Securing Green Hydrogen for the German Power Sector

Technology readiness & techno-economic feasibility study for three hydrogen value chains

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Summary:

The goal of the analysis was to assess whether alternative value chains for the provision of hydrogen, such as Iron-to-Hydrogen, are useful to consider, alongside more conventional options such as domestic hydrogen production in Germany (through electrolysis) or hydrogen import through ammonia as a hydrogen carrier. Three different value chains were assessed on their technology readiness, levelized costs for providing back-up power to the German grid, and their overall practicality in a SWOT analysis.

DNVs assessment concludes that Iron-to-Hydrogen is a potentially cost-effective and safe option for sourcing green hydrogen for Germany's back-up power plants. It is advisable to consider this option in addition to other hydrogen sourcing routes.

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GLOSSARY

Term	Definition
AE	Alkaline electrolysis (electrolysis technology)
AEM	Anion Exchange Membrane (electrolysis technology)
ATR	Autothermal reformers
BoP	Balance of Plant
CAPEX	Capital expenditure
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CNF	Climate Neutrality Foundation
DLE	Dry-low-NOx-emission
DRI	Direct Reduced Iron
GHG	Greenhouse gas
kW	Kilowatt
KWSG	Power Plant Safety Act, in German: “Kraftwerkssicherheitsgesetz”
LCOE	Levelized cost of electricity
LCOH	Levelized cost of hydrogen
LNG	Liquefied Natural Gas
LPG	Liquid Petroleum Gas
MW	Megawatt
NOx	Nitrogen Oxides (group of Nitrogen/oxide combinations)
OPEX	Operational expenditure
PEM	Proton Exchange Membrane (electrolysis technology)
PPA	Power Purchase Agreement
PSA	Pressure Swing Adsorption
RO	Reverse Osmosis
RTC	Rail Tank Carrier
SOE	Solid Oxide Electrolysis (electrolysis technology using steam)
TKNP	Tsau //Khaeb (Sperrgebiet) National Park
TRL	Technology readiness level
VFD	Variable Frequency Drive: allows pumps and compressors run slower and therefore adapt flow/throughput
WLE	Wet-low-emission

EXECUTIVE SUMMARY

Germany is modernizing its electricity system to integrate renewable energy and ensure reliability in times of low wind and solar power generation. A key development is the planned German Power Plant Safety Act (KWSG), which promotes hydrogen use within power plants to facilitate back-up power generation. To meet the anticipated hydrogen demand in the future power sector, routes such as domestic hydrogen production in Germany (through electrolysis) or import through ammonia as a hydrogen carrier are much discussed. In addition to these routes, less conventional routes, such as import of direct reduced iron, might be worthwhile to consider as well.

This study, carried out by DNV on behalf of Climate Neutrality Foundation (CNF), assesses the feasibility and potential benefits of three possible value chains for securing green hydrogen for back-up power generation in Germany:

- Domestic green hydrogen production in Germany
- Green ammonia import
- Iron-to-hydrogen – import of direct reduced iron

The goal of the analysis is to assess whether alternative value chains for the provision of hydrogen, such as Iron-to-Hydrogen, are useful to consider, alongside more conventional options. Three different value chains were assessed on their technology readiness, levelized costs for providing back-up power to the German grid, and their overall practicality in a SWOT analysis.

Our assessment concludes that Iron-to-Hydrogen is a potentially cost-effective and safe option for sourcing green hydrogen for Germany's back-up power plants. It is advisable to consider this option in addition to other hydrogen sourcing routes.

Background

The study takes account of the following key developments:

Demand: Power Plant Safety Act

- Under the planned German Power Plant Safety Act, tendering for 7 GW of hydrogen-ready power plant capacity and 500 MW of pure hydrogen power plant capacity (as part of a total 12.5 GW tender package) will take place in 2025.
- The plants are designed to provide back-up power for a mainly renewable electricity system, with the planned Act subsidizing a maximum of 800 full load hours per annum.
- The hydrogen-ready power plants must transition to hydrogen by the eighth year of commissioning or modernization, meaning that there will be a considerable demand for hydrogen for back-up power generation by the mid-2030s – up to 10 TWh for the full 12.5 GW package.

Supply option: Namibia

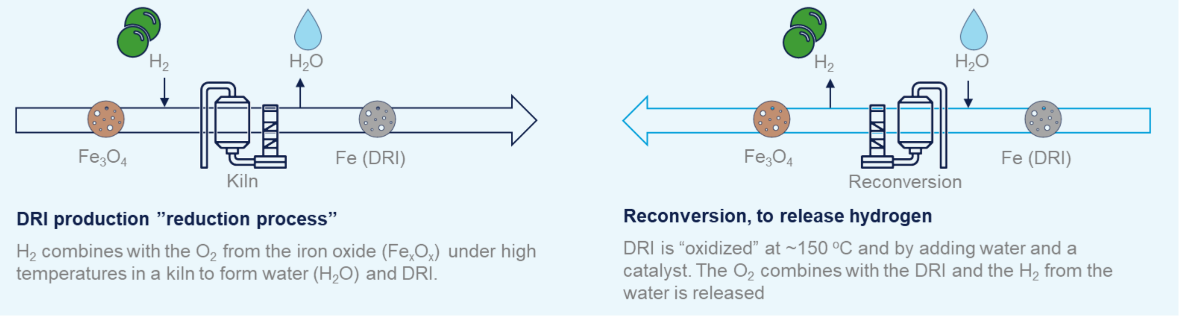
- With its abundant renewable energy resources and vast land availability, Namibia holds significant potential for green hydrogen production. Namibia has been at the forefront of green hydrogen strategy development and aims to be one of the prime exporters of green hydrogen and its derivatives in the future.
- Concrete projects are now underway, including 4 GW of wind and 3 GW of solar generation capacity in the Tsau //Khaeb (Sperrgebiet) national park, with associated green hydrogen production.
- Recognizing the need for imports of green ammonia, the German government has initiated collaborations with potential exporting countries, with Namibia being a key partner. The partnership between Germany and

Namibia aims to create a win-win scenario: exporting green ammonia to Germany while fostering industrial and economic transformation in Namibia.

- Namibia therefore provides a suitable case to explore international supply chains for green hydrogen as input to Germany's back-up power plants.

Technology: Iron-to-Hydrogen

- HyIron has developed a technology for iron ore reduction to produce direct reduced iron (DRI) using green hydrogen. A pilot plant is currently being tested in Germany and large-scale production in Namibia is set to be commissioned by the end of 2024. Hydrogen, produced by cheap renewable energy in Namibia, will be used to produce DRI. This can be exported to, for example, Germany where it can be used in the steel industry or where it can be reconverted to produce hydrogen.
- The case of this company exemplifies how an international Iron-to-Hydrogen supply chain could be established by shipping DRI at scale for the secure domestic provision of hydrogen in Germany.



Simplified explanation of the DRI production and reconversion process

Analyzed green hydrogen value chains

The study provides a detailed techno-economic comparison of the three value chains to provide green hydrogen for German gas-fired hydrogen-ready power plants. In each case, there must be enough gaseous hydrogen at the right time to provide capacity services to the German power system at times of low wind and solar electricity production:

1. **Domestic green hydrogen production:** Hydrogen is produced domestically in Germany using offshore wind energy. The hydrogen is injected into a hydrogen backbone network, stored in salt caverns, and transported to the power plant via the backbone.
2. **Green ammonia import:** Hydrogen is produced inland in Namibia using renewable energy. The green hydrogen is converted into ammonia and then shipped to the EU where it is distributed to hydrogen-fired power plants. At these power plants, the ammonia is reconverted to hydrogen, which is then used to generate electricity.
3. **Iron-to-Hydrogen:** Hydrogen is produced inland in Namibia using renewable energy sources. The hydrogen is used to reduce iron ore, producing direct reduced iron (DRI) and water. The DRI is then shipped to the EU where it is distributed to hydrogen-fired power plants. At these power plants, the DRI is reconverted to hydrogen for electricity generation.

Comparison 1: Technology readiness

The report provides a detailed technology readiness assessment of the different value chains and the respective technologies, including the challenges of each value chain. Each option has challenges, but we don't see any significant showstoppers for the Iron-to-Hydrogen route. Despite its low technology readiness level (TRL), DRI reconversion is relatively simple and could potentially progress rapidly through the TRL levels.

	Main Challenges	TRL
Domestic green hydrogen production	• Low TRL of fast cycling hydrogen salt caverns • Pressure fluctuations and impact on materials, especially steel (embrittlement)	5-8
Green ammonia import	• Low TRL and energy intensity of ammonia cracking at large scale • Flexibility of ammonia synthesis (intermittent renewables) and cracking (back-up power) • Toxicity	5-9
Iron-to-hydrogen	• Further maturing and upscaling of DRI production with green hydrogen • Low TRL of DRI reconversion technology	3-9

Comparison 2: Energy efficiency

In all value chains, considerable energy is lost in the process of hydrogen and derivative production, transport, storage, reconversion to hydrogen, and power generation. The value chain with the greatest energy losses is Iron-to-Hydrogen, and German hydrogen production sees the fewest losses. This means that German hydrogen production would require the lowest installed renewable capacity, and Iron-to-Hydrogen the highest.

- **German hydrogen production:** To provide 10 TWh per year to the German grid, 32.4 TWh/y of renewable energy needs to be produced in Germany. The total energy efficiency of the value chain is therefore 31%. Roughly 26% of the original energy is lost in the hydrogen production process, only 2% and 3% in hydrogen transport and storage (mainly for compression), and 38% is lost in power generation.
- **Ammonia:** To provide 10 TWh per year to the German Grid, 51.7 TWh/y of renewable energy needs to be produced in Namibia. The total energy efficiency of the value chain is therefore 19%. Roughly 33% of the original energy is lost in the hydrogen production process, 7% is lost in the ammonia synthesis process, 1% is lost in transport, 17% is lost in reconversion and 24% is lost in power generation.
- **Iron-to-Hydrogen:** To provide 10 TWh per year to the German Grid, 59.5 TWh/y of renewable energy needs to be produced in Namibia. The total energy efficiency of the value chain is therefore 17%. Roughly 21% of the original energy is lost in the hydrogen production process, 32% is lost in the DRI production process, 7% is lost in transport, 3% is lost in reconversion and 21% is lost in power generation.

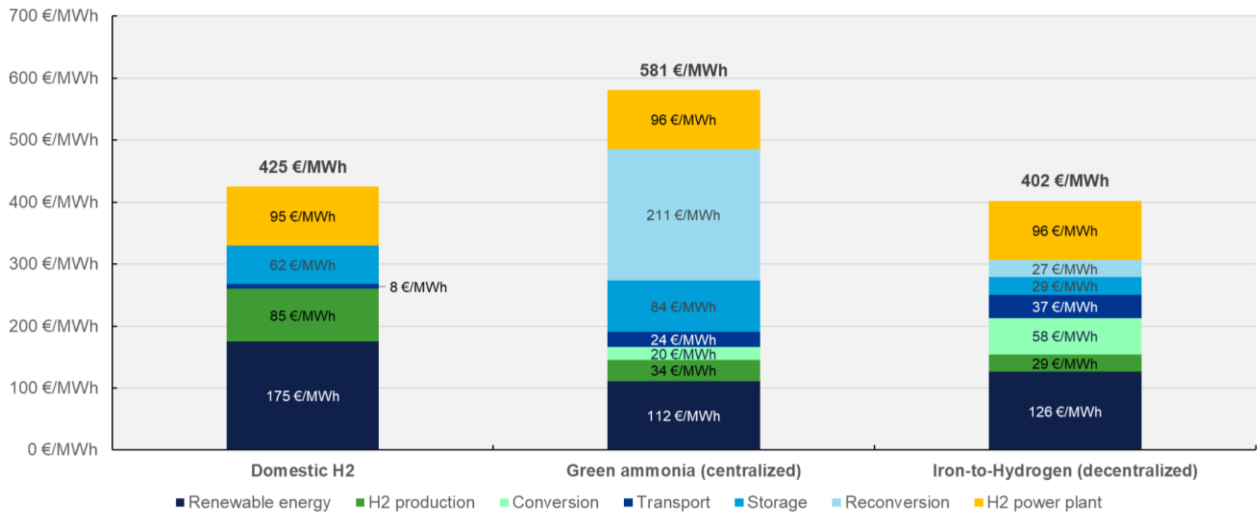
Comparison 3: Cost

For each value chain, the report provides a cost assessment, which considers the full value chain from renewable energy production until production of peak power in Germany:

- The **12.5 GW and maximum of 800 full load hours**, provided in the planned Power Plant Safety Act, are used as a basis for scaling the different value chains and required renewable power generation. This results in 10 TWh to be produced annually by the power plants. In our analysis the required renewable energy is scaled accordingly, depending on the overall efficiency of the value chain.
- The **levelized cost of energy (LCOE)** for each step of the value chain is expressed in terms of the LCOE per MWh of electricity generated by the hydrogen power plant in Germany. This allows for easy comparison between the value chains.
- For **green ammonia import**, centralized reconversion to hydrogen at the import harbor, with onward transportation of hydrogen via the backbone, is used as a basis. Decentralized reconversion of ammonia at the power plant is added as a sensitivity and provided in the main report.
- For **Iron-to-Hydrogen**, decentralized reconversion of DRI to hydrogen (at the power plant) has been used as a basis. Centralized reconversion has been added as a sensitivity in the main report – here the storage and reconversion take place directly at the harbor and further transport of hydrogen utilizes the backbone, as is the case with ammonia imports and domestic green hydrogen production in Germany.

A full description of the modelling parameters and assumptions is provided in the main body of the report. Overall, the cost modelling finds that:

- **Domestic hydrogen production**, at 425 €/MWh, is mainly driven by costs for renewable energy generation and hydrogen production. Hydrogen transport is only a fraction of the costs but costs for hydrogen storage in salt caverns are also significant.
- **Ammonia** has the highest LCOE of the three value chains, at 581 €/MWh (centralized option), mainly due to the very high cost of ammonia cracking and a higher cost of storing ammonia compared to DRI.
- **Iron-to-Hydrogen** has the potential to be the lowest cost of the three value chains studied, with an LCOE of 402 € per MWh of power generated at the German power plants (decentralized option).



LCOE of assessed value chains, expressed as euro per MWh of electricity generated by the hydrogen power plant in Germany.

Comparison 4: Practical considerations

Each value chain has other strengths and weaknesses, including the following practical considerations for back-up power generation as a use-case:

- **Different use cases:** DRI transport and storage is well understood and can be handled as a dry-bulk good with relatively simple safety precautions – in a water and airtight (weather tight) confinement with an inert atmosphere (e.g. nitrogen) with no ventilation. The relative ease of transport and storage make DRI suitable for local, decentralized solutions. This enables energy storage and provision at locations without access to the hydrogen backbone. In comparison, Ammonia is most likely to be restricted to centralized cracking at ports of entry, as it requires a more stringent safety protocol during transport & storage. Further, decentralized ammonia cracking, for back-up power provision, would be technically challenging due to the low flexibility of the cracker.
- **Versatility:** Iron-to-Hydrogen can be transported and stored relatively easily in large quantities and plays a crucial role in decarbonizing the steel industry. It could therefore provide a versatile medium, extending beyond a centralized hydrogen infrastructure (i.e. backbone and salt caverns). The same can be said for ammonia which can be used as a feedstock in the fertilizer industry and is also considered as a fuel in the maritime industry. However, the toxicity should be considered carefully.
- **Energy security:** Domestic German hydrogen production would maximize energy security within Germany as there is less dependence on other countries. However, energy imports are not necessarily unreliable as long as multiple potential suppliers exist from different global regions or countries.

Conclusions

DNV's assessment of the three green hydrogen value chains concludes that Iron-to-Hydrogen is a potentially cost-effective and safe option for sourcing green hydrogen for Germany's back-up power plants. It is advisable to consider this option in addition to other hydrogen sourcing routes.

This assessment was carried out exclusively for back-up power generation (up to 800 hours a year) as an end-use, requiring enough gaseous hydrogen to be available at the right time to provide the needed electricity generation capacity.

- **Technology readiness:** The three variants examined for the provision of back-up power generation each have different degrees of technological maturity with regard to the key components of generation, transportation, storage and reconversion. Iron–to-hydrogen still needs to undergo the most development but could potentially progress rapidly through the TRL levels
- **Levelized cost:** Import of DRI and conversion to hydrogen is a potentially cost-effective addition to importing green ammonia or producing green hydrogen domestically in Germany.
- **Practical considerations:** Green hydrogen based DRI can be transported and stored relatively easily in large quantities and plays a crucial role in decarbonizing the steel industry. It could therefore provide a versatile medium, extending beyond a centralized hydrogen infrastructure (e.g. as a decentral solution for areas more remote from the central infrastructure).

1 INTRODUCTION

The aim of this study is to assess the feasibility and potential benefits of direct reduced iron (DRI)[1], as an energy carrier and hydrogen storage system to enable green hydrogen gas-based power generation in Germany.

1.1 Background

Germany is modernizing its electricity system to integrate renewable energy and ensure reliability in times of low wind and solar power generation. The planned German Power Plant Safety Act (KWSG) promotes hydrogen use within power plants through incentives for technological development, production capacities, and infrastructure. A key element is the tendering in late 2024 or early 2025 of 7.5 GW of mainly hydrogen-ready power plant capacity, as part of a larger 12.5 GW package.

To meet the anticipated hydrogen demand in the future power sector, Germany is partnering with countries such as Namibia to source low-cost green hydrogen. HyIron, a collaboration between Namibian and German companies, has developed a carbon-neutral technology for iron ore reduction using green hydrogen. HyIron's pilot plant in Germany is currently being tested, with large-scale production in Namibia expected by the end of 2024.

In this context, Climate Neutrality Foundation (CNF) has commissioned DNV to study the feasibility of using iron as an energy carrier to help decarbonize the German power system, focusing on hydrogen-ready back-up power plants. This study will assess the techno-economic feasibility of three green hydrogen value chains: domestic green hydrogen production in Germany via electrolysis, import of hydrogen via green ammonia, and import of DRI to produce green hydrogen (Iron-to-Hydrogen). This assessment will be based on end-use in the German power system, where the hydrogen will be used in hydrogen-ready gas-fired power plants that support the German electricity grid, to provide back-up power at times of low renewable energy production.

Although relevant, the study limits itself to only the three value chains and does not compare other value chains such as blue hydrogen production, use of biomethane or natural gas with CCS.

1.2 Scope

This study focuses on potential pathways to provide green hydrogen to German hydrogen power plants, comparing domestic generation of hydrogen via electrolysis with the import of green ammonia and direct reduced iron (DRI) from Namibia.

There are various ways to provide green hydrogen to German hydrogen power plants. In this study, we analyze three value chains. The purpose of each value chain is the same, namely to provide green hydrogen to German gas-fired hydrogen-ready back-up power plants, in sufficient quantities at the right time to provide capacity services to the German power system in times of low wind and solar electricity production.

[1] Sponge Iron is produced from the direct reduction of iron ore, also called direct reduced iron (DRI). It is a semi-finished product in the steel industry and comes the form of lumps, pellets or fines (finer forms of DRI). It does not contain hydrogen but upon oxidation with water it releases hydrogen.

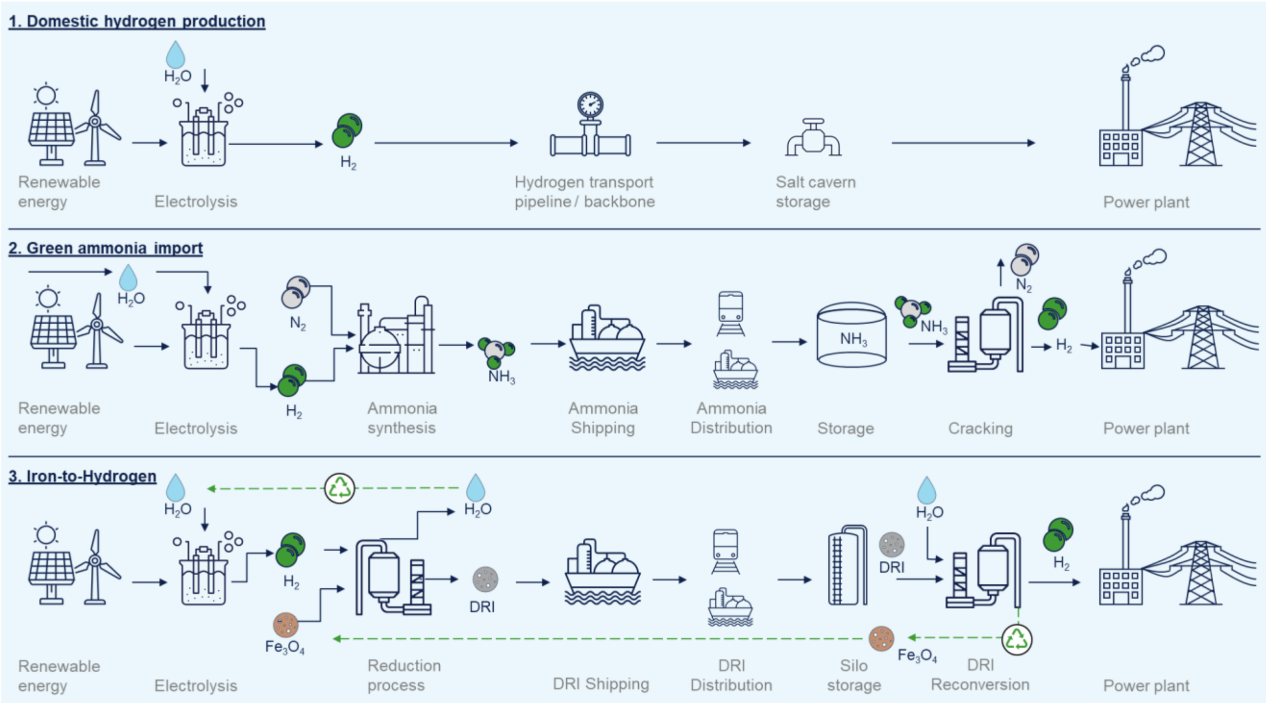


Figure 1: Overview of analyzed value chains

Each value chain has the same technology scope for the starting point and end point of the value chain. The starting point is green hydrogen from renewable energy and water, and the end point is hydrogen used in a hydrogen-based power plant in Germany. What differs is the midstream component of the value chain, namely the way hydrogen is transported from the production site to the end user:

1. **Domestic green hydrogen production in Germany:** The first value chain considers the production of hydrogen domestically in Germany via electrolysis using offshore wind energy. This hydrogen will be injected into a hydrogen backbone network and stored in salt caverns. In this case, the hydrogen is transported to the power plant via the backbone.

2. **Transport via ammonia:** In this value chain, green hydrogen is produced inland in Namibia using renewable energy. The green hydrogen is converted into ammonia and then shipped to Germany, where it is reconverted into hydrogen by using a cracker. The hydrogen is then then fed into the H2 backbone network and transported to the power plant.

3. **Transport via sponge iron:** This value chain uses renewable energy to produce green hydrogen in Namibia. The hydrogen is used to reduce iron ore and produce direct reduced iron (DRI). The DRI is then shipped to the EU where it is distributed to hydrogen-based power plants. At these power plants, the DRI is oxidized, a process to release hydrogen, to be used for electricity generation.

By comparing the three value chains to each other, this study aims to assess the feasibility and potential benefits of additional value chains such as Iron-to-Hydrogen, to enable green hydrogen-based power generation in Germany.

1.3 Report structure

This study is structured as follows:

- **Chapter 2: Basis of work –** Describes the projects and developments that were used as a basis for this work.
- **Chapter 3: Value Chains Description –** provides a description of the different value chains which are assessed in this study.
- **Chapter 4: Technology Readiness Assessment –** Describes the methodology and results of the technology readiness assessment.
- **Chapter 5: Techno-economic Feasibility –** Describes the methodology and results of the techno-economic modelling works and the implications for the feasibility of the analyzed value chains.
- **Chapter 6: Comparison –** Provides an overview of the key aspects for each value chain and provides a comparison for the TRL, the levelized costs and an overview of strengths, Weaknesses, Opportunities and Threats (SWOT).
- **Chapter 7: Conclusions–** sets out the main findings and conclusions of this study.

2 BASIS OF WORK

This chapter describes the basis of work and the approach for this study. It also discusses the data that was received from CNFs knowledge partner HyIron, and the subsequent review of this data that was performed by DNV.

2.1 Power plant safety act

The Power Plant Safety Act is an important policy driver for developing hydrogen-fueled power plants. Germany is making significant efforts to modernize its power system to accommodate higher shares of renewable energy and ensure reliability during periods of low wind and solar output. This strategic initiative is expressed in the Power Plant Safety Act (Kraftwerkssicherheitsgesetz, KWSG), which has been released in draft form and opened for consultation on 11 September 2024.

One key objective highlighted in the strategy is the promotion of the hydrogen use within power plants, through:

- Incentives for the technological development and testing of hydrogen power plants.
- Incentives for building production capacities for hydrogen power plants, as well as for the production, transport, and seasonal storage of hydrogen.
- Incentives for developing and establishing the necessary hydrogen infrastructure for the power plant sector.

A central element of the KWSG that addresses this objective is the tendering of 7.5 GW of mainly hydrogen-ready power plant capacity as part of a larger tender package totaling 12.5 GW of power plant capacity and 500 MW of long-term storage. The tender plan includes the development of:

- 5 GW of new hydrogen-ready gas power plants and 2 GW of comprehensive hydrogen-ready modernizations, which must transition to hydrogen operation by the eighth year of commissioning or modernization.
- 500 MW of pure hydrogen power plants that will immediately operate on hydrogen after commissioning, the so called *'hydrogen sprinter power plants'*.
- 500 MW of long-term storage solutions.
- 5 GW of new power plants to ensure supply security during periods of low wind and solar output. These plants will serve as a bridge to a comprehensive, technology-neutral capacity mechanism, set to be operational by 2028, which shall also utilize demand flexibility and storage.

The subsidy for feeding power into the grid is limited to a maximum of 800 full load hours in 100% hydrogen operation per year.

The next steps involve a consultation on the KWSG. Following this, the final state aid approval of the law will take place. The first tender is planned for late 2024 or early 2025.

2.2 Import of green ammonia

To meet the anticipated hydrogen demand, Germany foresees to import green hydrogen in addition to domestic production. Imports will take place via pipeline from neighboring countries, but also via long-distance maritime transport. For long-distance shipping, hydrogen conversion to ammonia is considered a more viable alternative than transport of hydrogen in pressurized or liquid form. Partnering with potential exporting countries, such as Namibia, can enable their abundant renewable energy resources to be used to secure a stable supply of green ammonia, and thereby hydrogen, for Germany.

With its abundant renewable energy resources and vast land availability, Namibia holds significant potential for green hydrogen production. The Namibian government published its national development strategy, Harambee Prosperity Plan II (HPPII). The HPP II, Goal 3, Activity 2, identifies green hydrogen as a key driver for economic recovery and inclusive growth in Namibia. To realize this vision, the government of Namibia established the Green Hydrogen Council (GHC) and actively sought investments in the green hydrogen industry, positioning Namibia to fulfil the objectives of HPP II.

Simultaneously, Namibia launched its Southern Corridor Development Initiative (SCDI), a tender for Namibia's first large-scale vertically integrated green hydrogen project in the Tsau //Khaeb (Sperrgebiet) National Park (TKNP).
In November 2021, Hyphen Hydrogen Energy was awarded preferred bidder status for the project, which is earmarked for the development of 4 000 km2 within the TKNP near Lüderitz. The project, worth an estimated US$14 billion, will ultimately produce 350,000 tons of green hydrogen or 2 million tons of Ammonia per year for regional and global markets. Hyphen expects to start production by the end of 2027 and be fully operational by 2030. This positions the project as one of the first GW-scale green ammonia plants in the world, which is why it serves as an exemplary ammonia supplier to Germany in this study.

The key aspects from this project which are used in our study are listed below:

- 7 GW of renewable generation capacity in Namibia's TKNP, consisting of 4 GW wind and 3 GW solar.
- Green Hydrogen production directly at the TKNP.
- Green hydrogen will be transported by pipeline to Lüderitz new port at Angra point where it is converted to Ammonia.
- The hydrogen pipeline will provide sufficient capacity to also store and balance intermittent hydrogen production for the less flexible ammonia production process.
- Water desalination will take place at the port and will be transported by pipeline to the electrolyzer site. The desalination plant also provides water for the ammonia production process.
- In addition to hydrogen and water transport pipelines, there will also be overhead transmission cables to provide surplus power to the Namibian grid and to provide back-up power to the renewable energy and electrolyzer plant at times of low renewable energy production.
- The produced ammonia will then shipped to customers around the world.

For the assessment, DNV made some adaptations which are further clarified in section 3.

2.3 HyIron pilot

HyIron has developed a technology for iron ore reduction using green hydrogen. A pilot plant is currently being tested in Germany and large-scale production in Namibia is scheduled to start up by the end of 2024. This could provide a new way of transporting energy at scale over long distances by ship to generate hydrogen at the destination.

HyIron, a collaboration between Namibian and German companies specializing in renewable energy and engineering, has developed an innovative technology for iron ore reduction, using green hydrogen in a rotary kiln. The company claims that this process, known as HyIron technology, replaces 1.8 tons of CO2 emissions for every ton of iron produced compared to conventional methods.

Production Process: In an airtight rotary kiln, oxygen from the iron ore reacts with hydrogen, producing water, which is continuously filtered from the air and reused in water electrolysis to generate hydrogen (see figure below). This closed-loop system ensures no water is consumed, making it ideal for regions with abundant energy but scarce water resources. The end product, Direct Reduced Iron (DRI), can be used in foundries, steel mills, 3D printing, iron-air batteries, and other applications. It can also be used as an energy carrier and energy storage with which one can generate hydrogen.

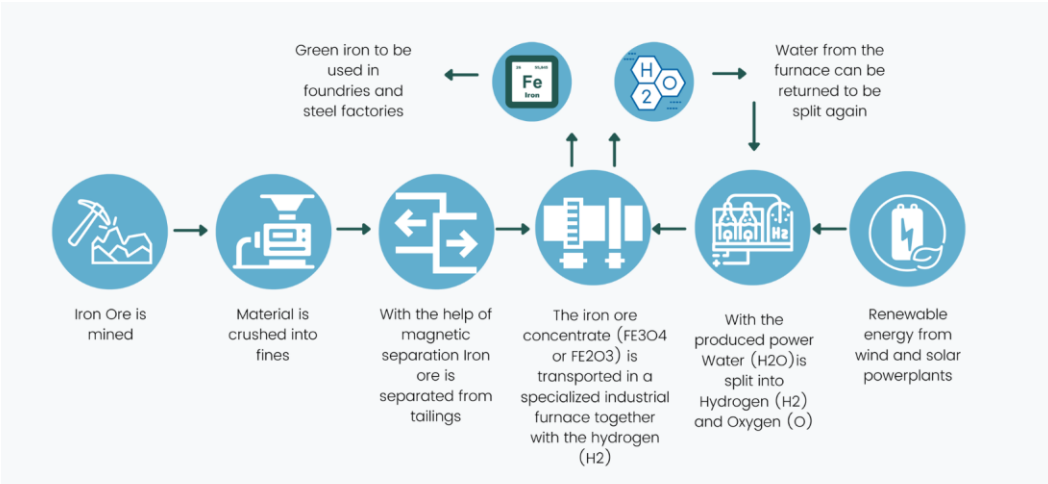


Figure 2: Simplified process flow diagram of the green iron production process. Source: (HyIron, 2023)

Current Technology Status: HyIron notes that it has launched its pilot plant in Lingen, Germany, following extensive laboratory tests and analyses in collaboration with several steel manufacturers. The plant produces up to 500 kg of DRI per hour, allowing for comprehensive testing of input and output materials.

Future Plans in Namibia: The first industrial-scale production of net-zero-emission iron using HyIron technology will be implemented through the Oshivela Project in Namibia. The initial phase aims to produce up to 15,000 tons of DRI annually, with operations expected to start by the end of 2024. This project will be one of the largest primary production sites for green iron globally.

3 VALUE CHAINS DESCRIPTION

This study focuses on potential pathways to provide green hydrogen to German hydrogen power plants, comparing imports from Namibia in the form of direct reduced iron (DRI) or ammonia to domestic production of green hydrogen. The purpose of each value chain is the same, namely to provide green hydrogen to German hydrogen-ready power plants, for providing back-up power to the German power system in times of low wind and solar electricity production. Each value chain is elaborated further below.

3.1 Domestic Green Hydrogen production in Germany

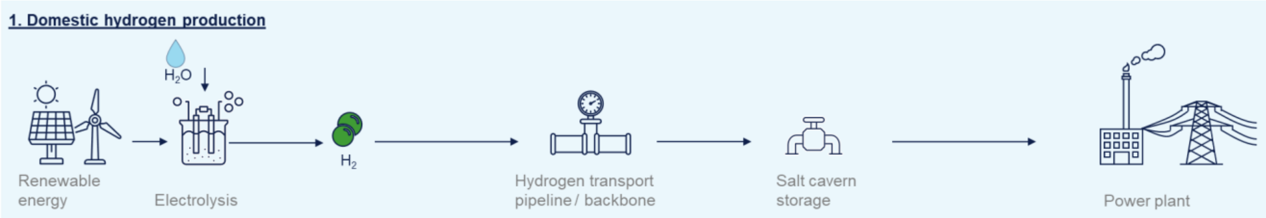


Figure 3: Process flow diagram of the domestic green hydrogen production in Germany.

The first value chain considers the production of hydrogen domestically in Germany via electrolysis using offshore wind energy. The produced hydrogen will be injected into a hydrogen backbone network and stored in salt caverns. Both the backbone and the caverns will be part of a common infrastructure. It is assumed that there will be a backbone connection to hydrogen-based power plants, which will support the German electricity grid. In this case, the hydrogen is physically transported to the power plants via the backbone.

3.2 International Green Ammonia value chain

Figure 4: Process flow diagram of the green ammonia value chain.

In this value chain, green hydrogen is produced inland in Namibia using renewable energy. The hydrogen is then transported to the coast via a 50-100 km long pipeline, which also serves as a storage vessel. At the coast, the hydrogen is converted into ammonia and shipped to Germany. Upon arrival, the ammonia is cracked (centrally) to release hydrogen which is then injected into a central hydrogen infrastructure (the hydrogen backbone). Similar to the domestic hydrogen production value chain, the hydrogen is transported to the hydrogen-based power plants to produce electricity and support the German electricity grid.

As a sensitivity, decentral ammonia cracking is also assessed. Upon arrival in the German ports, the ammonia is transferred onto smaller inland ships, or trains for distribution to hydrogen-fired power plants. At these power plants, the ammonia is cracked locally to release hydrogen, which is then used to generate electricity, supporting the German electricity grid.

3.3 Iron-to-Hydrogen value chain

Figure 5: Process flow diagram of the iron-hydrogen value chain.

The third value chain considers the transport of direct reduced iron (DRI) from Namibia to Germany where it is used to generate hydrogen again. Hydrogen is produced inland in Namibia using renewable energy sources. This hydrogen is then used in an iron reduction process, also conducted inland in Namibia, where iron ore (iron oxide) reacts with hydrogen to produce DRI and water (more detailed description provided below). The DRI is then transported to the coast by rail, where it is loaded onto bulk carriers and shipped to the EU. Upon arrival in the EU, the DRI is distributed to hydrogen-fired power plants via inland ship, or rail. At these power plants, the DRI is oxidized with the addition of water, heat and a catalyst to release hydrogen. This hydrogen is then used to generate electricity in a hydrogen-based power plant, supporting the German electricity grid. After oxidation the DRI is shipped back to Namibia to be reduced again, making a closed cycle.

DRI process:

- *Reduction* - In the reduction process of iron oxide (rust) the oxygen is removed by a reduction agent, in this case hydrogen. Under high temperature conditions, the oxygen will react with the hydrogen to form H_2O (steam). The reduced iron will remain and is called DRI.
- *Reconversion* – in the reconversion process, the DRI is oxidized by adding water or steam, heat and a catalyst to accelerate the process. In the process of oxidation, the oxygen in the water will react with the iron and the hydrogen molecules in the water are released. Purification of the hydrogen is needed afterwards before it can be used in the power plant. The sponge iron value chain therefore does not transport hydrogen in any form, but the hydrogen is formed from the water that is added at the reconversion process, in Germany.

3.4 Comparison of carrier characteristics

The table below compares the key characteristics of the three energy carriers. DRI has the highest energy density, compared to Ammonia and H2. One cubic meter of DRI can generate more than 2.5 times as much hydrogen as a cubic meter of ammonia. Further, one cubic meter of DRI can generate more than 22 times as much hydrogen as one cubic meter of hydrogen stored in a salt cavern at 200 bar, and almost 5 times as much hydrogen as one cubic meter of liquid hydrogen., In terms of weight however, DRI is much heavier. Per kg, DRI can potentially generate 0.043 kg of hydrogen, roughly 4 times less, compared to the amount of hydrogen from ammonia. This is also an important consideration for the transport and carrying capacity of bulk vessels. Unlike ammonia, DRI is not toxic, although it does need to be transported under a protective N_2 atmosphere. The comparison is less straightforward with domestically produced hydrogen, as gaseous hydrogen would be transported via pipeline rather than ship, so the lower volumetric energy density is less important.

Table 4-4: Comparison of carrier characteristics

	H2	NH3	DRI
Chemical composition	**99.999% H_2**	**100% NH_3**	**90% Fe, 10% Fe_3O_4**
Hydrogen density (volumetric)	0.0899 kg H_2/m³ H_2 (@200 bar) 14.94 kg H_2/m³ H_2 (liquid) 70.96 kg H_2/m³ H_2	121 kg H_2/m³ NH_3	340 kg H_2/m³ DRI
Hydrogen density (gravimetric)	1 kg H_2/kg H_2	0.179 kg H_2/kg NH_3	0.043 kg H_2/kg DRI
Material density (volumetric)		674 kg/m³	4,950 kg/m³
Environmental, Social, Health and Safety (ESHS)		High Toxicity	DRI is pyrophoric, it can auto-ignite when mixed with oxygen from air. Pyrophoric materials are often water-reactive as well and will ignite when they contact water or humid air. Therefore, transported under N_2 protective atmosphere.

4 TECHNOLOGY READINESS ASSESSMENT

DNV has performed a technology readiness assessment of the different value chains and the respective technologies. This section provides the outcomes of this assessment and provides insight into the following:

- A general introduction to the technology.
- The current status.
- Challenges for further development.
- Potential development opportunities.
- DNV's view on the technology readiness level (TRL).

4.1 TRL assessment methodology

The assessment is based on interviews with DNV experts, technology providers and literature. DNV applied the TRL definitions in the European Horizon 2020 framework program, used for EU Horizon funding applications. Originally the TRL scale was defined by NASA in the 1990s and it is largely adopted in the Horizon 2020 framework.

The TRL is defined by 9 levels. The stages 1-3 represent the different research levels to determine the technology's feasibility, the TRL evolves into levels 4-6 when development starts (system design, testing, demonstration) and as the innovation starts being deployed and ready for commercialization it enters the remaining stages 7-9. A more detailed overview, as well as DNV's view is provided below.

Table 4-1: Description of the TRL ladder.

TRL		EU H2020 Terminology	DNV Reading	DNV definition
Research	TRL1	Basic principles observed	Basic principles observed	Basic scientific research is translated into potential new basic principles that can be used in new technologies.
	TRL2	Technology concept formulated	Technology concept formulated	Potential applications of emerging technologies are identified, including their technological concept.
	TRL3	Experimental proof of concept	First assessment of the concept and technologies	A concept describes the problem to be solved and outlines a technical solution. Possible markets are identified.
Development	TRL4	Technology validated in lab	Proof of concept (PoC)	Shows technical feasibility of a novel application or solution addressing a previously identified problem.
	TRL5	Technology validated in relevant environment (industrially relevant environment in the case of key enabling technologies)	Demonstration in a user environment	Provides a simple demonstration of the technical solution to an identified business problem (external or internal). Demonstration is on a level that the customer can give detailed feedback on the solution and what potential requirements are missing.
	TRL6	Technology demonstrated in relevant environment	Minimum Viable Product (MVP) presented in user environment	Shows the business opportunity for a new product or the internal productivity opportunity. The product/service has just enough features to satisfy early customers, and to provide feedback for future development. The MVP has been validated with a few external customers or validated by the internal customer.
Deployment	TRL7	System prototype demonstration in operational environment	Low scale pilot production demonstrated	The delivery model is now operational at a low scale, producing actual commercial products/services. Lead clients test these final products/ services.
	TRL8	System complete and qualified	Delivery model made operational and tested, validated and qualified	The delivery organization, as well as the final version of the product/service is now fully established. This includes the organization of production and marketing. The product is formally launched into early adopter markets.
	TRL9	Actual system proven in operational environment	Production and product/service fully operational and competitive	Product rolled out. Full production is sustained; product/service expanded to larger markets and the product/service is maintained. Delivery model and overall production is optimized by continuous incremental innovations to the product/service.

Often an individual technology can have a high TRL, but when integrated in a complete process or when applied in specific situations, there are still challenges to overcome. In our assessment we have taken this into account when defining the TRL of the different technologies. The key aspects impacting the TRL of (more mature) technologies are the scale and the required flexibility to operate in correspondence with renewable energy or to respond quickly to back-up power needs from the German grid.

4.2 TRL assessment

4.2.1 Renewable electricity generation

To produce green hydrogen through electrolysis the main sources of renewable electricity are considered to be solar and wind. The production of renewable energy by solar and wind is currently fully mature and widely applied across the world.

One of the key challenges for the application of wind and solar in this project is potentially the "islanded" (off-grid) configuration. The operation of wind and solar without a strong grid reference becomes more challenging, especially during and after times of no renewable energy sources. Some form of back-up power is required (which could be batteries) to keep essential equipment running and to provide power for starting up again. There are already, however, many "islanded" configurations in operation.

Although considerable investment is still carried out in R&D, further optimization and upscaling, DNV considers both electricity production from solar and wind at a TRL 9.

4.2.2 Water purification

Water purification is currently widely applied across the world for many purposes (e.g. drinking water, process water, etc.). There are also many different technologies available depending on the size and source of the water. In this study we assume sea water as the primary water source, but other sources (inland) could also be used if available. To use the water in the electrolysis process the water needs purification and de-ionization to reach demineralized water quality; for electrolyzers a reference is usually made to ASTM D1193 (type II) or ISO 3696 (grade 2).

Current status

One of the most well-known technologies for (sea)water treatment is reverse osmosis (RO). This technology is widely applied and available at different sizes. Standardized RO units can be placed in parallel to increase capacity; e.g. 10-20 units to supply clean water to a 1 GW electrolyzer plant. To reach the required water purity multiple stages (passes) will be placed to purify the water. Here a "product stream" contains the purified water and a "reject stream" contains water with a higher concentration of contaminants/minerals that were taken out of the product stream.

Challenges

DNV has not assessed the RO technology in detail and while the technology can be considered fully mature, the flexibility to vary flow and operate in correspondence with intermittent renewable energy has not been thoroughly assessed. Means to mitigate this challenge could be to operate water purification as a base-load consumer and store the purified water.

Other challenges include the environmental impact of water desalination. For example, the reject water will contain a higher concentration of impurities/minerals which might provide environmental concerns. Other issues can include the higher volumes of water intake, the disturbance of marine life and the use of chemicals to avoid contamination of bio-organisms (e.g. algae). Usually this is situation specific and should therefore be considered carefully during the feasibility stage of a project and appropriate mitigations should be put in place.

Development Opportunities

Other technologies such as thermal desalination could provide opportunities to optimize complete system efficiency by using waste heat from the electrolysis and/or ammonia synthesis or iron reduction process. This technology also has a high technical maturity but requires further integration into the hydrogen (or carrier) production system.

Other opportunities arise when part of the water treatment capacity can also be used for providing drinking water. This can improve local acceptance and allow for more cost-effective production of the drinking water.

TRL level 9

Water treatment is a well-known process and fully commercial water treatment technologies are available. DNV therefore considers the TRL at level 9.

4.2.3 Electrolysis

At a basic level, electrolysis splits water (H_2O) into hydrogen (H_2) and oxygen (O_2) by applying an electric current. As simple as it sounds, researchers and developers have optimized this process and currently there are four main technologies: Alkaline electrolysis (AE), Proton Exchange Membrane (PEM), Solid Oxide Electrolysis (SOE) and Anion Exchange Membrane (AEM). While electrolysis has been a commercial technology, the energy transition has boosted further development on cost effectiveness, efficiency, scale-up and material selection. The new-generation electrolyzer technology therefore differs significantly from the existing technology, which was mostly applied in chlorine production.

Current status

AE and PEM are currently the most mature technologies and will be considered for this study. These technologies are commercially available at MW-scale, usually as containerized solutions. An electrolyzer plant can be roughly divided into:

- The stack, the core technology where the electrolysis process takes place,
- The balance of plant (BoP) containing the power supply (transformers and converters), all the process equipment (for gas treatment) and the other equipment such as control panel, sensors, etc.

Upscaling into larger capacities for both AE and PEM will be based on a repetition of the stack, which is currently in the range of 5 MW. For large scale plants the BoP can be combined for multiple stacks to utilize economies of scale. There are only a few projects at large scale (multi-100 MW-scale) that are commissioned or under construction (e.g. Shell's 200 MW Holland Hydrogen 1 or Sinopec's 260 MW Kuqa plant). Most other large-scale projects are still in design phase and have not yet passed FID (see figure below).

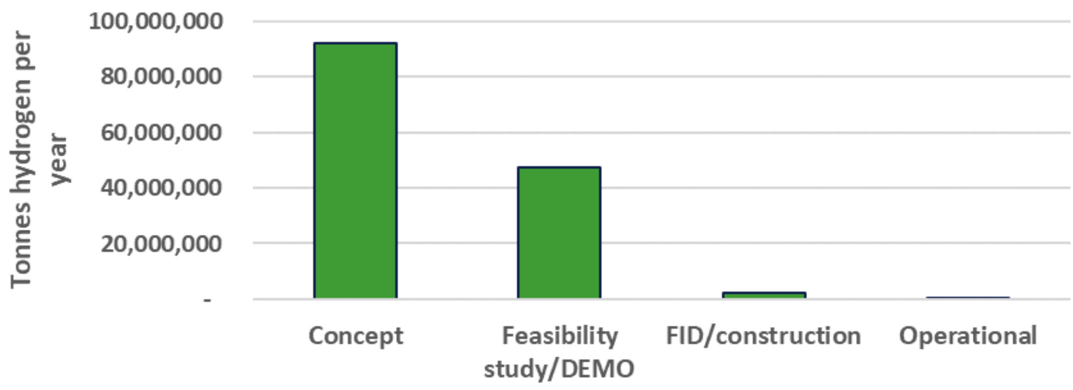


Figure 6: Status of electrolysis hydrogen production projects (2023, based on IEA H2 project database [1]).

Besides the novelty of large-scale electrolyzer plants, operational experience of the new-generation electrolyzers is also still limited (also at MW-scale). Most electrolyzers have only been in operation for a few years so far and long-term operational data is still a knowledge gap, especially operational experience with electrolyzers operating with fluctuating renewable energy.

Challenges

Hydrogen production through electrolysis is facing key general challenges for all electrolyzer technologies. These include the following:

- The cost effectiveness and business case for green hydrogen production are still challenging. As a feedstock it has to compete with grey or blue hydrogen and for decarbonization of the industry it has to compete with fossil fuels, biogas/biomethane and electrification. Currently the CAPEX of electrolyzers and the electricity price are still too high for green hydrogen to be cost competitive. Although funding (e.g. IPCEI or Hydrogen Bank) provides opportunities for cost reduction of hydrogen production, market demand is still lacking.

  The effect of these unfavorable market dynamics is that capital for further development and upscaling is not available. Many projects, which are needed for the further maturation and upscaling of the technology, are being postponed or cancelled.

- Upscaling of the technology itself is also challenging. Concepts for large scale electrolysis plants are in place, but the integration and optimization at the larger scale are much more complex. Projects at larger scale provide "technology jumps" (e.g. more complex power supply with higher voltages and different types of power equipment, different cooling concepts, challenges to keep systems compact, etc.).

  Additionally, there is still a lack of best practices for safe design and compliance with safety standards. Knowledge from the process industry will be relevant, but many developers come from a different background and don't have this experience. DNV currently sees multiple projects being delayed because (safe) design is more complex than anticipated.

- Long term operational experience is still limited and provides uncertainty on reliability and degradation. The combination with fluctuating renewable energy (excessive ramping and frequent start-stops) is a particular concern as it will likely have a negative impact on the degradation. The long-term performance/degradation and the effect of intermittent operation is a significant knowledge gap.

- Another challenge, especially for PEM, is the use of rare materials (for PEM mainly iridium). Manufacturers and research institutes are trying to develop means to reduce, replace or recycle the rare materials.

Development opportunities

One of the key developments allowing further upscaling of renewable hydrogen production is the funding from the Hydrogen Bank. 7 projects have recently been awarded funding (720 million Euro in total) to bridge the price difference between their production costs and the market price for hydrogen. The projects are mainly located in Spain, Portugal, Norway and Finland, where cheap renewable energy is available (solar and hydro) and where high electrolyzer utilization can be achieved.

Another promising development is the Dutch HyPro research program with a budget of 50.2 million Euro. The focus is to reduce technical risks and costs of green hydrogen production. The partners include some of the key project developers, such as Shell and RWE, as well as knowledgeable research institutes [2].

Other developments which will boost the industry are the large-scale projects which are under development worldwide, such as Shell's under-construction *Holland Hydrogen 1* and other projects that have recently taken FID, including EWE's *Clean Hydrogen Coastline - Electrolysis East Frisia* and Shell's *REFHYNE 2* in Germany.

TRL level 7-8

At the MW scale electrolyzers can already be considered commercially available. For large scale (100 MW+) there are some additional complexities to overcome, as well as understanding the effect of intermittent operation on reliability/degradation. DNV therefore considers the TRL at level 7-8.

4.2.4 Hydrogen Compression

Hydrogen compressors are key equipment in the refining and chemical industries and have a long history of service. Hydrogen as a molecule however, has several characteristics that make compression challenging compared to other gases. Hydrogen has a low molecular weight and has a low density (one eighth that of natural gas), this has important implications for compression, including the need for more energy and more compression stages to reach a given compression level. Its small molecular size also results in some additional sealing challenges for compressors to minimize internal and external leakages compared to the requirements when they handle natural gas.

Current status

There are thousands of compressors in existing services; the below list is a summary of commonly utilized and commercially available compressor technology:

- **Reciprocating compressors** use a motor with a linear drive to move a piston back and forth. This motion compresses the hydrogen by reducing the volume it occupies. Reciprocating compressors are the most commonly used compressor for applications that require a high compression ratio such a refinery process units. For these units materials such as cylinder valves and piston rings are already developed for hydrogen application and so they are a reliable piece of equipment.
- **Rotary compressors** compress through the rotation of gears, lobes, screws, vanes, or rollers. Hydrogen compression is a challenging application for positive displacement compressors due to the tight tolerances needed to prevent leakage. In addition, these compressors have historically been oil lubricated; however, with fuel cell product quality consideration dry compression is being developed. Dry rotary compressors are available commercially, however are likely to experience reliability issues as the product is being further developed.
- **Centrifugal compressors** are the compressor of choice for pipeline applications due to their high mass flow capabilities and moderate compression ratio. Centrifugal compressors rotate a turbine at very high speeds to compress the gas. Hydrogen centrifugal compressors must operate at tip speeds 3 times faster than that of natural gas compressors to achieve the same compression ratio because of the low molecular weight of hydrogen. Due to the technical challenges associated with centrifugal compressors in hydrogen service and the relatively small volumes required in society (versus natural gas), there are limited centrifugal compressors in service for hydrogen today. This is expected to change as hydrogen pipelines for energy transmission come into service and greater volumes of hydrogen will need compression.
- **Hydraulic, membrane and ionic compressors** are all used for high pressure applications such as cylinder and trailer filling. These types of compressors have advantages for high pressure service but are limited to low volume applications due to high capital costs per throughput. The compressors are under development to meet the increasing pressure and flow requirements of hydrogen trailer/MEGC market. While they are commercial products, they are not yet very reliable. It is expected that they will develop rapidly to reliable lower cost products over the next 5 years.

Challenges

Table 4-2: Considerations and challenges for hydrogen compression

Consideration	Reciprocating	Centrifugal	Rotary (screw)
High mass flow	+ Reciprocating compressors have high efficiency. - Frequent maintenance is required and they have a lower reliability than centrifugal compressors. - Scaling to larger flows is not efficient due to independent/unintegrated compression cylinders and cooling systems.	+ Low maintenance option, and highly reliable. - Less efficient than reciprocating compressors; however, as volumes increase this difference diminishes. + Scaling is considered to offer both CAPEX and process efficiency (vs reciprocating), as the multistage compression and cooling benefits from the integrated compression and cooling systems.	- Limited delta pressure capability. Used as suction pressure boosters for reciprocating or centrifugal compressors.
Load fluctuations	+ Capacity control (50-100% capacity) is implemented via valve unloaders or via use of multiple compression trains (required for maintenance and redundancy).	- Capacity control 60-100% is achieved via variable frequency drive VFD. - Starting and stopping wears compressor significantly.	+ Good capacity control 5-100%.
TRL	TRL 9: Commercially mature product.	TRL8-9: Existing but limited commercial use. Product development is underway for future high flow use cases.	TRL8-9: Existing but limited commercial use (especially unlubricated). Product development is underway for future use hydrogen use cases.
Seals	Long operating history.	Limited commercial applications. Seals will need development with the compressor product.	Limited commercial applications. Seals will need development with the compressor product.
Supply chain	+ Commercially mature product. Limited supply chain challenge.	- Limited existing operations. Product is in development with significantly different components than general gas compression products which will lead to supply chain constraints.	- As per centrifugal.

TRL level 8-9

Hydrogen compression for energy transmission is an advanced technology and not expected to limit implementation. Higher flow centrifugal compressors for hydrogen service are under development which should provide an improved alternative to the reciprocating machine dominating in industry today.

4.2.5 Hydrogen pipeline transport and repurposing

A key development for a hydrogen based decarbonization strategy is the implementation of a hydrogen transmission network. Multiple EU gas grid operators are currently developing such a network across Europe, the European hydrogen backbone. It considers the development of 5 corridors to cover multiple directions for hydrogen import and export to Europe through pipelines, to a large extent repurposed natural gas pipelines, but also new built pipelines [3].

Current status

Transportation of hydrogen through pipelines has already been done for many years and multiple hydrogen pipeline networks exist. For example, in Europe Air Liquide and Air products operate provide hydrogen to their customers (based in the Netherlands and Germany) through their own networks. Additionally, Gasunie has recently repurposed a natural gas pipeline connecting two large industrial players (DOW and YARA) for the transport of hydrogen. This could be seen as an initial step for developing an EU hydrogen backbone. The further development of the hydrogen backbone is currently ongoing with parts of the network planned to be in operation by 2030 already [3].

Challenges

While hydrogen transport through steel pipelines could already be considered mature, there are still many significant challenges with regard to operation, repurposing and financing.

- Hydrogen embrittlement is a much discussed topic for the use of steel pipelines for hydrogen transport. Hydrogen can cause embrittlement and weaken the steel structure through the formation of microscopic cracks. This process occurs when atomic hydrogen diffuses into the steel and accumulating at stress point or existing defects, leading to a reduction in structural integrity. The presence of hydrogen can facilitate crack initiation and propagation, making it a critical concern for pipelines transporting hydrogen..
- To address the impact of hydrogen embrittlement, pipeline design must incorporate considerations such as selecting appropriate steel types, wall thicknesses, and pressure ratings that align with the anticipated operating profile and conditions. However, the challenge lies in the fact that the operating profile remains uncertain due to the underdeveloped hydrogen market. The behaviors of future hydrogen consumers and producers will ultimately shape this operating profile, influencing the occurrence and severity of pressure fluctuations. An approach to mitigate this uncertainty could be to assume conservative design specifications (e.g. design pressure and capacity).
- This already provides uncertainty for new hydrogen pipelines, but even more so for repurposed pipelines as the design is already set. DNV deems it feasible to repurpose existing natural gas pipelines for hydrogen, however, this feasibility depends on the current condition of the pipeline infrastructure Factors such as existing defects, misalignments, welding quality, corrosion, and overall material integrity must be thoroughly assessed and understood. Additionally, the desired operational conditions, including pressure levels and cycling frequencies, play a crucial role in determining suitability. The suitability of an existing natural gas pipeline to also transport hydrogen should therefore be carefully assessed and is situation specific [4].
- Another challenge for repurposing is a gap in standards and regulations, and lack of long term operational experience of repurposed hydrogen pipelines. Current standards are focused on natural gas and new-build hydrogen pipes. There is limited guidance on the design and use of hydrogen in existing pipelines. Standards

that do provide guidance (e.g. ASME B31.12) are considered conservative leading to potential exclusion pipelines that are actually suitable [4].

- Besides the repurposing of the pipeline, other pipeline components and equipment also need attention. Repurposing needs to be assessed on a case to case basis

Development opportunities

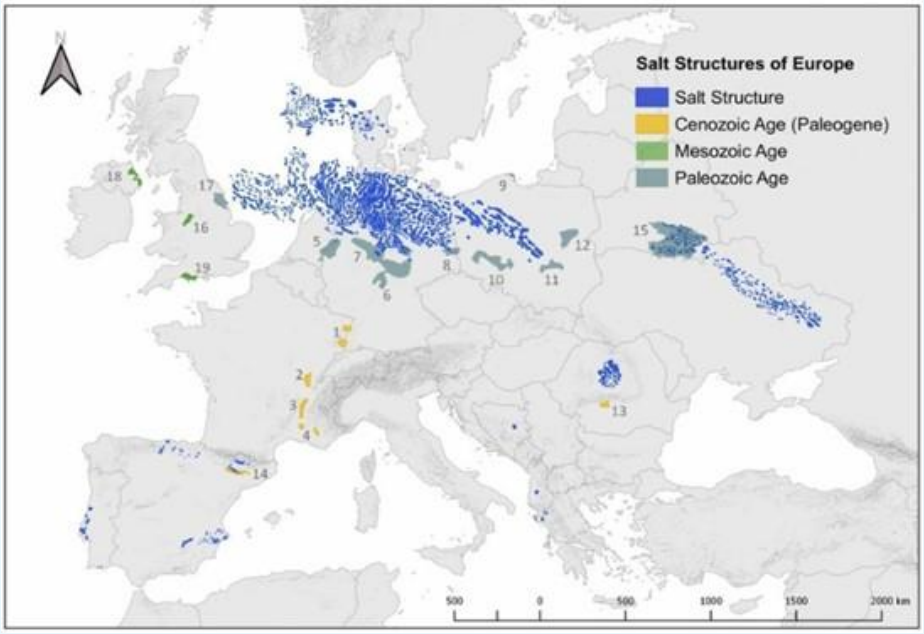
Currently there is considerable attention being paid to the development of hydrogen infrastructure. There is a drive for development from multiple sectors and governments are also willing to (partially) fund the development of an EU hydrogen backbone – for example, the European commission recently approved a €3 billion German State Aid scheme to support the development of the Hydrogen Core Network [5].

TRL level 7-9

Both new and repurposed (although only a short segment) pipelines for hydrogen are already in commercial operation, but a full network is yet to be developed. The technological development of such a network is therefore not explicit and some challenges still need to be overcome. DNV therefore considers the TRL in a range of level 7-9 depending on the operational profile, new vs repurposing and complexity of the overall system (i.e. many consumers or only one).

4.2.6 Fast cycling hydrogen salt caverns

Hydrogen salt caverns are underground spaces created within rock salt formations, used to store hydrogen gas. These caverns are particularly suitable for hydrogen storage due to their large capacity, safety, and cost-effectiveness compared to other forms of storage. Salt caverns are currently already used in the oil and gas sector, especially in northern Germany (e.g. Etzel) and in the Netherlands (e.g. Zuidwending). There are six hydrogen storage caverns in operation at present. Three of these caverns are located in Teesside, Great Britain, while the other three are located in Texas, USA. but the operation and design of these caverns are significantly different from the hydrogen storage salt caverns which are currently anticipated. The map below shows the locations of large salt formations and potential locations for hydrogen storage in salt caverns.



1. Alsace Basin; 2. Bresse Basin; 3. Greoux Basin; 4. Valence Basin; 5. Lower Rhine Basin; 6. Hessen Werra Basin; 7. Sub-Hercynian Basin; 8. Lausitz Basin; 9. Leba Salt; 10. Fore-Sudetic Monocline; 11. Carpathian Foredeep; 12. Lublin Trough; 13. Ocnele Mari; 14. Cardona Saline Formation; 15. Pripyat Basin; 16. Cheshire Basin; 17. UK Permian Zechstein Basin; 18. Larne Salt Field; 19. Wessex Basin

Figure 7: Map of European salt deposits and salt structures as a result of suitability assessment for underground hydrogen storage [6]**.**

Current status

The currently anticipated hydrogen storage salt caverns, to support the energy transition, can be considered "fast cycling caverns" to balance the fluctuations from renewable energy and green hydrogen production. A few pilot projects for this type of cavern are currently being developed or have recently entered operation. These pilots are essential for maturing and scaling up the technology, but development takes time and is CAPEX intensive. Future caverns are expected to have a geometric volume of 500,000-1,000,000 m³, while current pilots are in the scale of only a few thousand m³. For reference, the Hystock cavern (A8) of Gasunie at Zuidwending (NL) is only a borehole (the shaft of the cavern) with a volume of less than 100 m³.

Table 4-3: Examples and details of hydrogen salt cavern early pilot projects.

Project name	Operator/developer	Location	Geometric volume	Pressure
Hystock	Gasunie	Zuidwending, NL	<100 m³	200 bar
HPC Krummhörn	Uniper	Krummhörn, GER	3.000 m³	250 bar

Challenges

There are still significant uncertainties and challenges. These are outlined below:

- **Gas tightness (long term)** of the cavern is still to be proven. Due to the small molecular size of hydrogen there are concerns for diffusion, especially across elastomers used in the packers and well-head (soft sealings). Diffusion or leakage in the long term could lead to accumulated hydrogen on places where this is unwanted and where it can affect the integrity of other components/materials (e.g. steel and concrete).
- There are also concerns around **material suitability**. The main concern is which type of steel to apply that can withstand pressure cycling. Hydrogen can cause embrittlement and weaken the steel structure through the formation of microscopic cracks. This is stimulated by strong pressure fluctuations which make it easier for hydrogen to diffuse into the steel or already present cracks and further promote the formation of these cracks.
- The **impurities** which will be introduced while the hydrogen is stored underground are not fully clear and will be location specific. They could include residues from earlier uses, if a natural gas cavern is re-used, or impurities created by microbes which can convert hydrogen into hydrogen sulphide (H_2S). Gas treatment technologies are needed to clean the hydrogen when withdrawn from the cavern, but the specifications and the most suitable technology are still unknown. Although gas and hydrogen treatment technologies already have a high maturity, these can have an impact on CAPEX and footprint and therefore affect the business case.
- There is a lack of **best practices and standards** for hydrogen salt caverns which will need to be developed as soon as the technology further matures. This can take significant time and current standards for storing natural gas in salt caverns are insufficient. There is however already some development by parties as DNV and API.
  - DNV is developing a best practice for safe development and operation for hydrogen salt caverns [link].
  - API is developing a recommended practice for design and operation specifically for repurposed salt caverns which have been used for natural gas before [link].
- As the volumetric energy density of hydrogen is three times smaller than natural gas the **withdrawal flow rate** might also increase. A higher volume of hydrogen needs to be extracted to provide the same amount of energy compared to natural gas. This will lead to more severe fluctuations and stresses on the materials, which was already discussed above. The required flowrate is, however, highly dependent on the operational strategy of caverns and grid operators and on the demand profiles. As the hydrogen grid and market are also still under development, the required withdrawal rate is also uncertain. The main bottleneck would be at the installation

above ground (gas treatment, compression, etc.), although this can be built for specific withdrawal rates. Additionally, hydrogen can be withdrawn from multiple caverns, which reduces the rate per cavern.

- While considerable research and development is still ongoing, maturing of the technology to full scale (commercial) application will be CAPEX intensive (leaching, construction and filling the cavern). Furthermore, to commercially operate a cavern, the supply, demand and infrastructure should be in place.

TRL level 5

The small pilot projects so far have proven some of the key concept aspects on a small scale and demonstrated the technology in a relevant user environment. With this simple demonstration, stakeholders have been able to validate some of the concept aspects and form a basis for further development.

DNV therefore considers the TRL of “fast cycling hydrogen salt caverns” at level 5.

4.2.7 Ammonia production

Ammonia production is a widely applied process, primarily used to create fertilizers. The most common method for producing ammonia is the Haber-Bosch process. This process synthesizes ammonia by combining nitrogen (N_2) and hydrogen (H_2) under high pressure and temperature in the presence of an iron catalyst. Currently natural gas is the most important feedstock from which hydrogen and a large part of the nitrogen is extracted through reforming. Additional nitrogen is sourced from the air through large air separation units.

A high-level process description is provided below.

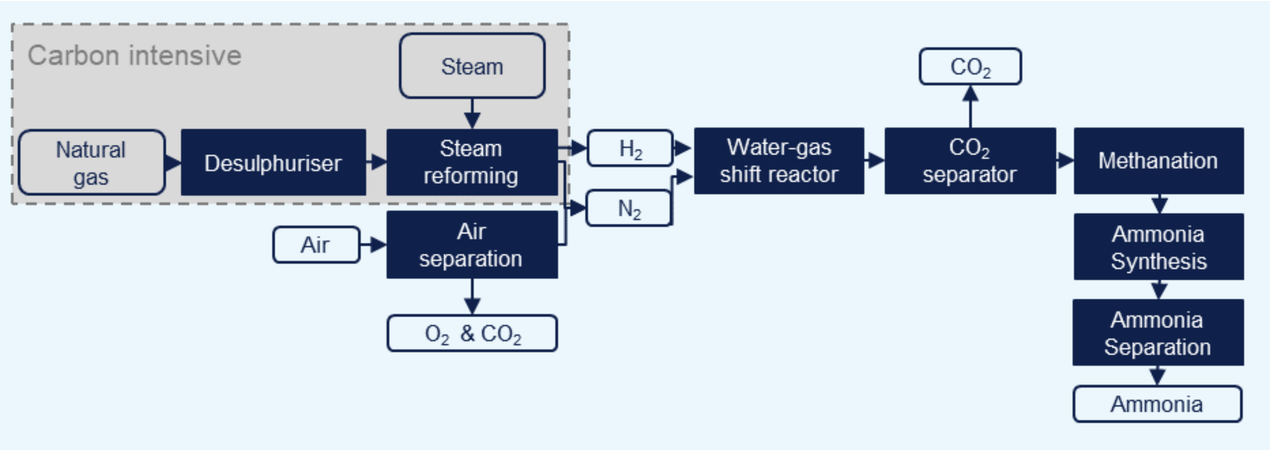


Figure 8: High level process breakdown of ammonia production.

Current status

Ammonia production is widely and commercially applied across the world with large producers such as YARA, BASF, CF Industries and Nutrien. Although energy and carbon intensive, the technology is at commercial scale and at high TRL (TRL 9). However, ammonia production with green hydrogen from renewable energy provides a few potential challenges. Currently no commercial installations exist that use green hydrogen as the primary input for producing ammonia.

Challenges

The key challenges for ammonia production using renewable energy, that are different from the current mature ammonia production process, are related to the fluctuating renewable energy profile and therefore the required flexibility from the installation. Current ammonia production is a relative stable process, and the supply of natural gas is constant.

With green hydrogen from renewable energy, the supply will fluctuate significantly, depending on the renewable energy source and the location.

Current ammonia production can operate between 30-100% of the reactor capacity and can ramp up/down within multiple hours to a day. This already provides considerable flexibility, but it is unknown what the long term effects will be on the installation due to thermal stresses. Especially at times of low renewable energy production, it can be challenging or costly to keep the reactor in operation.

To keep the reactor operating, even at the minimum level, hydrogen storage is needed to bridge times of low/no renewable energy production. Such storage can be costly (especially when longer periods need to be bridged) and is space consuming. Shutting the reactor down also provides challenges as it requires considerable energy (high electrical load) and at least a full day to start the reactor again. Shutting down and restarting the reactor is therefore in many cases impractical. A combination of hydrogen and renewable energy storage, and flexibility from the reactor, is currently the most feasible solution, although it adds costs and other challenges. Optimization of the balance between storage and flexibility is therefore highly recommended.

Development opportunities

The key areas for development of ammonia production technology, specifically for the use of renewable energy, are a large operating range and flexibility.

- Both Fukushima Renewable Energy Institute and the University of Oxford operate small scale pilot plants with a wider operating range. Although the plant in Oxford uses technology from Siemens, it is not commercially available.
- The University of Minnesota is developing a small-scale ammonia synthesis system looking to increase process efficiency by absorbing ammonia at modest pressures as soon as it is formed. This reduced pressure makes the system suitable for small-scale applications and more compatible with intermittent energy sources.

TRL level 7

While conventional ammonia production can be considered at TRL 9 and might in some cases be sufficient, ammonia production with higher flexibility should be considered less developed. The most developed “flexible” ammonia synthesis technology is currently at small scale pilot phase in Japan and the UK which provides a prototype that is demonstrated in a relevant operational environment. This can be considered as a steppingstone towards a larger scale commercial technology and has allowed stakeholders to perform the final validations/tests for scale up to a larger system.

DNV therefore considers the TRL of “flexible” ammonia production at level 7.

4.2.8 Ammonia transport and handling

Ammonia is already a widely traded and transported commodity, mainly for the fertilizer industry.

Current status

Regulations on transport, storage and handling are in place as well as the experience to transport and store. Ammonia is commonly transported in liquid form which can be achieved by either refrigeration (-33 ºC), pressurization (~16 bar), or a combination (semi-refrigerated and pressurized). Depending on the situation, the following technologies are used:

- <u>*Seaborne transport*</u> - For seaborne transport, ammonia is mainly transported in medium size LPG vessels with a carrying capacity of roughly 80,000 m^3 in liquid (refrigerated) form (equivalent to roughly 50 kt of ammonia). These are already at sufficient scale to transport large amounts of ammonia to Europe, but an increase in scale could lead to a reduction in transport costs. Larger-scale vessels are therefore already being ordered, anticipating a growing market for ammonia transport.

- *Inland shipping transport* – The transport of dangerous goods on inland waterways in Europe is regulated by the "European agreement concerning the international carriage of dangerous goods by inland waterways" (ADN). According to the ADN, ammonia should be transported by type G tankers, which typically have a maximum cargo tank size of 380 m^3 with six to eight tanks per vessel (equivalent to roughly 1.5-2 kt of ammonia). The tank size can be increased up to maximum 1000 m^3 with three tanks per vessel. But these bigger tanks are actually not suitable for ammonia. Ammonia transport on inland waterways usually consider pressurized tanks (~16 bar) at which the ammonia is liquid, but not refrigerated.
- *Railway transport* - Transport of liquid ammonia by railways is also mature and carried out in rail tank carriers (RTC) with a typical capacity of 50-110 m^3 (equivalent to roughly 30-75 t of ammonia). [7]
- *Storage* – Ammonia storage is already mature and multiple technologies are available in different sizes. It is usually stored in liquid form at low temperature (-33ºC) and atmospheric pressure at large scale (~50 kt) and for smaller scale, semi refrigerated or pressurized vessels are used [8]. At large scale, especially for import/export, it is currently being considered to build on the LNG infrastructure through either new built ammonia ready LNG infrastructure or through repurposing of existing infrastructure. However, there are still technical challenges/uncertainties regarding repurposing. [9]

Type	TRL	Typical pressure, bar	Design temperature, °C	t ammonia per t steel	Capacity, t ammonia	Refrigeration compressor
Pressure storage	9	16-18	20-25	2.8-6.5	<270 or <1,500	None
Semi-refrigerated storage	9	3-5	Ca. 0	10	450-2,700	Single stage
Low-temperature storage	9	1.1-1.2	-33	41-45	4,500-45,000 (<50,000)	Two-stage
Solid-state storage	3-4	1-30	20-250	-	-	None

Figure 9: Characteristics of ammonia storage methods [8] [10].

Challenges

Ammonia is highly toxic and while standards and regulations are in place to guarantee an acceptable level of safety, larger volumes give rise to concern, especially for inland transport. A research study on the safety for future transport of H2 carriers in the Netherlands expressed that the acceptable risk levels in current regulations are based on much lower ammonia volumes than what could be expected in the future. Higher volumes increase the chance of a calamity and due to the toxicity, the consequences could be significant. Current common practice is therefore to reduce the volumes of ammonia transport as much as possible. With the energy transition and ambition to use hydrogen and carriers, such as ammonia, to decarbonize, much larger volumes could be expected.

TRL level 8-9

Ammonia transport, storage and handling is fully developed and commercially available on a global scale. While safety and regulation are a concern, and some technical adaptations could be needed, the technologies themselves are mature. DNV therefore considers the TRL at level 9.

4.2.9 Ammonia cracking

Ammonia cracking is a process that decomposes ammonia (NH_3) into nitrogen (N_2) and hydrogen (H_2) gases. This process is highly energy intensive as the chemical conversion is endothermic in nature. Currently, commercially operating ammonia crackers produce around 1 to 2 tons of hydrogen per day [11] and are utilized predominantly within the metallurgy industry. Other small scale use cases for ammonia cracking include heavy water and stationary power production (low-temperature fuel cells) [12]. There are several technologies being developed, at differing stages of maturity, with a range of advantages and disadvantages. A typical process facilitates the breaking of the nitrogen-hydrogen bonds in ammonia, followed by hydrogen purification and compression. Feasibility and costs are highly dependent on whether the strategy of ammonia cracking is centralized or decentralized (on-site cracking), but cracking has been noted to account for the highest proportion of ammonia midstream costs, approximately 48% for a centralized methodology [13].

Current status

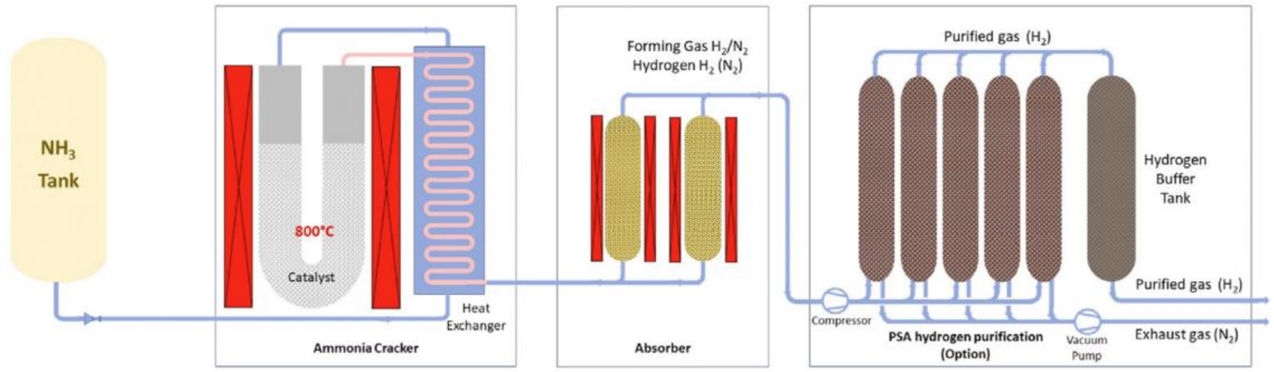


Figure 10: Schematic diagram of ammonia cracking process [12]

The most advanced processes involve the use of catalysts in a reformer style configuration, analogous to the steam methane reforming industry. This is a thermocatalytic process, requiring significant energy input to reach the 600-1000˚C cracking temperatures and expensive catalysts, typically Ni-, Fe—Co-, or Ru-based. The bulk of the product gas is then passed through a separation unit, a scrubber or pressure swing adsorption depending on specification, to be compressed and transported to the end user. Some designs combust a portion of the process gas to power the endothermic process, whilst others utilize electric or natural gas heaters. A typical configuration can be seen in Figure 10. This process has been utilized commercially since 1978 with the most significant ammonia cracking technology providers including, but not limited to: Fluor, JERA, Topsoe, Air Liquide, Johnson Matthey, Mitsubishi Heavy Industries, ThyssenKrupp & KBR.

Autothermal reformers (ATR) are also being developed, albeit at a slightly lower technology maturity. The reaction is performed in parts, with an initial partial oxidation to form NO without a catalyst, to provide the heat for the subsequent cracking. The following process reduces the NO and cracks the ammonia over a catalyst, having the major advantage of minimal NO_x production. This technique is more often used within blue hydrogen production but typically requires an air separation unit to provide oxygen for the reaction.

Membrane reactor technology has growing interest due to the simultaneous chemical reaction and selective separation of the hydrogen product. The separation further allows for the thermodynamic equilibrium to be shifted, allowing the system to go beyond its thermodynamic constraints. Further, operations can occur at lower operating temperatures and require less energy input. However, the use of Pd-based membranes is at an early development stage and faces standard membrane-related issues of durability, scarcity of required rare earth metals and stringent quality requirements due to potential for membrane fouling from feedstock impurities. Further, the product purity is lower than in PSA based solutions. Early analyses suggest a potential increase in thermal efficiency of 25%, with a 10% reduction in levelized cost of hydrogen, with a higher expected initial capital expenditure [14]. Catalytic membrane reactors are at demonstration scale by Fortescue Future Industries [15] and are being investigated by other companies like Bettergy and Ammogenix.

Other technologies include built-in absorbent columns, selective ammonia oxidation, plasma, electrolysis and photocatalysis methodologies, and are at early stages of development. The following section will largely discuss the state of the art of thermocatalytic ammonia cracking.

Challenges

- Emissions – The high temperatures required for the process lead to substantial NO_x and N_2O emissions that have a significant safety and global warming potential. Selective catalytic reduction and selective non-catalytic reduction technologies are typically adopted to reduce emissions, at a cost.
- Low Flexibility – Current large scale ammonia cracking systems often lack the flexibility to adapt to varying operational conditions due to low turndown rates, typically 20%/hour [16]. As a result, a consistent supply of ammonia and consistent demand for hydrogen is optimal, increasing pressure on storage and upstream logistics. It is therefore likely not suitable to provide hydrogen to a back-up power generator which needs to start up in a short timeframe.
- High Energy Consumption – The process requires significant energy input to achieve the high temperatures necessary for effective cracking. At the conceptual design phase, a decision must be made for the trade-off between the conversion rate and heat efficiency. Often a portion of the product gas is utilized to power the process, reducing external energy requirements but impacting capacity and process conversion.
    - Thermal efficiency is often increased through heat integration, with energy recovered from the product gas for preheating of the ammonia feedstock.
- Hydrogen separation – The reformer produces a hydrogen rich gas, with the stoichiometric equivalent of nitrogen and leftover ammonia feed. Separation of the hydrogen is necessary, with pressure swing adsorption (PSA) most often utilized due to the high product quality requirements (99.9%+).
    - Scrubbers, strippers and cryogenic cycles are used during startup or product finishing to reach fuel grade purity.
- Safety – Due to the toxic and corrosive nature of ammonia, extensive safety measures are necessary, especially given the high temperatures and pressures during the process. However, due to the well-established use and transport of ammonia for the fertilizer industry, many of the procedures are in place.
- Scale-Up – Scaling up ammonia cracking technology to industrial levels poses technical and economic challenges. Ensuring consistent performance and efficiency at larger scales is a critical hurdle, with organizations opting to develop demonstration plants at the scale of units within a commercial plant as a mechanism of de-risking scale up.

Development opportunities

- Catalyst innovation – Development of more efficient and cost-effective catalysts are ongoing to reduce energy requirements and costs. Recent advancements have focused on improving the efficiency and scalability of ammonia cracking, including catalyst development such as Lithium Imide ($LiNH_2$) or Iron.
- Integration with renewable energy and other systems - Using renewable energy sources to power the ammonia cracking process can enhance its sustainability and reduce overall carbon emissions. Companies such as Yanmar and Amogy are exploring scalable and efficient methods for integrating ammonia cracking with marine combustion engines and hydrogen fuel cell systems.

- Hybrid systems – Partial cracking allows for use of a blend of hydrogen and ammonia to be co-fired in an engine. This is being further developed by startups such as Sunborne Systems and Ammonigy.

TRL level 5-7

The TRL of ammonia cracking technology varies depending on the specific system and application. Generally, it is considered to be at TRL 4-7, indicating that the technology is in the demonstration phase with some systems being tested in relevant environments [17] [16].Particular technologies, such as Ni-based thermocatalytic methodologies are considered a TRL of 8-9 [12] at small scale, but at very large scale these are still at a lower TRL, 5-7.

4.2.10 Production of direct reduced iron

Iron reduction is a fully mature process and has been applied in the steel industry for many years. In the reduction process, oxygen is removed from the iron bearing material by a reducing gas which contains hydrogen and/or elemental carbon. When only hydrogen is used, no carbon dioxide is produced and emitted, making it a more environmentally friendly option.

The basic process involves the reduction of iron oxide where the oxygen is removed from the iron. The reduction agent (hydrogen or carbon) combines with the oxygen in the iron to form H_2O and CO_2 and leave reduced iron. The reduced iron is also called sponge iron or direct reduced iron (DRI). The basic formula is provided below (with hydrogen as reducing agent).

$$Fe_3O_4 + 4\ H_2 \rightarrow 3\ Fe + 4\ H_2O$$

Current status

Currently most reduction process use coal or natural gas/syngas (from waste streams of steel making), but as iron reduction with hydrogen does not result in emissions of CO_2, the steel industry is interested in the application to decarbonize their processes. An example of such a development is the HYBRIT demonstration in Sweden to produce direct reduced iron (DRI) pellets [18].

The process of iron reduction using hydrogen has been applied commercially since 1999 by ArcelorMittal, but was discontinued in 2017 due to cost-cutting. It used hydrogen from steam-methane-reforming of natural gas [19]. Other examples also include mixtures of hydrogen in the reduction gas and different furnace technologies (e.g. rotary, shaft, arc) [20].

The process can therefore be considered mature, but this reflects an integrated system at a steel making plant. Although DNV does not consider significant differences in the process and core design of the plant, the combination of hydrogen from fluctuating renewable energy might introduce new aspects.

Challenges

The novel application of the DRI process with hydrogen from renewable energy provides challenges regarding flexibility. The DRI process is flexible to some degree, but start-up takes a long time and consumes energy. It is therefore impractical to shut down the process at times of low renewable energy/hydrogen production. Furthermore, the long-term effects of both shut-down and varying hydrogen flow are not well-known.

To keep the process operating hydrogen storage is needed to bridge times of low/no renewable energy production. Such storage can be costly (especially when longer periods need to be bridged), is space consuming and provides additional safety concerns. A combination of hydrogen and renewable energy storage, and flexibility from the DRI process, is likely the most feasible solution, although it adds costs. Optimization of the balance between storage and flexibility is therefore highly recommended.

DNV did not assess the availability of standards and practices for designing and operating DRI plants with renewable hydrogen. This could however be a knowledge gap which needs further evaluation.

Development opportunities

HyIron has launched its DRI pilot project in Lingen, Germany, in cooperation with several steel producers. In this plant, processes from supply, reduction and utilization in steel factories will be optimised in cooperation with the German steel producer Benteler and the German energy provider RWE. The project has a DRI production of 500 kg/h, which should be considered small-scale. This project is part of GEiSt (German for “Green Iron in the steel industry”) [21]. This will be the steppingstone for a large-scale system of 5,000 kg/h of DRI production, which is under construction in Namibia (Project Oshivela) [22]. It is foreseen that this larger scale system will be the building block for further modular expansion for higher production capacities.

Other development opportunities arise from the introduction of the hydrogen-iron reduction process in the steel industry. The need for decarbonization in the steel industry could boost capital injection in further R&D, process optimization and upscaling of the supply-chain. At least 28 DRI projects proposed as hydrogen ready or using some proportion of hydrogen reductant have been publicly confirmed in Australia, France, Oman, China, Korea, Europe and Canada [20].

Finally, in a conversation with Metalot, other forms of DRI production were also discussed, directly using electricity for DRI production instead of first producing hydrogen as a reduction agent. This is however still at a lower TRL than HyIron’s technology.

TRL level 6-7

Although the DRI process using hydrogen has been applied for many years, the application with green hydrogen from a fluctuating source will require some degree of flexibility from the system and introduces a new environment. The soon to be started HyIron pilot project is considered by DNV as the first low scale pilot project, setting the basis for further upscaling and development of the technology. DNV therefore considers the TRL of DRI production with green hydrogen at level 6/7.

4.2.11 Transport and handling of sponge iron

DRI is relatively safe to handle (compared to ammonia), but still requires precautions to ensure safety. DRI is subject to rapid corrosion and oxidation when exposed to water, air or oxygen. These processes are exothermic and will create heat with a risk of self-ignition and fires. In contact with water, hydrogen can be produced which also causes safety concerns. The rate of these reactions depends on the surface area of the DRI – pellets are therefore safer to handle compared to powder (also called fines). It is however this last category, DRI fines, which is considered in this study (in alignment with the HyIron projects).

Current status

Although DRI is not a commonly traded substance, it is regulated under dry-bulk regulations. The recommended/required safety precautions depend on the situation and application. The relevant situations for this study and their current status are provided below.

- *Seaborne transport* – DRI is covered under the maritime regulation for dry bulk, the International Maritime Solid Bulk Cargoes (IMSBC). DRI fines are considered under category DRI(C) and require the most stringent safety precautions. This includes a water and airtight (weather tight) confinement with an inert atmosphere (e.g. nitrogen) with no ventilation [23].

  Most maritime bulk vessels are capable of carrying DRI(C) and have a weather tight cargo space. There are a number of bulk carriers with a standard nitrogen system fitted on the ship, but the majority will require some small adaptations (placement of nitrogen tank). The transport of DRI(C) overseas can however be considered mature.

- *Inland shipping transport* – The transport of (dangerous) goods on inland waterways in Europe is regulated by the "European agreement concerning the international carriage of dangerous goods by inland waterways" (ADN). This does not, however, contain any information on DRI. Additionally, DNV could not find information on available inland bulk vessels specifically focused on transport of DRI.

  While DRI is not covered under any regulation on inland waters, some reference could be made to the IMSBC and the provided safety requirements. Typical inland dry bulk vessels do not contain a weather tight cargo space and might therefore not be suitable to transport DRI(C). There are however more specialized vessels, such as cement transport vessels, which might be capable of transporting DRI(C). Further research into suitable ships for inland transport, as well as adaptation of regulation to cover DRI(C), is required.

- *Railway transport* – No specific regulations were found for transport of DRI on railways. However, ArcelorMittal, DB Cargo and Innofreight have tested and developed train wagons specifically for the transport and unloading of DRI. Innofreight confirmed to DNV that multiple successful tests and safety assessments have been performed (no nitrogen blanketing is needed for short transport, 48 hours) and that the wagons are suitable for DRI(C). Although the wagons are not yet in everyday operation, some major players in the steel sector are in favor of using these in the future.

- *Storage* – For storage of DRI, DNV uses the conditions provided in the IMSBC as a reference. Additionally, the International Iron Metallics association [24] also provides guidelines on storage, but these are more specific for pelletized DRI, which is less reactant (safer) and for harbor areas. These guidelines include:

  - keep clean and dry (with proper drainage)
  - keep free of combustible materials: wood, coal, coke, etc.
  - keep free of chlorides or past cargoes: avoid cement, lye, borax, fertilizers
  - store DRI at sufficient distance from other stored materials
  - ensure ability to monitor the storage space for temperature, hydrogen, carbon monoxide, and oxygen

  For long time periods, it is especially important to store the DRI properly to ensure safety and to avoid product losses (oxidation). Although precautions are needed, this would, in DNV's view, match with storage of dry bulk under inert conditions, which are commercially widely available.

Challenges

The challenges for transporting, handling and storing DRI are relatively simple. Methods and technologies are well known and available, but regulation, covering all areas of the value chain, require further development. Additionally, the availability of ships or rail wagons for inland transport is likely limited. Upscaling of the inland transport fleet therefore requires attention.

Development opportunities

Decarbonization efforts of the steel industry might boost investment into R&D, optimization and upscaling of the supply chain. While the focus of the steel industry might be mostly on decarbonizing the iron reduction process, the transport of DRI could also be of interest. This should be further confirmed.

TRL level 8-9

DRI transport, storage and handling is technically mature and commercially available. However, for scale-up, regulations and the supply chain still require further development. DNV therefore considers the TRL at level 8-9.

4.2.12 Reconversion of direct reduced iron

Upon oxidation of iron in the presence of water (H_2O), the oxygen (O_2) will combine with the iron to form iron oxide (Fe_xO_x), leaving the hydrogen (H_2). At ambient conditions this is a slow process (commonly known as rusting), but is accelerated at higher temperatures or with the presence of a catalyst. Therefore, multiple methods are possible for oxidation of iron, including the use of steam to provide a source of water and elevated temperatures (most favorable 125-525 °C [25]). This process, however, requires energy for producing steam and is therefore less flexible if hydrogen needs to be released quickly.

Current status

In DNV's analysis, the reconversion process proposed by HyIron is considered. The process takes place at ~150 ˚C but with the addition of a (patented) catalyst. The catalyst accelerates the oxidation process, which takes approximately 4 hours to release 90-95% of the potential hydrogen. Most of the hydrogen is released in the first 2 hours, after which there is a steep decline in the release rate.

The basis of HyIron's reconversion technology considers a simple electric boiler where water, DRI and the catalyst are heated to ~150 ˚C. Currently this is therefore a batch process, but HyIron is considering further development into a more continuous process with higher conversion yields. It is expected that 98% conversion yield can be achieved.

The technology is currently in an early stage of development and the proof of concept is yet to be carried out.

Challenges

- The most evident challenge is the low stage of development with potential uncertainties ahead. While the concept is relatively simple and rapid development should be possible, technological validation has yet to take place.
- The technology currently considers a batch process. This provides some limitations regarding flexibility. In small batches, the process can be started quickly, but afterwards a method for stopping the process is not yet implemented in the concept. This could, however, be done by increasing the pressure (to <50 bar), but this is not validated. Pressurized hydrogen storage could be used as a buffer for the initial demand of the power plant while the reconversion process starts, and to store hydrogen that is potentially released after the power plant stops. The process could be described as follows:
  1. Start of hydrogen power plant using hydrogen from pressurized buffer vessel.
  2. Start of hydrogen reconversion process by heating the water-DRI-mixture and inserting the catalyst into the heated mixture.
  3. Release of hydrogen from the DRI and gradual shift from using the pressurized hydrogen to hydrogen from DRI reconversion.
  4. Stop of power plant and therefore consumption of hydrogen.
  5. Compression of "excess hydrogen" from the reconversion process and storage in buffer tank to replenish the hydrogen buffer for next start.
- To minimize the start-up time, the iron water mixture could be kept at the operating temperature of 150°C in the pressure vessel and after inserting the catalyst into the mixture the reaction will start immediately. In any case a hydrogen storage is needed to balance the hydrogen flow. The size of the necessary hydrogen storage needs to be further investigated.
- Another challenge is the conversion yield (currently at 90-95%). After the reconversion process, when 90-95% of hydrogen potential is released, the "spent" DRI is taken out of the reactor. This means that there is a loss of 5-10% of potential hydrogen which eventually has an impact on the costs. Additionally, reconversion may still

take place but likely at a very slow rate. This also needs further investigation. Released hydrogen needs to be managed to avoid safety concerns, but also to avoid potential greenhouse gas effects (hydrogen is a GHG).

- Finally, the released hydrogen will likely include impurities, depending on the purity of the DRI. DNV did not assess which impurities could be encountered and which treatment process will be required, but the hydrogen will at least be released when it is fully saturated with a certain concentration of steam and water vapor. Hydrogen gas treatment/drying is therefore needed before the hydrogen can be utilized.

Development opportunities

Synergies between the oxidation process (which requires heat) and the availability of waste heat from the power plant could reduce the energy need and improve the overall efficiency. The start of the reconversion process will however still need to be done electrically.

TRL level 3-4

Reconversion of DRI is a relatively well understood process, but mature technologies to quickly release hydrogen are not yet available. The considered technology of HyIron can potentially meet the requirements for integration with back-up power production, but still requires considerable development. As validation of the technology still needs to take place, DNV considers the TRL at level 3-4.

4.2.13 Hydrogen fired power plant

Hydrogen fired power plants are foreseen to play a crucial role in decarbonizing the back-up capacity for the German electrical grid (Power Plant Safety Act). The plan includes both dedicated hydrogen-fired power generation which will immediately operate on hydrogen, as well as hydrogen-ready power generation which will initially use natural gas and later convert to hydrogen. Specific operational requirements are not yet known but will have a large impact on the selection of suitable technologies. The foreseen balancing services and response times are particularly relevant (see below).

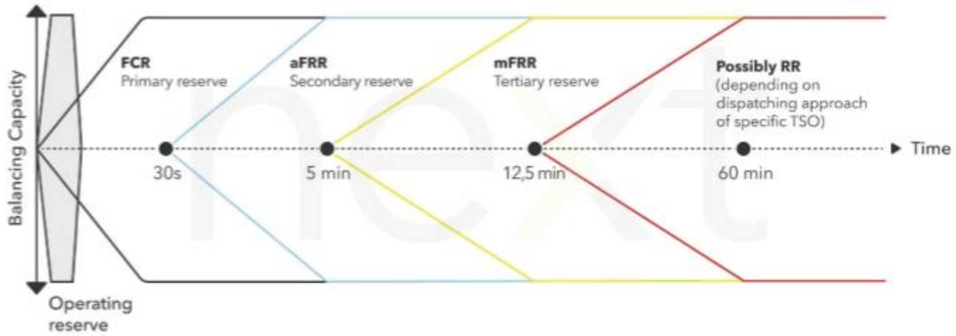


Figure 11: Balancing services according to the system envisaged by ENTSO-E [26].

Current status

For hydrogen fired power generation different type of gas-fired power plants can provide grid balancing services. Examples are combined cycle power plants (CCGT), aeroderivative power plants and gas engine platforms.

Manufacturers are developing solutions both for conversion of existing plants and for new build power plants. It includes solutions for (initial) hydrogen co-firing as well as 100% hydrogen firing. Various power plant types can be considered for their ability to firing hydrogen combined with power grid balancing services:

- *CCGT* – Combined cycle gas turbines are usually large-scale heavy duty (100 MW_e range) and combine electricity production from the gas turbine with power that is produced by a steam turbine that receives steam from a downstream heat recovery steam generator. The efficiency is between 50-60%. CCGTs mainly operate in baseload or flexible load mode. Once the CCGT is in operation it can ramp its capacity quickly and can therefore still participate in the FRR markets by reserving part of its capacity. Additionally, they can provide capacity on specific balancing markets.

CCGTs mainly operate on natural gas but have already demonstrated successful operation with mixtures of hydrogen of over $50\%_{volume}$ with minor modifications. CCGTs on 100% hydrogen are under development (e.g. by Mitsubishi) [27],. Operation with 100% hydrogen is for the near term expected to be less cost competitive due to its scale combined with its operations profile, requiring a substantial amount of hydrogen.

- *Aero derivative turbines* – As the name suggests, aero-derivative turbines originate from the aviation sector. The main difference to CCGT turbines is that these gas turbines can start up quickly, even when they are in a cold condition. If no downstream boiler is integrated, the efficiency is ~34-40%. Aero derivate turbine can also be combined with downstream boilers to enter other markets (e.g. producing additional electricity or delivering heat). The main advantage of aero derivative turbines is the high degree of flexibility; power can be provided within a few minutes from cold-start and ramping of ~50%/min.

  Operation of aero derivative turbines with $100\%_{volume}$ is already successfully demonstrated at MW scale, but abatement techniques for reducing increased levels of NOx are often needed.

- *Engines* – Gas engines are a robust technology that has already been used for peak power balancing. They are (relatively) low cost, have an efficiency of >40% and have a high degree of operational flexibility. Dedicated units are available for peak-power applications with quick start capabilities, e.g. 2-minute full load operation. However, quick start requires pre-heating, which means that the operator has to pay stand-by costs.

  Hydrogen-fired engines (both blend and 100%) are currently entering the market in the 1 MW_e-range but it is expected that a 10 MW_e-range will be available in the coming years (before 2030). Additionally, manufacturers are developing packages for retrofitting existing gas engines.

Challenges

One of the key challenges for any hydrogen fired power generation (or combustion in general) is the emission of Nitrogen Oxides (NO_x). Hydrogen has a higher combustion temperature than natural gas, which causes a higher formation of NO_x. Mitigations are either pre-combustion (primary) adaptations, typically lowering combustion temperature, or post-combustion (secondary), typically catalytic NO_x reduction. Manufacturers of turbines (CCGT and aero derivatives) have models that have primary NO_x reduction techniques included, *viz.* water injection (WLE) or dry-low-NOx-emission (DLE) adaptations.

WLE is generally combined with non-premix type of burners. Non-premix type of burners benefit from stable combustion and are therefore easier to convert to hydrogen, but have higher flame temperatures and therefore more NOx. Adding water or steam reduces flame temperature, hence lowers NOx, but also reduces efficiency and requires the production of demineralized water on-site, taking up additional space and requiring water supply. Furthermore, WLE generally reduces the lifetime of some parts of the turbine. WLE systems are mostly applied in industries when combusting process gas.

DLE or DLN burners are based on a premix burner type, which operates at a lower flame temperature. Then water injection is not needed for lowering flame temperature. The general challenge is to manage the stability of the combustion process. With hydrogen having a low ignition temperature and high flame speeds, combustion dynamics are more complex. However, substantial progress has been made on the development of new combustion systems, and this development is continuing.

In gas engines, the addition of hydrogen results in a loss of capacity. The main focus is on reducing the capacity loss, which is possible with new engines designed specifically for hydrogen.

TRL level 5-8

Gas turbines for both hydrogen blends and 100% hydrogen using WLE have progressed through the demonstration phase and are in the early commercial stage. Gas turbines using DLE are currently demonstration or early commercial phase for hydrogen blends and are in demonstration phase for 100% hydrogen. Hydrogen engines are currently entering the market in the MW-scale, and it is expected 10-MW-scale will be available in the coming years (before 2030). The table below provides DNV's view of the different TRL levels.

Table 4-4: TRL levels for hydrogen fired power generation.

Technology	Capacity	TRL 2024	Remark
Hydrogen blend			
CCGT	>100 MW_e	6-8	TRL 6 for DLE and 8 for WLE
Aero-derivative turbine	10-50 MW_e	6-8	TRL 6 for DLE and 8 for WLE
Engine	1 MW_e	8/9	
	10 MW_e	7	
100% hydrogen			
CCGT	>100 MW_e	5	Mainly for DLE, WLE not widely implemented or expected in the power market.
Aero-derivative turbine	10-50 MW_e	7/8	Mainly considering WLE.
Engine	1 MW_e	8	
	10 MW_e	6/7	

5 COST ASSESSMENT

The goal of this section is to understand the required investments and the main cost drivers, and to provide a cost comparison between the different value chains. For each value chain, this section provides:

- An overview of the value chain efficiency
- A breakdown of the levelized costs
- A breakdown of the total net present investments

5.1 Cost assessment methodology

The cost assessment is based on the value chains described in section 3 and based on the context of the power plant safety act and Hyphen described in section 2. The key aspects for understanding the set-up of our analysis are outlined below:

- The cost assessment considers the full value chains from renewable energy production until production of peak-power in Germany.
- The 12.5 GW and maximum of 800 full load hours, provided in the power plant safety act, are used as a basis for scaling the different value chains and required renewable power generation. Each of the value chains provides 12.5 GW for 800 hours per year, equivalent to 10 TWh of electricity per year. The required renewable power generation capacity depends on the efficiency of the value chain.
- No optimization was done between wind, solar and PtX capacity, but the Hyphen project was used as a starting point. The renewable energy production capacity therefore consists of 43% solar and 57% wind (4 GW wind and 3 GW solar in Hyphen).
- The value chains have been evaluated in a standalone manner, with a specific focus on dedicated renewable energy production. The cost assessment is performed at a high level to understand and compare the different value chains. No technical design and detailed integration of the value chain, or capacity optimizations and buffer/storage calculations, were carried out. The costs for a grid connection of the hydrogen power plant are also not included. However, DNV considers the level of detail to be sufficient for the purpose of this study and to compare the different value chains.
- DNV has used its proprietary techno-economic model for the cost assessment. The input parameters have been collected from DNV's database, DNV experts, equipment suppliers and literature. A description of the model, as well as an overview of the input parameters, is provided in **Error! Reference source not found.**.

5.2 Domestic Green Hydrogen Production in Germany

This section outlines results for domestic green hydrogen production in Germany. It involves the production of hydrogen using renewable energy produced in Germany (predominantly offshore wind). Hydrogen is produced onshore, stored in hydrogen salt caverns and transported to the hydrogen power plant through the hydrogen backbone pipeline network.

5.2.1 Chain efficiency

To provide 10 TWh per year to the German grid, 32.4 TWh/y of renewable energy needs to be produced in Germany. The total energy efficiency of the value chain is therefore 31%. Roughly 26% of the energy is lost in the hydrogen production process, only 2% and 3% in hydrogen transport and storage (mainly for compression), and 38% is lost in power generation. Note that these losses do not represent the efficiency of the individual process steps but the losses relative to the initial produced energy – for example, the efficiency of the hydrogen power plant is ~45% but much of the energy has already been lost in the previous steps and therefore only 38% is lost compared to the initial energy.

Conversion of power into hydrogen through electrolysis and the conversion back to power in the power plant make up almost all of the losses in this value chain.

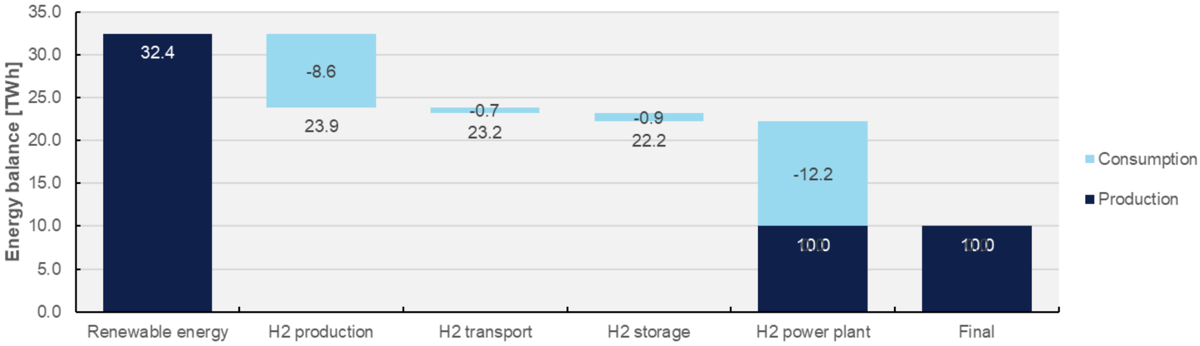


Figure 12: Waterfall plot of the energy losses of domestic green hydrogen production in Germany.

5.2.2 Levelized cost

The levelized cost for providing back-up power to the German grid through hydrogen production in Germany is 425 €/MWh. The largest shares are for the production of input energy and the hydrogen power plant. The LCOEs for hydrogen production through electrolysis and hydrogen storage in salt caverns are also significant.

- Based on the energy input-output ratio of roughly 1 to 3 (equivalent to the calculated efficiency factor of 31%), the cost of renewable energy generation (from offshore wind in Germany) of 55 €/MWh is increased by a factor of ~3 resulting in the overall LCOE of input energy of 175 €/MWh. Furthermore, the levelized cost for renewable energy production are higher compared to the cost in Namibia (provided in the sections below).
- The power plant takes a large share because of the low efficiency, but also because of the low utilization (only 800 hours per year).
- The costs for hydrogen production through electrolysis are also high because of the utilization (4,000 full load hours) and higher CAPEX (using European rather than Chinese Electrolyzers, applied in the import value chains).
- For hydrogen storage it was assumed that half of the energy that will be provided by the back-up power plants should be available and stored, i.e. provide 12.5 GW for 400 hours from the hydrogen storage. This may be a conservative assumption as storage will in reality fill and empty incrementally across a year.

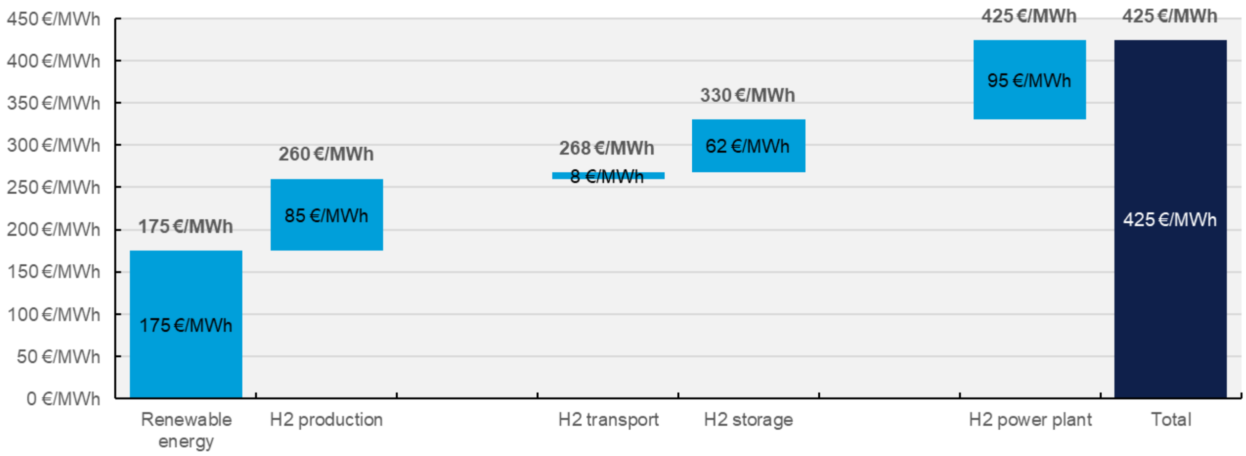


Figure 13: LCOE break-down of domestic green hydrogen production in Germany.

5.2.3 Investments

The total investments are discounted with a rate of 8% (real) and are broken down in the figure below. A total of roughly 66,1 billion euro is needed for building and operating the 12.5 GW back-up power capacity and for setting up the domestic hydrogen production supply chain. Roughly 46% are CAEPX and 54% OPEX. The investment drivers are similar to what is discussed for the LCOE above. Hydrogen transport is OPEX driven as the assessment assumes a transport tariff of 0.25 €/kg/1000km.

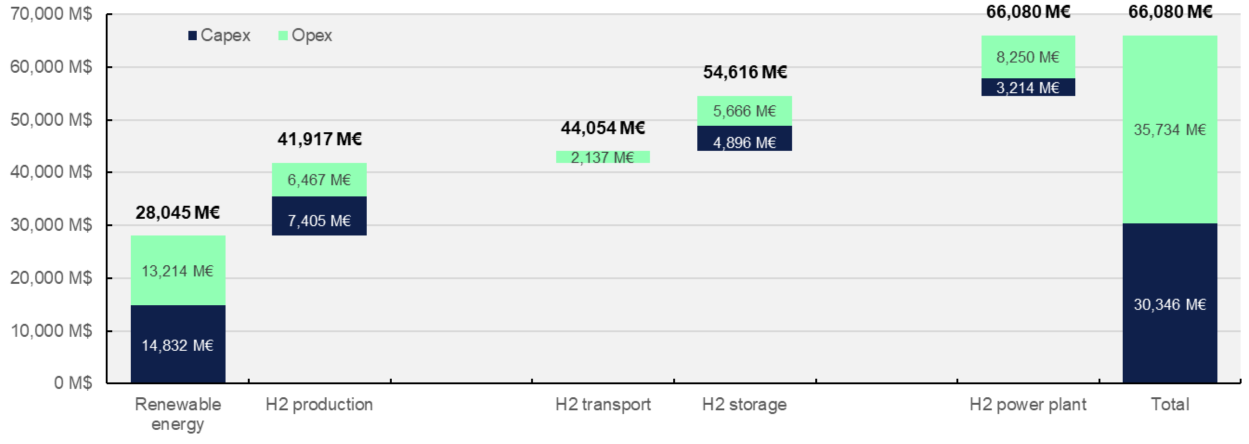


Figure 14: Investment break-down of domestic green hydrogen production in Germany.

5.3 Green Ammonia value chain

This section outlines results for the Green Ammonia value chain. It involves the production of ammonia using renewable energy and hydrogen produced in Namibia, transport to Europe by ammonia tanker, centralized cracking at the port and hydrogen transport via the hydrogen backbone to the power plant in Germany.

5.3.1 Chain efficiency

To provide 10 TWh per year to the German Grid, 51.7 TWh/y of renewable energy needs to be produced in Namibia. The total energy efficiency of the value chain is therefore 19%. Roughly 33% of the energy is lost in the hydrogen production process, 7% is lost in the ammonia synthesis process, 1% is lost in transport, 17% is lost in reconversion and 24% is lost in power generation. Note that these losses do not represent the efficiency of the individual process steps but the losses relative to the initial produced energy – for example, the efficiency of the hydrogen power plant is ~45% but much of the energy has already been lost in the previous steps and therefore only 24% is lost compared to the initial energy.

A large part of the energy is lost in the electrolysis process. Ammonia synthesis and transport make up for a small portion of the energy losses, but the reconversion (ammonia cracking) is very energy intensive. Furthermore, a significant amount of energy is again lost at the power plant. In practically all the processes the energy is lost as heat. Optimization by using waste heat is therefore interesting, especially at the ammonia cracking process and the power plant, as these processes are at higher temperatures.

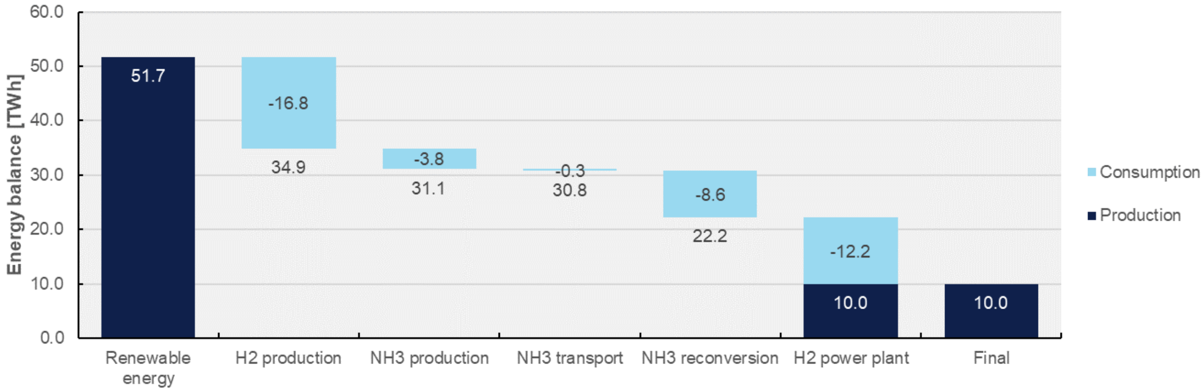


Figure 15: Waterfall plot of the energy losses in the green ammonia value chain.

5.3.2 Levelized cost

The levelized cost for providing back-up power to the German grid through the green ammonia route is 581 €/MWh. The largest share is for the ammonia cracking (around 36%), followed by the production of the input energy, the hydrogen power plant and the ammonia storage.

- The high LCOE for cracking is mainly due to the high energy consumption which will take place at times of high electricity prices in Germany (when the back-up power needs to engage).
- The share of ammonia storage is high because of a high CAPEX for ammonia storage tanks and the volume of storage required. It was assumed that half of the energy that will be provided by the back-up power plants should be available and stored, i.e. provide 12.5 GW for 400 hours from the ammonia storage. This may be a conservative assumption as storage will fill and empty incrementally across a year.
- The power plant takes a large share because of the low efficiency, but also because of the low utilization (only 800 hours per year).
- The renewable energy costs in Namibia are slightly lower than in the DRI value chain because the ammonia chain is slightly more efficient.

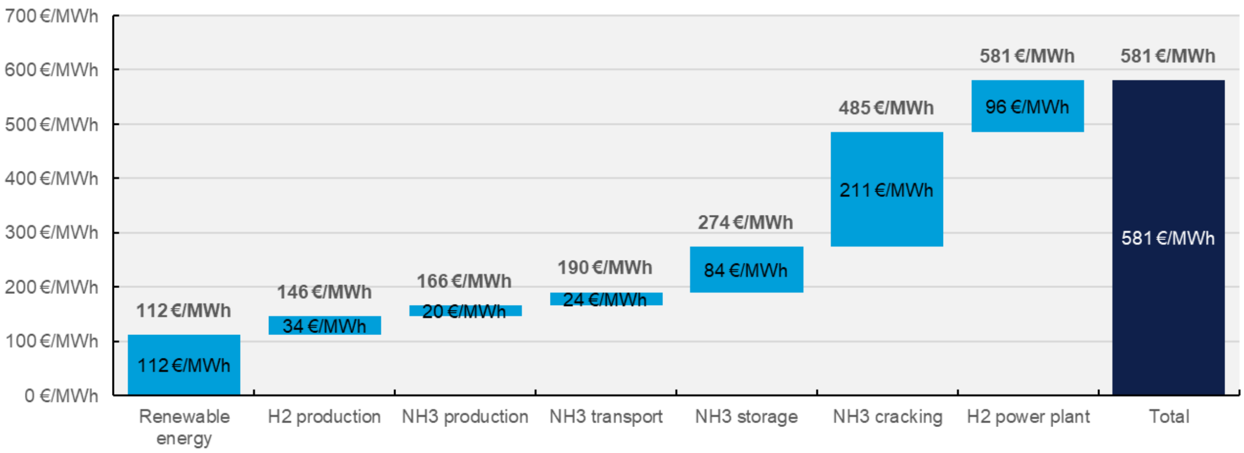


Figure 16: LCOE break-down of the (centralized) green ammonia value chain.

5.3.3 Investments

The total investments are discounted with a rate of 8% (real) and are broken down in the figure below. A total of roughly 91,4 billion euro is needed for building and operating the 12.5 GW back-up power capacity and for setting up the green ammonia supply chain. Roughly 46% are CAEPX and 54% OPEX. The investment drivers are similar to what is discussed for the LCOE above. Electricity consumption for ammonia cracking is included in the OPEX as electricity from the German grid is needed for the cracking process. Furthermore, transport of ammonia is OPEX driven as the assessment assumes chartering and has therefore used the (current) day-rates.

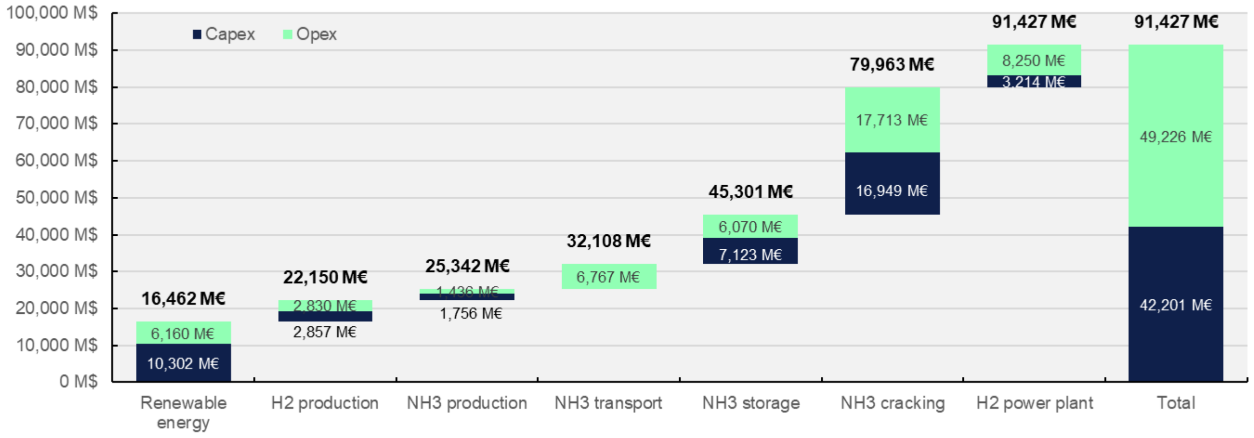


Figure 17: Investment break-down of the (centralized) green ammonia value chain

5.4 Iron-to-Hydrogen value chain

This section outlines results for the Iron-to-Hydrogen value chain. It involves the production of DRI using renewable energy and hydrogen produced in Namibia, transport to Europe by bulk vessel, distribution by inland shipping or rail and conversion to hydrogen at the power plant in Germany.

5.4.1 Chain efficiency

To provide 10 TWh per year to the German Grid, 59.5 TWh/y of input energy needs to be produced in Namibia. The total energy efficiency of the value chain is therefore 17%. Roughly 21% of the energy is lost in the hydrogen production process, 32% is lost in the DRI production process, 7% is lost in transport, 3% is lost in reconversion and 21% is lost in power generation. Note that these losses do not represent the efficiency of the individual process steps but the losses relative to the initial produced energy – for example, the efficiency of the hydrogen power plant is ~45%, but much of the energy has already been lost in the previous steps and therefore only 21% is lost compared to the initial energy.

A large part of the energy is lost by the electrolysis and DRI production process. Transport and reconversion only make up a small portion of the energy losses. At the power plant, a significant amount of energy is again lost. In practically all the processes the energy is lost as heat. Optimization by using waste heat is therefore interesting, especially at the DRI production process and the power plant, as these processes are at higher temperatures.

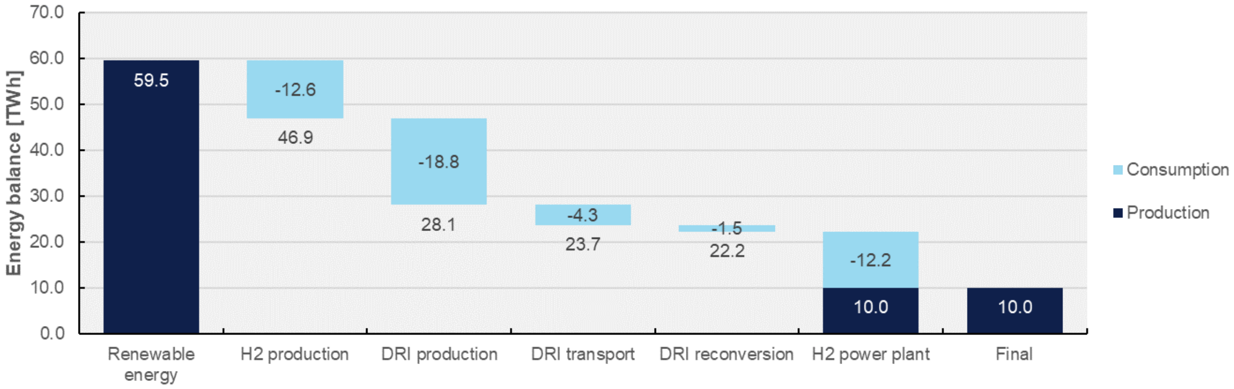


Figure 18: Waterfall plot of the energy losses in the Iron-to-Hydrogen value chain.

5.4.2 Levelized cost

The levelized cost for providing back-up power to the German grid through Iron-to-Hydrogen is 402 €/MWh. Note that the LCOE for each step of the value chain is expressed in terms of the LCOE per MWh of electricity generated by the hydrogen power plant. The largest shares of the LCOE are to produce the input energy and the hydrogen power plant.

- Based on the energy input-output ratio across the iron-hydrogen value chain of roughly 1 to 6 (equivalent to the calculated efficiency factor of 17%), the cost of renewable energy generation in Namibia of 21 €/MWh is increased by a factor of ~6 resulting in the overall LCOE of input energy of 126 €/MWh
- The power plant takes a large share because of the low efficiency, but also because of the low utilization (only 800 hours per year).
- The other cost components have a relatively equal share in the LCOE with DRI production slightly higher due to the energy efficiency, but also due to conservative CAPEX assumptions.

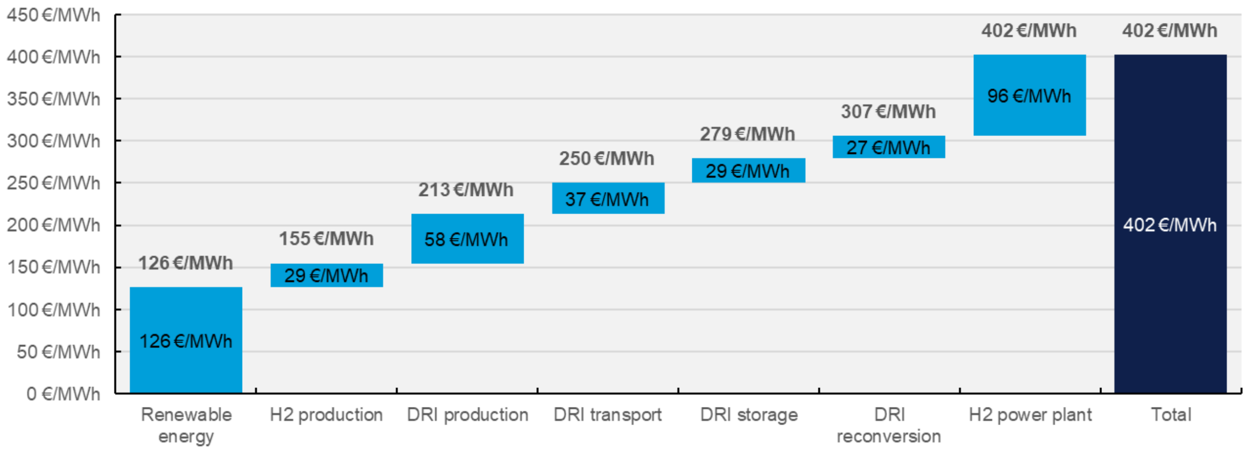


Figure 19: LCOE break-down of the (decentralized) Iron-to-Hydrogen value chain.

5.4.3 Investments

The total investments are discounted with a rate of 8% (real) and are broken down in the figure below. A total of roughly 66,5 billion euro is needed for building and operating the 12.5 GW back-up power capacity and for setting up the Iron-to-Hydrogen supply chain. Roughly 37% is CAPEX and 63% OPEX. The investment drivers are similar to what is discussed for the LCOE above. Transport of DRI is OPEX driven as the assessment assumes chartering and has therefore used the (current) day-rates.

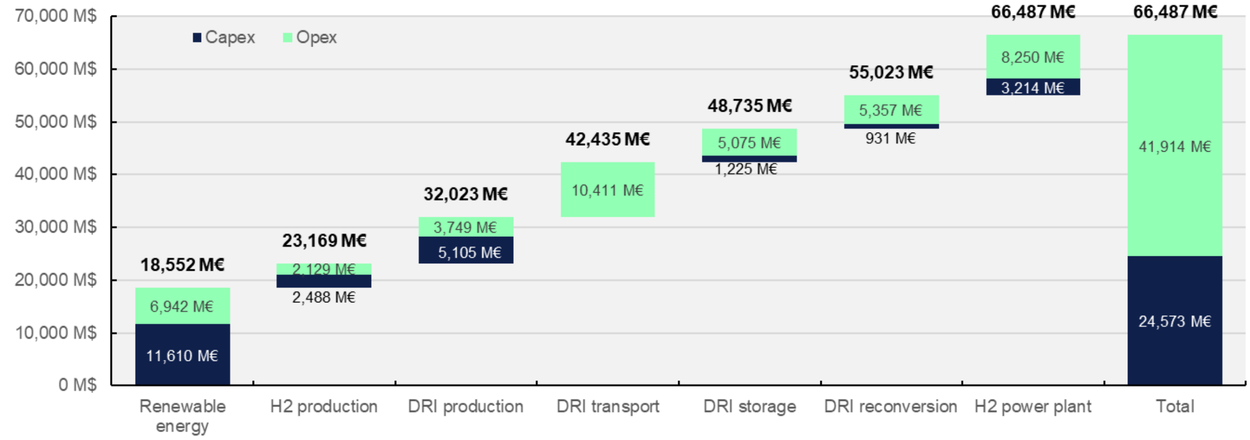


Figure 20: Investment break-down of the (decentralized) Iron-to-Hydrogen value chain.

6 COMPARISON

This section compares the results of DNV's assessments across the different value chains. It provides a comprehensive overview of the results for easier comparison and provides an analysis of the strengths, weaknesses, opportunities and threats of each value chain (SWOT).

6.1 Key figures

The key figures from the techno-economic analysis are summarized in the table below.

Table 6-1: Key figures summarizing all value chains

	Domestic Green Hydrogen Production in Germany	Green Ammonia import	Iron-to-Hydrogen
LCOE	425 €/MWh (centralized)	680 €/MWh (decentralized) 581 €/MWh (centralized)	402 €/MWh (decentralized) 410 €/MWh (centralized)
Main cost drivers	1. Renewable energy production 2. Hydrogen fired power plant 3. Hydrogen production	1. Ammonia cracking 2. Energy losses 3. Hydrogen fired power plant	1. Energy losses 2. Hydrogen fired power plant 3. DRI production
Local H_2 production costs	~5 €/kg (Germany)	~2 €/kg (Namibia)	~2 €/kg (Namibia)
Chain efficiency	31%	19%	17%
TRL level	5-8	5-9	3-9
Key challenges	• Costs of hydrogen production • Low TRL for scale up of fast-cycling salt cavern storage and backbone	• Toxicity of ammonia • Low TRL, and high energy consumption of ammonia cracking • Low flexibility of ammonia synthesis and cracking • Decentralized ammonia cracking not suitable	• Low TRL of DRI reconversion to H_2 • Low flexibility of DRI production and reconversion (manageable)
Capacity and volumes			
Renewable energy	7.9 GW offshore wind Germany 32.4 TWh/y	5.4 GW Solar Namibia 7.2 GW wind Namibia 51.7 TWh/y	6.1 GW Solar Namibia 8.1 GW wind Namibia 59.5 TWh/y
Hydrogen	540-600 kt/y	720-820 kt/y	550-600 kt/y
Carrier	x	4,000-4,600 kt/y ammonia	12,700-13,900 kt/y DRI
Indicative no. of ships Namibia-Germany* (per year)	x	85 ships to Germany (7 ships per month)	232 ships (64kt) to Germany (19 ships per month) 304 ships (64kt) to Namibia (25 ships per month)
Indicative storage in Germany (to bridge 400 hours of back-up power generation)	282 kt H_2 ~48 salt caverns (6 kt each)	2,150 kt ammonia 13 terminal tanks** ~3,200,000 m^3 in total	7,240 kt DRI ~1,460,000 m^3 in silo storage
Back-up power produced	12.5 GW 10 TWh/y	12.5 GW 10 TWh/y	12.5 GW 10 TWh/y

** For DRI transport by dry bulk vessels (64 kt), DRI is transported to Europe and the "spent DRI" (Iron Oxide) is shipped back to Namibia. Iron Oxide is heavier and therefore requires more voyages.*

*** Using LNG storage terminals as a reference, reference tank size: 250,000 m³*

6.1.1 Technology readiness

The table below provides a summary and comparison of the TRLs of the different technologies and value chains. It provides an overview of the TRL range and key challenges.

Table 6-2: Summary of the TRL assessment

Hydrogen production	**TRL 7-9**	• Renewable energy production is fully mature, as well as hydrogen production at MW scale. • Key challenge is the integration of renewable energy and electrolysis and the long-term effects on lifetime.
Domestic hydrogen production	**TRL 5-8**	• Hydrogen storage in salt caverns for fast cycling has the lowest TRL and only small-scale pilots are in operation. • Key concerns for the whole value chain (pipeline and cavern) are material suitability (steel and sealings) and effect rapid of pressure fluctuations due to operations.
Green ammonia import	**TRL 5-9**	• There are significant safety concerns due to the high toxicity of ammonia. Although it is a widely traded commodity, regulations might be insufficient for increased volumes. • Flexibility of both ammonia production and cracking could be a challenge. • Ammonia cracking requires significant technological development and is still at small demonstration scale.
Iron-to-Hydrogen	**TRL 3-9**	• Transport and storage of DRI has a high TRL and is regulated for maritime transport, regulation for inland transport is uncertain. Commercial transport systems are available. • DRI production (iron reduction) requires further maturing and scale-up but is well understood. • DRI reconversion has a low TRL but the process is relatively simple. The main challenge is to control the reduction process, which does currently not align with the requirements for use in back-up power.
H2 power plant	**TRL 8**	• 1 MW scale is commercially available (engines) and 10 MW scale can be expected in the near future. • CCGTs are suitable for much larger scale but are not suitable for dedicated back-up power. However, part of the capacity can be reserved to provide quick response. The TRL of 100% H2 turbines is lower and requires a boost for further development.

6.1.2 Cost comparison

The levelized cost to provide 10 TWh of back-up power to the German grid annually are compared in the figure below for each value chain. The costs are broken down into:

Renewable energy	The costs for producing the input energy by wind or solar in Namibia or by offshore wind in Germany
H2 production	The costs for hydrogen production by electrolysis
Conversion	The costs for conversion of hydrogen into DRI or ammonia
Transport	The costs for transport of either hydrogen, DRI or ammonia by pipe and ship
Storage	The costs for storage of either hydrogen, DRI or ammonia, in both Namibia and in Germany
Reconversion	The costs for reconversion of either DRI or ammonia back into hydrogen
H2 power plant	The costs for producing back-up power in the hydrogen power plants

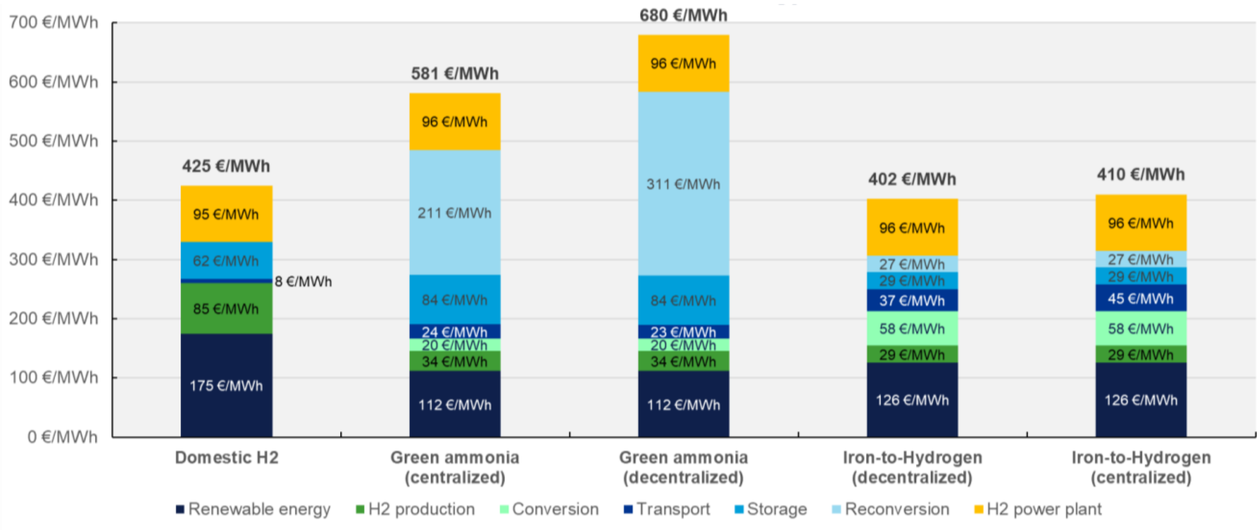


Figure 21: LCOE break-down of all value chains.

Iron-to-Hydrogen shows the lowest LCOE but is only slightly lower than domestic green hydrogen production in Germany. The key difference in all routes is in the LOCE for renewable energy generation and for hydrogen production through electrolysis. The input energy LCOE in Namibia is lower due to better renewable resources and by using a mix of wind and solar. This also has an influence on the costs for hydrogen production as the utilization rate is higher in Namibia, with more operating hours. Additionally, it was assumed that Chinese Electrolyzers will be used in Namibia, which have a much lower CAPEX (300 €/kW vs 800 €/kW), but also lower efficiency (8% lower efficiency)[2].

Between Iron-to-Hydrogen and domestic green hydrogen production in Germany, an additional difference is in the costs for transport and storage. Higher costs are incurred for shipping of DRI. However, the costs for storing DRI are much lower compared to storage of hydrogen in salt caverns. Here the volume of storage will be relevant and will depend on how much storage is (strategically) needed to ensure that back-up power can be provided when needed.

For the green ammonia value chain, storage is also a significant share in the costs. This is, however, a high-level-estimate and better cost figures will likely lead to a more accurate view. The key cost driver for the green ammonia value chain is the cracking of ammonia, which takes roughly 36% of the total LCOE. The development of direct ammonia firing is therefore interesting and could provide a significant cost reduction. This will however require decentralized storage of ammonia at the power plant and distribution of large volumes of ammonia through Germany. The safety concerns would therefore need to be resolved as well.

Overall, the attractiveness of centralized or decentralized reconversion for ammonia is therefore still uncertain. For the DRI route there are fewer safety concerns and the distribution through Germany is safer and potentially low cost. It would avoid large volumes of hydrogen cavern storage and would not add additional concerns of pressure fluctuations on the hydrogen backbone, which can be expected for hydrogen-fired peak power. Decentralized conversion of DRI at the power plant is therefore an attractive option.

2 Based on DNV database of current and future electrolyzer costs and performance. This database is based on manufacturer indications and data collected through projects.

6.2 SWOT

For each value chain the strengths, weaknesses, opportunities and threats have been identified and summarized in the overview below. These are based on the results of DNV's analyses as well as an expert session, taking a broader perspective.

Table 6-3: Overview of strengths, weaknesses, opportunities and threats of each value chain.

Strengths	Domestic H2 production	• Is a more efficient use of renewable electricity than the import value chains, requiring significantly lower installed renewable capacity • Low cost for hydrogen storage and transport • Less dependence on energy imports • Least complex value chain

	Green Ammonia import	• High TRL for production, transport and storage:
		  ◦ Ammonia transport is already operational
		  ◦ Safe practice for ammonia production, transport, and storage is well-known
		• Relatively high energy density in liquid phase compared to hydrogen transport

	Iron-to-Hydrogen	• Transport, storage and handling are not complex:
		  ◦ DRI is not toxic, and handling is therefore relatively safe
		  ◦ Regulation and practices for DRI are partially in place
		  ◦ Can be integrated into existing transport systems (large maritime fleet is already operational)
		  ◦ High volumetric energy density – can be easily stored for a long time if stored properly
		  ◦ Although TRL is low for the specific application, the processes are well-known and not complicated. TRL development can go quickly
		• Easily scalable complete value chain
		• Value chain with relatively low LCOE, at par with domestic green hydrogen production in Germany
		• Iron ore is an abundant resource

Weakness	Domestic H2 production	• High cost for hydrogen production • Technical challenge when transporting hydrogen in pipelines compared to the DRI value chain • Existing pipelines are sensitive to pressure fluctuations and hydrogen embrittlement • Low TRL of fast cycling hydrogen salt caverns and intensive investments needed to scale-up/further develop.

	Green Ammonia import	• Safety:
		  ◦ High toxicity and associated safety concerns
		• Ammonia cracking:
		  ◦ Low TRL
		  ◦ Low operational flexibility
		  ◦ High energy use and costs for cracking. The cracking process requires much energy in Germany. This provides a strong disadvantage, especially if the cracking is done at times of low energy availability, e.g. when the back-up power plant will operate
		• Ammonia synthesis has flexibility limitations, does not fully match intermittent RES. It will require storage of electricity or hydrogen
		• Is less suitable for decentralized cracking of ammonia at power plant due to flexibility and safety

	Iron-to-Hydrogen	• The reconversion process to hydrogen needs to be performed in a batch-wise fashion, it is not easy to stop the process once it has been started. Additionally, DRI reconversion has a low TRL • Less energy efficient compared to domestic green hydrogen production and imported ammonia value chains • Iron reduction has flexibility limitations, this does not fully match intermittent RES. It will require storage of electricity or hydrogen

Opportunities	Domestic H2 production	• Cost reduction potential if hydrogen market dynamics are utilized e.g., by buying hydrogen at low prices to fill strategic storage reserves (salt caverns) • Costs could potentially be reduced with a wider portfolio of input energy - power purchase agreements (PPAs) of both wind and solar, and power from the grid if allowed according to the renewable energy directlive. • Domestic green hydrogen production in Germany allows for stabilization of the European electricity market • More domestic labor compared to import value chains
	Green Ammonia import	• Green ammonia can be also used in other sectors: • Feedstock industry • Direct use/combustion of ammonia will avoid cracking step (one of the key bottlenecks) • Allows for sourcing from remote areas with abundant (cheap) RES • Currently high public exposure • Alignment with current strategies and ambitions • Synergies with LNG infrastructure

	Iron-to-Hydrogen	• Optimization potential:
		    • DRI can also be used in steel industry which allows for value chain optimizations e.g., volumes and economies of scale, use of spent DRI (iron oxide)
		    • Value chain provides space for further optimization, such as use of waste heat from power plant for reconversion
		• Does not require connection / development of H2 backbone infrastructure:
		    • Suitable for decentralized hydrogen-fired back up power
		    • Suitable for small-scale (MW-scale) capacity backup without CAPEX-intensive backbone connection
		• DRI technology can leverage on R&D and investment from the steel industry
		• Due to easy transport and storage, can be sourced from remote areas with abundant RES

Threats	Domestic H2 production	• High dependency on the development of hydrogen transport infrastructure including backbone and salt caverns:
		    • Sensitive to delayed development
		    • Location limitation: Power plants need to be relatively close to the backbone
		• Requires the build-out of more RES in Europe/Germany compared to energy import value chains:
		    • More time needed to develop additional RES capacity
		    • Higher social and environmental pressure

	Green Ammonia import	• Existing regulations and acceptable risk levels are based on lower volumes of ammonia transport and might not provide room for larger volumes • Creates dependencies on energy supply outside of EU • Value chain could be affected by political uncertainties depending on exporting country • Value chain can be impacted by price and market fluctuations • Requires significant additional installed renewable capacity, possibly restricting renewable energy development for domestic Namibian energy consumption/development.
	Iron-to-Hydrogen	• Creates dependencies on energy supply outside of EU • Value chain could be affected by political uncertainties depending on exporting country • Value chain can be impacted by price and market fluctuations • Compared value chains are more advanced in terms of public exposure, TRL & project development • Requires significant additional installed renewable capacity, possibly restricting renewable energy development for domestic Namibian energy consumption/development.

7 CONCLUSIONS

The aim of this study was to assess the feasibility and potential benefits of direct reduced iron as an energy carrier and hydrogen storage system to enable green hydrogen-based back-up power generation in Germany. Three different value chains were compared on TRL, levelized costs and a more general view on potential strengths, weaknesses, opportunities and threats.

Main conclusion: DNV's assessment concludes that it is worthwhile to consider Iron-to-Hydrogen as a potentially cost-effective and safe option for sourcing green hydrogen for German power plants.

This conclusion is based on a comparison with other selected green hydrogen value chains, namely importing green ammonia or producing green hydrogen domestically in Germany.

Import of DRI and conversion to hydrogen is a potentially **cost-effective** addition to importing green ammonia or producing green hydrogen domestically in Germany.

Based on DNV's modelling assessment it could provide the lowest LCOE (402 €/MWh), slightly below green hydrogen production from offshore wind in Germany (425 €/MWh) and much lower compared to importing and cracking green ammonia (581 €/MWh). The assessment considers the full value chain from renewable energy production by onshore wind and solar in Namibia, or offshore wind in Germany, all the way to electricity in dedicated hydrogen fired power plants to provide back-up power to the Germany electricity system.

Green hydrogen based DRI would use the abundant renewable wind and solar resources in Namibia and include the most energy intensive process steps directly at the start of the value chain. Costs for reconversion could be low, which would be a significant benefit compared to ammonia. Costs for ammonia cracking are significant and add roughly one third of the LCOE, which also leads to interest in direct combustion of ammonia (although low in TRL).

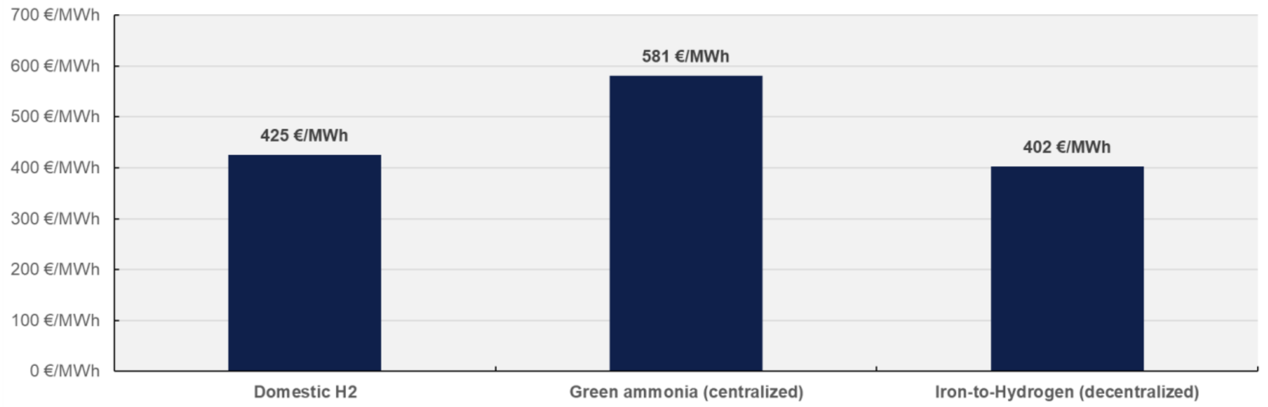


Figure 22: LCOE break-down of all value chains of assessed value chains, expressed as euro per MWh of electricity generated by the hydrogen power plant in Germany.

Green hydrogen based DRI can be transported and stored relatively easily in large quantities and plays a crucial role in decarbonizing the steel industry. It could therefore provide a **versatile** medium, extending beyond a centralized hydrogen infrastructure (i.e. backbone and salt caverns).

Transport and storage of DRI is well understood and can be handled as a dry-bulk good with relatively simple safety precautions - in a water and airtight (weather tight) confinement with an inert atmosphere (e.g. nitrogen) with no ventilation. It could provide an alternative to the supply of hydrogen to back-up power plants via a central hydrogen transmission system (i.e. hydrogen backbone).

There will be a need for back-up power generation in areas more remote from central hydrogen infrastructure. Local transport, storage and reconversion of DRI is technically feasible (although reconversion is low in TRL) and would not require the same level of stringent safety protocols as needed for local transport, storage and cracking of ammonia. Local ammonia cracking is technically challenging due to low flexibility of the cracker, not suitable for providing back-up power.

The three variants examined for the provision of back-up power generation each have **different degrees of technological maturity** with regard to the key components of generation, transportation, storage and reconversion.

For each of the assessed value chains there are different steps which have a low TRL or provide challenges. The key findings are outlined below per value chain.

- *General for all value chains* – TRL 7-9 - There is a large focus on hydrogen production from renewable energy through electrolysis. At MW scale the technology is mature, but a first 100 MW or GW scale project, using renewable energy, still needs to be commissioned successfully. Additionally, there are concerns about the long-term durability of electrolyzers when operated with fluctuations and frequent start/stops. This provides engineering challenges and uncertainties for project developers and investors. Many projects are currently postponed, which will also delay further development of large-scale green hydrogen production.
- *Domestic green hydrogen production in Germany* – TRL 5-8 – Besides the general challenges for green hydrogen production there are uncertainties for the effect of hydrogen on materials, especially steel. It is known that pressure fluctuations have an effect on the integrity of steel, which is also the case with natural gas, but which is more severe with hydrogen due to embrittlement. This should be taken into account when designing the hydrogen transmission infrastructure but will heavily depend on the operating mode. Currently, the operating mode is uncertain as the hydrogen market is not yet established. The use of hydrogen for back-up power can cause strong pressure fluctuations in the transmission network.
- Additionally, the TRL of fast cycling hydrogen salt caverns, as foreseen to be part the hydrogen transmission infrastructure, is still at level 5. Only small-scale pilot projects are in operation so far and uncertainties remain on the long-term gas tightness, impurities after withdrawing hydrogen from the cavern and a lack of best practices and standards for safe design. Further development is ongoing, but is capital intensive, meaning it will require dedication from the market.
- *Green ammonia import* – TRL 5-9 – The key challenge with ammonia is its toxicity and related safety concerns. Although production, transport and storage are well known and fully regulated, this is based on much lower ammonia volumes than anticipated in the future. The increase of these volumes should therefore be carefully considered with regards to safety and the environment, especially in dense populations.
- In addition, ammonia cracking (TRL 5) is currently at small scale, is very costly and energy-intensive and has a low flexibility. There is however a large momentum for globally developing ammonia as an energy carrier and as a feedstock.
- *Green hydrogen based DRI* – TRL 3-9 – DRI has been used in the steel industry for a long time and the production is therefore well known, but using only hydrogen, particularly from fluctuating renewable energy, is novel. Transport and storage do not differ but are not yet widely applied and regulation exists mainly for maritime transport. The value chain's weak point is in the reconversion process, which is currently at TRL 3-4 and provides challenges regarding flexibility in response time to peak-power demand. However, DNV did not identify significant showstoppers and expects further development can be carried out quickly as the processes are relatively simple.

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APPENDIX A: ASSUMPTIONS

For the assessment DNVs proprietary techno-economic model was used and adapted to the needs for this assessment. The model calculates energy and cost flows, based on a set of value chain specific parameters and a set of technology input data. A list of key assumptions, used in DNV's analysis, is provided in the table below. Please note that the list of input data is not complete as many of the inputs provided below are broken down in more detailed values and calculations. These parameters are recalculated in the model based on scale and specific set-up of the value chain and energy flows.

Table 0-1: Key assumptions

Input	Value	Comment
WACC/Discount rate (real)	8%	Generally assumed for full value chains
Base year	2024	All costs are made Net Present to 2024
Assessment period	30 years	
Begin operation	2035	
Decommissioning cost	10% of CAPEX	
Transport distances		
Namibia	100 km	
Overseas	26 day voyage	Including waiting time at harbor
Germany	500 km	
Electricity price for local power consumption	110 €/MWh	Used to power the ammonia cracking and DRI reconversion
Back-up power capacity	12.5 GW	Total capacity of back-up power plants
Back-up power operation	800 full load hours	the back-up capacity will operate for 800 full load hours per year
Storage requirement for back-up	400 hours	Storage of energy in Germany considers a capacity that is sufficient to provide back-up power for 400 full load hours.
Conversion factors		
Energy content hydrogen	39.39 kWh/kg H2	Higher heating value
Density (volumetric) hydrogen	0.0899 kg H_2/m³ H_2	At STP
Density (volumetric) NH3	674 kg/m^3	Liquid
Hydrogen density (volumetric) NH3	121 kg H_2/m³ NH_3	Liquid
Hydrogen density (gravimetric) NH3	0.179 kg H_2/kg NH_3	
Density (volumetric) DRI	4,950 kg/m³	powder
Hydrogen density (volumetric) DRI	340 kg H_2/m³ DRI	powder
Hydrogen density (gravimetric) DRI	0.043 kg H_2/kg DRI	
Wind Germany (offshore)		
CAPEX	1,700 €/kW	
OPEX	3%	% of CAPEX annually
Annual full load hours	4,000 h	
Wind Namibia (onshore)		
CAPEX	1,000 €/kW	
OPEX	2%	% of CAPEX annually
Annual full load hours	4,600 h	
Solar Namibia (onshore)		
CAPEX	400 €/kW	
OPEX	1.5%	% of CAPEX annually
Annual full load hours	2,800 h	

Input	Value	Comment
Electrolyzer Germany (onshore)		Based on EU systems
CAPEX	800 €/kW	
OPEX	3%	% of CAPEX annually
Stack replacement cost	20%	% of CAPEX
Stack lifetime	80,000	Full load hours
Degradation	0.125%/1,000 h	Loss of efficiency per 1,000 full load hours of operation
Energy consumption	49.9 kWh/kg	Including stack and balance of plant
Electrolyzer Namibia (onshore)		Based on Chinese systems
CAPEX	300 €/kW	
OPEX	3%	% of CAPEX annually
Stack replacement cost	20%	% of CAPEX
Stack lifetime	80,000	Full load hours
Degradation	0.125%/1,000 h	Loss of efficiency per 1,000 full load hours of operation
Energy consumption	55.5 kWh/kg	Including stack and balance of plant
Ammonia synthesis plant		Based on Chinese systems
CAPEX	650,000 €/tpd	Including synthesis, air separation, utilities and buffer
OPEX	3%	% of CAPEX annually
Energy consumption	0.55 kWh/kg NH3	
DRI production plant		
CAPEX		
Kiln	85,000 €/tpd	
DRI ore	83 €/t	
OPEX	2%	% of CAPEX annually
Energy consumption	1.4 kWh/kg DRI	
Hydrogen transport	0.25 €/kg_{H2}/1,000km	Based on hydrogen backbone
Hydrogen storage (salt cavern)		
CAPEX	15,800 €/t_{H2}	Per ton of storage capacity
OPEX	2.5%	% of CAPEX annually
Energy consumption	0.7 kWh/kg_{H2}	
Ammonia transport		
Seaborne transport (day rate)	50,000 €/d	51,800 t_{NH3} ship capacity, including all transport costs (fuel, crew, harbor costs, etc.). Total voyage duration is 26 days
Distribution (inland)	0.04 €/t/km	Distribution in Namibia 100 km and in Germany 500 km
Boil off	0.02%/d	
Ammonia storage		
CAPEX	2,800 €/t_{NH3}	Per ton of storage capacity
OPEX	3%	% of CAPEX annually
Energy consumption	0.017 kWh/kg_{NH3}	For (re)liquefaction
Boil off	0.02%/d	
DRI transport		
Seaborne transport (day rate)	15,000 €/d	64,000 t ship capacity, including all transport costs (fuel, crew, harbor costs, etc.). Total voyage duration is 26 days
Distribution (inland)	0.04 €/t/km	Distribution in Namibia 100 km and in Germany 500 km
DRI storage		
CAPEX	100 €/t_{DRI}	Per ton of storage capacity
OPEX	2%	% of CAPEX annually
Energy consumption	0.1 kWh/kg_{DRI}	For inertization (N2).

Input	Value	Comment
Ammonia cracking		
CAPEX (central)	120,000 €/tpd	
CAPEX (decentral)	155,000 €/tpd	
OPEX	3%	% of CAPEX annually
Energy consumption	1.5 kWh/kg_{H2}	
Conversion losses	25%	25% of the NH3 is lost in the cracking process
DRI reconversion		
CAPEX	85,000 €/tpd	
OPEX	2%	% of CAPEX annually
Energy consumption	0.1 kWh/kg DRI	
Conversion losses	1.2%	0.5% of the DRI is lost in the reconversion process
Hydrogen power plant		
CAPEX	550,000 $€/MW_{out}$	
OPEX	4%	% of CAPEX annually
Efficiency	45%	Based on lower heating value

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