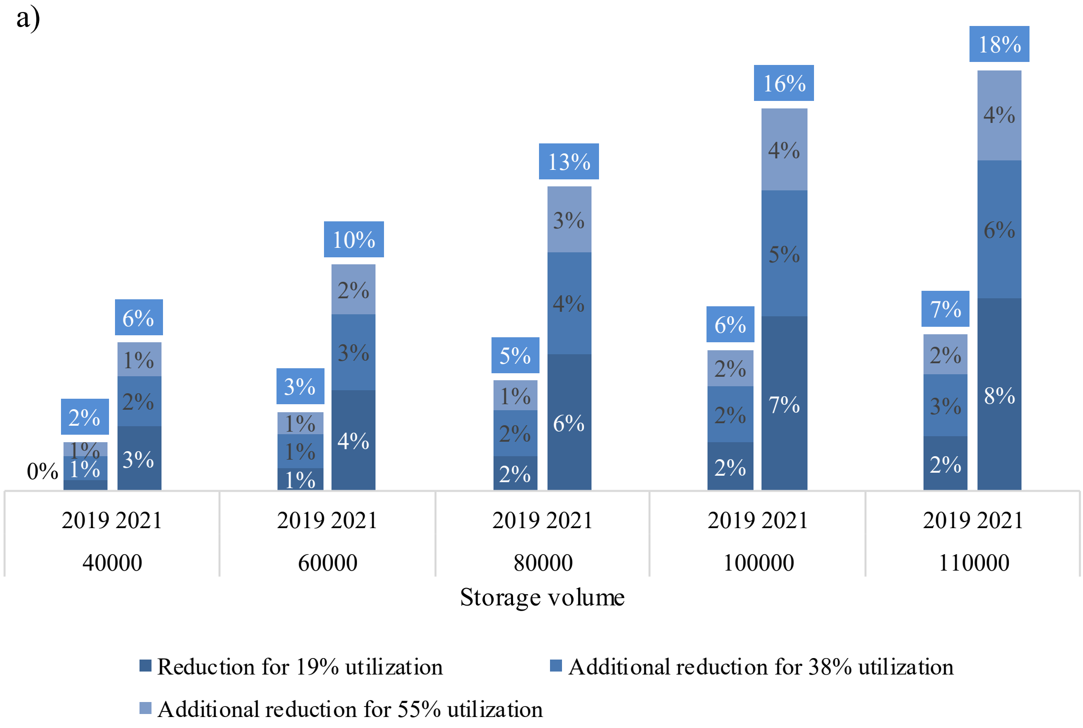
Table 9. Net OPEX (in M€) as a function of utilization rate of the storage for year 2019. Base value represents the OPEX without storage.

	Heat not sold			**Heat sold**		
Base	**252**					
Utilization rate → Volume ↓	55 %	38 %	19 %	55 %	38 %	19 %
40 000	247	249	251	234	236	238
60 000	244	246	250	231	233	237
80 000	241	244	249	228	231	236
100 000	237	241	247	224	228	234
110 000	236	240	247	223	227	234

Table 10. Net OPEX (in M€) for year 2021.

	Heat not sold			**Heat sold**		
Base	**396**					
Utilization rate → Volume ↓	55 %	38 %	19 %	55 %	38 %	19 %
40 000	371	377	385	358	364	372
60 000	358	366	379	345	353	366
80 000	345	356	373	332	343	360
100 000	331	345	367	318	332	354
110 000	325	340	363	312	327	351

a)



b)

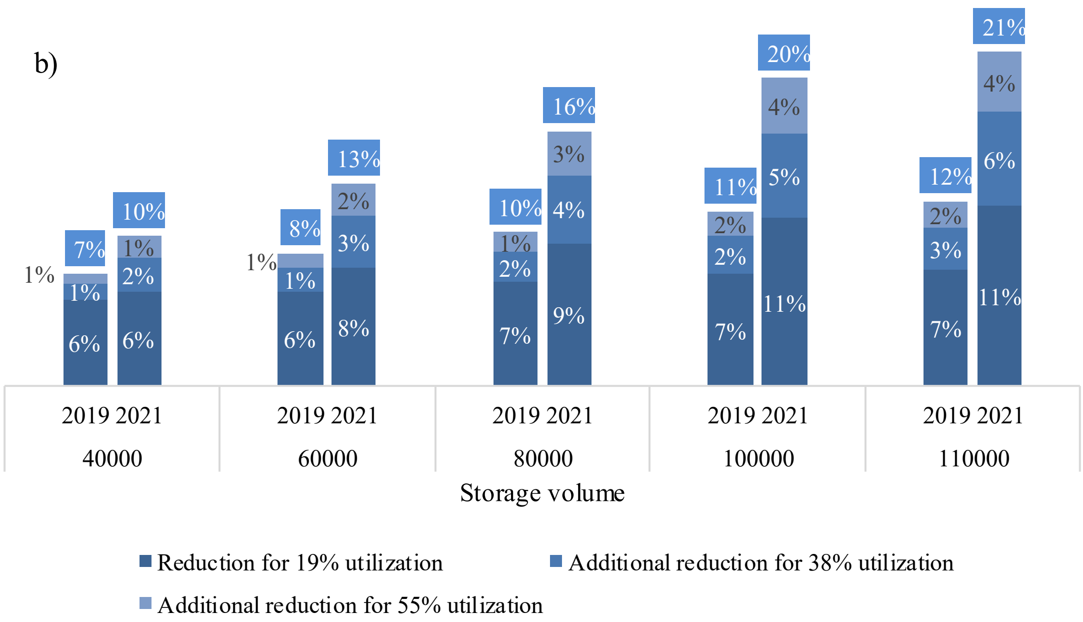


Figure 13. Reductions in OPEX, when heat is a) not sold and b) sold. The 19% utilization rate column represents the absolute OPEX reduction compared to the base scenario, while 38% and 55% utilization rate reductions are presented as additional percentual reductions relative to the previous value.

The electricity consumption by component is listed in Table 11. The total consumption of electrolyzers, 5 080 GWh, is divided between EBC and EOC so that the share of EOC increases as the storage capacity increases. The share of compressor in the total electricity consumption is small, 13 GWh at most, demonstrating that in comparison to hydrogen production via electrolysis, storing hydrogen in LRC requires rather a small amount of electricity.

Table 11. The annual electricity consumption of EBC, EOC and compressor, as well as annual heat production of the smallest and largest storages.

Parameter	Unit	40000 m^3	110000 m^3
EBC	GWh/a	4812	4345
EOC	GWh/a	267	734
Compressor	GWh/a	5	13
Heat production	GWh/a	641	641

5.3 Levelized cost of hydrogen

The CAPEX values constitute a minor part of the overall costs. If the costs related to the storage only, i.e., costs of LRC and EOC, are considered, the share is even smaller. The share of OPEX in LCOH is substantial: when CAPEX contributes between 0.54 – 0.68 €/kg_{H2} to the LCOH, the rest come from variable and fixed OPEX. The share of OPEX from the LCOH is 2.41–2.74 €/kg_{H2} using 2019 electricity price data, and 3.38–4.30 €/kg_{H2} using 2021 electricity price data. Thus, OPEX dominates the LCOH with 80% or more. More specifically, the OPEX of electrolysis dominates the total costs with the share ranging from 2.16–2.42 €/kg_{H2} (67–79% from LCOH) in 2019 and 3.12–3.98 €/kg_{H2} (74–86% from LCOH) in 2021. Tables 12 and 13 present the LCOH relative to the base scenario, where the cost of delivered hydrogen is 3.15 €/kg_{H2} using 2019 price data and 4.70 €/kg_{H2} using 2021 price data.

Table 12. LCOH presented as the difference from the base scenario (3.15 €/kg_{H2}) as a function of three different storage utilization rates. The price data used in this table was from the year 2019. The only scenarios where LCOH is below the base scenario can be found on the right side of the table within the scenarios where excess heat is sold.

	Raahe			**Oulu, no heat sold**			**Oulu, heat sold**		
Base	**3.15 €/kg_{H2}**								
Volume (m^3)	55 %	38 %	19 %	55 %	38 %	19 %	55 %	38 %	19 %
40 000	0.02	0.04	0.06	0.09	0.10	0.13	-0.05	-0.04	-0.01
60 000	0.02	0.05	0.09	0.09	0.11	0.15	-0.05	-0.03	0.01
80 000	0.02	0.06	0.11	0.09	0.12	0.18	-0.05	-0.02	0.04
100 000	0.02	0.07	0.13	0.09	0.13	0.20	-0.05	-0.01	0.06
110 000	0.02	0.07	0.14	0.09	0.14	0.21	-0.05	0.00	0.07

Table 13. LCOH values relative to the base scenario LCOH using price data from the year 2021.

	Raahe			**Oulu, no heat sold**			**Oulu, heat sold**		
Base	**4.70 €/kg_{H2}**								
Volume (m^3)	55 %	38 %	19 %	55 %	38 %	19 %	55 %	38 %	19 %
40 000	-0.20	-0.14	-0.04	-0.13	-0.07	0.02	-0.27	-0.21	-0.12
60 000	-0.30	-0.21	-0.07	-0.24	-0.15	-0.01	-0.37	-0.28	-0.14
80 000	-0.41	-0.29	-0.10	-0.34	-0.22	-0.04	-0.48	-0.36	-0.17
100 000	-0.52	-0.37	-0.13	-0.45	-0.30	-0.07	-0.59	-0.44	-0.20
110 000	-0.57	-0.40	-0.15	-0.50	-0.34	-0.08	-0.64	-0.48	-0.22

The results of 2019 imply that the only scenarios when the storage is competitive against the base scenario are the ones where the excess heat is sold. Furthermore, the storage utilization rate of 19% is not high enough to make the storage economically viable in comparison with the base scenario. The results also show that the LCOH increases with the storage volume. However, the difference in LCOH is small in all scenarios. Using 2021 price data yields larger differences in LCOH, as shown in Table 13. With that data, all scenarios except one yield lower LCOH compared with the base scenario LCOH. Moreover, 2021 price data resulted in greater dispersion in LCOH, up to 0.64 €/kg_{H2}, or 14%, difference from the base scenario, and instead of the results using 2019 price data, the LCOH decreases as the storage volume increases These results suggest that the OPEX strongly dominates the LCOH, and consequently, the price of electricity has a vast impact on the results. For example, the share of LRC from the LCOH is 2.3% with 2019 price data and 1.7% with 2021, when the storage size is 110 000 m^3 and the utilization rate is 55%.

5.4 The effect of location on the LCOH

As Table 8 in Chapter 5.1 shows, the contribution of the pipeline to the LCOH is 0.05 €/kg$_{H2}$. Siting the storage in Oulu is viable if the pipeline investment and fixed OPEX costs are compensated by revenues from selling the excess heat generated by the electrolyzers. According to the results, heat income is 0.14 €/kg$_{H2}$, compensating for the cost of the pipeline by a wide margin. Another aspect of the pipeline not considered in this thesis is the possibility to store hydrogen within the pipeline by altering the pressure. Utilizing the compressibility of hydrogen via line packing might improve the cost-effectiveness of the pipeline as the line can also serve as a buffer storage. Figure 14 presents the income from heat per kilogram of hydrogen produced as a function of the heat selling price. The two horizontal lines in the figure are pipeline CAPEX values calculated for the transmission line between Oulu and Raahe. The intersection of lines denotes the minimum price of heat that make up for the annualized CAPEX of the pipeline.

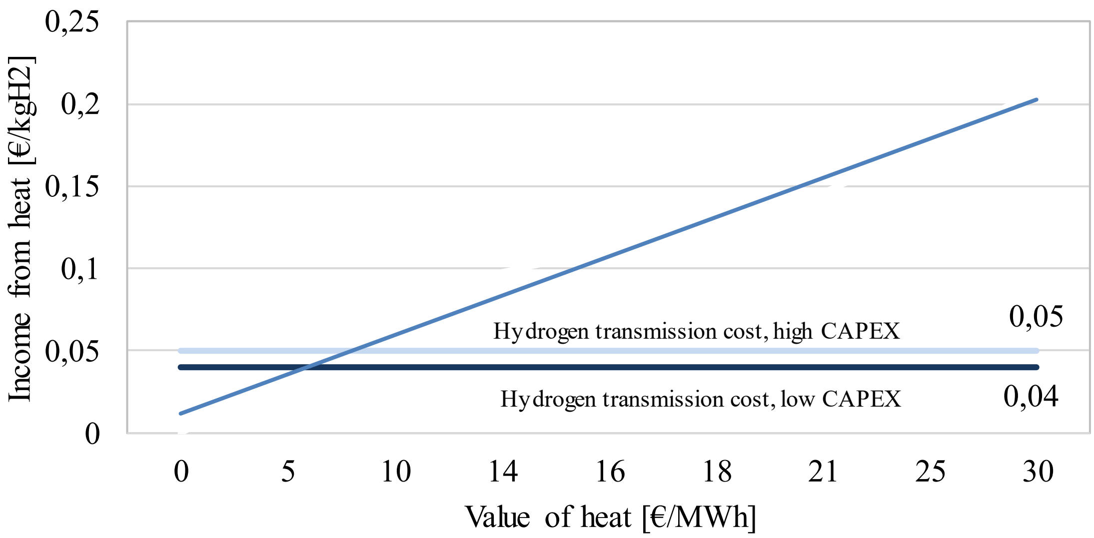


Figure 14. Heat income per kilogram of produced hydrogen as a function of heat price. Horizontal lines are the CAPEX values of the pipeline (€/kg$_{H2}$), and the intersection shows the minimum heat selling price that makes up for the annualized costs of the pipeline construction.

5.5 Sensitivity analysis

The setting of the simulations provides an insight into the effect of storage capacity and utilization rate on the LCOH. Additionally, it was found that regarding the system investment costs, electrolyzers comprise the largest share, approximately 80%. Being a significant cost factor, the investment cost of electrolyzer capacity was varied ± 20% from the original investment cost of 644 €/kW. The 20% change in investment cost led to 0.12 €/kg$_{H2}$ (3%) changes in LCOH, presented in Figure 15.

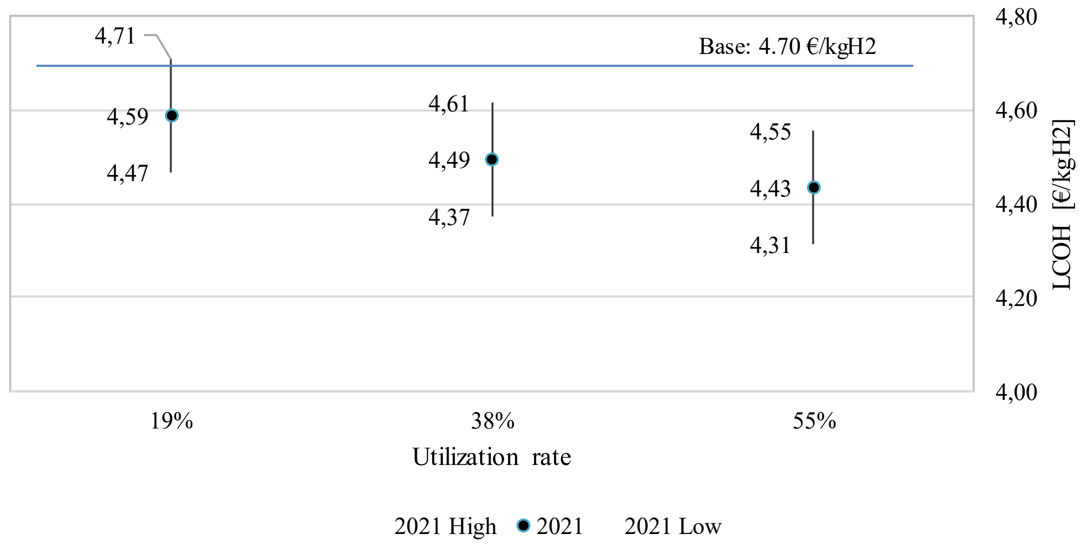


Figure 15. Changes in LCOH, when electrolyzer investment cost is increased and decreased by 20%. Both EBC and EOC IC were altered. The LCOH values are from 2021 scenarios where the production and storage are in Oulu, and the heat is sold.

The storage model does not recognize the storage limits, which allows excessive injection and withdrawal. Hence, the utilization rate was manually limited to 55%, or 7 cycles, to ensure that the storage balance remains within the range. However, simulations allowing exceeding the limits were conducted and compared with the results where the storage operation remained within the acceptable range. Figure 16 shows that storage fill level curves for utilization rates of 55% and 100% follow each other more consistently than the 19% and 55% utilization rate curves. This can be similarly observed in the net OPEX curves in Figure 17 and total cost curves in Figure 18, where the system experiences diminishing reductions in cost as the utilization rate increases. In the figures, utilization rates that are within the technical limits of the storage are displayed as continuous lines, and utilization rates exceeding the limits are displayed as dashed lines.

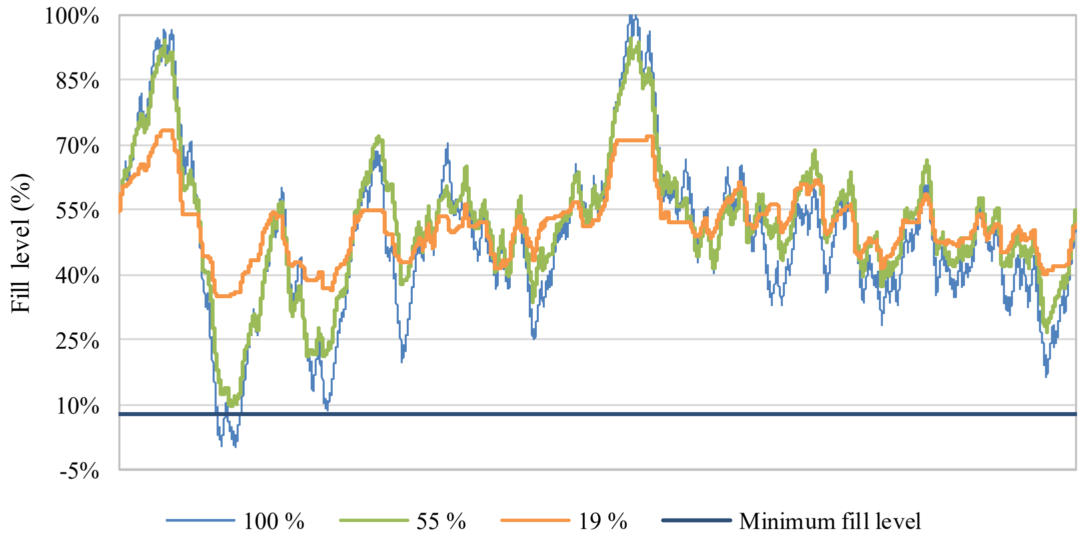
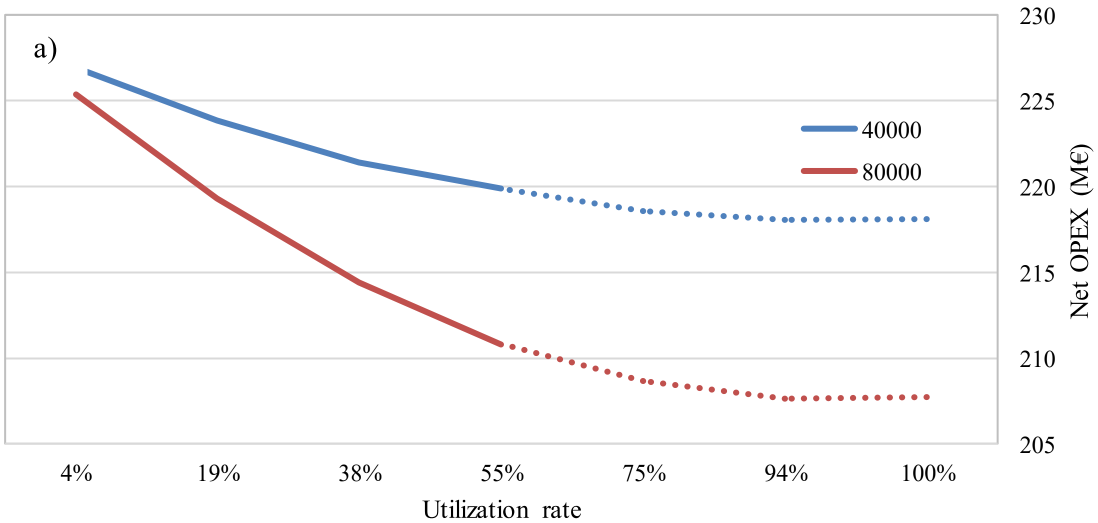


Figure 16. Storage operation in utilization rates of 19%, 55%, and 100%. As the model does not recognize storage limits, the utilization rate was manually limited to 55% to avoid under- and overfilling. The utilization rate of 100% is shown as a dashed line in the figure. The price data used is from the year 2019.



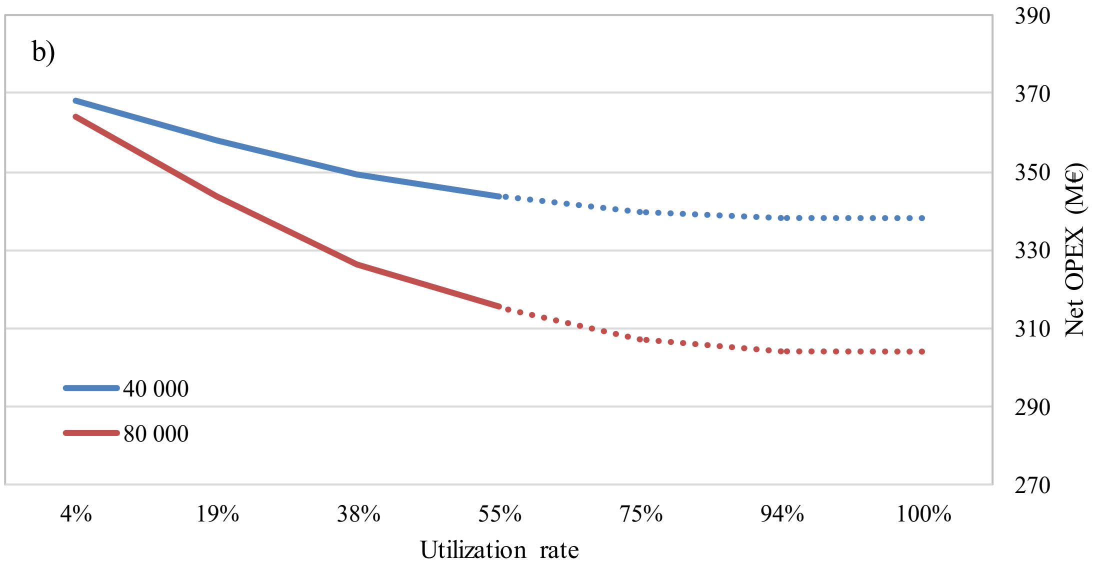
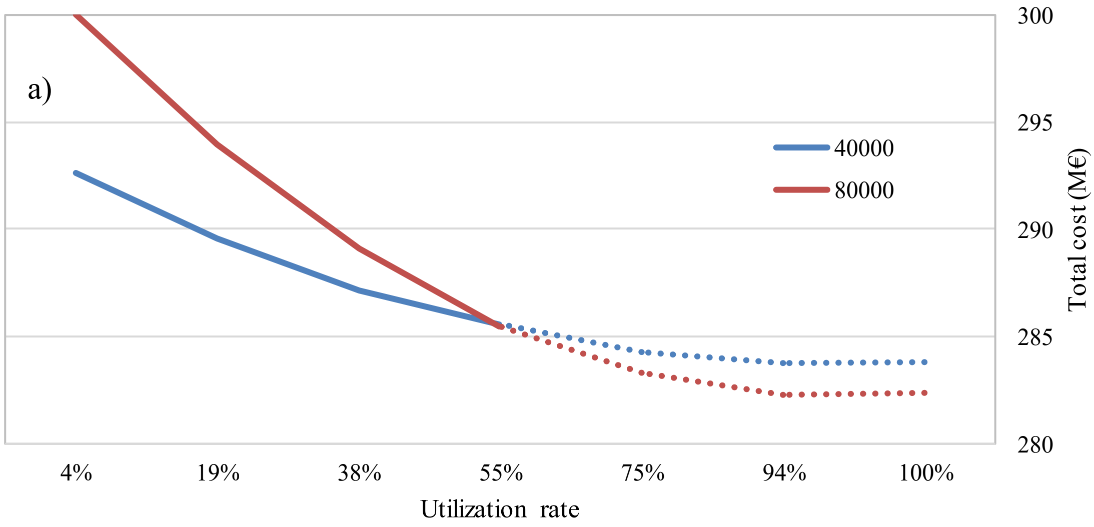


Figure 17. Net OPEX of the 40 000 m^3 and 80 000 m^3 storages using a) 2019 and b) 2021 electricity price data. Dashed lines denote utilization rates that lead to an exceeding of the technical limits in the storage fill rate.



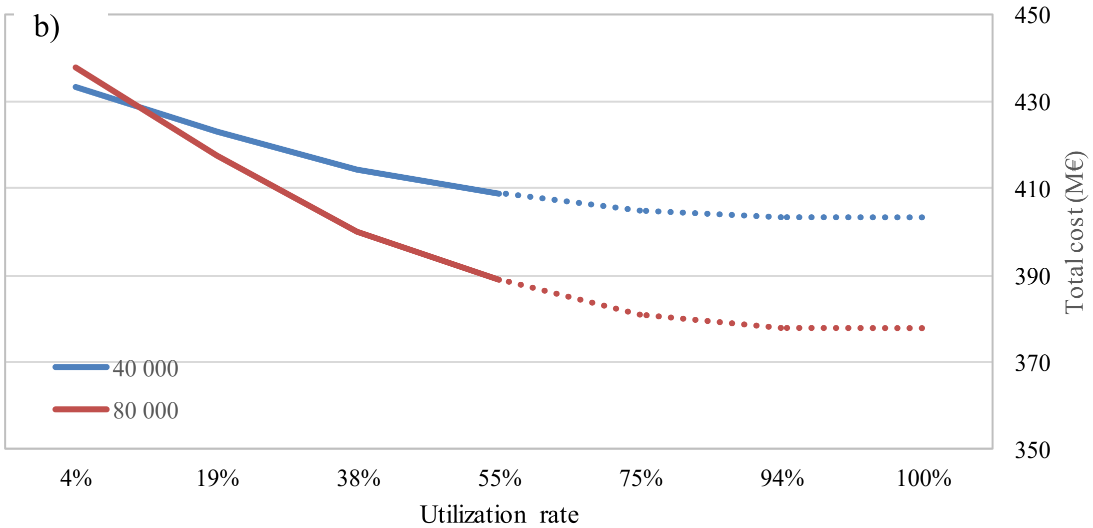


Figure 18. Total cost of the 40 000 m^3 and 80 000 m^3 storages using a) 2019 and b) 2021 electricity price data.

From the figures, it can be observed that increasing the utilization rate reduces the total costs of the system until 94%, after which the costs slightly increase. After that point, the OPEX of one additional hour of operation exceeds the cost reduction in hydrogen production, i.e., it is not economically feasible to increase the utilization rate of the storage further. Using 2021 electricity price data, the 80 000 m^3 storage reaches lower total costs than 40 000 m^3 storage, when the utilization rate is below 20%. Using 2019 price data, the total costs of the 80 000 m^3 storage decreased below the total costs of the 40 000 m^3 storage with the utilization rate above 55%. The results suggest that larger storage capacities have more favorable economics when the price volatility increases.

6 DISCUSSION

It is technically possible to store hydrogen in several ways, but only a few are viable for large-scale applications in their current states. Furthermore, salt cavern, which is the most used and economical hydrogen storage, is not an option in the Finnish context as no salt caverns exist in Finland. Liquefied hydrogen and LOHC technologies were ruled out of further assessment due to their better suitability for transportation applications rather than stationary storage. Liquid hydrogen storage would be a viable option as far as technology maturity for large-scale applications is concerned, but it is associated with complex operation and high energy demand. Apart from LOHC technology, this thesis did not study converting hydrogen to chemical hydrides. The economic performance of methanol as hydrogen storage has been studied by (Andersson and Grönkvist 2021). Among the technologies considered, the most attractive technology option was LRC. As a result, LRC was chosen for a more detailed study, and a LRC operation model was created, which was used to simulate the hourly operation of the storage facility as a part of steelmaking process over a one year.

The simulation results indicate that with the assumptions and price data used in this thesis, integrating a hydrogen storage into an industrial process can decrease LCOH up to 0.64 €/kg_{H2}, and that larger storage leads to greater reduction in LCOH. However, the volatility of the electricity price is a significant variable: the electricity prices of year 2019 with the standard deviation of 15.28 €/MWh led to marginal changes and principally increasing LCOH up to 0.13 €/kg_{H2}, or 0.05 €/kg_{H2} (2%) reduction at best while using the price data from 2021 with the standard deviation of 65.99 €/MWh yielded LCOH differences up to 14% in comparison with the base scenario. Out of 45 scenarios, 34 resulted in higher LCOH than the base scenario LCOH with 2019 prices, while 2021 price data resulted in 44 lower LCOHs out of 45. Thus, increased electricity price volatility makes the storage operation more profitable. The major contributor to the LCOH was electrolyzer variable OPEX, with the share of 67–79% of LCOH in 2019, and 74–86% in 2021. The share of CAPEX of all components was 0.68 €/kg_{H2} at the most. The share of LRC, 0.07 €/kg_{H2}, corresponds to 2.3% and 1.7% of the LCOH with 2019 and 2021 prices when the storage size is 110 000 m^3 and the utilization rate is 55%. The share of the pipeline was 0.05 €/kg_{H2}, which was outweighed by income from heat sales, which yielded 0.14 €/kg_{H2}. Figure 19 presents the breakdown of LCOH in the case of 110 000 m^3 storage with a 55% utilization rate. The results are in line with the findings of (le Duigou et al. 2017), where electrolysis was found to have over 80% share of LCOH, and salt cavern was found to have a small contribution to the total specific hydrogen cost regardless of the variation of electricity prices. LCOH decreased consistently as storage volume was increased, showing no change in the downward trend in LCOH. In the studied storage capacity range, increased capacity equals greater cost reduction, but the study should be extended further into larger capacities to find out the optimum. Additionally, configurations with more than one LRC cavern should be studied to clarify both the maximal technically viable storage size as well as the effect of dividing the same storage capacity into several caverns, for example using the methodology of (Žlender and Kravanja 2011).

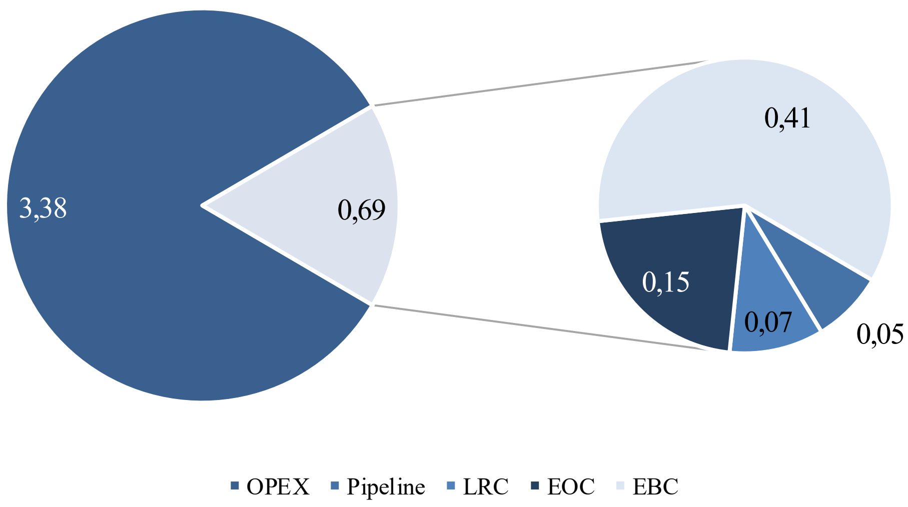


Figure 19. Breakdown of LCOH (in €/kgH2) for 110 000 m3 storage and 55% utilization rate.

The LRC storage must operate within a designed pressure range to avoid excessive mechanical stress applied to the cavern walls, as well as ensure adequate mass flow during injection and withdrawal. The maximal utilization rate that respected the calculated technical limitations of the LRC storage was 55%. For this reason, the simulations and techno-economic assessment mainly focused on utilization rates up to 55%. An additional factor affecting the resulting OPEX values is the used foresight. The length of foresight defines how far into the future the model can accurately predict electricity prices. In this thesis, the electricity prices were assumed to be known for 730 hours at a time, for which the price thresholds and operating strategy were established. It is not likely that detailed predictions of electricity prices can be made for such a long period. Shorter foresight is likely to lead to less optimal use of storage, however more realistic. Thus, it is important to develop algorithms to predict future electricity prices more accurately. The model presented in this thesis does not maximize the cost reductions in electrolytic hydrogen production. Additional savings may be gained by optimizing the production and storage operation. However, extending the simulations up to 100% utilization rate exhibited a diminishing reduction in total costs, suggesting that the most significant cost reductions could already be obtained with a utilization rate of 55%, and operation hours above that do not lead to substantial additional reductions.

The operation of the storage in the model was solely based on the hourly price of electricity, omitting other potential revenues, such as grid service provision and selling the oxygen formed in the electrolysis. The model assumed that the hydrogen production and storage system are price-takers, which denotes that electricity price profiles are not impacted by electricity consumption from hydrogen production. All consumed electricity was assumed to be purchased from the grid, omitting the possibility of bilateral contracts such as PPA. On one hand, purchasing even a part of the electricity at a pre-determined price would hedge the production against price risk, but on the other hand, limit the possibilities to create arbitrage. Because the price of electricity was shown to be the most important factor affecting the LCOH, future research focusing more in detail on the development of electricity prices and contract alternatives is suggested. Hydrogen storage systems with partial or full electricity sourcing from wind farms have been studied, for example, by (le Duigou et al. 2017) and (Langels and Syrjä 2021).

The model developed within the scope of this thesis does not comprehensively address all phenomena in the operation of the system. Losses, such as compressor leakages or degradation other than including one stack replacement in the fixed OPEX, were not included. Electrolyzers were assumed to turn on and off as well as ramp up without limitations, omitting minimum uptimes. As for the two storage locations, the bedrock quality is not clear, but it was assumed to be sufficient for cavern excavation. As the magnitude of the system created in this thesis is large and activities are assumed to be set in the year 2030, estimating and scaling the costs include considerable uncertainties. Due to limited experience in LRC technology, estimating the scale effect is challenging. Additionally, increasing technology maturity may result in decreased costs in the future. As for electrolyzers, the future CAPEX estimations in 2030 vary greatly in literature. However, the LCOH results are not sensitive to this type of variation as the CAPEX was shown to have a small contribution to the LCOH: varying the electrolyzer investment cost by ± 20% induced 3% changes in the LCOH.

The results imply that a large storage has better economic performance, regardless of whether electricity day-ahead prices from the year 2019 or 2021 were used. In other words, larger project sizes reach better cost-efficiency but require greater upfront investments. As LRC as hydrogen storage and the production-storage system studied in this thesis are concepts yet to be demonstrated, the market conditions must be right to facilitate an attractive investment case. An industrial consumer of hydrogen would guarantee stable and large long-term consumption, reducing investment risk (AFRY 2021).

Although the LRC model was created to simulate hydrogen production, storage, and delivery for the H-DR process, the simulation and assumptions are not tailored for steelmaking but can be deemed as generalized descriptions for any type of industry that uses hydrogen as a feedstock in continuous operation. This thesis focused on the industrial context and one producer and end-user, as well as performed a cursory examination of the benefits of integration with district heating. The property rights of this type of hydrogen production, storage, and transmission system of this extent are not very likely to be assigned to one entity. Hydrogen transmission pipeline infrastructure, for example, will be constructed and owned by a state-owned company Gasgrid Finland Oy. The company aims to construct a hydrogen transmission line covering the west coast of Finland so that the line would be in operation in the 2030s (Gasgrid Finland Oy 2022b; Kuokkanen 2022). For a more thorough assessment of hydrogen storage future business cases, it is important to assess the storage potential to provide ancillary services to the power sector, as well as identify the possibilities for synergistic gains with other markets, both for hydrogen and by-product heat and oxygen.

Another viewpoint is to expand the research to address the techno-economic aspects together with the regulatory framework and policies of the hydrogen-related business environment. This thesis did not categorize the grid-only hydrogen as grey, blue or green. At the time of writing this thesis, the revision of RED II was still ongoing. Thus, the criteria for hydrogen to be considered as 100% RFNBO were not implemented. While the requirement to use renewable energy in hydrogen production may seem straightforward, many projects may require power sourced from a wide mix of resources, making it possibly an unnecessary complex task to comply with the requirements of RFNBOs. For example, requiring power sourcing from additional renewable capacity may result in delayed hydrogen projects, if new dedicated renewable capacity must be built. The requirement for temporal correlation could lead to low utilization rates of electrolyzers as they can operate only when the renewable capacity is generating electricity. If the result of the revision is as described above, installing hydrogen storage would be an appealing solution, especially for industrial customers that require a continuous supply. Clear policies regarding green hydrogen as well as unambiguous definitions should be established to create a level playing field that does not hamper the development of the hydrogen economy.

This thesis studied the viability of hydrogen storage in a context where it is used as raw material, but the potential of hydrogen is more widespread: hydrogen may also have a role, e.g., as a transport fuel, or in power-to-hydrogen-to-power applications. However, the timelines for the adoption of hydrogen in these sectors are different. Industry is a probable sector to facilitate the first steps towards a large-scale hydrogen economy as the demand and technologies for hydrogen usage already exist.

7 CONCLUSIONS

This thesis reviewed different hydrogen storage technologies that could be applicable in large-scale hydrogen storage in Finland. The aim was to examine, how much storage can decrease the operation cost of hydrogen production in comparison with the cost of producing hydrogen without storage, as well as compare the LCOH between different scenarios. Another topic of interest was the benefits of selling the excess heat formed in the electrolysis process, for which scenarios with the hydrogen production and storage located near a heat sink were created.

It is technically possible to store hydrogen in numerous ways, but only a few technologies are suitable in Finland. After mapping the possible technologies, a dynamic simulation model to describe the dynamic performance of LRC storage as a part of the steelmaking process was created. The model can be deemed as a general description of any continuous industrial process that uses hydrogen as a raw material.

The results indicate that storage can decrease the LCOH compared to the base scenario if electricity price volatility is high enough. From the two price datasets used, only the simulations with price data characterized by greater price volatility led to lower LCOH in comparison with the baseline scenario, where no storage was included. Furthermore, the LCOH decreased as the storage volume increased when high volatility price data was used. Using price data with lower volatility, the results were the opposite: most scenarios resulted in higher LCOH than the base scenario, and the LCOH increased with the storage volume. The exact requirements of price volatility or price level to make a positive business case could not be defined in this thesis. The most significant contributor to the LCOH was the electricity consumption of the electrolyzers, while investment costs had a small contribution to the total cost. Furthermore, the revenue from annual heat sales was more than double the CAPEX of the transmission pipeline.

Based on the results, it is not possible to give a definitive answer if it is profitable to build hydrogen storage from the production cost reduction perspective. What can be deduced from the results, however, is that the electricity price development is of the utmost importance when the economic performance of hydrogen storage as a part of an industrial process is concerned. The results of this thesis can be used, for example, to support decision-making in production planning and price risk management in the industry.

The model created in this thesis has limitations and simplifications, but yields results that are in line with the previous research on the subject. A list of improvements to build on this model include;

- Modifying the foresight shorter to better reflect real-life decision-making
- extending the review on a broader set of storage capacities and configurations
- better inclusion of losses and degradation over the system lifetime
- assessment of the potential to provide ancillary services to the power sector
- synergistic gains with other markets
- including the limitations set by legislation.

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Table 1. Equation and values used to calculate LRC storage hydrogen mass capacity

Parameter	Value	Unit
Equation	$m_{gas} = \dfrac{PV_{gas}}{z \times 4124.18 \dfrac{Nm}{kgK} \times 298.15K}$	
P, max	250	bar
P, min	20	bar
V	40 000 – 110 000	m^3
z	1.1	

Storage volume	30 925	40 000	60 000	80 000	100 000	110 000
H2 max mass	500 000	739 324	1 108 986	1 478 648	1 848 310	2 033 141
Shaft	5 152 000	6 514 705	8 309 014	9 874 446	11 289 085	11 953 481
Dome	7 176 000	9 074 053	11 573 269	13 753 692	15 724 083	16 649 492
Liner	1 794 000	2 652 695	3 979 042	5 305 389	6 631 736	7 294 911
Concrete	1 656 000	2 448 641	3 672 962	4 897 282	6 121 603	6 733 764
Total underground costs	**15 778 000**	**20 690 093**	**27 534 287**	**33 830 809**	**39 766 506**	**42 631 648**
Engineering	2 346 000	2 966 517	3 783 569	4 496 399	5 140 565	5 443 103
Contingency	1 564 000	1 977 678	2 522 379	2 997 600	3 427 044	3 628 735
Permitting	460 000	581 670	741 876	881 647	1 007 954	1 067 275
Geological survey	1 058 000	1 337 841	1 706 315	2 027 788	2 318 294	2 454 733
Total other costs	**5 428 000**	**6 863 707**	**8 754 140**	**10 403 434**	**11 893 857**	**12 593 846**
Compressor	3 910 000	5 559 748	8 008 242	10 374 856	12 682 389	13 818 299
P&I, valves	1 242 000	1 570 509	2 003 066	2 380 447	2 721 476	2 881 643
Cushion gas	138 000	204 053	306 080	408 107	510 134	561 147
Land cost	276 000	408 107	612 160	816 214	1 020 267	1 122 294
Total aboveground costs	**5 566 000**	**7 742 417**	**10 929 549**	**13 979 623**	**16 934 266**	**18 383 383**
Total costs	**26 772 000**	**35 296 217**	**47 217 975**	**58 213 867**	**68 594 630**	**73 608 877**

Figure 1. LRC investment costs calculated using the approach by (Papadias and Ahluwalia 2021).

Parameter	Cost	Unit
Upper ground works	2982500	€
Underground works	2798025	€
C tunnel excavation	2440	€/m
C tunnel protection	1340	€/m

C cavern excavation	100	€/m3
C cavern protection	90	€/m2
C cavern drainage	60	€/m2
C wall concrete	190	€/m3
C steel lining	920	€/m2

Figure 2. Economic data of constructing LRC (Žlender and Kravanja 2011).

Storage volume	40 000	60 000	80 000	100 000	110 000
Tunnel	3 780 000	3 780 000	3 780 000	3 780 000	3 780 000
Cavern excavation	4 361 325	6 472 053	8 569 792	10 661 145	11 703 711
Cavern protection&drainage	1 052 008	1 209 165	1 456 338	1 687 206	1 794 697
Steel lining	3 641 731	4 740 031	5 774 283	6 630 725	7 081 144
Concrete	686 518	896 901	1 082 605	1 256 175	1 337 052
Investment cost	**19 302 107**	**22 878 675**	**26 443 543**	**29 795 776**	**31 477 129**

Figure 3. LRC investment costs calculated using the approach by (Žlender and Kravanja 2011).

Parameter	Value	Unit
H_2 density	3.949	kg/m3
Pipeline pressure, p	50	bar
Temperature, T	25	
Velocity, v	15	m/s
Mass flow, Q	2.93	kg/s
Diameter, D	0.25	m

Figure 4. Technical data for pipeline dimensioning.

$$IC_{low} = 2\ 200\ 000D^2 + 860\ 500D^2 + 247\ 500$$

	Distribution		Transmission		Unit
	Low	Upper	Low	Upper	
Pipeline cost	557 899	693 326	601 980	731 110	€/km
Pressure reduction station			1 000 000	1 000 000	€
Investment cost			**49 158 401**	**59 488 779**	€

Figure 5. Pipeline investment cost calculation equation and results for 80 km pipeline.

Parameter	40 000	60 000	80 000	100 000	110 000	Unit
H_2 mass	739 324	1 108 986	1 478 648	1 848 310	2 033 141	kg
EOC	76	114	152	190	209	MW
Investment cost, EOC	**48 906 648**	**73 359 972**	**97 813 296**	**122 266 620**	**134 492 960**	€

Figure 6. Electrolyzer overcapacity investment cost calculation results.

Parameter	Value
H2 cons	10541
H2 vol	116000
Electrolyzer cons	0.055
Compressor cons	1
Max press	250
Min press	20
Fill constant	0.00203
Disch constant	0.005625
Storage volume	40000
R	4124.18
Z	1.1
T	298.15
H2 dens	0.08375
e H2	142
MJ-kWh	0.277778
WACC	0.08
n LRC	30
n pipe	40
n electrolyzer	20
Transmission cost	3.47

Figure 1. Constants used in the simulation code.

```
import os
import pandas as pd
import numpy as np
import numpy_financial as npf

from matplotlib import pyplot as plt

FOLDER = os.getcwd()

CONSTANTS_PATH = "./constants250.xlsx"
ECON_CONSTANTS_PATH = "./econ_constants250.xlsx"
SYSTEM_DATA_PATH = "./elspot_2021.xlsx"
SCENARIOS_PATH = "./scenarios.xlsx"

TO_EXCEL = False # write results to Excel (set False if multiple scenarios)
TO_FIG = False   # create figures from the results
SINGLE = False   # study a single (True) or multiple (False) scenarios


#%% define functions for calculation

""" 1. Download technical raw data as well as electricity prices.
    Define the ratio between charge and discharge.
    Break the data into smaller sections, from which charging and discharging hours are selected.
    The hourly price data is sorted and based on maximum and minimum prices,
    an operating schedule is created.
    """

def get_data(excel_path: str, perc: float, storage: bool, to_excel=TO_EXCEL):

    df = pd.read_excel(excel_path)
    df.index = pd.date_range('2021-01-01', periods=8760, freq='1H', closed='left')
    df.reset_index(inplace=True)
    df = df.rename(columns={'index': 'Dates'})
    df = df.drop(columns=["Date", "Hours"])
    prices = df["FI"]

    if not storage:
        dispatch = [0] * df.shape[0]
    else:
        dispatch = []
```

```
        # production plan based on electricity price
        for n in range(0, 12):
            week = prices.iloc[n*730:(n+1)*730]
            threshold_up = week.quantile(perc)
            threshold_low = week.quantile((1-perc)*2.77)
            if threshold_up <= threshold_low:
                print("Warning: upper price threshold higher than lower threshold")

            for price in week:
                if price > threshold_up:
                    dispatch.append(1)  # withdrawal
                elif price < threshold_low:
                    dispatch.append(-1)  # injection
                else:
                    dispatch.append(0)
    df.insert(1, "Plan", dispatch)
    prod_plan = df[['Dates', 'Plan', 'FI']]
    if to_excel:
        prod_plan.to_excel(fr"{FOLDER}\prod_plan.xlsx")
    return prod_plan

""" 2. Define the operating principles: how is the electrolysis operated,
    what is the electricity consumption
"""

def define_production_capacity(df):

    # tänne myöhemmin myös LOHC-jutut (oma tiedosto vakioille)

    storage_volume = df['Storage volume']
    h2_cons = df["H2 cons"] # in kg/h
    h2_vol = df["H2 vol"]
    elyzer_cons = df["Electrolyzer cons"] # in MWh/kg H2
    compressor_cons = df["Compressor cons"]
    max_pressure = df["Max press"] # in bar
    min_pressure = df["Min press"] # in bar
    fill_const = df["Fill constant"]
    disch_const = df["Disch constant"]
    R = df["R"]
    Z = df["Z"]
    T = df["T"] # in K
    h2_dens = df["H2 dens"]
    e_h2 = df["e H2"]
    MJ_kWh = df["MJ-kWh"]
    ebc = (h2_cons * elyzer_cons) # MW
    max_mass = (max_pressure*100000*storage_volume)/(Z*R*T) # kg
    min_mass = (min_pressure*100000*storage_volume)/(Z*R*T) # kg
```

```python
    fill_rate = fill_const*(max_mass-min_mass) # kg/h
    discharge_rate = disch_const*(max_mass-min_mass) # kg/h
    if discharge_rate > h2_cons:
        print("Discharge rate over demand: replacing...")
        discharge_rate = h2_cons
    if bool(df['Storage']) is False:
        print("EOC set as 0")
        eoc = 0
    else:
        eoc = fill_rate * elyzer_cons
    settings = {
             "ebc" : ebc,
             "eoc" : eoc,
             "h2_cons" : h2_cons,
             "h2_vol" : h2_vol,
             "elyzer_cons" : elyzer_cons,
             "compressor_cons" : compressor_cons,
             "max_pressure" : max_pressure,
             "min_pressure" : min_pressure,
             "fill_const" : fill_const,
             "disch_const" : disch_const,
             "min_mass" : min_mass,
             "max_mass" : max_mass,
             "fill_rate" : fill_rate,
             "disch_rate" : discharge_rate,
             "h2_density" : h2_dens,
             "e_h2" : e_h2,
             "MJ_kWh" : MJ_kWh,
             "storage_volume": storage_volume,
             # sold heat from electrolyzer
             "bop": 0.15,
             "cooling_system_eff": 0.95,
             "heat_purchase_price": 20,
             # economic settings
             "WACC": df['WACC'],
             "n_LRC": df['n LRC'],
             "n_pipe": df['n pipe'],
             "n_electrolyzer": df['n electrolyzer'],
             # scenario settings
             "heat_sold": df['Heat sold'],
             "pipeline": df['Pipeline'],
             "storage": df['Storage'],
             "ebc_location": df['EBC location'],
             "storage_location": df['Storage location']
             }
         return settings

 def calculate_production(plan, settings, to_excel=TO_EXCEL):
```

```

        plan = plan.copy()
        cons = []
        h2 = []
        compressor = []
        balance = settings["max_mass"]/2

        # hydrogen storage operation
        for value in plan["Plan"]:
            if value == -1:  # charge
                cons.append(settings["ebc"] + settings["eoc"])
                h2.append(settings["fill_rate"])
                compressor.append(settings["compressor_cons"]/1000 * h2[value])
            elif value == 1:  # discharge
                cons.append(settings["ebc"] - (settings["elyzer_cons"] * settings["disch_rate"]))
                h2.append(-settings["disch_rate"])
                compressor.append(0)
            else:
                cons.append(settings["ebc"])
                h2.append(0)
                compressor.append(0)
        plan.insert(3, "Electrolyzer [MWh]", cons) # includes both EBC and EOC
        plan.insert(4, "Compressor [MWh]", compressor)
        plan.insert(5, "H2 in/out [kg]", h2)

        # hydrogen storage balance
        h2_balance = []
        for hour in plan.index:
            if hour == 0:
                state = balance
            else:
                state = h2_balance[hour - 1]
            h2_now = state + h2[hour]
            h2_balance.append(h2_now)
        plan.insert(5, "H2 balance [kg]", h2_balance)

        # hydrogen and heat production
        h2_production = plan["Electrolyzer [MWh]"] / settings["elyzer_cons"] # kgH2/h
        h2_production_HHV = h2_production * settings["e_h2"] * settings["MJ_kWh"]
        bop_nominal = plan["Electrolyzer [MWh]"]*1000 * settings["bop"] # MWh -> kWh
        heat_output = (plan["Electrolyzer [MWh]"]*1000 - h2_production_HHV - bop_nominal) * settings["cooling_system_eff"]
        plan.insert(6, "H2 production [kg]", h2_production)
        plan.insert(7, "Heat production [MWh]", heat_output/1000)

```

```python
    if to_excel:
        plan.to_excel(fr"{FOLDER}/production.xlsx")

    return plan

""" 3. Calculation of costs. Production cost of H2 (€), (revenue from O2 and heat)
"""

def calculate_costs(plan, settings, constants, econ_settings):

    # operating costs per process component
    plan["Electrolyzer OPEX [€]"] = plan["FI"] * plan["Electrolyzer [MWh]"]
    plan["Compressor OPEX [€]"] = plan["FI"] * plan["Compressor [MWh]"]
    plan["Production cost [€]"] = plan["FI"] * (plan["Electrolyzer [MWh]"] + plan["Compressor [MWh]"]) + constants["Transmission cost"]
    * (plan["Electrolyzer [MWh]"] + plan["Compressor [MWh]"])
    storage_vol = settings['storage_volume']
    if settings['storage']:
        capex_ann_LRC = npf.pmt(0.08, constants["n LRC"], econ_settings.loc["LRC CAPEX"][storage_vol])
        om_LRC = econ_settings.loc["LRC CAPEX"][storage_vol] * econ_settings.loc["LRC O&M"][storage_vol]
    else:
        capex_ann_LRC = 0
        om_LRC = 0
    if settings['pipeline']:
        capex_ann_pipe = npf.pmt(0.08, constants["n pipe"], econ_settings.loc["Pipe CAPEX"][storage_vol])
        om_pipe = econ_settings.loc["Pipe CAPEX"][storage_vol] * econ_settings.loc["Pipe O&M"][storage_vol]
    else:
        capex_ann_pipe = 0
        om_pipe = 0
    if settings['storage']:
        capex_ann_EOC = npf.pmt(0.08, constants["n electrolyzer"], econ_settings.loc["EOC CAPEX"][storage_vol])
        om_EOC = econ_settings.loc["EOC CAPEX"][storage_vol] * econ_settings.loc["Electrolyzer O&M"][storage_vol]
    else:
        capex_ann_EOC = 0
        om_EOC = 0
    capex_ann_EBC = npf.pmt(0.08, constants["n electrolyzer"], econ_settings.loc["EBC CAPEX"][storage_vol])
    om_EBC = econ_settings.loc["EBC CAPEX"][storage_vol] * econ_settings.loc["Electrolyzer O&M"][storage_vol]

    # income from sold heat
```

```python
        fraction = 1
        if settings['heat_sold']:
            plan["Heat revenue [€]"] = settings["heat_purchase_price"] * fraction * plan["Heat production [MWh]"]
        else:
            plan["Heat revenue [€]"] = plan["Heat production [MWh]"] * 0

        # total operating costs
        total_opex = plan["Production cost [€]"].sum(axis=0)
        eoc_kg = total_opex / (settings["h2_cons"] * len(plan.index))
        total_opex_ebc = settings["ebc"] * (plan["FI"] + constants["Transmission cost"])
        total_opex_ebc = total_opex_ebc.sum(axis=0)
        ebc_kg = total_opex_ebc / (settings["h2_cons"] * len(plan.index))

        # total costs
        tot_storage = -(capex_ann_LRC + capex_ann_pipe + capex_ann_EOC + capex_ann_EBC) + total_opex + om_LRC + om_pipe + om_EBC + om_EOC - plan["Heat revenue [€]"].sum(axis=0)
        tot_without_storage = -(capex_ann_pipe + capex_ann_EBC) + total_opex_ebc - plan["Heat revenue [€]"].sum(axis=0)
        LCOH_without_storage = tot_without_storage / (constants["H2 cons"] * len(plan.index))
        LCOH_storage = tot_storage / (constants["H2 cons"] * len(plan.index))

        # storage cycles
        h2_tot_to_storage = plan["H2 in/out [kg]"][plan["H2 in/out [kg]"] > 0].sum(axis=0)
        cycles = h2_tot_to_storage/econ_settings.loc["H2 mass"][storage_vol]

        KPIs = {
            # KPIs
            "total_opex": total_opex / 1E6,
            "eoc_kg": eoc_kg,
            "total_opex_ebc": total_opex_ebc / 1E6,
            "ebc_kg": ebc_kg,
            "tot_storage" : tot_storage / 1E6,
            "tot_without_storage" : tot_without_storage / 1E6,
            "LCOH_storage" : LCOH_storage,
            "LCOH_without_storage" : LCOH_without_storage,
            "cycles": cycles,
            "O&M LRC" : om_LRC,
            "O&M Pipe" : om_pipe,
            "O&M EBC" : om_EBC,
            "O&M EOC" : om_EOC,
            "heat_produced" : sum(plan["Heat production [MWh]"]),
            # summed costs and income
            'opex_electrolyzer': sum(plan["Electrolyzer OPEX [€]"]) / 1E6,
```

```
            'opex_compressor': sum(plan["Compressor OPEX [€]"]) / 1E6,
            'opex_total': sum(plan["Production cost [€]"]) / 1E6,
            'opex_net': sum(plan["Production cost [€]"]) / 1E6 - sum(plan["Heat revenue [€]"]) / 1E6,
            'income_heat': sum(plan["Heat revenue [€]"]) / 1E6,
            'pmt_lrc': capex_ann_LRC / 1E6,
            'pmt_pipe': capex_ann_pipe / 1E6,
            'pmt_eoc': capex_ann_EOC / 1E6,
            'pmt_ebc': capex_ann_EBC / 1E6
        }

        return KPIs
```

Figure 2. The operational and economic parts of the code.