Flagship Project
TransHyDE

European Hydrogen Infrastructure Planning

Insights from the TransHyDE Project System Analysis

SPONSORED BY THE

Federal Ministry
of Education
and Research

Disclaimer

The white paper was developed by a selected authorship of the TransHyDE Project System Analysis. The contents of the TransHyDE publications are produced in the project independently of the Federal Ministry of Education and Research.

Imprint

Flagship Project TransHyDE

TransHyDE Project System Analysis

Sponsored by the Federal Ministry of Education and Research

Editors

Dr. Florian Ausfelder – DECHEMA Gesellschaft für Chemische Technik und Biotechnologie e. V. (Society for Chemical Engineering and Biotechnology)

Prof. Dr. Mario Ragwitz - Fraunhofer Research Institution for Energy Infrastructures and Geothermal Systems IEG

Dr. My Yen Förster – DECHEMA Gesellschaft für Chemische Technik und Biotechnologie e. V. (Society for Chemical Engineering and Biotechnology)

Dr. Christoph Nolden – Fraunhofer Research Institution for Energy Infrastructures and Geothermal Systems IEG

doi:10.24406/publica-2733

List of Contributors

Şirin Alibaş – Fraunhofer Institute for Systems and Innovation Research ISI

Dr. Florian Ausfelder – DECHEMA Gesellschaft für Chemische Technik und Biotechnologie (Society for Chemical Engineering and Biotechnology)

Dr. Daniel Ditz – Salzgitter Mannesmann Forschung GmbH

Michael Ebner – Forschungsstelle für Energiewirtschaft FfE

Veronika Engwerth – Forschungsstelle für Energiewirtschaft FfE

Dr. Tobias Fleiter – Fraunhofer Institute for Systems and Innovation Research ISI

Dr. Joshua Fragoso García – Fraunhofer Institute for Systems and Innovation Research ISI

Lucien Genge – Brandenburg University of Technology

Prof. Dr.-Ing. Maria Greitzer – Fraunhofer Research Institution for Energy Infrastructures and Geothermal Systems IEG

Sofia Haas – Forschungsstelle für Energiewirtschaft FfE

Michael Haendel – Fraunhofer Institute for Systems and Innovation Research ISI

Dr. Christoph Hank – Fraunhofer Institute for Solar Energy Systems ISE

Ryan Harper – Forschungsstelle für Energiewirtschaft FfE

Dr. Philipp Hauser – VNG AG

Dr. Wolfram Heineken – Fraunhofer Institute for Factory Operation and Automation IFF

Maximilian Heneka – DVGW Research Center at Engler-Bunte-Institut of Karlsruhe Institute of Technology (KIT)

Jan Hildebrand – Institut für Zukunftsenergie- und Stoffstromsysteme gGmbH

Anne-Marie Isbert – Forschungsstelle für Energiewirtschaft FfE

Volkan Isik – DVGW Research Center at Engler-Bunte-Institut of Karlsruhe Institute of Technology (KIT)

Dr. Matthias Jahn – Fraunhofer Institute for Ceramic Technologies and Systems IKTS

Bernhard Klaassen – Fraunhofer Research Institution for Energy Infrastructures and Geothermal Systems IEG

Dr. Tanja Kneiske – Fraunhofer Research Institution for Energy Infrastructures and Geothermal Systems IEG

Wolfgang Köppel – DVGW Research Center at Engler-Bunte-Institut of Karlsruhe Institute of Technology (KIT)

Berkan Kuzyaka – Technical University of Berlin

Dr. Benjamin Lux – Fraunhofer Institute for Systems and Innovation Research ISI

Ammar Maghnam – Fraunhofer Research Institution for Energy Infrastructures and Geothermal Systems IEG

Dr. Sabine Malzkuhn – DVGW Research Center at Engler-Bunte-Institut of Karlsruhe Institute of Technology (KIT)

Friedrich Mendler – Fraunhofer Institute for Solar Energy Systems ISE

Tim Mielich – Technical University of Berlin

Stephan Mohr – Forschungsstelle für Energiewirtschaft FfE

Prof. Dr.-Ing. Joachim Müller-Kirchenbauer – Technical University of Berlin

Prof. Dr. Felix Müsgens – Brandenburg University of Technology

Felix Neuner – Fraunhofer Institute for Systems and Innovation Research ISI

Dr. Benjamin Pfluger – Fraunhofer Research Institution for Energy Infrastructures and Geothermal Systems IEG

Amanda Pleier – Forschungsstelle für Energiewirtschaft FfE

Prof. Dr. Mario Ragwitz – Fraunhofer Research Institution for Energy Infrastructures and Geothermal Systems IEG

David Ruprecht – Forschungsstelle für Energiewirtschaft FfE

Pantea Sadat-Razavi – Institut für Zukunftsenergie- und Stoffstromsysteme gGmbH

Marcel Scheffler – Fraunhofer Institute for Factory Operation and Automation IFF

Mithran Daniel Solomon – Fraunhofer Institute for Factory Operation and Automation IFF

Christopher Voglstätter – Fraunhofer Institute for Solar Energy Systems ISE

Bastian Weißenburger – Fraunhofer Institute for Systems and Innovation Research ISI

Contributors by section

Section Executive Summary, Section 1

Florian Ausfelder, Mario Ragwitz

Section 2

Şirin Alibaş, Veronika Engwerth, Tobias Fleiter, Michael Haendel, Ryan Harper, Friedrich Mendler, Felix Neuner, David Ruprecht, Christopher Voglstätter, Bastian Weißenburger

Section 3

Joshua Fragoso García, Lucien Genge, Philipp Hauser, Anne-Marie Isbert, Bernhard Klaassen, Benjamin Lux, Ammar Maghnam, Tim Mielich, Stephan Mohr, Felix Müsgens, Benjamin Pfluger, Amanda Pleier

Section 4

Michael Ebner, Joshua Fragoso García, Lucien Genge, Philipp Hauser, Wolfram Heineken, Maximilian Heneka, Bernhard Klaassen, Wolfgang Köppel, Berkan Kuzyaka, Friedrich Mendler, Tim Mielich, Joachim Müller-Kirchenbauer, Benjamin Pfluger, Marcel Scheffler, Mithran Daniel Solomon

Section 5.1

Matthias Jahn, Tanja Kneiske

Section 5.2

Daniel Ditz, Maria Greitzer, Sofia Haas, Christoph Hank, Maximilian Heneka, Anne-Marie Isbert, Volkan Isik, Wolfgang Köppel, Sabine Malzkuhn

Section 5.3

Jan Hildebrand, Pantea Sadat-Razavi

Executive Summary

Wasserstoff wird eine zentrale Rolle in der Transformation des Energiesystems zukommen. Das vom Bundesministerium für Bildung und Forschung (BMBF) geförderte TransHyDE Projekt Systemanalyse untersucht mit Methoden der Energiesystemanalyse Wasserstoff als einen Energievektor mit hoher Relevanz für die Erreichung der Klimaneutralität in 2045. Die Fragestellungen beinhalten die detaillierte Entwicklung des Wasserstoffbedarfs aus dem Industrie-, Haushalts- und Transportsektor im Kontext der räumlich und zeitlich hochaufgelösten Wasserstofferzeugung sowie des Imports und die Anforderungen an die Infrastrukturen, um den Ausgleich für den Bedarf und das Angebot von Wasserstoff oder seinen Derivaten zu gewährleisten.

Entsprechend können zum gegenwärtigen Zeitpunkt die Ergebnisse wie folgt zusammengefasst werden:

Ein bedeutender Bedarf an gasförmigem Wasserstoff in der Größenordnung von ungefähr 700 TWh (alle Angaben beziehen sich auf den unteren Heizwert (LHV) von Wasserstoff) wird für die EU27 + UK bis 2050 selbst in den Szenarien mit minimalem Wasserstoffbedarf erwartet.

Die Hauptverbraucher von Wasserstoff sind die Wärmebereitstellung für Hochtemperaturprozesse insbesondere in der energieintensiven Industrie, Bereitstellung von Feedstocks in der Industrie sowie für zentrale Kraft- und Heizkraftwerke. Somit führt die industrielle Nutzung von Wasserstoff zu einer bedeutenden, robusten Nachfrage nach Wasserstoff. Gleichzeitig ist eine Differenzierung nötig. Die Eisen- und Stahlerzeugung und verwandte Hochtemperaturprozesse sind prioritäre Anwendungen von Wasserstoff, die allein für einen langfristigen Bedarf von 200-300 TWh innerhalb der EU27 + UK verantwortlich sind. Die Erzeugung von Roheisen über die Direktreduktionsroute aus Eisenerz ist ein wichtiges Element der künftigen Wasserstoff-Wirtschaft. Zum einen entsteht eine robuste Nachfrage nach großen Mengen treibhausgasneutralen Wasserstoffs, zum anderen können diese Prozesse mit einer Mischung von Wasserstoff und Erdgas betrieben werden, was Flexibilität im Betrieb und damit eine eher kontinuierliche Transformation ermöglicht.

Die zukünftigen weltweiten Wertschöpfungsketten der chemischen Industrie können ein Treiber zum Hochskalieren der europäischen Wasserstoffinfrastruktur darstellen. Auf der einen Seite benötigen die Herstellung von grünem Ammoniak oder petrochemischen Grundstoffen große Mengen an Wasserstoff und eine direkte Elektrifizierung ist nicht überall technisch möglich, so dass auch für diese Prozesse absehbar große Mengen treibhausgasneutralen grünen Wasserstoffs benötigt werden. Allerdings ist auf der anderen Seite nicht klar, ob die gesamte Wertschöpfungsketten von der Produktion der Grundchemikalien bis hin zu den vielfältigen Produkten innerhalb Europas umgesetzt wird. Der Import von Zwischenprodukten, wie grünem Methanol oder Ammoniak kann den Bedarf an Wasserstoff im Industriesektor drastisch reduzieren. Unsere Szenarien für mittleren und hohen Wasserstoffbedarf nehmen eine Produktion von grünen Vorprodukten und Feedstocks wie Eisenschwamm, Ammoniak, Methanol und petrochemische Grundchemikalien an den gegenwärtigen Standorten in Europa an, was einen erheblichen Bedarf für Wasserstoff generiert, in einigen Fällen mit Wasserstoffbedarfen größer als 10 TWh in einigen NUTS-3 Regionen (Landkreise, Städte) in 2050. Insbesondere die Chemie- und Stahl-lastigen Regionen in Nordwesteuropa stechen heraus mit drei Regionen, die jeweils über 100 TWh Wasserstoffbedarf ausweisen.

Der zweitgrößte Wasserstoffbedarf entsteht im Verkehrssektor. Synthetische Kraftstoffe auf Basis von Wasserstoff spielen eine wichtige Rolle im internationalen Flug- und Schiffsverkehr und generieren einen Bedarf von etwa 450 TWh in 2050. Die größte Unsicherheit im Verkehrssektor ist der Wettbewerb zwischen Batterieelektrischen und wasserstoffbasierten Brennstoffzellen-Antrieben für den Schwerlastverkehr. Daher werden unterschiedliche Szenarien im Projekt betrachtet: Das *High_Demand* Szenario hat einen zusätzlichen Wasserstoffbedarf von ungefähr 380 TWh in 2050, da 40 % des Schwerlastverkehrs auf Basis von wasserstoffbasierten Brennstoffzellen betrieben werden. Dieses Ergebnis wird durch vorteilhafte Annahmen für die Kosten von Wasserstoff und Brennstoffzellen dominiert, während die Szenarien *Low_Demand* und *Mid_Demand* Parameter haben, die eine batterieelektrische Umsetzung bevorzugen.

Die Wasserstofferzeugung auf der anderen Seite hängt von einer ambitionierten maximalen Erschließung des europäischen Wind- und Fotovoltaik-Potenzials ab, was eine no-regret Maßnahme in allen Szenarien darstellt. In diesem Fall ist eine großskalige Umsetzung der heimischen Wasserstoffproduktion wettbewerbsfähig gegenüber dem Import von Wasserstoff in die EU.

Die Rolle der Wasserelektrolyse als zentrale Sektorkopplungstechnologie verändert sich im Laufe des Markthochlaufs. Zu Beginn werden Elektrolyseure in industriellen Clustern implementiert, wo sie die kritische Funktion einer sicheren und kontinuierlichen Grundlastversorgung für industrielle Anwendungen mit hohen Volllaststunden übernehmen. Sobald die Wasserstoffinfrastruktur, bestehend aus Pipelines und Speichern, implementiert wurde, wird der Einsatz der Elektrolyseure sich wandeln, um Flexibilität für das Stromsystem anzubieten, in Kombination mit niedrigeren Volllaststunden.
Dies bedingt eine Lokalisierung der Elektrolyseure vor den Netzengpassstellen, um einen möglichst großen Effekt im Sinne der Flexibilität für das Stromnetz zu erzielen, aber insbesondere auch um die Gesamtsystemkosten zu reduzieren, indem Netzengpässe und Abregelung reduziert werden. Darüber hinaus ist es vorteilhaft, die Abwärme aus der Elektrolyse in Wärmenetze einzuspeisen und synergetisch in der industriellen Wärmeversorgung oder der Fernwärme zu nutzen.
Die Produktion von grünem Wasserstoff kann gegebenenfalls in der frühen Hochlaufphase nicht den Bedarf von Wasserstoffanwendungen vollständig abdecken, daher werden auch andere Pfade der Wasserstofferzeugung, wie treibhausgasarmer blauer Wasserstoff, benötigt, um in der Hochlaufphase eine adäquate Versorgung zu gewährleisten.
Die Versorgungssicherheit und damit der Einsatz von Wasserstofftechnologien hängen an der zügigen Implementierung von Transportinfrastrukturen für Wasserstoff. Im Zentrum steht dabei ein paneuropäisches Wasserstoff-Netz, welches ein robustes Element in allen berechneten Szenarien ist – selbst in dem Szenario mit minimalem Wasserstoffbedarf, in dem die Produktion von chemischen Grundstoffen nicht enthalten ist. Dieses paneuropäische Wasserstoffnetz verbindet die großen Potentiale der erneuerbaren Stromerzeugung im Norden und Süden Europas mit den Untergrundspeichern und den industriellen Verbrauchszentren in Zentraleuropa. Es erlaubt die Nutzung der günstigen Erzeugungskostenpotentiale für Wind und Fotovoltaik und ermöglicht einen flexiblen Ausgleich der Stromerzeugung aus erneuerbaren Energien über den Kontinent. Für die Transformation der europäischen Industrie hin zu einer Treibhausgasneutralität stellt die Etablierung eines paneuropäischen Wasserstoffnetzes eine notwendige Bedingung dar, um die gegenwärtigen Produktionskapazitäten der Grundstoffindustrie zu halten. Die Ergebnisse der Modellrechnungen zeigen, dass das paneuropäische Wasserstoffnetzwerk die Gesamtsystemkosten reduziert und wichtige Systemdienstleistungen bereitstellen kann.

Die Umwidmung von Erdgasleitungen auf Wasserstoff spielt eine zentrale Rolle in der Transformation des deutschen und europäischen Energiesystems. Die Forschung zeigt, dass potenzielle Netzwerktopologien mit hohen Anteilen an umgewidmeten Pipelines die Versorgungsanforderungen verschiedener Szenarien effektiv abdecken können. Der wettbewerbsfähige Import von Wasserstoff aus nicht-EU Staaten erfolgt ebenfalls über Pipelines. Zusätzliche Kosten für Schiffstransport über weite Entfernungen machen diesen weniger wettbewerbsfähig. Pipeline-gebundene Importe sind aus der MENA-Region möglich. Allerdings können Importe von Derivaten oder Zwischenprodukten wie Ammoniak oder Eisenschwamm wettbewerbsfähig zur europäischen Produktion werden. Ammoniak aus Regionen, die über keine Pipelineanbindung verfügen, kann als Wasserstoffträger eine früh zu implementierende Importlösung darstellen. Gegenwärtig existieren verschiedene Optionen, um Ammoniak nach Anlieferung am Hafen in das Energiesystem zu integrieren. Die Wahl der Direktnutzung von Ammoniak oder das katalytische Cracken in zentralen oder dezentralen Versorgungsstrukturen ist abhängig von der spezifischen Anwendung und deren Energiebedarf. Daher ist es notwendig, die Modellierungsansätze um die Ammoniak-Wertschöpfungskette zu erweitern, um die Nutzungsmöglichkeiten in der Energieversorgung evaluieren zu können. Die Nutzung von Wasserstoff im Stromsektor legt den Schwerpunkt auf seine zentrale Rolle als Speicheroption für intermittierende erneuerbare Stromerzeugung. Salzkavernen sind prinzipiell für die Speicherung von Wasserstoff geeignet und verschiedene Forschungsprojekte untersuchen deren Machbarkeit, z.B. im Energiepark Bad Lauchstädt. Eine ausreichende Menge an Speicherkapazität für Europa bereitzustellen, ist jedoch eine größere Herausforderung. Der Betrieb der Wasserstoffspeicher ist abhängig von zukünftigen Wasserstofflastprofilen.
Daher sollte zusätzliche Forschung die Untersuchung von zukünftigen Speicherprofilen in großen Untergrundspeichern umfassen.
Die Energiesystemanalyse kann genutzt werden, um die Interaktion verschiedener Elemente im Energiesystem zu beschreiben. Mit einer Analyse der Nachhaltigkeitsaspekte von Wasserstofftechnologien und -transportoptionen ergibt sich eine tiefergehende Ebene des Verständnisses der Energiewende und ihrer Auswirkungen, wovon einzelne Aspekte im Detail diskutiert werden. Eine großskalige Produktion von Wasserstoff mit PEM-Elektrolyseuren führt zu einem stark erhöhten Bedarf an Iridium, ein seltenes Element aus der Gruppe der Platinmetalle. Während Fortschritte im Hinblick auf eine Reduzierung der Iridiumbeladung für die Anode existieren, sehen Studien einen potenziellen Flaschenhals aufgrund der weltweit begrenzten Iridiumproduktion. Der zukünftige Iridiumbedarf hängt von Annahmen zur jährlich installierten Kapazität von PEM-Elektrolyseuren, der Lebensdauer der Stacks, der spezifischen Iridiumbeladung, Recyclingraten und der globalen Iridiumproduktion ab. Das Recycling von Iridium aus PEM-Stacks ist dabei zentral. Während angenommen wird, dass der Iridiumbedarf in 2030 seinen Höhepunkt erreicht hat, wird Recycling nach 2030 vorherrschend, was sogar zu einer Reduzierung von primärer Iridiumproduktion führen kann.

Table of contents

1

Introduction and objective

Climate change, caused by anthropogenic emissions of greenhouse gases, is a fundamental global challenge. Industrialised nations have caused the bulk of the historic emissions by extensive use of fossil fuels for various energy services. In fact, the global energy system is based predominately on the use of (fossil) fuels. If humanity stands a chance to mitigate the worst effects from global warming, swift action needs to be taken. In accordance to the Paris agreement, most nations have agreed on phasing out fossil fuels soon. The European Union adopted a target year of 2050 to reach greenhouse gas neutrality, while Germany has decided to reach this target in 2045.

The energy transition towards a more sustainable, defossilised energy system will see the replacement of some fuel-based applications, like space heating or mobility options by their respective electric variants. However, there are applications that might still rely on molecular fuels. Furthermore, transforming (fossil) fuel-based heavy industry is challenging due to the large number of highly specialised and optimised processes.

Hydrogen is a key molecule that provides the properties of a molecular fuel while at the same time demonstrates a versatile spectrum of application. It can be used to power transport options, substitute natural gas in space and industrial heating applications, provide energy storage for fluctuating renewable generation, allows for alternative production of iron and act as feedstock for the chemical industry.

For all its advantages, hydrogen is currently not widely used in the energy system. Partly because, as secondary energy carrier, it needs to be generated from other primary energy sources and partly because it represents some technical challenges in handling and transport. While it can readily be transported as compressed gas, its volumetric energy density is inferior to most fossil alternatives. Other transport options might also be considered, like LOHC (liquid organic hydrogen carriers), ammonia, methanol, liquid hydrogen, synthetic methane etc. None of these technologies has established itself as the universal option and each technology might have its part to play in the overall energy system. Each of these technologies will have a significant impact on the required infrastructure for import, transport, storage and distribution in order to guarantee security of supply.

The German flagship project TransHyDE aims to investigate and to further develop these technologies to reach market readiness within this decade. The TransHyDE Project System Analysis researches the interactions of these technologies and their implications within the transforming energy system in Germany and Europe. Our aim is to map out the role of hydrogen within possible pathways for the energy transition.

With this flagship publication we aim to present our research questions and methodologies as well as our first results to a wider audience. The document outlines our approach to analyse future development of hydrogen demand, development of supply, infrastructure and storage options. It addresses aspects of sustainability, importance of communication to ensure social acceptance, considerations of robustness of the results are also discussed. The energy transition is ever evolving in the political and technical sphere and we plan an ongoing yearly publication to feature the progress in our perception and description of the challenges and opportunities of the energy transition.

2

Hydrogen demand

2.1 Why do we need to better understand future hydrogen demand?

Climate-neutral hydrogen has the potential to significantly contribute to the decarbonisation of energy demand sectors, such as industry, buildings, and transport. It has the technical capability to replace fossil fuels in most applications and offers key advantages, including zero carbon emissions from combustion and a relatively high energy density compared to the direct use of renewable energies. However, technologies based on hydrogen are not the sole climate-neutral solution available and face competition from other technologies, such as direct electrification, based on cost and efficiency. Consequently, there is a wide range of expectations regarding the future role of hydrogen, leading to significant uncertainty in infrastructure and energy system planning.

This section examines the potential future role of hydrogen in the demand sectors industry, transport and buildings as well as the potential demand for electricity and central heat generation. We begin by discussing the competitiveness of hydrogen both between and within demand sectors particularly looking at the technology maturity. Based on this qualitative analysis, we estimate future hydrogen demands for Europe and Germany. The quantification is conducted through model-based scenario analysis, aiming to explore a diverse range of future hydrogen demands. Specifically, we focus on the rate of adoption of the individual technologies and the regional distribution across Europe, as these factors play a major role in determining the need for hydrogen transportation and production infrastructure. Finally, we put these overall modelling results into perspective by comparing with current market dynamics in so called "hydrogen valleys" in Germany and reflecting with the perspective and plans of stakeholders. The chapter primarily concentrates on hydrogen demand in the industry, transport, and buildings sectors, while hydrogen demands in the energy system, such as power and district heating sectors, are discussed in section 2.5.

2.2 Today's energy demand in industry, buildings and transport: What are the challenges for decarbonisation?

The transformation to a carbon neutral energy supply and use in industry, buildings and transport sectors is accelerating in Europe, but still faces major challenges. These challenges are related to the sectoral structure. Figure 2.1 puts the challenges into perspective of today's overall energy demand by application in these sectors.

Throughout Europe, the **industry** sector uses huge quantities of natural gas for process heating. Often at high temperatures in highly specialised furnaces that need very high energy densities to e.g. melt or heat metals and minerals at temperatures above 1,000 °C. Coal on the other side is mainly used in the steel industry in large quantities to produce crude steel from iron ore in blast furnaces. These furnaces require coal for operation and switching to alternative energy carriers involves use of alternative furnace technology to replace the blast furnace. Overall, energy demand for process heating in Europe was about 2,000 TWh in 2020. The chemical industry not only needs process heating, but also has a huge demand for fossil energy carriers as a resource (feedstock) to production processes. E.g. it uses natural gas to produce ammonia and naphtha (an oil-product) to high value chemicals, which are subsequently used e.g. for plastic production. In total, energy demand for chemical feedstocks was about 1,000 TWh in 2020 in the EU27+UK countries.

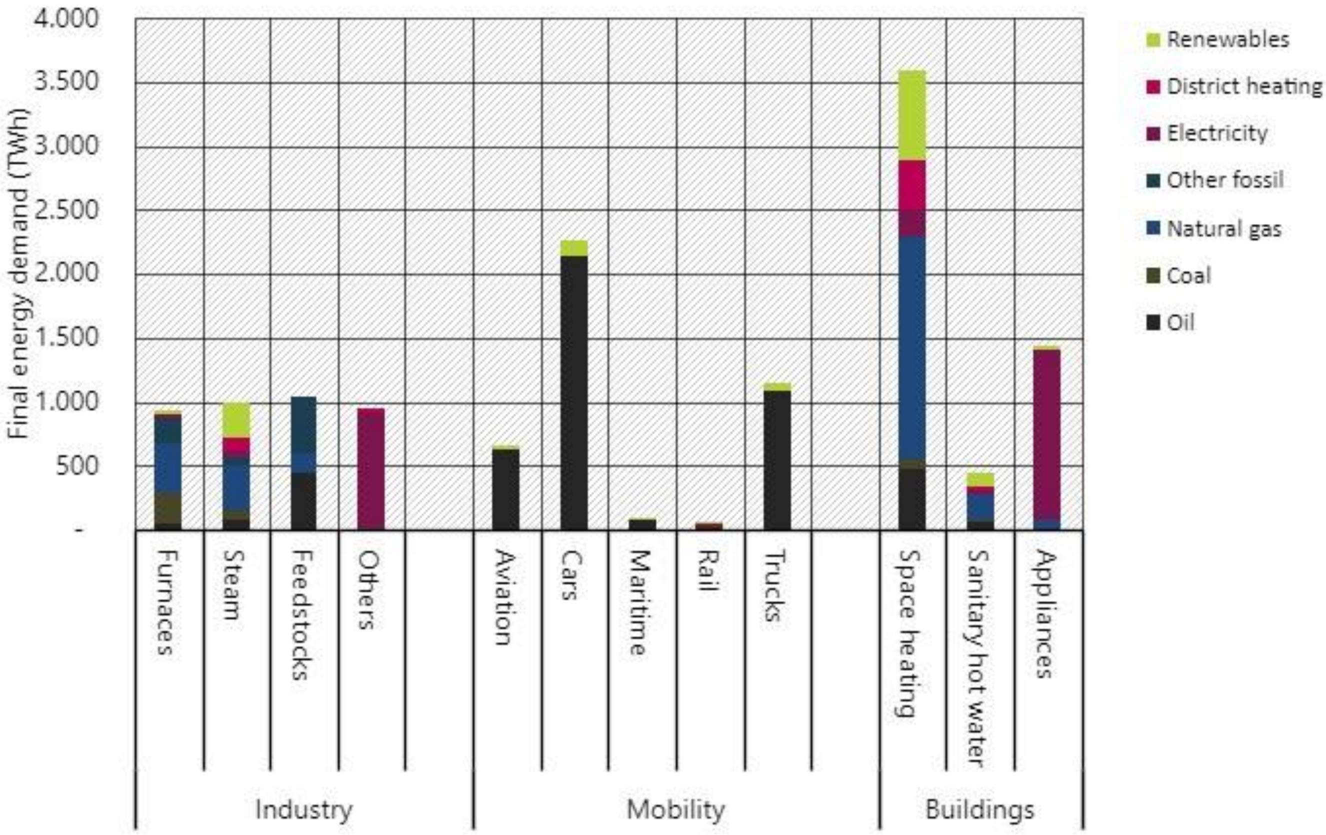

Figure 2.1: Energy demand in industry, transport and buildings in the year 2020 by energy carrier in the EU27+UK (Source: Fraunhofer ISI estimates based on Eurostat).

Energy demand for **transportation** of whatever transport mode is yet very dependent on various types of crude oil products in all European countries. Road transport including passenger cars but also trucks and busses completely dependent on fossil diesel and gasoline. Infrastructure and drivetrain technology are dominated by mineral oil-based fuels. Similarly, aviation and maritime transport are also depending on mineral oil-based fuels like kerosine or heavy fuel oil. Overall, the demand for crude oil products was about 4,000 TWh in the year 2020 in Europe.

Space heating in **buildings** is a major energy consumer throughout Europe. Its relevance and energy use vary across countries, but in total there is still a huge demand for natural gas and heating oil from this sector, which used more than 2,000 TWh of fossil fuels for space heating in 2020 in the EU27+UK. While the energy demand for space heating can technically relatively easily be replaced by renewable energies, a main challenge in the transition is the huge number of buildings and actors involved.

Overall, there are yet major challenges to decarbonising demand sectors. The next section discusses, in how far hydrogen can become a decisive solution to overcome the challenges and enable the transition to climate neutral industry, buildings and transport sectors by replacing parts of the still dominant use of gas, oil and coal in the various applications.

2.3. How can hydrogen decarbonise industry, buildings and transport?

Technologies to use hydrogen are under discussion in all three demand sectors, industry, transport and buildings for various applications and end-uses. In most applications, hydrogen competes with other climate neutral alternatives like direct electrification or use of biogenic energy carriers. The competitiveness of hydrogen depends on various factors including the technological maturity of hydrogen-based technologies and their competitors, the efficiency of the technologies and other factors like local storability, infrastructure needs and compatibility with the current system. These factors differ across the various applications. In this section, we discuss the possible role of hydrogen through all major applications in the three sectors. We particularly assess the technology readiness level (TRL) as major indicator of the technological maturity and compare with other climate neutral alternatives.

The potential uses for hydrogen in the demand sectors can be divided into two major types of applications: those in which hydrogen is needed as a feedstock due to its chemical properties, and applications where hydrogen as an energy carrier offers meaningful technical advantages but competes with other energy carriers like a direct electrification of biomass.

Table 2.1: Overview of hydrogen-based technologies in the demand sectors and their competing climate neutral alternatives.

Sector	Application	Hydrogen-based technology	TRL	Main competing climate neutral alternatives	TRL
Industry	Chemical feedstock for high value chemicals	Methanol to olefines process Fischer-Tropsch synthesis	7-8	Biomass-based processes	7-9
				Electrification not possible	-
	Chemical feedstock for ammonia	Haber-Bosch ammonia synthesis using climate neutral hydrogen	8	Electrification not possible	-
	Primary steel production	Direct reduction of iron ore	7-8	Electrification at low TRL	< 3
	Process heat: Furnaces at high temperature	Hydrogen-fired furnaces	3-6	Electric furnaces	3-9
	Process heat: Steam generation	Hydrogen-fired boiler or CHP	9	Electric boiler	8-9
	Process heat: Steam generation < 200 °C	Hydrogen-fired boiler or CHP	9	Electric boiler Electric heat pump (excess heat or geothermal) Solar thermal	9 (high-temp heat pumps 7-9)
Transport	Passenger cars	Hydrogen powered fuel cell electric vehicle	9	Battery electric vehicles	9
	Light- and heavy-duty road vehicles	Hydrogen powered fuel cell electric vehicle	Vehicle: 8-9 Refueling: 9	Battery electric vehicles	Vehicle: 8-9 < 350 kW Charging: 8 > 1 MW Charging: 6-7
	International & National shipping	Hydrogen based synthetic fuel	Fuel production and motors: 7	Biomass based fuel	Admixture: 8
	Short distance ferries and passenger ships	Hydrogen powered fuel cell	8	Battery electric ships (full electric vessels in small ferries and tug boats)	8
	International Aviation	Hydrogen based synthetic fuel	Fuel production: 6	Biomass based fuel	Admixture: 8
	National Aviation	Hydrogen based synthetic fuel	Fuel production: 6	Biomass based fuel	Admixture: 8
	National Aviation	Hydrogen direct combustion & Hydrogen powered fuel cell	5	Biomass based fuel	Admixture: 8
	Trains	Hydrogen powered fuel cell	8-9	(Overhead lines combined with) battery electric	8-9
Buildings	Space heating and hot water	Hydrogen-fired boiler or fuel cell	6-7	Electric heat pumps, district heating	9

2.4. Where is hydrogen irreplaceable?

In the first group of applications, hydrogen is required for its role in chemical reactions within the application. It is therefore difficult or impossible to replace with current technologies and will likely remain so in the medium-term based upon nearly-available technologies, unless the products themselves can be replaced. These applications are located primarily in the industrial sector and include several products that are key to many value chains, for example crude steel, ammonia, and high-value chemicals (HVC). A brief overview of the role of hydrogen in the transformation of these processes is presented in the following subsections.

Crude Steel

The first step in steel production is the reduction of iron ore. Around 70 % of German steel production proceeds as primary steel production via the blast furnace route. Within the EU total production amounted to 136 Mt in 2022, 56.7 % of which is produced as primary steel via the blast furnace route and 43.3 % produced as secondary steel. (The European Steel Association, 2023; Wirtschaftsvereinigung Stahl, 2022). Within the blast furnace, coke, iron ore and scrap are stacked and heated to more than 1,000 °C. Part of the coke and additional coal react with oxygen to product CO, which in turn reacts with the iron ore to CO_2 and iron (Harper et al., 2023).

Crude steel can also be produced by recycling scrap steel via the **secondary route**, most commonly in an electric arc furnace. The maximum share of secondary production is limited by the quality, availability, and collection chains of scrap steel (Bataille et al., 2018; Otto et al., 2017). Primary steel production will therefore remain necessary and will thus require a decarbonised process technology to replace the current blast furnace route.

Hydrogen-based direct reduction of iron ore (DRI) is forecasted as the technology most likely to replace the blast furnace route within Europe in the medium to long-term, with concrete plans for production plants taking shape (see section 2.8). Hydrogen is used as both a feedstock and an energy carrier in this process, reacting with the oxygen contained within the iron ore. In place of the carbon dioxide formed in the blast furnace route, in this reaction water vapor is formed. Direct reduction based on natural gas is also possible and is in use today, with a single **industrial-scale** plant located in Europe (Hamburg, Germany) (Albrecht et al., 2022). A flexible use of natural gas, hydrogen, and mixtures of the two is expected to offer a major advantage in the medium-term, when hydrogen supply might still vary and availability might be limited at certain times (Albrecht et al., 2022; Astoria, 2022). Thereby, it can mitigate uncertainties and economic risks, while also representing a key source of demand for the ramp-up of the hydrogen economy.

Ammonia Synthesis

Ammonia is one of the most-produced basic chemicals worldwide, with modern agriculture consuming around 80 % of global ammonia production due to its dependence upon ammonia-based fertilisers (International Energy Agency, 2019; Bazzanella et al., 2017). European production was approximately 11.2 Mt in 2021, including 2.3 Mt produced in Germany (Eurostat, 2023). Demand for ammonia is expected to grow for the foreseeable future, driven both by is continued importance for fertiliser production and potential new applications as a maritime fuel or as a vector for transporting hydrogen (Ausfelder et. al., 2022; International Energy Agency, 2019). The **synthesis of ammonia (NH_3) via the Haber-Bosch process** is a well-established process in use since the early 20th century. Prepared process gas is reacted at 450-550 °C under high pressures (150-350 bar) in the actual synthesis of ammonia from the hydrogen and nitrogen present in the process gas. This process is emission intensive and responsible for approximately 2 % of global CO_2 emissions, primarily because of producing the needed hydrogen via steam reforming (The Royal Society, 2020).

The Haber-Bosch process is expected to remain the main production process for future sustainable production of ammonia, but the required hydrogen and nitrogen can be obtained via routes which forego the emissions of conventional production (Ausfelder et al., 2022; Harper et al., 2023). The **Power-to-Ammonia** route sources hydrogen from electrolysis rather than steam reforming, and therefore also requires an additional air separation unit for the provision of nitrogen. These processes themselves produce no direct CO_2 emissions, but should be powered by renewable energy to ensure meaningful emission reductions. The technologies required for the Power-to-Ammonia route are individually mature and available, however industrial-scale production will require a major scaling-up of the production units, as well as experience operating them as an aggregate unit at scale to achieve efficient production at similar levels to the current process (Stevens, 2019). Although ammonia production itself produces no direct CO_2 emissions, downstream products such as urea and fertilisers will require a source of CO_2 to replace that currently available from the steam reformer used in conventional ammonia production.

High-value chemicals

So-called high-value chemicals (HVC) form the starting point of multiple value-chains in the chemical industry (Prognos, 2021) and comprise Ethylen, Propylen, Butadien and BTX. Ethylene and propylene are the main “target products”, while further valuable olefines and aromatics are formed as by-products. Ethylene in particular plays a major role in downstream industries, representing the building block for more than 30 % of all petrochemical products (Arnold et al., 2017). Plastics production (polyethylene and polypropylene) is one notable source of demand for HVCs. According to industry statistics, approximately 19.4 Mt of ethylene and 13.8 Mt of propylene were produced in 2021 in the 18 European countries included in the statistics (Petrochemicals Europe, 2023). German production was 5.2 Mt of ethylene and 3.6 Mt of propylene in the same year (Verband der Chemischen Industrie, 2023).

Current HVC production processes are petrochemical processes, one of many links between the chemical industry and refineries (Ausfelder et al., 2019; Stiftung Arbeit und Umwelt der IG BCE, 2021). To obtain the desired HVC, the chemical bonds of the long-chain naphtha molecules must be broken, or “cracked”, at high temperatures in a **steam cracker** to obtain the desired short-chain molecules (Ren, 2006). The target products, such as ethylene and propylene are collected, while many by-products are returned for further cracking (propane) or used as fuel for the process (methane) (Ren, 2006).

One option for the transformation of HVC-production is **direct electrification of the steam cracker**. The fossil-fired furnace of the conventional steam cracker must be replaced by electrical heating elements capable of achieving the high temperatures required in the process. The first large-scale demonstration unit is currently under construction in Ludwigshafen, Germany (BASF, 2022). A switch to electric steam-cracking, however, does not per se mitigate fossil-CO_2 that is embedded in the resulting chemical products and will remain there until it is released to the atmosphere at lifetime end of final products. In many cases this release happens in waste incineration plants.

Another pathway for sustainable production of HVC is the replacement of conventional naphtha with **synthetic naphtha**. Produced for instance from green hydrogen via the Fischer-Tropsch process, synthetic naphtha could be cracked in conventional or electric steam crackers without significant adjustment to the process. This could minimise the new investments needed in the chemical industry, but would require major adjustments to the processes and business models of refineries and needs significant quantities of climate neutral hydrogen.

A further potential pathway for sustainable HVC production is offered by the **Methanol-to-Olefins (MtO) and Methanol-to-Aromatics (MtA)** routes. A variety of proprietary process exist for the synthesis of olefins and aromatics from methanol via catalytic reactions (Harper et al., 2023). Such processes are currently used in China to synthesise olefins via methanol produced from coal (Agora Energiewende, 2019). This does not offer an advantage over conventional steam cracking in terms of emissions reduction. If significant emissions reductions are to be achieved via the MtO and MtA routes, sustainable methanol production via the use of climate-neutral hydrogen and a sustainable source of CO_2 or via the gasification of biomass will be necessary. Similar to the production of synthetic naphtha, this would require large amounts of climate neutral hydrogen.

Although hydrogen is considered a vital component of the industrial processes discussed above and is therefore widely considered to face minimal or no competition from other technologies within a given process, this does not mean competition will not exist. Instead, competition here is expected to emerge between companies or regions in the application of hydrogen-based production routes. Companies able to successfully develop a competitive proprietary technology or regions capable of applying the discussed technologies at lower costs will play a major role in determining future production locations of these products. In turn, the spatial distribution of hydrogen demand at global and regional levels will also be determined by this competition, and hydrogen demand at any given location should not currently be considered set in stone.

2.5. Where will demand for hydrogen be determined by technological competition?

Whereas the applications discussed above are nearly assured to see increased demand for hydrogen (and/or its derivatives), with competition rather occurring among companies or countries using the given technology, in many areas it is still unclear if hydrogen will be competitive compared to other solutions like direct electrification or biofuels. These applications are discussed in the following including the generation of electricity and district heating as well as the supply of low temperature process heat, transportation and space heating in buildings.

Conversion sector: Power plants and district heating supply

Hydrogen may play an important role in the conversion sector due to its potential for long-term storage. Stored hydrogen can be converted into electricity, particularly during periods of reduced availability of solar and wind resources, commonly referred to as the 'dark lull' (Dunkelflaute). Beyond questions of cost-optimal supply, hydrogen-fired power plants and CHP units will also improve security of supply of a future energy system that is heavily dependent on wind and solar generation.

Process heating in industry

Process heating is a main source of CO_2 emissions in industry, particularly in the basic materials industries like steel, chemicals, cement or glass and paper. In most sectors it is dominated by use of natural gas, while also coal and biomass play a certain role. The specific requirements and technical layout are very much tailor-made according to the needs of the production processes. Still, two main segments of applications can be distinguished for the analysis. While large parts of process heating in industry require high temperatures and energy densities with high feasibility for hydrogen, there is also a large segment of rather low temperature process heat that is provided in the form of steam or hot water. Both segments are discussed in the following.

For **high temperature process heating** individual furnaces are used that differ across industries and are optimised according to specific process needs. They typically need very high temperatures above 1,000 °C combined with high energy densities, which are in many cases challenging direct electrification. However, competition between hydrogen and electrification needs to be decided on process level. Many processes that use natural gas today can relatively easily switch to hydrogen by replacing the burner and adjusting furnace operation (Neuwirth et al., 2022). At the same time, demonstration projects are still needed to ensure product quality and long-term operation. Processes that use solid fuels today require more comprehensive modifications to switch to hydrogen. Switching to electrification might require more substantial rebuilding of entire plants than the use of hydrogen (Fleiter et al., 2023a). On the other side, there are also processes where electrification is already used today like inductive heating in metals processing or glass melting. However, these applications are mostly rather small scale. Overall, hydrogen will be an attractive solution for many high temperature process heating applications e.g. in metals manufacturing or in glass and ceramics production. In some processes, direct electrification, however, might be more competitive. Overall, the local availability of infrastructure and the supply cost will be very decisive factors.

Low temperature process heating is supplied in the form of steam or hot water and needed a lot in pulp and paper, food and chemical industries. This segment is relatively simple to electrify using electric boilers, which are available at industrial scale. Even more efficient electrification is possible in the temperature range up to 150 °C or potentially 200 °C in the near future by using industrial-scale electric heat pumps. Hydrogen-fired steam boilers are also available with high technology maturity. They can compete with electrification if hydrogen will become available soon at competitive prices. The choice between hydrogen and electrification might be made at site level, depending on the local situation.

Road Transport

In road transportation **hydrogen powered fuel cell vehicles** are to some extent competing with battery electric vehicles. The main advantage of hydrogen is the higher gravimetric energy density compared to batteries, leading to a higher range as well as fast refueling process (minutes instead of hours) leading to better utilisation rate of vehicles. Both technologies – battery as well as hydrogen technologies have been advancing in big steps in the recent years, the discussion is switched from a feasibility based to an economical one. For passenger vehicles and light duty vehicles (< 3.5 t) direct electrification using battery electric vehicles are widely seen (TRL 9) as the more efficient and economical option (DeWolf & Smeers, 2023).

For road transport applications with high mileages and heavy load, like heavy duty trucks the discussion is still going whilst very much depending on the infrastructure and price assumptions. A shift to battery electric models for long haul trucks has been observed in recent years. In case hydrogen will be widely available at low prices and required infrastructure, costs being low, **hydrogen fuel cell trucks** (TRL 8-9) can compete with battery electric ones (TRL 8-9). Still direct electrification of heavy-duty trucks faces challenges such as power demands up to 2 GW and therefore upgrades from medium voltage (MV) to high voltage (HV) systems. But the transition to hydrogen also involves considerations about energy density, standardisation (350 bar or 700 bar), and the availability of a comprehensive distribution network (tanker trucks, pipelines, or on-site electrolysis) and ramp up of hydrogen refueling stations (TRL 8) (DeWolf & Smeers, 2023).

Aviation and maritime transport

Hydrogen and its derivatives are also seen as one of the few potential solutions in several applications in the transport sector, alongside biomass-based sustainable fuel solutions. While potential for direct electrification exists in short-distance travel (for example, small commuter planes or ferries and small passenger boats), large technological advancements will be needed before the electrification of **long-distance travel and large freight transport** will be possible (Clean Air Task Force, 2021; Det Norske Veritas, 2021; International Transport Forum, 2018). In both aviation and maritime applications, the trade-offs between energy density and onboard storage limit the potential of direct electrification for defossilisation.

In aviation, the comparatively low gravimetric energy density of **electric batteries** means the necessary battery size for larger aircraft and longer distances brings unacceptable additional weight. While battery technologies continue to improve, electrification of commercial aircraft is not seen as feasible before 2050, with the exception of small aircraft traveling relatively short distances (McKinsey & Company, 2020; Searle, 2019). The direct use of hydrogen for short-distance flights (< 1500 km) is feasible, where its limited volumetric energy density compared to kerosene is less of a constraint, but the technological readiness of hydrogen aircraft is in an early stage (TRL 5). In particular, hydrogen turbines and solutions for onboard storage of hydrogen must be developed further (McKinsey & Company, 2020). Airbus aims to develop three types of hydrogen airplanes by the end of 2030s, but even if successful, their integration into the market will take time (McKinsey & Company, 2020). The use of hydrogen in long distance flights will require newly designed planes, with development projected in 2020 to take 20 years or more (McKinsey & Company, 2020). Research into aircraft design and feasible ranges is ongoing (Onorato et al., 2022).

Consequently, to achieve fossil-free flights in all distance categories by 2050, the major focus of the industry has been on the development of alternative fuels with comparably high energy densities, collectively known as **sustainable aviation fuels (SAFs)** (Clean Air Task Force, 2021). Whereas both direct electrification and the use of hydrogen as fuel would require redesign of conventional aircraft and infrastructure, SAFs are considered a drop-in solution compatible with existing technologies (International Air Transport Association; McKinsey & Company, 2020). Both biogenic- (TRL 8) and hydrogen-based (TRL 6) SAFs are certified for use, and competition between technologies can be expected. However, overall availability of biomass feedstock and regulatory constraints of what may be considered sustainable present hurdles to the scaling of biogenic fuels that are faced to a lesser extent by hydrogen-based fuels (O'Malley et al., 2021).

While battery powered **ferries and passenger ships** are feasible for shorter distances (TRL 8), the space that would be required for batteries capable of powering large maritime ships would lead to unacceptable loss of cargo space, as well as being extremely costly (Det Norske Veritas, 2021; International Transport Forum, 2018). **Hydrogen** can be used as an alternative fuel in this sector, with first hydrogen powered vessels entering service as ferries (Lohse, 2023) and in domestic shipping in recent years after (Binnenschifffahrt Online, 2023). Potential for the use of hydrogen also exists in long-distance maritime shipping, but as with long-distance aviation, first requires significant technological advancements in the design of propulsion systems and the construction of new fueling infrastructure (TRL 7). For **longer shipping routes**, hydrogen's low volumetric energy density compared to conventional fuels (8.5 GJ/m^3 for liquid hydrogen versus 36.6 GJ/m^3 for marine gas oil) remains a challenge (IRENA, 2021).

Ammonia (TRL 8) and methanol (TRL 8) have both received significant attention from the shipping industry as potential alternative fuels and can both be produced using (green) hydrogen. Both offer technical advantages over the direct use of hydrogen, such as requiring less storage space via higher volumetric energy densities than hydrogen and better compatibility with existing ship motors or relatively simple retrofits (IRENA, 2021). As both are already traded globally, infrastructure for their storage is already (at least partially) available in some dedicated ports; methanol would be compatible with existing fueling infrastructure as well. Despite concerns about ammonia's toxicity and potential NO_x pollution from incomplete combustion, decades of global transport as a commodity provide experience in its handling. While methanol does not come with such toxicity concerns, ammonia offers a potential cost benefit over methanol, as its production does not require a source of CO_2 and no CO_2 is emitted when combusted.

Just like in aviation, the shipping industry can use bio-based and hydrogen-based fuels as direct replacements for current fuels, but these options have similar challenges to sustainable aviation fuels (SAF). Producing alternative fuels like ammonia, methanol, or synthetic fuels from hydrogen increases the need for hydrogen and renewable electricity. It also brings extra costs with each step of processing. How much these hydrogen-based fuels will be used in the future mainly depends on their availability and cost. However, industry forecasts suggest that all these types of fuels will be part of the maritime sector's fuel mix moving forward (International Transport Forum, 2018; IRENA, 2021).

Space heating in buildings

H_2-ready technologies are available for both heating technologies for buildings and for district heating. For decentralised heating (heating of individual buildings not connected to district heating networks), modern heating units can utilise natural gas/hydrogen mixtures, although some further technological development is still required before these systems can operated with pure hydrogen. Technologies for pure hydrogen are currently being tested and certified (British Gas, 2023; Viessmann, 2023). A small-scale test is underway in the context of the TransHyDE Project Safe Infrastructure (H2Direkt), in which 10 households and a business are being supplied with hydrogen via a repurposed natural gas network in Bavaria (Bundesministerium für Bildung und Forschung, 2023). For such decentralised solutions, competition is primarily with electric heat pumps. As mature technology capable of making use of ambient heat from air, water, or ground sources, heat pumps already have high market shares, and the market is scaling up quickly in many European countries. They are proven to operate efficiently both in new and/or low-energy-demand buildings, as well as in existing buildings. The deciding factor is the required heating circuit temperature which depends on the specific heat demand of the building as well as the surface area of the heat exchangers. Operational limits of heat pumps mostly allow serving the typical supply temperatures in existing buildings, with some outliers where high temperature heat pump, secondary heating system or retrofit of the heat transmission system to lower supply temperature may be needed (Lämmle et al., 2023).

Centralised heating refers to heat generation in large plants, which is then distributed to households via district heating networks. Here, H_2-ready technologies compete with other renewable energy sources such as ambient heat through large-scale heat pumps (TRL 9, for example in Vienna), biogas and biomass (TRL 9, for example in Berlin) (Bundesverband Wärmepumpe, 2023; Forschungsgesellschaft für Energiewirtschaft, 2022; Vattenfall, 2023; Wien Energie, 2022).

The energy efficiency of hydrogen-based heating system roughly results in 60 %, when an electrolysis efficiency of 70 % and the average hydrogen boiler efficiency of 85 % are combined. Compared to heat pumps with a moderate coefficient of performance (COP) of 3-4, electricity demand for hydrogen-based heating systems is at least five times higher. Thus, hydrogen technologies for heating buildings are much less energy efficient than heat pumps or other available options, which is a major disadvantage for their economic competitiveness (International Energy Agency, 2022). Hydrogen, on the other hand, has e.g. advantages in terms of storage and supply outside Germany or the EU.

Independent analyses that have been conducted so far show that using hydrogen for heating homes comes at higher energy system costs and higher running heating costs for consumers when compared to other technologies that deliver decarbonised heating such as heat pumps or district heating. Whether or how much these costs will change over time is uncertain (Rosenow, 2022.) On the other hand, hydrogen use in complementary applications could be viable, such as serving peak demand in hybrid systems in areas where infrastructure is being built due to local hydrogen production or relevant industry sites (LCP Delta, 2023.)

Converting the existing natural gas distribution infrastructure to a hydrogen-compatible state depends on the physical feasibility of around 5 % of the pipelines and also on the hydrogen production sites. Technically, however, the adjustments are moderate, and the associated cost-estimates for the current network of around 550,000 km are about 15 billion Euro. When and where hydrogen will be available in the gas distribution network is not yet known, which makes it difficult to plan the optimal heating solutions. Nevertheless, planning for the conversion of the gas distribution network to hydrogen is already being driven forward by the distribution network operators with the gas network transformation plan (Gasnetzgebiets-transformationsplan GTP).

Overall, the future use of hydrogen for decentral supply of space heating in buildings is very uncertain, while it is already clear that the potential role will be substantially smaller than it is for natural gas today.

2.6. Energy system perspective: What hydrogen demands do we expect by 2030, 2040 and 2050?

Method and scenario definition

The following quantification of future hydrogen demand scenarios is a condensed summary of modelling analyses. An extended version with detailed description of method and input and results data is available in Fleiter et al. (2023b). We use an energy system toolbox that allows modelling the European energy system with a very high spatio-temporal resolution (see Figure 2.2).

In a **first step**, detailed sector models are used to develop alternative pathways for the uptake of hydrogen demand in the respective sectors, industry, transport and buildings. They feature a very high level of detail and consider market dynamics by simulating technology competition via total cost of ownership approach extended with behavioural parameters. All demand models simulate technology competition and investment at the national level for EU27+UK countries and calculate energy demand for each year until 2050. The resulting national level energy demand is disaggregated to individual NUTS-1 regions to improve spatial resolution. For Germany, data availability allows an even higher NUTS-3 resolution.
In a **second step**, the resulting energy demand is used by the Enertile system model to calculate least-cost energy supply (see section 3). The optimisation does include the main infrastructures of the European energy system (generation, transmission and transport, storage), whereas hydrogen (and other energy) demands are considered as fixed inputs resulting from step one.
We define **three main scenarios** which encompass a spectrum of future hydrogen demands. The scenarios are based on the same boundary conditions and assumptions ensuring maximum comparability and allowing the isolated evaluation of the impact of additional hydrogen demand on the energy system. All three scenarios exhibit a comparable level of ambition and achieve climate neutrality by the year 2050 in the EU. Table 2.1 provides an overview of the definition of the three scenarios for the demand sectors industry, transport and buildings. The scenarios build on each other and describe an increasing hydrogen demand from *Low_Demand* to *High_Demand* by gradually switching more end-uses to hydrogen.
The **scenario Low_Demand** is defined by assumptions that result in a low hydrogen demand. Here, hydrogen is mainly used in the industrial sector for process heat, where electrification is difficult due to high temperatures and energy densities. Further, it is assumed that selected very energy-intensive intermediate products (sponge iron, ammonia, methanol) are mostly imported from non-EU countries. Consequently, large potential users do not or only hardly demand hydrogen. However, they need large quantities of hydrogen derivatives like climate neutral ammonia or methanol. In buildings, there is no demand for hydrogen or its derivatives. Electric heat pumps increase from 5 % of heat supply to 60 % by 2050. In transport, hydrogen is used marginally in trucks and on a large scale as synthetic fuel for aircraft and ships. Electric vehicles diffuse fast and widely. Electric passenger cars account for about 100 % of the car fleet by 2050.
The **scenario Mid_Demand** builds on scenario *Low_Demand*, but differs in the industrial sector. In *Mid_Demand*, steel, ethylene (and other olefins), methanol and ammonia are produced in Europe based on hydrogen.
In **scenario High_Demand**, a broader diffusion of hydrogen-based technologies is considered in all three demand sectors: Industry, transport and buildings resulting in a higher demand for hydrogen. Still, the scenario aims for a realistic role of hydrogen in competition with alternatives, mainly direct electrification. It does not reflect a technical maximum, but an ambitious diffusion of hydrogen technologies in all demand sectors. In industry, hydrogen is also used to supply low-temperature process heating that is predominantly electrified in scenario *Mid_Demand*, mainly steam generation. In the transport sector, in 2050 about 40 % of the long-distance truck freight transport is driven by fuel cells with the remaining 60 % using direct electrification with batteries. For passenger cars, hydrogen propulsion remains a niche in scenario *High_Demand*, and electric passenger cars dominate the fleet. In buildings, hydrogen-powered heating systems also play a role in some segments, while electric heat pumps still dominate the stock of heating systems installed. The scenario design is summarised in Table 2.1.

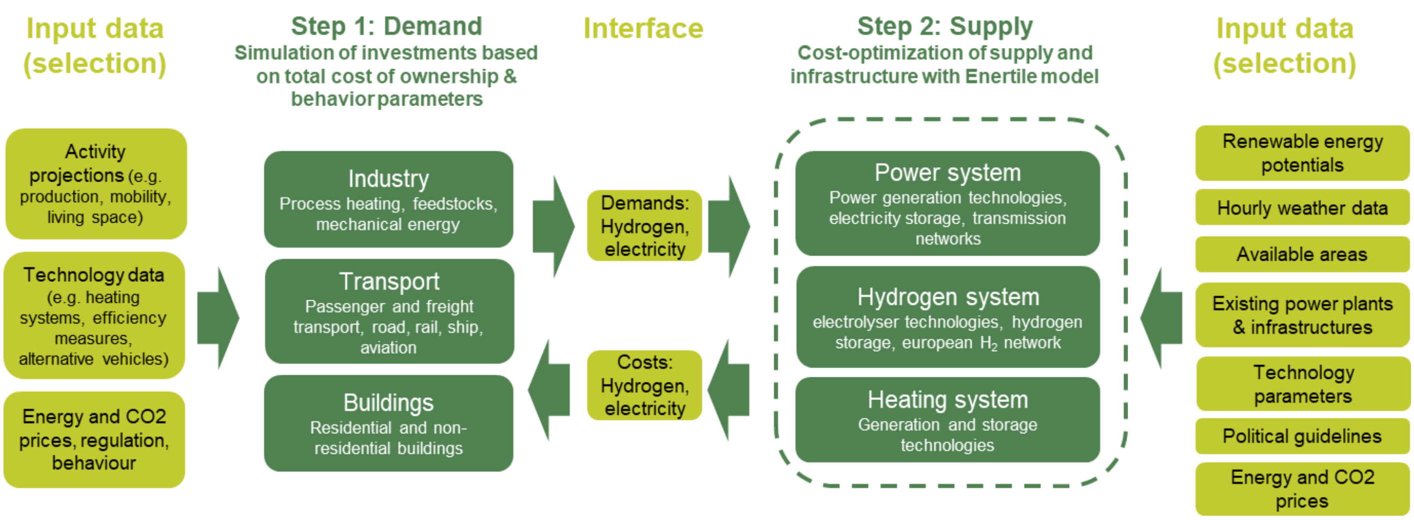

Figure 2.2: Simplified overview of model setup and input data.

Table 2.2: Definition of five scenarios by sector (Source: Fleiter et al. (2023b)).

Scenario	Summary	Industry	Transport	Buildings
Low_Demand	H_2 focused for process heat plus derivatives/synfuels for chemicals and maritime and aviation transport	High temperature process heat supplied by H_2 Import of green energy-intensive basic materials like iron sponge, ammonia and methanol from Non-EU	Electrification of passenger cars, busses and trucks Synfuels for maritime and aviation	No direct use of H_2 nor derivatives in buildings
Mid_Demand	Focus H_2 in chemicals and steel and synfuels in maritime and aviation transport	=*Low_Demand* plus domestic H_2-based production of green steel and chemicals	= *Low_Demand*	= *Low_Demand*
High_Demand	H_2 in all sectors incl. industry, transport and buildings	= *Mid_Demand* plus broad use of hydrogen for process heating including steam generation	= *Low_Demand*, but H_2 also for of long-range trucks (40 %)	= *Low_Demand*, but H_2 for decentral building supply

Scenario results

In the analysis of results, we will focus on overall EU27+UK figures, but also discuss results for Germany as focus country in the analyses. Resulting energy demands from industry, buildings and transport sector are summarised in Figure 2.3 This includes both final energy demand and feedstocks used to produce chemical products like high value chemicals or ammonia. Figure 2.4 zooms into resulting hydrogen demands including its derivatives. These figures also show demands from the conversion sector for power and district heating generation to provide a complete picture. However, details about the supply side of the energy system are discussed in section 3. The regional distribution is shown for scenario *Mid_Demand* for EU27+UK and Germany. A more detailed analysis of results is available in Fleiter et al. (2023b).

The energy demand of EU27+UK accounted to about 13,600 TWh in 2020, the base year of the analysis. All three scenarios show a substantial reduction of total energy demand towards 2050 ranging between 31 and 35 %, mainly driven by efficiency gains in transport and buildings. **Electricity demand** is sharply increasing and growing by a range of 44 % to 74 % across all scenarios. Scenario *Low_Demand* shows the highest increase with additional 1,900 TWh/a by 2050 compared to 2020. Even scenario *High_Demand* with the highest share of hydrogen in all demand sectors experiences a strong increase in electricity use. By 2050, electricity demand is ranging between ~3,700 to ~4,400 TWh across the scenarios. The role of **hydrogen** gets more important from scenario *Low_Demand* towards scenario *High_Demand* and mainly competes with electrification and biomass. Scenario *Low_Demand* includes about 300 TWh of gaseous hydrogen by 2050 (not accounting for its derivatives and synfuels). However, in this scenario, the EU27+UK imports large quantities of CO_2-neutral methanol, accounted for as synfuels in Figure 2.3. Total demand for such and other synfuels is about 1,350 TWh by 2050 in scenario *Low_Demand*. In other scenarios it ranges between 600 and 700 TWh and is mainly used for long-distance transport. Other important energy carriers in 2050 are **ambient heat**, **biomass**, and **district**

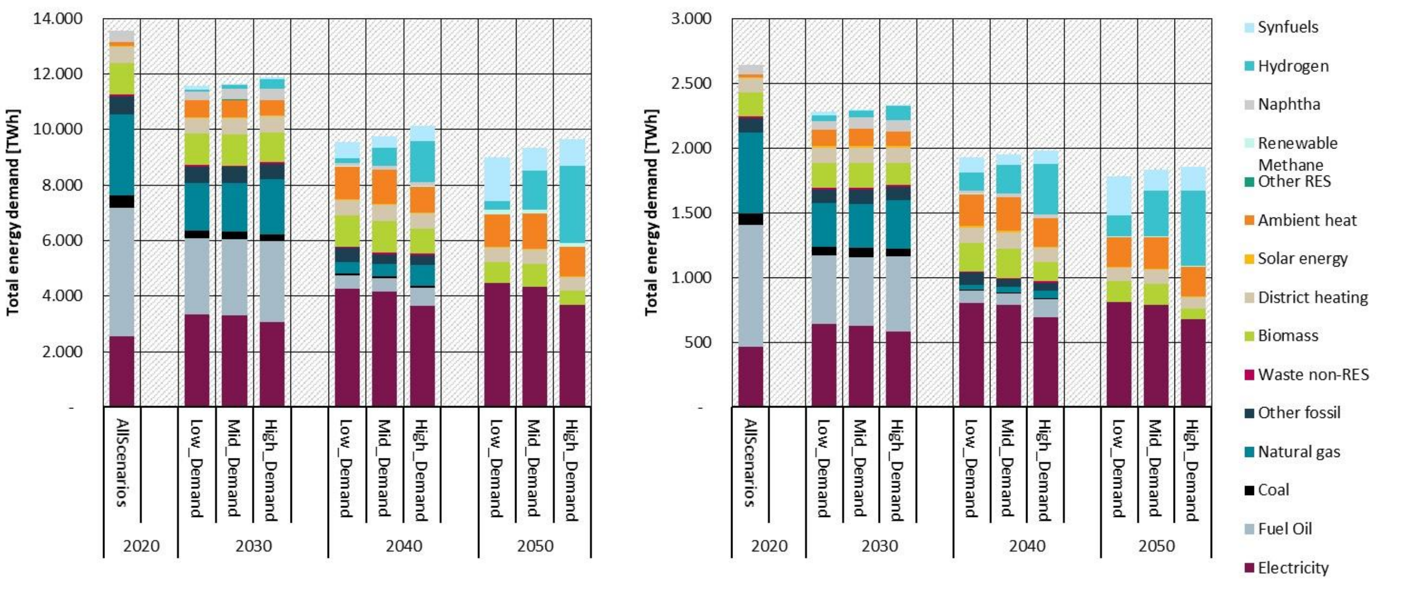

Figure 2.3: Final energy demand plus feedstocks for chemicals, EU27+UK (left) and Germany (right) in industry, buildings and transport sectors (based on Fleiter et al. (2023b)).

heating. Ambient heat is used in heat pumps in the buildings sector and biomass supplies some industries where biogenic production residues are used.

Zooming into resulting hydrogen demands, Figure 2.4 gives insights from which sectors and applications the demand is coming. Here, we show the complete hydrogen demand by adding the conversion sector (i.e. the central production of electricity and heat) on top of the final energy demand and feedstocks shown in Figure 2.3. The scenarios show a huge difference in long-term hydrogen demand and range from 690 to 2,800 TWh direct hydrogen use by 2050. The additional synfuels/derivatives demand ranges from about 820 to 1,570 TWh by 2050. Looking at the individual sectors and end-uses reveals that across all scenarios, industry will be the most important user, however, with varying patterns across the scenarios.

Industry sector: There is a relatively robust demand of about 190 (*Low_Demand*) to 315 TWh (*Mid_Demand* and *High_Demand*) for **high temperature process heat** demand in the industry sector. It is located in metal and mineral processing, where highly specialised furnaces are operating at high temperatures and high energy densities. The main energy carrier in these processes today is natural gas. Electrification can be possible in the future, but also still faces major challenges and requires substantial reinvestment.

The future value chain of climate neutral basic chemicals can be a major game changer for the hydrogen demand. If **chemical feedstocks** are fully produced in Europe based on climate neutral hydrogen, this will become the main hydrogen use with about 1,000 TWh of hydrogen demand by 2050 in this segment (*Mid_Demand* and *High_Demand*). This assumes high-value chemicals (HVCs), methanol and ammonia are produced from climate neutral hydrogen in Europe, replacing naphtha and natural gas as main **chemical feedstocks**. If, however, the global value chain for these basic chemical products will materialise in a different way and large quantities of climate neutral interim products like methanol, ammonia or ethylene are imported instead of produced within the EU, overall (gaseous) hydrogen demand can drop to a minimum of 700 TWh by 2050 as total across all sectors (*Low_Demand*). Thus, the future climate neutral value chains of a few basic chemical products will highly affect the overall hydrogen demand in Europe. At the same time, it is yet very uncertain, how these value chains will evolve in the future.

On the other side, if also **industrial steam generation** will use large quantities of hydrogen, instead of direct electrification, this can add another 400 TWh by 2050 (*High_Demand*). Here, hydrogen will mainly replace direct electrification via electric boilers, which are already available and applicable at industrial scale, but depend on competitive electricity prices.

Transport sector: Scenarios *Low_Demand* and *Mid_Demand* hardly have any direct use of hydrogen in transport despite domestic flights that account for about 60 TWh by 2050. Other transport modes like electric cars and heavy-duty vehicles are dominated by direct electrification. Synfuels based on hydrogen, however, play an important role in international aviation and shipping with a total of about 450 TWh by 2050 (see Figure 2.4). Main uncertainty in the transport sector is in the competition between electrification and hydrogen in long-haul trucks. Here, the scenario *High_Demand* shows an additional hydrogen demand of about 380 TWh by 2050, when 40 % of long-haul trucks are driven by fuel cells. This is driven by assumptions on cost of hydrogen, batteries and fuel cells that are more in favour of hydrogen systems, while scenarios *Low_Demand* and *Mid_Demand* use parameters more in favour of transport electrification.

Buildings sector: Also, for heating of individual buildings, hydrogen is under discussion in some member states. If hydrogen becomes available in the distribution grid and can compete economically with electric heat pumps and district heating, it can add a substantial demand. Under our assumptions in scenario *High_Demand*, it is 760 TWh of additional hydrogen demand by 2050, still considering that the heat supply of buildings will be dominated by heat pumps.

Enertile, an energy modelling tool, was used to assess the endogenous hydrogen demand of the **conversion sector**, comprising power and district heat supply, for 2030 and 2050 scenarios. An observed pattern is that the hydrogen demand of the conversion sector is inversely related to the exogenous demand in other sectors, including transport, industry, and tertiary. In 2030, the conversion sector's hydrogen demand varies between 100 TWh in the *Low_Demand* scenario and 28 TWh in the *High_Demand* scenario. By 2050, this range widens to 391 TWh and 61 TWh, respectively.

This inverse relationship is attributed to the higher availability of lower-cost renewable electricity, specifically solar PV and wind power, when the hydrogen demand in other sectors is lower. This enables the model to produce lower cost hydrogen, utilise it as storage, and later convert it into electricity or heat.

Additionally, the *High_Demand* scenario features a higher installed capacity of renewable energy generation. This greater renewable capacity provides more options to meet overall demand, lessening the reliance on hydrogen as a backup fuel source. Accordingly, the hydrogen demand in the conversion sector is lower in this scenario. These findings emphasise the important role of hydrogen as a seasonal energy storage mechanism for the conversion sector.

By 2030, total gaseous hydrogen demand for **EU27+UK** ranges between 160 and 370 TWh, which makes up 12 to 23 % of the 2050 demand. Given the uptake of needed infrastructure, this can be considered optimistic already. Most important demand sectors by 2030 are industry and the energy conversion sector. In addition, the scenarios assume a demand of 37 TWh of synthetic fuels based on hydrogen by 2030. In total, this demand is substantially below the 2030 target announced by the EU in its REPowerEU (European Commission 2023) plan of about 665 TWh of hydrogen demand and its derivatives (equals 20 million tons of H_2). In this context, **Germany** plays an important role in the future hydrogen system as a potentially large consumer when basic material industries like steel and chemicals convert to climate neutral production. The resulting hydrogen demands across the sectors and scenarios show similar pattern for Germany as observed for the EU27+UK (see Figure 2.4).

The **regional demand patterns for hydrogen** exhibit variations across different scenarios and sectors of usage (see Figure 2.5). The utilisation of hydrogen differs significantly depending on the specific sector structure within each region. If basic green materials like iron

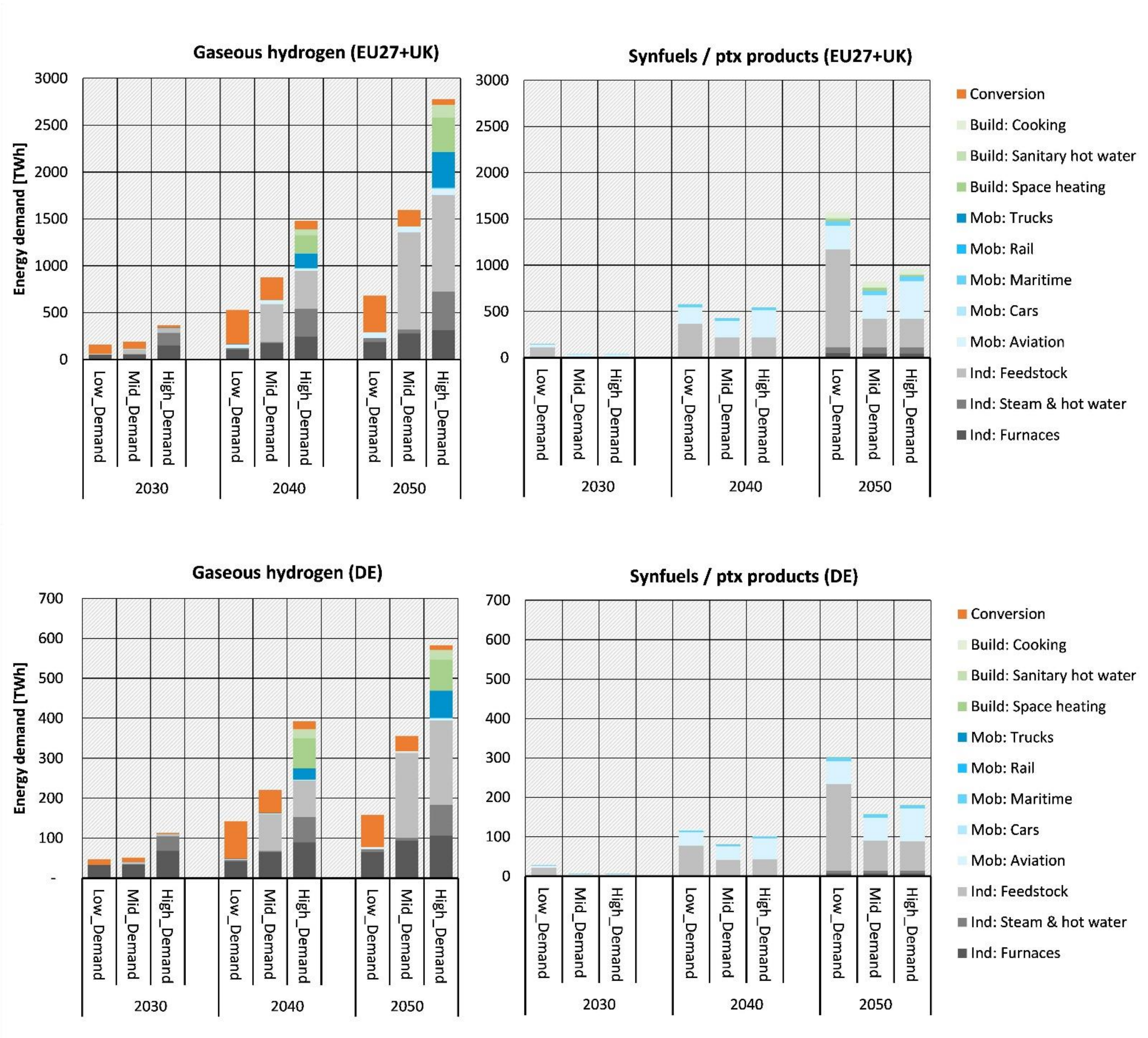

Figure 2.4: Hydrogen (left) and synfuels (right) demand from industry, buildings, transport and conversion sector, EU27+UK (top) and Germany (bottom) (based on Fleiter et al. (2023b)).

sponge, ammonia, methanol and high-value chemicals, are produced at their current locations as assumed in scenarios *Mid_Demand* and *High_Demand*, several regions will create a substantial demand for hydrogen, surpassing 10 TWh by 2050. This indicates a significant requirement for hydrogen in these regions. Particularly, the chemical/steel cluster in Northwest Europe stands out as a hotspot, with three regions displaying a demand exceeding 100 TWh for hydrogen. These regions are North-Rhine Westphalia in Germany (124 TWh), West Netherlands (139 TWh), and North of Belgium (Flanders) (103 TWh). The demand for hydrogen in these regions is primarily driven by the transformation towards hydrogen-based green basic materials. This includes the transition of integrated steelworks to DRI, steamcrackers to Methanol-to-Olefins (MtO), and the adoption of green hydrogen as a feedstock for ammonia production. One additional factor contributing to concentrated hydrogen demand is its use in industrial process heat, which is primarily concentrated in a few regions. In the scenario *High_Demand*, the usage of hydrogen in the transport and buildings sectors contributes to a more widespread demand across most regions. Still, the regions with heavy industries showcase the highest demand. This hydrogen demand pattern with large consumers in NW-Europe is an important driver for the transport corridors as shown in section 3.7.

For Germany, the analysis considers a higher granularity with about 300 regions distinguished to allow more specific analyses of hydrogen transport needs within the country. The modelling results show clear hot-spots in industrial clusters for scenario *Mid_Demand*, with the highest concentration in North-Rhine Westphalia. However, many demand centres are spread across the entire country following individual sites from (petro-) chemicals and steel industries. By 2030, results mainly forecast demands of more than 1 TWh in regions where primary steel production started to switch to direct reduction of iron ore (DRI). In the long-term, by 2050 or 2045, many regions showcase a demand of more than 1 TWh, now also including today's locations of basic chemicals and refineries.

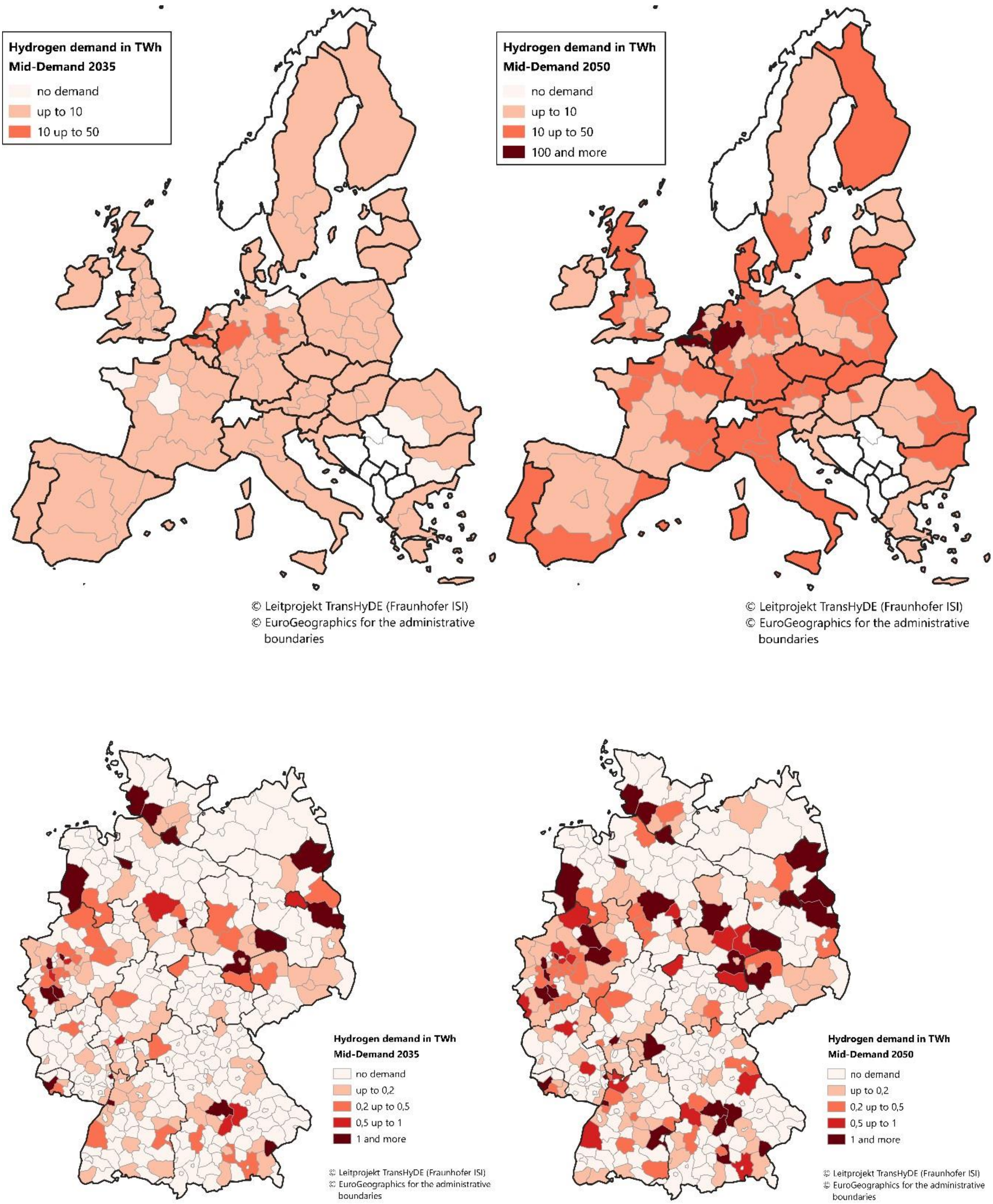

Figure 2.5: Resulting hydrogen demand of industry, transport and buildings in scenario *Mid_Demand* (excluding conversion sector and excluding ptx products) by region for EU27+UK (top) and for Germany (bottom) for 2050 (left) and 2050 (right) (based on Fleiter et al. (2023b)).

2.7. Towards implementation: What do the scenario results mean for upscaling at local level?

The scenario results summarised above are calculated at aggregated level for entire regions and countries and build on rather generic assumptions about technology diffusion. At the same time, there are substantial activity in many parts of Germany to establish so called "hydrogen valleys" and develop local hydrogen systems including production, transport of hydrogen and demand. The energy system analysis on European or national level cannot respect these. Therefore, the TransHyDE Project System Analysis aims to align the top-down perspective coming from energy system models with bottom-up activities in the hydrogen valleys. This section discusses implications of the long-term scenarios for the short-term uptake of the hydrogen system. It illustrates how hydrogen development will differentiate in isolated hydrogen valleys before a nation-wide hydrogen network is available. Moreover, the chapter shows how the projected demands would be located in a selected hydrogen valley in Germany, an indicator how a possible local distribution grid should be established. In the latter stages of the project different scenarios for supplying the local demands within hydrogen valleys will be analysed and optimised with a special focus on possible connections of the hydrogen valleys to a national hydrogen grid.

Hydrogen valleys develop independent green hydrogen business cases from production to supply during the market activation phase. These hydrogen valleys develop where interest from the public and private stakeholders is high. To enable the implementation of the hydrogen value chain, these valleys are awarded with public funding from federal level, mainly via the *HyLand* program and from state level. The German hydrogen regions can be seen in Figure 2.6. The regions are classified according to their level of development of the hydrogen economy also mirrored in the height of the funding they receive. It is important to mention that also regions below "implementation" phase are implementing hydrogen technologies but usually on smaller scale (single-digit MW instead of 100 MW or more).

The interest of public and private sector combined with governmental funding functions as a catalyst for the development of hydrogen production, infrastructure, and demand. Therefore, it can be assumed, that the demands for land-based hydrogen transport projected in section 2. will mainly arise in the hydrogen valleys. To show the effect of this regional shift, we performed two aggregations of the transport demands from the scenario *High_Demand* within the hydrogen valleys. The first, if hydrogen-based land vehicles (cars, trucks, trains and forklift trucks) would be implemented evenly across Germany according to the general traffic volumes, so no increased development in the hydrogen valleys. The resulting demands in 2030 for the hydrogen valleys can be seen in Figure 2.7 a). For the second aggregation all nationwide transport demands are concentrated in the hydrogen valleys with respect to their level of implementation. Beside the level of implementation as indicator for the development of (and local interest in) hydrogen economy, the availability of abundant hydrogen will also influence the implementation of hydrogen-based vehicles and therefore the demand. To consider this, the regions with a connection to the proposed hydrogen core network by the FNB are getting relatively higher shares of the national demands in transport sector.

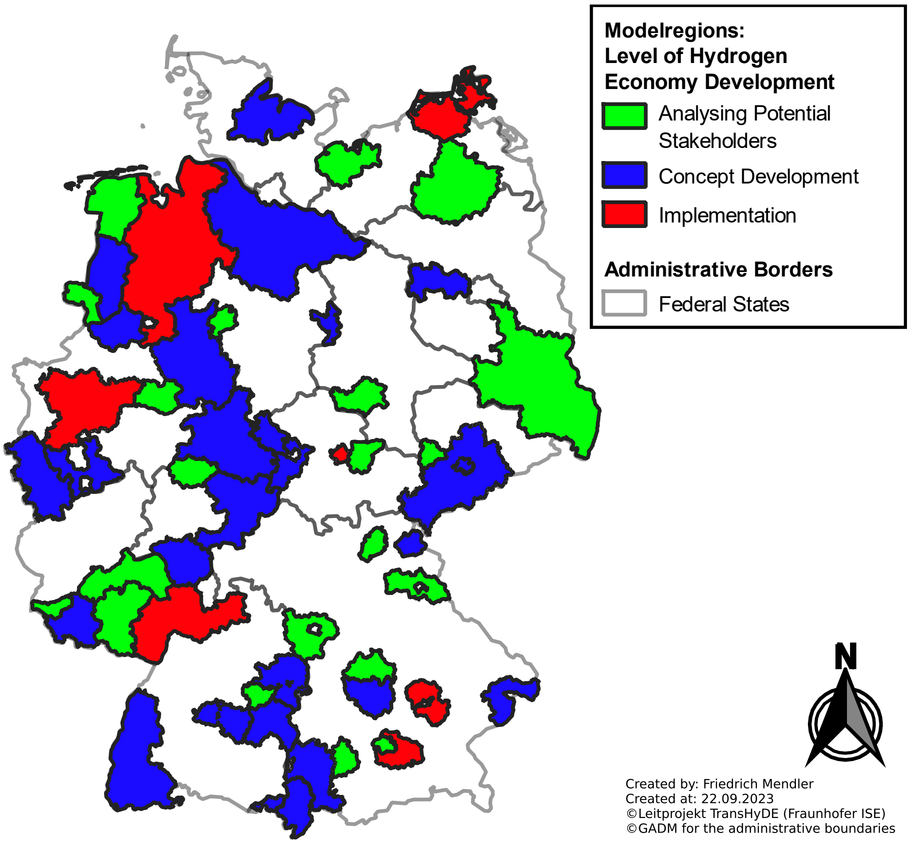

Figure 2.6: Hydrogen regions in Germany as of August 2023 (Klimapartner Oberrhein; Land Nordrhein-Westfalen; NOW GMBH, 2023a).

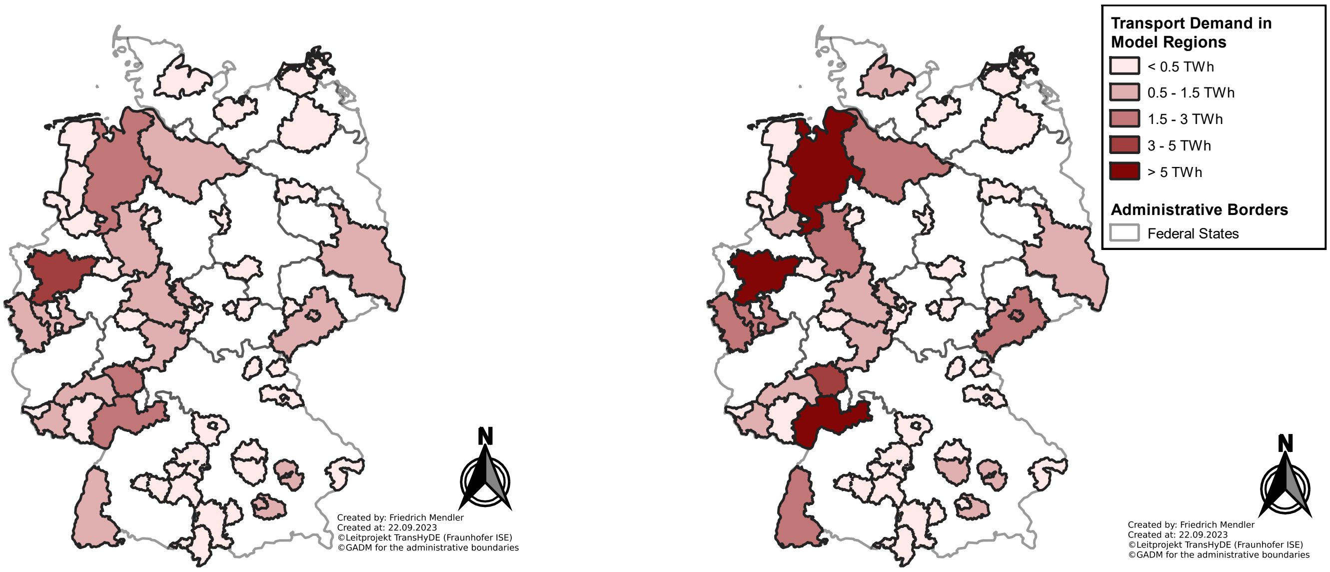

Figure 2.7: Transport demands in German hydrogen regions in 2030 without (a)) and with (b)) concentration of total national demand in the regions.

This method of aggregation, depicted in Figure 2.7 b), leads naturally to higher demands in the hydrogen valleys but has highly different effects on the individual regions. While regions in the first stage have nearly the same demand as from the flat aggregation in Figure 2.7 a), regions with high traffic volumes and already in implementation stage (Rhein-Ruhr, northern Lower Saxony, Rhein-Neckar region) now have substantially more demand for transport applications. This section has demonstrated, that even though the national demands will (in a cost optimal scenario) develop according to the projections in section 2, the regional development will differ greatly based on factors as availability of cheap hydrogen, existence of relevant stakeholders and political actions.

The implementation of the projected demands from section 2 on regional level is demonstrated on Ostwestfalen-Lippe (OWL). OWL is a region in north-western Germany with distributed industrial demands among multiple medium sized cities and relatively high traffic volumes (5th among the hydrogen values from Figure 2.6). Stakeholders interested in hydrogen, especially from the transport sector have been surveyed in the project *HyDrive-OWL* funded within the *HyLand* program. The demand aggregation shown in Figure 2.7 b), resulting in 833.47 tH_2/a for OWL in 2030, has been distributed among the surveyed stakeholders with respect to their potential demands. Then a potential network of hydrogen refueling stations (HRS) has been optimised regarding size and location of the HRS for cost-optimal supply of all stakeholders (for the methodology see Eissler 2023). This results in four HRS, two of size M, and one of size L and XL each (sizes based on H2Mobility) as shown in Figure 2.8 a).

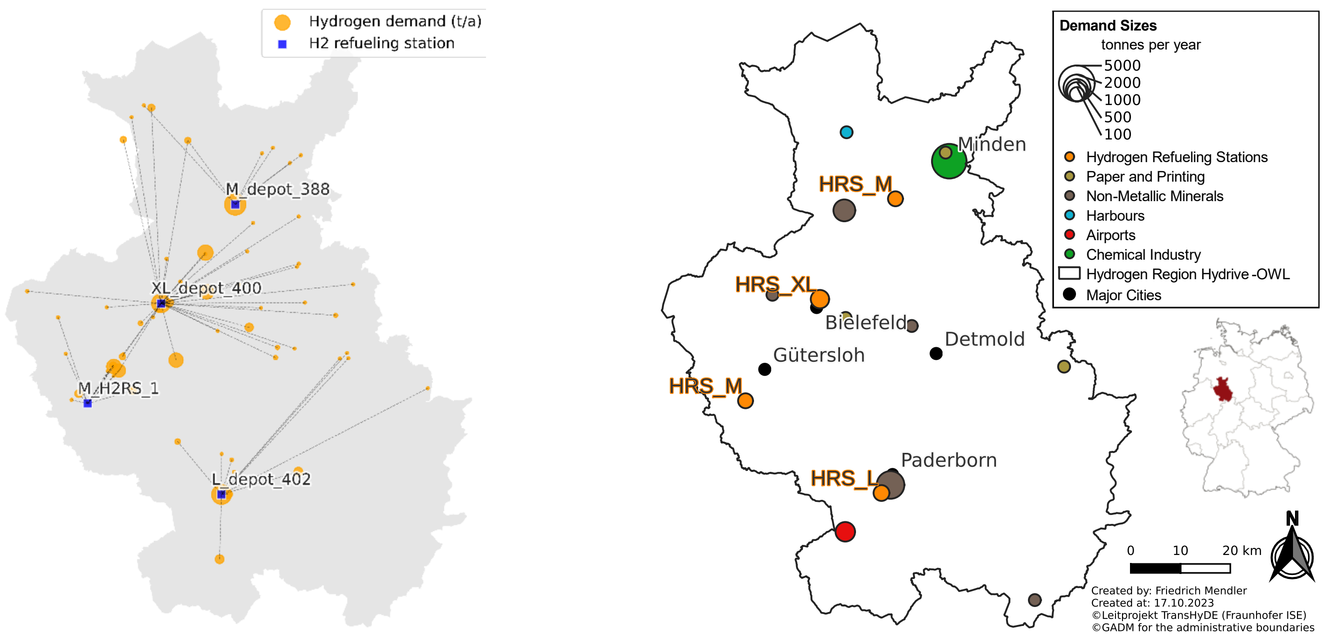

Figure 2.8: a) Required network of hydrogen refueling stations (HRS) in Ostwestfalen-Lippe (Germany) to fulfil projected transport demands by 2030; b) Comparison to potential industrial point demands.

In comparison, the demands projected for 2030 in scenario *Mid_Demand* with lower transport demands would require three HRS of size M to optimally supply the stakeholders of OWL. Even though the demands of these HRS in a region as OWL with high traffic volumes are substantial, they are still small compared to the potential point demands from chemical and cement industry, which will be the main driver in this region in the future.

This chapter illustrated the application of the national hydrogen demand projection on regional level. It shows, that even in scenarios with low transport demands, a basic network of well-located HRS is beneficial (also to supply transit through the region). However, the HRS will most likely not be the highest demand points and should therefore be developed in cooperation with large industrial point demands to benefit from economies of scale and optimally utilise a hydrogen production and transport infrastructure.

Based on the distribution of demands, potentials for RE production, possible connections to a national hydrogen grid and other local factors, the optimal supply structure for the hydrogen valleys for different scenarios will be analysed in the next phases of the TransHyDE Project System Analysis. The modelling of the hydrogen valleys will be using results of the energy system modelling on European level, e.g. for costs and amounts of possible hydrogen imports. On the other hand, it will create inputs for the hydrogen grid modelling or another iteration of energy system modelling, in which the hydrogen valleys will operate as sinks or sources for hydrogen. Furthermore, the modelling will demonstrate the structure and costs of hydrogen distribution on local level.

2.8. What are expected transformation pathways from the actors' perspective?

The scenarios presented above illustrate how different potential future worlds could look like from a systemic perspective. The extent to which real developments line up to the modelled scenarios will depend upon the plans and decisions of the individual and institutional actors involved in transforming the energy system. In the following subsections, the modelled scenarios presented above will be discussed in the context of transformations being planned by such actors.

Industry

In two of the three scenarios presented above, demand for hydrogen from the industrial sector is the main driver of overall demand (see Figure 2.4). The academic institutions of several energy intensive industries are directly involved in TransHyDE-Sys, and their expertise is invaluable in constructing transformation pathways from the actor's perspective. In the following subsections we will provide insight into the transformation pathways foreseen in the industrial processes present in the scenarios *Mid_Demand* and *High_Demand* presented in section 2.6 (Scenario results).

Steel

The transformation pathway foreseen in the European steel industry largely reflects the transformation presented previously in scenario *Mid_Demand*, indicating a general consensus between academia and industry regarding the transformation of this industry. The existing blast furnace route will be nearly completely replaced by a combination of direct reduction and steel recycling via the electric arc furnace. The ratio of primary production to secondary production is anticipated to remain relatively constant. Unlike in the scenarios presented above, in the agent perspective transformation pathway, a small share (< 5 %) of production via the blast furnace route does remain. This indicates the need for emissions compensation, for instance via carbon capture directly at the plant or increased natural carbon absorption, or additional incentives to accelerate the transformation ahead of the economic lifespan of such plants. An initial wave of DRI-adoption is foreseen between 2025 and 2030, with Thyssen-Krupp for example constructing a DRI unit expected to enter service in 2026 (Thyssenkrupp, 2023).

Ammonia

As with steel, the transformation of ammonia production anticipated in this project also features an overall consensus between industry and academia. The Haber-Bosch process remains as the established technology but is supplied directly with hydrogen and nitrogen rather than the integrated provision of these feedstocks via steam reforming. Still, the conventional production via steam reforming is currently projected by industry to remain relevant through 2050 in Europe, again indicating the need for carbon sinks and/or incentives for the acceleration of the industrial transformation.

High Value Chemicals (HVC)

From the actors' perspective, the future production of high value chemicals is anticipated to feature of mix of production pathways. A significant proportion is expected to be produced via electric steam crackers. This represents a departure from the systemic scenarios presented above, where Methanol-to-Olefins and Aromates (MtO/MtA) play the dominant role in HVC-production. MtO/MtA is also included in the transformation pathways of the actors' perspective, but features a smaller share of future production. The relatively high level of HVC production in electric steam crackers indicates in turn a major demand for synthetic naphtha, with the resulting hydrogen demand for this feedstock dependent on the pathways (hydrogen-based, biomass-based, or plastic recycling) to be chosen by individual companies. This question is equally relevant for the MtO process, where multiple methanol synthesis routes also are possible. The choice of feedstock production route and production location will be characterised by economic competition between the different technologies and production locations, making the comparison of scenarios such as Scenarios *Low_Demand* and *Mid_Demand* valuable indicators of the potential impacts of such competition.

Buildings and Transportation

In the transportation and buildings sectors, each road user and each building or household can be considered an individual actor, meaning one is quickly confronted with hundreds of millions of different perspectives to consider – an impossible task. However, each of these individual actors are influenced in their actions and decision making by regulatory goals set out for these sectors and the resulting conditions they create in the energy system and the sectors themselves. Among the EU member states, these national goals differ between countries. Germany, for instance, must reduce its greenhouse gas emissions from their 2005 level by 50 % in the year 2030 according to the EU Effort Sharing Regulation, while Bulgaria has a goal of a 10 % reduction (European Commission, 2023). The transportation and buildings sectors both fall under these targets. Simultaneously, the actors face different starting positions while pursuing these goals, depending on the country they live in. While battery-electric vehicles already make up the majority of new car registrations in Norway, in Bulgaria they make up less than 1 % (Eurostat, 2023b). Considering the building sector, the demand for heating, the prevalent technologies, the building stock, and the overall economic strength all vary between countries.

With these differences in mind, it is reasonable to expect a differing pace of the transformation of the actors within the transportation and building sectors based upon their country of residence. The agent perspective in these sectors is therefore accounted for by modelling countries with similar starting conditions and sectoral goals as aggregated clusters. A different best-guess transformation pathway is then defined for each cluster. Publication of detailed descriptions of the clusters and detailed results is forthcoming.

The transportation sector is divided into four clusters. While all four share a similar goal, a climate-neutral transportation sector, the road to achieving this goal differs between clusters with regard to their starting situations, the modelled transformation speed, and the modal split.

A majority of the final energy consumption in the buildings sector originates from technological applications for meeting the heating demand, making this the key for differentiating the countries into the resulting five clusters. These clusters feature different heating structures in the status-quo, larger or smaller levels of demand for heat, and different levels of both availability and profitability of district heating and hydrogen networks.

While this clustering approach means there are sometimes significant differences between the different cluster-specific transformation pathways, they share several similarities with regard to the role of hydrogen in the agent perspective of these sectors. Where particularly high demand for heating exists in the buildings sector, a small portion of gas-fired home heating units are replaced with hydrogen-fired units. This shift begins in 2030, primarily in the vicinity of industrial clusters already featuring high demand for hydrogen or in isolated microgrids. This facet of the buildings transformation reflects the reality that technology choices will be heavily dependent upon the decisions of individuals, rather than a systemic optimal choice.

In the transportation sector, hydrogen and synthetic fuels play a decisive role in the transformation of the applications where direct electrification is very difficult to infeasible, for instance in aviation and shipping. There is also a minor role for hydrogen in transport via cars, busses, trains, and trucks. With the exception of heavy-duty vehicles, this is based on the decisions and preferences of a small number of individual actors assumed to prefer hydrogen-based solutions for reasons beyond a pure cost consideration. In the actors' perspective scenario, a low level of hydrogen demand is assigned these areas to reflect this assumption. The maximum share of new registrations of fuel cell vehicles is 2.5 % for cars and trucks (< 3.5 t), 12 % for busses and 20 % for trucks (< 12 t) as well as 40 % for semi-trailer/trucks (> 12 t). Less than half of today's non-electrified trains will be replaced by hydrogen trains. However, particularly in the realm of heavy-duty transport, many actors have not yet committed to a single technology, with competition between electric and fuel-cell technologies, and therefore potential for both, continuing to exist (NOW GmbH, 2023b).

In this best-guess agent perspective scenario, as constructed from these cluster-specific transformation pathways, demand for hydrogen in the buildings sector falls between the levels seen in the scenario *High_Demand*. It is expected that not all households will choose a hydrogen-fired unit to heat their homes, and some competition for the available hydrogen with other sectors, most likely industry, is also seen as possible. Meanwhile in the transport sector, the hydrogen demand is similar to, but slightly higher than, the sectoral demand seen in scenario *High_Demand*. The main cause of this difference is the presence of a small share of fuel-cell vehicles in the car segment, due to individual preferences.

3

Hydrogen supply – Production and imports

3.1. Which sources of hydrogen are considered in Europe?

In the previous chapter we discussed the increasing demand for hydrogen and the need for cleaner production methods. The European Union has recently introduced two delegated acts to meet this demand. The first sets out the rules for the production of renewable liquid and gaseous fuels of non-biological origin (RFNBO)[1], hydrogen produced by an electrolyser powered by renewable electricity. The EU has clearly defined what qualifies as renewable and low carbon hydrogen[2] (European Commission, 2023b).

For renewable hydrogen, producers must demonstrate the use of renewable electricity and ensure that it is additionally generated. Suppliers must ensure that the production of hydrogen and renewable electricity match in terms of both time and geography. The use of grid electricity is also allowed, with options such as curtailment electricity or reaching a 90 % share of renewable electricity in a bidding zone, which exempts the need for additional electricity production.

The second delegated act deals with low-carbon hydrogen, setting a minimum threshold of 70 % greenhouse gas emission savings for RFNBO to be taken into account in emissions calculations. These savings can be achieved through various measures, including carbon capture and storage. In particular, nuclear energy, which is not classified as renewable by the EU, is discussed in this context. The methodology for measuring GHG emissions from RFNBO is to be established by 31 December 2024.

3.2. What are the European Union and German plans for procuring hydrogen?

The European Union (EU) has set its sights on ambitious climate targets, placing a significant emphasis on the potential of green hydrogen as a sustainable energy source. As outlined in the RePowerEU plan, the EU has a goal to consume 660 TWh of hydrogen by the year 2030. Notably, they aim for half of this consumption to be produced within the EU, while the other half will be imported. Reinforcing this commitment, the RED III directive, introduced in mid-2023, mandates that industrial consumers obtain at least 42 % of their total hydrogen production from green sources by 2030, increasing to 60 % by 2035. Looking ahead, the EU envisions that its hydrogen consumption could increase to as much as 2000 TWh annually in the long term (World Energy Council, 2021).

Germany has also outlined a strategic focus on the potential of hydrogen. The country's hydrogen strategy forecasts a demand of 95 to 130 TWh for hydrogen and its derivatives by 2030. To meet this demand, Germany aims to enable 10 GW of electrolysers by 2030. In addition, based on the hydrogen strategy, Germany allows and supports low carbon hydrogen for a market ramp-up phase. Regarding imports, the hydrogen strategy allows 50-70 % from both EU member states and non-EU countries. The strategy also highlights ships as the main mode of hydrogen import by 2030, suggesting a significant role for the shipping sector.

The demand and production of hydrogen will not be distributed

[1] Although the delegated act on RFNBO only addresses the transport sector, the definition is widely assumed to provide an indication on what energy carriers will be seen as green or clean.

[2] It is common practice to classify hydrogen production methods using colors. The prevailing method for hydrogen production involves using a steam methane reformer with natural gas, resulting in *grey hydrogen* and carbon dioxide emissions, which are sometimes utilised in the chemical industry. If the CO_2 is captured, the produced hydrogen is termed *blue hydrogen (low carbon hydrogen)*. In this case renewable energy corresponds to green hydrogen. Hydrogen produced through nuclear electricity is commonly referred as pink hydrogen.

uniformly across Europe. The exported hydrogen or PtX products will need to be transported from the ports or pipeline connections (mainly in southern Europe to MENA region or northern Europe to Norway) to the demand centres mainly located in Central Europe. Therefore the creation of a hydrogen network to transport the hydrogen is of vital importance (Figure 2.5).

3.3. What are the options for integrating electrolysers?

As mentioned above, there are several options for hydrogen production, with Europe emphasising renewable and low-carbon hydrogen. However, the integration of hydrogen into different applications poses its own challenges. Broadly speaking, there are three options for this integration, each with different challenges and infrastructure requirements. It is crucial to distinguish between these options for a full understanding.

First option: Blending H_2 into the natural gas networks

The first approach is to introduce hydrogen into existing natural gas networks. This has the advantage that it can be applied across different sectors, including those where alternative decarbonisation options, such as heat pumps, are available. However, it also has disadvantages. Firstly, its widespread use may inhibit the adoption of potentially more efficient alternatives in certain sectors. In addition, blending natural gas with hydrogen changes the properties of the transported gas, with an upper limit of 5-20 % by volume depending on the final application and the transport medium. Consequently, many assessments consider this option to be at best a temporary measure (Bard et al., 2022).

Second option: Integrated projects

In this approach, the supply is designed in the same location where the demand is located and locally organized in a cluster. There is a direct connection between supply and demand, most often close to each other with little need for pipeline infrastructure. German regulatory sandbox projects are an example, for instance the Energy Park Bad Lauchstädt (see Textbox 4.1 for further information). These projects can be seen as the starting points for a growing hydrogen market and as connecting points for the hydrogen network. The challenge here is the design and development of the entire hydrogen value chain. The way the electrolysers in integrated projects will be operated is strongly influenced by the requirements of the respective applications: Some applications or facilities do not necessitate a steady hydrogen supply: DRI steel production for example is assumed to be able to initially switch between hydrogen and natural gas, and some locations could temporally produce and use grey hydrogen. Still, integrated projects will often try to achieve the highest possible full-load hours that meet the requirements for low carbon hydrogen. If the process at hand requires a high security of supply, hydrogen storages will be required. As it discussed in section 4, storing large volumes of hydrogen long-term requires underground storages, which still need to be built and can only be built in certain locations. Therefore, for many sites and applications, a steady and reliable supply with hydrogen will require a connection to a hydrogen backbone.

Third option: Feeding into a hydrogen backbone

While the initial hydrogen production with electrolyser projects in the range of two-digit MW may be used in blending and integrated projects, the next phase of electrolyser projects with a capacity ranging from 100 to 500 MW will be used to provide hydrogen to multiple customers via a pipeline connection. The hydrogen production may not necessarily follow the demand where renewable energy potentials may not be ideal, but they may be installed where the best renewable potentials are available.

As it has already been described, current regulation requires hourly matching of the renewable sources to hydrogen to prove that it is renewable hydrogen. This may lead to an oversizing of the renewable energy infrastructure, either wind or photovoltaic, to produce a large amount of hydrogen when the renewable electricity is available. This will lead to an increased demand of hydrogen storage to guarantee its supply in the different demand centres.

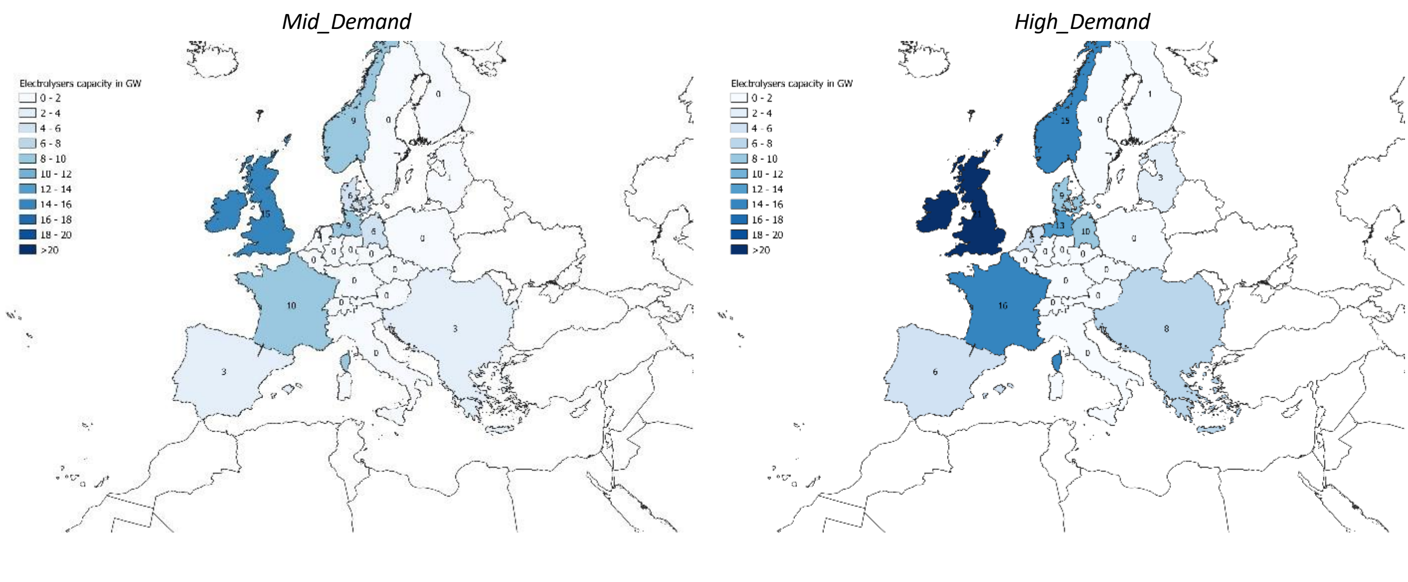

Figure 3.1: Electrolyser installed capacity in 2030 in GW.

3.4. Where is hydrogen produced in the early ramp-up until 2030?

In our modelling we focus on electrolysers connected to the grid. The analysis in 2030 was performed using the energy system optimisation model Enertile[3]. Enertile optimises the energy supply for the given demand from a cost perspective.

Our analyses consistently show that electrolysers should be located close to areas with the highest renewable energy potential to achieve optimal economics. Initially, regions with robust wind power, such as Norway and the UK, are favoured due to the higher full load hours of wind power compared to PV systems. However, as hydrogen demand grows, there is a noticeable shift in location preference towards southern Europe, known for its abundant PV resources. Within Germany, this trend is mirrored, with electrolysers mainly located in the northern regions, in line with its wind-rich zones (Figure 3.1).

However not all hydrogen will be domestically produced. Figure 3.2 shows the European hydrogen balance for 2030 for two different scenarios. The graph shows supply factors, such as domestic production and imports, above the x-axis, while demand from different sectors, including the transformation sector, is shown below the x-axis. In each scenario, domestic production largely satisfies demand. Specifically, scenario *Mid_Demand* shows imports of 11 TWh, just over 5 % of demand. Scenario *High_Demand* has the highest import requirement at 38 TWh, almost 10 % of the total. Even in scenario *Low_Demand*, which has the lowest hydrogen demand, some imports are needed. These imports come mainly from the MENA region, via pipelines in Italy and Spain. Even though the possibility of ship imports in the form of liquid hydrogen is considered in the model, the higher conversion and transport costs led to no ship hydrogen imports. This does however not disqualify imports via ship as a strategic option for Europe. As ships provide a flexibility option not only in regards of the geographical source of the hydrogen but also as the form of hydrogen carrier. In this regard, ammonia ships may be important in the initial phase as the technology and transport chain is fully mature. Further information about ship imports and ammonia as energy carrier is given in section 3.9.

In addition to imports from outside Europe, our results indicate a significant internal hydrogen trade within Europe by 2030. In both scenarios, the main flow of hydrogen transport is from northern Europe, areas rich in wind power, to central European demand centres. In particular, Norway and the UK emerge as the main hydrogen exporters. For imports from outside Europe, Italy stands out as the main entry point.

3.5. Where does the hydrogen come from in 2045?

For the long-term outlook, we applied the model PyPSA-EUR-SEC to investigate the European energy system. The model covers the full ENTSO-E area and follows a techno-economic optimisation approach to meet energy demands with the most cost-efficient solution, while adhering to the technical boundaries of the system.

The hydrogen sources considered in the model are electrolysis to produce green hydrogen, steam methane reformation (SMR) for blue hydrogen, and imports. Two primary import routes were modelled into PyPSA from the European Hydrogen Backbone supply corridors report corridor "A – North Africa & Southern Europe" through Italy and corridor "B – Southwest Europe & North Africa" through Spain. The assumed import price is 73.4 €/MWh for both routes, with an assumed daily flow limit of 680 GWh through Italy and 270 GWh through Spain. Only pipeline imports were considered in the model, as they generally prove to be more cost-effective compared to ship imports for transporting large volumes of hydrogen over short to moderate distances (Guidehouse, 2022).

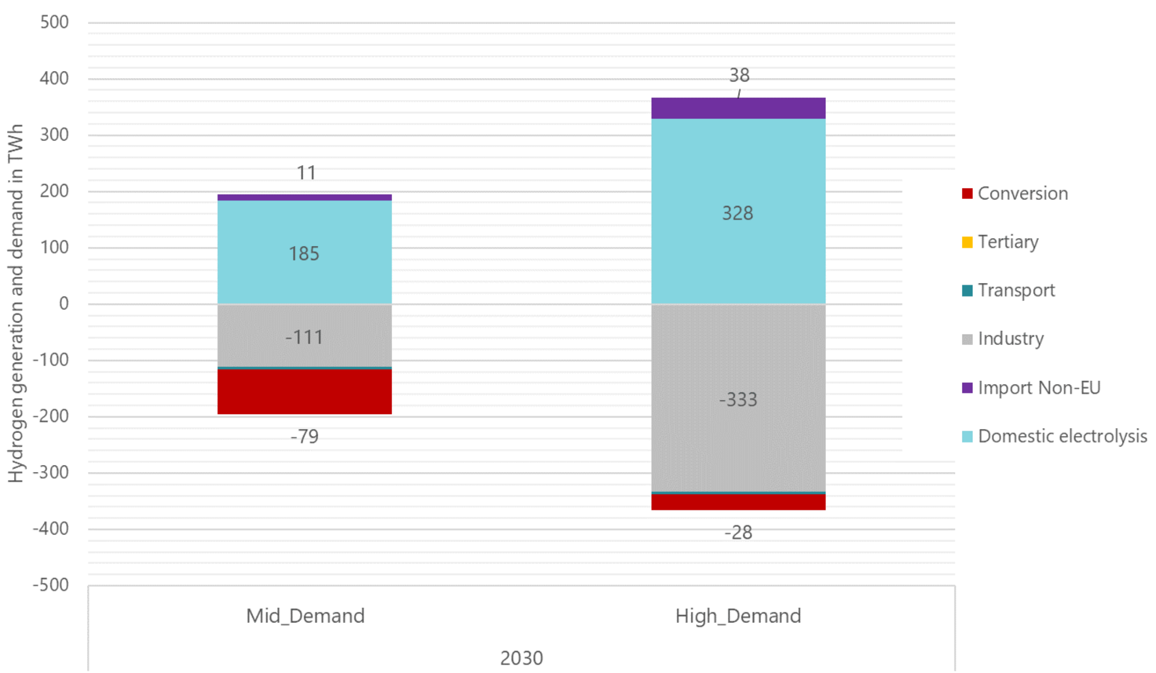

Figure 3.2: European hydrogen balance for 2030.

[3] Further information about Enertile can be found in https://langfristszenarien.de

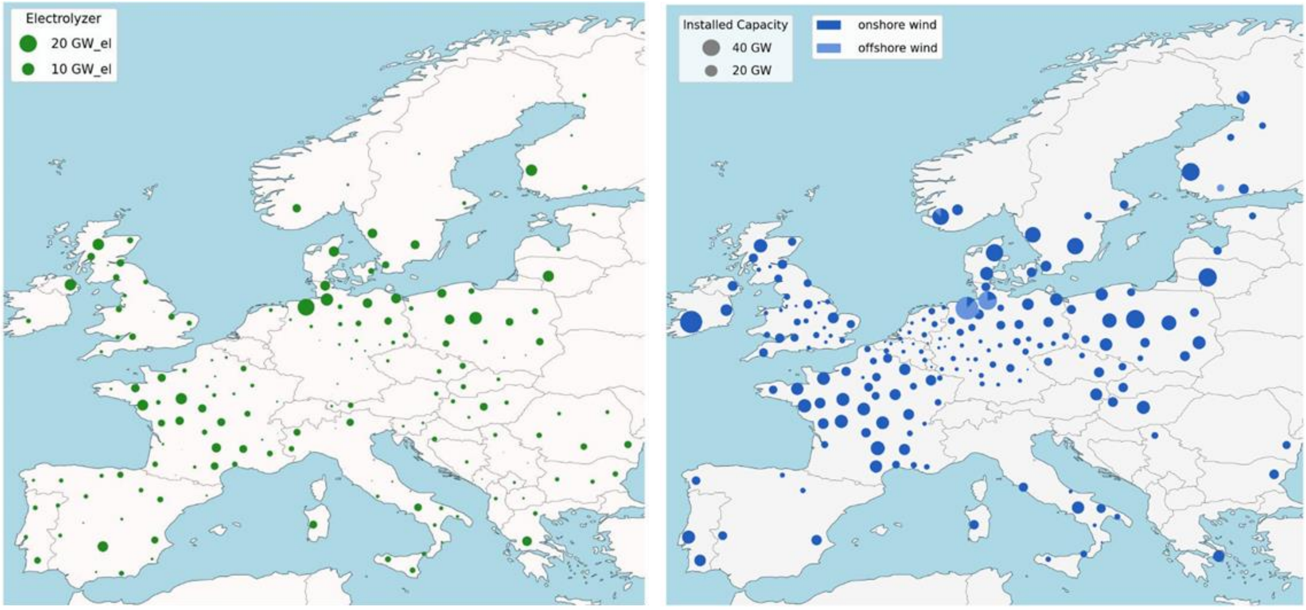

Figure 3.3: Optimised electrolysis units – Scenario *Mid_Demand* 2045 (left). Optimised wind generation capacities – Scenario *Mid_Demand* 2045 (right).

Capacities and locations of both electrolysis and SMR plants are optimised within the model. The results show that scenarios with higher hydrogen demand see higher installed electrolysis capacities, with the total European electrolysis capacity increasing from 600 GW in scenario *Mid_Demand* to 819 GW in scenario *High_Demand*. The optimised electrolysis results for scenario *Mid_Demand* are presented in Figure 3.3 (left), where it can be seen that larger electrolysis plants are installed in the northern regions with high renewable energy potentials, especially wind, as shown by the optimised installed wind capacities in Figure 3.3 (right).

While imports from North Africa are an attractive option, the optimisation results show that they play a smaller role in meeting Europe's demand. The complete hydrogen balance in Figure 3.4 breaks down hydrogen sources and sinks across the y-axis. The top half of the graph represents hydrogen supply and shows that the majority of hydrogen demand is met by electrolysis inside Europe across the different scenarios, with only 12-14 % of demand met by imports through Italy and Spain.

Although the model setup allows for SMR to produce blue hydrogen in 2045, results show that it was not utilised in the supply mix, under a resulting CO_2 shadow price of 315 €/ton and an assumed sequestration limit of 200 $MtCO_2$ for Europe.

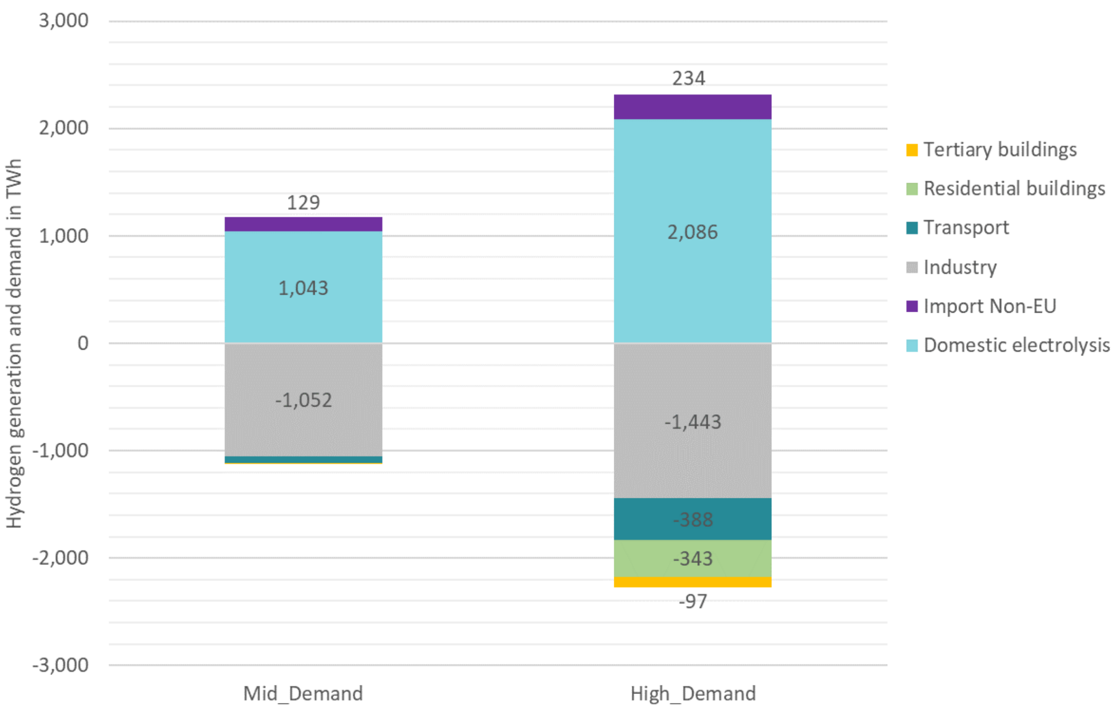

Figure 3.4: Europe hydrogen balance for 2045.

This section discussed the production of hydrogen, starting with a discussion about which type of hydrogen may be produced, the plans both in Europe and Germany to produce hydrogen, possible integration pathway into the system and our modelling results from a system perspective for 2030 and 2045.

The demand for clean hydrogen in Europe is outlined in European plans, which anticipate a hydrogen demand of 660 TWh by 2030, of which 50 % is expected to come from outside Europe. Contrary to these expectations, our results indicate that only 5-10 % of the hydrogen consumed will be produced outside Europe by 2030, with hydrogen imports increasing up to 15 % by 2045. It is important to note that our results do not take into account potential barriers to installing additional renewable hydrogen production capacity, such as acceptance issues. This is crucial, as meeting the increasing demand for hydrogen in the scenarios requires a higher number of renewable installations. These acceptance issues may also be present outside of the European Union.

Our results take into account the possibility of imports by ship, although pipeline imports were considered more cost effective in our models. In reality, factors other than cost need to be considered. Ship transport facilitates imports from different geographical sources and allows the transport of other hydrogen carriers, such as ammonia, for which infrastructure and transport chains are already established.

In addition, our modelling shows that the best locations for electrolysers are close to areas with the best renewable energy potential. However, this may not always be the case, as some electrolysers may be part of integrated or island projects that utilise local renewable potentials. It is important to consider the proximity to the future hydrogen network as these projects are scaled up. Lack of connection may result in a competitive disadvantage for the first hydrogen users, as hydrogen from the hydrogen backbone may have a lower cost.

3.6. Can Europe efficiently import hydrogen?

Building on the conclusions that highlight the limited potential for hydrogen imports into Europe by 2030 and the preference for pipeline over ship transport in models, the subsequent chapters offer a deeper dive into the economics of hydrogen imports. They explore various transportation methods, such as shipping and pipelines, and their cost implications. The analysis reveals that while pipelines are favoured for their cost-effectiveness within Europe, shipping provides flexibility in sourcing hydrogen from diverse geographical locations and is essential for transporting alternative hydrogen carriers like ammonia.

The chapters further discuss the evolving costs of different chemical energy carriers at the European border. They emphasise the role of green chemical carriers, such as ammonia and liquid hydrogen, in meeting the EU's climate goals. A comprehensive analysis of supply costs is presented, highlighting the importance of production and transportation costs in determining the overall feasibility of these carriers.

Focusing specifically on ammonia, its potential as a hydrogen import carrier and its integration into the energy system are examined. Ammonia's carbon-free nature and the existing infrastructure for its transport and storage are highlighted. The discussion explores various scenarios for ammonia utilisation, considering the implications for infrastructure development and industrial transformation pathways.

In summary, these chapters provide a detailed view of the hydrogen import landscape in Europe, discussing the practical and economic aspects of different transportation methods and the potential of ammonia as a key hydrogen carrier.

3.7. In which form and on which transport routes does the hydrogen reach the customer?

Various options exist for importing hydrogen into Europe and distributing it within the continent. Hydrogen and its derivatives can be conveyed through shipping or pipelines. In the case of shipping, hydrogen may be transported either in its liquid state or carried by derivatives such as ammonia or LOHC (Liquid Organic Hydrogen Carriers). Conversely, pipelines are primarily suited for transporting hydrogen in its gaseous form. In the subsequent section, we will assess these transportation methods with a focus on their associated costs. The method for the calculation can be found in http://www.ffe.de/et_2022_h2transportkosten (Forschungsstelle für Energiewirtschaft e. V., 2022, updated 2024).

Here, it should be noted that the calculation of the costs of transport includes the reconversion into gaseous hydrogen. The parameters used in the source were critically assessed and updated with recent values. In addition to updating the values in the calculation, a distinction was introduced regarding electricity prices in the exporting country and importing country.

In Figure 3.5, the transportation costs per kilogram of transported hydrogen are plotted against the transportation distance.

The distance-independent costs of conversion and conditioning facilities are indicated by the intersections with the ordinate. It is evident that the storage of hydrogen in a carrier medium such as LOHC (yellow curve), ammonia (red curve) or liquid hydrogen (orange curve) incurs significantly higher costs compared to the conditioning of gaseous hydrogen (dark blue curve). In this regard, the costs differ by a factor of 10-12, ranging from 0.2 €/kg H_2 for gaseous hydrogen (GH_2), to 1.5 €/kg H_2 for liquid hydrogen (LH_2), 1.7 €/kg H_2 for ammonia, and 1.9 €/kg H_2 for LOHC. This is based on current cost parameters. By 2050, the discrepancy between LH_2 and ammonia transport may decrease significantly (see Figure 3.6). The cost parameters for LH_2 are also subject to greater uncertainty due to the lower TRL compared to ammonia transport. Figure 3.6 also shows ranges in the costs.

Simultaneously, the slope of the lines indicates that the distance-dependent costs for pipeline transportation are higher than for shipping. The flat curves for shipping demonstrate that there is only a minimal correlation between costs and transport distance for these transport options.

However, the advantage of low conditioning costs prevails up to a transport distance of approximately 1,400 km, making pipeline transportation of gaseous hydrogen more cost-effective up to this distance. If the distance exceeds 1,400 km, causing the costs for

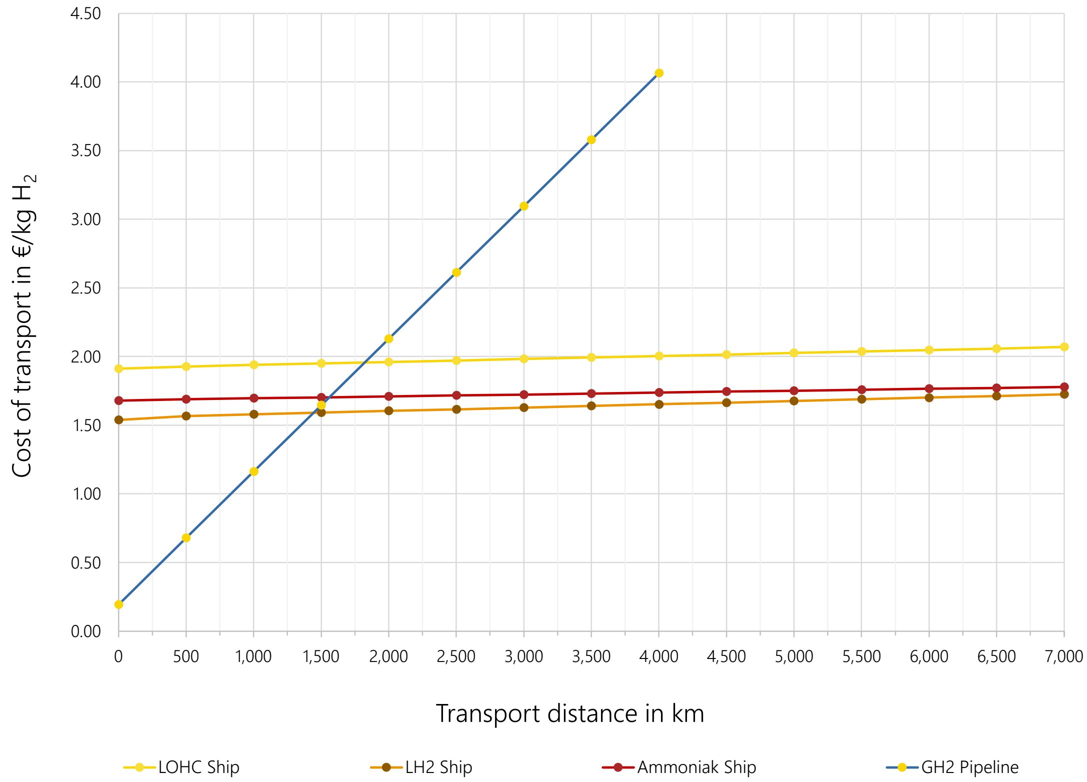

Figure 3.5: Comparison of transport costs for LOHC, LH_2, GH_2 and ammonia via pipeline or shipping. Based on updated calculations of Forschungsstelle für Energiewirtschaft e.V. (2022).

gaseous pipeline transportation to exceed the threshold of 1.6 €/kg H_2 for liquid hydrogen (LH_2), liquid hydrogen shipping emerges as the most cost-effective option. The cost trend for this transport method is nearly horizontal, with costs of 1.7 €/kg H_2 at a transport distance of 7,000 km (equivalent to the shipping route from Cairo to Hamburg), just 20 cents higher than the starting value of 1.1 €/kg H_2.

The electricity prices in the exporting country and importing country have a significant influence on the associated costs. As the provision of heat for the recovery of LOHC and ammonia after shipping is also assumed to be electrical, these two are particularly affected by high electricity prices in the importing country.

If the application requires the use of hydrogen in its gaseous form, then it can be concluded that for longer distances, for example for the import of hydrogen from other continents, ship transports may be the best option. As import hubs the ports of Rotterdam, Zeebrugge, Antwerp, Wilhelmshaven, Brunsbüttel and Le Havre are currently discussed options. Within Europe the transportation via pipeline is the most likely and cost-efficient transport option for large quantities of hydrogen. The transport routes are still to be determined. It is expected that the routes will be mostly planned along the natural gas pipelines, since the retrofitting of existing pipelines can save costs (see Chapter 4). The distribution of hydrogen can be complemented by truck, train or smaller pipeline transports.

3.8. How do costs for chemical energy carriers vary at the European border, and what implications does this hold for future policy and modelling?

To align with the European Union's climate objectives, a significant increase in the consumption of hydrogen and renewable chemical energy carriers is necessary. For European demand, gaseous hydrogen is expected to be sourced mainly within the continent or nearby regions like the Middle East and North Africa, due to its high transport cost sensitivity. In contrast, green chemical energy carriers such as ammonia (NH_3), liquid hydrogen (LH_2), methanol (MeOH), liquid methane (LCH_4), and Fischer-Tropsch-Diesel (FTD) present viable alternatives for long-distance transport, as highlighted in the previous chapter. These carriers are less impacted by transport costs, facilitating the movement of hydrogen over large distances, including imports from other continents, where ship transport emerges as the optimal choice. These carriers make it easier to move hydrogen over long distances or could potentially use directly. However, they do require extra steps to convert energy, and if hydrogen is desired, an additional step of reconversion.

Recognizing the significance of these energy-intensive production methods and their potential for direct use, multiple studies have focused on these chemical energy carriers. Nevertheless, the estimation of the supply costs for these carriers to Europe remains a complex task, leading to a range of cost estimates. In general, supply costs are the sum of the costs associated with the production of hydrogen, the conversion to a conditioned chemical energy carrier, and their transport. The upcoming discussion on the supply costs of five chemical energy carriers at the European border is based on a comprehensive meta-analysis. Meta-analyses, as introduced by Wolf (1986), are crucial for synthesising quantitative research results, aiming to systematically understand expanding research literature. These methodologies are known for their capacity to refine information, as well as to produce reliable reviews and in-depth analyses using statistical techniques. Gurevitch et al. (2018) discusses the field's achievements and limitations, encouraging rigorous meta-

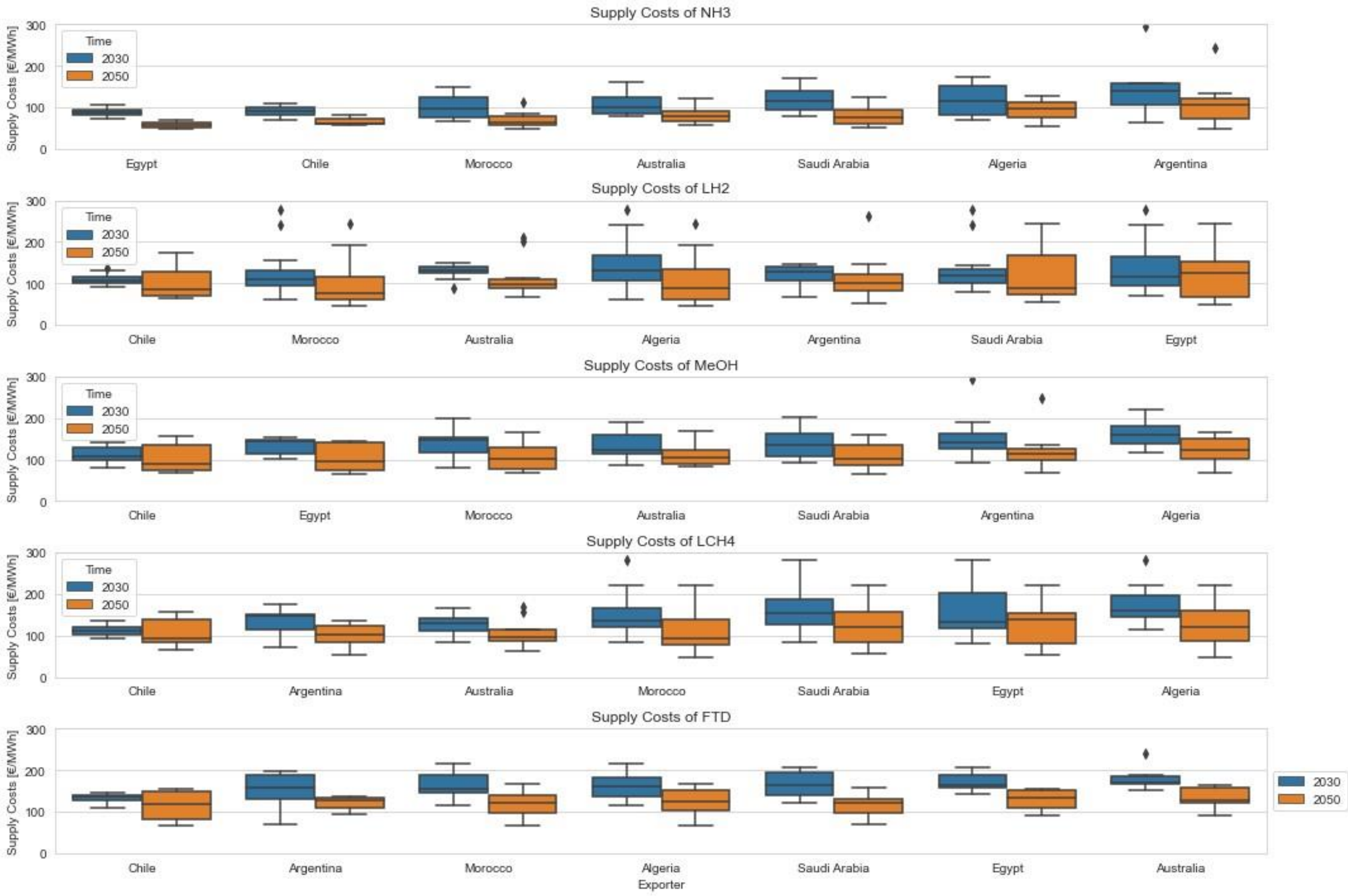

Figure 3.6: Distribution of supply costs of five chemical energy carriers at the European border in EUR/MWh. Exporters for each carrier are sorted from their lowest (left) to their highest (right) average supply costs in 2030.

analytic methods that include transparent inclusion criteria, sufficient sample sizes, and heterogeneity assessments. Genge et al. (2023) exemplify these principles in their meta-analysis, which consolidated 1,050 data points from 30 studies through a transparent process, highlighting study differences using statistical analyses. For a detailed description of the methodologies, studies analysed, results, and data, we refer to the publication of Genge et al. (2023), which is an outcome of the TransHyDE Project System Analysis. The costs have been normalized to 2023 Euros and the higher heating value. The focus was on the supply costs per energy unit at the destination, given the varied purposes of each energy carrier, the uncertainty of their future use, and the absence of reconversion costs data in many studies.

Importantly, these chemical energy carriers are transported by ship. In this analysis, we concentrated on Morocco, Saudi Arabia, Australia, Argentina, Chile, Egypt, and Algeria as they are extensively covered in the literature, with each being analysed in seven or more studies. The average shipping distances to Europe from these exporters are 3,200 km from Morocco, 3,400 km from Algeria, 5,900 km from Egypt, 9,600 km from Saudi Arabia, 12,900 km from Chile, 14,500 km from Argentina, and 20,000 km from Australia, respectively.

In the observed period between 2030 and 2050, a general trend emerged showing a significant decrease in the supply costs of all carriers, averaging a 22 % reduction. This trend was most pronounced in Morocco, where the average decrease reached 27 %, while Chile experienced the smallest decrease at 11 %. At the same time, variations in supply cost estimates also intensified over time. In 2030, estimates varied on average by a factor of two, but by 2050, this variation increased to a factor of three. The largest variations were observed in Argentina in 2030 and Morocco in 2050, whereas Chile consistently exhibited the smallest variations in both years. When examining trends across carriers, it was noted that in 2030, Chile's supply costs for chemical energy carriers were 19 % lower than the average of all exporters. By 2050, differences in exporter-specific supply cost estimates had narrowed, with Chile and Morocco both offering supply costs 8 % lower than their counterparts.

Carrier-specific analysis revealed distinct patterns. For NH_3, supply costs varied on average by a factor of two in both 2030 and 2050 (see Figure 3.6). Egypt in 2030 and Chile in 2050 showed the least uncertainty in supply cost estimates, with variations of two, while Argentina exhibited the highest uncertainty in both years, with a five-fold variation. Chile and Egypt were the most cost-effective suppliers in 2030 and 2050, respectively, offering NH_3 at 18 % and 27 % below the average. In contrast, LH_2 supply costs varied more significantly, with an average factor of three in 2030, escalating to four in 2050. Chile maintained the lowest uncertainty in both years, while the highest was seen in Egypt in 2030 and Algeria in 2050. Chile and Morocco emerged as the most economical suppliers for LH_2 in 2030 and 2050, respectively. Similar trends were observed for FTD, with Chile consistently offering the least expensive supply costs in both 2030 and 2050. LCH_4 and MeOH also showed significant

Table 3.1: Average supply costs at the European border for five chemical energy carriers and seven most investigated exporting countries. Based on a meta-analysis of Genge et al. (2023).

	2030					2050				
Carrier	**NH_3**	**LH_2**	**MeOH**	**LCH_4**	**FTD**	**NH_3**	**LH_2**	**MeOH**	**LCH_4**	**FTD**
Chile	91	110	112	113	131	67	103	104	108	114
Argentina	145	135	154	133	149	112	112	122	101	121
Egypt	89	143	132	161	172	59	126	105	126	128
Algeria	118	148	162	175	162	93	108	122	124	122
Saudi Arabia	119	135	140	162	166	81	118	112	120	119
Australia	109	129	134	127	181	82	114	114	106	135
Morocco	102	130	140	149	163	71	97	106	108	118

variations in supply costs and uncertainties, with Chile generally emerging as the most cost-effective supplier. However, for MeOH, the most expensive supply costs were reported for Algeria, being 16 % higher than the average in 2030 and 9 % in 2050. In carrier-specific supply cost analysis, Chile consistently proved to be the most economical supplier across various carriers, with Egypt and Morocco also being cost-effective in certain years, while Argentina and Algeria exhibited the highest uncertainties and costs.

The variance in supply costs underscores the importance of an in-depth examination of the underlying factors as performed in Genge et al. (2023). They observed that two primary elements, namely production and transportation, emerge as central to these costs. Among these, production costs stand out as the dominant component over transportation. Influential factors, such as the average costs of capital and specific conversion processes, significantly shape these production costs. It's noteworthy that NH_3 and LH_2 consistently display the lowest production costs. On the transportation side, while there's inconsistency in how costs correlate with various factors, there's a distinct relationship between transport costs, the selected energy carrier, and average costs of capital. Interestingly, the geographical distance seems to have a limited influence on these transport costs.

For upcoming studies and in the field of policymaking, a few key considerations stand out. First, it's crucial to maintain transparency in all assumptions, with a particular emphasis on those associated with costs. This ensures clarity and reliability of findings. Second, categorizing energy carriers based on their cost-effectiveness offers a more structured approach to understanding and leveraging their potential. Last, there's a significant benefit to supporting and investing in research and development. Such initiatives can pave the way for reductions in costs, especially those related to capital costs and expenditure.

Upon examining the evidence, it's clear that though multiple chemical energy carriers offer varied economic impacts for European imports, NH_3 distinguishes itself due to its exceptional role in chemical processes. This key attribute not only emphasises its significance as a hydrogen carrier but also for direct application, marking its pivotal role in the energy transition. Our next discussion will delve into ammonia's distinct place and its potential within the broader energy integration landscape. This focus specifies that stakeholders favour NH_3 for its adaptability, while those leaning towards LH_2 may find hydrogen to be the more suitable choice, illustrating the necessity for a nuanced approach in energy transition efforts.

3.9. How can ammonia be integrated into the energy system?

Building on the understanding of chemical energy carriers, with a particular emphasis on ammonia, this chapter delves deeper into the integration of ammonia into the energy system. One of the primary factors contributing to its prominence is the pre-existing infrastructure in place for ammonia transportation and storage. Additionally, ammonia stands out for its lack of carbon content, a notable advantage compared to other potential hydrogen carriers, such as synthetic natural gas (SNG) or methanol, which entail carbon.

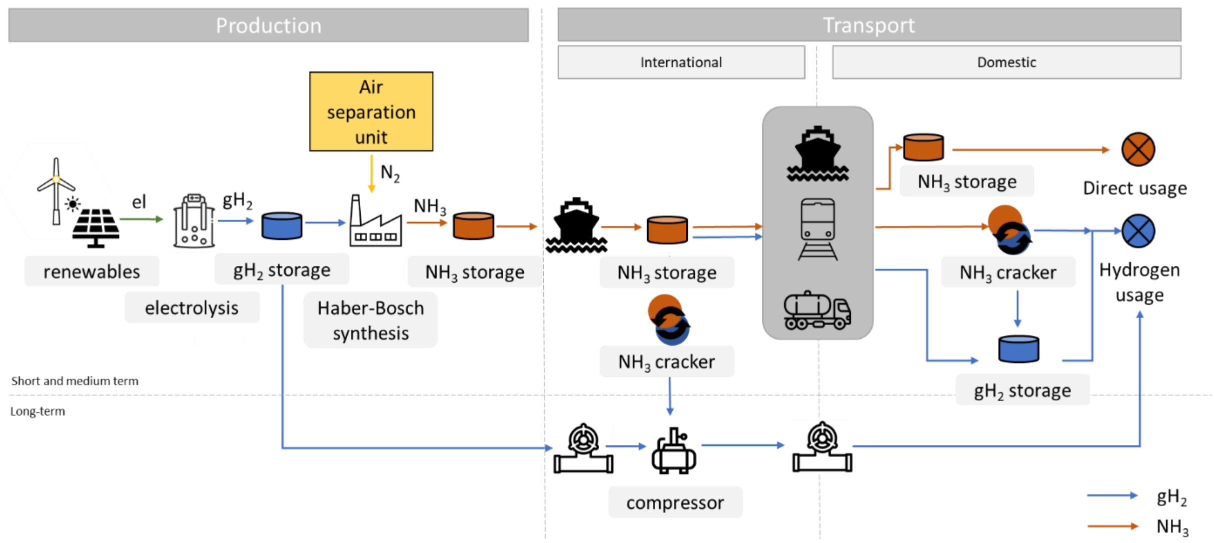

Figure 3.7: Illustration of the green ammonia value chain for energy import, encompassing production, conversion, shipping, reconversion, domestic transportation, and utilisation (Source: Own illustration).

The utilisation of ammonia shipping as a hydrogen carrier opens up the possibility of connecting regions with substantial renewable energy potential, such as Chile, to demand hubs in Europe. This can facilitate the efficient transfer of renewable energy resources from areas of surplus to regions with increased energy demand. The presence of import infrastructure, such as that in Rostock, further strengthens the case for ammonia as a hydrogen import carrier.

Ammonia also plays a significant role in the TransHyDE Projects CAMPFIRE and AmmoRef, which are centred on addressing various technological research inquiries. Within the TransHyDE Project System Analysis, a system perspective leads to the critical question of how to effectively integrate ammonia into the energy system after its importation at the coastal regions. This aspect has been thoroughly explored through the development of an analytical framework, as documented in Hauser et al. (2023).

Currently, ammonia primarily serves as a raw material within the fertiliser industry. However, there is growing interest in its potential role as an energy transport carrier to meet the rising demand for hydrogen. This transition is particularly pertinent during the initial phases of the hydrogen market's expansion, when the establishment of extensive pipeline networks for hydrogen imports may not be feasible.

The investigation in this study revolves around four distinct cases, as also illustrated in the accompanying Figure 3.8:

1. Domestic transport of ammonia and direct utilisation of ammonia.
2. No domestic transport, but direct utilisation near the port.
3. Domestic transport of ammonia followed by the conversion of ammonia into hydrogen.
4. No domestic transport, but conversion of ammonia into hydrogen near the port, with subsequent utilisation as hydrogen.

These four cases serve as focal points for understanding the potential pathways for utilising ammonia as an energy carrier, each with its unique set of advantages and challenges.

To conclude, the analysis explores diverse applications and integration pathways for ammonia within the energy system, all contingent upon the specific energy requirements of end consumers. Key findings are:

- Ammonia (NH_3) is a carbon-free energy carrier that can be considered as an early import option for hydrogen.
- The direct use of ammonia, both materially, e.g. in fertiliser production, and energetically, e.g. in power plants, is diverse. Depending on the application and location, the development of key infrastructure, like large-scale hydrogen pipelines and ammonia cracking facilities, could potentially result in path dependence.
- Regarding the current state of science on the systemic role of ammonia, it is necessary for energy systemic models to consider ammonia endogenously as an energy vector.
- The analysis of industrial needs shows that ammonia is already accepted and established as an early decarbonization option on a global scale. At the same time, aspects of the timeframe for implementation should be examined more closely.

Therefore, deliberate infrastructure planning is essential to prevent stranded investments and ensure planning security for industrial transformation pathways.

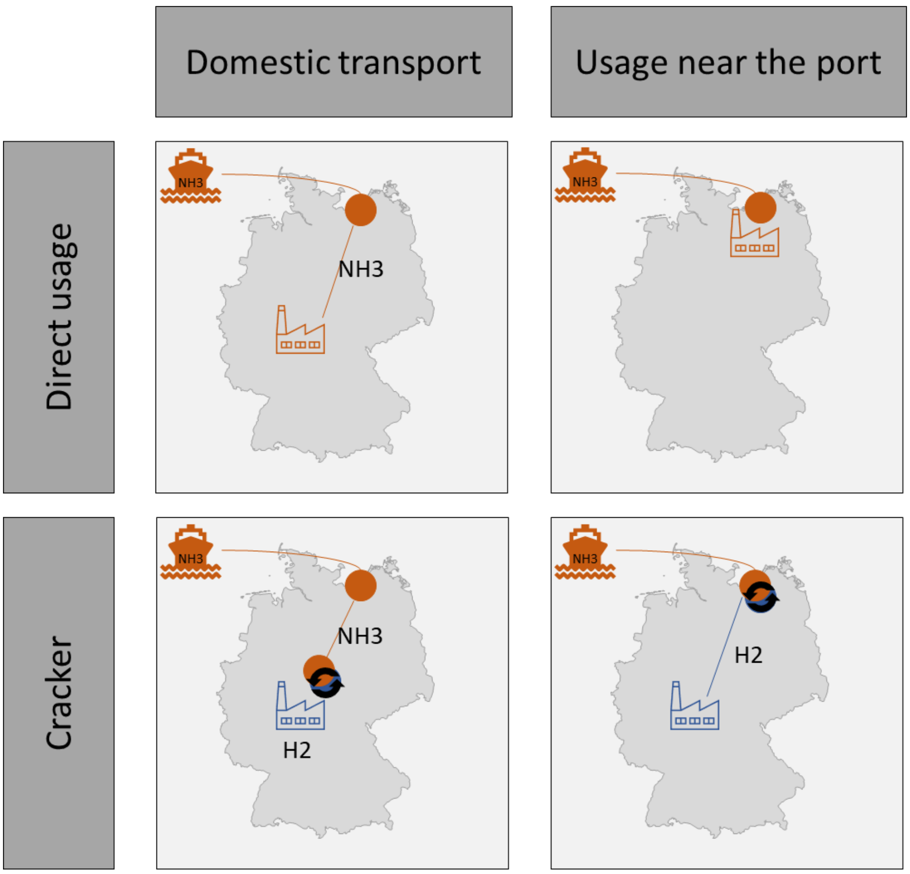

Figure 3.8: Analytic framework to discuss four distinct cases of integrating ammonia into the German energy system (Source: Own illustration).

4

Hydrogen infrastructure – Network and storages

4.1. What role does Germany's connection to the European network play?

Positioned as a central demand hub for future hydrogen consumption, Germany is expected to play a crucial role in the regional dynamics of hydrogen transport. Our modelling predicts a significant inflow of hydrogen from both the northern and southern regions of Europe, facilitated by pipeline transport, converging on central Europe, particularly Germany. In addition, hydrogen imported by ship may be delivered directly to Germany or other strategic locations in Europe, from where it can be distributed to various demand centres.

Given the interconnected nature of the European and German hydrogen networks, it is clear that the German infrastructure is an integral part of the wider European network. To illustrate this fact, we display the role of country-to-country interconnections within the existing gas grid together with planned routes for H_2.

The thicker green lines mark the so-called hydrogen corridors planned so far as European main transport routes, since there is no indication that Germany will produce the whole amount of needed hydrogen on its own.

- H2Med corridor: from Spain via France to Germany
- H2South corridor: from North Africa via Italy and Austria to Germany
- Central-East European corridor: from South-East Europe to Germany
- Baltic corridor: from Finland via the Baltic states and Poland to Germany
- Northern corridor: from Norway to Germany

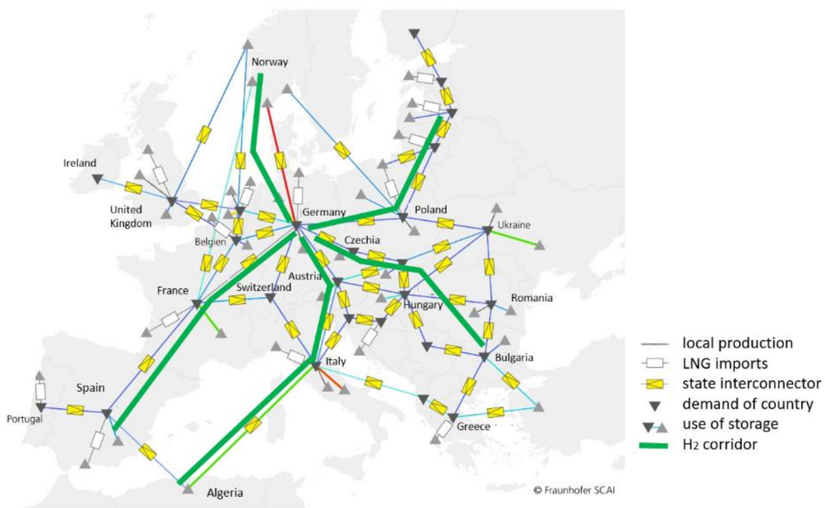

Figure 4.1: Interconnections within the current European gas grid with planned H_2 corridors.

Here the grid has been modelled in a hierarchical manner to demonstrate the central position of the German grid within Europe. (One should note that the directions of the interconnector flow are not meant to be fixed.)

In one aspect the interconnection of the future gas grid – especially between France and Germany – might be easier with hydrogen compared to NG: Currently the odorisation of French NG is restraining the transport direction France-Germany since German storage infrastructure is not compatible with odorisation. It can be expected to remove this obstacle during the transition to hydrogen.

Establishment of a European hydrogen network

The development of a European hydrogen network means that, on the one hand, a robust German hydrogen network must be available as a hub. On the other hand, pipeline connections to the countries bordering the Mediterranean Sea and a connection to LH_2 terminals as well as to pipelines from the southeast, north and south must be established. The inner-European centres of H_2 production and H_2 consumption in the regions of Italy, Spain, Denmark, Sweden, Germany, Belgium and France (Wachsmuth et al., 2023) are in a first step the framework conditions for the conception of a European hydrogen network. In a second step, municipal centres as well as distribution networks can be connected in order to supply timelines for the reduction of GHG emissions or non-electrified areas. For this purpose, the DVGW is collecting data in a centralised manner in the H2vorOrt project in order to be able to start detailed planning of potential conversions at the distribution grid level.

The time target for the conversion of network sections is set by politics with GHG emission reduction targets by 2030, 2040, 2045 and 2050, depending on the country, state or municipality. According to studies, these can only be achieved by transitioning lower-hanging-fruits in the industry by using existing infrastructure and using hydrogen. Therefore, the national start networks, which are to be connected European-wide until 2030, are essential for the achievement. This European start-up network, then with a length of approx. 28,000 km, is planned with a conversion of existing natural gas infrastructure to hydrogen and new construction of pipelines (Rossum et al.,2022). For example, additional pipelines are to be built in the protection zones of existing pipelines in the hope of shorter approval procedures. By 2040, the European hydrogen network should have grown to a total length of 53,000 km. Of this, about 60 % will consist of converted natural gas transport networks and 40 % of new hydrogen pipelines.

Preliminary work on assessing the hydrogen compatibility of the existing networks with about 200,000 km of transmission pipelines and 20,000 compressor stations (ACER, 2023) is well advanced, so that from a technical point of view the main issues have been clarified. For example, studies have shown that the pipeline steels are suitable for hydrogen, but that the aboveground equipment such as compressors must be replaced. In contrast, the regulations for gas transport have been largely harmonized and finalized at the European level.

Important projects for connecting the European gas network to the neighbouring countries are the TAP (Trans Adriatic Pipeline) (Trans Adriatic Pipeline, 2023), GALSI (Gasdotto Algeria-Sardegna Italia) (Schwikowski, 2023), EastMED (East Mediterranean Pipeline) (Sall, 2022) and the H2MED (Carreno, 2022).

In line with that, we investigated the future European hydrogen transport network with our PyPSA model. A greenfield approach was used to optimise and study the techno-economic optimum solution to meet the demands of scenarios *High_Demand* and *Mid_Demand*. The results show that the required hydrogen network capacity in the *High_Demand* scenario is notably higher than that needed in the *Mid_Demand* scenario, at 406 TWkm and 270 TWkm respectively.

The resulting optimised hydrogen networks for scenarios *High_Demand* and *Mid_Demand* are presented in Figure 4.2. Despite employing a greenfield modelling approach, the results still show alignment with the planned European hydrogen transport corridors shown in Figure 4.1, most prominently with the H2Med, H2South and Baltic corridors. The network layouts of both scenarios reflect the general direction of hydrogen flows in the system from outer Europe to demand clusters in central Europe, which is influenced by the hydrogen import routes from North Africa and optimised electrolysis plants in northern Europe as demonstrated in the production section in Figure 3.3.

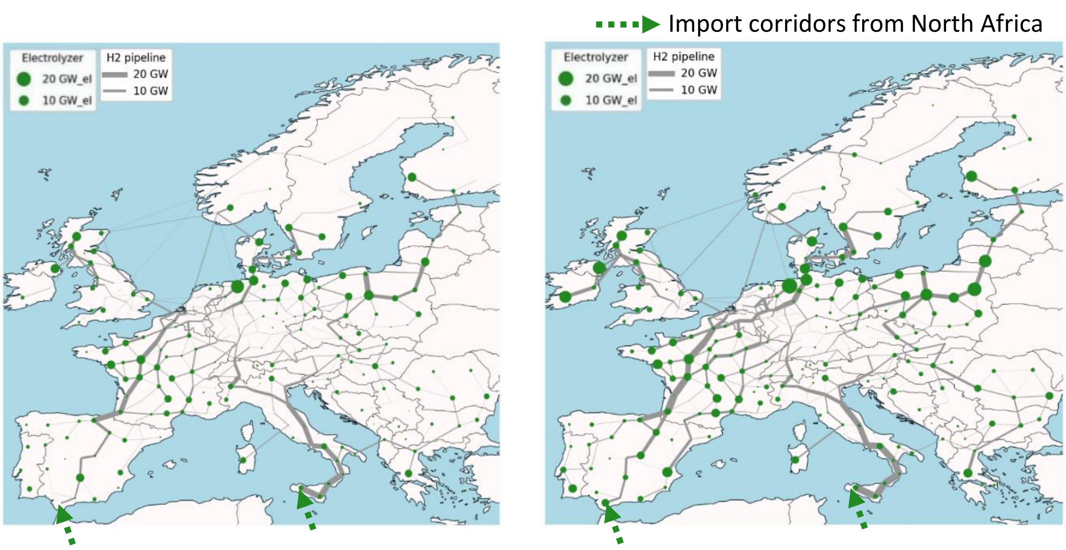

Figure 4.2: Optimised hydrogen network: *Mid_Demand* 2045 (left). Optimised hydrogen network: *High_Demand* 2045 (right).

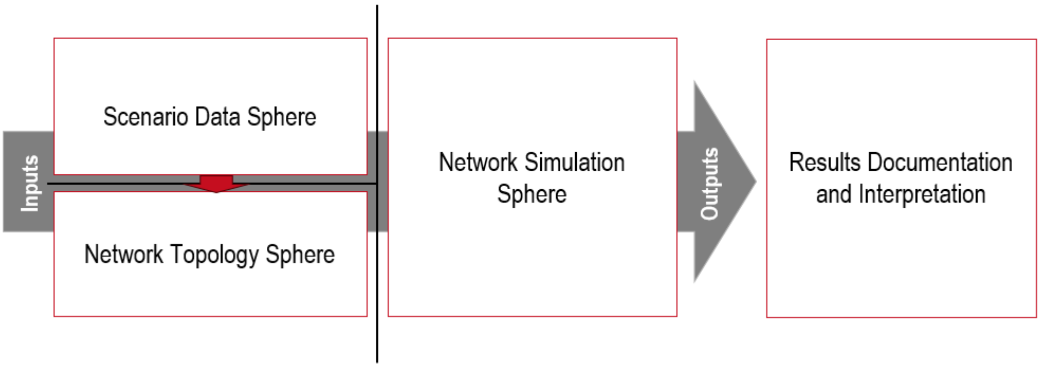

Figure 4.3: Overview of the toolchain of transport network simulation. (Source: Müller-Kirchenbauer et al., 2024)

4.2. What is the role of repurposed natural gas pipelines and new hydrogen pipelines – in network planning and design?

Following the description of future hydrogen demands and respective supplies in the future energy system, the necessity for an interlinked European hydrogen pipeline network is demonstrated. The following section outlines the development of a hydrogen transport network in Germany based on repurposed natural gas pipelines and new pipelines. The presented hydrogen transport network is embedded in a European network and context with transnational hydrogen flows.

Toolchain of the transport network modelling

The role of a transport network is to ensure security of supply to the customers connected to it. To model such a system, it is necessary to compile information from three different spheres: the topology sphere, the scenario sphere, and the simulation sphere. (Müller-Kirchenbauer et al., 2024)

As presented in Figure 4.3, the first sphere is the scenario data sphere, which describes the demand and supply requirements for the transport task. The second sphere is the network topology sphere. This sphere describes the spatial arrangement of the system elements. It should contain information about pipeline characteristics, supply, demand and interconnection nodes, further active elements and underground gas storages. Thirdly and in the last step, all the collected requirements flow in the network topology sphere, where the demand and supply data according to “selected” regions is allocated and simulated. (Müller-Kirchenbauer et al., 2024)

Creation of network topologies

From various perspectives, the repurposing of natural gas pipelines to hydrogen provides huge advantages compared to a whole newly built network. In order to model networks based on existing infrastructure, it is necessary to have data regarding the topology sphere. The base of the network topologies presented is the existing natural gas network in Germany. It includes many technical details about the length and diameter, the demand and supply points as well as other important aspects such as storage facilities, LNG terminals and powerplants. More details about this base topology can be found on tu.berlin/er/greenhyde.

The creation of network topologies based on planned projects for hydrogen transport networks can be described in five steps. Starting with the identification of pipelines based on published project data in the form of visual maps, these visually identified pipelines or pipeline segments are verified using the NDP-Gas 2022-2032. In a third step, the data is compared with public data on the planned hydrogen transport projects as can be seen in the following Figure 4.5.

In a fourth step, the data is transferred to the software platforms Q-GIS and SIMONE. In the last step, manual changes take place to guarantee the fluid-dynamic simulation capability of the network model. Depending on the study, the topology can be adapted and expanded, for example, by adding (hydrogen) pipelines from the core network or the pipelines that are part of the network development plan as well as strategic investment projects by the European Commission.

The topology that can be seen in the following Figure 4.6 is a depiction of the hydrogen core network plans of the association of supra-regional gas transmission companies in Germany (FNB GAS) (from June 2023). The illustrated onshore pipeline network spans 8,940 kilometers, with a notable distribution between repurposed and newly constructed pipelines, comprising 61 % and 39 %, respectively. Moreover, all federal states are interconnected within this infrastructure. The network not only encompasses traditional pipelines but also integrates interconnectors, storage facilities, and potential import terminals. Tailoring the design to accommodate demand and supply dynamics, the incorporation of power plants and electrolysers in each region is aligned with the parameters defined by the TransHyDE Project System Analysis scenarios.

Figure 4.4: Overview of the creation of network topologies in the toolchain of TUB. Source: TUB E&R, 2023.

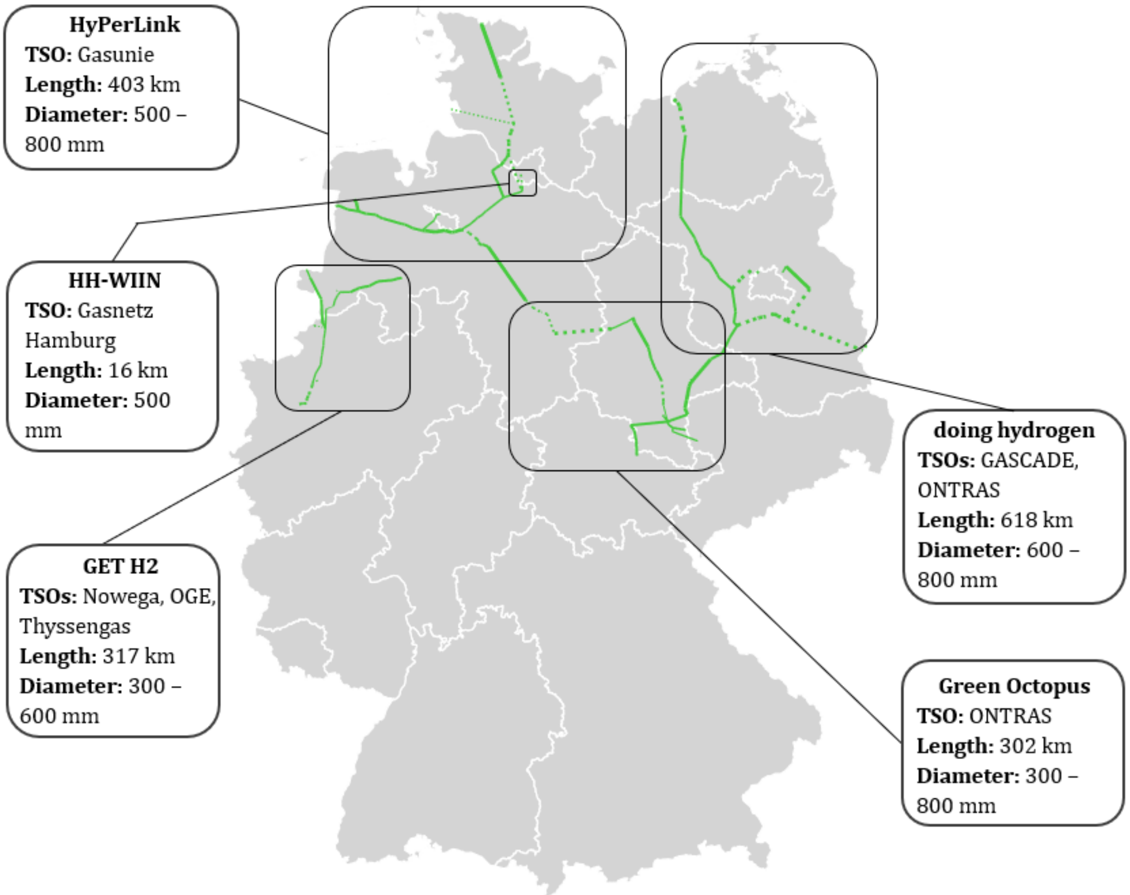

Figure 4.5: Step 3 from Figure 4.4 - Examples for the comparison of data with publicly available information on planned projects. Source: TUB E&R, 2023.

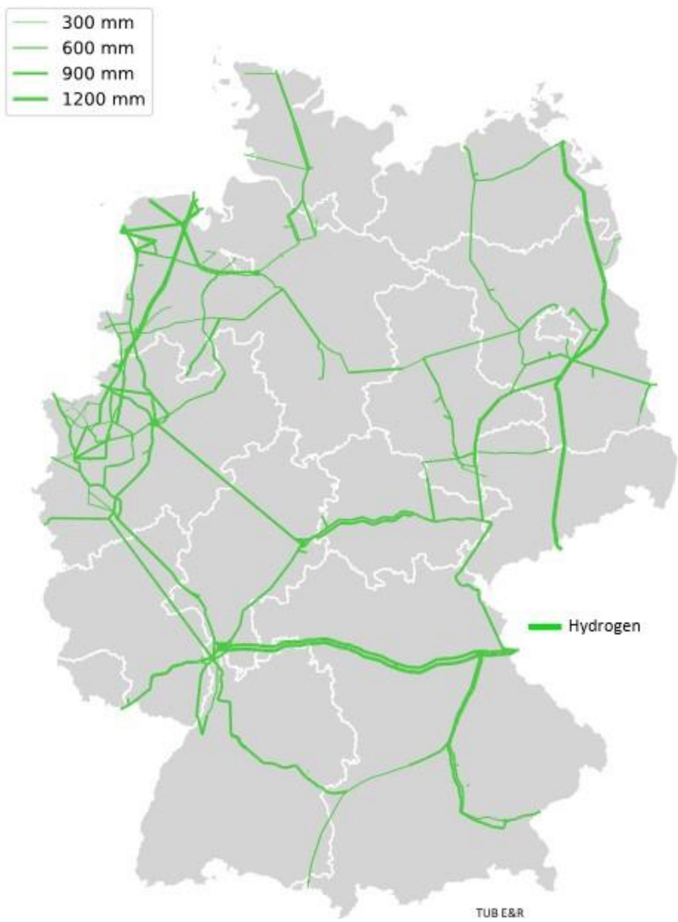

Figure 4.6: Hydrogen core network for the year 2032 by TUB E&R, Source: TUB E&R, 2023.

Matching topologies with TransHyDE scenarios

In the following, different hydrogen networks are illustrated and matched with the demands of the *Mid_Demand* and *High_Demand* scenarios.

The primary demand centres in the *Mid_Demand* scenario, such as Duisburg, Ludwigshafen, Bremen, and Wittenberg, are extensively connected across all topologies. However, in the first topology (compact), which solely covers the northern federal states, there is a constraint in fulfilling the demand of the southern federal states in both scenarios. Notably, the expanded hydrogen network broadens its scope to encompass Baden-Württemberg yet excludes Bavaria. However, the hydrogen core network is the most extensive, covering all states and establishing connections between eastern and western states through multiple routes.

In the *High_Demand* scenario, Bavaria and Baden-Württemberg record significant demand in a few counties, exceeding 200 GWh/year. Despite this, these demand centres face a connectivity gap in the compact hydrogen network. Moreover, the expanded network includes a connection with Switzerland. The hydrogen core network achieves complete coverage, ensuring connection to all demand regions, which includes the southern states. The network links not only the demand nodes but also includes underground storage sites in southern Bavaria.

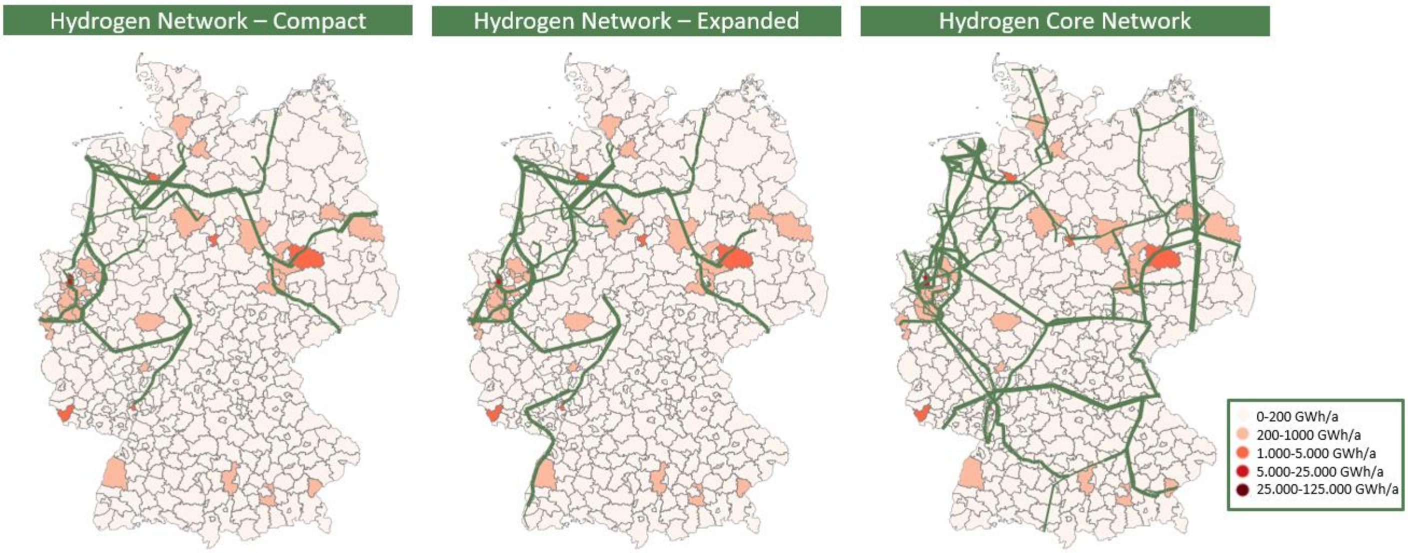

Figure 4.7: Overview of network topologies with hydrogen demand for the *Mid_Demand* scenario for 2030. Source: TUB E&R, 2023.

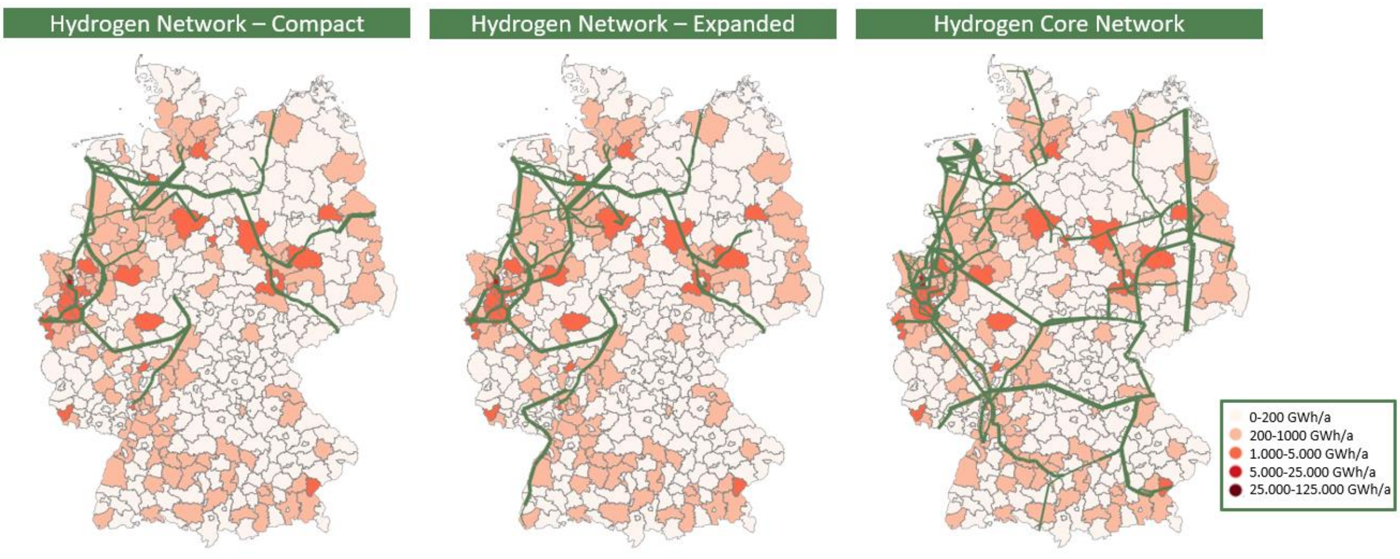

Figure 4.8: Overview of network topologies with hydrogen demand for the *High_Demand* scenario for 2030. Source: TUB E&R, 2023.

The figures below present the aforementioned topologies, together with supply data from the *Mid_* and *High_Demand* scenarios. Triangles extending to the respective countries visually illustrate cross-border transport, with their sizes reflecting the volume of international transport. Further, the domestic hydrogen production is intricately detailed at the NUTS-3 level. A strategic connection with neighbouring countries is established, initiated by the exceeding of a transport quantity of 1 TWh/a. This demonstrates a careful consideration of both national and international dynamics concerning hydrogen supply.

In all topologies, domestic hydrogen production prevails over comprehensive connectivity. The compact hydrogen network facilitates connections with all northern neighbouring countries, except Denmark, though this connection becomes crucial in both situations. The expanded version extends its reach by enabling a connection to Switzerland. This intricate network design ensures comprehensive coverage of domestic production, promoting seamless connectivity among NUTS-3 regions and addressing vital cross-border connections for the scenarios at hand. The strategic inclusion of Denmark and Switzerland in the respective topologies highlights meticulous consideration given to broader regional dynamics and the imperative of international collaboration in the hydrogen production landscape.

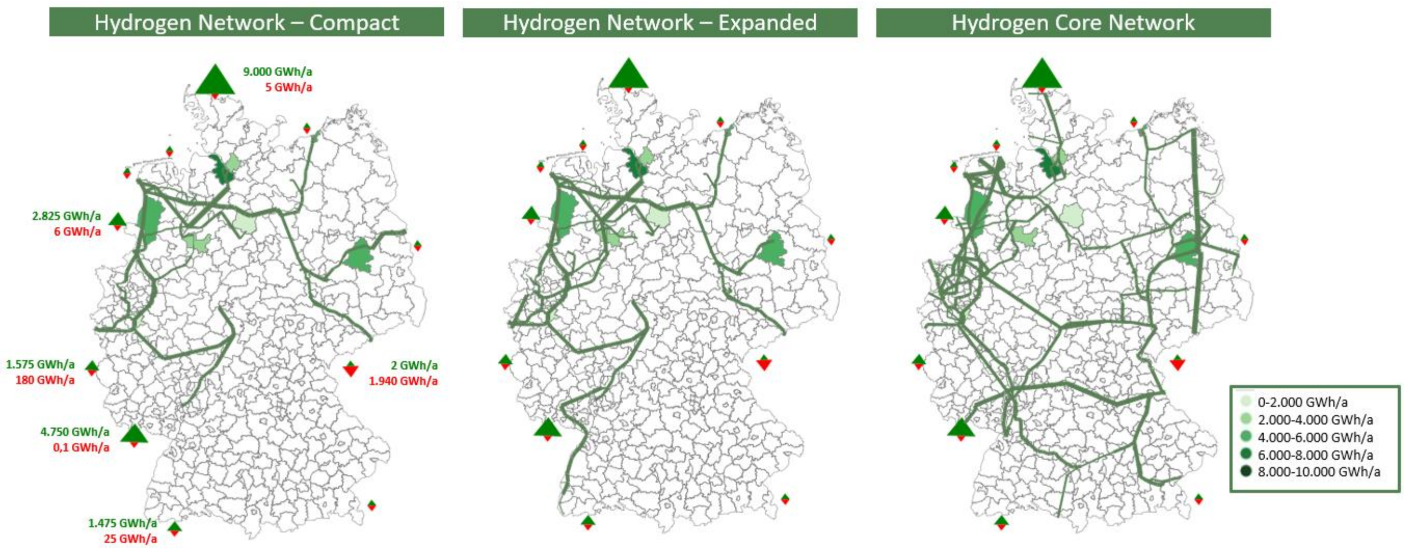

Figure 4.9: Overview of network topologies with hydrogen supply for the *Mid_Demand* scenario for 2030. Source: TUB E&R, 2023.

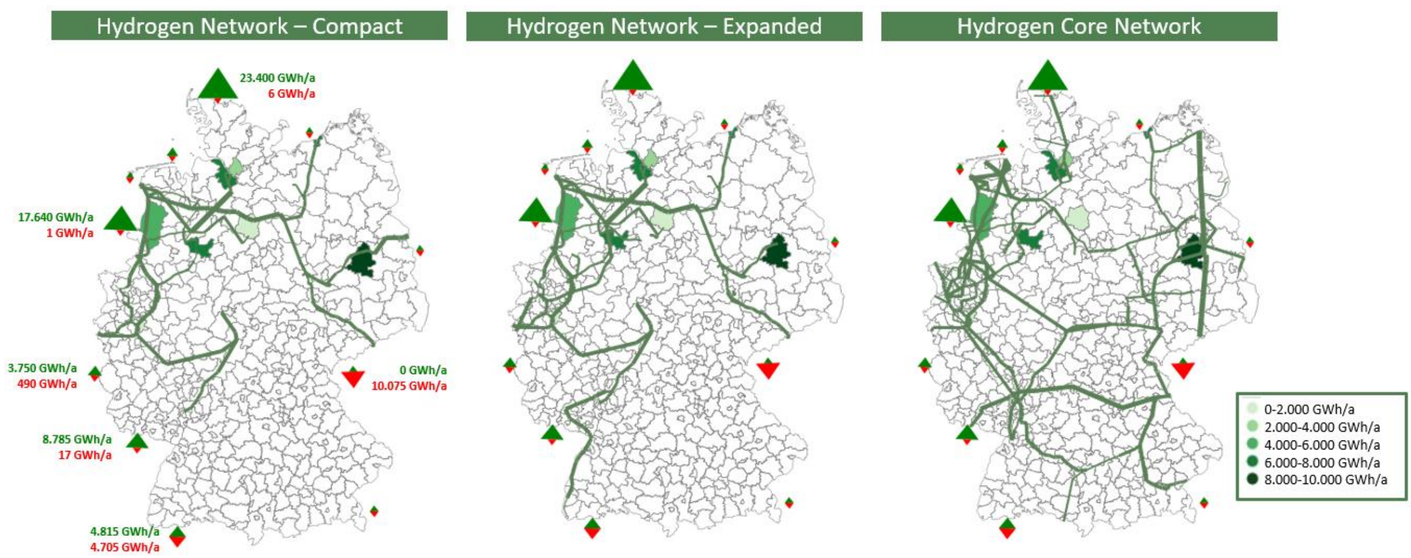

Figure 4.10: Overview of network topologies with hydrogen supply for the *High_Demand* scenario for 2030. Source: TUB E&R, 2023.

Fluid-dynamic simulation results

Simulation assumptions play a pivotal role in shaping the framework and parameters of the model. In this simulation, the equation of state adheres to GERG-2008, providing a foundation for accurate representation of thermodynamic properties. Considering fluid-mechanical constraints, the simulation restricts flow velocities to a maximum of 40 m/s, and pressures are constrained within the range of 30 to 70 bar. Furthermore, the treatment of compressor stations in the simulation is characterized by a simplified approach. This streamlined representation allows for a computationally efficient yet sufficiently informative depiction of the compressor station dynamics within the entire network area.

Results of Simulation for *Mid_Demand* scenario

Within various pipeline sections in northern states, the transport capacity can reach up to 17.5 GWh/h. It is important to note that the shipping import terminals of the hydrogen core network are currently underutilised due to the absence of significant volumes of imports by ship in the *Mid_Demand* scenario. Interestingly, pipeline sections with elevated transport capacities also demonstrate higher velocities, indicating a direct correlation between these two factors. The activation of six compressor stations operating at 70 bar ensures that a significant portion of pipeline segments maintain pressure levels above 50 bar. This intentional adjustment enhances the efficiency of the network and meets prescribed pressure criteria across diverse segments.

Results of Simulation for *High_Demand* scenario

In the *High_Demand* scenario, the network consists of six compressor stations with elevated pressures throughout the entirety of the network when compared to the *Mid_Demand* scenario. The configuration remains congruent throughout the network. The minimum pressure threshold is 45 bar, and heightened pressures surpassing 60 bar specifically occur in Lower Saxony and Saxony-Anhalt. Saxony-Anhalt, in particular, shows a significant disparity compared to the *Mid_Demand* scenario, with pressures exceeding 65 bar. This difference is due to increased demand from the respective counties within Saxony-Anhalt. Interestingly, demand balance across federal territories not only results in minor pressure differences but also leads to reduced velocity scales, emphasising the complexities of maintaining a balanced and efficient distribution network.

Based on the aforementioned results, the repurposing of natural gas pipelines to hydrogen plays a key role in transforming the German and European energy system. The research suggests that potential network topologies featuring a significant share of repurposed pipelines can effectively satisfy the supply requirements of various scenarios in TransHyDE.

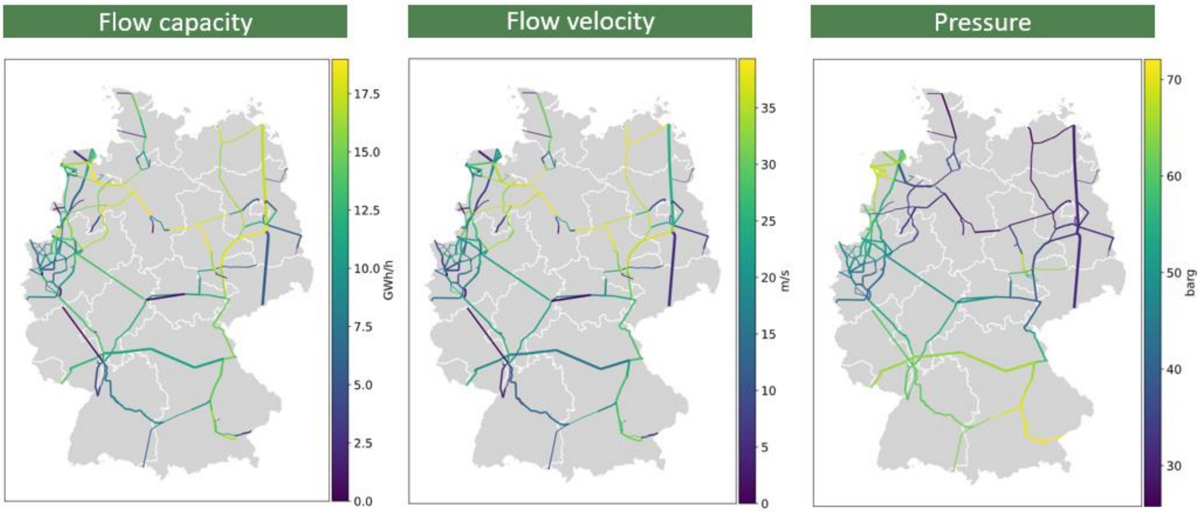

Figure 4.11: Simulation results for the hydrogen core network with Mid Demand scenario data. Source: TUB E&R, 2023.

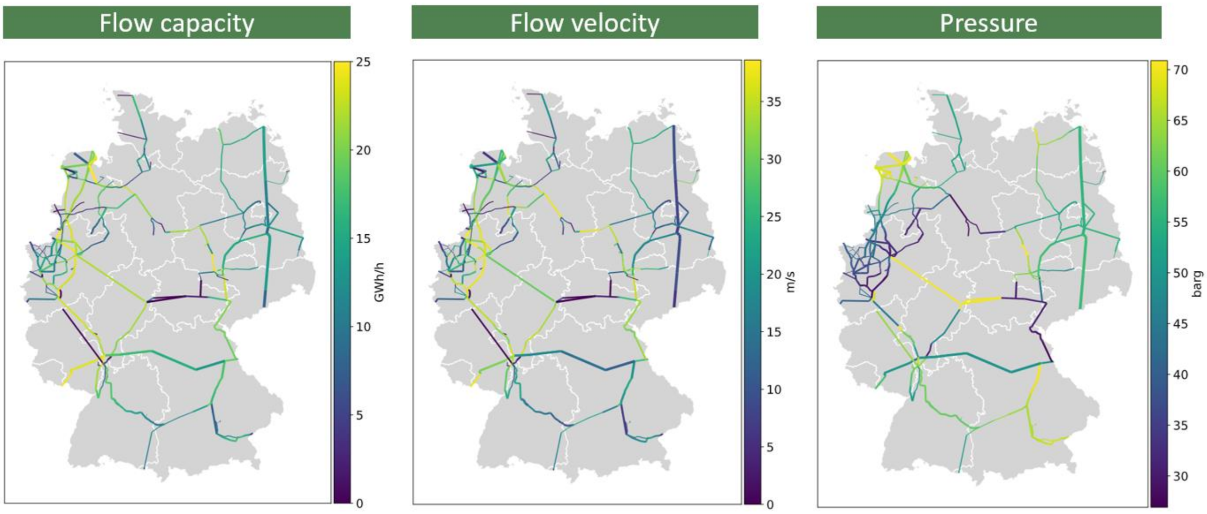

Figure 4.12: Simulation results for the hydrogen core network with *High_Demand* scenario data. Source: TUB E&R, 2023.

4.3. From larger volumes to precise location: What is the role of the distribution system?

In the previous section we talked about transporting large quantities of hydrogen over long distances using transmission pipelines, whether new or rebuilt. However, some users may require smaller quantities, so some sort of distribution will be needed. This section provides a detailed cost comparison between trailers and newly installed pipelines, focusing exclusively on compressed hydrogen gas. The costs associated with repurposed pipelines have not been considered.

For the domestic or local distribution of gaseous hydrogen, trailers or new pipelines with smaller diameters can be considered. By examining various important factors such as the pressure level, transported capacity, trailer capacity, pipeline diameter, pressure drop, and transport distance, the hydrogen supply chain can be optimised, and the cost-effectiveness of compressed hydrogen gas transportation can be improved. Figure 4.13 shows the least levelized cost of hydrogen transportation (LCOHT) of five different delivery modes, encompassing gaseous trailers with operating pressures of 350 bar and 540 bar, and pipelines with diameters of 100 mm, 150 mm and 200 mm. The costs calculated in €/kg are dependent on the hydrogen demand in *t/day* and the transport distance in *km*. Details for the calculation can be found in (Solomon et al., 2023), it provides valuable insights into the costs associated with hydrogen delivery within the European context. It is important to note that this study restricts its scope to examining transport logistics between two specific points, rather than encompassing broader geographical regions. Consequently, variables such as the road infrastructure type, elevation profiles relevant to pipeline installations, and other regional geographic peculiarities are not taken into consideration.

A comparison of the total LCOHT for all 5 types of hydrogen transport infrastructure is given in Figure 4.14. The comparison is for a case of 30 t/day hydrogen demand over different distances. This case highlights the differences in the types of infrastructure as the type with the least LCOHT varies three times over a distance of 500 km. Among the gas trailers, for shorter distances like 25 km, the compressor costs make up more than 50 % of the total LCOHT. For all distances, the compressor investment costs for a 540-bar trailer are more than twice the costs of a 350-bar trailer and the levelized compressor energy costs remain the same irrespective of the hydrogen demand and transport distances. For longer distances like 500 km, trucking investment costs and fuel costs have a bigger influence on the total LCOHT because of the increase in the number of trucks and trailers. For shorter distances, such as 25 km and 100 km, the 540-bar gas trailer has a higher LCOHT. However, as the distance increases to 500 km, the 540-bar gas trailer tends to have a lower LCOHT. Therefore, the choice between the two gas trailers depends on the specific distance being considered for hydrogen transportation. The LCOHT for pipelines varies based on their diameters. The investment costs for pipeline infrastructure generally increase with longer distances and larger pipe diameters because the specific installation cost which includes costs for material, laying, labour costs, excavation, etc., is directly proportional to the length and diameter of the pipeline. The en route compressor costs are present for cases where recompression is necessary. These costs have a significant impact on the total LCOHT if the required number of en route compressor stations is large. Overall, the most cost-effective option for transporting 30 t/day appears to be the 100 mm diameter pipeline for shorter distances (25 km and 100 km), the 350-bar gas trailers for a distance of 250 km and the 540-bar gas trailers for 500 km.

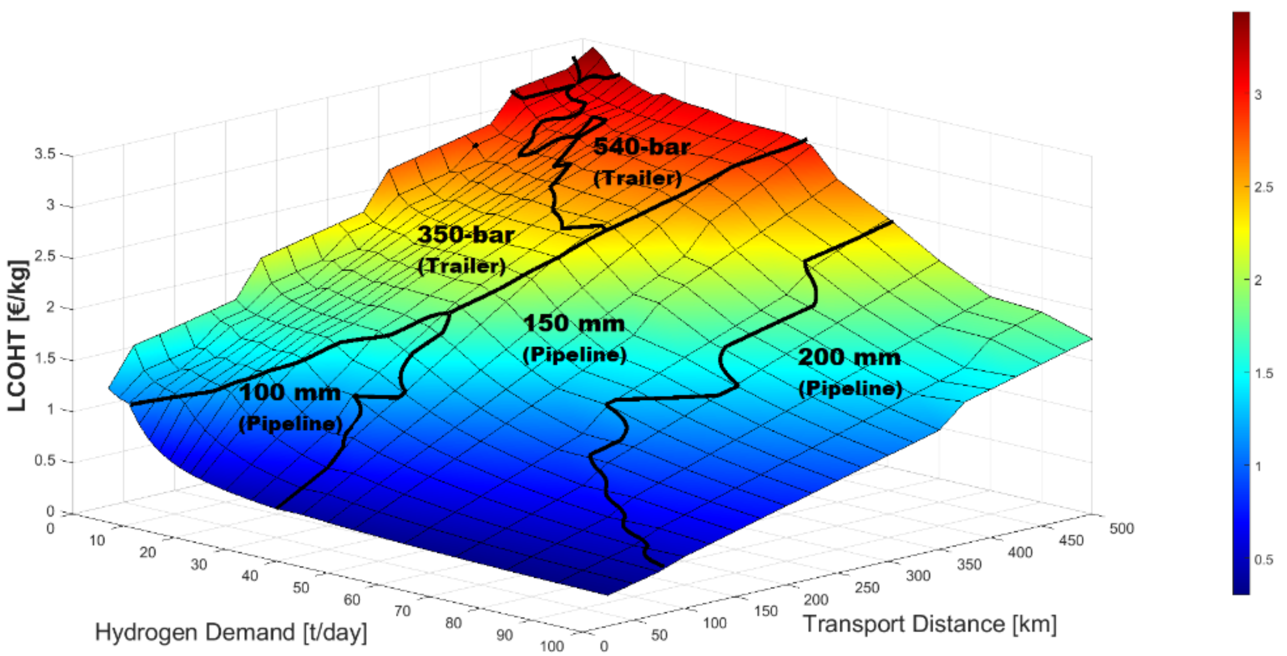

Figure 4.13: Least LCOHT as a function of hydrogen demand and transport distance.

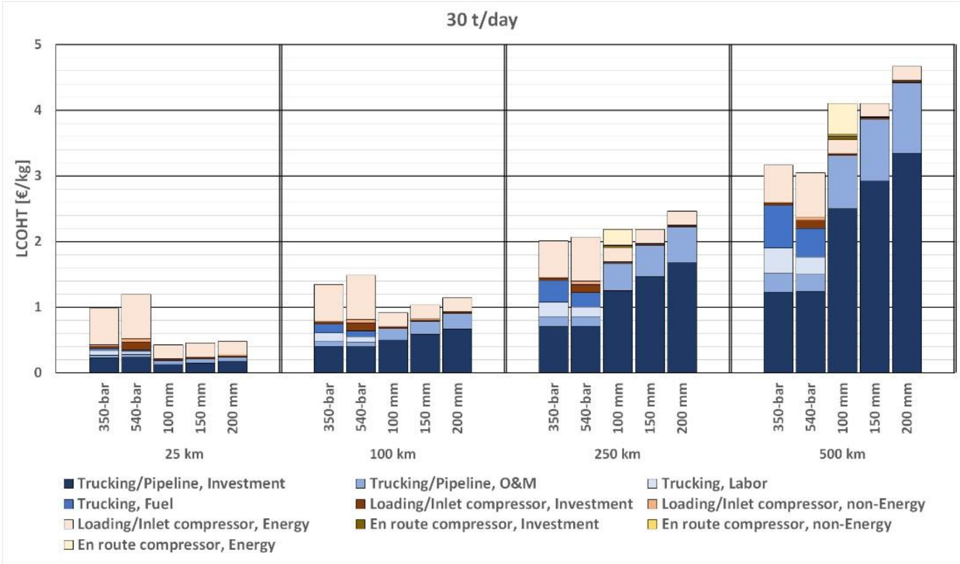

Figure 4.14: Detailed cost breakdown for transporting 30 t/day over different distances.

Some key takeaways from the comparison of different domestic hydrogen transport infrastructures are:

·The total levelized cost of hydrogen transportation (LCOHT) ranges from 0.3 €/kg to 3.44 €/kg. These cost fluctuations are observed over transport distances that extend from 25 km to 500 km and are dependent upon varying hydrogen demand levels, encompassing quantities of up to 100 tons per day.

- Gas trailers: The LCOHT for compressed hydrogen gas using gas trailers depends on the distance travelled. For shorter distances, (up to 350 km), the 350-bar gas trailer has a lower LCOHT, whereas for longer distances (above 350 km), the 540-bar gas trailer gradually becomes more cost-effective due to its larger trailer capacity and reduced trucking investment costs.
- Pipelines: Pipeline infrastructure entails high investment and operations costs. The specific installation cost and operations cost increase with longer distances and larger pipe diameters. The presence of en route compressor stations significantly affects the LCOHT of the pipeline, particularly the energy costs.
- Optimal transportation method: Based on the analysis, gas trailers are generally the most cost-effective option for hydrogen demands up to 30 t/day. For shorter distances, the 350-bar gas trailer is optimal, while for longer distances, the 540-bar gas trailer gradually becomes the preferred choice. However, there are specific scenarios where the 100 mm diameter pipeline is more desirable for shorter distances and certain hydrogen demand ranges. The 150 mm diameter pipeline is mostly optimal for a hydrogen demand between 40 t/day and 60 t/day, and the 200 mm diameter pipeline is preferred for larger demands and longer distances.

In conclusion, the choice of hydrogen transport infrastructure depends on factors such as transport distance, hydrogen demand, pipeline diameter, and the presence of en route compressor stations. Considerations should be given to investment costs, operations costs, and the specific requirements of each scenario to determine the most suitable and cost-effective option.

4.4. What is the role of storages for balancing?

Hydrogen plays a key role not only as an essential molecule for the chemical and energy intensive industry, but also in counteracting the seasonal variability inherent in renewable energy sources in the power sector. There are periods, often referred to as "dark lulls" or "dark flaute", when neither wind nor photovoltaic (PV) generation is feasible due to adverse conditions. At such times, hydrogen becomes essential to maintain power generation in the conversion sector. Our results show that hydrogen is an integral part of the conversion sector in all scenarios considered. The most pronounced requirements appear in *Low_Demand* scenario, which is characterised by reduced hydrogen demand from the industrial, transport and residential sectors.

One reason for this trend is that when less energy from renewable power plants is needed to supply these sectors, more cost-effective potentials are available to produce hydrogen for the conversion sector. Thus, domestic green hydrogen production is more available. Conversely, if there's an increased demand for hydrogen in the industrial, transport and residential sectors, a larger number of renewable power plants will be justified. The extensive installation of both wind and PV introduces alternative flexibility solutions, reducing the dependence on hydrogen within the conversion sector. The use of hydrogen in the power sector emphasises the vital role of storage solutions in managing the intermittent nature of renewable energy supply.

4.5. What contribution can German storage capacities have in Europe?

Gas storage technologies, well-established in the natural gas industry, can also be employed for hydrogen storage. Hydrogen can be stored under high pressure as a compressed gas or at cryogenic temperatures as a liquid. Additionally, alternative hydrogen storage options include organic compounds like Liquid Organic Hydrogen Carriers (LOHC), hydrogen derivatives such as ammonia (NH_3) or methanol (CH_4O), and metal hydride storage systems. While some of these methods are suitable for short-term storage, the subsequent section primarily focuses on the storage of large hydrogen volumes in underground facilities, encompassing salt caverns, depleted gas fields, and porous storage structures.

Salt caverns are viable for hydrogen storage, with numerous research projects exploring their feasibility. In contrast, pore storage facilities are generally unsuitable. Furthermore, each site requires individual examination, as bacterial chemical processes may convert injected hydrogen into methane, affecting the purity of the extracted hydrogen.

The feasibility of underground hydrogen storage depends on geological potential. Northern Europe and Northern and Central Germany have significant potential for salt cavern hydrogen storage. Germany currently has the largest natural gas storage capacity at 255 TWh, while 160 TWh refers to salt caverns. This infrastructure can be adapted for hydrogen storage, but it's important to consider the lower volumetric density of hydrogen. The initial salt cavern storage capacity translates to only around 40 TWh for hydrogen. Given Germany's identified hydrogen storage needs of 42-104 TWh, there is an obvious need to develop additional storage capacity.

Moreover, ensuring sufficient storage capacities in Europe presents a greater challenge. Germany possesses the largest storage volumes in Europe, and these reserves must also offer flexibility for securing hydrogen supply in neighbouring countries in the future. When looking at the wider European context, the projected maximum hydrogen storage requirement is between 143 and 268 TWh. Europe's total natural gas storage capacity is 1,130 TWh, which translates into a potential of 226 TWh for hydrogen storage. This capacity seems sufficient to meet the projected demand for the whole continent. However, it's worth noting that this overall sufficiency at the European level may mask disparities at the level of individual countries. Some countries may have more storage capacity than they need, while others may have insufficient capacity. Such variations require further investigation to understand the regional nuances of hydrogen storage capacity and demand. Furthermore, there is a challenge in providing storage capacities that meet the timing requirements for the hydrogen market. Simultaneously, it is essential to maintain an adequate storage level for the remaining natural gas market to ensure a secure supply for customers who need more time to transition their processes to hydrogen.

Additional research questions that should be considered within the scope of TransHyDE encompass the exploration of future storage profiles in large underground hydrogen storages. These profiles are contingent upon factors such as the hydrogen demand and supply patterns, as well as the availability of alternative flexibility mechanisms within the hydrogen network. Examples of such alternatives include the feasibility of line-packing or the role of ammonia-based storage solutions.

The short-term challenge for the upcoming decade pertains to the necessity of installing adequate storage capacity in a timely manner. Without this, there will be insufficient flexibility to balance supply and demand during the market ramp-up phase. This deficiency may result in unanticipated disruptions in industrial demand or the curtailment of electrolysis, particularly during the initial stages when there is a limited number of suppliers and demand hubs. It's essential to recognize that constructing hydrogen storage facilities is a time-consuming process, as illustrated by the Energy Park Bad Lauchstädt project (refer to Textbox 4.1, project Energy Park Bad Lauchstädt). Therefore, both European and national authorities must address the pressing need for storage projects linked to the European hydrogen backbone. Timely implementation of sufficient hydrogen storage facilities will ultimately ensure the ability of the power sector to achieve carbon neutrality by 2035, in accordance with the IEA's stipulations. This is because hydrogen storage will provide supply security for flexible hydrogen power plants.

Textbox 4.1: Experiences from the sandbox project Energy Park Bad Lauchstädt.

In the project Energy Park Bad Lauchstädt the production, transport, storage, and economic use of green hydrogen will be realised on an industrial scale in the Central German Chemical Triangle. The project is funded by the Federal Ministry for Economic Affairs and Climate Action in Germany and is coordinated by VNG that works together with its partners DBI, ONTRAS, Terrawatt, Uniper and VNG Gasspeicher. A large electrolysis plant of up to 30 MW will generate green hydrogen using renewable electricity produced from a nearby wind farm. The final investment decisions for both the wind park and the electrolysis, have been already made in 2023. The green hydrogen will then be fed into the hydrogen network of the chemical industry based in Central Germany via a converted gas pipeline and used in the future for urban mobility solutions. In a later stage of the project the green hydrogen will be stored in a specially equipped salt cavern – the up to now largest known salt cavern storage for hydrogen with a volume of 50 million cubic metres.

In this way, all aspects of the intelligent and economically optimal integration of the energy carrier green hydrogen – and thus a large-scale demonstration of sector coupling – are covered in the Bad Lauchstädt energy park. In addition, the next generation of green gas production projects can benefit from the best practice approaches of this sandbox project and the experience and feasibility of the European and national regulatory framework for the hydrogen value chain.

Further information: https://www.vng.de/en/energiepark-bad-lauchstaedt

Public funding number: 03EWR012

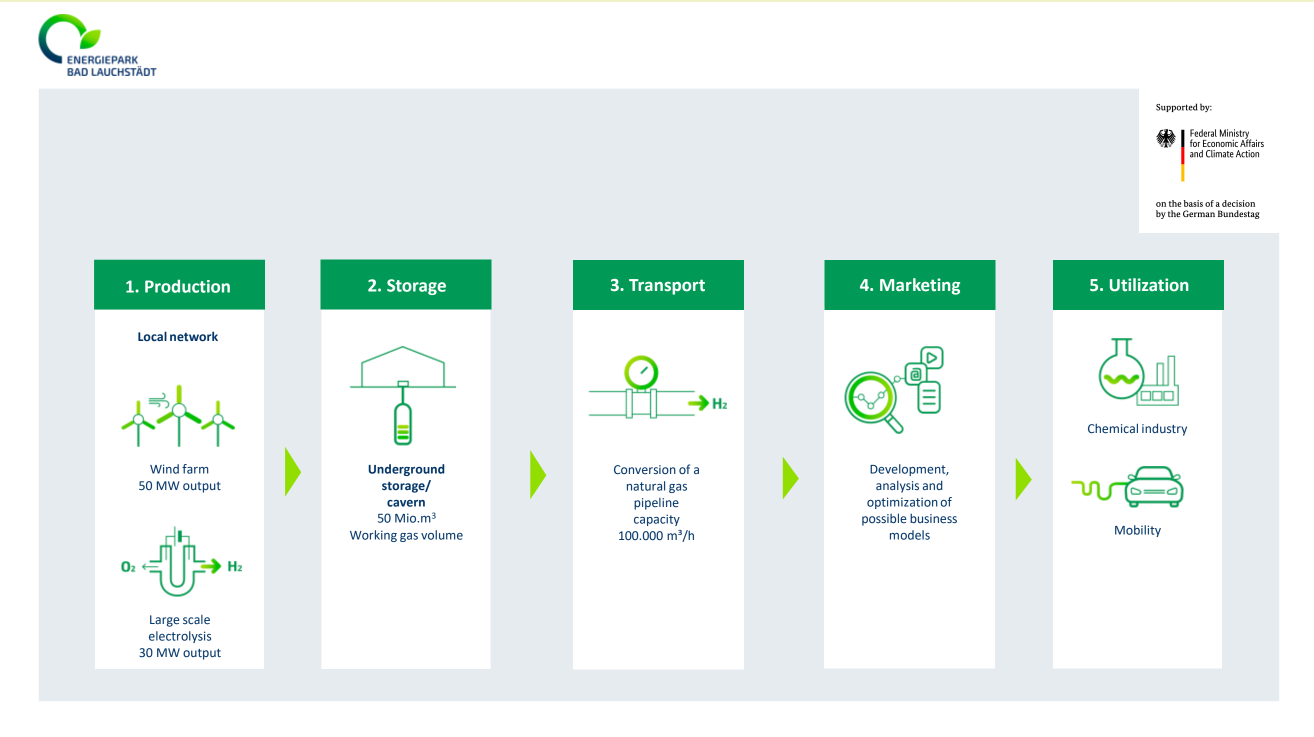

Figure 4.15: Illustration of the project value chain Energy Park Bad Lauchstädt (Energiepark Bad Lauchstädt, 2023).

5

Further aspects

5.1. Robust strategy – Evaluating robustness of strategy elements or measures

As we have seen in the preceding parts of this paper, hydrogen infrastructure development is a complex terrain marked by intricate challenges and evolving dynamics.

To understand the need and the method of robust results which lead to a robust transformation pathway we will first have to define what we mean when talking about robustness in the context of TransHyDE energy system analysis.

The first and very simple definition lies within the method of modelling itself. The uncertainties of different futures are dealt with by computing all the results from different pre-defined scenarios. These scenarios should account for many uncertainties like the development of energy prices, different hydrogen demand and production settings and possible technological advancements. Therefore, the first definition of robustness lies in the fact, that some results occur identical, or at least similar in many of these defined scenarios. Similar to a sensitivity analysis, “model robustness” can be defined by persistent results independent of the input data and assumptions. But there are other more comprehensive definitions of robustness, which should also be part of this discussion.

The central objective of hydrogen strategies is to achieve robustness, which requires a comprehensive understanding and meticulous evaluation of various factors that influence its resilience and adaptability. In the context of hydrogen strategies, robustness manifests in different dimensions, such as technical, economic, operational, and environmental aspects, all of which contribute to the overall strength of the hydrogen ecosystem. However, a main focus is specifically on the concept of "strategic robustness," which encompasses the ability to develop and implement resilient and adaptable strategies within the hydrogen domain. The central objective of hydrogen strategies is to achieve robustness, which requires a comprehensive understanding and meticulous evaluation of various factors that influence its resilience and adaptability. Strategic robustness encapsulates the infrastructure's inherent resilience, poised to navigate and thrive within an ever-shifting terrain defined by dynamic market forces, evolving technological paradigms, regulatory intricacies, and the evolving preferences of consumers and stakeholders. This holistic approach forms the cornerstone of our investigation, steering our quest to unravel the critical factors influencing the robustness of hydrogen infrastructure in an era of profound energy transition and transformation.

In addition to strategic robustness, it is crucial to closely examine the dimension of economic robustness in hydrogen strategies, as it ensures the viability, cost-effectiveness, and long-term sustainability of the economic framework supporting the development and deployment of hydrogen technologies. Economic robustness is a cornerstone that underpins the viability and attractiveness of hydrogen infrastructure projects to stakeholders, spanning public and private domains. It encompasses the infrastructure's ability to withstand the ebbs and flows of financial markets, to deliver predictable returns on investment, and to ensure the allocation of resources in an economically prudent manner. In essence, economic robustness aligns seamlessly with strategic robustness, forging a symbiotic relationship that is indispensable for the realisation of sustainable hydrogen ecosystems. The significance of economic robustness extends beyond financial aspects and is inherently linked to the overarching strategic vision of hydrogen as a key element in the future energy landscape. Secure investments, supported by economic robustness, play a vital role in driving hydrogen infrastructure projects. They inspire confidence among various stakeholders, including venture capitalists, industry leaders, policymakers, and the general public, creating an enabling environment for the accelerated development and adoption of hydrogen technologies.

In the future, we plan to analyse both strategic robustness and economic robustness based on the results and models presented in this research. However, for the current discussion, our focus will be on examining the model robustness and the implications it has for industry stakeholders and policy makers. By evaluating the model robustness, we aim to provide valuable insights into the results of these models in guiding decision-making processes.

Recommendation for industry

Based on modelling results, it is recommended that industry companies consider the substantial minimum hydrogen demand projected to reach approximately 700 TWh of gaseous hydrogen for the EU27+UK by 2050 (Scenario *Low_Demand*). The industry sector, particularly high-temperature and energy-intensive process heat applications, along with central power and district heating generation, are expected to be the main consumers. Therefore, industry companies should consider prioritizing hydrogen utilisation in sectors such as steel production and other high-temperature process heating applications, which could contribute to a long-term hydrogen demand of around 200 to 300 TWh in the EU27+UK. Differentiation within the industry sector is crucial to effectively address the diverse requirements and potential applications of hydrogen.

For industry companies, it is furthermore recommended to consider the establishment of a pan-European hydrogen backbone, which proves to be a robust element in all calculated scenarios. This backbone network would connect regions with significant renewable energy potentials in Northern and Southern Europe to main underground storage sites and countries with industrial demand in Central Europe. Such a network would enable the deployment of cost-effective wind and solar energy sources and provide flexibility in balancing renewable generation across the continent. In the case of Germany and other larger countries with industries and substantial wind/solar potentials, establishing a core network that connects major demand centres is a no-regret strategy. Modelling results indicate that this core network reduces overall system costs and facilitates important system services. Additionally, the ambitious deployment of Europe's wind and solar potentials at maximum scale is deemed a no-regret element across all scenarios. It is worth considering that large-scale domestic hydrogen production within Europe can be more competitive than importing hydrogen from non-EU countries, particularly if the imports are pipeline-bound. Additional costs associated with long-range shipping can make imports less competitive. However, pipeline-bound imports can still be sourced from the MENA region. For pipeline-bound imports the effort and time of construction should be considered.

Recommendations for policy makers

Policy makers are advised to consider the significant minimum hydrogen demand projected by modelling results, which is approximately 700 TWh of gaseous hydrogen for the EU27+UK by 2050 (Scenario *Low_Demand*). The primary consumers of hydrogen are expected to be high-temperature and energy-intensive process heat applications in industry, as well as central power and district heating generation. The industry sector presents a robust and substantial demand for hydrogen. To effectively address this demand, policy makers should prioritize differentiation. Specifically, steel production and various other high-temperature process heating applications should be considered as priority sectors for hydrogen utilisation. These applications alone could result in a long-term hydrogen demand of around 200 to 300 TWh in the EU27+UK. Policy makers are furthermore recommended to prioritize the establishment of a pan-European hydrogen backbone, as it emerges as a robust element in all calculated scenarios. This backbone network would interconnect regions in Northern and Southern Europe with significant renewable energy potential to main underground storage sites and countries in Central Europe with industrial demand. By facilitating the deployment of cost-effective wind and solar energy sources, this network would enhance flexibility in balancing renewable generation across the continent. In the context of larger countries like Germany, policy makers should consider implementing a core network that connects major demand centres. This strategic approach is considered a no-regret strategy, as modelling results demonstrate its ability to reduce overall system costs and enable important system services. Furthermore, policy makers should prioritize the ambitious deployment of wind and solar potentials at maximum scale, as this is found to be a no-regret element across all scenarios. When considering hydrogen imports, policy makers should recognize that large-scale domestic hydrogen production within Europe can be more competitive than relying on imports from non-EU countries, especially if the imports are pipeline-bound. The additional costs associated with long-range shipping can diminish the competitiveness of imports. However, if imports are pipeline-bound, they can still be sourced from the MENA region. In conclusion, policy makers should focus on fostering the establishment of a pan-European hydrogen backbone, promoting core networks in major demand centres, and encouraging the ambitious deployment of wind and solar potentials. Additionally, they should carefully evaluate the competitiveness of hydrogen imports, taking into account the costs associated with long-range shipping.

Despite significant progress in understanding the robustness of hydrogen infrastructure, there are several aspects that remain uncertain and warrant further investigation. The future global value chains of the chemical industry have the potential to significantly impact Europe's hydrogen infrastructure. On one hand, the production of green ammonia or ethylene requires large quantities of hydrogen, and direct electrification is not technically feasible. However, on the other hand, it is uncertain whether the entire value chain, from hydrogen production to various chemicals, will be established in Europe. Imports of intermediate products like green methanol or ammonia could substantially reduce the demand for gaseous hydrogen in Europe, with up to 1,000 TWh potentially at stake. Furthermore, the integration of hydrogen into the distribution grid for space heating purposes shows relatively low overall demands. Regarding hydrogen for specific transport applications, the role of imports from non-EU countries is also subject to uncertainty.

5.2. Environmental aspects of a future hydrogen infrastructure

This chapter takes a sustainability perspective on the TransHyDE chain with a focus on raw material requirements and greenhouse gas emissions (GHG). For this purpose, various aspects and sections of the TransHyDE chain with a focus on sustainability were discussed at the TransHyDE General Assembly and three "environmental focus topics" were chosen at the end, which will be examined in more detail in the form of targeted work:

- Iridium requirements of a future hydrogen production in Germany
- Greenhouse gas emissions from the production of hydrogen pipelines
- Climate impact resulting from hydrogen emissions with a focus on hydrogen transport in pipelines

These focus topics therefore only illuminate a section of the extensive TransHyDE Project System Analysis chain and do not claim to be a complete sustainability assessment for the entire chain. Rather, the topics dealt with, and the results achieved are intended to shed light on certain aspects and allow statements to be made and, if necessary, recommendations to be made to policymakers.

However, it must be emphasised that the results of the three "environmental focus topics" discussed below are within a wide range of uncertainty and, even though quantitative results are given, a qualitative discussion based on these results is intended. The uncertainty results from the large number of assumptions that must be made to carry out the calculations and analyses. For many of the input parameters considered, there are currently no concrete simulation results, let alone empirical measurements. For example, regarding a future hydrogen transport network, this includes its future length, design (pressure, pipe thickness, meshing, etc.) and hydrogen throughput. The same applies to the electrolysis capacities installed in Germany and Europe in the future as well as the shares of respective electrolysis technologies (AEL, PEM, SOEC, etc.). Within the scope of the TransHyDE Project System Analysis, these questions are investigated as part of extensive energy system simulations and central results and statements on the future development of the hydrogen infrastructure in Germany and Europe are achieved. These results also serve as a basis for the following calculations, but do not provide the necessary detail in all aspects at the present time to provide a complete quantitative basis for the calculations of the "environmental focus topics". The necessary assumptions resulting from this context are mentioned and discussed at the appropriate points.

The structure of this chapter is based on the three focus topics, whereby the methodology applied is described for each of them, the underlying technology parameters and related sources are named, and finally the results are discussed.

Iridium requirements of a future hydrogen production in Germany

It is already foreseeable that extensive electrolysis capacities at the GW-scale will be required in Germany on the way to defossilisation. In addition, there is a dependence on electrolysers installed in other European countries. Part of this capacity will be covered by proton exchange membrane electrolysis (PEM) technology. Although investment costs of PEM electrolysers are currently clear higher than investment costs of alkaline electrolysers (AEL), PEM technology allows higher utilisation of fluctuating renewable electricity (e.g. good start-up behaviour, flexible operation at high efficiency and maintaining high gas quality of end products). Therefore, PEM electrolysis is considered one of the key technologies for a future energy system, which is one of the reasons why central players (e.g. Siemens Energy, MAN subsidiary H-TEC) are also advocating for the production of PEM electrolysers in Germany.

But besides the abovementioned advantages, the PEM electrolysis stacks require iridium, one of the rarest elements on earth, as a catalyst for oxygen evolution at the anode. The specific iridium loading of a less than one gram per kilowatt of electrolysis capacity appears very low at first glance, and in recent years significant reductions in the specific iridium loading of the catalysts have been achieved through intensive technological developments. However, in view of the need for future global electrolysis capacities at gigawatt scale and the low global iridium production volume, several studies stated a potential bottleneck for the ramp-up of PEM electrolysis in Germany and worldwide. For this reason, this focus topic examines the future iridium demand in the case of a ramp-up of PEM electrolysis capacities in Germany, considering specific iridium loading and recycling rates. Even though this topic has been analysed by existing work and comprehensive model-based analyses (Clapp et al., 2023; Minke et al., 2021), we supplement the discussion with calculations based on TransHyDE-internal simulation results for a future electrolysis ramp-up in Germany.

Underlying assumptions and parameters:

Basically, our procedure for estimating future iridium requirements and identification of potential bottlenecks is based on following central values and assumptions:

- the installed PEM electrolysis capacity to be expected in Germany in the future and an estimate for the associated ramp-up in the years before.
- the lifetime of PEM electrolysis stacks
- the specific iridium loading for PEM electrolysis catalysts
- an expected ramp-up of an iridium recycling infrastructure and associated recycling rate for electrolysis stacks
- global iridium production rates

Regarding the future installed electrolysis capacities in Germany, the assumptions are based on results of the TransHyDE Project System Analysis for scenario *High_Demand*. The consideration of the *High_Demand* scenario for the analysis of the iridium demand represents, so to speak, a worst-case scenario for the future PEM electrolysis and thus the resulting iridium demand in Germany. Based on the scenario for a *Mid_Demand* of hydrogen and derivatives an installed electrolysis capacity in the year 2045 of 106 GW_{el} is to be expected. Considering a ramp-up of electrolysis capacities from today to the year 2045, we use the updated target value of the National Hydrogen Strategy of 10 GW_{el} in Germany for the 2030 electrolysis capacities. The years thereafter result from a simplified linear interpolation between these identified target values. To estimate the PEM share of these installed electrolysis capacities, it was assumed that PEM technology will have a 30 % market share starting in 2023 and increasing up to 70 % until 2045. The lifetime of PEM stacks was considered to be 75,000 hours in 2023 with the increasing trend up to 90,000 hours from 2035 on.

In view of the future demand for iridium in the production of PEM electrolysis stacks, specific loading of the anodes and cathodes must be considered. So far, no materials appear suitable for replacing iridium with satisfactory cell performance. This is since the coating of the PEM anodes must be highly corrosion-resistant and at the same time have sufficient electrochemical activity (Rozain et al., 2016). As a starting point in our analysis, 0.67 kg Ir/MW_{el} has been chosen for the year 2023 for iridium. For future demands a trend of rapid decreasing of this platinum group metal down to 0.15 kg Ir/MW_{el} in 2045 has been considered (Clapp, 2023; Deutsches Institut für Luft- und Raumfahrt e. V., 2020).

Regarding the production for iridium, it must be considered that there is no national iridium production. Therefore, the analysis focuses on the characterization of the first phase of the iridium life cycle, i.e. the production at the global scale. Around 80 % of iridium comes from South Africa, the rest is almost completely mined in Russia with minor production in Zimbabwe. Considering the lifetime of mining fields for platinum group metals and financial indicators, we assume an unchanged iridium production up to 2045 at the level of 8.5 tons/a for iridium based on the USGS minerals yearbook and a recent study by DLR (Deutsches Institut für Luft- und Raumfahrt e. V., 2020; Singerling/Schulte, 2021).

There is great uncertainty related to the recycling scenarios and future recycling rates for iridium. However, one thing is already clear: without a significant ramp-up of closed-loop recycling for components containing iridium (e.g. PEM stacks), the large PEM capacities cannot be installed - both at a German and global level Kiemel et al., 2021). State-of-the-art components and hardware already have recycling rates of 20-30 % for iridium. In special industrial processes, recycling rates of 40-50 % can be achieved for iridium (Minke et al., 2021; UNEP, 2011). Although iridium recycling processes are established for electrochemical components, it should be noted that in the case of the ramping-up hydrogen economy, a recycling architecture must first be developed and implemented that can recover the iridium contained in the PEM stacks in a high-quality and cost-efficient manner. It is therefore assumed in this chapter that a closed-loop recycling rate of 20 % can be achieved from the first years in which there is a need for PEM stack recycling, which will be steadily increased in the following years. From 2035 onwards, the recycling rate is expected be optimised to 90 % due to stakeholders' strong interest in recovering iridium.

Figure 5.1 shows the annually added PEM electrolysis capacities as well as the cumulative increase of PEM capacities (incl. stack replacements) for Germany. The figure shows a significant increase in the necessary annual expansion in 2030. This is due to the framework values of a target value of 10 GW of PEM capacities by 2030 based on the National Hydrogen Strategy (necessitating annual expansion rates of 0.3-0.5 GW/a) and the TransHyDE simulation result of 106 GW in 2045, thus resulting in annual expansion rates of 2.6-4.4 GW/a. The cumulative PEM electrolyser capacity in Germany until 2045 sums up to 65 GW including necessary stack replacements. In 2032, the first stacks will reach the end of their assumed lifetime and will have to be replaced. This results in a resulting annual demand for PEM stack replacements, which is in the range of 0.3-0.6 GW/a in the first few years, then increases significantly to 2.6-2.9 GW/a from 2040.

The resulting demand for iridium can be seen in Figure 5.2. The

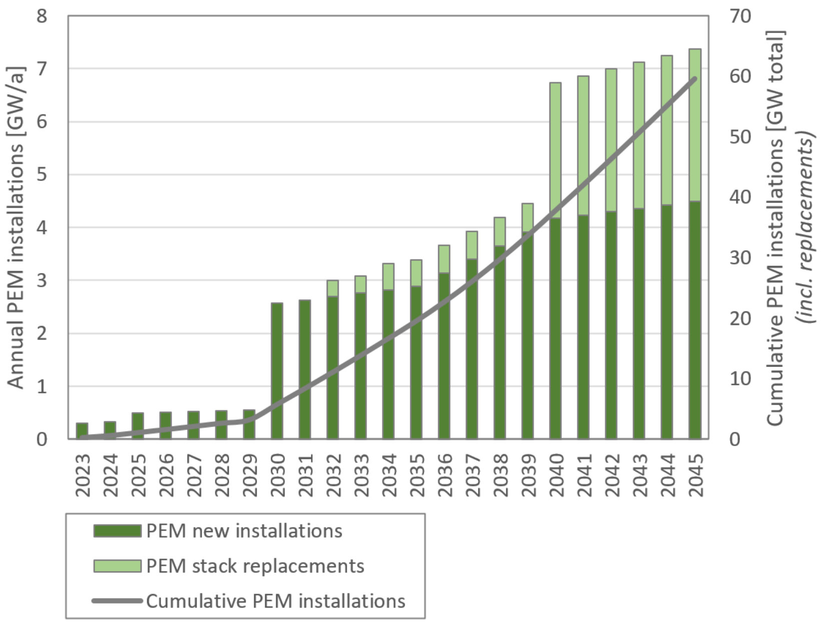

Figure 5.1: Ramp-up of PEM electrolysis capacities in Germany until 2045, divided into electrolysis capacities newly added to the market and the replacement of existing PEM stacks that will become necessary from the 2030s onwards and have reached the end of their service lives. The apparent "leap" from 2029 to 2030 in the annual PEM installations results from the set framework conditions of 10 GW electrolysis capacities in Germany in 2030 (National Hydrogen Strategy with an assumed 30 % PEM market share) and the target value of 106 GW electrolysis capacities in Germany in 2030 calculated in the TransHyDE Project System Analysis (*Mid_Demand* with an assumed 70 % PEM market share).

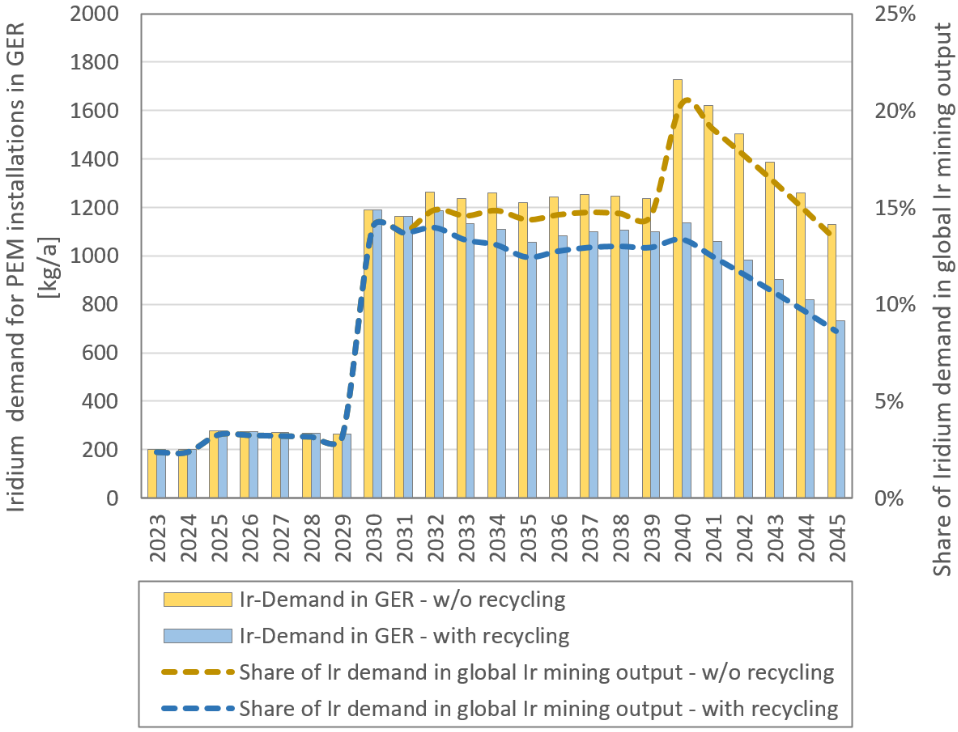

Figure 5.2: Illustration of the annual iridium demand for PEM electrolysis capacities constructed and replaced in Germany. A distinction is made here between iridium demand without (yellow bars) and iridium demand with existing recycling infrastructure (blue bars) in Germany. The latter can lead to a significant reduction in the demand for iridium, particularly during the peak years of the electrolysis ramp-up in Germany, thus reducing dependence on the iridium world market. The right axis shows the share of German iridium demand in global iridium production (assumption 8.5 t/a).

figure differentiates between a scenario with and a scenario without recycling iridium from PEM stacks after their lifetime. The latter scenario was included to highlight the impact of iridium recycling from PEM stacks.

The figure shows that at the beginning of the PEM electrolysis ramp-up in Germany, around 200-280 kg Ir/a will be required. This corresponds to about 2-3 % of the global iridium production. With the significant increase in the required PEM capacity output in 2031, the demand for iridium will also increase dramatically. Its share of global production will therefore increase to 14 % in 2031 for this German electrolysis market alone. To bring it into perspective, a team at Johnson Matthey works with the assumption of a 20 % share of iridium used for electrolysers on the global annual iridium production to be realistic, the IEA in its conservative Announced Pledges Scenario counts with annual primary iridium demand for electrolysers to be over 20 % of global iridium production up to 2032 (Bullerdiek et al., 2024).

As first stacks reach the end of their lifetime around 2030, recycled iridium can be re-used for the next generation of stacks with expected lower loading per MWel. Although this only slightly reduces the demand for annual production of iridium in the first 2030s (12.4 % instead of 14.4 %), it will become a non-negligible factor in a tight iridium market. In the further phase of the energy transition and the ramp-up of the PEM infrastructure in Germany from the late 2030s, the importance of iridium recycling becomes apparent. The share of global production without recycling of PEM stacks would be up to 20.3 % in peak times (~2040) but can be reduced to around 13.4 % with a PEM stack recycling industry within the framework of the assumptions made.

It should be emphasised that above-mentioned results are based on a few assumptions that cause the high variability of results:

- Iridium availability and global iridium market: The data availability on the global iridium market is low; the metal production is usually reported in “6E” - estimates covering six platinum group metals (PGM). Moreover, iridium is a co-product in platinum (Pt) and palladium (Pd) mine production and its production highly depend on the platinum and palladium demand, geological and financial conditions of mining and platinum group metals (PGM) trading.
- Iridium loading: The decrease of the iridium loading for the anode in PEM stacks depends on breakthroughs in the electrochemistry field. The loading of iridium in an electrolysis cell can have an impact on the performance, efficiency and durability of the electrolyser. In this context, it must be emphasised that reducing catalyst loading means increasing current density. Both changes lead to an increase in cell voltage and thus to lower cell efficiency. These relationships are the subject of the technological advancement of PEM electrolysis. However, it remains to be seen to what extent the iridium loading targets can be achieved in the coming decades.
- Other key variables in the calculations presented are the share and establishment of PEM technology in future water electrolysis capacities in Germany and the assumptions regarding an iridium recycling rate for future electrolysis stacks.

All these aspects should be considered in further discussion of this topic, analysed using in-depth sensitivity analyses and included in other scientific literature.

GWP of Pipeline production

The envisioned future of hydrogen infrastructure necessitates the construction of a hydrogen pipeline grid, a crucial component for the transportation of hydrogen across long distances. According to modelling of the TransHyDE Project System Analysis, an initial hydrogen grid spanning approximately 9,000 km is envisioned. This grid comprises a hybrid of retrofitted natural gas pipelines (6,000 km) and newly constructed pipelines (3,000 km), all made from steel due to its compatibility with the demanding requirements of hydrogen transport.

Comparing this prospective hydrogen grid with the current natural gas pipeline landscape reveals a significant shift. The model focuses on high-pressure, long-distance pipelines, acknowledging the unique challenges posed by hydrogen distribution. With 35,000 km of natural gas long-distance, high pressure pipelines and 540,000 km of low-pressure pipelines at regional level, the hydrogen grid, even in its early stages, demands meticulous planning and strategic placement. Nevertheless, it is already becoming apparent that a future hydrogen network will not have the same decentralised dimensions as the current natural gas supply system, which is laid all the way to the end customer with its widely branched low-pressure pipelines.

However, primary steel making, integral to the production of these pipelines, introduces an environmental conundrum. On the one hand steel is the optimal and most likely only material for hydrogen infrastructure. On the other hand, its production – even if it is changing rapidly – is currently still emissions-intensive. Critics might focus on the environmental burden associated with the fabrication and construction of the proposed 3,000 km of new pipelines, disregarding the envisaged improvement of status quo. Therefore, this discussion is being anticipated here.

In a gedankenexperiment it is assumed that the future hydrogen pipelines will mimic the distribution of current natural gas high-pressure pipelines, regarding pressure and flow velocity levels (Lange et al., 2021). The intricate interplay of pressure, diameter, and wall thickness leads to an estimated steel demand of 610,000 tons for the proposed 3,000 km of pipelines. This production triggers approximately 1.5 million tons of greenhouse gas emissions (Mannesmann Line Pipe GmbH, 2022). For comparison, Germany's steel sector emitted approximately 48 million tons of CO_2 equivalents in 2020 (Statista, 2023). The emissions from the steel production for hydrogen infrastructure, though lower than the overall sector's emissions, still constitute a substantial environmental investment. In the following it is analysed when this investment exclusively compared to the current natural gas infrastructure pays off. For this purpose, the specific greenhouse gas potential of hydrogen is first discussed below, from which the climate impact that could result from fugitive hydrogen emissions from a future pipeline network is then estimated. This is then finally compared with the indirect GHG emissions from steel production for a future hydrogen network presented above.

Climate impact resulting from hydrogen emissions with a focus on hydrogen transport in pipelines

Hydrogen itself does not have a direct impact on the climate. Due to its symmetry and structure it neither absorbs nor reflects thermal radiation. However, it has an indirect effect on the climate, due to its reaction with other species in the atmosphere. The main reaction for molecular hydrogen is as follows:

Reaction with hydroxyl radicals in the troposphere:

$$H_2 + OH = H_2O + H \qquad (R1)$$

Hydroxyl radicals are known as the "detergent" of the atmosphere, and they are an important chain reaction initiator. For example, they oxidise CH_4 and without this reaction the lifetime of methane and its climate impact would be several orders of magnitude higher than it is today ($CH_4 + OH = CH_3 + H_2O$). Therefore, an increased hydrogen concentration in the atmosphere could possibly lead to a lower concentration of hydroxyl radicals available for the oxidation of methane and thus prolonging its lifetime in the atmosphere, since H_2 also reacts with OH. Further, the reaction leads to more water vapor (see R1), especially in the stratosphere (10-50 km height). Through this "moisturising" of the stratosphere, the stratosphere becomes cooler, leading to a higher probability of stratospheric clouds and this could ultimately influence the ozone layer (Derwent, 2018).

The indirect effects of hydrogen are mainly due to:

- the perturbation of the lifetime of methane and other organic compounds in the atmosphere,
- through the emerging of water vapor especially in the stratosphere,
- and finally, the reaction of hydrogen radicals, leading to more tropospheric ozone that leads to further warming.

The main uncertainty is the hydrogen sink. It is estimated that up to 75 % of hydrogen emissions are ending up in the soil sink (Arrigoni | Bravo Diaz, 2022). This process is presumably driven by hydrogen digesting microorganisms in the soil. However, there is not much data available, and this is still subject to further research.

Table 5.1: GWP 20 and 100 values from Literature in comparison to GWP values from methane (last line).

Literature	GWP 20	GWP 100
Derwent et al., 2020		5 ± 1
Field |Derwent, 2021		3.3 ± 1.4
Ocko| Hamburg, 2022	33 ± 20	11 ± 5
Warwick et al., 2022	33 ± 20	11 ± 5
Hauglustaine et al., 2022	40.1 ± 24.1	12.8 ± 5.2
Methane (Forster et al., 2021)	82.5 ± 25.8	29.8 ± 11

Note: GWP 20 refers to a 20-year time horizon, GWP 100 represents a 100-year time horizon.

To allow for a comparison between different greenhouse gases and their warming potential, one widely used metric is the global warming potential (GWP). It is a measure of how much energy is absorbed by 1 kg of a gas over a certain period of time, usually 20 and 100 years, relative to the emission and energy absorption of 1 kg of CO_2 (EPA, 2023). CO_2 as the reference has a GWP equal to 1, and the larger the GWP of a certain species, the higher the warming potential over a period of time. For example: methane has a GWP of 28 over 100 years, meaning that 1 kg of methane emitted to the atmosphere has the same warming potential as 28 kg of CO_2.

To calculate the GWP, several approaches are possible and leading to different values. Most of the calculations are based on the Intergovernmental Panel on Climate Change (IPCC) reports and it depends on the following factors:

- the absorption of infrared radiation (IR radiation)
- the time horizon of interest (integration period, for example 100 years for GWP100)
- the atmospheric lifetime of the gas (short live species equilibrate faster)

For example, for faster equilibrating species, it makes sense to take the GWP20 into account.

As stated before, hydrogen does not absorb any IR radiation itself, however it has an indirect impact which is difficult to quantify and describe. As seen in Table 5.1, the given values estimated over the last 3 years differ substantially, though all estimates are still below the GWP of methane.

Overall, the substitution of fossil methane with green hydrogen can have a major advantage for the climate. On the one hand, the lifetime of hydrogen in the atmosphere is shorter, equilibrating faster. And on the other hand, the substitution of methane with hydrogen will lower the total amount of methane present in the atmosphere.

As described earlier, the GWP is giving its value relative to the mass of a gas emitted. However, hydrogen is a significant smaller and lighter molecule than carbon dioxide (22 times heavier than H_2) or methane (8 times heavier than H_2). The behaviour for leakages is therefore different and further described in the following sections, showing an advantage for hydrogen over methane despite having an indirect influence on the climate (United States Environmental Protection Agency, 2023).

How can fugitive hydrogen emissions from a future hydrogen transmission grid be estimated?

To estimate future fugitive emissions from a hydrogen transmission grid, it is useful to first consider the causes and quantity of methane emissions in the existing natural gas transmission grid.

Fugitive emissions in the gas transmission grid are primarily due to leakage. A major source is compressor stations, which are used to maintain pressure in the pipelines. Compressor stations are spaced at intervals of about 100-200 km (Cerbe, Lendt, 2016). Leakage occurs both at the compressors (moving parts) and at leaking flanges, bolted connectors or fittings (Böttcher, 2022; Schütz et al., 2015). Additional possible leakage sources are shut-off devices (e.g. sliding sleeves) located along the high-pressure pipelines as well as systems for regulating and metering gas pressure. In case of pipelines, external influences or corrosion and the associated formation of cracks, holes or ruptures can lead to fugitive emissions (Schütz et al., 2015). Further emissions occur due to maintenance and repair work and the associated blowouts. However, their share has decreased in recent years due to the increasing use of mobile compressors (Böttcher, 2022). In 2020, 17 kt of fugitive methane emissions were released at transmission system operator (TSO) level (including underground gas storage) (UNFCCC, 2023) (see Figure 5.3), which corresponds to about 0.06 % of the total greenhouse gas emissions in Germany (= 735 Mt CO_2-eq) (UNFCCC, 2023).

For the indicative estimation of fugitive hydrogen emissions from a future hydrogen transmission grid, the typical emission pathways for methane are transferred to hydrogen via a conversion factor.

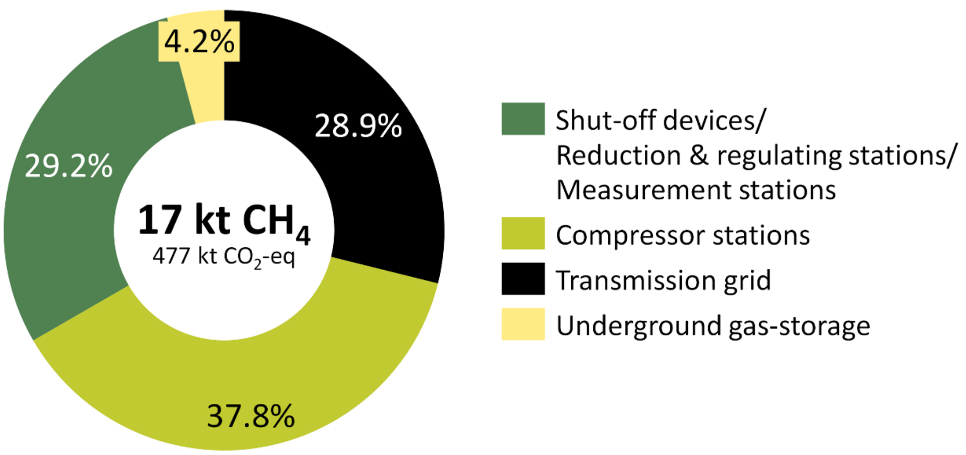

Figure 5.3: Fugitive methane emissions at TSO level including underground gas-storage (UNFCCC, 2023).

Therefore, some assumptions and simplifications must be made:

- Due to uncertainties in both the GWP of hydrogen (see Section GWP of Pipeline production) and the amount of fugitive hydrogen emissions in a future hydrogen transmission grid, the results are presented using minimum/maximum ranges.
- Emissions from all transport network assets (including storage) are exclusively due to leakage. Emissions due to blowouts are neglected.
- The hydrogen transmission grid has the same complex structure as today's natural gas transmission grid.
- The share of aggregated transmission grid assets (pipelines, underground gas-storage storage, compressor stations, etc.) is proportional to the pipeline length of the gas transmission grid.
- Only cavern reservoirs are used as underground gas-storage.
- Furthermore, a constant implicit emission factor is assumed for methane and for hydrogen. National and international efforts to reduce fugitive emissions at TSO level are ignored.

According to German Federal Environment Agency, a total of 16.8 kt methane was emitted in 2020 at TSO level (including cavern reservoirs, excluding porous-rock reservoirs[4]) (Böttcher, 2022). Considering the length of the gas high-pressure transmission grid of 33,809 km (UNFCCC, 2023), the ratio of aggregated methane emissions and grid length results in an implicit emission factor of 496 kg CH_4/(km*a) or 692 m³ CH_4 (NTP)/km for 2020[5] (Cerbe, Lendt, 2022).

To estimate the future fugitive hydrogen emissions a so-called conversion factor (CF), which is used for leakage measurements, is applied below. The CF describes the ratio of the volumetric flow rates of two gases (here: H_2 and CH_4) under same operating conditions and depends on the existing flow regime and the fluid properties (Anghilante et al., 2023). The outflow of gas from a leakage will be laminar or turbulent, depending on gas characteristics and the ratio of hole area to length of the leak (Kiwa Technology, 2019). Laminar leaks are typically found in fittings, while turbulent leaks occur, for example, from holes in pipelines (Kiwa Technology, 2019). At laminar flow, volumetric gas flow rates are inversely proportional to their dynamic viscosities. At turbulent flow, flow rates are inversely proportional to the square root of the density ratio. According to Anghilante et al. (2023) and Züttel et al. (2008) the fluid properties of hydrogen and methane result in a methane-based hydrogen conversion factor of 1.26 for laminar flow and of 2.83 for turbulent flow. Therefore, the following range applies to the implied emission factor (IEF) of hydrogen[6]:

$$IEF_{H_2,low} = 1.26 \frac{m^3 H_2}{m^3 CH_4} \cdot 692\ \frac{m^3\ CH_4}{km \cdot a} = 872\ \frac{m^3\ H_2}{km \cdot a} = 78\ \frac{kg\ H_2}{km \cdot a}$$

$$IEF_{H_2,high} = 2.83 \frac{m^3 H_2}{m^3 CH_4} \cdot 692\ \frac{m^3\ CH_4}{km \cdot a} = 1958\ \frac{m^3\ H_2}{km \cdot a} = 176\ \frac{kg\ H_2}{km \cdot a}$$

How high are greenhouse gas emissions from fugitive hydrogen emissions compared to current methane emissions at transmission grid level?

Considering the highly uncertain GWP bandwidths of hydrogen (GWP 100: 3.3 ± 1.4 to 12.8 ± 5.2 and GWP 20: 33 ± 20 to 40.1 ± 24.1)[7] and the GWP of methane[8], the calculated implicit emission factors result in the following bandwidth for GHG emissions arising from fugitive H_2 emissions at TSO level (including cavern gas-storage) (see Figure 5.4):

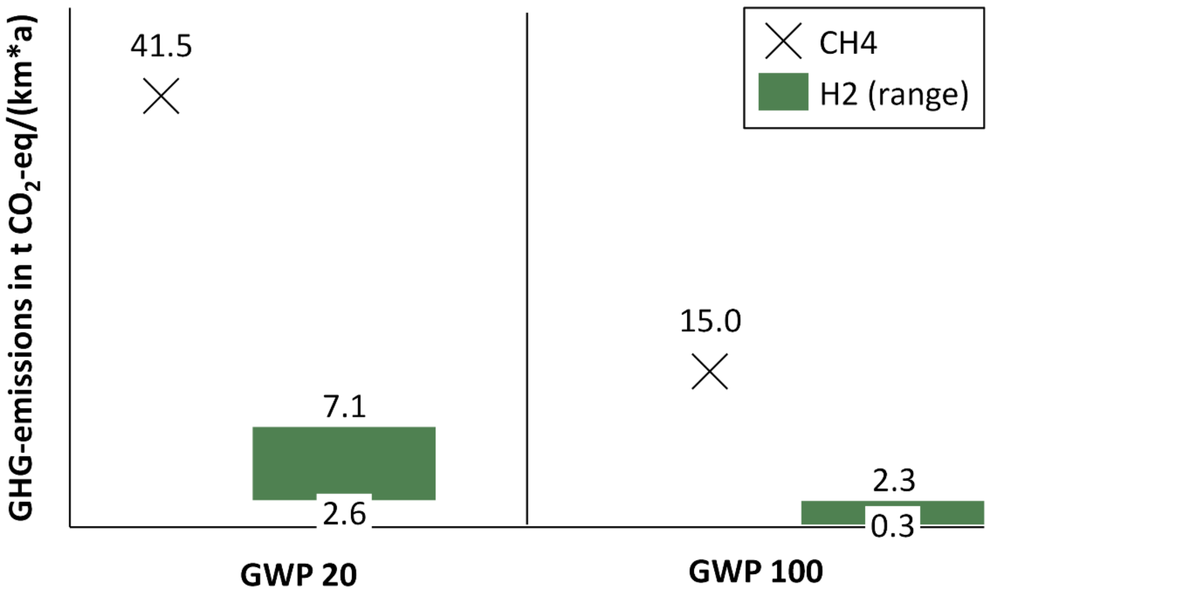

Figure 5.4: Comparison of specific GHG emissions caused by fugitive emissions in the existing (2020) natural gas network according to Umweltbundesamt (2022) in a future hydrogen network. The range of H_2 emissions is composed of the different implied emission factors due to different leakage rates for laminar ("H_2,low") and turbulent flow ("H_2,high") and the minimum and maximum GWP range for hydrogen according to the literature survey in section GWP of Pipeline production.

[4] Aggregated methane emissions including porous-rock reservoirs are 17.0 kt CH_4 resulting in an implied emission factor of 503 kg/(km*a).
[5] NTP: Normal temperature and pressure. Density of methane at normal temperature and pressure: 0.7175 kg/m³ (NTP).
[6] Density of hydrogen at normal temperature and pressure: 0.08989 kg/m³ (NTP) (Cerbe, Lendt, 2016).
[7] See previous section for more details on the Global Warming Potential (GWP) of hydrogen.
[8] Global Warming Potential of methane according to IPCC AR 6 (2021): GWP 20 (CH_4) = 82.5 ± 25.8, GWP 100 (CH_4) = 29.8 ± 11 (Forster et al., 2021).

As shown in Figure 5.4, specific GHG emissions decrease from 41.7 t CO_2-eq/(km*a) to at least 7.1 t CO_2-eq/(km*a) and from 15.0 t CO_2-eq/(km*a) to 2.3 t CO_2-eq/(km*a) by switching from methane to hydrogen. The reason for the lower GHG emissions, is the lower global warming potential[9], and the lower density of hydrogen. The latter leads to a lower implied emission factor for hydrogen (78 to 176 kg H_2/(km*a) vs. 503 kg CH_4/(km*a)) despite the higher leakage rates by a factor of 1.23 to 2.83 compared to methane.

What are the limitations of the performed estimation for fugitive hydrogen emissions at TSO level?

The methodological estimation is largely based on the structure of today's natural gas transmission grid. However, the future hydrogen transmission grid will differ significantly from today's gas transmission grid (e.g. limited grid extension or length, fewer compressor stations, younger age structure due to new or newly repurposed pipelines, different operating conditions). As a result, it can be assumed that the fugitive H_2 emissions of the future hydrogen transmission grid will be lower. However, more detailed conclusions can only be drawn on the basis of measurements at the various assets of the transmission grid, as already being done in the context of the OGMP 2.0 initiative for methane emissions.

Coming back to the environmental burden from the construction of newly built steel-based hydrogen pipelines: it now can be set in contrast to the analysed GHG benefit of a hydrogen grid of approx. 35 t CO_2-eq/(km*a). From this it can be deduced that the infrastructural investment in 3,000 km of new pipeline to enable a 9,000 km long launch network can therefore avoid fugitive emissions of approx. 300 kt CO_2-eq per year compared to an existing analog natural gas infrastructure – including the indirect GHG emissions from steel production. The environmental impact would therefore be amortized in less than five years, not even taking into account the other advantages of hydrogen. Considering the limitations of this study, amortization time is probably even shorter.

Recommendations for policy makers:

- Platinum is the key metal for producing iridium. Platinum is used a coating for both, the anode and the cathode in stacks and therefore demand for platinum is expected to grow with the increased production of PEM electrolysers. Convey a message to industry for reserving platinum for electrolyser production.
- In 2030s, closed iridium recycling loops will impact the total amount of iridium for next generation of stacks. To facilitate the process of recycling, stacks built now shall be designed so that required metals are easily recycled at the end of the life lime of stacks. Support the design guidelines for stacks from the life cycle perspective.
- The GHG emissions for the construction of the new sections of a future hydrogen base network would be amortized within approx. 5 years if compared to the emissions that would be generated by the continued operation of a comparable natural gas network section.
- In Germany, fugitive emissions at TSO-level play a minor role, accounting for 0.06 % of total GHG emissions in 2020 (UNFCCC, 2023). A methodical and conservative estimation of fugitive emissions from a future H_2 transmission grid shows that the GHG emissions from hydrogen emissions will be much lower than those from current methane emissions due to the lower density and the associated lower implied emission factor, as well as the lower GWP of hydrogen compared to methane. Nevertheless, it is important to minimise fugitive emissions at the transmission grid level as much as possible to enable the most efficient and climate-neutral H_2 supply possible. Guidance on minimising fugitive emissions is currently being developed for methane as part of the EU methane strategy.

5.3. Communication

The transformation of the energy system to a PtX- or hydrogen-based economy represents a major social challenge. It should be noted that within this transformation, a social dimension must be considered in the change process in addition to the technical, economic and legal dimensions. This is not only about possible conflicts and acceptance problems in developing and expanding new infrastructures but much more about the potential offered by a broad and active support of different societal actors. Various studies deal with the factors relevant to acceptance or non-acceptance of energy projects. The concept of social acceptance was prominently introduced by Wüstenhagen et al. (2007) as a three-stage approach to understanding wind energy development, namely socio-political, market and local acceptance. The model is based on a systemic understanding according to which technologies are always embedded in a human-technology-environment system and can be applied to the field of hydrogen. Acceptance issues are relevant at different levels of society:

- At the socio-political level, it is about the overall social discourse on energy technologies, which is strongly linked to higher-level discourses such as the energy transition and the nuclear or coal phase-out.
- At the market level, the willingness to invest and the degree of deployment are relevant indicators.
- At the local level, the focus is on the direct impacts associated with energy infrastructures, such as potential risks, effects on local flora and fauna, etc.

Psychologically, aspects such as perceptions of justice and social norms play a role on all three levels. At the current time, acceptance discourses towards hydrogen are mainly located on the socio-political level, accordingly, hydrogen related information and communication processes play a special role: This is where possible concerns, experiences, facts and myths are discussed, which as subjective convictions ("beliefs") have attitude-relevant significance. Consequently, special attention should be paid to the dynamics of societal discourses.

[9] There is still a high level of uncertainty regarding the GWP of hydrogen (see section GWP of Pipeline production).

When it comes to public acceptance, the results of our studies in TransHyDE show that there are still many uncertainties in the assessments and provide concrete indications of where there is still a need for information and communication and where, consequently, corresponding opportunities for participation in the transformation process can be created.

In this context, the special role of trust should be emphasised; this is in line with the results of other studies (Huijts et al, 2012). Trust in communication, in institutions and underlying research processes is the base that provides information on new technologies that can have an impact on the attitude formation process. The complexity of the topic of hydrogen illustrates the special responsibility not only of industry players but also of science communication to contribute to opinion formation through factual and well-founded information and to enable informed decisions. Especially when connected to a high degree of uncertainty, the role of affect and emotional responses in explaining attitudes is relevant.

Furthermore, the results indicate that it is not sufficient to focus exclusively on individual technologies or applications to understand acceptance formation processes and assess individual acceptance factors such as risk perception. Rather multi-level approaches that consider the entire chain are necessary. This becomes even more important when considering the diffusion process of new technologies through the complex levels of society, where a socio-technical understanding of the system shows the different stakeholder perspectives and acceptance dimensions, e.g. with local or community, market and socio-political acceptance. As mentioned, this is, of course, a challenge at an early stage, since there are still relatively few opportunities to perceive and experience hydrogen infrastructures. In this context, for example, communicating the different hydrogen types and "colours" (e.g. green hydrogen vs. blue hydrogen) is an important basis for public understanding, acceptance building and the discussion of priorities within society. By this means, it can be addressed in the public and political discourse how to balance economic and ecological criteria, and to sensitize for consequences in the exporting countries which are invisible to the consumers in the import countries.

The results also show that a social discourse on the goals and framework conditions of a hydrogen economy is necessary, driven by the target to ensure sustainable supply chains throughout their life cycle.

Overall, next to the observation of an underlying positive sentiment around the topic of hydrogen, our analysis of media discourses also shows that in the context of acceptance factors, only a minor differentiation between various transport infrastructures is visible. Figure 5.5 displays the number of intersections between transport technologies and acceptance factors in the coded segments, thus reflecting the relatively low occurrence of specific transport technologies in media reporting (Sadat-Razavi & Hildebrand, 2023).

It seems relevant to transparently discuss possible existing conflicts of interest or trade-offs between the different sustainability goals. In this context, the results of the effects (impacts) of PtX paths on the different impact categories within the life cycle analyses play a relevant role in science communication. Especially the questions of which quantities are needed, when and in which sectors they are required as well as how these needs can be met, are questions that are directly linked to societal perspectives and acceptance issues - be it security of supply or possible costs. As described above, this is not about the contradiction of either expanding renewable energies in Germany or importing them from other countries. Rather, from a sustainability point of view, both strategies must happen in parallel, expansion of renewables in Germany and import of renewable hydrogen (see section 3). In principle, there is support for both paths in society, as shown by the survey results and discourse described above. To obtain this support, the remaining uncertainties must be reduced accordingly, and concrete implementation paths must be developed. This process should take place in a participatory and dialogical manner in exchange with social groups so that the justice dimensions and criteria mentioned are fulfilled.

For holistic research and understanding of society, not only the discourse on the level of broad population should be analysed, but also specific stakeholder groups which are affected by the hydrogen transformation. Following this approach, the TransHyDE project surveyed municipal stakeholders throughout Germany as employees of industries undergoing transformation (steel, glass, refineries) not only as potentially passively affected parties but rather as actively shaping stakeholders regarding their perspectives, assessments and opportunities regarding hydrogen. To this end, standardised questionnaire surveys were carried out in municipalities throughout Germany on the current status of planning for hydrogen transport infrastructures, as well as employee surveys in selected companies from the steel and glass industries and a refinery.

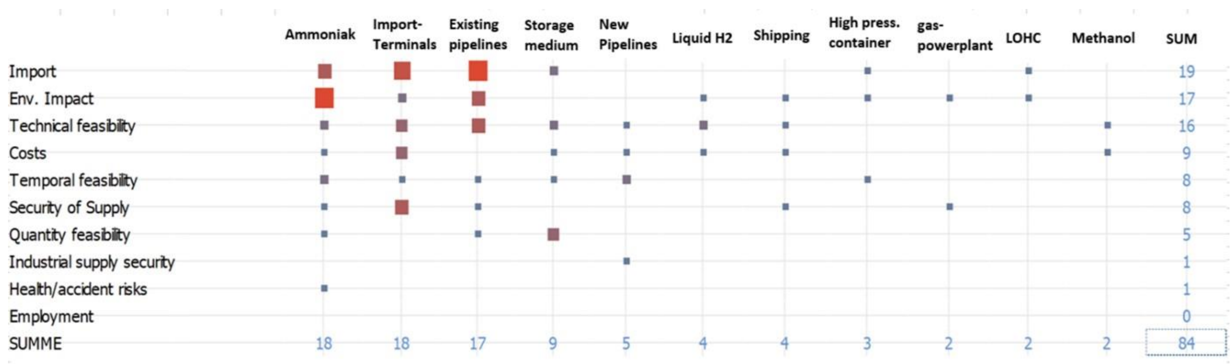

Figure 5.5: Comparison of Number of intersections of specific transportation technologies and acceptance factors in hydrogen media articles.

Topics of the industry focused polls are i.e. the degree of knowledge of the use of hydrogen in industry applications and corresponding information needs, acceptance of the transition process, perceived risks/opportunities (int. competitive advantage, jobs, safety/accidents, regional development) as well as social norms in the (work) environment connected to transformation requirements of training practices for H_2 specialists. Regarding the municipalities, hydrogen-related planning and permitting procedures are especially addressed and by this means the degree of availability of resources for planning and approval processes (knowledge/expertise, funding, personnel, vision/strategy), envisioned areas of application for hydrogen in the community (mobility, heat, industry, others) as well as previous experiences with H_2 projects and other energy infrastructures with resulting knowledge about obstacles and needs for support.

For multilevel communication strategies

The transition towards a hydrogen-based economy calls for a multi-level communication model, highlighting and spanning the complexity of aspects that are part of communication. This model could depict the diverse interaction between the stakeholders holding different roles in the communication process, the content that is communicated, the communication methods, as well as the contexts in which the communication takes place. The following figure visualizes the different levels on which technological diffusion processes take place and the interaction between the levels and corresponding stakeholder groups. The interaction between those levels is characterized by complex communication processes being relevant for the public discourse and the individual attitude formation process, likewise.

Developing and implementing different solutions for the transportation and storage of hydrogen involves a myriad of stakeholders each with their roles and influences. It is pivotal to address the diversity of informational needs and influential capacities of these stakeholders, ensuring that communication is widespread and at the same time contextually relevant and impactful. Within the context of a hydrogen transportation and storage infrastructure various factors are apparent, such as environmental impacts, costs, risks, feasibility (e.g. technical, time), which ultimately can influence the perception and acceptance of infrastructures. Next to the stakeholders as a part of the communication and the content to be communicated about, the diverse set of communication methods and tools can be implemented and selected to match certain informational needs, respectively, ensuring that stakeholders are not only informed but also able to contribute meaningfully to the dialogue and decision-making process. Regarding the time frame, perspective should be placed on these opportunities and potentials. In addition, previous survey results document a fundamental interest in helping to shape the transformation (Ausfelder | Tran, 2023).

Spanning up a multi-level communication model gives room for creating communication systems which allow for collaborative and continuous information exchange between stakeholders. Thereby, ideally enabling a collective commitment towards hydrogen infrastructures that considers different societal expectations, values and needs.

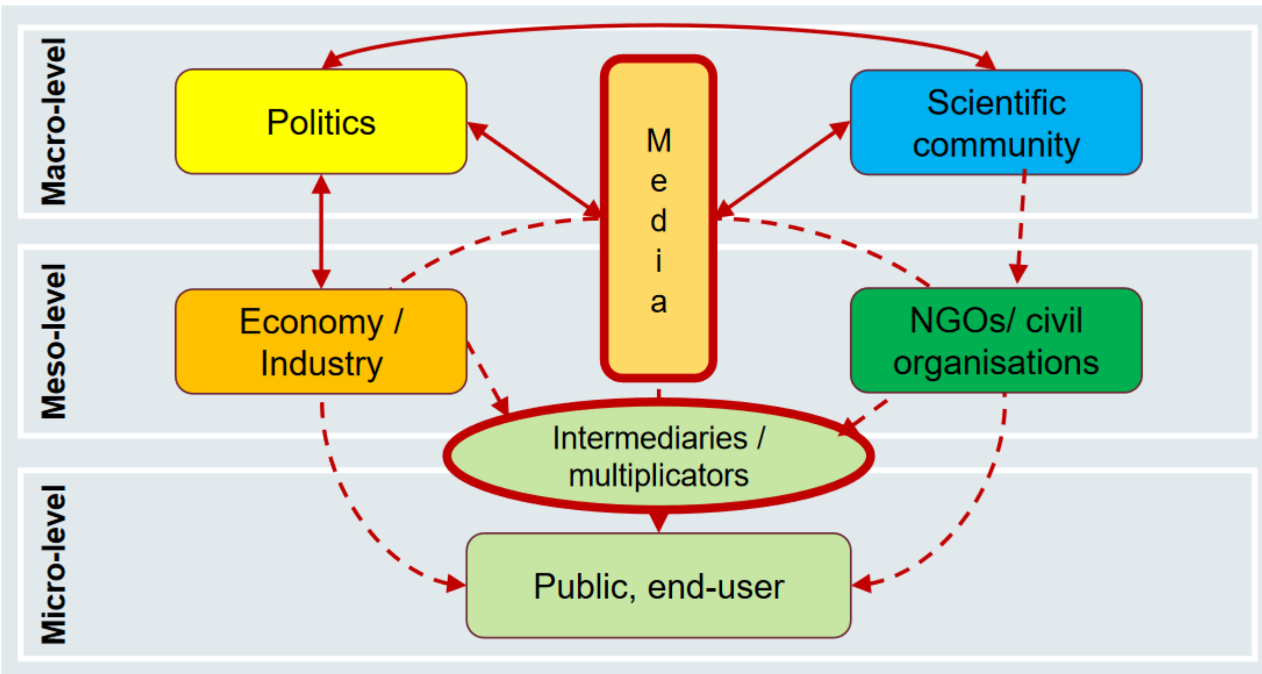

Figure 5.6: Technological innovations in a multi-level-system.

List of figures

List of figures

List of tables

List of textbox

References

ACER – The European Union Agency for the Cooperation of Energy Regulators (2023). Gas fact sheet. [online] available at: https://www.acer.europa.eu/gas-factsheet (14.06.2023).

Albrecht, U., Ball, M., Bünger, U., Kutz, C., Michalski, J. (2022). Emissionsfreie Stahlerzeugung - Metastudie zu den technischen, technologischen und wirtschaftlichen Parametern für die Umstellung der deutschen Stahlindustrie auf eine emissionsarme Stahlproduktion auf Basis von grünem Wasserstoff. Ottobrunn: Ludwig-Bölkow-Systemtechnik GmbH (LBST)

Agora Energiewende & Wuppertal Institut. (2019). Klimaneutrale Industrie: Schlüsseltechnologien und Politikoptionen für Stahl, Chemie und Zement. Berlin.

Anghilante, R. et al. (2023). Experimentelle Charakterisierung der Leckraten von Prüflecks mit H2 und/oder CH4-H2-Gasgemischen gegenüber Luft (ECLHYPSE): Forschungsbericht G 202138. Abschlussbericht, Bonn, März 2023.

Astoria, T. (2022). Dealing with an Uncertain Future: Direct Reduction in the Hydrogen Economy." Midrex Technologies, Inc. [online] available at: https://www.midrex.com/tech-article/dealing-with-an-uncertain-future-direct-reduction-in-the-hydrogen-economy/ (02.11.2023).

Arnold, K., Kobiela, G., Pastowski, A. (2017). Technologiebericht 4.3 Power-to-liquids/-chemicals innerhalb des Forschungsprojekts TF_Energiewende.

Arrigoni, A.; Bravo Diaz, L. (2022). Hydrogen emissions from a hydrogen economy and their potential global warming impact, EUR 31188 EN, Publications Office of the European Union, Luxembourg.

Ausfelder, F., Bazzanella, A., Möller, A., Geres, R., Wehrl, A., Lenz, S. (2019). Roadmap Chemie 2050 - Auf dem Weg zu einer treibhausgasneutralen chemischen Industrie in Deutschland.

Ausfelder, Florian; Herrmann, Eghe Oze; Lopez Gonzales, Luisa Fernanda (2022). Perspective Europe 2030 – Technology Options for CO2-emission reduction of hydrogen feedstock in ammonia production. DECHEMA Gesellschaft für Chemische Technik und Biotechnologie e. V. Frankfurt am Main.

Ausfelder, F. & Tran, D. D. (Editors) (2023). 4. Roadmap des Kopernikus-Projektes P2X Phase II. OPTIONEN FÜR EIN NACHHALTIGES ENERGIE-SYSTEM MIT POWER-TO-X-TECHNOLOGIEN. Transformation – Anwendungen – Potenziale. [online] available at: https://www.kopernikus-projekte.de/lw_resource/datapool/systemfiles/elements/files/EC7C18F68BCE7C0DE0537E695E86F60F/live/document/221025_DEC_P2X4_V08_Web.pdf.

Bard, Jochen; Gerhardt, Norman; Selzam, Patrick; Beil, M.; Wiemer, Martin; Buddensiek, Maike. (2022). The Limitations of hydrogen blending in the European gas grid. A study on the use, limitations and cost of hydrogen blending in the European gas grid at the transport and distribution level. 10.13140/RG.2.2.30093.41448.

Bataille, Christ et al. (2018). A review of technology and policy deep decarbonisation pathway options for making energy-intensive industry production consistent with the Paris Agreement. In: Journal of Cleaner Production 2018 (187) 960-973. Amsterdam: Elsevier Ltd. DOI: 10.1016/j.jclepro.2018.03.107

BASF, SABIC, & Linde. (2022). BASF, SABIC and Linde start construction of the world's first demonstration plant for large-scale electrically heated steam cracker furnaces. [online] available at: https://www.basf.com/global/en/media/news-releases/2022/09/p-22-326.html. (14.11.2023)

Bazzanella, A. M., Ausfelder, F. et al. (2017). Low Carbon Energy and Feedstock for the European Chemical Industry. Frankfurt am Main: DECHEMA Gesellschaft für Chemische Technik und Biotechnologie e.V.

References

Böttcher, Christian (2022). Aktualisierung der Emissionsfaktoren für Methan für die Erdgasbereitstellung. Umweltbundesamt. Fachgebiet Emissionssituation V1.6. [online] available at: https://www.umweltbundesamt.de/sites/default/files/medien/479/publikationen/texte_159-2022_aktualisierung_der_emissionsfaktoren_fuer_methan_fuer_die_erdgasbereitstellung.pdf (11.12.2023).

British Gas (2023). How might hydrogen help heat our homes? [online] available at: https://www.britishgas.co.uk/the-source/greener-living/hydrogen-boilers.html. (06.12.2023).

Bullerdiek, N.; Neuling, U.; Kaltschmitt, M. (Editors) (2024). Powerfuels – Status and Prospects. Springer. [not yet published]

Bundesministerium für Bildung und Forschung (2023). TransHyDE demonstriert Umstellung des Gasnetzes. [online] available at: https://www.wasserstoff-leitprojekte.de/aktuelles/news/h2direkt. (28.02.2024)

Bundesverband der Energie- und Wasserwirtschaft e. V. (2021). Grüne Fernwärme für Deutschland – Potenziale, Kosten, Umsetzung.

Carreno, B. (2022). Hydrogen pipeline between Spain and France to cost $2.6 bln. [online] available at: https://www.reuters.com/business/energy/h2med-hydrogen-pipeline-france-cost-25-bln-euros-spanish-pm-sanchez-says-2022-12-09 (14.06.2023).

Clapp, Mark; Zalitis, Christopher M.; Ryan, Margery (2023). Perspectives on current and future iridium demand and iridium oxide catalysts for PEM water electrolysis. Catalysis Today, Volume 420, 114140. https://doi.org/10.1016/j.cattod.2023.114140.

Cerbe, G.; Lendt, B. (2016). Grundlagen der Gastechnik: Gasbeschaffung - Gasverteilung – Gasverwendung. 8. Aufl. München: Hanser Carl.

Clean Air Task Force. (2021). Transportation Deep Decarbonisation Initiative Synthesis - Options and Strategies Identified by a Roundtable of Experts from Industry, Academia, and Environmental Advocacy. Rotterdam.

Derwent, R. G. (2018). Hydrogen for heating: Atmospheric impacts – A Literature Review. BEIS Research Paper Number 2018: no. 21. Department for Business, Energy and Industrial Strategy.

Derwent, R. G.; Stevenson, D. S.; Utembe, S. R.; Jenkin, M. E.; Khan, A. H.; Shallcross, D. E. (2020). Global modelling studies of hydrogen and its isotopomers using STOCHEM-CRI: Likely radiative forcing consequences of a future hydrogen economy. International Journal of Hydrogen Energy, 45, 9211-9221.

Det Norske Veritas (2021). Maritime Forecast to 2050 - Energy Transition Outlook 2021. Hovik.

Deutsches Institut für Luft- und Raumfahrt e. V. (2020). Wasserstoff als ein Fundament der Energiewende – Teil 2: Sektorenkopplung und Wasserstoff: Zwei Seiten der gleichen Medaille. [online] available at: https://elib.dlr.de/139867/2/wasserstoffstudie-teil-2%281%29.pdf. (08.12.2023).

Eißler, T. (2023). Detailed Cost Analysis of Hydrogen Refueling Costs for Fleets, Chemie Ingenieur Technik, Manuscript submitted for publication.

Energiepark Bad-Lauchstädt (2023). [online] available at: https://energiepark-bad-lauchstaedt.de. (08.12.2023)

EPA – United States Environmental Protection Agency (2023). Understanding Global Warming Potentials. [online] available at: https://www.epa.gov/ghgemissions/understanding-global-warming-potentials. (30.10.2023)

References

Eurofer. (2023). European Steel in Figures 2023 [PDF]. Available at: https://www.eurofer.eu/assets/publications/brochures-booklets-and-factsheets/european-steel-in-figures-2023/FINAL_EUROFER_Steel-in-Figures_2023.pdf. (06.12.2023)

European Commission (2023a). Effort sharing 2021-2030: targets and flexibilities. [online] available at: https://climate.ec.europa.eu/eu-action/effort-sharing-member-states-emission-targets/effort-sharing-2021-2030-targets-and-flexibilities_en. (15.11.2023)

European Commission (2023b). “Questions and Answers on the EU delegated acts on Renewable Hydrogen” [online] available at: https://ec.europa.eu/commission/presscorner/detail/en/qanda_23_595. (06.12.2023)

Eurostat (2023a). Statistics on the production of manufactured goods; Total production [ds-056121__custom_8536799] [online} available at: https://ec.europa.eu/eurostat/databrowser/bookmark/e7fbe927-18f6-43f8-8639-f264a979c89d?lang=en. (06.12.2023)

Eurostat (2023b). New passenger cars by uploaded weight. [online] available at: https://ec.europa.eu/eurostat/databrowser/view/ROAD_EQR_UNLWEIG$DEFAULTVIEW/default/table. (06.12.2023)

Field, R. A.; Derwent, R. G. (2021). Global warming consequences of replacing natural gas with hydrogen in the domestic energy sectors of future low-carbon economies in the United Kingdom and the United States of America. International Journal of Hydrogen Energy 2021, 46, 30190-30203.

Fleiter, Tobias; Rehfeldt, Matthias; Hirzel, Simon; Neusel, Lisa; Aydemir, Ali; Schwotzer, Christian; Kaiser, Felix; Gondorft, Carsten; Hauch, Justin; Hof, Jan; Sankowski, Lukas; Langhorst, Moritz (2023a): CO2-neutrale Prozesswärmeerzeugung. Umbau des industriellen Anlagenparks im Rahmen der Energiewende: Ermittlung des aktuellen Stand der Technik und des weiteren Handlungsbedarfs zum Einsatz strombasierter Prozesswärmeanlagen. Umweltbundesamt.

Fleiter, Tobias; Fragoso, Joshua; Lux, Benjamin; Al-Dabbas, Khaled; Alibas, Sirin; Manz, Pia; Neuner, Felix; Weißenburger, Bastian; Rehfeldt, Matthias (2023b). The role of hydrogen infrastructure in the future CO2-neutral energy system - an energy-system modelling study. Submitted to Energy and Technology, Wiley

Forschungsstelle für Energiewirtschaft e. V. (2022). Wasserstofftransport: Analyse der Prozessketten, Kostenbewertung und gegenüberstellender Vergleich. [online] available at: https://www.ffe.de/veroeffentlichungen/wasserstofftransport-analyse-der-prozessketten-kostenbewertung-und-gegenueberstellender-vergleich. (08.12.2023)

Forschungsgesellschaft für Energiewirtschaft mbH (2022). Wärme- und Kältekonzepte mit Großwärmepumpen - Überblick Informationen Referenzprojekte. Kurzstudie im Auftrag des BDEW – Bundesverband der Energie- und Wasserwirtschaft e. V.

Forster, P.; Storelvmo, T; Armour, K.; Collins, W.; Dufresne, J.-L.; Frame, D.; Lunt, D. J.; Mauritsen, T.; Palmer, M. D.; Watanabe, M.; Wild, M.; Zhang, H. (2021). In: The Earth’s Energy Budget, Climate Feedbacks, and Climate Sensitivity. In: Masson-Delmotte, V.; Zhai, P.; Pirani, A.; Connors, S. L.; Péan, C.; Berger, S.; Caud, N.; Chen, Y.; Goldfarb, L.; Gomis, M. I.; Huang, M.; Leitzell, K.; Lonnoy, E.; Matthews, J. B. R.; Maycock, T.K.; Waterfield, T.; Yelekçi, O.; Yu, R.; Zhou, B. (eds.). Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 923–1054

References

Genge, L., Scheller, F., & Müsgens, F. (2023). Supply costs of green chemical energy carriers at the European border: A meta-analysis. International Journal of Hydrogen Energy. https://doi.org/10.1016/J.IJHYDENE.2023.06.180

Guidehouse (2022). Five hydrogen supply corridors for Europe in 2030. European Hydrogen Backbone [online] available at: https://ehb.eu/files/downloads/EHB-Supply-corridors-presentation-ExecSum.pdf. (08.12.23)

Gurevitch, J., Koricheva, J., Nakagawa, S., & Stewart, G. (2018). Meta-analysis and the science of research synthesis. Nature, 555(7695), 175-182.

H2 Mobility Deutschland GmbH & Co. KG (2021). Wasserstoffbetankung von Schwerlastfahrzeugen – die Optionen im Überblick. [online] Available at: https://h2-mobility.de/wp-content/uploads/sites/2/2021/10/H2M_Ueberblick_BetankungsoptionenLNFSNF_TankRast_2021-10-21.pdf. (15.11.2023)

Harper, R., Freiberger, L., Hübne, T., von Roon, S. (2023). The Industrial Sector in Transition - Effects of Transformation on the Local Level. FfE Discussion-Paper: 2023-01. January.

Hauglustaine, D.; Paulot, F.; Collins, W.; Derwent R.; Sand, M.; Boucher, O. (2022). Climate benefit of a future hydrogen economy. Commun Earth Environ 3, 295.

Huijts, N. M. A., Molin E. J., & Steg L. (2012). Psychological factors influencing sustainable energy technology acceptance: A review-based comprehensive framework. Renewable and Sustainable Energy Reviews, 16(1), 525-531. DOI: 10.1016/j.rser.2011.08.018

International Air Transport Association (IATA). Fact Sheet 2: Sustainable Aviation Fuel: Technical Certification. [online] available at: https://www.iata.org/contentassets/d13875e9ed784f75bac90f000760e998/saf-technical-certifications.pdf. (15.11.2023).

International Energy Agency. (IEA) (2019). The Future of Hydrogen - Seizing today's opportunities. [online] available at: https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf. (06.12.2023).

International Energy Agency (2022). IEA (2022) World Energy Outlook 2022, Paris. [online] available at: https://www.iea.org/reports/world-energy-outlook-2022. License: CC BY 4.0 (report); CC BY NC SA 4.0 (Annex A) (Accessed 15.11.2023).

International Transport Forum (ITF). (2018). Decarbonising Maritime Transport - Pathways to zero-carbon shipping by 2035. Paris.

IRENA (2021). A pathway to decarbonise the shipping sector by 2050. Abu Dhabi.

Kiemel, Steffen; Smolinka, Tom; Lehner, Franz; Full, Johannes; Sauer, Alexander; Miehe, Robert (2021). Critical materials for water electrolysers at the example of the energy transition in Germany". International Journal of Energy Research, volume 45, issue 7, 9914-9935.

Kiwa Technology (2019). Management Summary of „first inventory of hydrogen leakages at small permissible leaks. [online] available at: https://www.netbeheernederland.nl/_upload/Files/Waterstof_56_f1ec1f8adb.pdf (11.12.2023).

Klimapartner Oberrhein (2021). Wasserstoftechnologien am Südlichen Oberrhein (H2-SO). [online] available at: https://www.klimaschutz-oberrhein.de/de-de/projekte/wasserstofftechnologien_am_suedlichen_oberrhein-h2-so. (28.09.2023).

References

Lämmle, Manuel & Metz, Jakob & Kropp, Michael & Wapler, Jeannette & Oltersdorf, Thore & Günther, Danny & Herkel, Sebastian & Bongs, Constanze. (2023). Heat Pump Systems in Existing Multifamily Buildings: A Meta-Analysis of Field Measurement Data Focusing on the Relationship of Temperature and Performance of Heat Pump Systems. Energy Technology. 10.1002/ente.202300379.

Land Nordrhein-Westfalen. Wasserstoffregionen [online] available at: https://www.h2land-nrw.de/alle-h2-projekte/wasserstoffregionen. (28.09.2023)

Lange, Ronny; Schwigon, Agnes; Steiner, Michael (2021). Bestands- und Ereignisdatenerfassung Gas – Ergebnisse aus den Jahren 2011 – 2020. In: energie |wasser-praxis 12-2021. [online] available at: energie-wasser-praxis-dvgw-bestands-ereignisdatenerfassung-gas.pdf. (10.12.2023)

Mannesmann Line Pipe GmbH (2022). Environmental Product Declaration – Steel Oil and Gas Line Pipe. EPD-SMM-20210242-IBB1-EN. [online] available at: https://www.mannesmann-linepipe.com/fileadmin/footage/MEDIA/gesellschaften/smlp/Documents/EPD-Steel-Oil-and-Gas-Line-Pipes.pdf. (11.12.2023)

McKinsey & Company (2020). Hydrogen-powered Aviation - A fact-based study of hydrogen technology, economics, and climate impact by 2050. Luxembourg. Ministerium für Wirtschaft, Klimaschutz und Energie des Landes Nordrhein-Westfalen. H2Land NRW. Wasserstoffregionen [online] available at: https://www.h2land-nrw.de/alle-h2-projekte/wasserstoffregionen. (28 Sep. 2023)

Minke, Christine; Suermann, Michel; Bensmann, Boris; Hanke-Rauschenbach, Richard (2021). Is iridium demand a potential bottleneck in the realisation of large-scale PEM water electrolysis? International Journal of Hydrogen Energy, Volume 46, Issue 46, Pages 23581-23590, https://doi.org/10.1016/j.ijhydene.2021.04.174.

Müller-Kirchenbauer et al. (2023a). Germany's way from Russian natural gas to green hydrogen – network data, procedures and topologies for feasible transition paths to a green hydrogen transport infrastructure in Germany. [submitted for publication].

Müller-Kirchenbauer, Joachim; Ragwitz, Mario; Kneiske, Tanja; Klaassen, Bernhard; Mielich, Tim; Herrmann, Ulrike (2024): A Network Modeling Systematics for Transition Paths Toward Climate Neutral Gas Networks—NeMoSys [ˈnɛmɒsis] –. In: Energy Technology. 2300977. DOI: 10.1002/ente.202300977

Neuwirth, Marius; Fleiter, Tobias; Manz, Pia; Hofmann, René (2022): The future potential hydrogen demand in energy-intensive industries - a site-specific approach applied to Germany. In: Energy Conversion and Management 252, S. 115052. DOI: 10.1016/j.enconman.2021.115052.

NOW GmbH (2023a). HyLand – Wasserstoffregionen in Deutschland Website. [online] available at https://www.ly.land. (28.09.2023)

NOW GmbH (2023b). Market development of climate-friendly technologies in heavy-duty road freight transport in Germany and Europe.

Ocko, I. B.; Hamburg, S. P. (2022). Climate consequences of hydrogen emissions. In: Atmospheric Chemistry and Physics, V22, 14, 9349-9368.

O'Malley, Jane, Pavlenko, Nikita, Searle, Stephanie (2021). Estimating sustainable aviation fuel feedstock availability to meet growing European Union demand. [online] available at: https://theicct.org/sites/default/files/publications/Sustainable-aviation-fuel-feedstock-eu-mar2021.pdf. (15.11.2023).

References

Otto, Alexander; Robinius, Martin; Grube, Thomas; Schiebahn, Sebastian; Praktiknjo, Aaron; Stolten, Detlef (2017). Power-to-Steel - Reducing CO2 through the Integration of Renewable Energy and Hydrogen into the German Steel Industry. In: Energies, 10(4), 451. Basel: MDPI.

Petrochemicals Europe (2023). Petrochemical Production Statistics Westerm Europe (EU15 + Hungary, Norway & Slovakia).[online] available at: https://www.petrochemistry.eu/wp-content/uploads/2023/05/950-Olefins-Prod-2022-Q4.pdf

Prognos AG. (2021). Klimaneutrales Deutschland 2045 - Wie Deutschland seine Klimaziele schon vor 2050 erreichen kann. Berlin

Ren, Tao, Patel, M., Blok, K. (2006). Olefins from conventional and heavy feedstocks: Energy use in steam cracking and alternative processes. In: Energy, 31, 425-451.

Rosenow, Jan. (2022). Is heating homes with hydrogen all but a pipe dream? An evidence review. Joule. 6. 10.1016/j.joule.2022.08.015.

Rossum R. van, Jens J., Guardia G. La, Wang A., Kühnen L., Overgaag M. (2022). A European Hydrogen Infrastructure: Vision Covering 28 Countries.

Rozain, C; Mayousse, E.; Guillet, N.; Millet, P. (2016). Influence of iridium oxide loadings on the performance of PEM water electrolysis cells. Part I–pure IrO2 - based anodes. In: Applied Catalysis B: Environmental, Volume 182, 153-160.

Sadat-Razavi, P., Hildebrand, J. (2023): Analyse zum medialen Diskurs von Wasserstoff-Transportinfrastrukturen. Saarbrücken: IZES gGmbH. [online] available at: https://www.wasserstoff-leitprojekte.de/lw_resource/datapool/systemfiles/elements/files/FF45D5F7BA2D103BE0537E695E8620CE/live/document/Analyse_zum_medialen_Diskurs_von_Wasserstoff-Transportinfrastrukturen.pdf. (28.02.2024)

Sall, P. (2022). DNV further confirms feasibility and maturity of the EastMed pipeline. [online] available at: https://www.dnv.com/news/dnv-further-confirms-feasibility-and-maturity-of-the-eastmed-pipeline-226712. (28.06.2023).

Schütz, S.; Große, C.; Kleinickel, C. (2015). Treibhausgas-Minderungspotenziale in der europäischen Gasinfrastruktur. Umweltbundesamt. [online] available at: https://www.bmuv.de/fileadmin/Daten_BMU/Pools/Forschungsdatenbank/fkz_3712_41_344_treibhausgas_minderungspotenziale_bf.pdf. (11.12.2023)

Schwikowski M. (2023). African countries seek to revive Sahara gas pipeline. [online] available at: https://www.dw.com/en/african-countries-seek-to-revive-trans-saharan-gas-pipeline-dream/a-62778681. (28.02.2024)

Searle, Stephanie. (2019). Long-term aviation fuel decarbonisation: Progress, roadblocks, and policy opportunities. Washington DC: The International Council on Clean Transportation (ICCT).

Singerling, Sheryl A.; Schulte, Ruth F. (2021). Platinum-Group Metals Statistics and Information In: U. S. Geological Survey Minerals Yearbook - 2018. [advanced release] 57.1 – 57.12. [online] available at: https://d9-wret.s3.us-west-2.amazonaws.com/assets/palladium/production/atoms/files/myb1-2018-plati.pdf. (08.12.2023)

Solomon, M.D., Heineken, W., Scheffler, M. and Birth-Reichert, T. (2023). Cost Optimization of Compressed Hydrogen Gas Transport via Trucks and Pipelines. Energy Technol. 2300785. https://doi.org/10.1002/ente.202300785]

Statista (2023). Treibhausgasemmisionen der deutschen Stahlindustrie in den Jahren 1995 bis 2021. [online] available at: https://de.statista.com/statistik/daten/studie/476860/umfrage/treibhausgasemissionen-der-deutschen-stahlindustrie. (11.12.2023)

References

Stevens, Rob (2019). Decarbonised Ammonia for Food and Energy. In: Ammonia Energy Conference 2019. Orlando, Florida: Yara International.

Stiftung Arbeit und Umwelt der IG BCE. (2021). Branchenausblick 2030+: Mineralölverarbeitung und Raffinerien - Transformationstrends in Raffinerien. Berlin.

The European Steel Association (EUROFER) (2023). European Steel in Figures. [online] available at: https://www.eurofer.eu/assets/publications/brochures-booklets-and-factsheets/european-steel-in-figures-2023/FINAL_EUROFER_Steel-in-Figures_2023.pdf. (28.02.2024)

The Royal Society. (2020). Ammonia: zero-carbon fertiliser, fuel and energy store. [online] available at: https://royalsociety.org/-/media/policy/projects/green-ammonia/green-ammonia-policy-briefing.pdf. (28.02.2024).

Thyssenkrupp (2023). Thyssenkrupp Steel vergibt Milliardenauftrag für Direktreduktionsanlage an SMS group: Start eines der weltweit größten industriellen Dekarbonisierungsprojekte. [online] available at: https://www.thyssenkrupp.com/de/newsroom/pressemeldungen/pressedetailseite/thyssenkrupp-steel-vergibt-milliardenauftrag-fur-direktreduktionsanlage-an-sms-group--start-eines-der-weltweit-grossten-industriellen-dekarbonisierungsprojekte-163183. (15.11.2023)

Trans Adriatic Pipeline (2023). About TAP [online] available at: https://www.tap-ag.com/about-tap. (14.06.2023).

UNEP (2011). Recycling Rates of Metals – A Status Report of the Working Group on the Global Metal Flows to the International Resource Panel. [online] available at: https://wedocs.unep.org/handle/20.500.11822/8702;jsessionid=5561D70DC0B9F692BBFF450AA55F5421. (08.12.2023).

UNFCCC – United Nations Framework Convention on Climate Change (2023). GHG data from UNFCCC – Detailed data by partner. [online} available at: https://unfccc.int/topics/mitigation/resources/registry-and-data/ghg-data-from-unfccc. (19.10.2023)

United States Environmental Protection Agency (2023). Understanding Global Warming Potentials. [online] available at: https://www.epa.gov/ghgemissions/understanding-global-warming-potentials. (28.02.2024)

Vattenfall (2023). Biomasse für die klimaschonende Fernwärme. [online] available at: https://wärme.vattenfall.de/energie-news/biomasse-fuer-die-klimaschonende-stadtwaerme. (06.12.2023)

Verband der Chemischen Industrie e. V. (VCI) (2023). Chemiewirtschaft in Zahlen 2023. [online] available at: https://www.vci.de/vci/downloads-vci/publikation/chiz-historisch/chemiewirtschaft-in-zahlen-2023.pdf.(28.02.2024)

Viessmann (2023). Klimaneutral heizen mit Wasserstoff – Lösungen von Viessmann. [online] available at: https://www.britishgas.co.uk/the-source/greener-living/hydrogen-boilers.html. (06.12.2023)

Wachsmuth, Jakob; Duscha, Vicki, Wietschel, Martin; Oberle, Stella; Herrmann, Ulrike; Graf, Marieke; Pfluger, Benjamin; Sorayaei, Mona; Brandes, Frederik; Gehrmann, Stefan; Rommelfanger, Janosch; Isik, Volkan; Köppel, Wolfgang; Heneka, Maximilian; Zubair, Asif; Vayas, Louis (2023). Transformation der Gasinfrastruktur zum Klimaschutz. [online] available at: https://www.umweltbundesamt.de/sites/default/files/medien/1410/publikationen/2023-03-31_cc_09-2023_transformation-gasinfrastruktur-klimaschutz.pdf. (08.12.2023)

References

Warwick, N.; Griffiths, P.; Keeble, J.; Archibald, A.; Pyle, J.; Shine, K. (2022). Atmospheric implications of increased hydrogen use. [online] available at: https://dutchmobilityinnovations.com/spaces/86/dutch-mobility-innovations/files/45598/atmospheric-implications-of-increased-hydrogen-use-pdf. (11.12.2023).

Wien Energie (2022). “Stärkste Großwärmepumpe Mitteleuropas pumpt in Wien“. [online] available at https://www.wienenergie.at/blog/staerkste-grosswaermepumpe-mitteleuropas-pumpt-in-wien-2. (06.12.2023)

Wirtschaftsvereinigung Stahl (2022). Fakten zur Stahlindustrie in Deutschland 2022. [online] available at https://www.stahl-online.de/wp-content/uploads/WV-Stahl_Fakten-2022_RZ_neu_Web.pdf. (08.12.2023)

Wolf, F. M. (1986). Meta-analysis: Quantitative methods for research synthesis (Vol. 59). Sage.

World Economic Forum (2020). Clean Skies for Tomorrow – Sustainable Aviation Fuels as a Pathway to Net-Zero Aviation Insight Report in collaboration with McKinsey & Company.

World Energy Council (2021). Decarbonised hydrogen imports into the European Union: challenges and opportunities. La Revue de l’Énergie, octobre 2021.

Wüstenhagen, R., Wolsink, M., & Burer, M. (2007). Social Acceptance of Renewable Energy Innovation: An Introduction to the Concept. Energy Policy 35, 2689-2691. DOI: 10.1016/j.enpol.2006.12.001.

Züttel, A.; Borgschulte, A.; Schlapbach, L. (ed.) (2008). Hydrogen as a future energy carrier. Weinheim: Wiley-VCH.