**Master's Thesis**

# DEVELOPMENT OF SUPPLY CONCEPTS AND BUSINESS ANALYSIS OF HYDROGEN REFUELING STATIONS

accomplished at


Master's Degree Programme
Automation Technology - Economy

by
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Graz, September 2025 .....

Signature

# DECLARATION OF AUTHORSHIP

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# ACKNOWLEDGMENTS

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# ABSTRACT

This thesis does a comprehensive examination of scalable technological and economic models for hydrogen refueling stations (HRS), with a particular focus on facilitating the widespread adoption of fuel cell electric vehicles (FCEVs) through sustainable infrastructure. Given the escalating demand for hydrogen in transportation, the analysis considers various supply pathways, including compressed gaseous hydrogen ($CGH_2$) delivered by truck, pipeline distribution, liquid hydrogen ($LH_2$) transport and on-site production by renewable energy sources. A modular station architecture designed for a variety of vehicle fleets, including buses, heavy-duty trucks and passenger cars, is supported by each strategy.

The proposed station design includes essential components such as storage tanks, compressors, cryogenic pumps, cascade systems and dispensers. The framework is intentionally flexible, enabling incremental expansion in response to increased utilization.

Techno-economic modeling reveals notable distinctions among supply strategies in terms of both capital and operational expenditures. Pipeline integration, while requiring high upfront investment, offers the lowest ongoing costs and is therefore advantageous in high-demand, stable environments with possibility for future scaling. In contrast, $LH_2$ supply can reduce initial infrastructure costs but entails higher operational expenses, primarily due to the energy demands of liquefaction and losses from boil-off. $CGH_2$ delivery, reliant on frequent truck deliveries and high compression energy, incurs high logistical costs and is most appropriate for smaller, nearby stations. On-site production provides potential independence from supply chains but needs major investment in electrolysis and renewable energy generation infrastructure. Its viability is closely linked to favorable electricity prices and the availability of adequate site area.

A support tool created with Excel is used to compare not only the levelized cost of hydrogen (LCOH), capital expenditure (CAPEX), operating expenditure (OPEX) and return on investment (ROI) for every supply option, but also forecasts hydrogen demand between 2025 and 2035.

Besides, a ten-year Net Present Value (NPV) analysis for each option using the ROI target as the discount rate and the internal rate of return (IRR) as alternative performance indicators. With investment planning, technical design and demand forecasting, the thesis lays the basis for determination of the most suitable hydrogen supply strategy

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# 1 INTRODUCTION

## 1.1 Background and motivation

The world energy scene is currently changing to accommodate the growing demand for low-carbon and sustainable fuels. Hydrogen is one of the main drivers of this shift since it can be used as a clean, highly adaptable and effective energy carrier. Since hydrogen produces no $CO_2$ (carbon dioxide) or GHG (greenhouse gas emissions) during use, unlike fossil fuels, it is essential to reducing greenhouse gas emissions. [1,2]

Hydrogen serves more purpose than just as fuel. It is a fundamental medium for storing renewable energy. An increased need for more reliable energy storage options complements the growing share of variable renewable energy sources such as wind and solar in the energy mix. One of the promising answers to this problem is hydrogen, which can be used to store excess renewable energy and then transform it back into electricity or other forms of energy when needed. [1]

However, there are major obstacles in the development of strong hydrogen infrastructure. With experimental installations and commercial fueling stations being constructed worldwide, the current infrastructure for hydrogen refueling is still in progress. Another problem is the absence of scalable and profitable business models that could be used to fund the widespread installation of hydrogen fuel stations across nations and regions. Furthermore, current technologies for producing, storing and distributing hydrogen are frequently used separately without a comprehensive plan that aims to optimize those elements into an integrated system. [3,4]

Success will demonstrate the ability to overcome these challenges and build an integrated, optimized system that meets the needs of the highly critical transport sector. It is from here that this thesis seeks to contribute by investigating technical solutions maximizing the efficiency further, reliability and scalability of hydrogen refueling infrastructure. [3]

## 1.2 Objectives of the work

The goal of this thesis is to examine and evaluate technical solutions that will help hydrogen technologies overcome the challenges of being incorporated into the overall energy supply system, including infrastructure for hydrogen refilling stations. The study will help address the critical issue of developing a technically and financially viable hydrogen-refueling infrastructure that can meet the increasing demand between 2025 and 2035.

The strengths and weaknesses of the current operating models are identified through an analysis of the infrastructure for hydrogen refueling as it stands today. The evaluation of various supply options, including pipeline delivery, trailer transportation and on-site production is the main objective of the study. The refueling station’s cost-effectiveness, scalability, logistical requirements and the unique requirements of different vehicle fleets are all taken into consideration when evaluating these options.

Apart from the technical research, the thesis then goes ahead to develop prototype technical concepts that would be applied to the actual world. These are scaled up so that as soon as the demand rises, the

hydrogen refueling stations grow at a rapid rate. The design utilized an economic method in creating a business case that has the capability to automatically estimate profitability and long-term viability of hydrogen refueling stations. The economic evaluation headlines financial measures, including capital costs, recurring costs, revenues cash flows and investment yields. It also makes sure that the solution being proposed is not only technically feasible but also economically viable.

To structure the work, the following goals are set:

- Develop a modular, scalable design concept for HRS based on different supply strategies, adaptable to different site conditions and fleet demands.
- Determine and specify technical sizing rules for the key elements such as storage systems, compressors, cascade systems and dispensers, divided by hydrogen form ($GH_2$/$LH_2$) and fleet requirements (cars, buses and trucks).
- Assess the economic feasibility of every supply option based on indicators like LCOH, CAPEX, OPEX and return on investment.
- Support decision-making by creating a framework which recommends the most favorable supply option for given boundary conditions.

At the same time, the non-goals of the thesis are:

- Detailed political or regulatory analyses, beyond what directly impacts technical and economic feasibility.
- Full environmental impact or lifecycle assessments of hydrogen supply chains.
- Physical prototyping or hardware testing of station components.
- Deep technological development of hydrogen production methods (e.g., electrolysis), unless required for integration into the overall station concept.
- Optimization of trailer logistics (e.g., delivery routing).

In addressing the defined goals, the thesis aims to answer the following research questions:

i. What are the key technical components of hydrogen refueling stations and how do their specifications differ based on the chosen hydrogen supply method?
ii. How can such stations be scaled and configured to efficiently serve diverse fleets at different pressure levels?
iii. What design rules and dimensioning criteria govern the sizing of equipment for each supply model?
iv. Under what circumstances is each supply variant the most economically and technically viable?
v. What are the major cost drivers and financial performance indicators relevant to hydrogen refueling stations?
vi. How can business cases be structured to promote both profitability and long-term viability in the hydrogen infrastructure sector. What are the most suitable tools for it?

## 1.3 Structure of the work

This master's thesis was carried out in cooperation with **HyCentA Research GmbH**. The collaboration provided valuable technical insight and access to project data related to hydrogen refueling infrastructure. The work combines academic research with practical aspects relevant to industrial implementation.

The thesis is structured in a chronological way, with the basic background of hydrogen technology at first, followed by technical modeling of scalable hydrogen refueling stations (HRS) and ending with the complete economic evaluation. After an introduction which reflects motivation, targets and challenges of the project, in the second chapter a theoretical introduction is given based on setting up hydrogen as energy carrier, presenting production methods and treating important aspects of storage, transport and usage. This context sets the technological and systemic framework within which hydrogen refueling stations need to be created.

Expanding on these basics, the third chapter explores the technical framework of hydrogen refueling stations, detailing their key elements and functioning principles. Diverse supply routes, such as pipelines, truck transport in gaseous and liquid states and on-site generation, are presented and evaluated regarding their technical requirements and consequences. The fourth chapter broadens the viewpoint to encompass the larger infrastructure, examining international and European advancements to underscore existing progress and ongoing deficiencies in hydrogen supply systems.

The fifth chapter offers innovative concepts for scalable hydrogen refueling stations, which is the main focus of this thesis. Technical models that enable the systematic scaling of various supply options are developed, starting with system architecture and component design. This creates the methodological framework for the sixth chapter's economic analysis. In this case, financial analyses and technical models are combined to evaluate each supply potential. Financial parameters like Net Present Value (NPV) and Internal Rate of Return (IRR) support the evaluation's thorough analyses of pipeline supply, liquid hydrogen distribution, gaseous hydrogen distribution and on-site electrolysis. Furthermore, sensitivity analyses are carried out to investigate how changes in the demand for hydrogen affect the relative competitiveness of various supply methods.

At the end of the thesis, a summary of the results and a discussion of future implications are provided. The final chapter examines how the findings vary under different hydrogen demand levels and how these demand scenarios affect the development of a scalable hydrogen infrastructure, including factors that could influence the choice of supply strategies and areas for further technological improvement.

# 2 BASICS OF HYDROGEN TECHNOLOGY

## 2.1 Hydrogen as an energy carrier

Hydrogen, $H_2$, is the lightest and most abundant element in space, constituting about 75 % of the elemental mass of the universe. Hydrogen being the lightest element contains only one proton and one electron. Two hydrogen atoms form $H_2$ – a colorless, odorless molecule that is highly flammable. Hydrogen, though abundant in the universe, is quite rare because it seldom naturally occurs as a pure element on Earth. Because of its bonding affinity, it readily forms covalent bonds with most nonmetals, particularly electronegative elements like oxygen, nitrogen and halogens. Hydrogen has the chemical properties of being a very important source for organic chemistry and of vital feeds for several industrial processes. [5]

Currently, most of the hydrogen applied by consumers has its origin in fossil sources such as natural gas, oil and coal. Steam methane reforming is the basis of hydrogen production: natural gas reacts at high temperature with steam, yielding hydrogen, carbon monoxide and a small amount of carbon dioxide. The process releases $CO_2$ into the atmosphere which contributes to the global rise in greenhouse gases. This contributed in the global transition to more environmentally friendly hydrogen production techniques, with an emphasis on green hydrogen produced using renewable energy sources. [6] To clarify it, electrolysis breaks down water into hydrogen and oxygen, while using electrical energy for it. If the electricity is sourced from a renewable system, this process is practically carbon-zero, placing green hydrogen in a privileged position that may help decrease the carbon footprint in transport, manufacturing and energy production. Alternative for green hydrogen, so-called blue hydrogen, made by converting natural gas into hydrogen while capturing and storing the carbon dioxide (also known as steam methane reforming), represents probably the best transition alternative, since it cuts at least some of the $CO_2$ emissions. When considering the full life cycle, including upstream methane emissions, blue hydrogen production emits about 9-12 kg $CO_2$ per kg $H_2$, compared to 10-12 kg $CO_2$ per kg $H_2$ for grey hydrogen. [7–9]

Hydrogen is increasingly considered one of the indispensable keys to an energy transition toward a greener and climate-neutral future. Among its key roles, hydrogen is set to play an important part in the long-term storage of energy to bridge the variability in renewable generation with the need for reliable supply. All renewable energies, be they originating from wind or the sun, are variable sources of generation-meaning energy generation does not always coincide with demand. Additional renewable energy will be used for the production of hydrogen, which will then be stored and used again as a renewable feedstock. It gives a way to make extra energy from variable renewable sources and deliver it to places where energy demand is high. Also, hydrogen will be able to store a lot more energy over time and in larger amounts. This makes it one of the most important parts of a low-carbon energy system in the future. [10]

The International Renewable Energy Agency (IRENA) reports that the transport sector is responsible for close to a quarter of global energy-related $CO_2$ emissions and hydrogen technology has huge potential to reduce these emissions [11]. Hydrogen fuel cells convert hydrogen gas into electrical energy with only water vapor and heat being released as by-products. Fuel cell electric vehicles (FCEVs) have thus been regarded as a zero-emission alternative to conventional internal combustion engine vehicles. Where battery electric vehicles (BEVs) could only enable shorter-distance travel and light-duty transport, hydrogen fuel

cells have been considered more viable for longer distances, heavy transports and even buses due to their faster refueling times and higher energy densities. [12]

Within that framework, the extensive use of hydrogen as transport fuel will heavily rely on the considerable extension of hydrogen refueling infrastructure. Besides that, the world hydrogen market is likely to show rapid growth due to a decrease in production cost, an improvement in technologies and strong government policy regarding the mitigation of greenhouse emissions. IRENA states that this could become up to 85 % cheaper by 2050 because the cost of renewable electricity is continuing to go down and the production of electrolysers is becoming more cost-effective on a large scale [13]. In addition to this, the European Union has also made a detailed plan to boost both the supply and demand of green hydrogen. [7,6]

But there are some problems that need to be fixed before hydrogen can be fully used. Building a strong hydrogen infrastructure requires a lot of money, careful planning and the ability for government agencies, private companies and industry groups to work together to create a large network of pipelines, refueling stations and storage facilities. [12,14]

Even more important, hydrogen will be a key part of the world's movement to a new energy system because it can be used as a very flexible source of clean energy to reduce carbon emissions in transportation, industry and other areas. Also, grid stabilization, storage, industrial use and transportation are all great ways to cut down on emissions and move toward a net-zero future. Even though there are problems, hydrogen will reach its full potential in the next couple of decades thanks to ongoing research, policy support and the building of new infrastructure. [15]

## 2.2 Technical basics of hydrogen production

Hydrogen production methods are often grouped by color, which shows how they affect the environment and how they are made: gray, blue, turquoise and green. Each has different effects on protecting the environment, saving energy and making businesses profitable. [16]

**Grey hydrogen** is mostly produced through a process called steam methane reforming. It consists of a reaction between methane in natural gas and steam at high temperatures, producing hydrogen and carbon dioxide ($CO_2$). The biggest disadvantage is its contribution to environmental impact with huge $CO_2$ emissions and feeding into global greenhouse gas (GHG) emissions. "For every ton of hydrogen produced through the steam methane reforming process (SMR), about 12 tons of $CO_2$ are emitted into the atmosphere." [17]. Thus, gray hydrogen has become a high-carbon option that would simply be unconscionable in any serious pursuit of climate goals. While gray hydrogen is everywhere, it does not fit into the long-term goals set by achieving climate neutrality. [8]

On the opposing side, **blue hydrogen** relies on the same process of steam methane reformation (SMR) but includes carbon capture and storage technology (CCS) in decreasing emissions. In other words, it captures the $CO_2$ that would be produced in extracting hydrogen and storing it in geological formations and that will make the production of blue hydrogen far cleaner. The CCS technology has the potential to seize as much as 90 % of the $CO_2$ emissions from the SMR process, hence generating a low-carbon alternative [18]. Blue hydrogen, however, derives its feedstock from sources of fossil fuel and the carbon dioxide by-product captured must be stored securely over timescales that are long enough to prevent leakage back to

the atmosphere. While blue hydrogen is mainly just one step in the transition towards purer hydrogen production, involving natural gas, with growing concerns regarding methane leakage, it is not really a sustainable option down the full decarbonization pathway. [19]

**Turquoise hydrogen** may also be considered as a new, alternative way of producing hydrogen. It refers to methane pyrolysis, a process whereby methane is broken down into hydrogen and solid carbon at very high temperatures, normally around 1000 °C. Contrary to SMR, it doesn't give any $CO_2$ as a byproduct in the pyrolysis process of methane. That yields, instead, a solid carbon which can be used later, from the production of black carbon up to the making of steel. That attribute makes turquoise hydrogen an even more excellent low-carbon alternative than gray or blue hydrogen. However, the process depends on natural gas as the key feedstock is not regarded as completely renewable. [20]

**Green hydrogen**, which is produced by electrolyzing water with renewable energy, represents the most environmentally sustainable production method. The hydrogen and oxygen atoms in water split apart to form $H_2$ and $O_2$ when an electric current flows through it. If this process only uses renewable energy, the produced hydrogen will be the most sustainable alternative. [6]

Since green hydrogen production only uses renewable energy, it is an essential component of the global effort to achieve climate neutrality. Electrolysis, the main process for producing green hydrogen, is powered by renewable electricity from hydropower, solar power and wind. This process, shown in Figure 2-1, uses an electric current to split water ($H_2O$) into hydrogen ($H_2$) and oxygen ($O_2$). The process is the most ecologically friendly method of producing hydrogen because it does not use fossil fuels and gets its electricity from renewable sources, so it does not release any $CO_2$. [6]

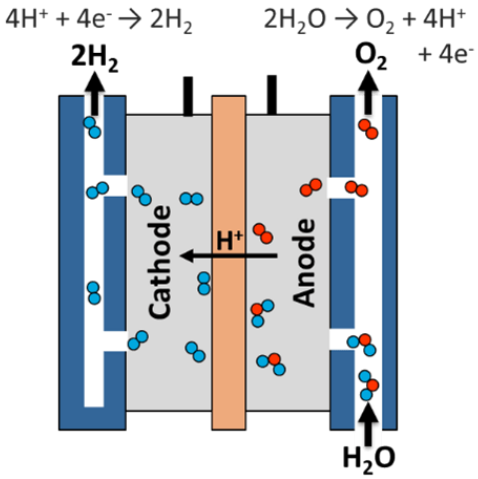


Figure 2-1: Electrolysis scheme. [21]

Green hydrogen's primary advantage is its capacity to support renewable energy systems by acting as a large-scale energy storage solution. Because solar and wind energy are unstable, they may not always be able to supply demand during periods of high demand. This is addressed by green hydrogen, which uses electrolysis to turn excess electricity into hydrogen when production is high. After being stored, this hydrogen may then be used to power industries, transportation or fuel cells to produce electricity. Long-term energy storage is essential for balancing the supply and demand for renewable energy. The cost of green hydrogen is currently its biggest obstacle. Electrolysis requires a lot of electricity and renewable

energy remains more expensive than fossil fuels in many areas, making green hydrogen more costly to produce than gray or blue hydrogen (see Figure 2-2). However, this is expected to change as renewable energy costs fall and electrolysis technologies improve. [6,22]

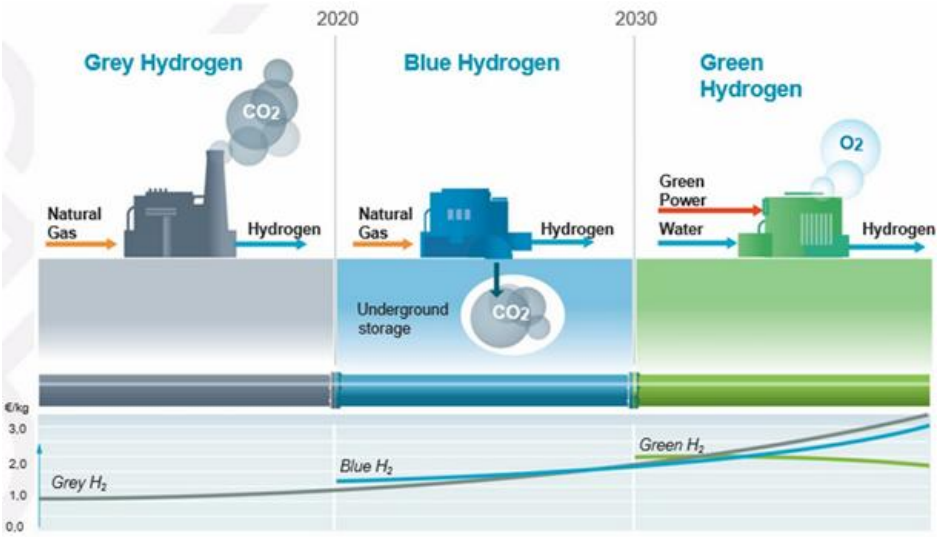


Figure 2-2: Hydrogen cost estimations until 2030. [22]

Another challenge is the need for high infrastructure development. Producing, storing, transporting and distributing green hydrogen will require new pipelines, storage facilities and refueling stations. To support its expansion, numerous governments and organizations are making huge investments in green hydrogen infrastructure. [7]

Green hydrogen is an essential element of the global effort to reach net-zero emissions by 2050. As countries work to achieve the climate targets set forth in the Paris Agreement, green hydrogen is anticipated to play an important role in decarbonization strategies. It will reduce emissions in many areas, particularly those that are difficult to electrify. Its versatility as an energy carrier and a raw material for industrial processes further increases its importance in the future energy landscape. [19]

Green hydrogen is a promising technique for producing sustainable hydrogen. Since it produces no $CO_2$, it is uniquely positioned to aid in global decarbonization initiatives. As renewable energy capacity grows and technology advances, green hydrogen will become more accessible and contribute to the transition to a net-zero future.

A key process in the creation of green hydrogen is **electrolysis**. In order to maintain environmental sustainability when producing green hydrogen, for electrolysis must renewable energy sources be used**.** [23]

This process typically involves an electrolyte (usually water with added ions to improve conductivity), two electrodes (an anode and a cathode) and an electric current supplied from renewable sources for green hydrogen production. [24]

During electrolysis, the following reactions occur (see Figure 2-3):

- At the cathode (negative electrode): Cations (positive ions) are attracted and gain electrons, undergoing reduction.

- At the anode (positive electrode): Anions (negative ions) are attracted and lose electrons, undergoing oxidation.

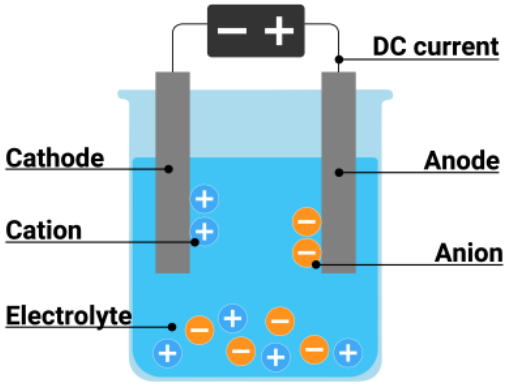


Figure 2-3: Main electrolysis components. [25]

The equation ( 1 ) can be used to summarize the process:

$$2H_2O(I) \rightarrow 2H_2(g) + O_2(g) \qquad (1)$$

1Efficiency of electrolysis is influenced by temperature. As temperature increases, part of the required energy can be supplied as heat, which reduces the electrical energy needed per mole of hydrogen produced. The total energy demand for splitting water remains the same, but a higher temperature allows a larger fraction to be provided thermally rather than electrically. [26]

The thermodynamics of electrolysis are needed to understand its efficiency. The Gibbs free energy (ΔG) for the hydrogen-oxygen reaction at standard conditions (25 °C, 1 atm) is 237,2 kJ/mole. This translates to a thermodynamic voltage of 1,229 V for a hydrogen-oxygen fuel cell operating at standard temperature and pressure. [27]

However, the total energy required to split water includes both the Gibbs free energy and the heat energy (TΔS). At 25 °C, this totals 285,8 kJ/mole, corresponding to a thermoneutral voltage of 1,48 V. This voltage represents the point at which an electrolysis cell operating at 25 °C can function without generating or absorbing heat. [27]

The Nernst equation, shown in equation ( 2 ), is needed for calculating the thermodynamic voltage at varying pressures and reactant concentrations:

$$E = E^\circ - \left(\frac{RT}{nF}\right) * \ln(Q) \qquad (2)$$

where E is the cell potential, $E^\circ$ is standard cell potential, R is the gas constant (R = 8,314 $J*K^{-1}*mol^{-1}$), $T$ is temperature, $n$ is the number of electrons transferred, F is Faraday's constant (F = 96485 C/mol) and $Q$ is the reaction quotient. [27]

The process of hydrogen production through electrolysis can be done using many technologies, each with its benefits and drawbacks (see Figure 2-4). Mostly used technologies are PEM (proton exchange method), AEM (alkaline electrolysis method) and SOEC (solid oxide electrolysis) method.

Advanced and frequently discussed method is **proton exchange membrane** electrolysis. In this method, a solid polymer electrolyte is used to transfer protons from the anode to the cathode while blocking

electrons. This approach is highly efficient and works well with fluctuating renewable energy conditions, making it a suitable match for renewable sources. However, the use of costly metals, such as platinum, in the electrodes makes PEM electrolysis expensive, which hinders its large-scale adoption. [28]

**Alkaline Electrolysis** is a more mature and less expensive technology. It employs liquid alkaline electrolyte, usually potassium hydroxide, to conduct ions and has been widely used in industrial applications for many years. Although it is cheaper and more durable than PEM electrolysis, AEM tends to be less efficient and slower to respond to variations in electricity supply. [6]

**Solid Oxide Electrolysis** is a newer development in electrolysis technology, operating at higher temperatures (around 700 °C to 1000 °C) than PEM or AEM. These elevated temperatures make SOEC more efficient, as part of the total reaction energy can be supplied as heat, reducing the electrical energy required to split water molecules. The use of steam as an input in SOEC further improves its efficiency compared to low-temperature electrolysis technologies. However, the high temperatures involved pose durability challenges for the materials used in SOEC electrolyser, limiting their commercial use. Nonetheless, SOEC shows great promise for industrial applications and could play an important role in hydrogen production in the future. [10,29]

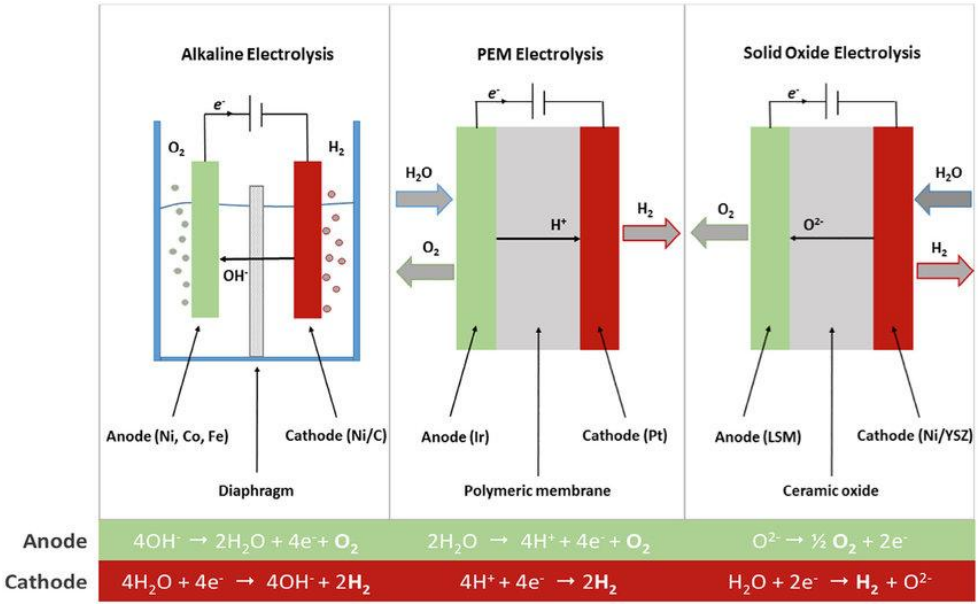


Figure 2-4: Operational principles of AEM, PEM and SOEC. [30]

In addition to electrolysis, other methods of hydrogen production are being considered to reduce dependency on fossil fuels. Solar thermal processes, for instance, use concentrated solar power to generate the temperatures required for thermochemical reactions that split water into hydrogen and oxygen. This approach, which harnesses direct solar energy, could pave the way for sustainable hydrogen production, particularly in sun-rich regions. One of the most promising solar thermal processes is the cyclic oxidation-reduction reactions that metal oxides go through at high temperatures to release oxygen and produce hydrogen. Although it is still in the experimental stage, solar thermal hydrogen production could provide a clean alternative to electrolysis, especially in areas with abundant solar resources. [8]

Thermochemical production, including the sulfur-iodine cycle, is another exciting field of study. Usually powered by nuclear or solar energy, this process uses a sequence of chemical reactions to split water into

hydrogen and oxygen at extremely high temperatures. High efficiency and the possibility of producing large amounts of hydrogen are two advantages of thermochemical production methods. But they have technical difficulties, especially with regard to reactor material durability. [6]

In conclusion, there are several ways to produce hydrogen and each has a unique effect on carbon emissions and sustainability. The most promising method for decarbonizing hard-to-electrify sectors is green hydrogen, which is produced by electrolysis powered by renewable energy sources. Green hydrogen is expected to grow over the next few decades thanks to continued technological advancements and encouraging government policies, despite infrastructure and cost issues.

## 2.3 Storage and transportation of hydrogen

### 2.3.1 Storage of hydrogen

These days, high-pressure tanks are the most widely used method for storing gaseous hydrogen, primarily in FCEVs and other mobile applications. In this respect, hydrogen is stored at pressures of 350–700 bar in carbon-fiber-reinforced tanks to achieve sufficient storage capacity within a limited volume [31]. High-pressure storage represents the most developed technology for hydrogen applications in general and is certainly that for mobile, transport-related applications. [19]

In case the demand is seasonally variable, hydrogen shall have to be provided with larger-scale and longer-term storage technologies matching the requirements of the advanced energy system. **Liquid hydrogen ($LH_2$) storage** method cools hydrogen to -253 °C and is in development for such large-scale, high-density needs (see Figure 2-5). Liquid hydrogen storage offers higher volumetric energy density than compressed gas. Regarding this point, liquid hydrogen is particularly relevant for compact and high-capacity storage applications, such as space and heavy transport. Meanwhile, liquefaction is an extremely energy-intensive process that uses up to 40 % of the energy in hydrogen, while the requirement for highly insulated cryogenic tanks jacks up the price even further [32]. Besides, boil-off – the gradual evaporation of liquid hydrogen due to heat ingress into the storage tank – gradually reduces efficiency over time in applications. [8]

Figure 2-5: Liquid hydrogen large storage tanks. [33]

Apart from the storage problems in its elemental form, the other option of using chemical carriers has also been brought forward, especially in applications related to long-distance/long-term transport. One of them

is ammonia ($NH_3$), which has gained attention due to its relatively soft storage conditions-lower than -33 °C for liquid ammonia at atmospheric pressure. It is transported in the tanks and pipelines extant today. At the point of use, ammonia can be "cracked" back into hydrogen and nitrogen in a process that offers a very efficient way to pipe hydrogen from production to consumption regions. Anyhow, the synthesis process and the process of cracking require enormous amounts of energy with some losses. It is very interesting to note that scalability and harmony with existing infrastructure make ammonia very attractive for large-scale hydrogen storage. [6]

Another approach to hydrogen storage is **methanol**, $CH_3OH$. Like ammonia this chemical is a liquid at ambient temperature and can be produced from hydrogen and carbon monoxide. Methanol may either be used directly in the fuel cell or first converted back to hydrogen in a reforming step. Again, both processes of conversion from hydrogen to methanol and back require energy. However, methanol is way more amenable to handling compared to liquid hydrogen and could conceivably fit into the current liquid fuel infrastructure. The use of methanol for hydrogen fuel cells has a big advantage for maritime applications where energy density and long-range transport matter a lot. [8]

One such technology in further development involves **Liquid Organic Hydrogen Carriers** (LOHCs). These are organic chemical compounds that can bind hydrogen chemically. Key LOHC systems include compounds such as dibenzyltoluene/perhydro-dibenzyltoluene and methylcyclohexane/toluene. These carriers offer high thermal stability and low melting points, making them suitable for large-scale applications. Hydrogen stored in this way allows it to be both safe and feasible for transportation within an ambient temperature and pressure environment. LOHCs might also be transported using already existing liquid fuel infrastructure, which does partly reduce the need for expensive new investment in infrastructure. Currently, technology has undergone the development procedures and is showing good potential on a low scale for hydrogen storage. [19]

Among the long-term bulk storage possibilities, one of the most promising directions is in the underground storage of hydrogen. **Salt caverns** – natural or artificially created cavity formations within underground salt domes – offering an already demonstrated solution for the storage of natural gas, can be employed in similar ways for hydrogen storage too (see Figure 2-6). Salt is not permeable to gas, so these caverns are perfectly adequate to hold hydrogen without the risk of leakage. The United States and Germany have been storing natural gas in salt caverns for years. However, now they're studying how those caverns might be adapted to store hydrogen. Storage in salt caverns has big advantages, it can store large capacities at relatively low costs. [34,35]

Another technology currently under research and one that might supplement the above particularly well, for areas not having suitable salt caverns is **pore storage**. This is a technology that will involve the injection of hydrogen into porous rock formations. While still in its infancy, pore storage has the potential to offer large hydrogen storage capacity, especially in regions with good geological conditions. [6]

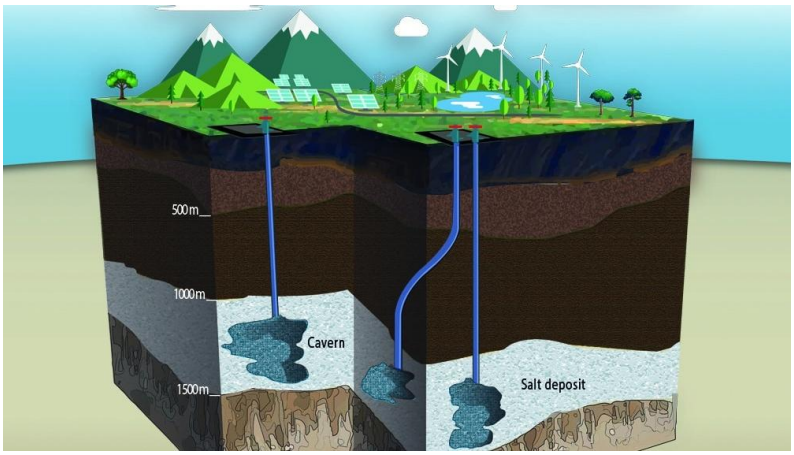


Figure 2-6:Salt cavern illustration. [36]

### 2.3.2 Transportation of hydrogen

Efficient transportation of hydrogen can only be considered as a form of energy carrier for those regions where transportation is affected economically. Any mode of transportation is chosen based on different factors that may include but are not limited to distance one needs to overcome, quantity of hydrogen required and infrastructure available. **Pipelines** remain the most economic option for transporting large quantities over large distances, assuming demand concentrates in industrial nodes or along the existing energy corridors (see Figure 2-7).


Figure 2-7: Hydrogen pipeline. [37]

Hydrogen may be transported by blending natural gas in those pipeline systems where natural gas infrastructure has been developed. This way could be gradually deployed into the energy markets with a minimum requirement for major investment. In most applications, hydrogen can be blended up to 20 % without major changes in the pipeline and/or relevant downstream applications. While blending represents a relatively low entry cost of hydrogen into the energy grid, its deficiencies involve energy content lower than natural gas alone and pipe embrittlement starting at higher hydrogen concentrations. Thus, blending is transitional and is a no long-term solution for hydrogen transportation. [20]

On a larger scale, over long periods and to move pure hydrogen, this would be more functional and scalable by way of dedicated hydrogen pipelines. Most often, **stainless steel pipelines** are employed owing to the

avoidance of hydrogen embrittlement, a phenomenon whereby hydrogen atoms penetrate metals, thus making them brittle. On the other hand, stainless steel is far more expensive than the material normally used in natural gas pipelines, hence driving the capital expenditure for new hydrogen pipelines up. Further, the much lower energy density of hydrogen means that very much larger quantities are required to provide the same amount of energy as natural gas, which complicates pipeline design. Once in place, however, hydrogen pipelines provide a cost-effective and high-capacity means to transport hydrogen long distances and therefore generally are well-suited for connecting hydrogen production sources with industrial users or refueling stations. [8]

Another great advantage of pipeline transport is the fact that continuous feeding of hydrogen can be realized. Essentially, what this describes for countries, where demand for hydrogen is expected to be many times higher, is a roadmap for an extended piping infrastructure connecting the places of hydrogen production, usually large-scale from renewables. [20]

Currently, long-distance liquid hydrogen is still being tested in a **cryogenic state** of transport, especially over long distances, from areas with abundant renewable resources such as Australia to hydrogen-importing countries like Japan and South Korea. Liquid hydrogen requires transportation in cryogenic containers at very low temperatures to keep the hydrogen in its liquid state. It's a very energy-intensive option, with liquefaction and re-gasification once it's been delivered. [6]

It can also be pursued by shipping hydrogen as **ammonia** or **methanol**, which are easily transported by existing tanker fleets and reconversion to hydrogen carriers into hydrogen upon arrival at its point of use. Although the processes are accompanied by energy losses, this route is particularly favorable for very long-distance transportation because doing so builds on most of the existing shipping infrastructure worldwide and minimizes requirements for hydrogen-specific vessels. [19]

**On-site production** becomes a very attractive alternative when long-distance hydrogen transport is not viable or cost-effective. It makes it possible to produce hydrogen right at the point of use, doing away with the need for transportation infrastructure. This method works especially well in isolated or remote locations without pipeline infrastructure. However, it requires a reliable electricity source, which is not always accessible. Combining on-site production and hydrogen storage can help stabilize the energy supply in areas with sporadic renewable energy sources like solar or wind. [6]

## 2.4 Hydrogen consumption and fields of application

Hydrogen has gained much importance in the decarbonization process. Being a flexible energy carrier, it can be applied in transport, thermal generation, generation of electricity and industrial functions. Accomplishing this hydrogen on large scales would contribute to the greenhouse gas reductions.

### 2.4.1 Mobility

On a global basis, the transport sector stands as one of the highest contributing sectors to greenhouse emissions. Hydrogen is starting to point out a very feasible path towards carbon mitigation for transport industries, especially in the field where most of the challenges were accrued to battery electric vehicles (BEVs). FCEVs have more advantages compared to traditional internal combustion engines (ICEs) and

BEVs in relation to refueling speed and operational range from hydrogen conversion to electrical energy through an electrochemical process. Hydrogen fuel cells generate power without combustion, releasing only water vapor – a perfect source for solving tailpipe emissions.

Hydrogen-based propulsion systems will have the most impact on heavy transport modes of travel, ranging from trucks to buses and even trains. Payload capacity and frequency of refueling can easily become critical issues in long hauls by trucks and buses. BEVs are not feasible because of the weight and volume required by the batteries. Hydrogen, by contrast, can be stored in lightweight, high-pressure tanks such that these FCEVs can operate within practical ranges with no heavy batteries on board. Hydrogen-powered trucks are currently in development by diverse automotive companies (see Figure 2-8), including Toyota, Hyundai and Nikola, whereby hydrogen-powered buses are already being deployed by cities like Hamburg and Seoul to meet their public transport requirements. In the process of its efforts to decarbonize transport, the European Union's Clean Hydrogen Alliance has set ambitious targets to establish hydrogen refueling network for heavy-duty vehicles. [19]


Figure 2-8: Hyundai Motor's XCIENT Fuel Cell Truck. [38]

Hydrogen is considered a low-emission alternative when electrification of railways is infeasible owing to high infrastructural costs. German Coradia iLint is a supposedly world-first hydrogen-powered passenger train operating on regional routes, though plans still exist to extend its use across Europe and elsewhere [39]. Green hydrogen aviation, particularly for short-distance flights, is also in the pipeline. Companies like Airbus are developing aircraft concepts that use hydrogen, either directly or as a component of sustainable aviation fuels (SAFs), which could significantly reduce aviation’s emissions, at least for short- and medium-distance flights. [8,6]

### 2.4.2 Heat supply and electricity generation

Besides the key implications in mobility, hydrogen could ensure value additions with its use in revolutionizing the processes of heating and power generation. Hydrogen is currently applied in several industrial processes requiring high-temperature heat, like steelmaking, cement making and the manufacture of chemicals, as a clean replacement feedstock for natural gas and coal. Hydrogen-fueled industrial heating systems emit just water vapor as a waste product, hence offering great options for industries that would want to reduce their carbon emissions. The possible extra push toward industrial

decarbonization is the amount of $CO_2$ that would be freed by the industries around the world by shifting to hydrogen heat production. [40]

Hydrogen can, therefore, be blended with natural gas or used directly in hydrogen-ready boilers in residential and commercial heating. Several countries, such as the United Kingdom, have already reached the pilot project stage of blending hydrogen into the existing natural gas grids and are working their way up to go full transition to 100 % hydrogen in the future. [6]

Hydrogen is also a very promising medium in generating electricity and grid balancing, especially along with variable renewable energies. One of the key challenges when considering renewable sources is related to the intermittency of those sources: wind and solar power. Any time renewable generation exceeds demand, excess electricity is channeled through electrolysis into hydrogen and can be stored for later use. This later can be directly injected into cavern storage facilities or into any other large-scale facilities where these can remain stored for longer periods without deterioration. At any time when electricity is in demand, it is possible to convert this hydrogen into electrical energy via fuel cells or gas turbines. The only emission from this is water vapor, although the overall efficiency of this conversion process is relatively low due to energy losses during electrolysis, storage and reconversion. [10]

### 2.4.3 Green hydrogen and the decarbonization of natural gas

Hydrogen can play one of the most important roles in the decarbonization process, just as natural gas does today. Natural gas covers a high percentage of total consumption from the global point of view, mainly in heating, the generation of electrical energy and industries. Eventually, green hydrogen replaces natural gas in many of its applications and, on scale, offers a chance for the abatement of critical greenhouse gas emissions sectors worldwide. [6]

In existing natural gas pipelines, hydrogen can be blended at concentrations of up to 20 %, with relatively minor modifications to the pipeline infrastructure. Such methods have been under intense investigation nowadays in many European countries to upscale hydrogen into the gas network gradually. The domestic and industrial widescale green hydrogen distribution on larger time scales will be delivered by the dedicated hydrogen pipes, which will fully replace the older pipes from natural gas. [20]

Green hydrogen is also functioning as an enabler to produce synthetic fuels or e-fuels. Production of e-fuels is done by the reaction of hydrogen with carbon dioxide captured from the atmosphere or industrial emissions to get a synthetic hydrocarbon that could be used in combustion engines. Thus, this might introduce a pathway for the decarbonization of industrial sectors, where direct electrification cannot work due to the huge amount of energy density required. [8]

### 2.4.4 Application goals

Hydrogen will also directly contribute to climate neutrality in the energy systems. It could therefore help Europe meet the goals set forth in the Paris Agreement by achieving low emissions in those critical regions where the replacement of fossil fuels is needed. This will enable more options for reductions from a range of sources, especially from the industrial sectors of manufacturing, transportation and heating that are responsible for the majority of the world's $CO_2$ emissions. [19]

Despite hydrogen's potential, several challenges must be overcome to ensure its successful deployment. First and foremost, hydrogen needs to be green. Today, most of the world's hydrogen supply is gray hydrogen, coming from fossil fuel sources with associated $CO_2$ emissions. For hydrogen to deliver on its promise, it needs to be made via electrolysis powered by renewable energy.

The other problem is energy efficiency: the production, storing and conversion of hydrogen into usable energy by very intensive energy methods, such as electrolysis, liquefaction and reconversion – all steps that have great energy losses and may offset the real efficiency of hydrogen systems. For hydrogen to be considered a promising, economically viable and ecologically compatible alternative for the future, efficiency improvement of these systems will be needed.

Various serious issues are associated with hydrogen storage, from large-scale to long-term storage, some technologies have huge infrastructure investment and are bound by geographic limitations. More research and development is thus important in order to provide economically viable and scalable storage options which shall ensure a reliable supply of hydrogen, particularly during periods of peak demand. [6]

# 3 TECHNICAL SOLUTIONS FOR HYDROGEN REFUELING STATIONS

## 3.1 General structure of hydrogen filling stations

HRS are designed to meet the requirements of a wide range of hydrogen fleets, from trucks and passenger cars to specialized applications. As the use of FCEVs increases, pressure grows on refueling infrastructure to become more efficient, safe and user-friendly. The main elements of safety infrastructure, HRS connectivity, layout and design considerations and the development regulations are described in the section that follows.

Hydrogen is stored just like any fuel and subsequently conducted by the dispenser directly into the vehicle tank. That is why the use of these technologies would not radically change our current refueling habits. It must be taken into consideration that the time spent for normal refueling with a full tank of hydrogen by an FCEV is approximately 15-20 min in the case of a bus, while for a car this is about 3-5 min. A classification of HRS into four main categories, based on the hydrogen supply chain or based on the hydrogen thermodynamic status, is presented in Figure 3-1. [41]

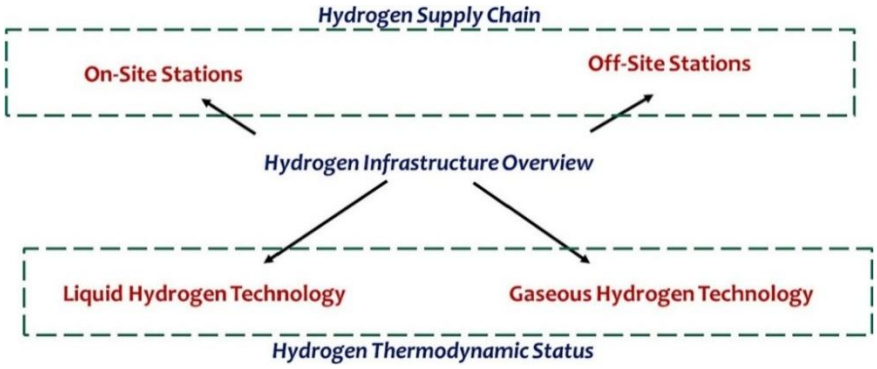


Figure 3-1: Hydrogen station classification. [41]

The layout of a hydrogen refueling station is based on four principal operational areas, which include **storage**, **compression**, **cooling** and **dispensing** (see Figure 3-2 and Figure 3-3). Hydrogen may be stored in the station either as a compressed gas or in a cryogenic liquid state, depending on the demand by the station and the vehicle types it serves. The storage area usually is located far from the dispensing zone to reduce the risks according to industrial standards. For example, ISO 19880-1:2020 specifies minimum separations among storage and dispensing units, considering pressures and storage volume to ensure safety in case there are any leakages or mechanical failures. [42]

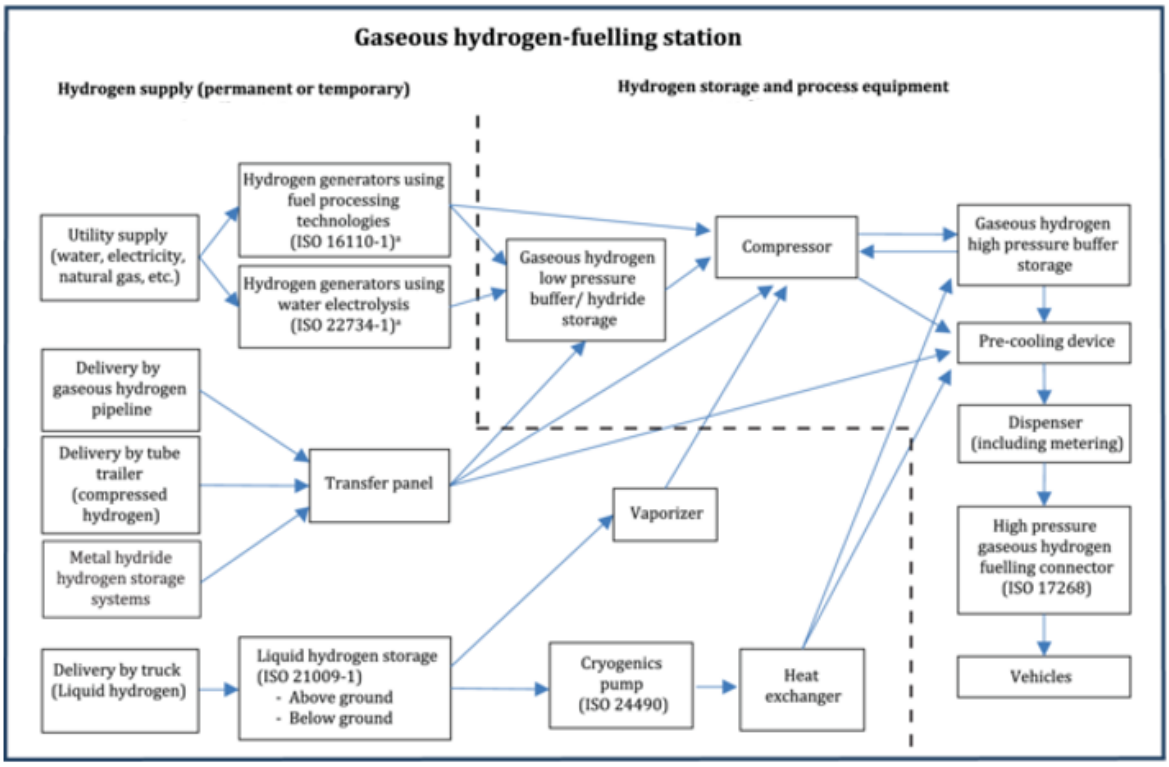


Figure 3-2: Typical elements that gaseous hydrogen-fueling station consists. [42]

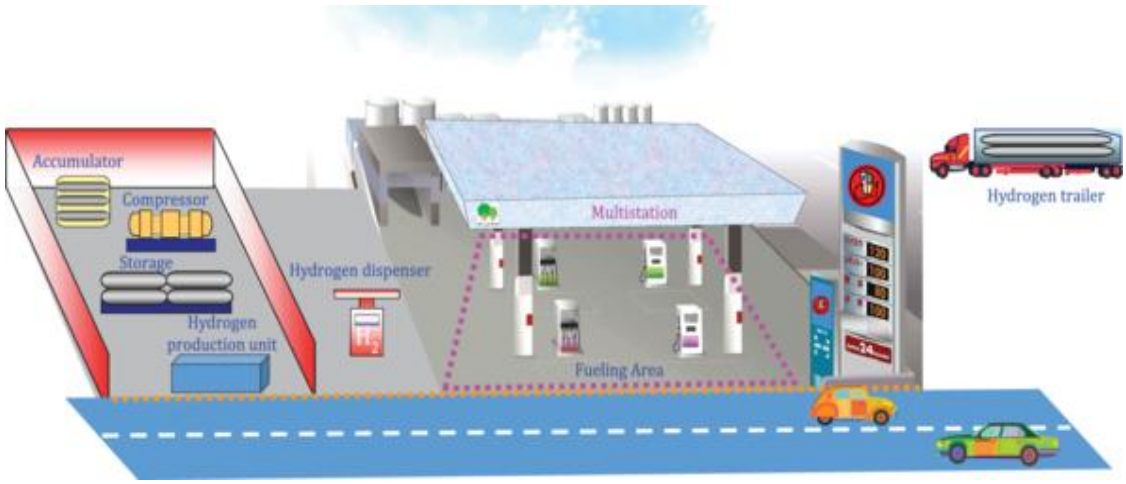


Figure 3-3: An example of HRS. [42]

One important aspect of station design is safety zoning. Safety zones around high-pressure equipment are specified by regulatory standards like the EU ATEX Directive with the goal of managing the inherent risks of working with hydrogen, a highly flammable gas. By establishing distinct separations between storage tanks, compressors and dispensers and allocating emergency access points, these zones are intended to reduce the risk of accidents. [19]

**Hydrogen storage facilities**

Hydrogen filling stations have either a high-pressure gaseous storage system or a cryogenic liquid storage system, depending on the demand of the station. High-pressure gas storage usually works within a range of 350-700 bar, which would again be apt for light-duty vehicles. Liquid hydrogen storage, which serves

high-demand applications, offers higher volumetric energy density about 70,8 kg/m³ compared to approximately 40 kg/m³ for compressed hydrogen at 700 bar, but requires cryogenic temperatures to maintain hydrogen in its liquid state. Again, this will depend on the chain and infrastructure of hydrogen supply at the location. [10]

Storage capacity planning is very important since it is directly related to the ability of a station to meet refueling demand. For example, stations that serve large vehicle fleets may have notably larger storage capacity compared to stations serving passenger cars. A well-planned placing and sizing of storage facilities will optimize the refueling operation process and ensure that hydrogen is in ready supply to the vehicles with minimum queue time. [43]

**Compression and dispensing systems**

Compression and dispensing systems compress hydrogen to the required pressures of specific vehicles, preparing it for refueling. Compression reaches up to 700 bar for light-duty vehicles. The dispensing units are equipped with nozzles ensuring safety during connection and disconnection, no leakage and compatibility with different vehicle requirements. The placement of cooling systems in the refueling arrangement is also of importance, as they help maintain hydrogen temperatures to avoid damage or overheating of equipment in the refueling. [8]

**Safety and monitoring infrastructure**

With hydrogen being flammable and permeable, a robust safety and monitoring infrastructure is attained at HRS. Sensors for leakage detection are mounted around storage tanks, compressors and dispensers, particularly in enclosed or semi-enclosed areas, since hydrogen is very light and disperses rapidly in open air. These would instantly detect hydrogen leakage and hence trigger alarms to shut off the systems in case of prevention of ignition. [42]

HRS design needs to conform to regulations and it is not an option. The European Union's Green Deal includes policies that will promote green hydrogen, guarantee that hydrogen infrastructures meet EU climate goals and set standards that ensure high safety standards. This helps the stations comply with the law and lowers the environmental risks associated with hydrogen refueling. [44]

**Integration with other hydrogen infrastructure**

Modern hydrogen refueling stations are increasingly being designed with features that provide efficiency and sustainability by being integrated with the greater hydrogen infrastructure network. Supply to the station can be piped from local sources, produced by on-site electrolysis or sourced from regional storage depots. On-site electrolysis systems powered by renewable energy sources enable the station to generate hydrogen within its premises. For city or high-demand outlets, direct pipeline connections allow the constant supply of hydrogen to feed high refueling volumes without large on-site storage. [8]

Future station designs are more often adopted and the layouts are such that they can be upgraded in tune with growing hydrogen demand. This modular approach allows each station to scale their storage, compression and dispensing systems as hydrogen-powered vehicles come increasingly into operation. In anticipation of future upscaling, a hydrogen station hasn't limited its preparation to the long-term infrastructure needs, but has similarly contributed to the transition toward a low-carbon economy. [45]

## 3.2 Technical components and their functions

The technical components that support hydrogen refueling stations guarantee their dependable, safe and effective operation. To meet the various requirements of hydrogen-powered vehicles, these technical components include those for hydrogen storage, compression and dispensing at low temperatures and high pressure. Storage systems, compressors and dispensers are examples of basic technical parts that can be found in hydrogen refuelers.

### 3.2.1 Storage systems and cascading

Hydrogen storage systems are an important integrating unit in maintaining functionalities regarding the availability of hydrogen to refill into the vehicles. Hydrogen has a few unique properties, like low molecular weight and high energy density by mass with high flammability. These make advanced storing solutions highly important for handling hydrogen at refueling stations in a safe and effective manner. Such systems, in turn, need to keep hydrogen at either ultra-high pressure or extremely low temperature centric on storage type to minimize volume while meeting safe and accessible fuel storage. [10]

There are two main types of storage used in hydrogen refueling stations**:** high-pressure gaseous storage and cryogenic liquid storage. The type of storage system depends on refueling demand, space constraints and the vehicle type served by the station.

The pressure vessels for **storage of gaseous hydrogen** are frequently modular and can be used in series to satisfy the storage requirements of a particular station. A high-pressure hydrogen tank intended for a refueling station typically has a small volume of around 50 to 100 liters for smaller tanks, while larger industrial tanks may exceed 500 liters or more per tank. [10]

For instance, a conventional 700 bar hydrogen storage module can be composed of 8 to 10 tanks, each having 100 liters storage capacity hence totaling 800-1000 liters storage of compressed hydrogen. Under this pressure the gas storage of hydrogen has an energy density of about 5,6 MJ per liter, whereas gasoline contains roughly 32 MJ per liter [46]. In the large-volume refueling stations aiding high call-off applications the total storage capability might go up to few thousands of liter of gaseous hydrogen packaged possibly in multiple high-pressure segments. [19]

Each high-pressure tank is usually made with a composite structure. The inside is often lined with aluminum and wrapped in layers of carbon fiber-reinforced polymer to provide strength while keeping the weight down. This multi-layer design enables the tanks to endure extreme pressures while ensuring durability. According to ISO 19884:2018, hydrogen storage systems with a nominal working pressure of 700 bar(g) are hydrostatically tested up to 875 bar (≈ 1,25 × Nominal Working Pressure), which includes a 25 % safety margin to accommodate possible pressure surges during refueling. During refueling, short-term filling pressures can temporarily reach around 825 bar(g) to compensate for temperature effects, after which the gas cools down and stabilizes near the nominal 700 bar(g) operating pressure. [47]

**Cryogenic liquid hydrogen storage tanks** are designed to contain hydrogen at -253 ˚C, the boiling point of the liquid hydrogen, achieving a density of around 70,8 kg/m³, nearly twice that of compressed hydrogen at 700 bar. These tanks normally are cylindrical with well thermally insulated walls which help in maintaining sufficient cryogenic temperature as well as contain loss caused by boiling. The min/max storage tank

depends on the capacity of the station, more specific on volume and sizes of the storage tank run from 1000 liters to 20000 liters at most (see Figure 3-4). [8]

Cryogenic tanks use multilayer insulation, typically incorporating vacuum-insulated panels and reflective foil to limit radiative heat transfer and reduce boil-off losses. Boil-off is the slow vaporization of liquid hydrogen caused by heat entering from the surroundings. Controlling boil-off is important for preserving storage efficiency, especially in large-capacity tanks, even though modern cryogenic tanks can achieve boil-off rates as low as 0,1-0,3 % per day. There are vent systems in place to safely release any boil-off, maintaining tank pressure and avoiding any uncontrolled emissions. [45]

Figure 3-4: Cryogenic tanks. [48]

A **cascading storage system** is frequently used by hydrogen refueling stations to maximize the use of stored hydrogen and enhance refueling efficiency. Because cascading uses a sequence of tanks at progressively lower pressures, hydrogen can flow by pressure equalization during refueling, thereby reducing the need for active compression. In practice, cascade systems typically consist of several storage banks with pressure levels in the range of 300 to 900 bar, where the highest-pressure bank (around 850–900 bar) serves primarily as a buffer for vehicle refueling rather than for long-term storage. This arrangement exploits the pressure gradients between the storage banks and the vehicle tank to enable efficient gas transfer while minimizing compressor operation and associated energy consumption. [45]

A cascading system might include three sets of storage tanks: a high-pressure of roughly 700-900 bar, a medium pressure of roughly 600 bar and a low pressure of roughly 450 bar (see Figure 3-5). Each vehicle is first fueled from the lowest-pressure storage tank and when the pressure difference between the vehicle tank and the storage tank becomes too small, fueling continues from the next higher-pressure storage level until the vehicle tank reaches its target pressure. This arrangement minimizes the compressor working hours and load, resulting in longer equipment life and decreased costs of working. Cascading configurations are most advantageous at overworked stations where hydrogen exchange has to be achieved at the earliest for improving the refueling rate. [19]

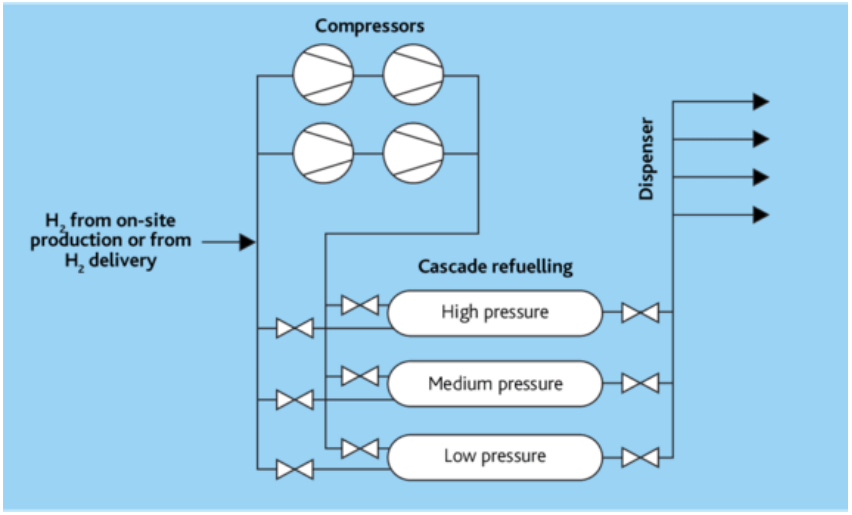


Figure 3-5: Scheme of a cascade storage with three pressure banks and compressors to restore the required pressure levels in each bank. [49]

According to current industry standards, the hydrogen storage system in the refueling stations is supposed to submit to the further characteristics corresponding to safety because of high pressures and temperatures. Standards like ISO 19884:2018 confirm that tanks must be able to handle much more than ambient pressure and define the safety and performance requirements for hydrogen storage cylinders with high pressure. For instance, to account for the pressure increase during refueling, a 700 bar tank is typically pressurized to 875 bar.

The search for appropriate solutions is made easier by the ongoing evolution of hydrogen storage technology's efficiency. Carbon fiber reinforced polymer is chosen for high pressure tanks because of the high strength to weight ratio which makes it possible to store hydrogen safely with reasonable pressure in tanks with reasonable weight. Cryogenic tanks are also changing with the new features of multilayer insulation and vacuum them to increase thermal performance and decrease boil – off ratio. All these are helpful where big stations or stations located in constrained geographical regions are a concern. [50]

Hydrogen is flammable and a small molecule, so pressure specific sensors and leak detection sensors are employed in high pressure storage and cryogenic systems to detect presence of hydrogen gas at level as low as 1 % by volume. Most of these sensors are fixed around storage tanks and are fitted with alarms that can notify one whenever a leakage occurs so that proper measures can be planned. High-pressure tanks also contain Pressure Relief Devices (PRD) that release hydrogen in a controlled manner if the pressure inside the tank becomes dangerous. These devices effectively reduce the chances of an explosion and in the case of hydrogen excess, these units release hydrogen in a safe manner. [42]

In outside premises, the European Union ATEX Directive requires that hydrogen reservoirs must be accompanied by particular isolation regions owing to the element’s consequent explosion danger. [44]

### 3.2.2 Compressor technology

In hydrogen refueling stations, compressors are important in storing and dispensing hydrogen at the high pressures needed for vehicle refueling. They elevate the hydrogen pressure from lower storage levels to the necessary refueling pressures, which typically range from 350 bar for heavy-duty applications up to

about 850-900 bar for 700 bar vehicle tanks. Although vehicle tanks have a nominal working pressure of 700 bar, hydrogen is typically dispensed at up to 850-900 bar to compensate for temperature-induced pressure drops during fast filling and to ensure the correct mass of hydrogen is delivered according to the SAE J2601 fueling protocol. Different types of compressors are used in hydrogen refueling stations, such as reciprocating compressors, diaphragm compressors and ionic liquid compressors. The selection of each type depends on operational requirements, target pressure and efficiency considerations.

**Reciprocating compressors** are commonly found in hydrogen stations due to their capability to generate high pressures while maintaining high flow rates. Their use significantly influences the overall efficiency of hydrogen storage and refueling processes. These compressors use a piston-driven system, in which hydrogen gas is compressed in stages by pistons that travel inside cylinders. Multi-stage reciprocating compressors are a common option for HRS because they can reach pressures of up to 900 bar. Since FCEVs require rapid, high-pressure refueling, technology is always changing, which makes it simpler to find appropriate solutions. [10]

Depending on the necessary pressure and flow rate, the power ratings of typical reciprocating compressors used in hydrogen applications range from 30 kW to 250 kW. A multi-stage reciprocating compressor typically operates with an isentropic efficiency of roughly 65 %, depending on factors like cooling and the number of compression stages. During compression, the gas temperature rises significantly due to the conversion of mechanical work into heat, which must be removed to prevent efficiency losses and mechanical stress. Therefore, these compressors require effective heat management. Air-cooled or water-cooled intercoolers are commonly used between stages to control this heat and increase compression efficiency, preserving system performance. [51]

Since their design lowers the chance of contamination, **diaphragm compressors** are frequently chosen when preserving hydrogen purity. In contrast to reciprocating compressors, diaphragm compressors compress hydrogen using a flexible membrane, which prevents the gas from coming into direct contact with any moving parts. Because diaphragm compressors do not use lubricants that could contaminate the gas, this design enables them to deliver ultra-pure hydrogen efficiently. Additionally, these compressors can achieve extremely high pressures, typically up to 850-900 bar, which makes them ideal for high-pressure refueling applications, particularly in fuel cell vehicles that demand very pure hydrogen. [42]

Depending on the required pressure and flow rate, they typically consume 50 kW to 150 kW and can handle flow rates of approximately 50 to 150 $Nm^3/h$ at pressures up to 900 bar. The thermodynamic efficiency of compression is fundamentally limited by heat generation, which must be dissipated through cooling. In practice, diaphragm compressors reach isentropic efficiencies of around 65 %, depending on pressure ratio and cooling effectiveness. Compared to reciprocating compressors, their design often restricts achievable flow rates, making them more suitable for stations that prioritize hydrogen purity over throughput. [45]

A recent development in technology, **ionic liquid compressors** are notable for their effectiveness and minimal maintenance requirements. These compressors reduce friction and component wear by using an ionic liquid as both the compressing medium and a sealing agent. Because they rely less on mechanical seals, which are frequently the cause of hydrogen leaks in other compressor types, they can achieve high efficiency. These compressors are perfect for stations that need frequent and high demand refueling because they can reach pressures of up to 700 bar. [8]

Ionic liquid compressors typically use between 75 kW and 200 kW, depending on the flow rate and pressure needed. They can operate at efficiencies close to 80 % and their distinctive design makes them ideal for high-usage stations where minimizing downtime is essential. With little energy loss, these compressors can deliver flow rates between 50 and 200 $Nm^3/h$. Additionally, the ionic liquid provides effective internal heat transfer, allowing the compression heat to be removed more efficiently and improving the thermal stability and reliability of the system. [8]

In hydrogen compressors, **safety shut-off** mechanisms and **pressure relief valves** (PRVs) are essential, particularly in high-pressure environments. To prevent high pressures, PRVs are made to activate when internal pressures surpass safe thresholds, enabling controlled hydrogen escape. For applications operating at 700 bar, these valves usually open at 750-800 bar, ensuring a safety buffer for high-pressure tasks. Additionally, safety shut-off systems automatically turn off compressors if they detect unusual pressure or temperature, preventing mechanical failures and ensuring safety regulations [50]

### 3.2.3 Dispensers and refueling technologies

Hydrogen dispensers are essential parts of refueling stations, built to securely and effectively move hydrogen from storage units to vehicle tanks. These systems need to function under intense pressure while ensuring exact regulation of overflow rates and temperature. Contemporary hydrogen dispensers generally include high-pressure hoses and nozzles designed to endure pressures reaching 900 bar. [52]

The SAE J2601 standard outlines the refueling procedure for light-duty vehicles, which involves pre-cooling hydrogen to -40 °C before delivery, managing the pressure increase rate (usually between 10-30 MPa/min) and capping the maximum fill pressure according to ambient temperature (up to 700 bar at 15 °C). The refueling procedure usually takes about 3-5 min for cars. For heavy vehicles, the refueling process may require 10-15 min because of larger tank capacities, with fill rates reaching up to 120 g/s. [53]

A contemporary hydrogen dispenser should have a nominal operating pressure of 700 bar (H70) or 350 bar (H35), flow rates of up to 60 g/s for light-duty vehicles or 120 g/s for heavy-duty ones and an accuracy of ±1 % of the measured value. Standards like ISO 19880-1:2020, which specify the distances between storage and dispensing units to ensure safety in the event of leaks or mechanical malfunctions, must be taken into consideration when designing and operating dispensers. [52]

Multi-pressure dispensing offers important benefits for hydrogen refueling stations, increasing the overall effectiveness. Through enabling one dispenser to serve both 350 bar and 700 bar vehicles (see Figure 3-6), it allows for greater flexibility in serving hydrogen-fueled vehicles. This adaptability is essential as the market for hydrogen vehicles grows and incorporates models with different pressure requirements. By integrating multiple pressure functionalities into a single unit, stations can reduce the physical size of the refueling infrastructure and capital expenditures by doing away with the need for multiple dispensers. [54]


Figure 3-6: HH's hydrogen refueling dispenser. [55]

In addition, through optimizing station usage, multi-pressure dispensing can boost operational efficiency. Stations can attract a greater variety of customers and increase throughput by serving various vehicle types from a single dispenser. This is particularly helpful during periods of high demand when multiple vehicles may require simultaneous refueling. [56]

The cost-effectiveness of multi-pressure dispensing also considers operating and maintenance costs. Because less individual dispensers are needed, stations can lower maintenance costs and speed up training for employees using the equipment. [57,58]

## 3.3 Supply variants

Hydrogen can be obtained by hydrogen refueling stations in several ways, each with pros and cons of their own. The location of the station, the amount of demand and the infrastructure that is already in place are some of the factors that affect the supply options that are selected. The primary methods of supplying hydrogen to refueling stations are on-site generation, pipeline delivery and trailer delivery (liquid and gaseous hydrogen). [59]

### 3.3.1 Pipeline supply

Pipeline supply is one of the most effective and scalable methods of delivering hydrogen to refueling stations, particularly in regions with a high demand or established hydrogen infrastructure. In this concept, hydrogen must be transported via specialized pipelines, similar to those used for natural gas distribution.

Depending on the system's length and design, hydrogen pipelines typically operate at pressures between 10 and 100 bar. To prevent hydrogen embrittlement, these pipelines are made of special materials, usually premium stainless steel or steel coated with polymers. The inner diameters of hydrogen pipelines range from 100 to 300 mm, allowing for high flow rates and requirements. [60]

A major benefit of pipeline supply is its capacity to offer a steady and dependable source of hydrogen. This removes the need for regular deliveries via truck or rail, lowering transportation expenses and related

emissions. Up to 100000 kg of hydrogen can be transported daily over more than 100 km by a single 200 mm diameter pipeline operating at 50 bar, which is sufficient to supply multiple refueling stations. [61]

Additionally, pipeline systems save money. The cost of transporting one unit of hydrogen decreases as the network expands, making it a desirable option for regions with rising hydrogen demands. Depending on the terrain and existing infrastructure, the initial investment needed to build a pipeline can range from 500000 € to 1,7 million € per kilometer. [61]

The development of the hydrogen economy is related to the growth of hydrogen pipeline networks. The economic viability of pipeline infrastructure is increasing because of the expanding number of refueling stations and the expanding use of hydrogen technologies across various industries. Development of hydrogen refueling networks depends on the interdependent relationship between supply infrastructure and demand expansion. [62]

### 3.3.2 Trailer supply

Hydrogen trailer supply system typically consist of high-pressure storage tanks, regulation of pressure systems, security measures and cooling systems. They must withstand severe conditions while maintaining a safe and efficient distribution of hydrogen, so their structural integrity and design are essential. [63]

The storage capacity of hydrogen trailers differs based on the method of storage employed. Standard tube trailers for compressed gaseous hydrogen can transport approximately 300-600 kg of hydrogen at pressures between 200 and 500 bar. In contrast, liquid hydrogen trailers can carry much greater volumes, with capacities between 3000 and 3800 kg of hydrogen. Storing liquid hydrogen provides a greater density, but requires cryogenic temperatures around -253 °C, posing further technical difficulties and energy demands to sustain such low temperatures. [64,65]

Figure 3-7: Gaseous hydrogen tube trailers. [66]

Recent progress in hydrogen storage technologies features the creation of high-capacity solid-state hydrogen storage materials and systems based on Mg. These materials provide possible improvements in storage capacity and safety when compared to conventional compressed or liquefied hydrogen storage techniques. Moreover, investigations continue into liquid organic hydrogen carriers (LOHCs) as a viable option for transporting high amounts of hydrogen, which could provide the conversion of current oil infrastructure for hydrogen storage and transit. LOHCs are organic substances that can reversibly attach hydrogen through catalytic hydrogenation and liberate it through dehydrogenation (see Figure 3-8). This

method enables hydrogen to be kept and moved in a liquid form at normal conditions. Using LOHCs removes the requirement for high-pressure tanks or cryogenic setups, minimizing safety hazards linked to hydrogen's instability and flammability. [67,65,68]

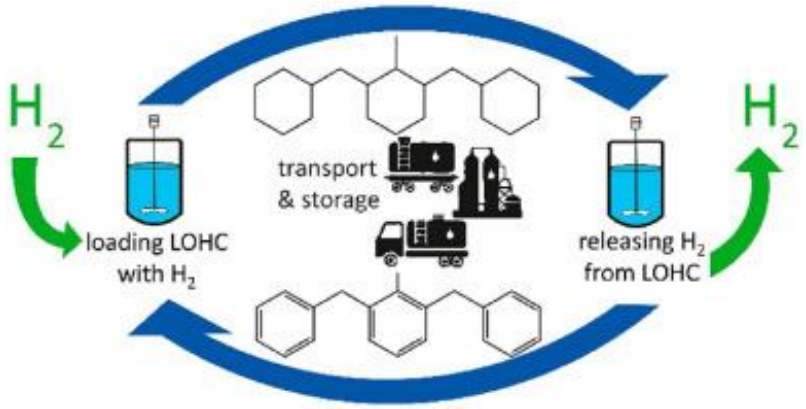


Figure 3-8: LOHC hydrogenation and dehydrogenation cycle. [69]

Nevertheless, it's important to recognize that increasing the size of storage tanks can result in excessive expenses. The ideal tank capacity relies on several factors, such as the application needs, load profile and system limitations. [70]

### 3.3.3 On-site production

On-site hydrogen production is a developing method to create hydrogen where it is needed, not requiring extensive transportation and large storage systems. The primary techniques for on-site production consist of water electrolysis, steam methane reforming (SMR), partial hydrocarbon oxidation and autothermal reforming. Water electrolysis is regarded as the most eco-friendly technique, using electricity to divide water molecules into hydrogen and oxygen, particularly when driven by renewable energy sources to generate "green" hydrogen with negligible carbon emissions (see Figure 3-9). [71,72]

The technical specifications of on-site hydrogen generation systems differ based on the technology implemented. Alkaline and proton exchange membrane (PEM) electrolysers are commonly used for electrolysis. These systems can vary in size from small units that produce several kilograms each day to larger facilities that can generate hundreds of kilograms daily. For example, a system intended for gas turbine fuel provision could feature a 2,1 MW alkaline electrolyser energized by an 8 MWp solar plant. [73]

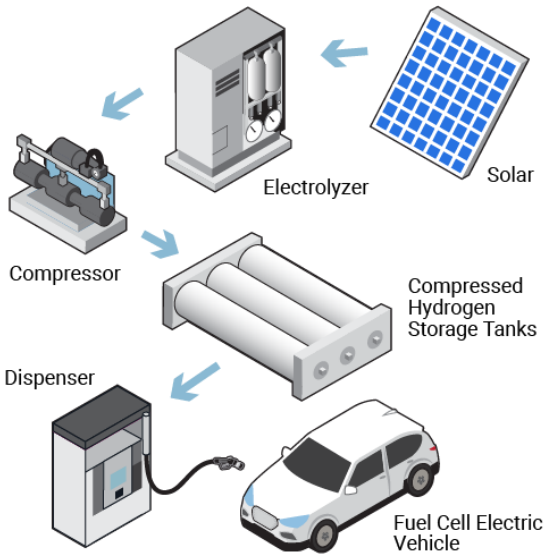


Figure 3-9: On-site green hydrogen production. [74]

On-site hydrogen generation offers numerous advantages, such as lower transportation costs, fewer emissions and the potential to integrate with renewable energy sources. However, there are still issues, like the need for a dependable and reasonably priced renewable energy source and the high capital costs of electrolysers. [71]

Recent advances in on-site hydrogen generation have integrated artificial intelligence and machine learning to increase system efficiency and lower operating costs. Additionally, improvements in electrolyser design are making on-site production systems more reactive and flexible, making them better suited for integration with variable renewable energy sources. [71]

## 3.4 Liquid vs gaseous hydrogen station

The advantages and disadvantages of various refueling station types were examined, along with their layouts with liquid ($LH_2$) and gaseous ($GH_2$) storage tanks.

The infrastructure for gaseous hydrogen storage today is usually provided by tube trailers or on-site facilities, but future stations could be supplied through a pipeline. In any case, regardless of the source of the gaseous supply, the gaseous station may be conservatively built to handle a supply pressure of 20 bar hydrogen. These hydrogen stations have a high-pressure compressor, which extracts hydrogen from the power source and compresses it to about 950 bar before storing it in a high-pressure storage facility. Hydrogen from the high-pressure system is then pumped into the vehicle onboard tank via a refrigeration device. The chiller pre-cools the hydrogen to about -40 °C, thus preventing the scorching of the tank while refilling at a fast pace. Another variant includes a storage compressor extracting hydrogen from the source supply and compressing it to a pressure of approximately 500 bar and storing it in a medium pressure hydrogen storage system. A booster compressor draws hydrogen from a medium-pressure hydrogen storage vessel and compresses it to a pressure of about 900 bar and delivers it to the vehicle storage tank via a pre-cooling device and a dispensing unit. Along with that, the high-pressure buffer tanks are installed to dampen the influence of the booster compressor's pulsing on the station and vehicle gauges, while the dispenser monitors and adjusts the hydrogen flow in the vehicle's onboard tank. [75]

For liquid storage, hydrogen is pressurized using a cryogenic pump and gasified using an evaporator. The high-pressure gaseous hydrogen coming from the evaporator should be stored in the high-pressure system storage tank, which was then pre-cooled up to -40 °C by the cooling unit (chiller) and then transferred to the vehicle tank. In this design, hydrogen is cryogenically cooled by means of cryogenic hydrogen through the pre-cooling unit. [75]

From an energetic point of view, benchmarks could be defined even for liquid and gaseous hydrogen filling stations. Bauer et al. have analyzed the energy consumption of all major components in $GH_2$-HRS using a direct refueling procedure and in $LH_2$-HRS using a cryogenic pump, during a period of 500 s for a sequence of three refueling processes, assuming [75]:

- Compressor capacity: 56 kg/h
- Cryogenic pump capacity: 56 kg/h
- Low-pressure storage: 41,5 kg (maximum 50 bar)
- High-pressure storage: 20 kg (maximum 500 bar), 20 kg (maximum 700 bar), 14 kg (max. 900 bar).

However, the studied refueling processes should be regarded as valid only within narrow conditions, that is, for successive fills separated by small time intervals and with negligible boil-off losses at liquid hydrogen filling stations and losses due to gaseous hydrogen filling stations. In fact, these effects become larger and hardly negligible as the refill rates decrease.

The analysis of the refueling processes demonstrated that consumption was 2,43 kWh/kg in the case of $GH_2$-HRS and 0,37 kWh/kg for $LH_2$-HRS. In any case, this means that the compressor is the main consumer in the gaseous hydrogen arrangement, but these results are valid only for the consumption related to refueling. [75]

While liquid hydrogen is favored because of low refueling energy use, its generation is very inefficient as quite a lot of energy is used in the liquefaction process. The estimated consumption for hydrogen liquefaction, when considering future large-scale distribution, ranges from 5 to 8 kWh/kg, while compression for truck transport of gaseous hydrogen requires about 1,1 kWh/kg-based on an initial pressure level of 100 bar and a final value of 550 bar. Transportation consumption must be accounted as well. Bauer et al. studied a 200 km trip and transport capacities of 1 t and 3,5 t of $GH_2$ are considered. In this case, a diesel truck's consumption of 30 l/100 km and a diesel LHV of 11,33 kWh/l have been considered. Hence, the transport consumption for gaseous hydrogen resulted in being 0,68 kWh/kg and for liquid hydrogen 0,20 kWh/kg. The rough estimate for the energy consumption from production would amount to 4,21 kWh/kg for the gaseous state and to 5,57-8,57 kWh/kg for the liquid state of hydrogen, according to Figure 3-10. [75,76]

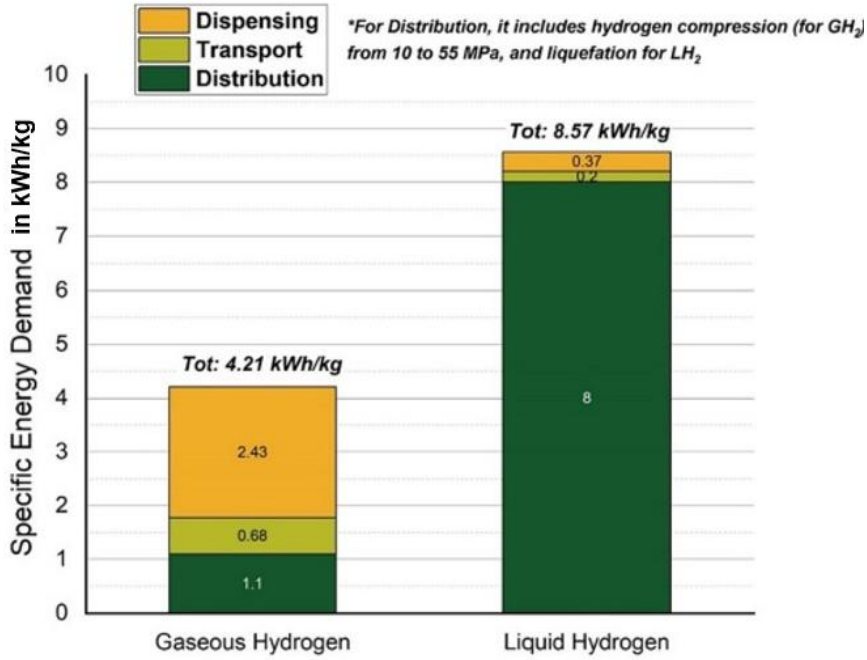


Figure 3-10: Energy demand for $GH_2$-HRS and for $LH_2$-HRS, from production to dispensing. [75]

Therefore, while energy savings on station consumption and some on transportation are realized, the liquid hydrogen path is less viable when the big picture is considered.

# 4 ANALYSIS OF THE HYDROGEN SUPPLY INFRASTRUCTURE

Examining hydrogen supply infrastructure is essential for the effective establishment of a hydrogen-oriented economy. Manufacturing plants, storage options and transportation networks are all part of this infrastructure. One major obstacle to the development of hydrogen supply infrastructure is the requirement for long-term, extensive storage options to meet increasing demand. The method of hydrogen production that is selected affects the overall infrastructure requirements and costs. [77]

The profitability of hydrogen supply systems depends on several factors, such as production volume, transportation options and local energy prices. As the hydrogen economy expands, increasing the synergy of production, storage and distribution systems will be needed for minimizing costs and boosting overall efficiency. [78]

## 4.1 National and international developments

Major efforts are being made to develop robust hydrogen refueling systems as countries all over the world recognize the potential of hydrogen as an environmentally friendly energy carrier. Austria's ambitious plan to build an advanced hydrogen network by 2050 is outlined in the $H_2$ Roadmap 2.0, which is shown in Figure 4-1. The network will mostly be created by modifying existing gas pipelines, building 730 km of new pipelines and renovating 1420 km of existing infrastructure. The plan aims to guarantee a steady supply of hydrogen that grows as demand increases. [79]

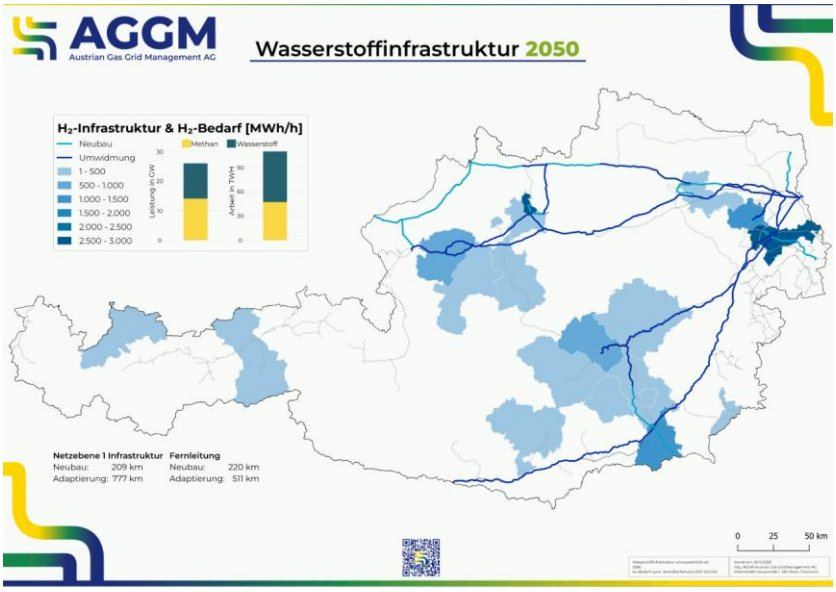


Figure 4-1: $H_2$ Roadmap - Austrian hydrogen strategy. [79]

An agreement to establish the Southern Hydrogen Corridor has been signed by Germany, Italy and Austria. As shown in Figure 4-2, this global project aims to move green hydrogen from Northern Africa to Southern Germany via Italy and Austria. By 2030, the 3300 km pipeline should be operational, potentially contributing up to 40 % of the EU's RePowerEU target. [80]

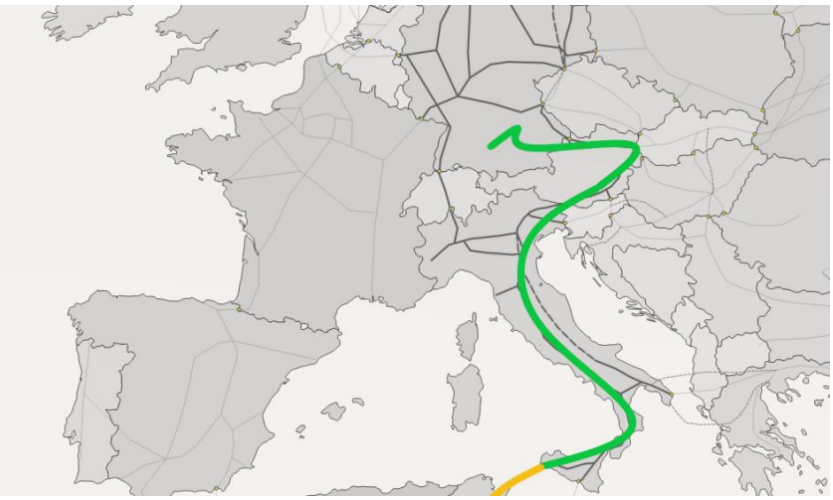

Figure 4-2: Map of South Hydrogen Corridor. [80]

The REPowerEU initiative has identified Ukraine as a key partner for the European supply of renewable hydrogen. Ukraine's renewable energy resources, especially from solar and wind, make it a potential major supplier of "green" hydrogen for the European Union. They offer advantageous conditions for building hydrogen infrastructure. The Central European Hydrogen Corridor is one important initiative to connect Ukrainian hydrogen production to European markets. Ukraine's possible involvement in the 2 x 40 GW initiative seeks to develop 10 GW of electrolysis capacity nationally by 2035, reinforcing its position as a major hydrogen provider to the EU. [81]

Nonetheless, considerable advancements are occurring in the establishment of hydrogen refueling stations too. Several hydrogen-related funding initiatives are part of Italy's National Recovery and Resilience Plan. The nation plans to build 48 hydrogen fueling stations for cars and 10 hydrogen-powered train lines by 2026. [82]

The possibility of producing hydrogen with low carbon emissions is being investigated by the US. The levelized cost of hydrogen produced from natural gas with carbon capture and storage ranges from 1,43 € to 1,76 € per kg $H_2$, while life cycle emissions in Wyoming range from 3,85 to 5,74 kg $CO_2$/kg $H_2$. The creation of hydrogen clusters in these locations can profit from the accessibility and availability of a variety of natural resources as well as transportation systems, which could lower supply costs. [83]

The Japanese government has been actively encouraging the growth of a hydrogen-focused society to address certain social issues. The Japanese government finalized its "Basic Hydrogen Strategy" in 2017 and revised it in June 2023 to enter international markets. This plan establishes challenging targets for the amount of hydrogen used, with roughly 3 million tons per year by 2030, 12 million tons per year by 2040 and 20 million tons per year by 2050. [84]

Strategic policy initiatives are required to accelerate the integration of hydrogen into the global energy landscape and these include government subsidies, research and development support and international partnerships. With the aid of a thorough policy framework, that is in line with international sustainability goals, hydrogen can be established as an essential component of future sustainable energy policies. [85]

## 4.2 Evaluation of the existing filling station infrastructure in Europe

By focusing on meeting the needs of both passenger cars and heavy-duty vehicles, Europe's network of hydrogen refueling stations has been gradually growing. By the end of 2023, there were 265 operational hydrogen refueling stations throughout Europe, with Germany having the most (see Figure 4-3). [86]

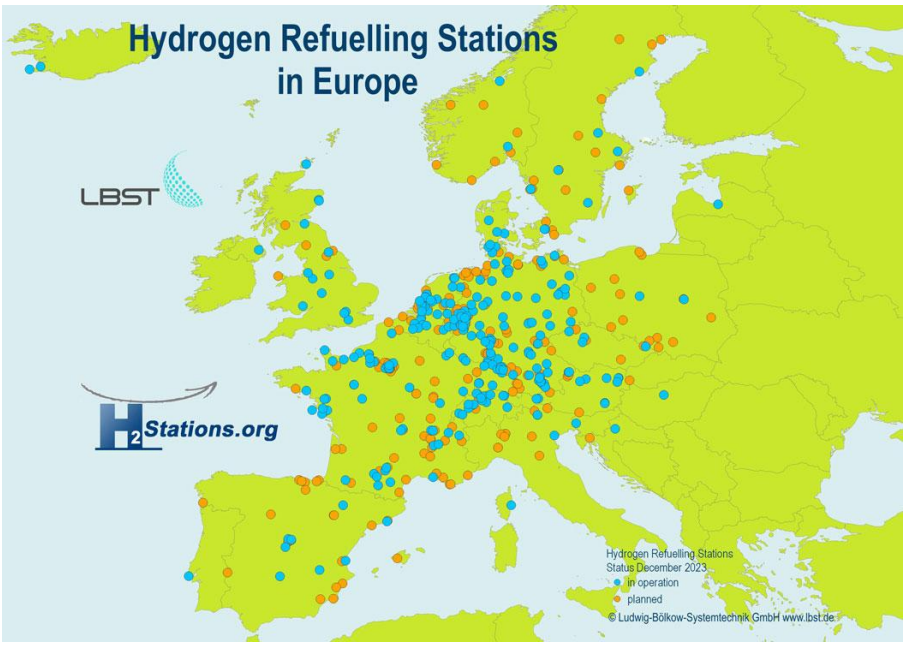


Figure 4-3: Map of hydrogen refueling stations in Europe. [86]

France has 51 operational stations, while the Netherlands and Switzerland operate 22 and 17 stations. This distribution demonstrates the unequal development of hydrogen infrastructure in many European nations, with some adopting a more proactive approach to creating an extensive network of refueling stations. [86]

Heavy-duty vehicle adaptation has become popular in recent years. In 2023, 92 % of the newly constructed hydrogen refueling stations in Europe were made to fit both passenger cars and big commercial vehicles like buses and trucks. This change shows how hydrogen's potential to reduce carbon emissions in the commercial transportation sector is becoming increasingly recognized. [86]

A growing focus on new configurations is a sign of the development of the HRS. In 2019, about 70 % of newly constructed refueling stations were designed specifically for passenger cars. With this change, hydrogen mobility will be approached more comprehensively, enabling a greater variety of vehicle types and possibly increasing the adoption of hydrogen technology in numerous transportation sectors. [86]

Germany has been actively improving its current infrastructure, even though it only opened 8 new hydrogen refueling stations in 2023. A lot of existing locations were upgraded to support heavy-duty vehicle refueling, indicating a dedication to adjusting the network to changing requirements. [86]

# 5 INNOVATIVE CONCEPTS FOR HYDROGEN REFUELING STATIONS

Hydrogen refueling station concepts are evolving to address infrastructure design challenges, scalability and adaptability to diverse customer needs. As the global transition to decarbonization accelerates, hydrogen's position as a clean and adaptable energy source becomes increasingly important. [41]

Scalability and modularity are placed as top priority in modern designs, enabling rapid station deployment and expansion in response to growing demand. These modular techniques provide a flexible structure for urban, suburban and rural applications while reducing construction costs and operational disruptions [87]. Furthermore, by lowering carbon emissions associated with hydrogen storage and transportation, the use of on-site hydrogen production techniques enhances the environmental advantages of these stations. [41]

The use of hydrogen refueling stations is essential for the deployment of a range of hydrogen-powered vehicle fleets, from compact cars to massive trucks. Building infrastructure to meet those demands requires advanced engineering and a deep comprehension of the dynamics of vehicle fleets. [88]

Economic factors need to be considered when designing hydrogen refueling stations, with an emphasis on lowering capital and operating costs. By making use of already existing infrastructure, such as natural gas pipelines and electrical grids, hydrogen distribution networks can be expanded in a cost-effective manner. These strategies ensure that hydrogen refueling stations can be constructed in a way that is both economically viable and practical, even in locations with low initial demand. [41,89]

## 5.1 System architecture of the HRS

A compressor, dispenser, high-pressure storage container, water chiller, heat exchanger and other necessary hardware are all parts of the HRS system. Only when the entire system is successfully integrated and optimized can the best possible balance between cost and performance be determined. Hydrogen is typically produced, transported to stations, compressed to predetermined pressure using compressors, stored in stationary high-pressure tanks and then dispensed into FCVs using hydrogen dispensers during the HRS process. The process mostly depends on how hydrogen is transported and stored as well as how equipment is set up. The feasibility of implementing the options for HRSs with different hydrogen refueling capacities is shown in Figure 5-1. It is more economical and sensible to use $CGH_2$ trucks or tube trailers for delivery during the early stages of the small-scale HRS market. [90]

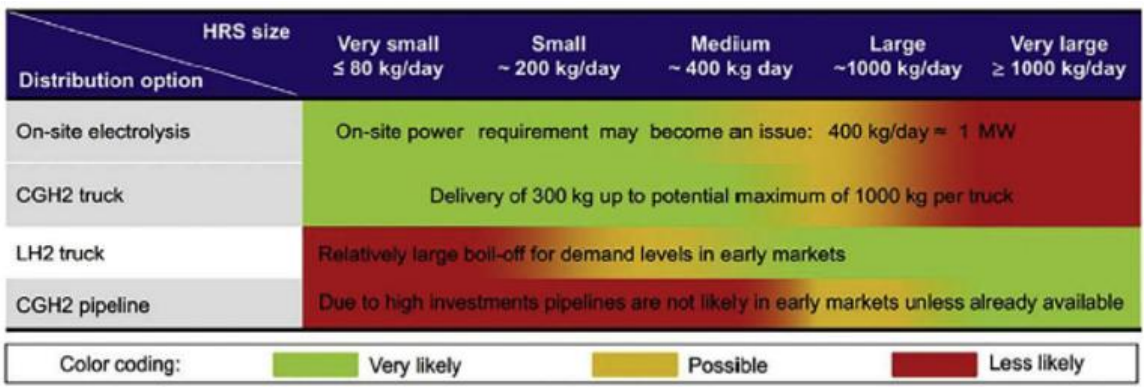


Figure 5-1: Economic feasibility of different $H_2$ distribution options for different station sizes. [90]

The principal elements for determining the optimum configuration of the refueling station include:

- Dispenser configuration
- Demand profile
- Cascade charging system
- Cost optimization

The number of buffer tanks (cascades) considers the number of FCEVs served during standard times (operational efficiency). Furthermore, tanks need to be replenished below 700 bar prior to a FCEV arriving at the HRS. Examples of refueling with multiple vehicles should also be considered. This parameter is called the “hose occupied fraction” (HOF), which represents the average amount of time each hose is using during the busiest hour of the busiest day and reflects the effective functioning of the HRS, allowing for an estimate of the number of dispensers. The correct values for HOF should be at or under 50 % (approximately 30 min/h). To achieve this, HOF is computed for each scenario to ascertain the ideal quantity of dispensers through the equation:

$$\mathrm{HOF} = \frac{\mathrm{n_v} \cdot \mathrm{t_{tot}}}{\mathrm{n_h} \cdot 60} \qquad (3)$$

Where $n_v$ are the maximum refueled vehicles per hour, $t_{tot}$ is the total occupied hose time in min and $n_h$ is the number of available hoses at HRS. [91]

Having established HOF, the quantity of dispensers needed for different refueling station capacities was computed, as shown in Figure 5-2. The figure additionally indicates that the divergence from the perfect HOF of 50 % diminishes at the greater station sizes. This could lead to cost advantages, since having fewer dispensers might lead to reduced maximum flow rates and consequently lower expenses for compressors and cascade charging. Despite the dispersion in the graph, the equation ( 4 ) can be used to determine the number of dispensers, reliant on the daily capacity of the refueling station [92]:

$$\text{Number of dispensers} = \frac{\text{daily capacity}}{(305{,}85 \cdot \text{daily capacity}^{0{,}0763})} \qquad (4)$$

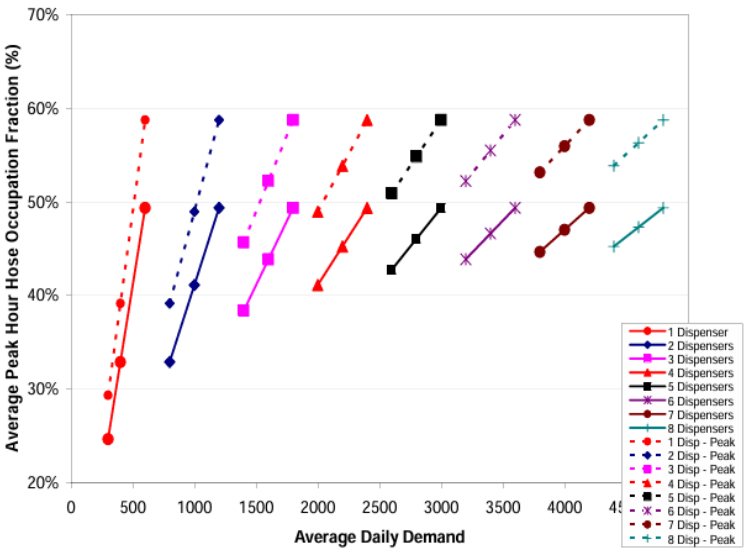


Figure 5-2: Recommended number of refueling station dispensers. [99]

The compressor size and cascade charging system are ultimately dictated by the dispenser configuration and station demand. Typically, the average daily fuel requirement dictates the dispenser setup, with station capacities between 300 and 4800 kg/day needing 1 to 8 dispensers. [92]

**Demand profile**

Besides the dispenser setup and the typical capacity, the daily demand pattern greatly influences the needs for compression and the cascade charging system. Recognizing the demand pattern throughout the whole day is important because of the inter-hour impacts on the cascade charging system and the compression needs. Creating the system solely to fulfill an hourly requirement can negatively impact performance in later hours. For instance, if a compressor capacity of 75 kg/h and a useful cascade charging system capacity of 25 kg are required to satisfy an hourly demand of 100 kg, the cascade charging storage will deplete and the system cannot fulfill any hourly demand exceeding 75 kg in the next hour. Similar to the dispenser calculations, the station calculations relied on the Friday daily demand (see Figure 5-3). [92]

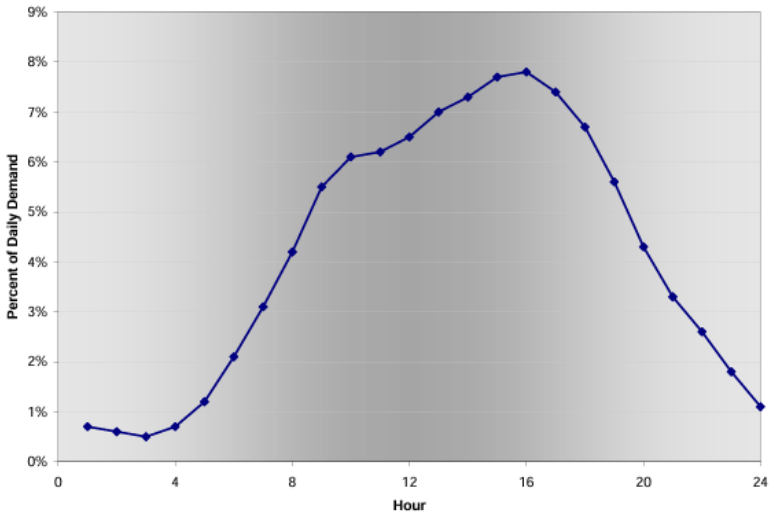


Figure 5-3: Refueling demand curve for Friday. [92]

**Cascade charging system**

The storage system consists of a three-tier cascade that is refilled by the compressor. Every vessel is capable of functioning at the designed pressure of 450 bar. Nevertheless, two out of three vessels typically function at decreased pressures to minimize the daily energy requirements of the compressor. For instance, the low-pressure vessel delivers hydrogen when the vehicle's tank pressure is below 140 bar, the mid-pressure vessel provides hydrogen when the tank pressure ranges from 140 to 300 bar and the high-pressure vessel supplies the vehicle with hydrogen from 300 to 415 bar. [92]

As the model advances through the demand cycle, a logical system identifies which vessels require refilling from the compressor. When the pressure in a container drops beneath the limit, the compressor starts to refill that container. Should the pressure in a vessel drop below its minimum value at any stage of the demand cycle, the storage vessels are insufficiently sized. If the model assesses the complete demand cycle without a low-pressure mistake, there is adequate storage available for the specified demand and compressor capacity. Figure 5-4 illustrates an example of pressure calculations throughout an entire demand cycle for a refueling station. [92]

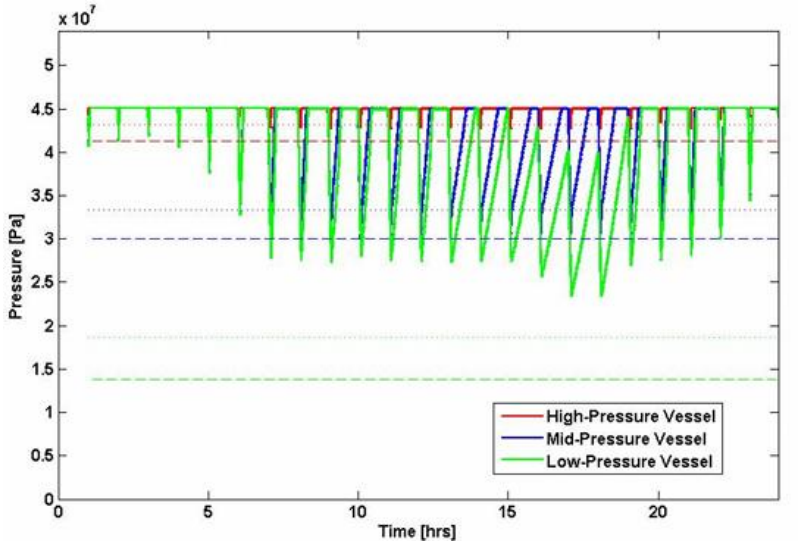


Figure 5-4: Fluctuations in cascade charging system pressure during a demand cycle. [92]

Calculations were created for various refueling station capacities. Based on this information, two dimensionless parameters were created, as outlined below:

- The compressor dimensions are standardized by using the smallest compressor size (*Cm*) to formulate the non-dimensional variable *C/Cm*. The smallest compressor size is the daily station capacity, in kg/day, divided by 24 hours per day.
- The storage size (*St*) is standardized by the station's daily capacity in kilograms (*Cap*) to form the non-dimensional parameter, *St/Cap*.

Findings from the scenarios of the ten refueling stations are shown in Figure 5-5. The non-dimensional parameters distinctly demonstrate a connection between cascade charging and compressor capacities across different sizes of refueling stations. Consequently, the identical correlation between the capacity of the cascade charging system and compression for gaseous refueling stations shown in Figure 5-5 is relevant to the connection between cascade capacity and pump/vaporizer for liquid refueling stations. [92]

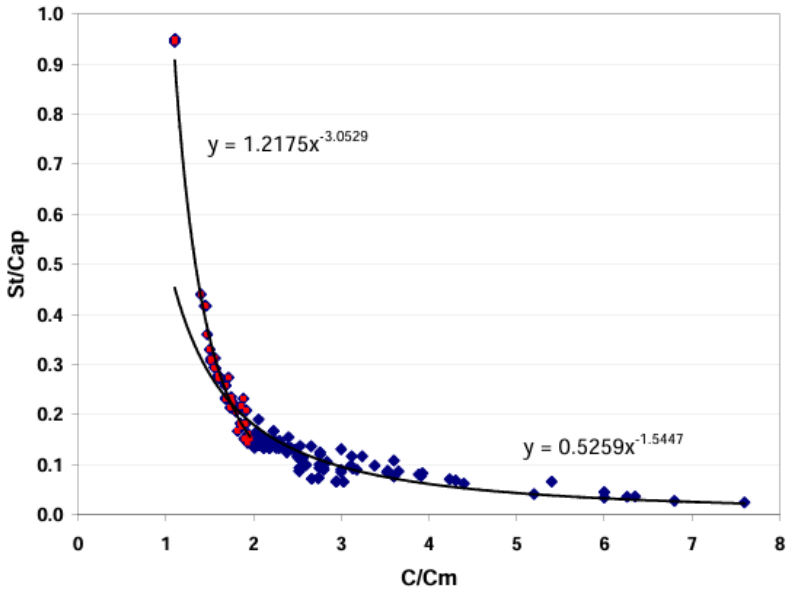


Figure 5-5: Relationship between compressor and cascade charging capacity. [92]

## 5.2 Technical model of the HRS

### 5.2.1 Objectives and scope

The technical model of the HRS is a systematic framework that converts site-specific factors and estimates hydrogen demand into an accurate technical configuration for the station. By providing a methodical evaluation of several hydrogen supply options under identical conditions, the main objective is to ensure that the chosen setup is both technically feasible and scalable to meet the future demands.

The model was designed to operate at an existing fuel station using a demand forecast for 2025–2035. According to this forecast, the hydrogen infrastructure is designed to make the most of the space and resources that are available while ensuring that the HRS can consistently meet future demands.

The entire technical process is included in the model, from on-site generation or delivery of hydrogen to dispensing at the necessary pressure levels. It describes the components, flow patterns and operational requirements of each supply option. The supply options considered are:

- Pipeline supply ($CGH_2$)
- $CGH_2$ truck delivery
- $LH_2$ truck delivery
- On-site electrolysis (powered by PV, wind or grid electricity)

The scope of the model includes:

- Identifying essential input factors like hydrogen requirements, site area accessibility, operational hours and infrastructure readiness.
- Organizing the technical setup for each supply option, encompassing storage solutions, compressors or pumps, cooling systems and dispensers.
- Applying sizing guidelines derived from demand patterns to assure the required capacity for each key component.
- Assessing technical viability while taking operational constraints, space requirements and scalability potential into account.

Only the technical aspects of the HRS model are covered in this chapter. Chapter 6 - Economic feasibility analysis will address the analysis of economic feasibility, including CAPEX, OPEX and profitability.

### 5.2.2 Input parameters

To determine the station's configuration and capacity needs, the operator must submit some parameters to the technical HRS model. These inputs are directly entered into the model and serve as the basis for all technical sizing calculations. The numbers are adjusted using projections for the years 2025-2035 and are based on operational data from the current fuel station. To start determining the size of a hydrogen refueling station, demand analysis must be prioritized first.

**Number of vehicles per day**

Choosing the best hydrogen supply method for a refueling station largely relies on the anticipated daily dispensing capacity. This parameter tracks the current daily flow of passenger cars and heavy-duty vehicles at the current fuel station. As shown in Table 1, the station presently accommodates an average of 65 passenger vehicles and 70 trucks/buses daily. These figures are inputted into the model as provided by operators and establish the baseline for forecasting future hydrogen demand for every vehicle category.

| **Information from existing filling station** | |
|---|---|
| Number of cars per day | 65 |
| Number of trucks/buses per day | 70 |
| Available area in $m^2$ | 60000 |
| Operating time in h/day | 16 |

Table 1: Current number of vehicles per day at the existing station (Source: own illustration based on model configuration).

Compared to other driving technologies like BEV and hybrid cars, the growth in hydrogen passenger vehicles is expected to be relatively modest in the 2025-2035 forecast (see Table 2). Therefore, during the forecast period, the demand for hydrogen in passenger cars will remain comparatively low. To ensure accurate sizing of the 700 bar dispensing capacity, the demand for passenger cars must be taken into account. In contrast, the heavy-duty segment shows a different trend. According to predictions, the percentage of hydrogen trucks and buses will increase by 2035 as a result of EU $CO_2$ emission reduction targets. [93]

Although the current number of hydrogen-fueled heavy-duty vehicles is still limited, forecasts indicate an increase by 2035. This expansion affects technical sizing, as one truck refueling typically requires about 65 kg of hydrogen, whereas a passenger car consumes roughly 6 kg per refueling (own estimation based on FCEV specifications such as Toyota Mirai and Hyundai Nexo). Consequently, heavy-duty demand will be the primary factor affecting total station capacity, impacting the dimensions of storage tanks, the quantity and flow rates of compressors or pumps and the required delivery volumes in truck-based supply situations ($CGH_2$ or $LH_2$). The projection indicates that although hydrogen use in passenger cars grows slightly, the demand from trucks and buses escalates, exceeding 630 kg/day by 2035.

| | | |
|---|---|---|
| **Realistic forecast for year** | 2031 | ***Please select a year (2025-2035)!*** |
| **$H_2$ daily requirement in kg/day** | **363** | *The daily requirement in 2031: 3,6 kg for cars and 359,5 kg for trucks/buses, which corresponds to 1 cars and 6 trucks/buses* |

| **Car** | | | | | |
|---|---|---|---|---|---|
| **Jahr** | **2025** | **2026** | **2027** | **2028** | **2029** |
| **Share ICE (incl. HEV)** | 71,00% | 65,50% | 60,00% | 54,50% | 49,00% |
| **Share BEV (incl. PHEV)** | 27,00% | 32,30% | 37,60% | 42,90% | 48,20% |
| **Share FCEV** | 0,80% | 0,82% | 0,84% | 0,86% | 0,88% |
| **$H_2$ daily requirement forecast in kg/day** | **3,1** | **3,2** | **3,3** | **3,4** | **3,4** |
| **$H_2$ annual demand forecast in kg/year** | **1138,8** | **1167,3** | **1195,7** | **1224,2** | **1252,7** |

| **Truck/Bus** | | | | | |
|---|---|---|---|---|---|
| **Year** | **2025** | **2026** | **2027** | **2028** | **2029** |
| **Share ICE** | 90,40% | 87,20% | 84,00% | 80,00% | 78,00% |
| **Share BEV (incl. PHEV)** | 6,60% | 9,00% | 12,00% | 15,00% | 16,00% |
| **Share FCEV** | 3,00% | 3,80% | 4,00% | 5,00% | 6,00% |
| **$H_2$ daily requirement forecast in kg/day** | **136,5** | **172,9** | **182** | **227,5** | **273** |
| **$H_2$ annual demand forecast in kg/year** | **49822,5** | **63108,5** | **66430,0** | **83037,5** | **99645,0** |

| **Car** | | | | | | |
|---|---|---|---|---|---|---|
| **Jahr** | **2030** | **2031** | **2032** | **2033** | **2034** | **2035** |
| **Share ICE (incl. HEV)** | 43,50% | 38,00% | 32,50% | 27,00% | 21,50% | 16,00% |
| **Share BEV (incl. PHEV)** | 53,50% | 58,80% | 64,10% | 69,40% | 74,70% | 82,00% |
| **Share FCEV** | 0,90% | 0,92% | 0,94% | 0,96% | 0,98% | 1,00% |
| **$H_2$ daily requirement forecast in kg/day** | **3,5** | **3,6** | **3,7** | **3,7** | **3,8** | **3,9** |
| **$H_2$ annual demand forecast in kg/year** | **1281,2** | **1309,6** | **1338,1** | **1366,6** | **1395,0** | **1423,5** |

| **Truck/Bus** | | | | | | |
|---|---|---|---|---|---|---|
| **Year** | **2030** | **2031** | **2032** | **2033** | **2034** | **2035** |
| **Share ICE** | 73,00% | 70,00% | 69,00% | 63,30% | 57,20% | 51,60% |
| **Share BEV (incl. PHEV)** | 20,00% | 22,10% | 23,00% | 27,00% | 32,20% | 34,50% |
| **Share FCEV** | 7,00% | 7,90% | 8,00% | 9,70% | 10,60% | 13,90% |
| **$H_2$ daily requirement forecast in kg/day** | **318,5** | **359,45** | **364** | **441,35** | **482,3** | **632,45** |
| **$H_2$ annual demand forecast in kg/year** | **116252,5** | **131199,3** | **132860,0** | **161092,8** | **176039,5** | **230844,3** |

Table 2: Forecast of hydrogen demand per day (2025-2035) by vehicle category
(own illustration based on model configuration). [93]

These input values, along with the anticipated adoption rates of fuel cell vehicles from 2025 to 2035, serve as the foundation for determining yearly $H_2$ demand for passenger cars and heavy-duty vehicles. [93]

The applied values are presented in Figure 5-6, which displays the projected yearly hydrogen usage by vehicle type for the upcoming ten years. In contrast to the small percentage of passenger cars (shown in blue), it highlights the contribution of heavy-duty vehicles (shown in orange) to the overall hydrogen demand. The high rise in heavy-duty vehicles indicates both the anticipated growth in hydrogen-powered trucks and their considerably greater consumption per vehicle. In contrast, the demand for passenger cars remains relatively steady, with just a minor increase.

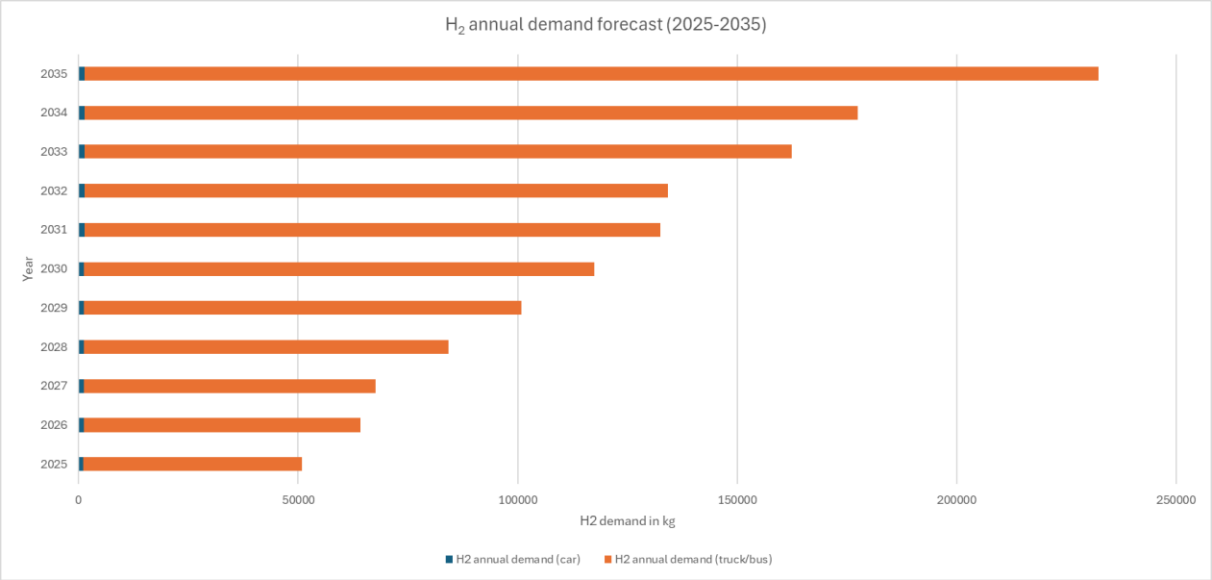


Figure 5-6: Forecast of annual hydrogen demand by vehicle category (2025-2035) (own illustration based on model configuration). [93]

**Available site area**

The space available at the station site is a physical limitation that dictates which supply options are technically viable. Methods for supplying hydrogen vary greatly in their needs:

- HRS supplied by pipelines typically need less space, since extensive storage systems can be minimized or eliminated, with hydrogen delivered continuously under pressure.
- The delivery of $CGH_2$ trucks requires high-pressure storage capacity to accommodate the interval between deliveries, thereby increasing the footprint requirements.
- Delivery of $LH_2$ by truck requires space for cryogenic tanks, vaporizers and related safety areas.
- On-site electrolysis demands room for the electrolyser, water treatment and compression equipment, in addition to needing space for photovoltaic arrays or wind turbines if powered by renewable sources, which can take up considerable space.

To generate hydrogen on location through electrolysis, you require both ultrapure water and photovoltaic (PV) or wind power electricity. Below is the amount needed for each:

- Hydrogen demand: 363 kg $H_2$/day
- Electrolyser water requirement [94]:
  - Theoretical minimum: 9 liters of $H_2O$/kg $H_2$
  - Practical range (including purification and losses): 18 liters of $H_2O$/kg $H_2$
  - Ultra-pure water needed (daily requirement): 363 kg $H_2$ * 9 l $H_2O$/kg $H_2$ = 3267 liters $H_2O$/day (theoretical minimum)
  - Recommended practical estimate:

    363 kg $H_2$ * 18 l $H_2O$/kg $H_2$ = 6534 liters $H_2O$/day (for system losses and water treatment)

- Electrolyser electricity requirement [95]:
  - Electrolyser consumption: 45-55 kWh per kg $H_2$ (assume 50 kWh/kg $H_2$ as an average)
  - Total daily energy: 80 kg $H_2$ * 50 kWh/kg = 18150 kWh/day

- PV system sizing [95]:
  - Average solar yield in Europe: ~ 4 kWh/kWp/day (varies by location and season)
  - Performance ratio: 70 %
  - Required PV capacity: 18150 kWh/day ÷ (4 kWh/kWp/day * 0,7) = 6483 kWp
  - Average PV panel: 400 W (0,4 kW) per panel
  - Number of panels (0,4 kW): 6483 kWp ÷ 0,4 kW/panel = 16207 panels
- Field requirement [96]:
  - Typical area per 0,4 kW panel: ca. 2 $m^2$
  - Total area needed 16207 panels * 2 $m^2$ = 32414 $m^2$
- Wind power system sizing [97]:
  - Specific wind yield: 6,10 kWh/kW/day
  - Performance ratio: 70 %
  - Required wind turbine capacity:
  - 18150 kWh/day ÷ (6,10 kWh/kW/day * 0,7) = 4251 kW total installed capacity
  - Average turbine capacity: 2776 kW per turbine
  - Required number of turbines: 4251 kW ÷ 2776 kW/turbine ≈ 2 turbines
- Space requirement [98]:
  - Typical land area per turbine: 4000 m² (including safety distance and infrastructure)
  - Total land area for 2 turbines: 2 * 4000 m² = 8000 m²
  - Area requirement per kg $H_2$/day: 22,04 m²/kg $H_2$/day

This calculation indicates that meeting the daily hydrogen requirement of 363 kg $H_2$ solely via wind-powered electrolysis would need a pair of contemporary wind turbines with a total capacity of around 4,25 MW, covering about 0,8 hectare of land. Local wind conditions and turbine configuration affect the precise yield and amount of land required. By defining the exact site area, the model ensures that only physically feasible configurations are evaluated.

**Operating time**

The daily operating period establishes the timeframe during which the entire hydrogen requirement must be fulfilled. This parameter has a direct effect on the required throughput of main HRS components, including compressors, pumps, vaporizers and cooling systems. Due to shorter operating hours, the same amount of hydrogen must be delivered daily in less hours.

Demand for hydrogen refueling, particularly for fleets, typically happens during concentrated periods rather than being distributed evenly throughout the day. This implies that even with extended daily operating hours, equipment dimensions must account for peak demand. To ensure that the system is sized to handle both average and peak demand without causing problems or unused capacity, the operating time input is important.

**Cost-related parameters**

The station operator directly inputs all the model's cost-related parameters. Since it affects every energy-consuming process in the HRS, from compression and pre-cooling in $CGH_2$ delivery to pumping and vaporization in $LH_2$ systems, the price of electricity in €/kWh is a significant consideration. Since electricity

usually accounts for a big part of total operating expenses, even slight price changes can have an impact on overall profitability. The high demand for ultra-pure water and the requirement to account for water treatment costs make the **water cost** in €/l, which is typically a small part of overall OPEX, more important for on-site electrolysis

Another important factor is the **existence of a hydrogen pipeline** close to the station (see Table 3). If a connection is possible over a short distance, it enables continuous, large-scale supply without the need for road transportation, reducing transportation costs and environmental impacts while reducing the need for substantial on-site storage. Because it has a direct impact on the connection cost, the operator also provides the pipeline distance in km in addition to the "Yes/No" input for pipeline availability. Longer distances require more investment and may render this supply option unfeasible, but shorter distances result in lower CAPEX for the connection line and faster implementation.

| | |
|---|---|
| Electricity price in €/kWh | 0,13 |
| $H_2O$ price in €/l | 0,001 |
| | |
| $H_2$ pipeline nearby? | Yes |
| Distance to grid connection point in km | 3 |

Table 3: Cost - related input parameters
(Source: own illustration based on model configuration).

In the end, the operator's provided **hydrogen market price** in €/kg is essential for determining revenue and profitability. This amount is the most realistic price at which hydrogen could be sold given the station's current market conditions. Additionally, the tool's default target ROI (Return on Investment) is set at 6 %, but users can adjust it to suit their own investment goals (see Table 4). The model ensures that the technical design and the subsequent economic assessment are tailored to the actual conditions by obtaining all these parameters straight from the operator.

| **Market price (e.g. Germany)** | |
|---|---|
| Status 2025 in €/kg | 13 |
| | |
| **Target ROI** | **6%** |

Table 4: Market price and target ROI input parameters
(Source: own illustration based on model configuration).

### 5.2.3 Technical structure of supply variants

The technical framework of every hydrogen supply variation outlines the main technical components, their connections and the operational process from hydrogen delivery or production to ultimate dispensing. The model considers four main supply alternatives: pipeline supply, $CGH_2$ truck transportation, $LH_2$ truck transportation and on-site electrolysis (with PV, wind or grid power). Every variant possesses its unique equipment setup, structural needs and operational features. The subsequent sections detail the technical framework of each alternative.

#### 5.2.3.1 Pipeline supply

The most efficient logistical method for getting hydrogen to a refueling station is pipeline supply. According to this model, a regional or national hydrogen pipeline system is directly connected to the station. If a pipeline operates close to the station, it presents a lot of benefits, both technically and economically, since it does not require transportation of hydrogen by road and minimizes on-site storage needs. The hydrogen in these transmission lines is delivered as a gas, usually at pressures ranging from 20 to 100 bar, according to the upstream setup.

Upon arrival at the station through the pipeline interface, fitted with isolating valves, filters, metering devices and pressure control, the hydrogen is directed to a compressor (see Figure 5-7). For refueling both passenger cars and heavy-duty vehicles, the compressor is sized for the station's lowest mass flow rate, incorporating a reserve factor of about 1,3 to secure adequate capacity during high demand. Standard compression energy requirement is approximately 2,43 kWh for each kilogram of hydrogen. The heat produced during compression is removed by a cooler and coolant pump, which has a cooling capacity of approximately 5 % of the compressor's power and a cooling energy of about 0,12 kWh/kg $H_2$. [92]

Hydrogen is sent from the compressor into a high-pressure storage system configured in three pressure levels – 450, 600 and 900 bar. The overall gaseous storage capacity is calculated by applying a storage factor of 0,3 to the daily demand of the station and this is then distributed equally across the three stages. Standard vessel sizes for this application are approximately 9,1 m long and 0,4 m wide. [92]

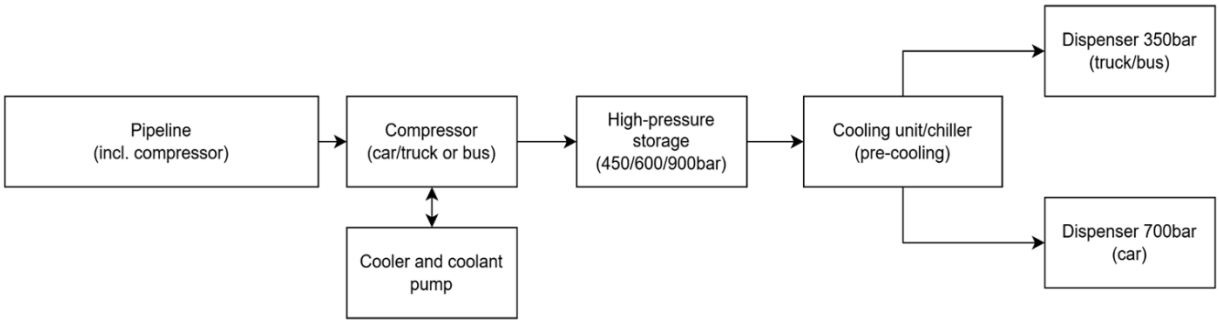


Figure 5-7: Process flow diagram of a pipeline-supplied hydrogen refueling station
(Source: own illustration based on model configuration).

Prior to dispensing, hydrogen designated for 700 bar refueling is routed through a pre-cooling unit (chiller) to attach the SAE J2601 fueling standards. The energy requirement of the chiller usually averages about 0,40 kWh/kg $H_2$, with the overall daily energy usage varying with the station's throughput. This secures that gas temperatures stay within safe ranges during rapid fills, avoiding overheating in vehicle tanks. [99]

Cooled hydrogen is subsequently released through specialized dispensers: one designated for heavy-duty 350 bar refueling (e.g., trucks/buses) and another for light-duty 700 bar refueling (e.g., passenger cars), each fitted with the suitable number of hoses to accommodate anticipated peak rates.

The main benefit of pipeline supply is the removal of hydrogen transportation logistics. There is no requirement for $LH_2$ or $CGH_2$ transport vehicles, no reliance on road transportation timetables and no susceptibility to hold-ups due to traffic or weather conditions. Reduced on-site storage is made possible by ongoing inflow, which lowers structural requirements and CAPEX. The lack of large cryogenic tanks or high-

capacity trailer unloading areas streamlines the site design and makes this alternative ideal for places with restricted space. Furthermore, the system can operate with fewer handling steps, increasing safety and the environmental impact is reduced because delivery vehicles do not emit any emissions.

Furthermore, the system can operate with fewer handling steps, increasing safety and the environmental impact is reduced because delivery vehicles do not emit any emissions. Although pipelines are typically reliable and safe, maintenance activities or upstream disruptions can lead to supply shortfalls, making it prudent to keep at least a minor high-pressure buffer to compensate for short interruptions. The connection must apply to exact safety standards, typically requiring collaboration with different stakeholders, such as pipeline operators, grid regulators and local officials.

In conclusion, pipeline supply offers hydrogen refueling stations an effective, portable and simple operational solution — that is, if the infrastructure is close by and the connection fees are reasonable. The model incorporates this by using pipeline availability and pipeline distance as input factors that directly impact the technical setup and the economic evaluation.

#### 5.2.3.2 $LH_2$ truck delivery

In the $LH_2$ truck delivery option, hydrogen is delivered at cryogenic temperatures (around -253 °C) using vacuum-insulated tank trailers. At this temperature, the density of liquid hydrogen is approximately 71,08 kg/m³, resulting in a much higher volumetric energy density than compressed gaseous hydrogen and providing much larger delivery payloads per journey. This makes $LH_2$ especially attractive for high-throughput facilities where reducing delivery frequency is important.

Upon reaching, the $LH_2$ trailer discharges into a cryogenic storage tank (see Figure 5-8). In the configured model, a small tank type is considered, with total and usable volumes customized to meet the station's needs. The tank features multi-layer insulation and a high-vacuum jacket to reduce heat transfer, leading to extremely low boil-off rates of approximately 0,01 % of the stored volume daily. This storage solution acts as a cushion for deliveries and a way to manage variations in daily demand. [100]

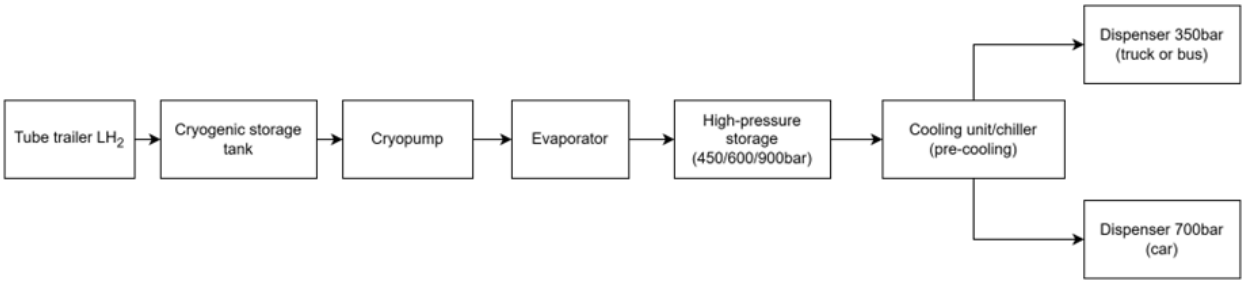


Figure 5-8: Process flow diagram of an $LH_2$ truck-supplied hydrogen refueling station (Source: own illustration based on model configuration).

Liquid hydrogen is moved from the cryogenic tank to a cryogenic pump (cryopump). In contrast to gaseous compression, which requires a lot of energy, cryopumps compress hydrogen while it remains in liquid state, thus improving energy efficiency. Standard usage rates are approximately 0,37 kWh for each kilogram of hydrogen. The pump is sized to handle maximum hourly refueling needs, incorporating a reserve factor to manage unforeseen increases in throughput. [75]

After pressurization, the $LH_2$ is directed to an evaporator, where it transforms into gaseous hydrogen at the required high pressure. Vaporization needs energy amounting to a latent heat of approximately 445 kJ/kg (around 0,12 kWh/kg $H_2$). Vaporizers are typically ambient-air heat exchangers or electrically heated devices, chosen and sized to correspond with the maximum pump output. Typically, it is constructed with a safety factor of 1,3. This secures that, besides the nominal mass flow, short-term peak demands or concurrent refueling activities can be managed without restricting throughput, thus ensuring continuous operation even in times of unanticipated high demand. [101]

Gaseous hydrogen is subsequently moved into high-pressure storage system featuring different pressure levels (450, 600 and 900 bar). This setup enables rapid filling tasks while ensuring that the cryopump can function consistently without being forced to line up with maximum demand directly. The quantity of tanks is determined by the daily hydrogen requirements and refueling pattern of the station.

Prior to being dispensed at 700 bar, hydrogen goes through a pre-cooling unit (chiller) to attach the SAE J2601 fueling standards and to keep gas temperatures within safe limits in the vehicle tanks. Hydrogen stations generally need about 0,40 kWh for each kilogram of hydrogen handling. Dispensing is managed by 350 bar units for heavy-duty vehicles and 700 bar units for light-duty vehicles, with each unit having one or more hoses based on the expected refueling capacity per category. [99]

The $LH_2$ truck delivery setup provides numerous benefits for extensive hydrogen refueling activities. The higher density of liquid hydrogen enables much larger delivery volumes than gaseous hydrogen, leading to fewer truck arrivals and contributing to supply security. Using a cryopump to pressurize hydrogen in liquid form is more energy-efficient compared to compressing gaseous hydrogen from low inlet pressures, lowering operational energy expenses. Additionally, since most of the hydrogen is kept in liquid form, the space required for gaseous high-pressure storage is less than that in $CGH_2$ delivery setups, which can be advantageous for stations with constrained space.

Nonetheless, the $LH_2$ delivery framework also poses some difficulties. Even at low boil-off rates, ongoing losses take place and these losses become more pronounced when demand is low or delivery times are extended. Compared to gaseous systems, cryogenic infrastructure is more technically complex and necessitates specialized storage tanks, pumps, vaporizers and associated safety systems, all of which increase investment costs. Furthermore, producing liquid hydrogen has a significant energy cost that affects overall well-to-wheel efficiency. High operational and safety standards are also enforced by the extreme cold of liquid hydrogen, necessitating trained personnel and careful handling procedures.

In conclusion, $LH_2$ truck delivery is a reliable choice for stations with high demand since it combines a large delivery capacity with efficient pressurization and a reduced need for on-site gas storage. In order to manage boil-off, energy efficiency and safety aspects, it also necessitates a larger upfront investment and careful operational oversight.

#### 5.2.3.3 $CGH_2$ truck delivery

The $CGH_2$ truck delivery option uses high-pressure gas tube trailers to deliver hydrogen to the refueling station. These trailers deliver hydrogen in discrete batches rather than in a continuous stream and they do so at pressures between 200 and 300 bar. This supply approach is especially relevant in situations where there is no hydrogen pipeline accessible and where producing it on-site is either impractical or not cost-

effective. When it arrives, the trailer is connected to the station's unloading interface, which features safety valves, non-return valves and metering systems. Due to inadequate delivery pressure for refueling vehicles at 350 or 700 bar, the gas is directed at a multi-stage compression system (see Figure 5-9).

To accurately size the compressor, the minimum mass flow rate is initially calculated and then multiplied by a reserve factor of 1,3 to secure the system can handle demand spikes. This specifies the operational throughput along with buffer capacity. The energy consumption for compression is approximately 2,43 kWh for each kilogram of hydrogen, representing a big part of the station's daily electricity needs. [92]

The compression process produces heat that needs to be dissipated by a specific cooler and a coolant circulation pump. The share of cooling capacity attributed to the compressor is typically 0,05 of the compressor's energy requirements. The cooling system requires 0,12 kWh of energy for each kilogram of hydrogen, which keeps the compressor operating at safe temperatures and upholds efficiency. [99]

After compression, the hydrogen is kept in a high-pressure storage system arranged in a cascade. To determine this storage, a factor of 0,3 is used, meaning the overall storage capacity is established at roughly 30 % of the daily hydrogen flow. This capacity is subsequently allocated evenly among three pressure levels (450, 600 and 900 bar). The tank design is based on a length of 9,1 m and a diameter of 0,4 m. [92]

Hydrogen goes through a pre-cooling unit (chiller) before being dispensed at 700 bar. This is important for regarding to SAE J2601 fueling standards and preventing high temperatures in the vehicle tanks during fast fills. For design reasons, the energy requirement of the chiller is generally 0,40 kWh for each kilogram of hydrogen, from which the daily cooling energy needs can be calculated based on anticipated throughput. The ultimate delivery to the client is by specialized dispensers, featuring 350 bar units for heavy vehicles and 700 bar units for passenger vehicles. Each dispenser can accommodate one or two hoses based on the anticipated number of refueling activities. [99]

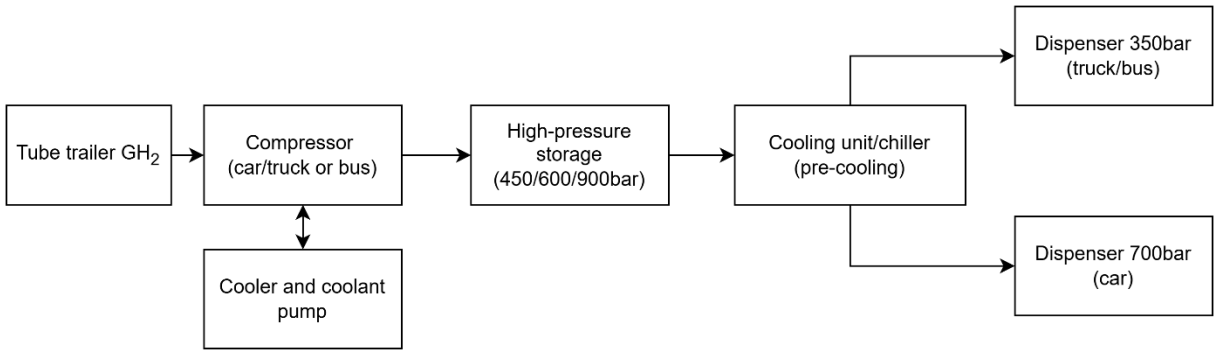


Figure 5-9: Process flow diagram of a $CGH_2$ truck-supplied hydrogen refueling station (Source: own illustration based on model configuration).

$CGH_2$ truck delivery provides hydrogen to stations situated in areas that lack direct access to a hydrogen pipeline. It provides sourcing flexibility, allowing hydrogen to be gained from several production sites, which enables operators to choose competitive providers. The system design is quite simple, requiring no cryogenic equipment and it can be implemented modularly.

An important drawback is the dependence on delivery logistics. The station functions depend on consistent truck deliveries and disruptions from traffic, weather or supplier problems can result in fuel shortages. Due

to hydrogen being supplied in batches, considerable on-site storage is required to ensure supply continuity between deliveries, leading to higher CAPEX and greater space needs. Storage must be engineered for frequent cycling, as banks are continuously emptied and replenished. Moreover, the energy expense for compression is greater than that of pipeline supply, as the incoming gas comes in at relatively low pressure. From an ecological standpoint, the operation of diesel-powered delivery vehicles contributes to $CO_2$ emissions and enlarges the total carbon footprint of the delivered hydrogen.

In summary, $CGH_2$ truck delivery represents a technically advanced and adaptable solution for stations lacking pipeline access. However, its sustained economic and environmental effectiveness is influenced by delivery frequency, transportation distances and compression expenses.

#### 5.2.3.4 On-site electrolysis (PV, wind and grid)

The diagram below (see Figure 5-10), shows the on-site electrolysis process, outlining the entire sequence from renewable or grid electricity provision to hydrogen production and buffering, followed by compression, storage, pre-cooling and dispensing.

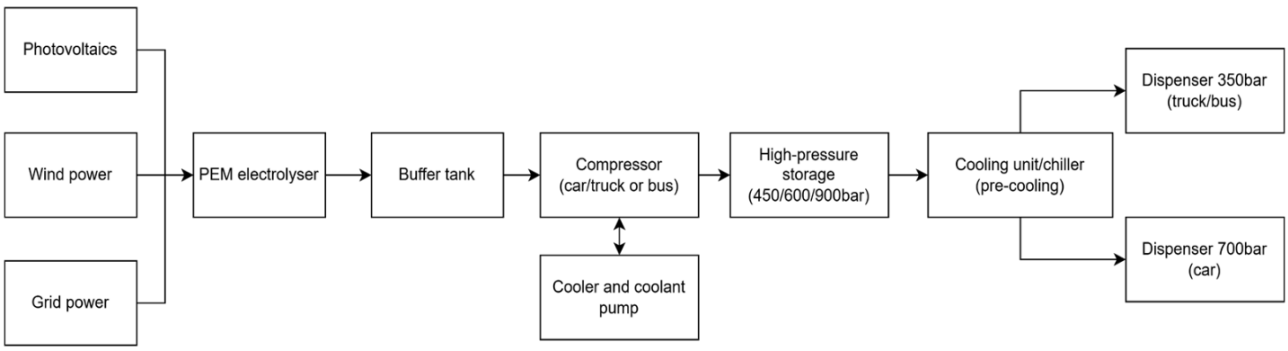


Figure 5-10: Process flow diagram of an “on-site”-supplied hydrogen refueling station (Source: own illustration based on model configuration).

In this model, hydrogen is generated right at the refueling station using a PEM electrolyser powered by photovoltaic (PV), wind or grid electricity. The renewable generation capacity sizing is based on the electrolysers specific electricity demand of 50 kWh for every kilogram of hydrogen. [95]

For PV supply, a defined PV yield of 4 kWh/kWp/day and performance ratio of 70 % are presumed. Using these parameters, the required PV capacity is determined (detailed calculation in 5.2.2.), along with the quantity of modules. Every PV module covers around 2 m², which rules the overall land needed. In this case, 89,29 m² of surface area are needed for each kilogram of production capacity per day. [96]

For wind energy, the computation relies on a designated wind output of 6,10 kWh/kW/day and an identical performance rate of 70 %. From this, the installed capacity is calculated and using a single turbine rating of 2776 kW. The total footprint of the wind park can be calculated assuming that each turbine uses 4000 m² of land. The exact space needed is 22,04 m² for each kilogram of daily hydrogen capacity. [97]

When provided by the electricity grid, the emphasis is on using renewable electricity. The connection capacity, which is sized to support the electrolysers peak load, is the technical requirement in this case.

The specific energy requirement and the total water demand are the two most important parameters for the PEM electrolyser. The rate at which hydrogen is produced is used to calculate the electrolysers total

installed capacity in kW. Furthermore, because operating at partial load for brief periods of time increases the levelized cost of hydrogen, the minimum daily operating hours are set to ensure efficient use.

A low-pressure buffer tank is incorporated to maintain short-term supply stability and to separate electrolyser operation from immediate refueling requirements. By assuming a buffer period of 2 hours, the buffer mass is computed and considering a storage capacity of 125 kg for each tank, the overall number of tanks needed is established. [102]

Each technical component, such as compressor, cooler, cascade high-pressure storage, pre-cooling unit and dispenser, has the same design as that of the $CGH_2$ truck delivery and pipeline supply setups.

From a strategic standpoint, the key benefits of on-site electrolysis are its autonomy from external hydrogen supply chains. The station is independent of truck deliveries or distance to a hydrogen pipeline, removing related transportation expenses, logistical risks and $CO_2$ emissions from road travel. The system can be constructed in a modular way, enabling operators to increase capacity as demand increases and it provides the flexibility to alternate between renewable and grid supply based on availability and economic factors.

Nevertheless, there are certain challenges. On-site electrolysis requires high capital investments, such as land acquisition, renewable energy sources, like solar panels or wind turbines. In expensive or urban areas, the amount of land required, particularly for PV systems, can be enormous and is often a barrier. The capacity factor of the renewable system has an impact on economic viability. Lower solar irradiance or wind speeds directly reduce hydrogen production and raise the levelized cost of hydrogen. Grid-based operations take the weather out of the equation, but they also expose users to changes in electricity prices and may require costly upgrades to the local grid connection.

### 5.2.4 Sizing rules for main components

The input criteria listed in Chapter 5.2.2 and the process-related technical frameworks discussed in Chapter 5.2.3 dictate the sizes of the main components in each hydrogen supply setup. The model takes a series of calculation guidelines to ensure that every component is sized to satisfy the maximum hydrogen demand in the specified year, while preserving enough reserve capacity for dependable operation.

**Cryogenic storage tank ($LH_2$ supply only)**

In a refueling station configuration that relies on cryogenic transport ($LH_2$ trailer), the cryogenic storage vessel serves as the main storage component for liquid hydrogen ($LH_2$ trailer). Table 5 displays a segment from the calculation tool that highlights the main design parameters. In this case, a small tank type was recognized as the best option, as it meets the daily requirements while offering better flexibility for arranging deliveries. The density of $LH_2$ is roughly 71 kg/m³ at cryogenic temperatures (around –253 °C). [103]

The boil-off rate is approximately 0,01 % daily for small tanks and a bit less (0,009 %) for larger tanks, though the actual daily loss relies on the withdrawal rate. The determined gross capacity of the tank is approximately 19 m³, with 95 % available as usable volume. This leads to a storage mass of around 1,3 tons of $LH_2$. Given the specified boil-off rate, this leads to a daily loss of approximately 0,01 % of the stored volume, which maintains low efficiency losses. The autonomy duration, the span the station can function without a new supply, is approximately 3,4 days under the selected conditions. Moreover, there is no requirement for extensive high-pressure storage as a main storage system, as the conversion to gaseous

hydrogen occurs solely when needed. Nevertheless, the primary difficulties are in thermal insulation and managing boil-off gas. [100]

Even in optimized tanks, ongoing evaporation losses cannot be eliminated, which must be considered in the operational plan. Moreover, managing a cryogenic tank requires safety and regulatory protocols, especially related to pressure relief, emergency venting and material durability at very low temperatures.

| **Cryogenic storage tank (cold liquid tank)** | |
|---|---|
| *Recommended tank type is:* | **small tank** |
| Tank type | small tank |
| Density LH2 in kg/m3 | 71,08 |
| Evaporation rate (small tank) | 0,01 |
| Evaporation rate (large tank) | 0,009 |
| Gross volume in m3 | 19,12 |
| Net volume (95%) in m3 | 18,16 |
| Mass LH2 in kg | 1291 |
| Boil-off loss in kg/day | 12,91 |
| Autonomy duration in days | 3,4 |

Table 5: Extract from calculation tool – design parameters for cryogenic storage tank (Source: own illustration based on model configuration).

### Cryogenic pump and vaporizer ($LH_2$ supply only)

In the $LH_2$ refueling station model, the cryogenic pump and vaporizer create the essential connection between liquid hydrogen storage and the high-pressure gaseous hydrogen supply chain. Table 6 illustrates the key design values applied during the sizing procedure.

| **Cryopump ($LH_2$ supply)** | |
|---|---|
| Energy requirement per kg H2 in kWh/kg | 0,37 |
| Daily energy consumption in kWh/day | 134,3 |
| Mass flow rate (minimum) in kg/h | 22,69 |
| Reserve factor | 1,30 |
| Mass throughput including buffer in kg/h | 29,50 |
| | |
| Electricity costs per kg H2 in €/kg | 0,05 |
| Daily electricity costs in €/day | 17,46 |
| Annual electricity costs in €/year | 6374 |
| | |
| **Evaporator ($LH_2$ supply)** | |
| Heat of vaporization (1 bar, 20 K) in kJ/kg | 445 |
| Energy requirement per kg H2 in kWh/kg | 0,12 |
| Daily energy consumption in kWh/day | 44,88 |
| Mass flow rate (minimum) in kg/h | 22,69 |
| Reserve factor | 1,30 |
| Mass throughput including buffer in kg/h | 29,50 |
| | |
| Electricity costs per kg H2 in €/kg | 0,02 |
| Daily electricity costs in €/day | 5,8 |
| Annual electricity costs in €/year | 2129 |

Table 6: Extract from calculation tool – design parameters for cryogenic pump and vaporizer (Source: own illustration based on model configuration).

The cryogenic pump takes liquid hydrogen from the insulated storage tank and elevates its pressure prior to gasification. Pressurizing the liquid phase is considerably more energy-efficient than compressing gaseous hydrogen, which is why this setup is preferred in high-capacity stations. With an energy demand of roughly 0,37 kWh/kg $H_2$, the pump's daily electricity need for the specified throughput is about 134 kWh. A reserve factor of 1,3 is used on the minimum mass flow rate of 22,69 kg/h, giving a design capacity of 29,5 kg/h, which ensures stable operation during high demand times. [102]

After being pressurized, the hydrogen moves to the vaporizer, where it transforms from liquid to gas at the required dispensing pressure. This method depends on the latent heat of vaporization for hydrogen, approximately 445 kJ/kg at 1 bar and 20 K, which relates to an electrical demand of about 0,12 kWh/kg $H_2$ or 45 kWh/day in this scenario. Since the vaporizer is built with the same 1,3 reserve factor, there will always be gas available for continuous operation, even during periods of high refueling demand. [101]

Multi-stage compressors are no longer necessary thanks to this pump-vaporizer system, which allows the station to deliver high-pressure hydrogen while using less electricity than gas compression. Since both humidity and temperature can affect vaporizer efficiency, the system's dependability depends on regular maintenance and the ability to maintain stable outlet conditions even in the face of shifting environmental conditions.

**Compressor unit with cooling system (gaseous supply variants)**

To ensure that hydrogen is supplied at high pressures for both passenger cars and heavy-duty trucks, the compressor unit is an essential part of the design of hydrogen refueling stations. In this configuration, the compressor raises the intermediate and final storage pressures from the supply pressure (for instance, from a pipeline, tube trailer or low-pressure buffer tank in on-site electrolysis).

The station's maximum hourly requirement is used to determine the compressor's minimum mass flow rate, which is 22,69 kg/h. To be able to handle demand fluctuations and preserve operational dependability during simultaneous refueling operations, a reserve factor of 1,3 is employed. This results in a design throughput that accounts for a buffer capacity of 29,50 kg/h. [92]

With a specific energy consumption of 2,43 kWh per kilogram of hydrogen, the compressor is expected to use about 882 kWh of energy per day at the expected operating load. These values are consistent with modern high-pressure hydrogen compression systems for 350 and 700 bar applications found in refueling stations. Appropriate compressor sizing is important for both current requirements and anticipated demand growth. [102]

The system has an integrated cooling solution that includes a heat exchanger and a coolant circulation pump to handle the heat produced by hydrogen compression. To ensure efficient heat dissipation, the cooling capacity is sized at about 5 % of the compressor's output power. The cooling energy required for one kilogram of hydrogen is 0,12 kWh, which translates to a daily requirement of 44,11 kWh. The cooling system, even though it consumes less energy than the compressor, is essential for preserving safe operation, avoiding overheating and minimizing mechanical wear.

Through the integration of the compressor and cooling components into a single operational unit, the design offers efficient thermal management, uninterrupted operation during times of peak demand and reduced downtime. The integrated system is also a contributor to the overall electrical demand of the station and is

therefore considered in OPEX calculations. A comprehensive section from the calculation tool displaying the technical specifications of the compressor and cooling unit is shown in Table 7, illustrating how these figures are integrated into the component sizing procedure.

| **Compressor car/truck or bus** | |
|---|---|
| Mass flow rate (minimum) in kg/h | 22,69 |
| Reserve factor | 1,3 |
| Mass throughput including buffer in kg/h | 29,50 |
| Energy requirement per kg H2 in kWh/kg | 2,43 |
| Daily energy consumption in kWh/day | 882 |
| | |
| Electricity costs per kg H2 in €/kg | 0,32 |
| Daily electricity costs in €/day | 115 |
| Annual electricity costs in €/year | 41860 |
| | |
| **Cooler and coolant pump (for compressor)** | |
| Cooling capacity share compressor | 0,05 |
| Energy requirement per kg H2 in kWh/kg | 0,12 |
| Daily energy consumption in kWh/day | 44,1 |
| | |
| Electricity costs per kg H2 in €/kg | 0,02 |
| Daily electricity costs in €/day | 0,75 |
| Annual electricity costs in €/year | 272 |

Table 7: Extract from calculation tool – design parameters for compressor unit and integrated cooling system (Source: own illustration based on model configuration).

### High-pressure cascade storage

The high-pressure cascade storage system acts as the intermediate buffer between hydrogen compression (or pumping and vaporization for $LH_2$) and the dispensers, ensuring that vehicles can be quickly refueled while the upstream equipment functions at a consistent rate. Table 8 presents the sizing method used in this research.

| **High-pressure storage tank (cascade)** | |
|---|---|
| Memory requirement factor | 0,3 |
| Total storage requirement in kg | 108,9 |
| Storage requirement per pressure level in kg | 36 |
| | |
| Tank length (cylinder height) in m | 9,1 |
| Diameter in m | 0,4 |
| Tank volume in m3 | 1,14 |
| H2 density (450 bar) in kg/m3 | 30 |
| H2 density (600 bar) in kg/m3 | 39 |
| H2 density (900 bar) in kg/m3 | 47 |
| | |
| 450 bar tank capacity (fixed) in kg | 34,31 |
| 600 bar tank capacity (fixed) in kg | 44,60 |
| 900 bar tank capacity (fixed) in kg | 53,75 |
| | |
| Number of tanks 450 bar | 2 |
| Number of tanks 600 bar | 1 |
| Number of tanks 900 bar | 1 |

Table 8: Extract from calculation tool – design parameters for high-pressure cascade storage (Source: own illustration based on model configuration).

A storage factor of 0,3 is used to determine total storage capacity, which links the amount of hydrogen required to maintain continuous operation to the peak hourly dispensing demand. This results in a total capacity of about 109 kg in the reference scenario, which is divided equally among the three cascade pressure levels, with about 36 kg for each stage. [92]

Each storage container is presented as a vertical cylinder with dimensions of 9,1 m in height and 0,4 m in diameter, for a total volume of 1,14 m³. The density of stored hydrogen changes with pressure, measuring 30 kg/m³ at 450 bar, 39 kg/m³ at 600 bar and 47 kg/m³ at 900 bar and determining the actual mass capacity of each vessel, 34,31 kg at 450 bar, 44,60 kg at 600 bar and 53,75 kg at 900 bar. According to these values, the design specifies two tanks in the lowest pressure level, one tank in the middle level and one tank in the highest level. [92]

This three-stage setup enables efficient “fast-fill” refueling, because vehicles first extract from the highest-pressure bank, then subsequently from lower banks, as the compressor refills the emptied tiers in the background. This not only decreases refueling durations but also lowers compressor cycling frequency and related wear. Additionally, the cascade technique increases the efficiency of onsite space by lowering the total storage capacity required in comparison to a single large high-pressure tank.

To create such a system, one must be committed to pressure vessel safety regulations, consider thermal impacts during rapid gas extraction and coordinate with pre-cooling units to ensure alignment with SAE fueling guidelines. The dimensions must balance site area, capital costs and operational flexibility.

**PEM-electrolyser**

The PEM electrolyser is fundamental for on-site hydrogen production. In this configuration, it runs on renewable electricity from the grid, wind power or solar power. The systems design, which requires a total hydrogen production of 64,83 kg/h, dictates the infrastructure and electrical power requirements. Since each kilogram of hydrogen requires 50 kWh of energy, 3241 kW of installed electrical capacity is needed. This ensures that the system can meet hydrogen needs, even in situations with high demand. The daily energy usage amounts to 18152 kWh, which is then used to determine electricity supply needs and energy expenses in different sections of the model. [95]

For uninterrupted and consistent hydrogen production, a minimum daily operation time of 5,6 hours is calculated. This value indicates the lowest operational limit below which the electrolyser would be neither economically nor technically feasible. Besides electricity, the system needs large amounts of pure deionized water as a feedstock. According to an average of 18 to 20 liters for every kg of $H_2$, the overall daily water usage for this setup totals 6535 liters. [95]

Since electrolysers function optimally in continuous or steady-state conditions, a low-pressure buffer tank is employed to separate production from the fluctuating demand at the dispensers. The buffer tank mitigates temporary variations and enables the electrolyser to function at a steady load, increasing system efficiency. The buffer is sized according to a 2-hour buffer time, determined from the electrolysers hourly output rate of 64,83 kg/h. This leads to a complete buffer demand of 130 kg of hydrogen.

Buffer tanks can hold 125 kg, indicating that two tanks are needed to satisfy the computed buffer capacity with a small safety margin. Each tank takes up around 50 m³, bringing the overall buffer volume to 100 m³.

These tanks are intended for low-pressure use (usually 30-50 bar) and are situated downstream of the electrolyser and upstream of the compressor. [102]

This setup provides the hydrogen supply with both flexibility and dependable operation. Furthermore, by separating electrolyser behavior from dispensing spikes, it makes it possible to integrate various renewable electricity sources. Based on the determined energy and water needs, the model also determines operating costs for electricity and water, which are essential elements in the overall OPEX computation. Table 9 lists the calculated input parameters for the buffer tank and the electrolyser.

| **PEM-Electrolyser** | |
|---|---|
| Total power in kW | 3241 |
| H2 production in kg/h | 64,83 |
| Energy requirement per kg H2 in kWh/kg | 50 |
| | |
| Total water consumption in l/day | 6535 |
| | |
| Daily electricity consumption in kWh/day | 18152 |
| | |
| Min. capacity utilization in h/day | 5,60 |
| | |
| Electricity costs per kg H2 in €/kg | 6,50 |
| Daily electricity costs in €/day | 2360 |
| Annual electricity costs in €/year | 861308 |
| Daily water costs in €/day | 6,5 |
| Annual water costs in €/year | 2385 |
| | |
| **Buffer tank (Low Pressure Buffer Tank)** | |
| Buffer time in h | 2 |
| Production in kg/h | 64,83 |
| Buffer quantity in kg | 130 |
| Storage capacity per tank in kg | 125 |
| Number of tanks required | 2 |
| Volume per tank in m3 | 50 |
| Total volume in m3 | 100 |

Table 9: Extract from calculation tool – sizing parameters for PEM electrolyser and low-pressure buffer tank (Source: own illustration based on model configuration).

**Pre-cooling unit (chiller) and dispenser**

A key part of hydrogen refueling stations is the chiller unit, which safely dispenses hydrogen into vehicle tanks while following fueling procedures. In fast-fill scenarios, hydrogen must be cooled prior to delivery to comply with SAE J2601 procedures and prevent high temperature increases in vehicle tanks during rapid fills. The chiller currently uses 0,40 kWh of energy for every kilogram of hydrogen dispensed or roughly 145 kWh of energy per day. The unit can serve simultaneous refueling conditions without going over thermal limits because the cooling capacity corresponds to an electrical demand of about 9,08 kW. [99]

The number of hoses and dispensers in use is directly correlated with the chiller's capacity. To determine how many hoses are needed for each pressure level, the model uses the HOF concept, which is described in Chapter 5.1.), to ensure the required number of hoses for each pressure level. No hose should be used for over half of the peak operation times, according to sizing guidelines. This HOF target of 0,5 ensures

that the system keeps a buffer for concurrent refueling activities, small delays and pre-cooling needs. This method makes sure that every refueling hose is kept available with an adequate operational buffer, preventing extended wait times and providing consecutive refueling and system recovery.

The configuration features a 700 bar dispenser for passenger cars with one hose and a 350 bar dispenser for heavy-duty vehicles with two hoses, enabling simultaneous refueling. Table 10 displays a section from the calculation tool, demonstrating the technical specifications employed for determining the dimensions of the pre-cooling system in the simulated hydrogen refueling station setup.

| **Cooling unit/chiller (pre-cooling)** | |
|---|---|
| Energy requirement per kg H2 in kWh/kg | 0,40 |
| Daily energy consumption in kWh/day | 145,2 |
| Required power in kW | 9,08 |
| | |
| Electricity costs per kg H2 in €/kg | 0,05 |
| Daily electricity costs in €/day | 18,9 |
| Annual electricity costs in €/year | 6890 |
| | |
| **Number of dispensers (2 hoses)** | |
| Car (700 bar) | 1 |
| Truck/bus (350 bar) | 1 |
| | |
| **Number of hoses** | |
| Car (700 bar) | 1 |
| Truck/bus (350 bar) | 2 |

Table 10: Extract from calculation tool – design parameters for pre-cooling unit and dispenser (Source: own illustration based on model configuration).

### 5.2.5 Technical output and evaluation criteria

The technical results of the HRS model reflect the entire parameters for each hydrogen supply option once all specific inputs are established. These results are the direct consequence of the dimensioning logic applied in Chapters 5.2.2 to 5.2.4 and serve as the foundation for both the technical and economic evaluation in Chapter 6. For every configuration (pipeline supply, $CGH_2$ truck delivery, $LH_2$ truck delivery and on-site electrolysis) the model produces a sizing and performance profile enabling a direct comparison of the concepts under same boundary conditions.

A primary key result is the daily hydrogen capacity total in kg/day, derived from the projected demand for passenger cars and heavy-duty vehicles during 2025–2035. This value ascertains if the chosen configuration can achieve the maximum daily throughput in the specified year without exceeding the capacity limits of components. Very important is the autonomy duration without resupply, which reflects the length of time the station can function at maximum efficiency without delivery (in truck-based versions) or during a production halt (in on-site electrolysis). This parameter is especially important for far stations or those sensitive to possible supply chain interruptions.

For each variant, the model also provides an extensive component-sizing summary. This includes the low-pressure buffer tank volume for on-site electrolysis, the cryogenic tank capacity for $LH_2$ delivery with associated boil-off rates, the high-pressure storage capacity, which is split into three cascade stages and

represented as both mass in kg and tank count and the nominal and maximum compressor capacity in kg/h, which is established by the essential mass flow plus reserve factor. The model also calculates the number of PV modules or wind turbines, the corresponding land area required in m² and the necessary PV or wind capacity in kWp or kW for production based on renewables.

Another essential aspect of technical evaluation are energy-related outputs. The model evaluates the overall daily energy consumption [kWh/day] and the specific energy expenditure in kWh/kg $H_2$ for each variant based on the primary subsystem. The water consumption in l/day for on-site electrolysis is also provided by the model based on the production rate. These outputs are essential for estimating future OPEX.

In addition to these direct technical results, the model uses a series of assessment criteria to evaluate the supply options within practical limitations:

- Demand coverage: Verification that the setup can accommodate the expected peak daily demand in the selected year without exceeding capacity.
- Technical feasibility: Assessment of the configuration's viability at the designated location, taking pipeline and grid connection constraints into account as well as physical space. Regardless of its financial feasibility, a 32000 m² field for PV modules is impractical for urban areas.
- Scalability: Evaluation of the configurations' ability to expand in response to future spikes in demand. More scalability is shown by modular systems, such as electrolyser stacks or additional cascade storage banks.
- Renewable energy integration: A review of the system's ability to incorporate or use renewable electricity to reduce the carbon footprint of the hydrogen produced.
- Energy efficiency: an evaluation of the exact energy usage throughout the entire supply chain, from manufacturing to delivery. Variants with lower kWh/kg $H_2$ values typically have both financial and environmental benefits.
- Space efficiency: Assessment of the overall site area needed for each kilogram of hydrogen produced.

The evaluation criteria are applied systematically across all supply options to provide a consistent standard by which to compare them. This method enables the model to show not only the most financially appealing option but also the one that best satisfies the structural and technical constraints.

Another factor is the correlation between technical and financial results. A technically feasible setup that requires a large PV field but has high energy efficiency could still be rejected if land acquisition costs are too high. However, a version with a little higher energy consumption might be preferred if it can be implemented within the designated site limits and provides greater operational reliability.

In conclusion, the technical result connects the engineering design in Chapter 5.2 and the economic viability analysis in Chapter 6. They ensure that every evaluated hydrogen supply concept is founded on practical, location-specific and demand-oriented component sizing and that all relevant performance criteria are available for the decision-making process.

# 6 ECONOMIC FEASIBILITY ANALYSIS

The economic feasibility study offers a detailed examination of different hydrogen supply options for refueling stations. This section focuses on the financial feasibility of each variant, while earlier chapters addressed the technical design and scalability of hydrogen refueling stations. The analysis takes transportation and hydrogen acquisition costs into account, together with capital expenditure (CAPEX) and operating expenditure (OPEX), to calculate the levelized cost of hydrogen (LCOH). Common financial indicators like Net Present Value (NPV), Internal Rate of Return (IRR) and Return on Investment (ROI) are used to evaluate long-term profitability and economic viability.

The approach relies on input data gained from the case study and improved by benchmark figures from global research. Four supply alternatives are assessed individually: pipeline delivery of compressed gaseous hydrogen, transport of liquefied hydrogen and compressed gaseous hydrogen by truck and on-site hydrogen generation. Ultimately, a comparison reveals the price variations among the models and offers suggestions on the best choice.

## 6.1 Methodology and assumptions

The analysis of economic feasibility relies on a systematic method where all relevant expenses of a hydrogen refueling station are divided into three groups: CAPEX, OPEX and hydrogen procurement costs.

The investment costs of the refueling station's technical components are referred to as CAPEX. The daily hydrogen requirement and the selected supply method have a direct impact on the amount of CAPEX. Investment costs were dispersed over 20 years in the financial assessment, demonstrating the long lifespan of infrastructure assets such as storage tanks, pipelines and refueling stations. This method prevents exaggerating yearly expenses and is consistent with common practices in energy infrastructure initiatives.

OPEX includes the ongoing operational costs that come within the station itself. The primary cost factor is electricity usage and maintenance. However, OPEX excludes expenses for hydrogen production or transportation, as these are addressed individually within the procurement price.

Hydrogen procurement costs present the price of hydrogen supplied to the station. This includes the expense of hydrogen production and extra logistics expenses, if they apply. For pipeline delivery, transportation expenses are minimal. For $LH_2$ supply, costs for liquefaction and delivery by truck are included, whereas for $CGH_2$ supply, compression and truck delivery costs are considered. These expenses establish the actual hydrogen procurement cost for the operator and they are separated from OPEX.

The average cost per kilogram of hydrogen supplied during the assessment period was calculated as the LCOH based on these expense categories. The main metric for assessing the cost-competitiveness of various supply options is LCOH, which combines CAPEX, OPEX and hydrogen procurement costs.

Return on Investment (ROI), Internal Rate of Return (IRR) and Net Present Value (NPV) were the three primary metrics used for economic evaluation. A baseline ROI of 6 % was assumed, which is typical for infrastructure projects. Operators can adjust the retail price of hydrogen and ROI according to their unique business scenarios using the excel-based tool. The model calculates the annual profit, the margin per

kilogram of hydrogen and the highest feasible hydrogen purchase price that preserves the intended return on investment using these inputs.

The NPV and IRR evaluation periods of ten years were chosen, suggesting a reasonable infrastructure refueling investment cycle. Direct alignment between the discount rate and the desired return on investment ensures accurate methodology. While projects with an IRR above the ROI are deemed profitable, those with an IRR below the ROI fail to meet investors financial goals.

The baseline rate of inflation was set at 2,5 %, which primarily impacted OPEX components like maintenance and electricity costs. As long-term profitability is greatly impacted by inflation, this factor can be adjusted. Every hydrogen supply variant is reliably compared thanks to this methodological framework. By distinctly identifying CAPEX, OPEX and hydrogen procurement expenses and applying recognized financial standards, the evaluation connects the technical configuration of hydrogen refueling stations to their economic viability, offering a dependable basis for investment decisions.

## 6.2 Pipeline ($CGH_2$) – economic evaluation

The economic evaluation of the pipeline supply was conducted by methodically organizing all into procurement, investment and operation costs. The hydrogen acquisition cost was set at 3,6 €/kg, resulting in yearly procurement expenses of approximately 477000 € based on the hydrogen requirement of the case study (see Table 11). With the nearest hydrogen pipeline just 3 km away, the connection expenses stay relatively low. This represents a benefit, since building a hydrogen pipeline involves extremely high specific costs of 2750000 €/km. For 3 km distance, the cost for the pipeline connection totals 8250000 €. Even minor increases in distance would quickly result an increase in overall project expenses, thereby dropping the financial stability. [104]

| | |
|---|---|
| H2 purchase price in €/kg | 3,6 |
| Annual procurement costs H2 in €/year | 477032 |
| | |
| **CAPEX (pipeline)** | |
| Pipeline construction costs in €/km | 2750000 |
| CAPEX pipeline in € | 8250000 |
| | |
| Depreciation period in years | 20 |
| Depreciation in €/year | 412500 |

Table 11: Hydrogen procurement price and annual procurement costs for the pipeline supply option (Source: own illustration based on model configuration).

Figure 6-1 shows the CAPEX structure, displaying the total investment expenses for each component. The pipeline connection represents a major part of the overall investment. Although these components are technically essential, their financial importance is minor in relation to the primary cost of the connection pipeline. This clearly shows that the competitiveness of pipeline-based stations heavily relies on their geographical location and the availability of hydrogen infrastructure.

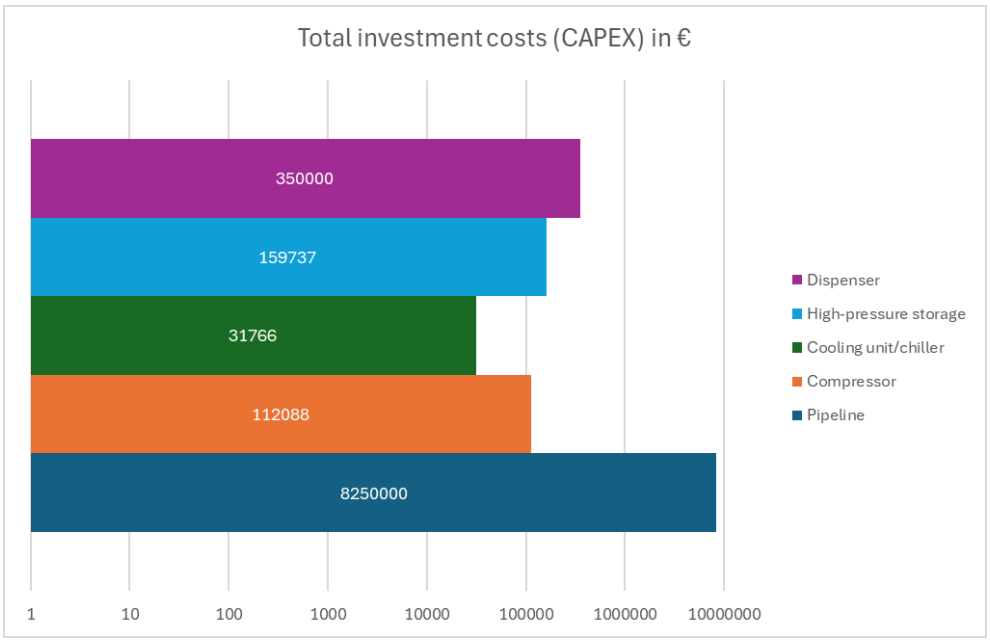


Figure 6-1: Distribution of total investment costs (CAPEX) for the pipeline station
(Source: own illustration based on model configuration).

The same conclusion is confirmed by the depreciation analysis (see Figure 6-2). Due to its annual depreciation exceeding 400000 €, the pipeline connection is the primary component of the cost structure. This shows that the long-term financial performance of pipeline-based stations is greatly affected by pipeline cost amortization. The calculated LCOH is directly impacted by the annual depreciation, which rises by over 137000 € (2750000 € ÷ 20 years) for every additional kilometer of distance.

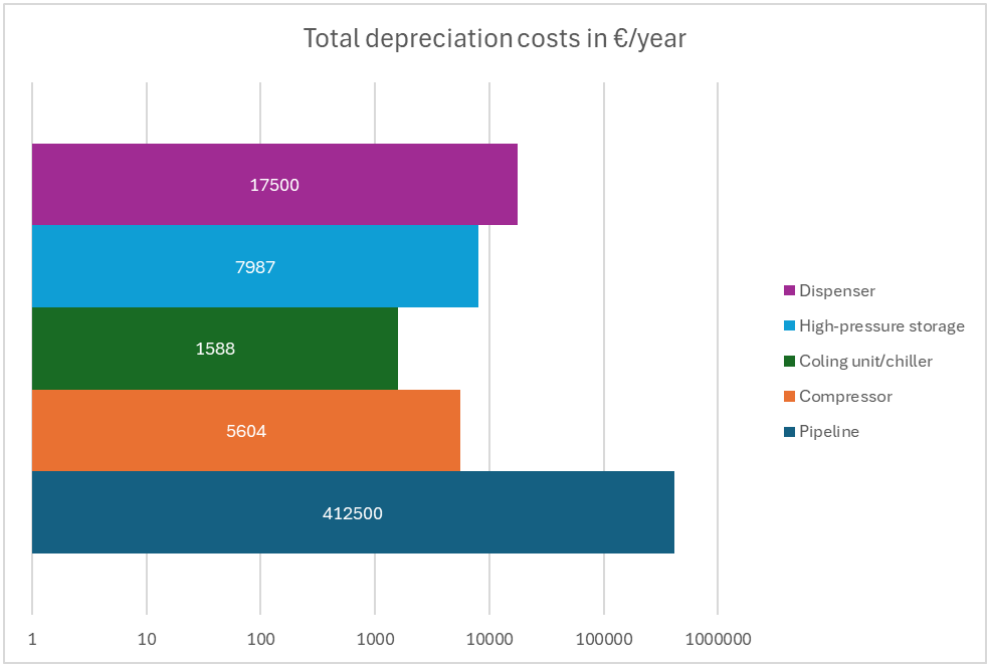


Figure 6-2: Annual depreciation costs of the main station components
(Source: own illustration based on model configuration).

The OPEX distribution, shown in Table 12, reveals that ongoing annual expenses are lower than CAPEX, but they still represent huge part of the annual cash flow. In this situation, OPEX primarily includes two parts [105]:

- established yearly connection charges to the hydrogen pipeline operator (18906 € annually), which constitute an essential fixed expense and
- operational expenses, including power usage for the compressor (41860 €) and cooling system (6890 €), along with maintenance and service.

In total, the annual OPEX for the pipeline station is around 249000 €. These expenses are ongoing and thus highly affected by inflation. However, in relation to the valuable CAPEX, they have less impact on the overall economics.

| **OPEX (pipeline)** | |
|---|---|
| Distance to the pipeline in km | 3 |
| Annual fee in €/kWh/h booked power | 25 |
| Connected load in kWh/h | 756 |
| Annual costs for network connection fee in €/year | 18906 |
| Operating costs including maintenance in €/year | 165000 |
| | |
| **OPEX (compressor incl. compressor cooler)** | |
| Compressor electricity costs in €/year | 41860 |
| Electricity costs for radiator and coolant pump in €/year | 272 |
| Operating costs including maintenance in €/year | 4484 |
| | |
| **OPEX (cooling unit/chiller)** | |
| Operating costs including maintenance in € | 1271 |
| Electricity costs for cooling unit (pre-cooling) in €/year | 6890 |
| | |
| **OPEX (high-pressure storage)** | |
| Operating costs including maintenance in € | 3195 |
| | |
| **OPEX (dispenser)** | |
| Operating costs including maintenance in € | 7000 |
| | |
| **OPEX Total** | |
| OPEX HRS in € | 248877 |

Table 12: Breakdown of operating costs for the pipeline station
(Source: own illustration based on model configuration).

According to this cost evaluation, the LCOH for the pipeline-based hydrogen supply was determined to be 8,84 €/kg. As shown in Table 13 and Figure 6-3, this amount is lower than the estimated sales price of 13 €/kg, resulting in a margin of 4,03 €/kg. This equates to an annual profit exceeding 530000 €, based on the stated assumptions. The sensitivity of this finding was assessed by determining the highest achievable hydrogen procurement cost to realize the specified ROI of 6 %. The maximal procurement price was identified as 8,97 €/kg, indicating that profitability is secured as long as the hydrogen purchase price stays under this amount. [106]

| **LCOH (Levelized Cost of Hydrogen)** | |
|---|---|
| LCOH pipeline in €/kg | 8,84 |
| | |
| Market price in €/kg H2 | 13 |
| | |
| **Return on Investment (ROI)** | |
| Yield per kg in €/kg | 4,03 |
| Annual profit in €/year | 534215 |
| **Target ROI in %** | **6%** |
| | |
| **Max. procurement price for target ROI in €/kg** | 8,97 |

Table 13: Calculation of LCOH, annual profit and maximum hydrogen procurement price for the pipeline supply option (Source: own illustration based on model configuration).

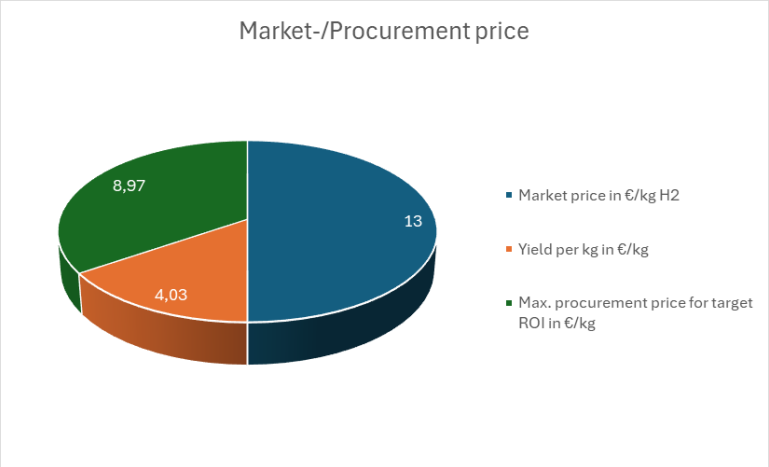


Figure 6-3: Comparison of hydrogen market price, profit margin per kilogram and maximum procurement price for the target ROI for pipeline delivery
(Source: own illustration based on model configuration).

In conclusion, the pipeline alternative might be more cost-effective, especially if the connection is limited to a few kilometers. According to the analysis, fixed OPEX, such as annual connection fees, also affects the feasibility of this supply route, but CAPEX is the main determinant due to the high pipeline construction costs.

## 6.3 $LH_2$ truck – economic evaluation

Like pipeline-based supply, the economic analysis of the $LH_2$ truck delivery option considers the costs of purchasing, investing in and operating hydrogen. Purchasing liquid hydrogen and accounting for liquefaction came at a cost of 4,15 €/kg, which amounted to about 549900 € in procurement costs annually (see Table 14). In addition, specific transportation costs of 0,2 €/kg were considered, resulting in annual expenses of 26500 €. Despite being a distinct cost category, these expenses are not included in the procurement value itself. The total yearly supply of hydrogen is approximately 576400 €. [107]

| | |
|---|---|
| H2 purchase price including liquefaction in €/kg | 4,15 |
| Annual procurement costs H2 in €/year | 549912 |
| | |
| H2 transport costs in €/kg | 0,2 |
| Daily transport costs in €/day | 73 |
| Annual transport costs in €/year | 26502 |

Table 14: Hydrogen procurement and transport costs for $LH_2$ truck delivery (Source: own illustration based on model configuration).

Table 15 and Figure 6-4 provide an overview of the investment costs. The primary cost is divided among multiple cryogenic components and they add up to about 1 million €. For the management of liquid hydrogen, the vaporizer, cryogenic pump and cryogenic storage tank are vital supply chain elements. Additionally, high-pressure storage and dispensers make up an important part, whereas the chiller represents a comparatively minor share. In contrast to infrastructure intensive options like a pipeline connection, the $LH_2$ station needs less initial investment, making it attractive from a CAPEX standpoint.

| **CAPEX (cryopump)** | |
|---|---|
| Investment costs per kg/h in €/kg/h | 5738 |
| Total investment cryopump in € | 169238 |
| | |
| Depreciation period in years | 20 |
| Depreciation in €/year | 8462 |

| **CAPEX (evaporator)** | |
|---|---|
| Investment costs per kg/h in €/kg/h | 4407 |
| Total investment cryopump in € | 130000 |
| | |
| Depreciation period in years | 20 |
| Depreciation in €/year | 6500 |

| **CAPEX (cryogenic storage tank)** | |
|---|---|
| Investment costs per kg/h in €/kg/h | 127 |
| Total investment (depending on tank size) in € | 163969 |
| | |
| Depreciation period in years | 20 |
| Depreciation in €/year | 8198 |

| **CAPEX (cooling unit/chiller)** | |
|---|---|
| Investment costs per kg/h in €/kW | 3500 |
| Total investment cooling unit in € | 31766 |
| | |
| Depreciation period in years | 20 |
| Depreciation in €/year | 1588 |

| **CAPEX (high-pressure storage)** | |
|---|---|
| Investment costs per 450 bar pressure level in €/kg | 1000 |
| Total investment high-pressure accumulator 450 bar in € | 36304 |
| Investment costs per 600 bar pressure level in €/kg | 1500 |
| Total investment high-pressure accumulator 600 bar in € | 54456 |
| Investment costs per 900 bar pressure level in €/kg | 1900 |
| Total investment high-pressure accumulator 900 bar in € | 68977 |
| Total investment in high-pressure storage in € | 159737 |
| | |
| Depreciation period in years | 20 |
| Depreciation in €/year | 7987 |

| **CAPEX (dispenser)** | |
|---|---|
| Investment costs for 350 bar dispenser in € | 150000 |
| Investment costs for 700 bar dispenser in € | 200000 |
| Total investment dispenser in € | 350000 |
| | |
| Depreciation period in years | 20 |
| Depreciation in €/year | 17500 |

| **Total CAPEX** | |
|---|---|
| CAPEX HRS in € | 1004710 |

Table 15: Capital expenditures (CAPEX) of hydrogen refueling station components for $LH_2$ truck delivery (Source: own illustration based on model configuration).

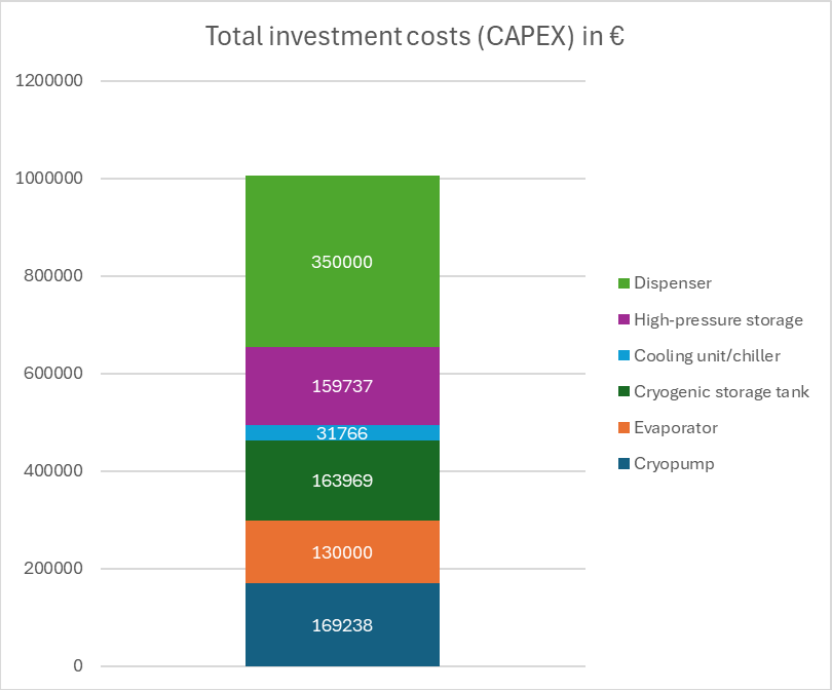


Figure 6-4: Breakdown of total investment costs by component for $LH_2$ truck delivery (Source: own illustration based on model configuration).

Depreciation costs, shown in Figure 6-5, are evenly spread across different technical components. Yearly depreciation amounts vary from 6500 € for the vaporizer to 17500 € for the dispensers, with the cryogenic tank and pump accounting for 8200 € and 8500 €.

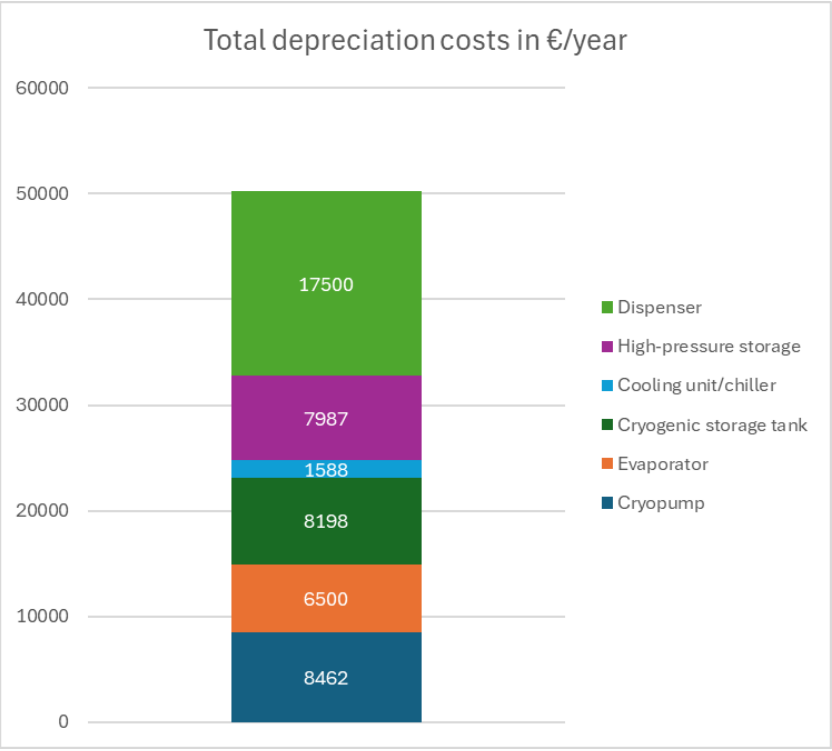


Figure 6-5: Annual depreciation costs by component for $LH_2$ truck delivery (Source: own illustration based on model configuration).

Operating costs amount to approximately 42000 € per year (see Table 16). They include the electricity usage of the cryogenic pump and vaporizer, pre-cooling expenses for the chiller and standard maintenance costs for every component. Unlike supply options with fixed yearly connection fees, the OPEX profile of the $LH_2$ truck alternative is closely tied to real technical operation.

| | |
|---|---|
| **OPEX (cryopump)** | |
| Electricity costs for cryopump in €/year | 6374 |
| Operating costs including maintenance in €/year | 6770 |
| | |
| **OPEX (evaporator)** | |
| Electricity costs for evaporators in €/year | 2129,3 |
| Operating costs including maintenance in €/year | 5200 |
| | |
| **OPEX (cryogenic storage tank)** | |
| Operating costs including maintenance in € | 3279 |
| | |
| **OPEX (cooling unit/chiller)** | |
| Operating costs including maintenance in € | 1271 |
| Electricity costs for cooling unit (pre-cooling) in €/year | 6890 |
| | |
| **OPEX (high-pressure storage)** | |
| Operating costs including maintenance in € | 3195 |
| | |
| **OPEX (dispenser)** | |
| Operating costs including maintenance in € | 7000 |
| | |
| **OPEX Total** | |
| OPEX HRS in € | 42108 |

Table 16: Operational costs of components for $LH_2$ truck delivery (Source: own illustration based on model configuration).

According to Table 17, the LCOH produced by this supply route is 5,05 €/kg. The station makes a tiny profit margin of 0,45 €/kg in relation to the anticipated market price of 13 €/kg, which translates to an annual profit of about 60000 €. The highest price at which hydrogen can be purchased to reach the desired 6 % return on investment is 12,55 €/kg. The relationship between market price, procurement cost and return on investment is presented in Figure 6-6. This illustrates that the $LH_2$ truck alternative can stay financially attractive as long as the hydrogen procurement price stays below the specified limit, although it is more sensitive to changes in procurement costs compared to other options. [106]

| | |
|---|---|
| **LCOH (Levelized Cost of Hydrogen)** | |
| LCOH LH2 in €/kg | 5,05 |
| | |
| Market price in €/kg | 13 |
| | |
| **Return on Investment (ROI)** | |
| Yield per kg in €/kg | 0,45 |
| Annual profit in €/year | 60283 |
| **Target ROI in %** | **6%** |
| | |
| **Max. procurement price for target ROI in €/kg** | **12,55** |

Table 17: Calculation of LCOH, annual profit and maximum hydrogen procurement price for $LH_2$ truck delivery (Source: own illustration based on model configuration).

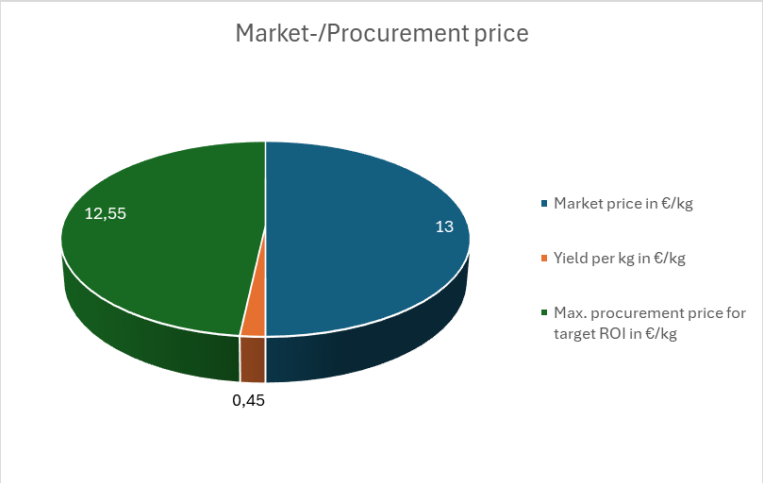


Figure 6-6: Comparison of hydrogen market price, profit margin per kilogram and maximum procurement price for achieving the target ROI for $LH_2$ truck delivery
(Source: own illustration based on model configuration).

In conclusion, the $LH_2$ truck supply model is characterized by average operating costs and comparatively low capital expenditures. However, the potential profit margin is reduced by transportation and procurement costs. Profitability is largely dependent on stable liquefaction costs and transportation logistics, even though the infrastructure requirements are technically feasible and the cost distribution among components is neutral.

## 6.4 $CGH_2$ truck – economic evaluation

The investment costs for a truck-based $CGH_2$ station are considerably less than pipeline-based ones (see Table 18 and Figure 6-7). Unlike the $LH_2$ supply route, a key difference is the absence of a stationary storage tank. Hydrogen is directly extracted from the trailer into the refueling system. This minimizes the requirement for expensive cryogenic tank facilities but results in logistical and structural difficulties. That means that with high hydrogen consumption, several deliveries daily would be needed, requiring a lot of parking and space for trailers.

The depreciation costs, shown in Figure 6-8, directly align with this distribution. Given a projected lifetime of 20 years, the yearly depreciation amounts to approximately 32700 €. In this case, dispensers once more represent the largest part (17500 € annually), followed by high-pressure storage and the compressor.

Combined, the investment and depreciation framework emphasize how financially important are the high-pressure storage and dispenser in the $CGH_2$ scenario. The $CGH_2$ station highlights a different factor than other supply methods, such as $LH_2$ delivery, where cryogenic tanks and pumps significantly impact costs. The infrastructure for compression, storage and dispensing largely dictates its investment structure. This suggests that improvements in these aspects, whether via increased durability, modular structures or lowered costs, would directly influence both the capital and the station's long-term economic results.

| CAPEX (compressor including compressor cooler) | |
|---|---|
| Investment costs per kg/h in €/kg/h | 3800 |
| Total investment compressor in € | 112088 |
| | |
| Depreciation period in years | 20 |
| Depreciation in €/year | 5604 |

| CAPEX (cooling unit/chiller) | |
|---|---|
| Investment costs per kg/h in €/kW | 3500 |
| Total investment cooling unit in € | 31766 |
| | |
| Depreciation period in years | 20 |
| Depreciation in €/year | 1588 |

| CAPEX (dispenser) | |
|---|---|
| Investment costs for 350 bar dispenser in € | 150000 |
| Investment costs for 700 bar dispenser in € | 200000 |
| Total investment dispenser in € | 350000 |
| | |
| Depreciation period in years | 20 |
| Depreciation in €/year | 17500 |

| CAPEX (high-pressure storage) | |
|---|---|
| Investment costs per 450 bar pressure level in €/kg | 1000 |
| Total investment high-pressure accumulator 450 bar in € | 36304 |
| Investment costs per 600 bar pressure level in €/kg | 1500 |
| Total investment high-pressure accumulator 600 bar in € | 54456 |
| Investment costs per 900 bar pressure level in €/kg | 1900 |
| Total investment high-pressure accumulator 900 bar in € | 68977 |
| Total investment in high-pressure storage in € | 159737 |
| | |
| Depreciation period in years | 20 |
| Depreciation in €/year | 7987 |

| Total CAPEX | |
|---|---|
| CAPEX HRS in € | 653591 |

Table 18: Breakdown of total investment costs by component for the $CGH_2$ truck supply station (Source: own illustration based on model configuration).

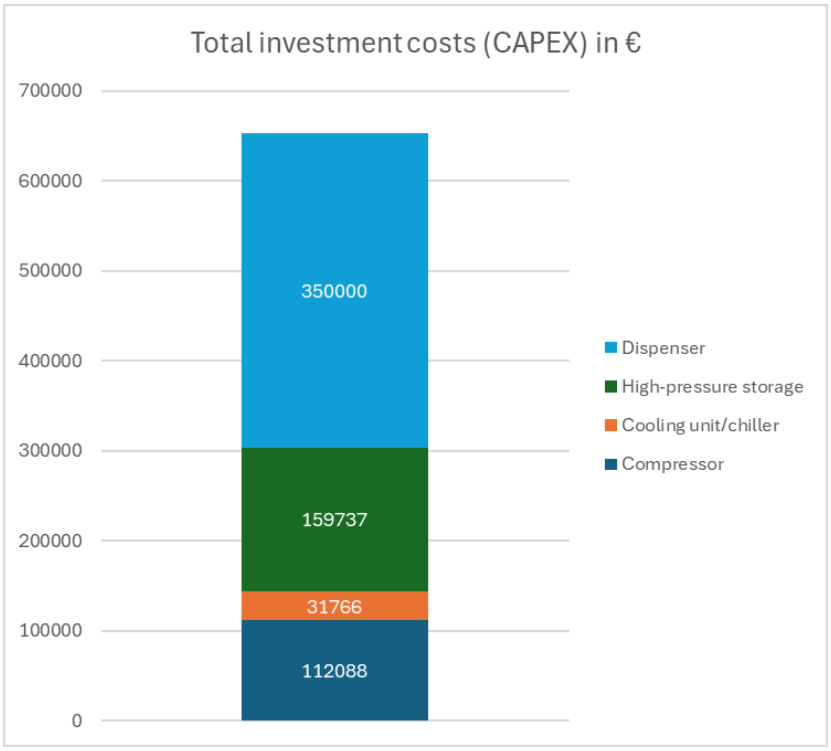


Figure 6-7: Breakdown of total investment costs by component for $CGH_2$ truck supply station (Source: own illustration based on model configuration).

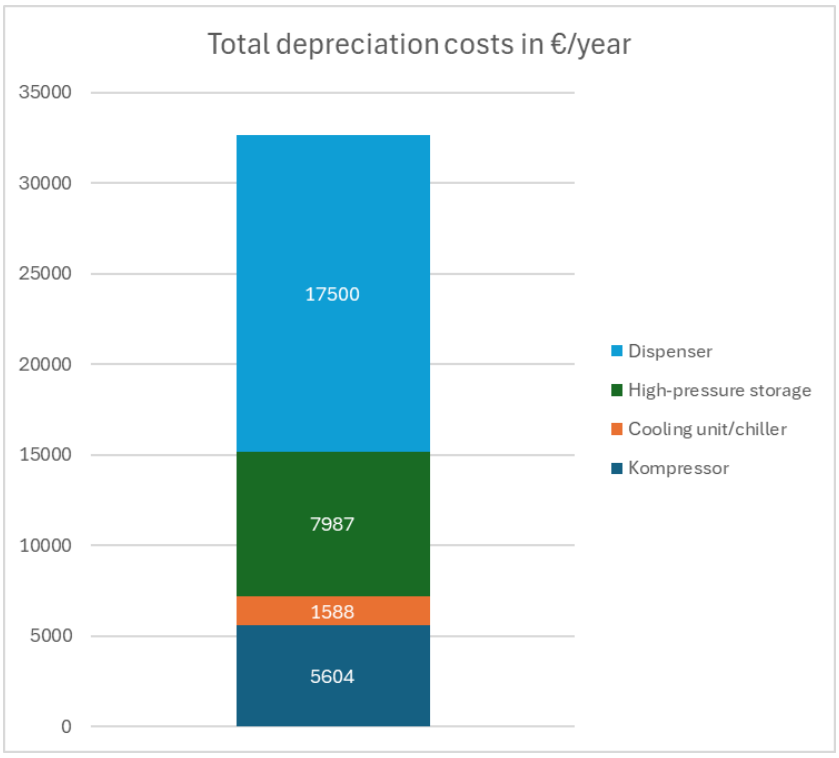


Figure 6-8: Annual depreciation costs by component for $CGH_2$ truck supply station (Source: own illustration based on model configuration).

The annual operating costs, summarized in Table 19, are based on the electricity usage of the compressor, essential for achieving refueling pressures of up to 700 bar. Extra expenses come from cooling (pre-cooling), but these don't account for that much. Overall, the OPEX of the $CGH_2$ truck concept is reduced compared to the pipeline variant, as there is no grid connection fee and maintenance expenses are lower. The cost framework clearly demonstrates a benefit in operating flexibility and lower fixed costs, although energy-intensive compression continues to be an important element.

| **OPEX (compressor incl. compressor cooler)** | |
|---|---|
| Compressor electricity costs in €/year | 41860 |
| Electricity costs for radiator and coolant pump in €/year | 272 |
| Operating costs including maintenance in €/year | 4484 |
| | |
| **OPEX (cooling unit/chiller)** | |
| Operating costs including maintenance in € | 1271 |
| Electricity costs for cooling unit (pre-cooling) in €/year | 6890 |
| | |
| **OPEX (high-pressure storage)** | |
| Operating costs including maintenance in € | 3195 |
| | |
| **OPEX (dispenser)** | |
| Operating costs including maintenance in € | 7000 |
| | |
| **OPEX Total** | |
| OPEX HRS in € | 64971 |

Table 19: Breakdown of total operational costs by component for the $CGH_2$ truck supply station (Source: own illustration based on model configuration).

From a supply perspective, the procurement cost of hydrogen is 4,50 €/kg, plus an additional transport fee of 1 €/kg (see Table 20). These expenses have an impact the overall supply chain, yet they ensure adaptability and independence from established pipeline infrastructure. [107]

| | |
|---|---|
| H2 purchase price in €/kg | 4,50 |
| Annual procurement costs H2 in €/year | 596289,9 |
| | |
| H2 transport costs in €/kg | 1 |
| Daily transport costs in €/day | 363 |
| Annual transport costs in €/year | 132509 |

Table 20: Hydrogen procurement and transport costs for the $CGH_2$ truck supply option (Source: own illustration based on model configuration).

The LCOH generated for this case is 6,24 €/kg, which is much lower than the current market price of 13 €/kg (see Table 21). However, reaching an average profit of 0,30 €/kg is leading to an annual revenue of about 39000 €. Using the target ROI of 6 %, the highest permissible procurement cost is determined to be 12,70 €/kg, offering a solid financial buffer (see Table 21 and Figure 6-9). [106]

| | |
|---|---|
| **LCOH (Levelized Cost of Hydrogen)** | |
| LCOH CGH2 in €/kg | 6,24 |
| | |
| Market price in €/kg H2 | 13 |
| | |
| **Return on Investment (ROI)** | |
| Yield per kg in €/kg | 0,30 |
| Annual profit in €/year | 39215 |
| **Target ROI in %** | **6%** |
| | |
| **Max. procurement price for target ROI in €/kg** | 12,70 |

Table 21: Calculation of LCOH, annual profit and maximum hydrogen procurement price for the $CGH_2$ truck supply (Source: own illustration based on model configuration).

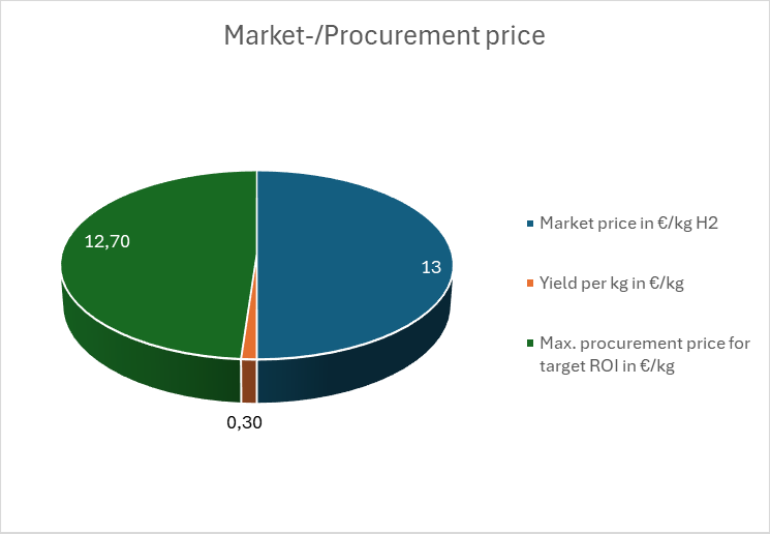


Figure 6-9: Comparison of hydrogen market price, profit margin per kilogram and maximum procurement price for achieving the target ROI for the $CGH_2$ truck supply (Source: own illustration based on model configuration).

In conclusion, the $CGH_2$ truck delivery choice is noted for its minimal CAPEX and OPEX, yet the primary expense falls on procurement and logistics. The lack of stationary storage provides adaptability but requires enough on-site area and regular trailer shipments, particularly during peak demand periods. From an economic perspective, this approach is viable and offers a pragmatic answer for small to medium hydrogen demand situations, but for greater quantities, logistics and site specifications may be challenging.

## 6.5 On-site production – economic evaluation

In the on-site production variant, the key difference from the delivery-based alternatives is the generation of hydrogen at the refueling station through a PEM electrolyser. In this setup, the main driver of CAPEX is evidently the PEM electrolyser, requiring an investment of more than 3,2 million €, exceeding the total expenses of all other station parts and shaping the overall investment framework (see Table 22). [108]

The buffer tank serves as an extra component unique to on-site production. Its aim is to temporarily store the constantly generated hydrogen and be a connector between consistent production and variable refueling needs. Even though the buffer tank investment is relatively minor, it increases the technical complexity of the station.

| **CAPEX (PEM-electrolyser)** | |
|---|---|
| Investment costs per kW in €/kW | 996 |
| Total investment PEM electrolyzer in € | 3228445 |
| | |
| Depreciation period in years | 20 |
| Depreciation in €/year | 161422 |

| **CAPEX (cooling unit/chiller)** | |
|---|---|
| Investment costs per kg/h in €/kW | 3500 |
| Total investment cooling unit in € | 31766 |
| | |
| Depreciation period in years | 20 |
| Depreciation in €/year | 1588 |

| **CAPEX (buffer tank)** | |
|---|---|
| Investment costs per kg/h in €/kg | 632 |
| Total investment buffer tank in € | 81943 |
| | |
| Depreciation period in years | 20 |
| Depreciation in €/year | 4097 |

| **CAPEX (dispenser)** | |
|---|---|
| Investment costs for 350 bar dispenser in € | 150000 |
| Investment costs for 700 bar dispenser in € | 200000 |
| Total investment dispenser in € | 350000 |
| | |
| Depreciation period in years | 20 |
| Depreciation in €/year | 17500 |

| **CAPEX (compressor incl. compressor cooler)** | |
|---|---|
| Investment costs per kg/h in €/kg/h | 3800 |
| Total investment compressor in € | 320251 |
| | |
| Depreciation period in years | 20 |
| Depreciation in €/year | 16013 |

| **CAPEX (high-pressure storage)** | |
|---|---|
| Investment costs per 450 bar pressure level in €/kg | 1000 |
| Total investment high-pressure accumulator 450 bar in € | 36304 |
| Investment costs per 600 bar pressure level in €/kg | 1500 |
| Total investment high-pressure accumulator 600 bar in € | 54456 |
| Investment costs per 900 bar pressure level in €/kg | 1900 |
| Total investment high-pressure accumulator 900 bar in € | 68977 |
| Total investment in high-pressure storage in € | 159737 |
| | |
| Depreciation period in years | 20 |
| Depreciation in €/year | 7987 |

Table 22: Breakdown of investment costs by component for the “on-site” hydrogen supply station (Source: own illustration based on model configuration).

The on-site production option using PEM electrolysis requires complex operating cost framework compared to delivery-oriented models. The biggest part of OPEX is the PEM electrolyser, making yearly operating and maintenance costs exceeding 125000 €, along with extra expenses for water supply (see Table 23).

These figures by themselves exceed the overall OPEX of the majority of other HRS elements. This indicates high service demand of electrolyser stacks alongside the support systems needed for water treatment and overall plant operations. [109]

Apart from the electrolyser, the compressor remains one of the primary cost contributors. With yearly electricity needs exceeding 40000 €, OPEX for the compressor makes a big ongoing expense. [110]

| **OPEX (compressor incl. compressor cooler)** | |
|---|---|
| Compressor electricity costs in €/year | 41860 |
| Electricity costs for radiator and coolant pump in €/yea | 272 |
| Operating costs including maintenance in €/year | 12810 |
| | |
| **OPEX (PEM-electrolyser)** | |
| Operating costs including maintenance in € | 129138 |
| Water costs PEM electrolyzer in €/year | 2385 |
| | |
| **OPEX (cooling unit/chiller)** | |
| Operating costs including maintenance in € | 1271 |
| Electricity costs for cooling unit (pre-cooling) in €/year | 6890 |
| | |
| **OPEX (buffer tank)** | |
| Operating costs including maintenance in € | 819 |
| | |
| **OPEX (high-pressure storage)** | |
| Operating costs including maintenance in € | 3195 |
| | |
| **OPEX (dispenser)** | |
| Operating costs including maintenance in € | 7000 |

Table 23: Breakdown of operational costs by component for the “on-site” hydrogen supply station (Source: own illustration based on model configuration).

For the on-site supply choices, the cost framework varies considerably based on whether the electricity comes from PV, wind energy or grid connection. In terms of CAPEX, solar and wind are the two relevant options. A photovoltaic system needs an investment of approximately 600 €/kWp, leading to total installation costs of about 3,89 million €. The related yearly depreciation totals just under 195000 €, reflecting a long-term fixed cost load [111].

Wind energy, on the other hand, demands considerably greater initial investments, both for the turbine (1200 €/kW) and for the grid connection (116 €/kW). This results in a total CAPEX of 5,59 million €, with yearly depreciation around 280000 € (see Table 24). [112]

This implies that wind energy is more expensive than photovoltaic, even though both options require large financial investments. However, because it does not require infrastructure investment, grid electricity is more attractive from a CAPEX standpoint even though it transfers all costs to OPEX.

The total investment differs among the three on-site options when considering the entire station (PEM electrolyser and HRS essential equipment), as well as the electricity supply alternative (see Table 24 and Figure 6-10). Using grid electricity, the total capital cost amounts to 4172142 €, as there is no generation facility constructed and the investment is primarily influenced by the PEM electrolyser and the conventional HRS elements. Incorporating a PV system brings the total to 8061835 €, whereas including wind energy raises it to 9766498 €. Basically, PV almost doubles and wind exceeds double the initial capital needed compared to the grid-only configuration.

This range has direct effects on yearly depreciation (20-year lifespan): approximately 208607 €/year (grid), 403092 €/year (PV) and 488325 €/year (wind). The increased annual depreciation for PV and wind represents a fixed expense. It increases long-term price stability but raises financial requirements.

In terms of structure, the PEM electrolyser is an important CAPEX component in all three scenarios, although its importance changes when renewable generation is included. In the PV variant, the costs for the PV system (≈ 3,9 million €) are comparable to that of the electrolyser (≈ 3,2 million €), leading to two nearly equal cost factors. In the wind variant, the wind turbines even exceed the electrolyser (≈ 5,6 million €), making on-site generation the largest investment category. The electrolyser leads to the CAPEX profile only in the grid-based option since no infrastructure is needed for it.

| **CAPEX (PV)** | |
|---|---|
| Investment per kWp in €/kWp | 600 |
| Total investment PV system in € | 3889693 |
| | |
| Depreciation period in years | 20 |
| Depreciation in €/year | 194485 |
| | |
| **CAPEX (wind power)** | |
| Investment per kW in €/kW | 1200 |
| Grid connection costs in €/kW | 116 |
| | |
| Total investment network in € | 5594356 |
| | |
| Depreciation period in years | 20 |
| Depreciation in €/year | 279718 |

| **Total CAPEX (grid power)** | |
|---|---|
| CAPEX HRS in € | 4172142 |
| | |
| **Total CAPEX (PV)** | |
| CAPEX HRS in € | 8061835 |
| | |
| **Total CAPEX (wind power)** | |
| CAPEX HRS in € | 9766498 |

Table 24: Breakdown of total investment costs for different the “on-site” hydrogen supply stations (Source: own illustration based on model configuration).

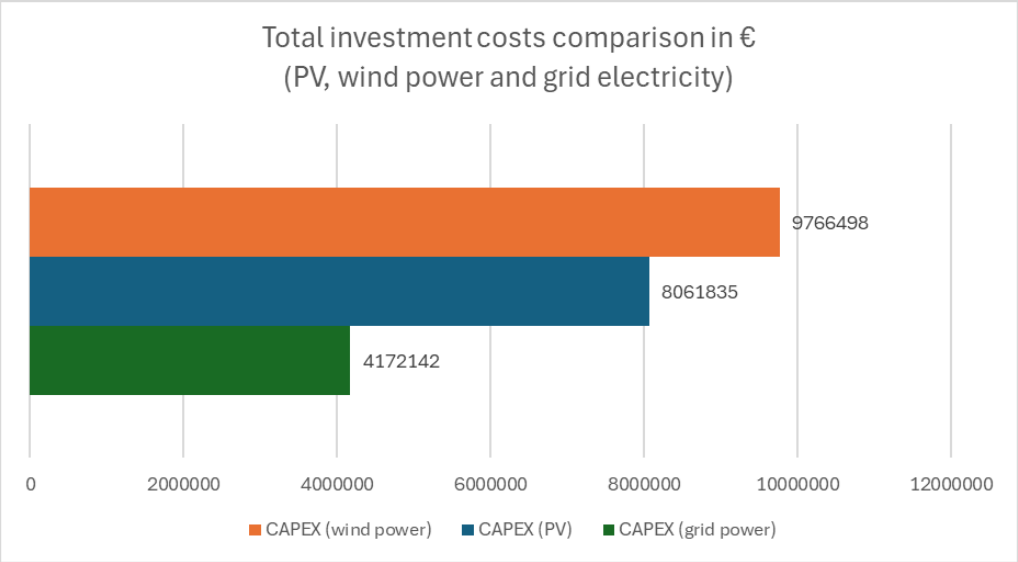


Figure 6-10: Total investment costs for different “on-site” hydrogen supply stations (Source: own illustration based on model configuration).

In terms of OPEX comparison, the scenario among the three on-site supply options appears differently from the CAPEX perspective. Electricity from the grid is the less attractive choice regarding yearly operating expenses, as each kilogram of hydrogen generated is directly related to the cost of the purchased electricity. OPEX exceeds 1,06 million € annually (see Table 25), despite having the smallest CAPEX needs.

PV shows the least OPEX among the three alternatives, which costs approximately 264000 € annually. This is because after the solar system is set up, the ongoing expenses are primarily maintenance. Wind energy is positioned between photovoltaic (PV) and the grid, with yearly OPEX totaling approximately 448000 €, indicating maintenance demands of wind turbines and continuous expenses of grid connectivity.

The trade-off is evident: grid electricity needs no initial investment but has very high OPEX, whereas PV has a moderate investment with the lowest long-term OPEX. Wind energy is the most capital-intensive option and its running costs are higher than those of photovoltaics. In the long run, though, it still surpasses grid electricity. This balance is emphasized by the OPEX overview (see Table 25), which shows how the energy supply influences both the investment pattern and the financial performance of the stations.

| | | | | |
|---|---|---|---|---|
| **OPEX (grid power)** | | | | |
| Annual electricity costs in €/year | 861308 | | **Total OPEX (grid power)** | |
| | | | OPEX HRS in € | 1066948 |
| **OPEX (PV)** | | | | |
| Operating costs including maintenance in € | 58345 | | **Total OPEX (PV)** | |
| | | | OPEX HRS in € | 263985 |
| **OPEX (wind power)** | | | | |
| Operating costs including maintenance in €/kW | 57 | | **Total OPEX (wind power)** | |
| Operating costs including maintenance in €/year | 242309 | | OPEX HRS in € | 448006 |

Table 25: Summary of operational costs for different the “on-site” hydrogen supply stations (Source: own illustration based on model configuration).

The Levelized Cost of Hydrogen shows imbalance between the three on-site supply options (see Table 26). When based on a generation-only basis, which includes only the annualized CAPEX and OPEX of the PEM electrolyser along with the corresponding electricity supply system, PV demonstrates the lowest expenses at 4,12 €/kg, followed by wind at 6,15 €/kg, whereas grid electricity shows the highest cost at 8,71 €/kg. This illustrates the structural benefit of renewable self-generation over dependence on grid electricity (see Table 26).

When expanding the analysis to a site-specific point, where the entire HRS infrastructure's depreciation and OPEX are considered, the expenses naturally rise. In this scenario, PV increases to 5,03 €/kg, wind to 7,07 €/kg and grid electricity to 9,63 €/kg. The rankings remain unchanged, though, with PV remaining the least expensive choice, wind having somewhat higher costs and grid supply clearly being the most expensive (see Figure 6-11).

These results demonstrate that while solar and wind energy require high upfront investment, they have much lower operating costs and provide a long-term hedge against changes in electricity prices. The least competitive LCOH is produced by grid electricity, which, in contrast, removes the need for infrastructure investment but results in high annual OPEX.

| | |
|---|---|
| **LCOH (grid electricity; generation-related)** | |
| LCOH in €/kg | 8,71 |
| | |
| **LCOH (grid electricity; site-specific)** | |
| LCOH grid power in €/kg | 9,63 |
| | |
| **LCOH (PV; production-related)** | |
| LCOH in €/kg | 4,12 |
| | |
| **LCOH (PV; site-specific)** | |
| LCOH PV in €/kg | 5,03 |
| | |
| **LCOH (wind power; generation-related)** | |
| LCOH in €/kg | 6,15 |
| | |
| **LCOH (wind power; site-specific)** | |
| LCOH wind turbine in €/kg | 7,07 |

Table 26: Levelized Cost of Hydrogen for different "on-site" hydrogen supply variants (Source: own illustration based on model configuration).

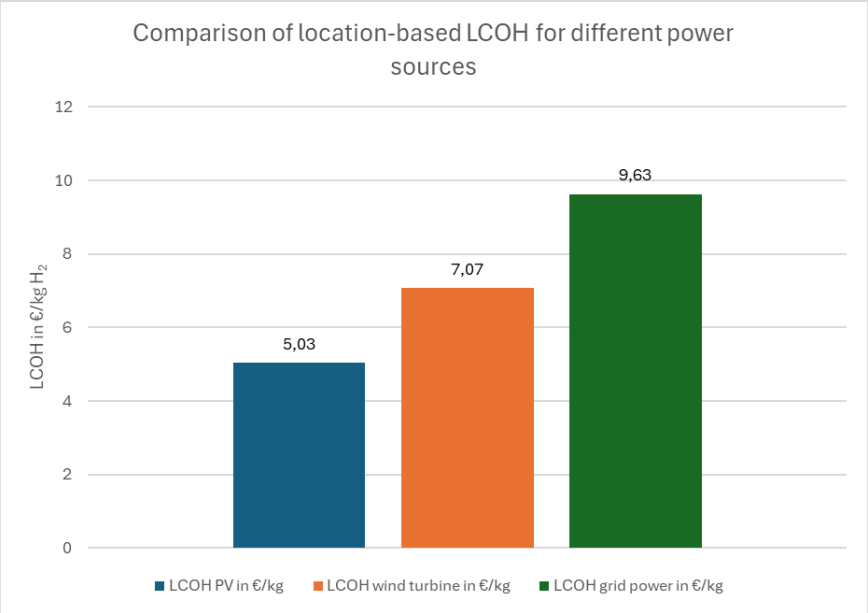


Figure 6-11: LCOH for different "on-site" hydrogen supply variants based on total HRS infrastructure (Source: own illustration based on model configuration).

The ROI analysis, using a hydrogen market price of 13 €/kg, reveals clear variations among the three on-site supply options. For PV, the needed ROI of 6 % results in an annual net profit of approximately 484000 €, equating to a required margin of 3,65 €/kg. From this margin, the highest acceptable procurement cost is 9,35 €/kg. Wind energy, although having a greater CAPEX, requires an annual return of approximately 586000 € to achieve the same ROI, leading to a margin of 4,42 €/kg and a reduced acceptable procurement limit of 8,58 €/kg (see Table 27). [106]

In comparison, the grid electricity scenario produces the lowest profit margin of just 1,89 €/kg, resulting in approximately 250000 € annually. Nevertheless, due to smaller investment base, the same ROI target can

be achieved with a higher maximum procurement price of 11,11 €/kg. This indicates that grid supply needs minimal CAPEX responsibilities, however big OPEX.

The analysis reveals that PV and wind are limited in procurement costs because of their high capital costs, but ultimately provide lower long-term hydrogen production costs and are less affected against fluctuations in electricity prices. Even though grid supply allows for a higher procurement price in the ROI framework, it is still the least competitive option under present assumptions and is basically disadvantaged by ongoing electricity costs.

| | |
|---|---|
| Market price in €/kg H2 | 13 |
| | |
| **Return on Invest (ROI) - with PV** | |
| Yield per kg in €/kg | 3,65 |
| Annual profit in €/year | 483710 |
| **Target ROI in %** | **6%** |
| | |
| **Max. procurement price for target ROI in €/kg** | 9,35 |
| | |
| **Return on Investment (ROI) - with wind power** | |
| Yield per kg in €/kg | 4,42 |
| Annual profit in €/year | 585990 |
| **Target ROI in %** | **6%** |
| | |
| **Max. procurement price for target ROI in €/kg** | 8,58 |
| | |
| **Return on Investment (ROI) - with grid power** | |
| Yield per kg in €/kg | 1,89 |
| Annual profit in €/year | 250329 |
| **Target ROI in %** | **6%** |
| | |
| **Max. procurement price for target ROI in €/kg** | 11,11 |

Table 27: Calculation of annual profit and maximum hydrogen procurement price for different “on-site” hydrogen supply stations (Source: own illustration based on model configuration).

## 6.6 Comparative financial analysis

Although the earlier sections evaluated the economic performance of each supply option separately, combined view is required to assess their financial viability under steady assumptions. In addition to fixed standards like CAPEX, OPEX and LCOH, an ongoing evaluation throughout the project’s duration offers further understanding of sustained profitability and interest in investment. Financial indicators for this include Net Present Value (NPV) and Internal Rate of Return (IRR). The fact that they both take into account the time value of money and the anticipated cash flow trends allows for a thorough examination of supply options under the same conditions.

### 6.6.1 Financial indicators (NPV and IRR)

To determine the profitability of an investment or project, a financial metric called net present value (NPV) compares the current value of cash inflows and outflows over a specified period. Future projected cash flows are reduced to their present value using a particular discount rate, typically the required rate of return or the capital cost. In this model, the desired ROI of 6 % is matched by the discount rate. An investment may be worthwhile if the project generates a return higher than the designated discount rate, as indicated

by a positive net present value (NPV). A negative NPV, on the other hand, suggests that the project may result in a net loss and should be reviewed. [113]

If there is a single cash flow from a project that will be received one year later, the formula for calculating the NPV of the project is as follows [113]:

$$\mathrm{NPV} = \frac{\text{cash flow}}{(1+\mathrm{i})^{\mathrm{t}}} - \text{investment costs (CAPEX)} \quad (5)$$

Where:

*i* – required ROI or discount rate

*t* – number of time periods

For a long-term project with several cash inflows, the NPV formula for the project is as follows [113]:

$$\mathrm{NPV} = \sum_{\mathrm{t}=0}^{\mathrm{n}} \frac{\mathrm{R_t}}{(1+\mathrm{i})^{\mathrm{t}}} \quad (6)$$

where:

$R_t$ – net cash inflow-outflows during a period of time *t*

*i* – discount rate or return

*t* – number of time periods

Since 1 € now is worth more than 1 € in the future, NPV takes the time value of money into account. Businesses can use this principle to evaluate projects objectively and choose those that primarily add value.

An essential financial metric that displays the discount rate at which a project's net present value equals zero is the internal rate of return or IRR. Simply put, assuming that all cash flows are reinvested at the IRR rate, IRR is the annual return rate for a project or investment. It is widely used because it allows investors to evaluate different projects using the same metrics. Projects with an internal rate of return (IRR) greater than the required return rate, 6 % in our case, are considered viable, while those with a lower IRR may be rejected. [114]

When developing and evaluating a business case, both NPV and IRR are important. These indicators can be used to identify investments that support long-term objectives and long-term financial viability. NPV ensures that only projects that increase business wealth are carried out by offering a transparent evaluation of expected value creation. On the other hand, IRR provides a standard for evaluating the percentage return on investments, highlighting the most profitable opportunities. [113,114]

### 6.6.2 Comparison of supply variants

There are some differences in economic performance between the six supply options financial evaluations at a 6 % discount rate and a 2,5 % estimated inflation rate (see Table 28).

With the best results, NPV of roughly 6,6 million € and an IRR of 94 %, liquid hydrogen ($LH_2$) is the most financially appealing choice. Similarly, the delivery of compressed gaseous hydrogen ($CGH_2$) yields a strong profit despite the truck delivery costs, with an NPV of 5,4 million € and an IRR of 101 %. Therefore, both delivery-based solutions greatly exceed the other supply options regarding investment returns.

From the on-site production options, only photovoltaic (PV) supply shows the favorable result, making an NPV of 1,55 million € and an IRR of 9 %. Although the returns are less than those for truck delivered hydrogen, PV-based generation remains a viable investment option given the projected growth.

On the other side, wind energy generated on-site (NPV: –1,87 million €, IRR: 3 %) and on-site electrolysis using grid power (NPV: –2,07 million €, IRR: –1 %) continue to be unprofitable. The substantial CAPEX of wind turbines leads to insufficient returns, whereas the high OPEX cost of purchased grid electricity reduces profitability even with a lower upfront investment. Of all the options, pipeline supply is the least effective and produces the most unfavorable outcome, with an NPV of -2,49 million € and an IRR of nearly 1 %. The big initial costs for infrastructure cannot be offset by savings in operations within the 10-year timeframe evaluated.

| | Year | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | H2 annual requirement in kg/year | 50961 | 64276 | 67626 | 84262 | 100898 | 117534 | 132509 | 134198 | 162459 | 177435 | 232268 | |
| | Sales in € | 662497 | 835585 | 879135 | 1095402 | 1311670 | 1527937 | 1722615 | 1744575 | 2111971 | 2306649 | 3019481 | |
| Variant $LH_2$ | CAPEX in € | 1004710 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | OPEX in € | 42108 | 43160 | 44239 | 45345 | 46479 | 47641 | 48832 | 50053 | 51304 | 52587 | 53901 | |
| | Procurement costs in € | 211489 | 266744 | 280647 | 349686 | 418725 | 487765 | 549912 | 556922 | 674206 | 736353 | 963911 | |
| | Transport costs in € | 26502 | 27164 | 27843 | 28540 | 29253 | 29984 | 30734 | 31502 | 32290 | 33097 | 33925 | |
| | Cash flow in € | -622312 | 498516 | 526405 | 671831 | 817212 | 962547 | 1083137 | 1106098 | 1354171 | 1484612 | 1967744 | |
| | Present value in € | -622312 | 470298 | 468498 | 564082 | 647309 | 719271 | 770619 | 735618 | 849624 | 878739 | 1098778 | |
| | | | | | | | | | | | NPV | 6580525 | |
| | | | | | | | | | | | IRR | 94% | |
| Variant $CGH_2$ | CAPEX in € | 653591 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | OPEX in € | 64971 | 66995 | 68260 | 69967 | 71716 | 73509 | 75346 | 77230 | 79161 | 81140 | 83168 | |
| | Procurement costs in € | 229326 | 289241 | 304316 | 379178 | 454040 | 528901 | 596290 | 603891 | 731067 | 798455 | 1045205 | |
| | Transport costs in € | 132509 | 135822 | 139217 | 142698 | 146265 | 149922 | 153670 | 157511 | 161449 | 165485 | 169623 | |
| | Cash flow in € | -417899 | 343927 | 367342 | 503560 | 639649 | 775606 | 897309 | 905942 | 1140294 | 1261568 | 1721485 | |
| | Present value in € | -417899 | 324460 | 326933 | 422799 | 506662 | 579578 | 632568 | 602503 | 715435 | 746720 | 961268 | |
| | | | | | | | | | | | NPV | 5401026 | |
| | | | | | | | | | | | IRR | 101% | |
| Pipeline variant | CAPEX in € | 8903591 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | OPEX in € | 248877 | 255099 | 261477 | 268014 | 274714 | 281582 | 288621 | 295837 | 303233 | 310814 | 318584 | |
| | Procurement costs in € | 183461 | 231393 | 243453 | 303342 | 363232 | 423121 | 477032 | 483113 | 584854 | 638764 | 836164 | |
| | Cash flow in € | -8673432 | 349093 | 374205 | 524046 | 673724 | 823234 | 956962 | 965625 | 1223885 | 1357071 | 1864733 | |
| | Present value in € | -8673432 | 329333 | 333041 | 439999 | 533663 | 615169 | 674620 | 642196 | 767880 | 803248 | 1041257 | |
| | | | | | | | | | | | NPV | -2493035 | |
| | | | | | | | | | | | IRR | 1% | |
| On-site variant (PV) | CAPEX in € | 8061835 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | OPEX in € | 263985 | 270585 | 277350 | 284283 | 291390 | 298675 | 306142 | 313796 | 321640 | 329681 | 337924 | |
| | Cash flow in € | -7663323 | 565000 | 601785 | 811119 | 1020279 | 1229262 | 1416473 | 1430780 | 1790331 | 1976967 | 2681557 | |
| | Present value in € | -7663323 | 533019 | 535587 | 681031 | 808157 | 918576 | 988558 | 951550 | 1123276 | 1170164 | 1497368 | |
| | | | | | | | | | | | NPV | 1553962 | |
| | | | | | | | | | | | IRR | 9% | |
| On-site variant (wind power) | CAPEX in € | 9766498 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | OPEX in € | 448006 | 459206 | 470686 | 482453 | 494514 | 506877 | 519549 | 532538 | 545851 | 559498 | 573485 | |
| | Cash flow in € | -9552007 | 376379 | 408449 | 612949 | 817155 | 1021060 | 1203066 | 1212037 | 1566120 | 1747151 | 2445996 | |
| | Present value in € | -9552007 | 355075 | 363518 | 514644 | 647264 | 762996 | 848114 | 806074 | 982603 | 1034136 | 1365831 | |
| | | | | | | | | | | | NPV | -1871753 | |
| | | | | | | | | | | | IRR | 3% | |
| On-site variant (grid power) | CAPEX in € | 4172142 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | OPEX in € | 1066948 | 1093621 | 1120962 | 1148986 | 1177710 | 1207153 | 1237332 | 1268265 | 1299972 | 1332471 | 1365783 | |
| | Cash flow in € | -4576593 | -258036 | -241827 | -53584 | 133959 | 320784 | 485283 | 476310 | 811999 | 974178 | 1653698 | |
| | Present value in € | -4576593 | -243430 | -215225 | -44990 | 106108 | 239709 | 342106 | 316773 | 509458 | 576614 | 923416 | |
| | | | | | | | | | | | NPV | -2066054 | |
| | | | | | | | | | | | IRR | -1% | |

Table 28: Annual cash flow development of different hydrogen supply variants
(Source: own illustration based on model configuration).

A closer look at the connection between NPV and IRR reveals why certain cases might seem contradictory (see Figure 6-12 and Figure 6-13). For example, the wind-powered supply has an IRR of 3 % that is positive, yet its NPV is negative. This indicates that the project can produce some returns, but because the IRR is still below the target discount rate of 6 %, the total present value of future cash flow is negative. In other words, the project generates revenue, but it falls short of covering the capital costs, which accounts for the negative NPV. The same reasoning for the pipeline variant (IRR 1 %, NPV –2,49 million €), since the large upfront investment cannot be recovered through the restricted future cash inflows.

The grid-based version is even more demonstrative: the IRR is negative (–1 %) and the NPV is remarkably negative (–2,07 million €). Frequent electricity purchases have an influence on the cost structure, indicating that the project not only fails to recover the investment, but also reduces value-based market price for hydrogen. The PV option, on the other hand, shows how a positive NPV (+1,55 million €) can be generated with a moderate IRR of 9 %. The relationship between CAPEX, OPEX and potential hydrogen earnings is favorable in that the initiative generates value beyond the capital cost even though returns are lower than those from $LH_2$ and $CGH_2$.

According to the current assumptions, the results show a clear hierarchy: hydrogen delivered via $LH_2$ or $CGH_2$ trucks is more profitable and PV is marginally feasible. Wind, grid and pipeline supply have negative net present values (NPVs) and should therefore be viewed as economically unappealing. The importance of aligning investment choices with the return benchmark and anticipated demand growth is emphasized by the combined analysis of NPV and IRR.

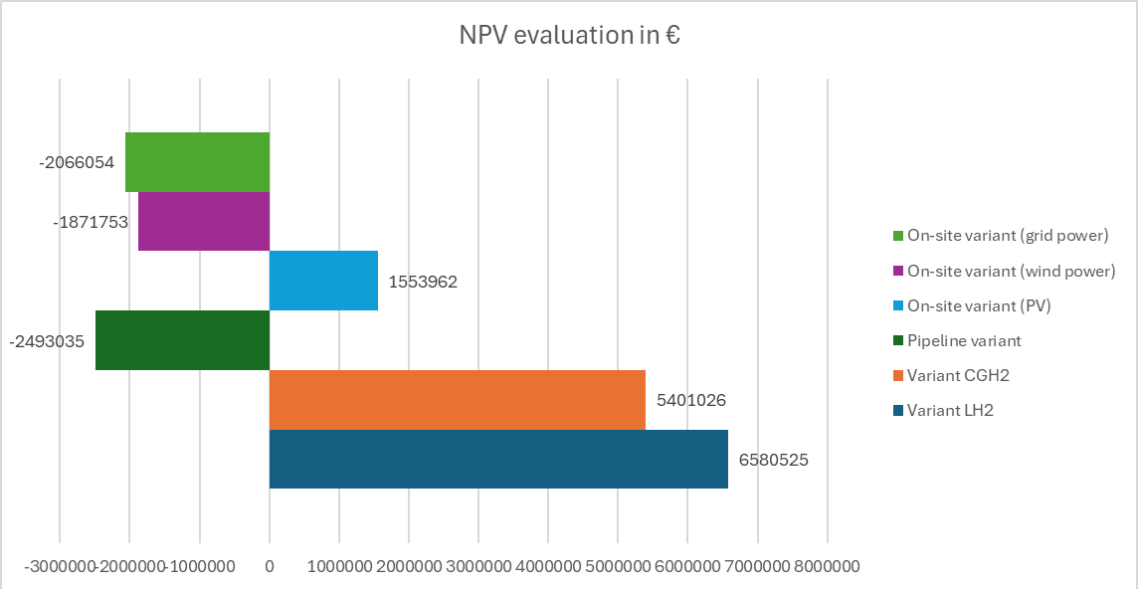


Figure 6-12: Net Present Value (NPV) results for different hydrogen supply variants (Source: own illustration based on model configuration).

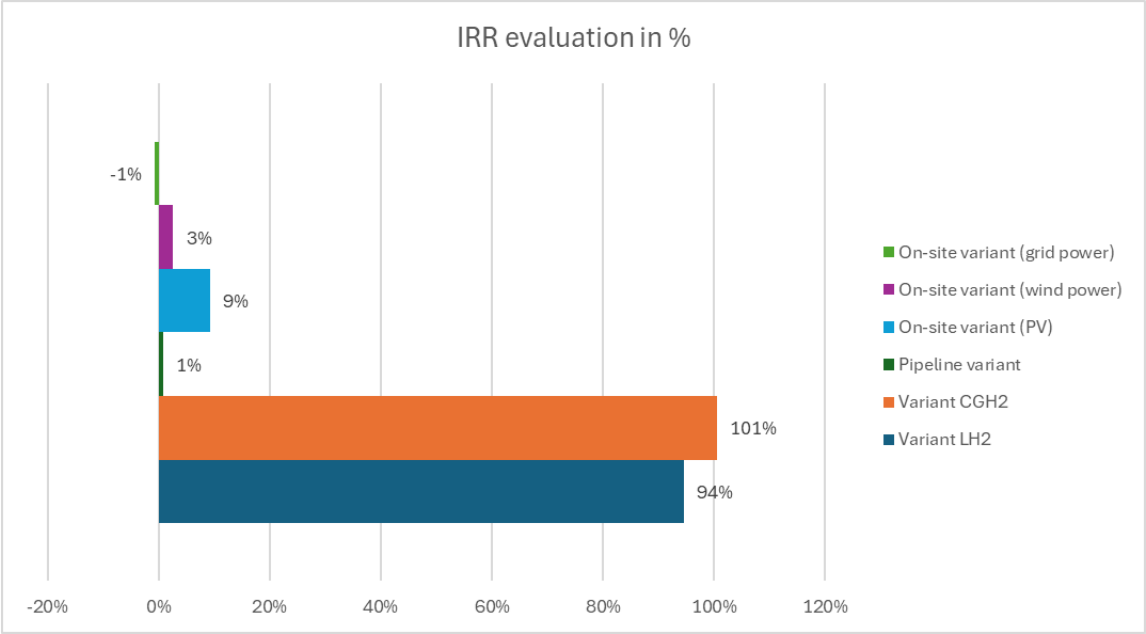


Figure 6-13: Internal Rate of Return results for different hydrogen supply variants
(Source: own illustration based on model configuration).

Based on the hydrogen demand profile from 2025 to 2035, these results reflect the scenario that was studied. The relative performance of the variants would also alter if there was a change in the demand level, either up or down. Increased demand would increase the economics of capital-intensive supply variants like pipelines or wind energy, as fixed costs could be distributed across greater production volumes. In contrast, small demand would further disadvantage these variants and promote ones with less investment costs, like grid electricity. This analysis by changing the demand levels will be examined further in Chapter 6.7.

## 6.7 Sensitivity analysis of hydrogen demand

This chapter examines the impact of varying hydrogen demand levels on the results, in addition to the comparative financial evaluation described in Chapter 6.6. Given the anticipated increase in demand for hydrogen at refueling stations over the next several years, it is critical to assess how well supply options perform in relation to various consumption trends. Three examples are examined in order to achieve this: a low-demand scenario (up to ~ 180 kg/day by 2035), a medium-demand scenario (up to ~ 590 kg/day by 2035) and a high-demand scenario (up to ~ 2250 kg/day by 2035).

The pipeline connection is assumed to exist at a constant distance of 1 km and year 2035 has been chosen as input parameter, which delivers maximum investment costs at the beginning. All other boundary conditions stay the same as in the previous chapter, including a stable hydrogen purchase price of 13 €/kg. Maintaining these external factors unchanged, the evaluation is based exclusively on how demand oscillations affect the NPV and IRR for every supply variant. This offers important perspectives on how the economic feasibility of pipeline transport, truck-based supply ($CGH_2$ and $LH_2$) and on-site generation varies with the scale of daily hydrogen requirements.

### 6.7.1 Case 1 – low demand (up to 200 kg/day)

For a minimal daily hydrogen requirement beginning at 40 kg in 2025 and increasing to 180 kg by 2035, the financial evaluation reveals clear imbalance among the supply options. According to economic analysis, only the compressed gaseous and liquid hydrogen delivery methods produce financially feasible results. With an NPV of roughly 1,13 million € and an IRR of 25 %, $LH_2$ produces the best results, while $CGH_2$ also performs well, with an NPV of 0,08 million euros and an IRR of 24 %. With small-scale operations, these two delivery-oriented solutions are the only ones that remain profitable. The explanation is found in their cost framework. Both need only reasonable investment, while the variable expenses (sourcing and shipping per kilogram of hydrogen) correlate directly with the real demand. This makes them flexible and ideal for circumstances where the hydrogen demand is controlled.

In comparison, pipeline connections and on-site production through PV, wind or grid supply make negative NPVs of –1,7 million € to –3,8 million €, with IRRs ranging from –11 % to nearly zero (see Figure 6-14 and Figure 6-15). The negative NPVs indicate a disorder between big capital investments (especially for on-site renewables and pipelines) and low hydrogen throughput in this demand scenario. The critical element is the CAPEX intensity of these variations. A pipeline or electrolyser requires big upfront investment regardless of hydrogen processing volumes, which implies that fixed costs cannot be recovered at low demand. Although IRR might present positive indicators in certain situations, the total cash flows are too low to compensate for the capital costs, resulting in value loss (negative NPV). In other terms, the capital cannot be recovered within the 10-year timeframe.

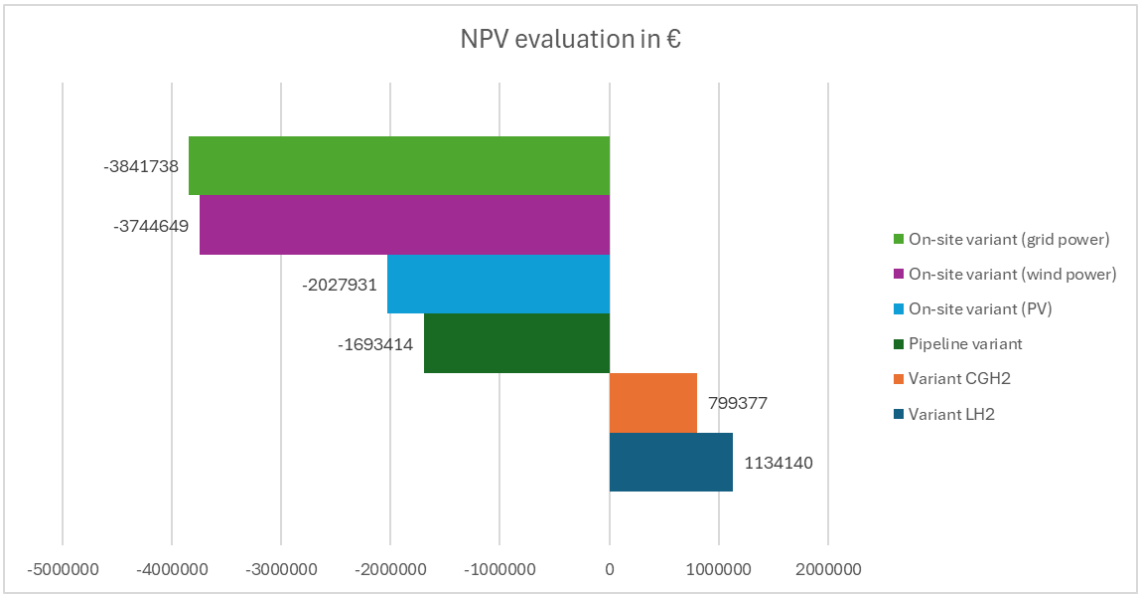


Figure 6-14: Net Present Value (NPV) results for the low-demand case
(Source: own illustration based on model configuration).

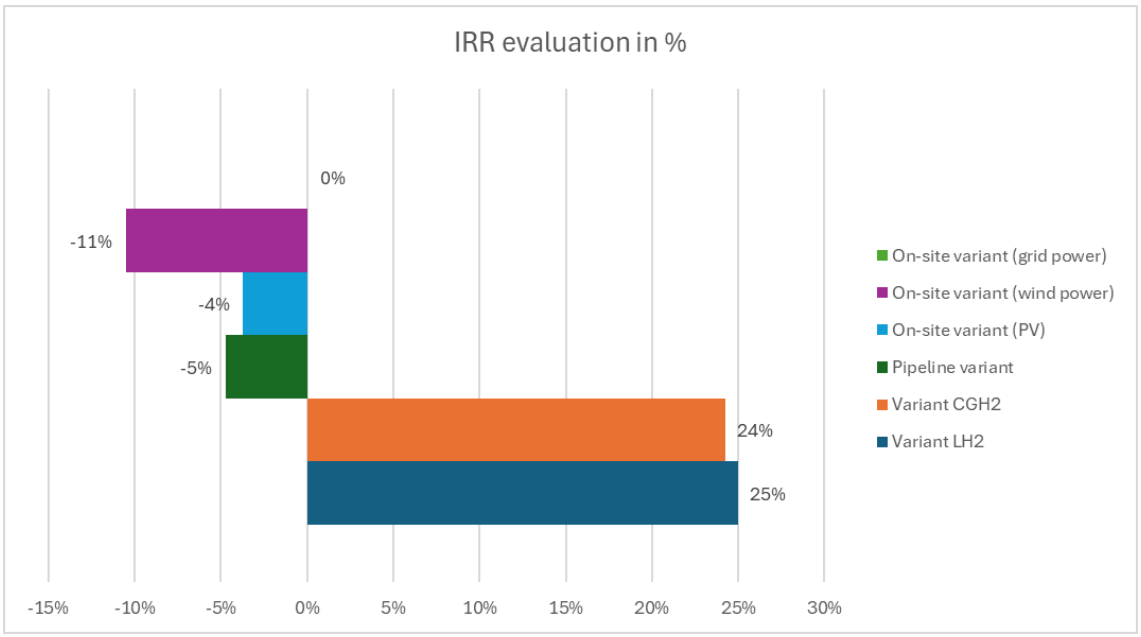


Figure 6-15: Internal Rate of Return (IRR) results for the low-demand case
(Source: own illustration based on model configuration).

The difference between NPV and IRR is important in this context. For instance, in the pipeline scenario, the IRR is positive (1 %), yet the NPV is clearly negative, indicating that although the project could ultimately make returns, they remain below the expected discount rate of 6 %. Similarly, on-site PV and wind demonstrate minimal IRRs in initial stages. However, this does not result in adequate cash flow levels being able to reach a break-even point. This shows that IRR can sometimes mislead when demand is weak, indicating that a project might realize a positive return rate while still reducing value in current terms (negative NPV).

This clarifies why just $LH_2$ and $CGH_2$ appear as attractive options within this demand range. They reduce financial risk by closely relating costs with demand, while preventing minor capital in big infrastructure. Nonetheless, this balance could change considerably as hydrogen flow builds up. In the next section (Case 2), a medium-demand scenario will be explored to analyze how increased demand impacts the economic feasibility of the supply options.

### 6.7.2 Case 2 – medium demand (up to 600 kg/day)

In the medium-demand scenario, where daily hydrogen demand begins at around 130 kg in 2025 and rises to close to 590 kg by 2035, the economic outcomes of the supply options change remarkably from the low-demand case. The results, illustrated in Figure 6-16 and Figure 6-17, indicate that three variants, liquid hydrogen, compressed gaseous hydrogen distribution and pipeline connection, achieve positive financial feasibility, whereas all on-site generation methods are still unattractive.

In $LH_2$ delivery, the increased flowrate enables the relatively moderate initial CAPEX. Beside relatively low OPEX and procurement costs, this results in a highly favorable NPV of 5,44 million € and an IRR of 61 %. This implies that $LH_2$ is currently the greatest choice and scales well with increasing demand.

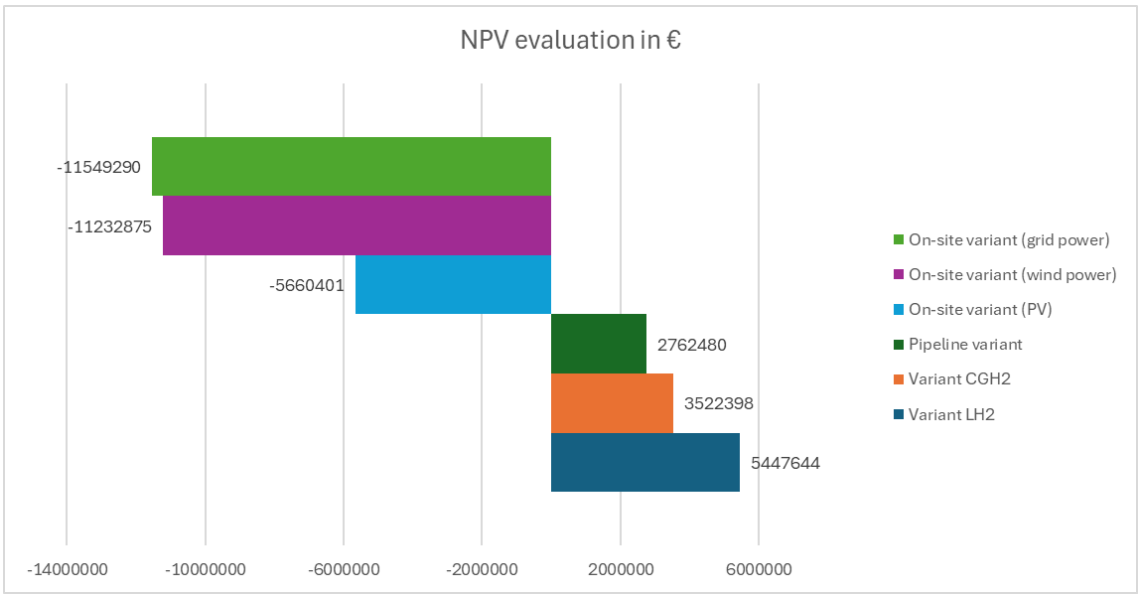


Figure 6-16: Net Present Value (NPV) results for the medium-demand case
(Source: own illustration based on model configuration).

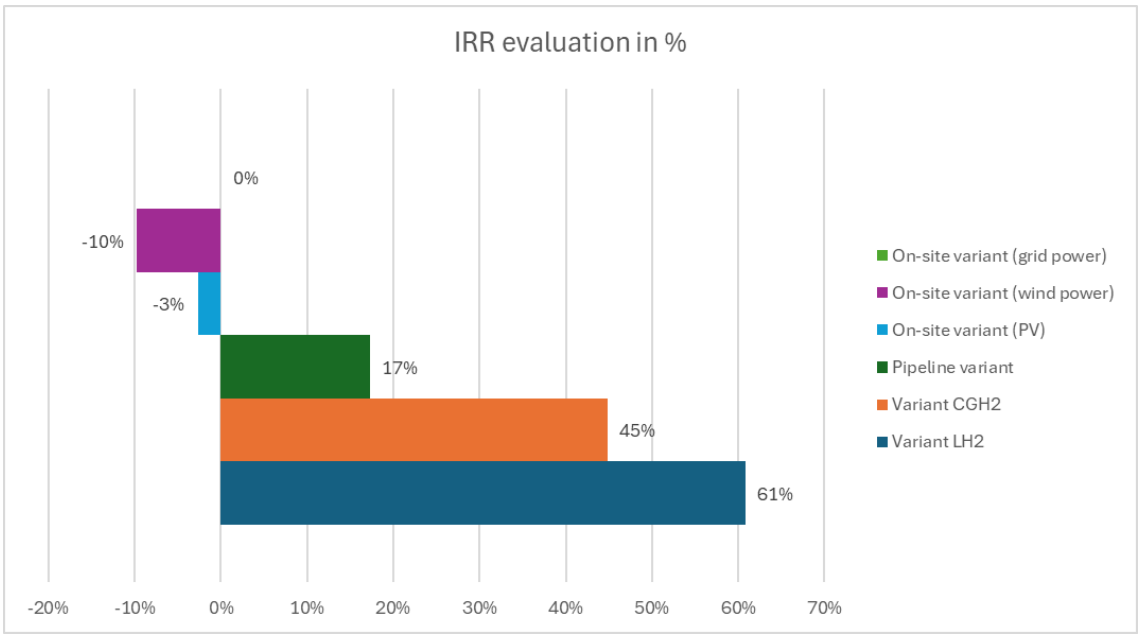


Figure 6-17: Internal Rate of Return (IRR) results for the medium-demand case
(Source: own illustration based on model configuration).

The $CGH_2$ truck delivery option displays similar trend. Even with transport expenses and slightly elevated OPEX, the reduced CAPEX results in an NPV of 3,52 million € and an IRR of 45 %. This confirms that $CGH_2$ keeps competitive as long as logistics costs are properly controlled.

At this level of demand, pipeline supply, which requires high initial investment of 3,6 million €, also becomes feasible, generating a positive net present value of 2,76 million € and an internal rate of return of 17 %. Despite being less profitable than $LH_2$ and $CGH_2$, this shows that pipelines must reach a certain minimum scale for their cost benefits in consistent supply to outweigh the initial investment.

In contrast, on-site generation using PV or wind is still not financially attractive within this range. Both options face high initial CAPEX needs (12,9 million € for PV and 15,7 million € for wind) and this demand

cannot cover these expenses. This results in negative NPVs (–5,66 million € for PV and –11,23 million € for wind) and negative IRRs (–3 % and –10 %). On-site electrolysis using grid electricity makes negative results as well, with an NPV of –11,55 million € and no visible IRR, highlighting the huge and required operating costs (electricity).

In general, the medium-demand scenario highlights $LH_2$ and $CGH_2$ as the most attractive options, whereas pipeline supply appears as a viable, but less attractive one. On-site production is uncompetitive at this demand level since the capital intensity of renewable generation and electrolyser infrastructure requires bigger demand to achieve better financial outcomes.

### 6.7.3 Case 3 – high demand (up to 2200 kg/day)

In the high-demand scenario, where hydrogen demand rises from about 500 kg/day in 2025 to roughly 2200 kg/day in 2035, the economic evaluation shows clear patterns.

The $LH_2$ and pipeline options stand out as the most attractive, demonstrating profitability at this level of demand. The $LH_2$ alternative reaches the most favorable outcome, demonstrating an NPV of approximately 21,9 million € and an IRR of 99 %, indicating that liquid hydrogen distribution is extremely effective in meeting high and consistently rising demand. The pipeline supply choice is currently nearly equal in performance, featuring an NPV of 19,7 million € and an IRR of 52 % (see Figure 6-18 and Figure 6-19). In contrast to the lower demand scenarios, this indicates a notable improvement, showing that the pipeline becomes more attractive as daily hydrogen demand increases, as the fixed investment costs are balanced by the bigger transport volumes.

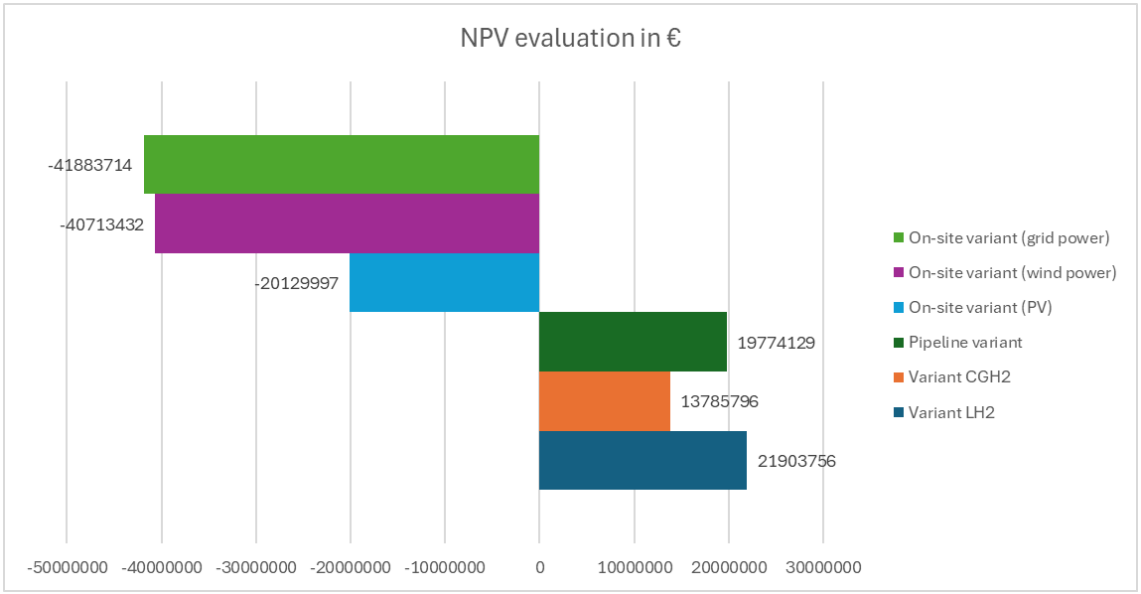


Figure 6-18: Net Present Value (NPV) results for the high-demand case
(Source: own illustration based on model configuration).

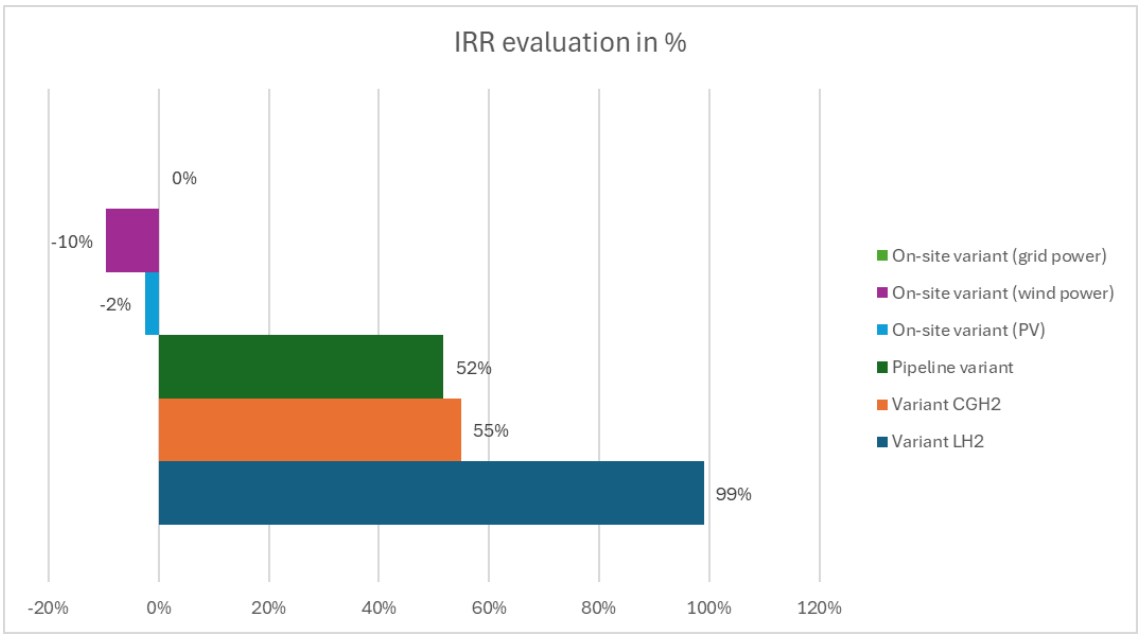


Figure 6-19: Internal Rate of Return (IRR) results for the high-demand case
(Source: own illustration based on model configuration).

The $CGH_2$ delivery option continues to be profitable. Having an NPV of 13,7 million € and an IRR of 55 %, it remains a desirable choice, although it becomes less efficient at elevated demand levels because of its dependence on regular truck deliveries and related transportation expenses. In other words, although $CGH_2$ is appropriate for low and medium demand, its scalability is limited compared to $LH_2$ and pipeline supply.

On the other hand, options for on-site production remain unattractive. Despite the strong demand, they continue to be uncompetitive, with very negative NPVs (–20,1 million € to –41,8 million €) and without any valuable IRR values. The high capital costs for renewables, combined with high operational expenses for grid electricity, make these options unattractive.

### 6.7.4 Overall evaluation of demand scenarios

The sensitivity analysis clearly shows that the financial evaluation of different hydrogen supply options is highly dependent on the scale of demand. At low volumes, truck delivery is the only viable choice, as pipelines and on-site production fail to cover their fixed expenses. As volume increases, pipelines and $LH_2$ deliveries grow more profitable, while $CGH_2$ begins to lose its advantage because logistical challenges. In all scenarios, on-site electrolysis is consistently negative structurally within the 10-year outlook based on these assumptions.

The lack of profitability for on-site solutions is primarily due to the high CAPEX required for the electrolyser, along with further investments in renewable energy sources (PV or wind). Although these assets offer long-term freedom from unstable electricity markets, their expense cannot be covered over a relatively short 10-year timeframe. Extending the project duration to 20 or 30 years would instantly improve the business scenario, as initial expenses could then be spread over more operational years. Similarly, expected reductions in electrolyser capital costs, due to continuous technological advancements, may slowly bond the profitability gap.

Another factor is the reduction of OPEX. As electricity is the main cost factor for electrolysis, reduced power purchase prices would have an impact on the expenses. Policy tools are vital as well, with subsidies for electrolyser capital costs, investment grants for solar and wind or supportive regulations all contributing to improving site economics. At the same time, a strong carbon pricing mechanism or increased market prices for hydrogen could elevate revenues beyond the current expected 13 €/kg, thereby reducing the gap further.

In contrast, pipeline delivery demonstrates the greatest economies of scale. Although unattractive at small demand, the economics increases with higher demand as the fixed infrastructure expenses can be distributed over much larger volumes. This trend would become even more evident if current natural gas pipelines were converted to hydrogen, as this would lower CAPEX in comparison to constructing a new pipeline. In that case, even with moderate levels of demand, pipeline supply may seem like the best option.

In conclusion, the results show a range of perspectives. While on-site electrolysis is currently not competitive, it could become so with a combination of technological advancements, supportive policies, lower electricity costs and longer investment timelines. Truck deliveries ($LH_2$ and $CGH_2$) continue to be the most flexible options for the initial market and low demand levels. Pipelines also gain interest as demand rises and offer a clear long-term cost benefit. These results show that, in addition to growing demand, future hydrogen supply competitiveness will be influenced by the combination of regulatory policies, market price fluctuations and infrastructure improvements.

# 7 CONCLUSION AND FUTURE OUTLOOK

This thesis has shown a methodical approach to the development of scalable hydrogen refueling stations by combining technical system modeling with economic evaluation in order to close the gap between technical and economic viability. To ensure that the infrastructure can adjust to changing levels of hydrogen demand between 2025 and 2035, one outcome is the creation of sizing guidelines for all relevant components, including dispensers, compressors, cryogenic pumps and cascade storage. The study offers a clear framework that helps with engineering design and investment decisions by directly connecting component scaling to demand projections.

Storage, compression or pumping systems, space requirements and safety protocols vary depending on whether the gas is delivered via trailer, liquefied hydrogen, pipeline connection or on-site electrolysis. The analysis demonstrated that a technical setup is impacted by the supply method selection. By establishing dimensioning guidelines that determine the equipment sizing for each supply model, the study also showed how these stations can be modified and designed to efficiently serve a variety of fleets at 350 and 700 bar.

The economic analysis showed which circumstances make each supply option the most practical. While liquefied hydrogen delivery becomes competitive for higher demand and longer distances due to increased trailer capacity and lower logistics costs, pipeline supply offers the most economical overall costs only when local availability is present. Compressed gaseous hydrogen delivery, on the other hand, is logistically constrained and comparatively expensive on a larger scale. Over the next ten years, on-site electrolysis will continue to face structural challenges because of the high cost of electrolysers and the production of renewable energy. Despite its technical appeal, the financial aspects are unattractive unless remarkable equipment cost reductions are obtained.

At the same time, considerable uncertainties remain that hold up the security of long-term planning. The infrastructure for transporting and distributing hydrogen is currently limited, with only a small number of pipelines being developed in Europe. Hydrogen mobility demand forecasts lack precision and it is uncertain whether the market conditions in a decade will correspond with current predictions or if higher hydrogen demand will be realized only after 20 or 30 years. Moreover, fuel cell vehicle technology remains in the development phase. Improvements in system performance, reductions in stack costs and greater market insight will be necessary before FCEVs become more attractive to consumers, which is important for boosting hydrogen demand and enhancing station economics.

Future improvement relies on different elements: enhancement of station parts to reduce CAPEX and OPEX, growth of core infrastructure like hydrogen pipelines and storage, favorable political policies to offset the cost gaps of green hydrogen and ongoing technological improvements in production. In this regard, the framework developed in this thesis provides a strong basis for evaluating and sizing hydrogen refueling stations. However, its results should be interpreted in the context of a constantly evolving dynamic. The forecast can be improved by extending the analytical period to 20 or 30 years and assessing hybrid supply strategies that combine local production and central delivery. The study indicates that hydrogen refueling stations are important for the larger growth of a hydrogen economy, whose future depends on technological developments, infrastructure construction, market acceptance and political support.

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