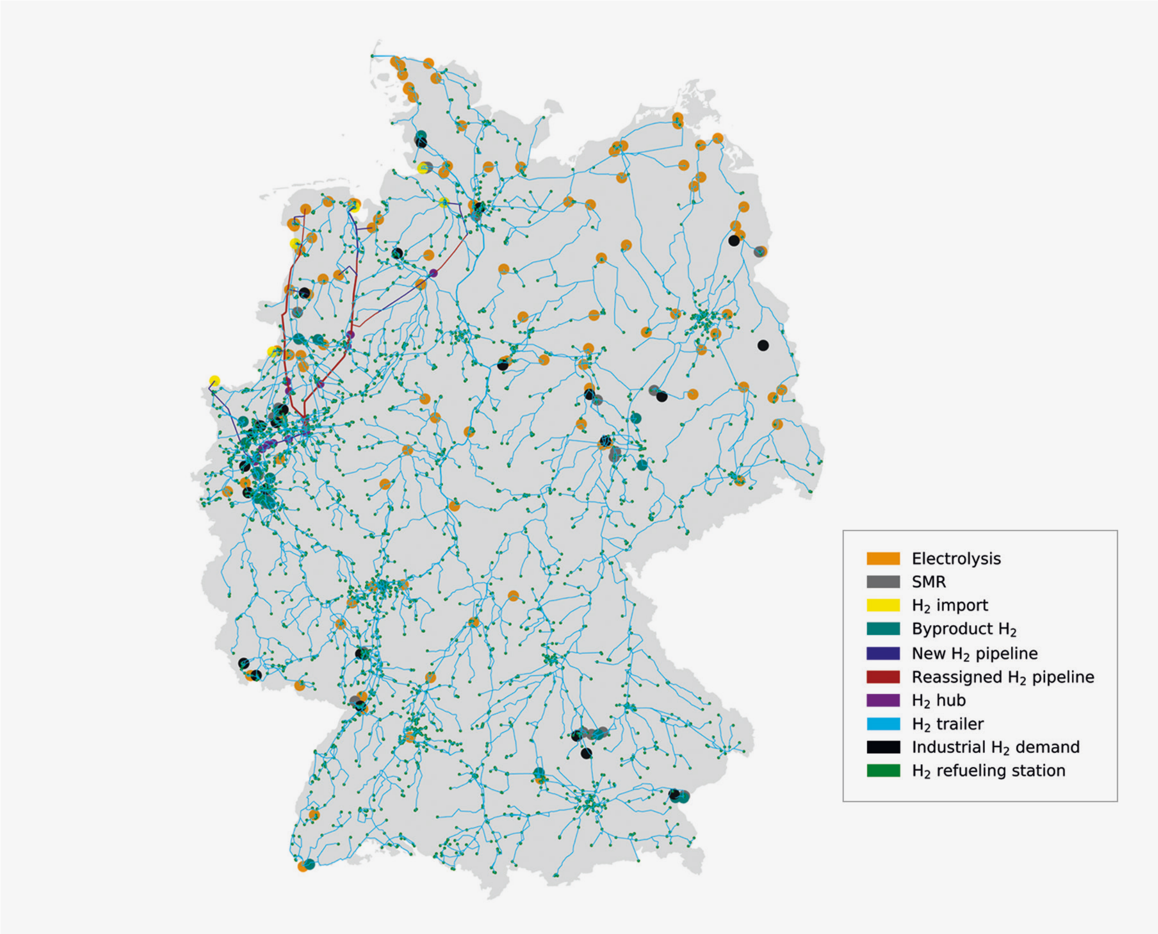

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Simonas Cerniauskas

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Abstract

Efforts to alleviate climate change and curb greenhouse gas (GHG) emissions increasingly anticipate the widespread use of hydrogen for transportation and industrial purposes. Given the increased focus on hydrogen infrastructure development, it is essential to devise measures capable of assessing and mapping strategic choices to guide the further development of the hydrogen market.

The goal of this work is to investigate what infrastructure and demand-side strategies best facilitate hydrogen infrastructure development for the transportation and industrial sectors in Germany and thus enable the transition towards a cost-optimized system in the long term.

To achieve these goals, a spatially-resolved model to represent relevant features of a hydrogen infrastructure is developed and populated with country-specific data on hydrogen demand allocation and energy infrastructure. The approach incorporates four different aspects of the transition to a hydrogen-based system: transformation of the hydrogen market, reconfiguration of hydrogen production and storage, the evolution of a delivery infrastructure and the changeover of refueling stations.

It was found that gaseous (GH2) and liquid (LH2) hydrogen trailers, as well as utilization of the existing infrastructure, such as the use of aging wind power plants and the reassignment of natural gas pipelines, constitute the most attractive pathways for the introduction of a hydrogen infrastructure. A high concentration of supply is favored by LH2 delivery, whereas GH2 pathways benefit from growing demand concentration in industrial and population centers. Accordingly, GH2 pipeline and trailer delivery should be the main focus of infrastructure development, while LH2 transport is better used as a supplementary alternative to optimize the utilization of the existing LH2 infrastructure and seaborne imports.

It was shown that cost-competitive hydrogen delivery for transportation could be attained by 2030, and broad market adoption of hydrogen in transport is required if cost-competitive hydrogen delivery for industry is to be achieved.

Zusammenfassung

Zur Eindämmung des Klimawandels und zur Begrenzung der Treibhausgasemissionen wird zunehmend von einem weitverbreiteten Einsatz von Wasserstoff für Verkehrs- und Industriezwecke ausgegangen. Angesichts der verstärkten Konzentration auf die Entwicklung der Wasserstoffinfrastruktur ist es unerlässlich, Methoden zu entwickeln, um die strategischen Entscheidungen zur Entwicklung des Wasserstoffmarktes zu bewerten.

Ziel dieser Arbeit, ist es zu untersuchen, welche Infrastruktur und Nachfrage Strategie den Aufbau einer Wasserstoffinfrastruktur für die Mobilität und Industrie in Deutschland unterstützt und langfristig einen Übergang zu einem (kosten-) optimierten System ermöglicht.

Um diese Ziele zu erreichen, wird ein räumlich aufgelöstes Modell zur Darstellung der diesbezüglich relevanten Merkmale einer Wasserstoffinfrastruktur entwickelt und mit regionspezifischen Daten zur Verteilung der Nachfrage und Energieinfrastruktur ausgestattet. Der gewählte Ansatz umfasst vier verschiedene Aspekte des Übergangs des Wasserstoffsystems: die Transformation des Wasserstoffmarktes, die Neukonfiguration der Wasserstoffproduktion und -speicherung, die Entwicklung der Lieferinfrastruktur und die Umstellung der Tankstellen.

Es wird gezeigt, dass GH2- und LH2-Trailer sowie die Nutzung der bestehenden Infrastruktur, wie post-EEG Windkraftanlagen und die Umstellung von Erdgasleitungen, attraktive Wege für die Einführung einer Wasserstoff-Infrastruktur sind. Dabei wird die LH2-Lieferung durch eine hohe Konzentration der Quellen begünstigt, während GH2-Pfade von der wachsenden Nachfragekonzentration in Industrie- und Bevölkerungszentren profitieren. Entsprechend sollte der GH2-Transport den Schwerpunkt der Versorgung bilden, während der LH2-Transport durch optimierte Nutzung von bestehenden LH2 Infrastruktur und Seefracht Importen die Infrastrukturentwicklung ergänzen wird.

Die Ergebnisse zeigen, dass bis 2030 eine kosteneffiziente Wasserstofflieferung für den Transport erreicht werden kann. Darüber hinaus zeigen die Ergebnisse, dass eine breite Markteinführung von Wasserstoff im Verkehr für eine kosteneffiziente Wasserstofflieferung für die Industrie erforderlich ist.

Acknowledgements

This dissertation was written at the Institute of Energy and Climate Research – Techno-economic Systems Analysis (IEK-3) at Forschungszentrum Julich GmbH. Scientific research is a collaborative effort and thus I would like to express my sincere gratitude to key people who accompanied me during the preparation of this work.

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My sincere thanks are due to my group leader Dr. Thomas Grube, who was always open to my technical, methodological, organizational, and personal questions. Many thanks to the colleagues Dr.-Ing. Martin Robinius, Dr.-Ing. Peter Markewitz, Dr.-Ing. Jochen Linssen, Theresa Groß and Felix Kullmann for their support and encouragement as well as fruitful collaboration in various third-party projects. I would also like to thank all fellow doctoral students at the institute for the constructive discussions during and after working hours, especially Dr.-Ing. Markus Reuss, Timo Kannengiesser, Dr.-Ing. Dilara Caglayan and Dr.-Ing. Severin Ryberg as well as Lara Welder.

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1 Introduction

The Earth's average surface temperature has been steadily increasing since the beginning of industrialization, leading to an exceptionally rapid change in the global climate and rising sea levels. The sharply increasing anthropogenic emissions of greenhouse gases (GHG) such as carbon dioxide (CO_2) have been identified as the primary culprit behind the problem [1]. Current efforts to curb these were codified in the Paris Climate Treaty, which declared the goal of reducing the global temperature rise to well below 2 °C compared to the pre-industrial era and pursuing efforts to limit the increase even further, to 1.5 °C [2].

In accordance with international efforts, the German Federal Government has set out a GHG reduction target of 55% by 2030 and 80% to 90% by 2050 against the reference year of 1990 [3]. It also recently announced the Climate Protection Program 2030, wherein the prerequisites for achieving the interim climate targets for 2030 will be designed [4]. One of the critical elements of this program is the widespread use of hydrogen (H2), which is a versatile energy carrier that can be utilized for seasonal renewable energy storage, transport purposes through fuel cell-electric vehicles (FCEV) and industrial processes, such as steel, ammonia and methanol production, as well as refining. Additionally, the German Federal Government published its National Hydrogen Strategy and aims to create a coherent framework for the future production, transport and use of hydrogen, as well as pledging 7 bn EUR for the initial market ramp-up in Germany through 2030 [5]. Moreover, an ever increasing number of studies on the development of a hydrogen pipeline system also indicates substantial interest by the natural gas industry [6-8]. Given the increased policy and industry focus on hydrogen and substantial funding dedicated to broader hydrogen adoption, it is essential to develop measures capable of assessing and mapping strategic choices in order to guide the further development of the hydrogen market.

1.1 Motivation

Previously, the technical feasibility of a pipeline-based hydrogen infrastructure for passenger car traffic in Germany was showcased by the Institute of Techno-Economic Systems Analysis (IEK-3) at the Jülich Research Center [9]. Under the condition of a massive expansion of renewable energy by 2050, it has been shown that a renewable hydrogen supply for hydrogen-based transportation with up to 75% market penetration in Germany is both feasible and economical [10]. In a further analysis, hydrogen transport by means of liquid hydrogen (LH2) trailers and gaseous hydrogen (GH2) pipelines with subsequent distribution were identified as being the most cost-effective means of countrywide hydrogen delivery [11]. Furthermore, geological storage options were identified as being vital to a low-cost hydrogen system [11].

Given these findings of the techno-economic feasibility of a countrywide hydrogen supply chain and the increased number of recently published roadmaps and strategies by industry and the German Federal Government [5, 12] **the question of introduction strategies** for such a system in Germany arises. In particular, questions about the available strategic options and preferential measures to facilitate the **cost-effective development of hydrogen infrastructure** are of central interest. To investigate these and derive advantageous actions, a novel numerical model is developed herein that maps the available country-specific strategic options and computes the associated outcomes of the infrastructure's implementation in Germany.

1.2 Research Questions

This work aims to extend the strategy development process by incorporating a computer-based model to investigate what infrastructure and demand-side strategies facilitate a cost-optimized hydrogen infrastructure for the transportation and industry in Germany. This research question can be further divided into the following sub-questions:

- What are the **most promising markets** in terms of anticipated hydrogen adoption and relevant infrastructure options?
- What positive effects can be attained through the **utilization of the existing infrastructure**?
- Which infrastructure features would facilitate a **low-cost infrastructure introduction** and align its development with an **optimized system in the long-term**?
- What are the **market-specific infrastructure requirements** and possible synergy effects across different markets?

To address the stated research questions, this work aims to develop a well-founded introduction strategy for hydrogen in the transportation and industry sectors. For this purpose, a novel model named **Hydrogen Market & Infrastructure Development** (**H2MIND**) to investigate the relevant value chains for the supply and use of hydrogen up to the year 2050 is developed. This model encompasses a variety of unique hydrogen markets and associated anticipated market growth, as well as sufficient technical detail to describe the use of existing infrastructure, such as natural gas pipelines and, high voltage substations and onshore wind power plants, as well as occurring synergies of the hydrogen supply chain components between the individual markets. The necessary technical components are described in a model by reference to characteristic data on their operating behavior and scaling functions. Viable hydrogen infrastructure pathways are evaluated by using the evaluation criteria of domestic energy input, associated CO_2 emissions and final hydrogen costs. Then, optimal measures in accordance with the boundary conditions throughout the market launch are derived.

1.3 Thesis Structure

Adapted from the strategy development process [13], this work is structured into five main components designated to answer the stated research questions (Figure 1). Following definition of the research problem and associated sub-questions in this **first chapter**, the problem is further framed and contextualized in the next chapter. There, in a **second chapter** a strategic environment analysis is conducted to assess the relevant aspects of the status quo, encompassing the current hydrogen market, governmental targets and hydrogen commercialization projects. Then, long-term market adoption scenarios and techno-economic features of the components of the hydrogen supply chain are presented. Based on these results, selected literature on hydrogen demand and supply chain modeling is reviewed to identify gaps in the research, while an appropriate modeling approach to answer the research questions of this work is outlined.

In the **third chapter**, building upon the previously derived, overarching modeling approach, the methods to map the individual strategic options in five main areas are designed. First, the methodological aspects of the modeled temporal and spatial development of hydrogen demand are presented. Second, in the next subchapter, considerations regarding the features of domestic hydrogen production via electrolysis and industrial processes, as well as hydrogen imports, are discussed. Third, the chosen representation of hydrogen storage, as well as processing and conditioning to ensure the required hydrogen state and quality, are described. Fourth, transport routes for hydrogen delivery and the reassignment of natural gas pipelines are displayed. Fifth, the most relevant features of the chosen representation of hydrogen refueling stations for different transport markets are illustrated.

In the **fourth chapter**, a demand scenario is constructed based on the National Hydrogen Strategy, which was published by the German Federal Government; the associated transition of the countrywide hydrogen supply chain system is also evaluated. The overall transition is sub-divided into four main pillars of transition: **(1)** the transformation of the hydrogen market; **(2)** reconfiguration of production and storage; **(3)** evolution of the hydrogen delivery infrastructure; and **(4)** changeover of the hydrogen refueling infrastructure. Building on the individual assessments, the long-term costs of the supply chain alternatives are assessed and additional expenditures of hydrogen delivery with regards to the benchmark fuels under the relevant European and national environmental policies [3, 14-16] are evaluated from 2023 to 2030. Finally, the sensitivity analysis of the critical system parameters highlights the key points of leverage for the implementation of the introduction strategy for the hydrogen infrastructure, including capital cost, subsidies and hydrogen imports [17-21]. In the fifth, final chapter, the findings of this work are summarized and the overarching conclusions are drawn.

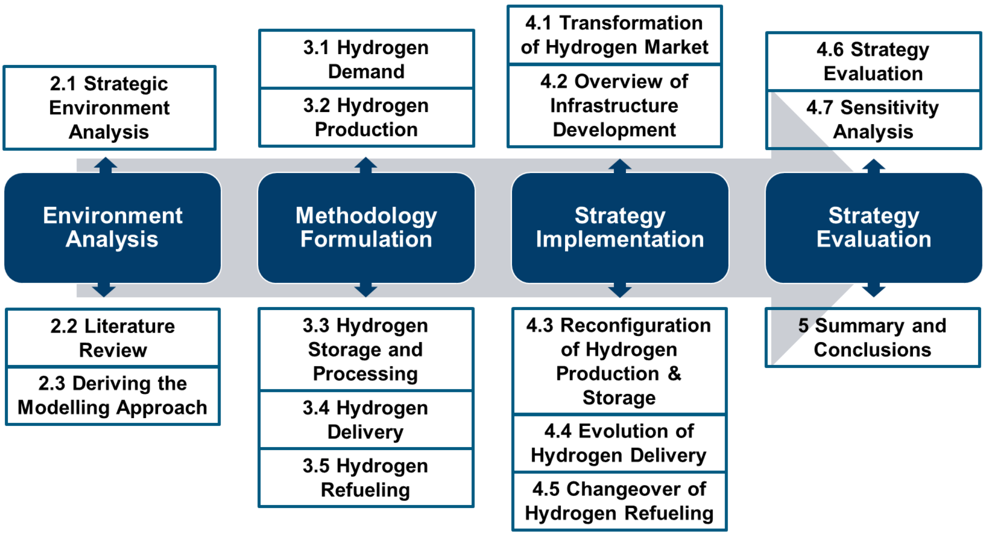

Figure 1. Overview of the thesis structure.

2 Related Literature and Modeling Approach

To address the first research question regarding promising hydrogen markets and anticipated market adoption, as well as relevant hydrogen infrastructure options, this chapter begins with a **strategic environment analysis** that encompasses an overview of the current hydrogen market, government goals for the hydrogen market and infrastructural development. Then, a brief review of current hydrogen market commercialization projects in Germany and of literature relating to anticipated market-specific adoption scenarios are presented. Subsequently, key components of the hydrogen supply chain are addressed, with the most promising technology options discussed with regard to their **technical and economic characteristics**. Based on the strategic environment analysis and technology overview, model requirements for infrastructure strategy development are derived and applied to **evaluate relevant literature**. Finally, in accordance with the model requirements and research gap in the literature, a novel **modeling approach is outlined**.

2.1 Strategic Environment Analysis

The following section gives an overview of the current national targets on hydrogen and fuel cell commercialization is provided. Then it describes the most prolific current uses of hydrogen and its market structure. Furthermore, an extensive survey of current market commercialization projects in Germany is conducted in order to identify the core markets that will play a major role in hydrogen commercialization. Based on these results, a literature review of hydrogen adoption scenarios is presented so as to estimate further market development. Subsequently, the most prominent current hydrogen-related technologies are assessed.

2.1.1 Governmental Targets

Hydrogen's role in a future decarbonized energy system is increasingly attracting the attention of policymakers around the globe. At present, there are approximately 50 implemented policy incentives, mandates and targets that are designed to directly support the commercialization of hydrogen production and utilization [22]. Amongst the main motivations for this development are the reduction of GHG and local emissions, as well as the storage of intermittent renewable energy. These developments raise awareness in various regions, especially those with high renewable energy potential, such as Australia and New Zealand, that are preparing their hydrogen roadmaps with a particular focus on possible hydrogen export [23, 24]. The highest interest in hydrogen-related technology development can be observed in the United States (USA) and Canada, the countries of the European Union (EU) and East Asia [22]. Table 1 and Table 2 and provide an overview of the current state of development and individual national plans for a selection of countries, with a focus on passenger cars and hydrogen infrastructure development.

Table 1. Current status and future targets for hydrogen refueling station deployment [12, 25-33].

Continent	Country	2019	2020-2025	2025-2030
Asia	Japan	130	320	900
	South Korea	33	310	520
	China	24	300	1000
North America	USA (California)	52	200	1000
	Canada	6	-	-
Europe	Germany	86	400	-
	France	24	100	1000[1]
	United Kingdom	17	150	-
	Netherlands	4	50	-
	Italy	3	140	-
	Belgium	3	80	-
	Spain	3	25	-
	Total	385	2085	4265[2]

The collected data indicate that at present, in the analyzed regions, there are approximately 12,500 vehicles and 385 hydrogen refueling stations. However, despite a low initial market adoption of FCEVs and fuel station development, a significant improvement is envisaged in the coming decade, with approximately four million FCEVs on the road anticipated and over 4000 hydrogen refueling stations. To put these numbers into perspective, as of 2018, the global fleet of battery electric vehicles totaled 3.3 million; a number that required approximately a decade to be reached [34]. A rapid increase in the number of hydrogen refueling stations is planned, especially before 2025, as the initial refueling infrastructure that supports the minimal countrywide coverage necessary for fuel cell vehicle adoption will be deployed. The FCEV fleet is also expected to increase by more than 30 times during this period to reach approximately 400,000 vehicles by the year 2025. The required industrial capacity to facilitate such substantial progress is mostly already in place, as a single hydrogen refueling station manufacturer can produce 300 units p.a. and one of the major FCEV manufacturers is planning to increase its FCEV production capacity to 130,000 p.a.

---

[1] Upper range
[2] Countries without quantified targets considered with values for the time frame 2020-2025

through 2025 [35, 36]. In comparison to the other analyzed regions, Germany is a compelling case for a further infrastructure development analysis, as it possesses a developed hydrogen industry and features the second largest number of hydrogen refueling stations. Furthermore, the current FCEV fleet makes up approximately 4% of the global FCEV fleet, which is on the same order of magnitude as the relationship between the German and global vehicle fleets.

Table 2. Current status and future targets for cumulative FCEV sales. [25, 28-33].

Continent	Country	2019	2020-2025	2025-2030
Asia	Japan	130	320	900
	South Korea	900	100,000	630,000
	China	1791	50,000	1,000,000
North America	USA (California)	5923	48,000	1,000,000
	Canada	18	-	-
Europe	Germany	487	-	-
	France	324	5,000	500,000[1]
	United Kingdom	138	-	-
	Netherlands	48	-	-
	Italy	17	-	-
	Belgium	1	500	-
	Spain	17	-	-
	Total	385	2085	4265[3]

2.1.2 Current Hydrogen Market

Currently, worldwide hydrogen demand of 115 Mt p.a. is dominated by the heavy and chemical industry sectors [37, 38]. Energy demand related to hydrogen production makes up 2% of yearly global primary energy consumption [22]. Thus, hydrogen already plays a significant role in the global economy. It is primarily utilized for non-energetic purposes such as chemical feedstock for the refining of oil, methanol and ammonia production [37] (see Figure 1). Less prominent uses of hydrogen can also be found in the food-processing, electronics and glass manufacturing sectors [39].

As can be seen in Figure 2, current hydrogen production is dominated by hydrogen extraction from fossil fuels such as natural gas and coal. A further significant source of hydrogen is by-product hydrogen, which primarily comprises excess hydrogen produced during catalytic reforming and steel processing. Nevertheless, the rising proportion of light oil-derivatives in refineries increases hydrogen demand, therefore making refineries total net sinks for hydrogen. Approximately 2% of hydrogen is produced by electrolysis as a by-product of chlorine production [22]. Consequently, the

[3] Countries without quantified targets considered with values for the time frame 2020-2025

viability of the large-scale application of electrolysis has been already proven in the chemical sector [37]. Nevertheless, despite these developments, to date, the further market expansion of electrolytic hydrogen, especially of green hydrogen, to other applications in the chemical industry or energy sector has been limited [40].

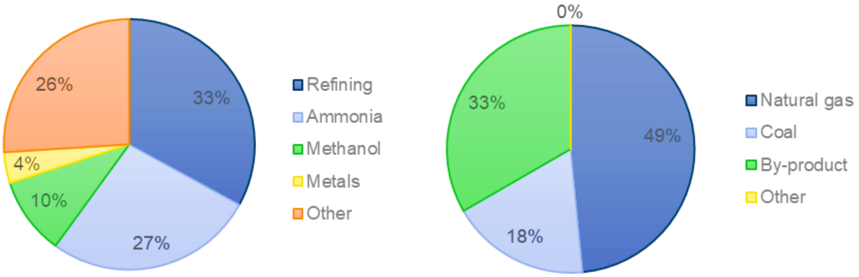

Figure 2. Status quo of the worldwide hydrogen market. Left: hydrogen utilization. Right: Structure of hydrogen production.

Currently, Germany produces approximately 2% of the world's gross hydrogen, i.e., 2.15 Mt p.a. [41, 42]. However, with respect to the future development of hydrogen delivery infrastructure, net hydrogen demand is more important and is not covered by process-related hydrogen output. The bottom-up assessment of this work regarding individual hydrogen plant capacities indicates overall hydrogen production by captive plants to be 1.3 Mt p.a. This value is comparable to the assessments in the literature of between 1.3 to 1.6 Mt p.a. [43, 44]. Additionally, hydrogen merchant plants and available by-product hydrogen are estimated to reach 0.15 Mt p.a., and so the overall hydrogen market considered in this work reaches 1.45 Mt. p.a. The distribution of the hydrogen market in Germany is primarily characterized by the locations of chemical industry facilities and the resources required for hydrogen production. Figure 3 displays the existing hydrogen market in Germany. These are two islanded pipeline systems connecting the main centers of demand in North Rhine-Westphalia and North Saxony, the Central German chemical triangle. The low geographic coverage of the hydrogen infrastructure indicates a high degree of centralized generation at the demand sites. In these two regions alone, more than 50% of total German hydrogen output is concentrated. Other regions with a substantial petrochemical industry and large refineries also have significant on-site hydrogen production capacities.

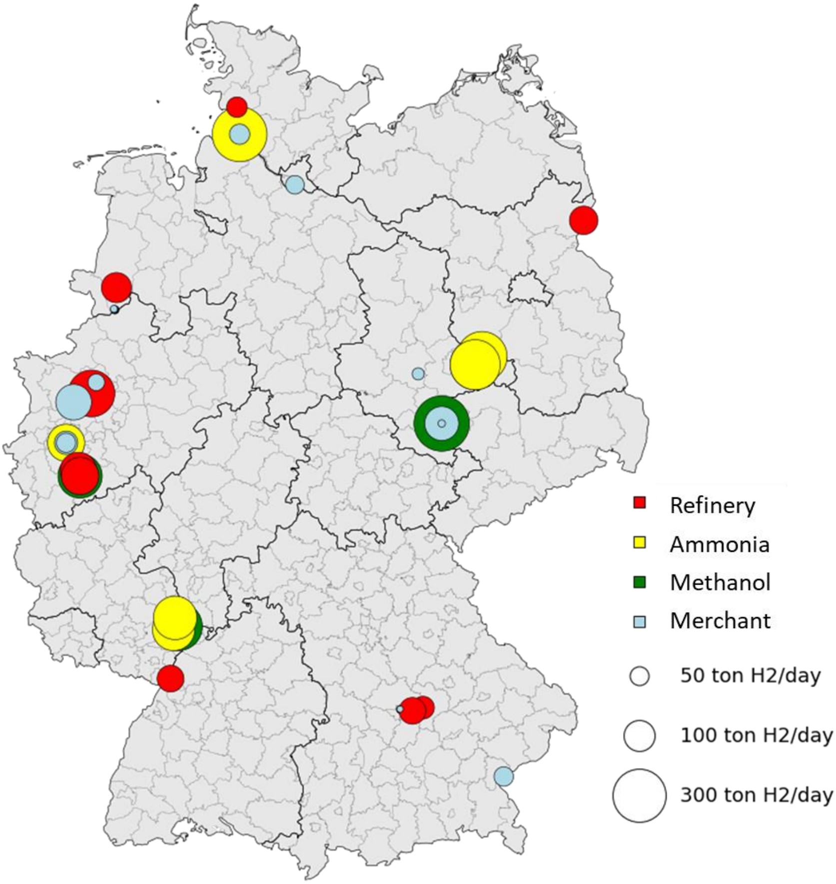

Figure 3. Current hydrogen market and structure in Germany.

2.1.3 Hydrogen and Fuel Cell Commercialization Projects in Germany

The present state of the hydrogen market and ambitious targets for the development of the hydrogen infrastructure indicate that Germany is amongst the countries with the most extensive progress towards hydrogen commercialization. Figure 4 displays the data collected from public information on the relevant hydrogen commercialization initiatives in Germany, which showcase various designs of hydrogen systems (see Appendix A). The ELEMENT EINS project intends to assess the integration of the electricity and gas systems by constructing a 100 MW electrolyzer and use the nearby wind power plants to produce hydrogen that will be fed into the natural gas grid [45, 46]. Another approach is taken by the ReWest100 project in Heide, which is intended to develop a system encompassing a 30 MW electrolyzer, a salt cavern and a dedicated hydrogen delivery infrastructure to vehicles and the refinery in Heide [45].

Current industrial hydrogen demand plays a major role, also in the project GreenHydroChem, for which it is planned to build 100 MW of electrolysis capacity that will supply the refineries and methanol production in the so-called Central German chemical triangle [45]. In the vicinity of the area, the project EnergieparkBL will feature a 35 MW electrolysis system and a salt cavern storage facility near Leipzig and connect it via reassigned pipeline to the existing hydrogen pipeline grid in the Central German chemical triangle [45]. A similar approach is being followed by the HYBRIDGE project, which will see the building of 100 MW of electrolysis capacity and use a reassigned natural gas pipeline to supply the refinery in Lingen and other consumers in the vicinity of it [47, 48]. The steel industry, with projects such as H2Stahl and SALCOS, is also actively working towards a gradual integration of hydrogen into the steel-making process [45, 49]. A substantial amount of these projects also consider hydrogen generation from phased out from feed-in tariff of renewable energy act (EEG) onshore wind plants. As many of these plants are located outside the currently eligible areas [50] and thus cannot be repowered, this approach is an alternative to the power purchase agreements (PPAs) [51, 52].

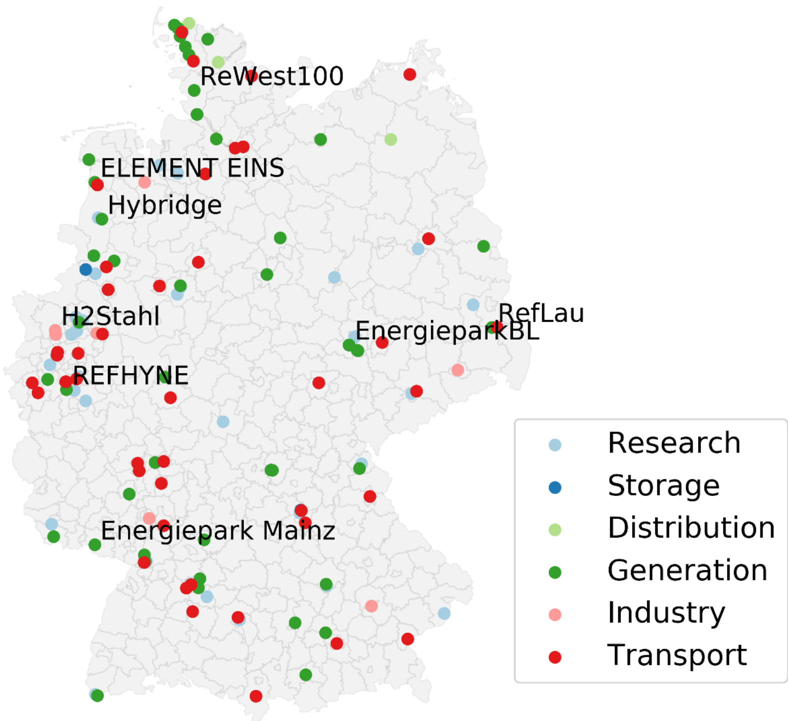

Figure 4. Overview of the current commercialization projects in Germany.

Despite the numerous industry-related initiatives described above, the largest fraction of commercialization projects is comprised of various transportation-related initiatives such as public hydrogen refueling stations and demonstration projects of captive buses, trains, forklifts and trucks (see Figure 4 and Figure 5). Consequently, it can be concluded that the rising interest by the relevant stakeholders indicates the highest technology readiness of these fuel cell applications. Among the most notable projects in the transport sector is a Dutch project at the Port of Rotterdam that involves 1000 heavy-duty FCEV trucks on roads to Belgium and West Germany [53]. Furthermore, various train and bus projects that are primarily located in North-Rhine-Westphalia, Baden-Wuerttemberg and Lower Saxony also play a major role in the evolving hydrogen market [54, 55].

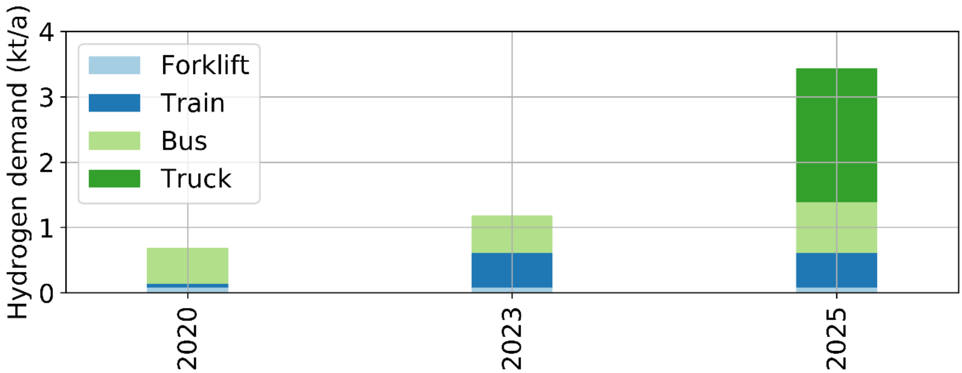

Figure 5. Anticipated demand from the published hydrogen commercialization projects for fleets from 2020 to 2025.

When the project locations are compared with current hydrogen demand sites, the influential role of North Rhine-Westphalia in the commercialization of hydrogen is reflected. It can be noted that hydrogen demand-related projects are generally concentrated in the core population centers, whereas electrolysis projects are often situated in more rural areas, corresponding to favorable renewable energy and electrical grid conditions. Notable exceptions are demand-driven projects in industrial sites such as the 6 MW and 10 MW electrolyzers in Energiepark Mainz and the Rhineland refinery (project REFHYNE), respectively [56, 57]. The most important location factors for electrolysis plants that have been highlighted in the literature are proximity to high- and medium-voltage substations, regional users of hydrogen, the gas network and large-scale hydrogen storage sites [39, 58-60]. Because of the low to medium full-load hours of the electrolyzers, a delivery system dedicated to only supplying seasonal storage contents would suffer from low utilization. This explains the necessity of a power-to-gas (PtG) plant to be near potential salt cavern storage sites [61-63]. For cavern leaching, the desired water can either be obtained from groundwater sources or surface water ones like lakes and rivers [64-66]. A few different methods exist for the disposal of brine, most notably drainage into an open saline water body, and therefore proximity to navigable waterways, which act as a proxy for high water throughput, is also crucial if potential sites in the interior of Germany [67] are to be assessed.

2.1.4 Potential and Scenarios of Green Hydrogen and Fuel Cell Adoption

Figure 6 shows the potential long-term hydrogen market size for different energy market segments in Germany. Despite the smaller market size of public transport and forklifts, a low number of the required fueling stations and the generally challenging requirements for parameters such as range, refueling speed and power capacity make them very attractive markets for the first adopters of hydrogen technologies. It was found that the associated market potential of public transport and forklifts is sufficient to provide a cost-competitive, countrywide hydrogen supply [68]. Larger transport markets, such as freight vehicles and passenger cars, will require a more extensive hydrogen refueling station network, and therefore these will be more challenging to enter. Despite a similar Wobbe index, the admixture of hydrogen with natural gas is currently limited by natural gas quality requirements, which vary significantly amongst countries, from 0.01 to 12%vol. [69]. The thermal use of admixed hydrogen and the cost-competitiveness of natural gas makes this market more difficult to penetrate than is the case of transportation applications. Even more difficult markets to enter are those in the chemical and heavy industrial sectors, which encompass the use of green hydrogen in current chemical processes, as well as novel applications such as the direct reduction of iron (Power-to-Steel) and the production of synthetic fuels (Power-to-Fuel). The high cost-competitiveness of the global commodity markets, as well as technological and market development uncertainties, significantly diminish the willingness of industrial consumers to shift to green hydrogen in the short- to medium-term perspective. Therefore, the large-scale adoption of green hydrogen in heavy industry is generally anticipated in the later stages of the hydrogen market's development [70, 71]. Hydrogen use in the power sector is expected to have the most significant potential, which is, however, also the most difficult to access. Various energy system analyses indicate a substantial re-electrification need at only very large renewable energy penetration levels to cover seasonal variations in renewable energy generation [72-74]. This finding suggests that re-electrification cost-competitiveness is associated with high renewable energy penetration, leading to large amounts of electricity surplus and fossil fuel generation surcharged with high carbon taxes. As these conditions display an as yet very remote energy system design, re-electrification is not expected to play a major role in the hydrogen market's development in the medium term.

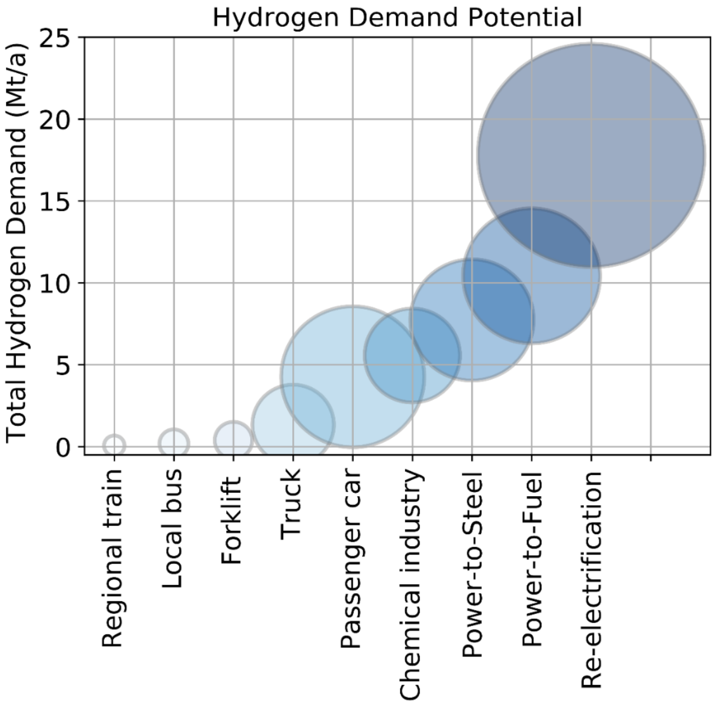

Figure 6. Hydrogen market potential for Germany including transport, energy and industry sectors.

Based on these findings and the markets associated with most extensive commercialization activities, a review of market adoption scenarios from 2023 to 2050 for each relevant hydrogen market was conducted in order to assess the anticipated market evolution. The scenario overview was focused on Germany, however, due to the limited availability of data; relevant European or global market scenarios and targets were also considered. For the years until 2025, pilot and commercialization projects were also considered in the assessment. From the overview depicted in Figure 7, it can be observed that various scenarios yield contradictory conclusions regarding the future importance of hydrogen. The scenarios differ not only in terms of the required time-frame to reach a specific market penetration but also with regard to total market adoption over the observed period. This finding indicates substantial uncertainty with respect to fuel cell technology adoption, creating a challenge for long-term supply chain infrastructure development. As the review encompasses different types of scenarios, including expert judgment, simulation and optimization scenarios, the impact of scenario type on the results was assessed, but no clear link between the scenario type and anticipated demand could be found. It should be noted that despite the displayed uncertainty, even the most conservative estimates anticipate 20-25% fuel cell vehicles in local bus and non-electrified train fleets by 2050, thus highlighting the role of these markets. Generally, no scenario anticipates a fleet penetration larger than 20% by 2030, indicating a gradual market adoption after the initial commercialization phase through 2030. Here, data for passenger cars constitute an exception, as it contains data points that form a longer time-frame that reaches back to publication in 2008 [75]. Consequently, this indicates a broader market adoption 10 years earlier than later scenarios, thus highlighting the generally anticipated period of a decade to introduce the technology. Again, the importance of the initial markets is emphasized as data for local bus and non-electrified trains, as well as forklifts point towards faster adoption than in other assessed markets. Nevertheless, it should be noted that data on these markets are sparse in comparison to passenger car and freight truck markets, highlighting the need for further research. Forklifts in particular, despite the adoption of more than 20,000 vehicles [76], require more analysis with regard to market diffusion.

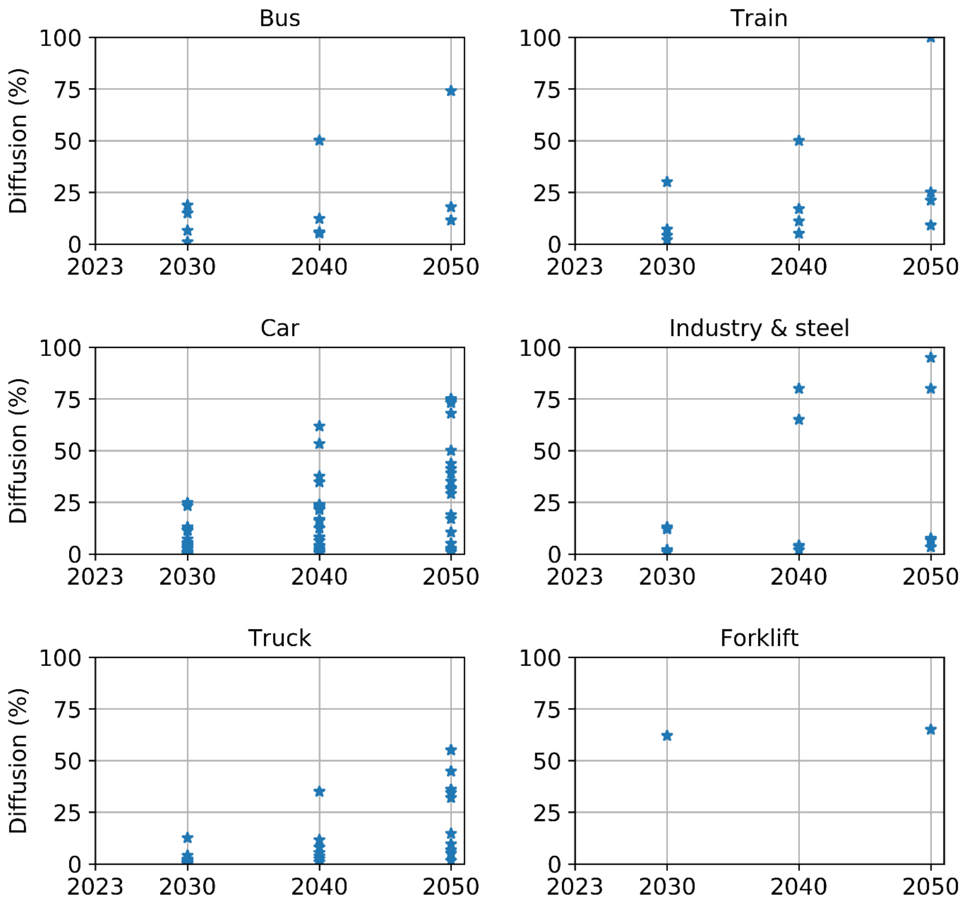

Figure 7. Gathered data for hydrogen penetration scenarios for the years 2023 to 2050 [55, 70, 71, 77-104].

Previous studies indicate that the common property of new technologies is an s-shaped market penetration curve that encompasses three major phases: an initially slow introduction, a rapid market expansion and a phase of saturation associated with decelerating market growth [105, 106]. Among the most often applied approaches to anticipate the long-term adoption of new technologies and products is the Bass model. The Bass diffusion model is a differential equation that uses the concepts of innovators and imitators to model the spread of innovation amongst potential adopters in the population [107-110]. The main assumptions of this model are the zero-initial level condition and the omission of subsequent generations of the product. One option to solve the latter issue is the application of Markov chains, which describe the sequence probability of events based on the state of the previous event [111]. Another general challenge in the use of the Bass diffusion model is the estimation of parameters for innovation and imitation. This is especially true for fuel cell applications that are still in the early commercialization phase and do not provide sufficient data for appropriate regression analyses. Methodologies to alleviate this issue include discrete choice experiments based on the potential consumer survey [112] or regression analysis on the basis of comparable products with extensive sales data [113-115]. However, the derived results are highly influenced by the sample of the survey and generally focus on a single application, such as FCEVs.

2.1.5 Technology Overview

The following section will provide a brief overview of the most prominent elements of hydrogen supply chains, such as production, storage, processing and conditioning, as well as delivery and refueling. Each supply chain element is assessed with regard to technological alternatives and its associated key techno-economic characteristics. Then, characteristic assumptions for the subsequent analysis are selected. For a more detailed overview of the technical parameter selection, see the Appendix B.

2.1.5.1 Hydrogen Production

Hydrogen can be produced from fossil and biogenic feedstocks or water via electrolysis. The element hydrogen is colorless, but due to the broad spectrum of possible production alternatives, there exist different names for classifying hydrogen according to the CO_2 emissions associated with its generation, such as 'gray', 'blue' and 'green' hydrogen [22] (see Figure 8). In general, the term grey hydrogen refers to hydrogen production via fossil fuels, with the most common process being steam methane reforming (SMR). Depending on the CO_2 intensity of the electricity mix, hydrogen produced using electrolysis from grid electricity may also be referred to as grey due to its high associated CO_2 emissions. Nonetheless, additional sub-classes of CO_2-intensive production output, such as 'brown' and 'white' hydrogen, have also been proposed. Brown hydrogen refers to hydrogen produced from coal and is the most CO_2-intensive of the common production sources. It has been proposed to refer to by-product hydrogen that is not used as a feedstock but thermally exploited near its production site as white hydrogen. In other use cases, on-site thermal utilization can be substituted by the combustion of natural gas, thus leading to less CO_2 intensity than in the case of grey hydrogen. Blue hydrogen generally refers to non-renewable hydrogen production that meets the low CO_2-intensity criteria. The application of carbon capture and storage (CCS) to coal gasification and SMR enables these processes to sufficiently reduce the associated emissions and meet this criterion. However, additional classes of turquoise and yellow hydrogen have also been proposed. Turquoise hydrogen is produced by methane pyrolysis, wherein methane (CH_4) is split in a thermochemical process into solid carbon and hydrogen and, if the heat supply of the high-temperature reactor is provided by renewable energy sources, the process has a low CO_2 emission intensity. Hydrogen produced by nuclear powered electrolysis is called yellow hydrogen. Green hydrogen, in turn, is produced exclusively from renewable energy sources. Typically, green hydrogen is produced by water electrolysis. Further possibilities are the gasification and fermentation of biomass and the reforming of biogas. The following sections will explore the key features of the essential hydrogen production processes that define the described classification.

Brown	Coal gasification
Grey	Water electrolysis using power from fossil fuels
	Reforming of natural gas
White	By-product of industrial processes
Blue	Coal gasification with CCS
	Reforming of natural gas with CCS
Turquoise	Methane pyrolysis
Yellow	Water electrolysis using nuclear power
Green	Reforming of biogas
	Gasification and fermentation of biomass
	Water electrolysis using regenerative power sources

Figure 8. Color classification of the origins of produced hydrogen.

Currently, the most widely utilized options to retrieve hydrogen from hydrocarbons are SMR, partial oxidation and gasification (gray hydrogen) [37]. SMR consists of a high-yield endothermic reaction of natural gas and steam to enable intermediate-purity hydrogen production [116]. The partial oxidation of hydrocarbons has a lower material efficiency and hydrogen purity but can utilize a larger variety of fuels, including oil residues [116]. Gasification has the lowest material efficiency and hydrogen purity; however, it enables the use of more widely accessible fuels, such as coal (brown hydrogen) and biomass [116]. Based on the observed largest share of hydrogen production with SMR, its favorable technical specifications and potentially sufficient degree of spare capacity, it is selected to represent incumbent hydrogen production technologies. Against the background of CO_2 emission reduction policies, these processes can be extended with the addition of CCS (blue hydrogen), thus enabling the CO_2 footprint of hydrogen production to be diminished, which is expected to be the key bridge technology to bring about widespread, low-emission hydrogen production [22]. However, the current limitations of technology acceptance in the population with respect to the development of CCS projects strongly limits blue hydrogen production potential in Germany [117]. Therefore, only blue hydrogen imported from neighboring natural gas-producing countries is considered in this work. Another possibility of providing hydrogen while avoiding CO_2 emissions is represented by methane pyrolysis (turquoise hydrogen), which entails the thermal non-catalytic splitting of methane into hydrogen and carbon at high temperatures. However, despite up-and-coming applications, due to its low technology readiness level (TRL), methane pyrolysis is not expected to become commercially viable within the next 10 to 20 years [118]. To put the state of the technology's development into perspective, the latest pilot project aims to reach a production capacity of fewer than 12 kg_{H2}/h [119] while an SMR plant's capacity can reach up to 50,000 kg_{H2}/h [120]. Thus, due to its low TRL and uncertain technological scaling, methane pyrolysis will not be further considered in this work.

Table 3. Comparison of natural gas-based hydrogen production methods [118, 119, 121-126].

	SMR		**SMR+CCS**		**Methane Pyrolysis**	
	Low	High	Low	High	Low	High
Efficiency$_{LHV,CH4}$(%)	70	78	70	78	55	75
Cost €/kg_{H2}	1	2.2	1.2	2.8	1.0	2.5
	TRL: 9		TRL: 8		TRL: 5	
Advantages	Low production costs Established technology Scalable process		Intermediate CO_2 emissions Medium production costs Scalable process		Potentially high efficiency Use of exhaust heat Reversibility of the process	
Disadvantages	High CO_2 emissions		Intermediate CO_2 emissions Requires CO_2 infrastructure		Tradeoff of H_2 and carbon quality No clearly preferable process	

Alternatively, with the intensifying decarbonization of electricity production (green and yellow hydrogen) by means of water electrolysis (EL), hydrogen can be extracted from water (H_2O). The main electrolysis variants currently being discussed are alkaline (AEL), polymer electrolyte membrane (PEMEL), and solid oxide (SOEL). AEL is the most mature technology and is already implemented on an industrial scale to several MW and accounts for 2-4% of current hydrogen production [53]. Due to its inability to operate at low current densities, AEL has important constraints on its operating range, with a minimal load of 20% and relatively slow dynamics between operating points of

<30 s [127, 128]. Alternatively, PEMEL has a wider operating range of 0% to 150% and dynamic operation between operating points of <2s, thus enabling the coupling of PEMEL with highly intermittent power sources such as solar photovoltaic (PV) and wind [56-58]. Another alternative is SOEL, which operates at high temperatures (700-1000 °C with ZrO_2 ceramic as the electrolyte) that in the event of freely available heat from exothermal systems, such as high temperature nuclear reactors, allow higher efficiency than in the case of other electrolyzer systems [128]. However, the high operating temperature also increases the thermal inertia and thus the feasible size of the cells, which poses a significant challenge for larger-scale SOEL deployment and integration with variable renewable energy technologies. Furthermore, current SOEL must overcome important deficiencies, such as short lifetimes and material degradation [127]. Table 4 provides an overview of the most important features of electrolytic hydrogen production technologies. Based on the uncertain scalability of the SOEL technology and its low TRL, it is not considered in this work. Furthermore, due to the uncertainty regarding the dynamic operation of AEL and possible additional investment associated with direct coupling to renewable power sources, PEMEL investment costs are considered in the further analysis. Nevertheless, the electrolysis investment costs aspect is addressed in the sensitivity analysis in Sub-chapter 4.6.

Table 4. Comparison of electrolytic hydrogen production methods [40, 128-133].

	PEMEL		**AEL**		**SOEL**	
	Today	Future	Today	Future	Today	Future
$Efficiency_{LHV,el}$(%)	63	70	65	70	75	83
CAPEX (€/kW)	1500	250-500	1000	300-500	2500	500
	TRL: 7-8		TRL: 9		TRL: 4-5	
Advantages	High gas purity High load flexibility High power density		No rare metals in catalysts Low specific cost Established technology		Potentially high efficiency Use of exhaust heat Reversibility of the process	
Disadvantages	Precious metals in catalysts		Limited flexibility		High material stress	

Figure 9 summarizes the literature review of CO_2 intensity and the cost of hydrogen production for a selection of the most promising technologies. The results consider estimates of lifecycle emissions of production and primary energy sources. In the case of coal-based processes, underground mined coal and, in the case of electrolysis, renewable electricity is considered in the analysis. Furthermore, emissions occurring in the natural gas supply chain are also considered for SMR and SMR+CCS [122, 134].

The respective technologies are displayed as areas encompassing underlying uncertainties and variations of the data in the literature. The displayed variation of fossil fuel-based production is mainly affected by efficiency and the costs of primary energy and CCS where applicable, whereas in the case of electrolysis, the uncertainty appears primarily due to the differing availability of renewable energy and the anticipated future technological development of electrolysis and renewable energy technologies. It can be observed that moving from top to bottom along the y-axis, these technologies display a Pareto frontier of both the hydrogen production cost and associated CO_2 intensity. On the one hand, coal and SMR lead to the lowest cost but also the highest CO_2 emissions and on the other, green electrolytic hydrogen enables the lowest CO_2 emissions at the cost of higher production expenses. In between, pyrolysis and coal, as well as natural gas-based hydrogen production with CCS, can be considered. Nevertheless, as mentioned above, pyrolysis is still at an early stage of development. Thus, the initial transition to less CO_2-intensive production will potentially not be able to rely on this technology.

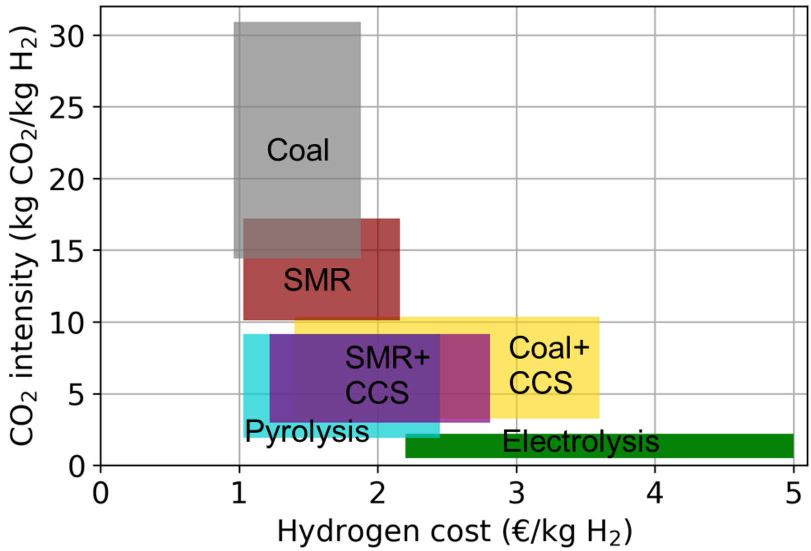

Figure 9. Hydrogen production cost and CO2-intensity (adapted from the literature [122, 135]). Life cycle emissions of the technologies are included in the evaluation.

Due to the currently low level of electrolysis deployment, learning effects occurring with expanding technology deployment will play a major role in the future development of the investment costs of electrolyzers. These learning effects can be modeled with learning curves that depict a cost reduction of a product with increasing cumulative production [136]. Learning curves can have various features, but their most notable aspects arise in the manufacturing process and the optimization of resource use. Nevertheless, due to the broad nature of the learning curve concept, several ambiguities occur. First, the resembling concept of the experience curve was introduced, which is designed to depict the overall cost reduction of a product over time, including related marketing, logistics and research and development (R&D) [137]. However, available technology cost data often do not reveal which components are factored into the cost, thus making it very difficult to differentiate between these two concepts. Secondly, ambiguity considers economies of scale, as mass production and changes in production capacity can also affect technological learning [136]. Despite these drawbacks of the concept, learning curves can be considered a useful first approximation to assess the future development of the technology. Learning curves are characterized by learning rates (LRs) that depict relative cost reduction with each doubling of cumulative capacity. The literature shows that early-stage energy technologies tend towards LRs in the range of 15-25% [136]. Assessments of water electrolysis have found an LR of 18 ± 6% [129, 138]. Similar results of 18% were yielded by expert elicitation studies of AEL and PEMEL as well [127]. Due to the technological similarities to electrolysis, fuel cell cost data can also be used to determine the LR of electrolysis. Typical values in the literature range from 16-22% for proton-exchange fuel cells [139-142]. Furthermore, LR assessment can be improved by applying multi-factor learning curves that enable a better fit to the data [143]. A recent assessment of multi-factor learning curves, which also incorporate component-specific assessments, has estimated a mean LR of 18% for AEL, PEMEL and SOEL, respectively [144]. In conclusion, various literature sources indicate an LR of approximately 18% for novel electrolysis components, such as stacks. The component-based analysis hints that other components, such as the balance of plant (BoP), gas conditioning, and power electronics, possess significantly lower LRs, ranging between 7% and 13%, highlighting the extensive adoption of these components into other technologies [145]. Moreover, as stacks and power electronics currently account for up to 2/3 of system costs [146], only learning effects for these two components will be considered in this study, thus providing a weighted average LR for the system of 16.4%. As with developed components, in the case of the broadly adopted current hydrogen production methods, such as SMR, learning effects can be neglected. The aforementioned economies of scale in water electrolysis plants and SMR are, however, considered on the production plant level. While the scaling factor for the total BoP, electronics and gas conditioning is determined to reach 0.7, the scaling of SMR was found to be 0.71 [145]. Due to the expected modularization of large electrolyzer plants, the scaling of the components can be expected to only take place up to a unit nameplate capacity of 20 MW_{el} [147].

2.1.5.2 Storage

Seasonal variations in renewable energy sources such as wind and solar PV require long-term storage solutions to cope with intermittent power production. The long-term storage requirements of renewable energy integration can be fulfilled with hydrogen. Hydrogen storage can be facilitated by the storage of pure hydrogen or by the use of hydrogen carriers (e.g., liquid organic hydrogen carriers (LOHCs)) [148]. Pure hydrogen can be stored in specialized steel containers in a compressed, liquid state or, alternatively, compressed hydrogen can be stored in underground facilities. The high storage capacity and relatively low costs of underground storage make it an especially attractive solution for seasonal renewable energy variations. Gaseous and liquid storage options, by contrast, are more expensive and thus more suitable as buffer systems at, for example, hydrogen refueling stations. The utilization of underground storage in industrial facilities since the 1960s has already proven the technical feasibility of GWh-scale underground hydrogen salt caverns [149]. However, despite large potential in Europe and some other regions [67], the geological limitations of the required rock formations for salt caverns and porous rock diminish the global availability of underground hydrogen storage (and multiple media may compete for underground deposits, such as compressed air, CO_2 and hydrogen itself). Alternatively, hydrogen can be deposited in the form of synthetic fuels or by making use of specialized hydrogen carrier materials (i.e., LOHCs). While the use of synthetic fuels would allow the existing infrastructure to be used, drawbacks include high energy losses during conversion and the cost of CO_2 separation from the air, as it is anticipated to decarbonize the energy system by 2050. Specialized hydrogen carrier materials, such as hydrides and LOHCs, offer advantageous energy density properties under low pressure, thus mitigating potential hydrogen-related risks [148]. However, these technologies also carry drawbacks in terms of efficient energy discharge and must still be proven in day-to-day operations to demonstrate their readiness for commercialization. Due to the high TRL level and high adoption of liquefied natural gas (LNG) as analogy technology for LH2, during the introduction phase no substantial learning can be assumed for LH_2 tanks. As for the salt caverns, due to its similar nature the technology can be approximated with geothermal power or hydraulic fracturing in the shale oil sectors. Potentially due to the high sensitivity to site-specific conditions no literature on learning curves in geothermal could be found. Alternatively, the learning rate of 3 to 4% was reported for hydraulic fracturing in the USA [150]. Hence, learning effects for the salt caverns will be neglected in the further study. Nevertheless, in the case of gaseous H_2 bundles, 500 bar bundle technology, which uses type 4 composite cylinders and is anticipated to become commercially available by 2025, offers significant cost reductions compared to the current 200 bar gaseous hydrogen bundles. Based on the varying technical specifications and high TRL, all three hydrogen storage options will be considered in subsequent work.

Table 5. Comparison of hydrogen storage methods [40, 128, 147, 148, 151-154].

	Salt cavern		**Gaseous H2 Bundle**		**Liquid H2 Tank**	
	Today	Future	Today	Future	Today	Future
Density GJ/m3	1.44	1.44[4]	2.88	3.84	8.5	8.5
CAPEX (€/kg)	21	21	800	600	25	25
	TRL: 8-9		TRL: 8-9		TRL: 9	
Advantages	Seasonal storage Low specific cost		Long cyclic lifetime No geological technology limitations		Long cyclic lifetime No geological technology limitations	
Disadvantages	Geological limitations		High specific cost		Requires liquefaction	

2.1.5.3 Hydrogen Processing and Conditioning

The varying technical characteristics of the components along the hydrogen supply chain with respect to the hydrogen's state, purity and pressure necessitates conversion steps such as compression, liquefaction and purification. In the case that energy carriers are used for the storage and transport of hydrogen, charging and discharging units must also be taken into consideration.

Electrolytic hydrogen production output is typically conducted between 1 and 20 bar, whereas, to accommodate sufficient quantities of hydrogen and save space, mobile hydrogen fuel cell applications operate at 350-700 bar. This creates a significant pressure increase that must be maintained and operated along the supply chain. Furthermore, hydrogen supply chain components, such as high-pressure pipelines and 500-bar trailers, have additional hydrogen pressure constraints. To fulfill the

[4] Operating pressure difference of 150 bar

aforementioned hydrogen pressure requirements, the compression can be facilitated via mechanical, electrochemical and hydride means. However, only the former is an established technology with proven operational viability. Alternatively, for the gradual pressure increase along the supply chain, hydrogen can be liquefied at the point of production and subsequently evaporated and compressed to the required pressure level at the refueling station. The techno-economic parameters for these approaches can be found in Robinius et al. [93].

As with the pressure, hydrogen purity is defined by the hydrogen quality requirements of the final consumer; for example, PEMFCs have a 99.97% purity requirement [155], which is also cited in documents such as EU directives on the deployment of alternative fuel infrastructures [156]. However, the maximum concentration level of single contaminants, such as water, oxygen (O_2) and carbon dioxide (CO_2), can be two orders of magnitude smaller than the fraction of total non-hydrogen gases allowed [155]. Furthermore, depending on the hydrogen supply chain pathway used, additional hydrogen purity constraints can arise when SMR and by-product hydrogen or hydrogen liquefaction are taken into account [157, 158]. Amongst the most widely used purification methods are pressure swing adsorption (PSA) and temperature swing adsorption (TSA), as both of these purification processes can achieve comparably high hydrogen purity levels and sufficiently high hydrogen recovery rates [159-164] (see Table 6). Special membranes are also promising for smaller throughput applications [165, 166]. The marginal difference of recovery efficiency is of indicative nature because it is subject to varying plant designs and a number of purification steps reported in the literature.

Table 6. Comparison of hydrogen purification methods.

	TSA		**PSA**	
	Low	High	Low	High
Output purity (%)	99.9%	99.999%	99.9%	99.999%
Recovery efficiency (%)	75%	97.5%	90%	99%
	TRL: 9		TRL: 9	
Advantages	Efficiency at low adsorbent concentrations		Efficiency at high adsorbent concentrations Small bed size	
Disadvantages	High heat demand		High electricity demand	

A further purification method is a cryogenic distillation, which uses the different boiling temperatures of the gas flow components [167]. However, substantial energy intensity and limitations in relation to very high purities diminish its applicability [168]. Due to the higher efficiency at low absorbent concentrations, TSA is commonly used for hydrogen drying in, for example, cavern storage [169]. PSA, however, is more effective at higher adsorbent concentrations, is less complex, requires lower bed sizes, and is more versatile, and therefore it is often applied to by-product and SMR-based hydrogen [169-171]. A further possible hydrogen contamination can take place during pipeline delivery. Nonetheless, by using state-of-the-art, non-lubricated hydrogen compressors, the risk of oil contamination can be significantly reduced [172]. Therefore, in the following sections, only TSA and PSA are considered as purification technologies. Relevant techno-economic parameters regarding purification technologies can be consulted in Cerniauskas et al. [68, 173]. An overview of the hydrogen contamination considered at each relevant supply chain link is provided in Table 7.

Table 7. Assumed hydrogen contamination in the hydrogen supply chain [174-178].

Molecule	PEMEL	By-product	SMR	Cavern storage
H_2O	0.01%	0.25%	-	0.28%
CO_2	-	-	15-25%	-
CH_4	-	-	3-6%	-
CO	-	-	1-3%	-
O_2	-	0.2%	-	-

2.1.5.4 Hydrogen delivery

The three main land-based routes of hydrogen distribution are gaseous hydrogen trailers and pipelines, as well as liquid hydrogen trailers. The choice of the most effective delivery method depends on the chosen means of storage, as changes in the state of hydrogen increase energy losses as well as the required delivery distance and hydrogen throughput [148, 154]. Gaseous hydrogen trailers could offer a cost-effective solution during the introduction phase, which will be marked by low and sparsely-distributed demand. However, they become less economical in later market stages when hydrogen demand increases. Nevertheless, even with significant hydrogen demand, the last mile distribution from hydrogen pipeline to refueling station remains a cost-effective option [179]. Alternatively, hydrogen can be liquefied or transported in the form of LOHCs. Both options enable cost-efficient, long-distance hydrogen transport, which is especially significant to the prospect of overseas hydrogen trade [135]. Challenges relating to the transport of LH2 are comparable to those of liquefied natural gas (LNG), which requires high insulation to avoid boil-off losses. Therefore, as with LNG transport, LH_2-transporting ships and trucks can be operated with the hydrogen boil-off losses. In the case of LOHCs, transportation is very similar to that of liquid fuels, and therefore few modifications to current fossil fuel pipelines and trailers would be necessary. However, studies have shown that the economic viability of LOHC delivery depends strongly on the availability of low-cost heat energy [11, 180], constraining LOHCs to more specific environments. Table 8 provides an overview of the aspects of hydrogen delivery considered in this work.

Table 8. Features of hydrogen delivery methods [9, 40, 128, 147, 148, 151, 152].

	Pipeline		**GH2 Trailer**		**LH2 Trailer**	
	Today	Future	Today	Future	Today	Future
Capacity	2.4 t/h	245 t/h	400 kg	1100 kg	4300 kg	4300 kg
CAPEX	500 €/m	3400 €/m	500 €/kg	600 €/kg	200 €/kg	200 €/kg
	TRL: 8-9		TRL: 9		TRL: 9	
Advantages	High capacity Low space demand		Low initial investment		Low initial investment High capacity	
Disadvantages	High initial investment cost		Low capacity		Requires phase change (liquefaction)	

Hydrogen pipelines are often considered the most cost-efficient and environmentally-favorable means of delivering large volumes of hydrogen over medium to large distances [181] and can minimize the impact of hydrogen delivery on the already intensive road-based traffic [182]. This makes it especially attractive for a transmission network and the connection of industrial sites. Currently, there are already several isolated hydrogen pipeline networks supplying industrial sites in the EU and the USA, with a total length of 3000 km, for which construction is undertaken in observation of international hydrogen piping norms [183, 184]. The risk of low pipeline utilization and elevated initial investment in steel pipelines (see Figure 10) is a challenge to the implementation of hydrogen pipelines during the market introduction phase. The displayed data are subject to different approaches and considerations in the literature, ranging from project data to specific bottom-up assessment. Furthermore, it is not always clearly indicated if only the pipeline material and associated works or also the rights of way for the land lot are included.

However, the described uncertainty and the overall pipeline costs can be alleviated through the reassignment of existing natural gas pipelines, which, with the increasing electrification of the heating sector and shift from low- to high-caloric natural gas, will increasingly become available. Initial investigation of the German natural gas (NG) transmission grid by Cerniauskas et al. [173] has shown that, despite additional measures for mitigating hydrogen-related material embrittlement, pipeline reassignment can reduce yearly pipeline expenditures by up to 80% in comparison to a new, dedicated hydrogen pipeline. Another option for using hydrogen in the natural gas grid is to blend hydrogen with natural gas. Historically, there have been many cases of utilizing hydrogen-rich town gas (50-60% H_2), which was abandoned in favor of natural gas in the 1960s [185]. Currently, different countries make use of hydrogen gas admixtures for natural gas of up to 10% w/m [69], which can be further increased if heating devices and natural gas turbines and compressed natural gas vehicles, which currently allow a maximum of 2% vol, are adapted for higher hydrogen concentrations [186]. A comparable large-scale change in consumer devices was already observed during the transition from town gas to natural gas in the 1960s, as well as during the ongoing shift from low- to high-caloric natural gas [185, 187]. Nevertheless, despite the apparent benefits of the widespread availability of a natural gas infrastructure and the avoidance of new infrastructure implementation, hydrogen blending might lock-in hydrogen to thermal use, as any other hydrogen applications would require subsequent purification [155]. For these reasons, only the reassignment of natural gas pipelines will also be considered in future work.

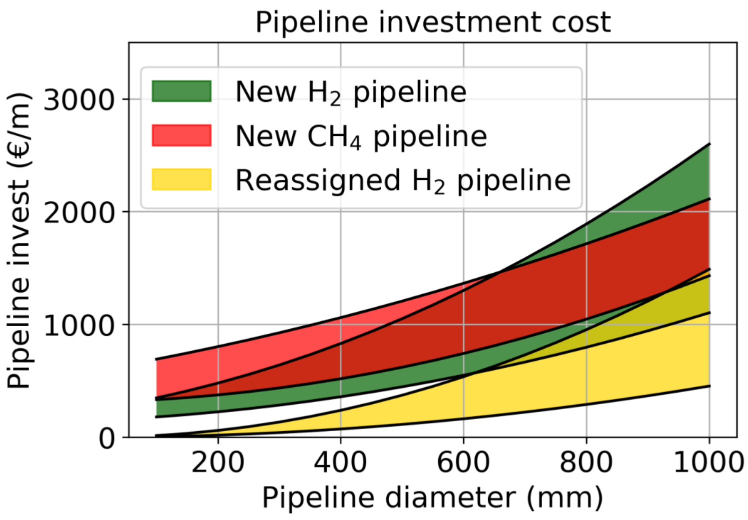

Figure 10. Pipeline investment cost overview from the literature. Including project data, bottom-up calculations and industry averages. Not always indicated if rights of way are also included [9, 94, 173, 187, 188].

Hydrogen pipelines can be operated at various pressure levels, depending on consumer requirements, pipeline system design and pipe material properties. Table 9, below, describes the various input parameters required to describe a hydrogen pipeline system. Due to the limited available data, additional parameters from a natural gas system are included. On the one hand, due to the well-known costs and operational properties of a natural gas system, the operation and maintenance (O&M) costs and pipeline depreciation provide the best case for the values. On the other hand, due to associated uncertainty regarding the costs and operation of a hydrogen pipeline system, the parameters are substantially more conservative. To appropriately factor in the described uncertainty, the conservative pipeline parameter values are chosen for this work.

Table 9. Parameters of the pipeline system.

Parameter	Assumption	Literature	Source
Pipeline O&M	5%	0.8% - 5%	[9, 189]
P_{max}	100 bar	100 bar	[148]
P_{min}	70 bar	70 bar	[148]
Compressor O&M	4%	1.5% - 4%	[190, 191]
Gas regulation O&M	4%	1.7%	[190]
Pipeline depreciation	40 a	40 a – 55 a	[9, 191]

2.1.5.5 Hydrogen Refueling

Currently, all hydrogen-powered vehicles prefer gaseous over liquid on-board hydrogen storage, as the latter would inevitably lead to boil-off losses in the vehicle. For use in passenger cars, the current state of the art is a gauge pressure of 700 bar, while 350 bar is the prevailing pressure for hydrogen use in buses and other commercial applications [192-196]. Furthermore, different vehicle markets feature varying requirements for refueling speed and refueling volume [197-202] as well as a characteristic refueling time [203-205]. The underlying structure of hydrogen refueling stations is comparable to that of current fossil fuel refueling and consists of a buffer storage, dispenser, cooling and fuel-processing unit that create the necessary pressure gradient to facilitate refueling. This principle holds for gaseous as well as liquid and LOHC delivery [206, 207]. The additional cooling of hydrogen is required to compensate for the temperature increase during refueling, which is caused by the Joule-Thomson effect [208]. Detailed hydrogen refueling station designs generally differ with regard to the form of hydrogen delivery and the chosen method for creating the required pressure gradient. For the 700 bar hydrogen refueling of passenger cars, the pressure is increased to 875 bar in order to enable rapid refueling rates of 1.8-3.6 kg/min [151, 209]. To achieve this, hydrogen is generally either stored in high-pressure vessels that facilitate the refueling process or medium-pressure vessels, with a small additional compressor that covers the highest pressure-gradient requirements installed. In the case of liquid or LOHC hydrogen delivery, hydrogen is evaporated or discharged from the hydrogen carrier and compressed to the required pressure. Alternatively, if a cryogenic pump is used, liquid hydrogen is first compressed and only subsequently evaporated for refueling [210]. In the case of 350 bar vehicles, rapid refueling requires a lower pressure gradient, and therefore 500 bar trailers can be employed as high-pressure hydrogen storage media for vehicle refueling, thus reducing the required capacity of the pressure management system [211, 212]. Corresponding to the selected hydrogen delivery methods, 350 and 700 bar hydrogen refueling station designs for pipeline GH2, as well as LH2 trailer delivery, will be considered in subsequent work. For a more in-depth overview of the parameters observed in this work, see Appendix B.

2.1.6 Summary

In this chapter, a strategic environment analysis was conducted to answer the first research question on the most promising hydrogen markets, with anticipated precipitation of hydrogen adoption and relevant hydrogen infrastructure options. Based on the current hydrogen market structure, stated policy goals, as well as implemented hydrogen commercialization projects most promising markets were selected for further analysis: local buses, non-electrified passenger trains, freight trucks, passenger cars, forklifts as well as heavy industry, including methanol, ammonia, refining and steel production. Then, a literature overview of scenarios for the potential hydrogen adoption in each market was conducted to verify the choice of markets and provide quantitative data for expected market growth and overall potential. For each stage of the hydrogen supply chain technologies were then discussed in terms of their relevance to short- to mid-term infrastructure deployment and characteristic techno-economic parameters were selected for consideration herein.

2.2 Literature Review on Modeling Methodology

From the stated overarching research question relating to the infrastructure and demand-side strategy for the introduction of a hydrogen infrastructure, it can be determined that the model must encompass a detailed representation of hydrogen supply and delivery, and also include a high level of detail with respect to the hydrogen demand. In order to address infrastructure and market development, the spatial and temporal features of the technology and market growth must also be considered. Furthermore, in order to consider the utilization of the existing infrastructure, a high level of technical detail and representative infrastructure characteristics must be considered in the model. In addition, a detailed consideration of the individual hydrogen market characteristics is also required in order to identify available synergy effects amongst different consumers.

On the basis of the strategic environment analysis, the following model scope can be established. For the hydrogen **demand**, the following markets must be considered in the model: local buses, non-electrified trains, passenger cars, freight trucks, material handling vehicles and industry, including ammonia and methanol production, refining and steel. From the **supply** side (see Figure 11), key identified hydrogen provision-related technologies include electrolysis, as well as SMR for domestic hydrogen production and the import of green and blue hydrogen. For the **storage** of hydrogen, selected alternatives are salt caverns, as well as GH_2 and LH_2 tanks. Amongst the selected hydrogen **processing and conditioning** technologies are compressors, liquefaction and evaporation units, as well as TSA and PSA purification components. The chosen hydrogen **delivery** options include GH_2 and LH_2 trailers, as well as new and reassigned hydrogen pipelines. Congruently to the selected markets and hydrogen delivery options, 350 and 700 bar refueling station designs for trailer and pipeline delivery are also considered herein. Consequently, such a broad set of different hydrogen markets with varying market adoption speeds necessitates the detailed modeling of the supply chain components, incorporating **scaling and learning effects** and market-specific hydrogen **quality requirements** such as pressure and purity. The nature of these requirements places a large emphasis on spatial and technical detail for both infrastructure and demand representation, indicating the need for multiple smaller models operating in **different spatial and technical dimensions** rather than a large homogenous model.

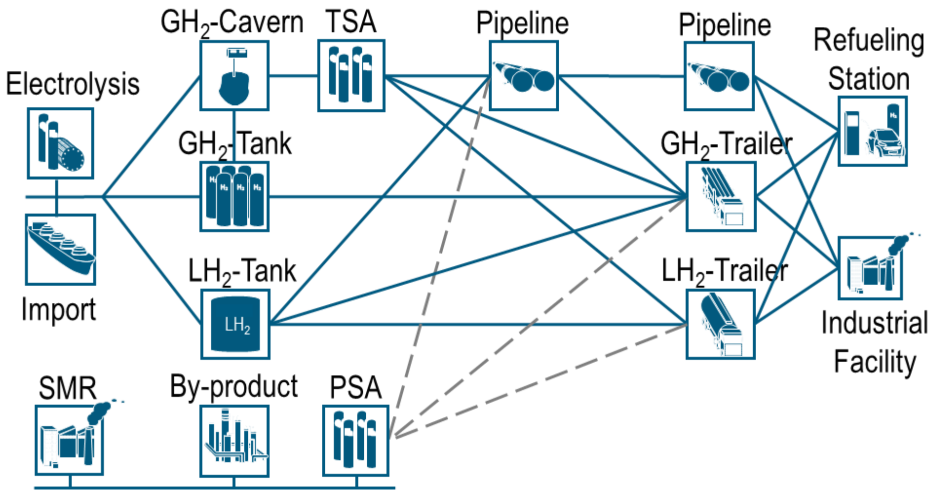

Figure 11. Overview of the considered hydrogen supply chain pathways.

In this chapter, in order to derive a modeling approach, relevant literature on two different research areas of hydrogen infrastructure and demand modeling are reviewed with regard to the applicability to the stated modeling requirements. Then, applicable modeling approaches from the literature, as well as research gaps requiring novel development, are identified. Finally, based on the derived conclusions from a strategic environment analysis and literature overview, an appropriate modeling approach is devised.

2.2.1 Infrastructure Modeling

The problem of hydrogen infrastructure design can generally be tackled via two distinct approaches: optimization amongst supply chain alternatives and simulation of the selected pathways (see Table 10). Scientific literature on the optimal design of a hydrogen supply chain and its introduction is generally focused on minimizing the supply chain costs of different infrastructure pathways to connect the source and sink regions. Key publications in this field include papers that focus on the general mathematical formulation of the problem of hydrogen supply chain optimization [213, 214]. From this point, ongoing research can be distinguished on the basis of the spatial scope and granularity of the analysis. The majority of research is focused on countrywide optimization and usually incorporates only a small number of single regions with lower geospatial resolutions [215-225]. These studies are primarily concerned with strategic decisions on the countrywide level concerning production and hydrogen delivery capacities amongst the defined sub-regions. Studies analyzing hydrogen infrastructure optimization within the sub-regions of countries or smaller areas apply an improved geospatial granularity, as the questions regarding trailer or pipeline routing and refueling station localization receive greater attention [226-229]. Furthermore, an even higher geospatial resolution is applied in the case of district optimization [230-232], which often focuses on optimized refueling station localization regarding transport flows and the spatial coverage of the area. To explore the core features of the optimization approach, HyPro [233] and MOREHyS [234] models that are specifically designed to optimize hydrogen infrastructure, will be presented in greater detail.

Table 10. Features of simulation and optimization approaches.

Model features	Simulation models	Optimization models
Technological scope	Limited number of technologies	Broad scope of alternative pathways
Technological detail	High level of detail	Linearized properties
Spatial scope	High number of points	Limited number of nodes
Temporal resolution	No substantial limitations	Limited by the tractability of the problem
Spatial resolution	High level of detail up to individual data points	Aggregation according to considered nodes

The HyPro [233] model is primarily focused on the temporal aspect of the optimized development of a hydrogen infrastructure, and so it neglects the geospatial dimension of the problem. The main goal of the model is to derive low-cost transition pathways, minimize stranded assets and provide information on system configuration changes. HyPro encompasses a broad spectrum of hydrogen production and delivery options, with techno-economic parameters derived from H2A models. A case study for Los Angeles has shown a 50% cost reduction of the supply chain in less than ten years of the analysis. The proposed cost-optimal technology shows that, due to high investment and electricity costs, electrolytic hydrogen will only be cost-competitive with SMR by the year 2030. Furthermore, the case study indicates that centralized hydrogen production with a dedicated pipeline delivery system requires approximately 10 years to reach the same production costs as forecourt SMR [233]. A similar model is MOREHyS [234], which is a mixed-integer linear program (MILP) designed to analyze the spatio-temporal development of a hydrogen infrastructure. It employs the Baltic Model of Regional Energy Market Liberalization (BALMOREL) model [235] as a starting point and includes myopia in the infrastructure optimization. This model includes data on regional renewable energy resources to derive local hydrogen production potentials. MOREHyS simulates the regional development of the demand-differentiating regions in terms of the year of connection to the hydrogen system. Moreover, the model employs spatial coverage parameters to distribute the hydrogen refueling stations within a region, which are then subsequently clustered to establish hub locations for the transmission network. In a German case study, it was found that onsite SMR was the most cost-effective technology during the initial phase of the analysis. As in the case of other studies, increasing hydrogen demand shifts the system configuration towards centralized coal gasification units. Remote regions are primarily supplied with LH2 trailers, whereas the supply of larger urban areas is gradually shifted from LH2 trailers to a pipeline supply model. Furthermore, the distribution of hydrogen in large urban areas was already found to be cost-effective in the very early phases of market introduction [75].

HyPro is capable of considering the temporal aspects of optimal transition measures, but it omits the geospatial dimension of the problem, thus limiting its applicability for strategic infrastructure analyses. This drawback can be mitigated by a smaller regional analytical scope, as in the case study, but such an approach is not applicable to a countrywide infrastructure strategy analysis. In contrast, the MOREHyS model encompasses improved infrastructure representation and a broader spatial scope. Nevertheless, due to the regional data aggregation, the MOREHyS model neglects the different infrastructure requirements across varying hydrogen markets; thus, information relating to market-specific infrastructure requirements and potential synergy effects is lost in the process.

To summarize, in order to adapt their methodology to specific questions of optimized infrastructure design, optimization models must often make the trade-off between the complexity problem, the geospatial resolution and the geographical scope of the analysis. A more extensive review regarding hydrogen supply chain optimization and the features of the associated models can be found in the literature [236]. As optimization problems are mostly formulated as linear or mixed-integer linear problems, technology characteristics relating to the supply chain components are often incorporated in the simplified linear format. As a result, these modes often neglect scaling and learning of the supply chain components. Thus, a trade-off between the level of detail of the technology description and the size of the solution space must be made. To alleviate this issue, various piece-wise linearization methods can be applied [237-239], but a careful balance between the computability of the problem and level of technical detail must be maintained.

As an alternative, the above-mentioned shortcomings of linearized descriptions of technologies and geospatial resolution can also be alleviated by reducing problem complexity by means of pathway simulation, which – at the cost of the variety of analyzed pathways – enables the inclusion of more technical details and increases the model's geospatial resolution (see Table 10). Corresponding to the optimization approach, pathway simulation primarily relies on the generalized problem definition, which mostly encompasses single component analyses [148, 154, 240-242] that describe characteristic techno-economic and scaling aspects of the components. Afterward, the derived regressions and cost functions are applied to simulate a sub-regional [243] or countrywide [9, 244-246] hydrogen delivery system. The simulation of pathways enables an analysis with a significantly better geospatial granularity, thus allowing it to include details up to the final point of hydrogen demand. Nonetheless, the reduced scope of pathway alternatives limits the spectrum of the analysis, and therefore a suitable preselection of the pathways is required.

The model family of Hydrogen Analysis (H2A) [247] encompasses the H2A production model, hydrogen delivery systems analysis model (HDSAM), hydrogen refueling station analysis model (HRSAM) and heavy-duty refueling station analysis model (HDRSAM) [248-252]. Various centralized and decentralized hydrogen production options from a broad spectrum of primary energy sources are considered in the H2A production model that computes necessary component costs and the overall profitability of the system. The HDSAM model includes an analysis of GH2 pipelines and trailers, as well as the LH2 trailer delivery option. Furthermore, it includes a detailed assessment of the conditioning and storage components in the supply chain. The delivery system is modeled using the idealized city model of Yang et al. [154], which derives the refueling station locations in order to establish the optimal spatial coverage of a uniform area. Results based on this model show that due to the substantial initial investment costs of pipelines and liquefaction, only GH2 trailer delivery is cost-effective for supplying small cities. Nevertheless, in the case of larger urban areas, the necessary throughputs are large enough that the pipelines can provide the most cost-optimal solution. In a further study by Paster [253] it was shown that, in case of larger urban areas with short distances to the hydrogen source and up to 20% total passenger car market penetration, GH2 trailers are the least expensive hydrogen delivery option, and are only surpassed by pipelines in larger market penetration scenarios. In contrast, in the case of rural areas with long distances to hydrogen production sites, LH2 trailers are the lowest cost delivery option [253].

The level of detail of H2A models enables the scaling of the components to assess key characteristics, such as dimensioning and costs. However, the missing geospatial representation limits the scope of the model to small supply chain scenarios in which the analyst manually defines the delivery distances. Furthermore, theoretical city modeling is not sufficient to investigate infrastructure introduction pathways, as relevant information on refueling station placement and associated infrastructure development is missing.

Another approach to hydrogen market implementation is offered by the Hydrogen Transition (Hytrans) model, which is a dynamic market simulation focusing on the market competitiveness of hydrogen [254]. The model primarily investigates stakeholder behavior and vehicle purchase decision-making in a competitive market environment, thus neglecting infrastructure components and the spatial aspects of the problem. The model encompasses perspectives on fuel producers and sellers, original equipment manufacturers (OEMs), private and public vehicle owners. The functionalities of the model include vehicle evolution, the computation of hydrogen delivery costs and parameter elasticities for vehicle purchase decisions. A case study conducted by Leiby et al. [254] has shown that for successful market penetration, FCEVs require subventions of $1,500 per vehicle until 2030. Moreover, the suggested hydrogen production rollout begins with onsite SMR at hydrogen refueling stations during the initial phase of the market and subsequently moves towards centralized SMR and coal gasification facilities [254].

The hydrogen deployment system modeling environment (HyDS ME) [255] computes various production and delivery technologies to derive the least cost solution for regional hydrogen supply. This model includes a regional perspective with the spatial granularity of an urbanized area and uses geospatial data to consider spatial aspects and interrelationships between neighboring regions. HyDS ME utilizes H2A models to derive the cost parameters of hydrogen production and delivery components. Then, stepwise hydrogen production curves encompassing centralized and decentralized facilities are derived for each region. Similarly, regressions predicated on city area and demand are created to simplify hydrogen delivery cost computations. Subsequently, the minimum spanning tree algorithm is applied to compute the least cost of the delivery infrastructure among the regions. Demand for a region is computed with the use of census data on household vehicle ownership. In a case study for the USA that assumed a 15% FCEV penetration of the passenger car market, the dominance of distributed SMR production could be observed. After doubling the natural gas cost, 18% of urban areas, which represent 69% of the total demand, select centralized coal gasification facilities. The remaining smaller and remote urban areas still select distributed SMR, as these regions are too small to justify centralized hydrogen production and delivery and are also too far away from the main demand centers to utilize other centralized facilities [255].

Despite the critical component of hydrogen competitiveness in the market, the Hytrans model omits the geospatial dimension of the problem, as well as infrastructure considerations beyond hydrogen refueling stations, and therefore is not appropriate for a strategic analysis of hydrogen infrastructure implementation that focuses on regional diversity and its impact development. The capabilities of the HyDS ME model appear to be appropriate to determining the optimal production mix in separate regions and the split between centralized and decentralized hydrogen production. However, this model only uses a very simplified infrastructure representation and does not differentiate amongst hydrogen markets, thus limiting its applicability for infrastructure planning and the assessment of synergies across the markets.

Another model family developed at the IEK-3 in Jülich Research Center focuses primarily on the technical representation of the hydrogen system. Krieg started with a technical concept of a countrywide pipeline system to supply the transport sector [9]. It focuses on material requirements and hydrogen-induced material fracturing to develop cost functions for hydrogen pipelines. Subsequently, pipeline routing based on the Dijkstra algorithm [256] was developed to compute the potential pipeline routes. The economic and environmental aspects of such a hydrogen system were assessed using a German case study and, with the help of a Monte Carlo analysis, the robustness of the derived results confirmed. Amongst the primary outcomes of the work was the conclusion that hydrogen is comparable to methane from the perspective of technical security. Moreover, materials and methods were identified that could efficiently minimize negative hydrogen permeability and embrittlement effects. The resulting pipeline network was found to reach 12,000 km with a mean cost of 79 ct/kg$_{H2}$. In a system with hydrogen production via wind to electrolysis systems and coal gasification, the final cost at the pump was calculated to be 5.36 €/kg for electrolytic hydrogen and, in case of coal gasification, lay in the range of 3.07 to 5.3 €/kg, depending on CCS costs. Robinius built on this work by analyzing potential market designs characterized by a high share of fluctuating renewables and hydrogen use in the transport sector [10]. Robinius investigated renewable energy potentials and developed a model that took into account the electricity, gas and hydrogen markets and used these to design and localize hydrogen production capacities. Hydrogen demand was distributed on the basis of population density, registered vehicles, household income, the vehicle ownership rate and the overall population. Refueling station placement and pipeline routing approaches were applied in accordance with Krieg. One of the key insights from this work is the economic viability of such a renewable hydrogen system, with 16 ct/kWh at the pump. Finally, a Monte Carlo analysis showed that in 81% of the cases, the hydrogen cost remains below 22.9 ct/kWh. Reuß assessed the techno-economic as well as environmental aspects of hydrogen infrastructure options, such as pipeline, trailers and LH2, as well as LOHC to supply the transport sector [11]. An abstract techno-economic model was developed to derive general conclusions regarding distance and demand impact on the hydrogen supply chains. Subsequently, the model was applied to the cases of Germany, France and Japan to investigate the region-specific aspects of a hydrogen infrastructure. The most promising pathways in all three countries were identified to be pipeline transmission and distribution, pipeline transmission with subsequent trailer distribution and LH2 trailer delivery, as these lie within 10% of the least expensive option. Moreover, geological storage options were identified as being the lynchpin of a low-cost hydrogen system in hydrogen-producing countries.

The models developed at the IEK-3 stand out through an appropriate combination of detailed technical modeling, high spatial resolution and the broad geographical scope of the model, allowing countrywide infrastructure scenarios to be analyzed. Nevertheless, current models do not consider more than one hydrogen demand segment and associated infrastructure network effects. Furthermore, to date, these models have not included the use of existing infrastructure such as pipelines and hydrogen production plants, nor an analysis of the transition pathways, focusing instead on the final state of the system.

In conclusion, it can be stated that despite their strengths of encompassing a broad set of alternatives and considering the global optimum, optimization models have substantial limitations in terms of the geospatial resolution and technical representation of the components. In contrast, pathway simulation enables the alleviation of both of these limitations, thus providing sufficient spatial and technical detail necessary to differentiate the market-specific infrastructure requirements and associated synergy effects, as well as to assess the utilization of existing infrastructure. The caveat of pathway simulation is the selection of supply chain pathways to be investigated and the risk of obtaining a sub-optimal solution, as no global optimization is performed. As was discussed previously, the first challenge can be mitigated by an informed selection of pathways, for example on the basis of techno-economic data and previous results from optimization models. The second challenge can be addressed with more realistic technical representation and the incorporation of scaling effects which, during the market introduction, are characterized by low unit size and utilization and will provide a significantly more realistic result than optimization models with typically linearized and aggregated component representation. Therefore, in light of the modeling scope and requirements, pathway simulation can be identified as an adequate approach to facilitate the investigation of the stated research questions.

2.2.2 Demand Modeling

Pathway simulation and optimization are generally applied statically, thus focusing on the optimal future system without a detailed assessment of various structural arrangements during system transition. Commendable cases of supply chain optimization are found in studies that apply exogenous hydrogen market penetration scenarios to investigate hydrogen supply chain evolution [218, 227, 257]. In the case of simulation of pathways, reduced problem complexity allows for a more detailed assessment of various hydrogen supply chain arrangements at different maturity levels of the hydrogen market, as well as transition pathways between different market evolution phases [244, 245]. An additional aspect of infrastructure rollout is the geospatial distribution of demand and its temporal evolution, as this can considerably affect the optimal development pathway of the hydrogen supply chain. Moreover, different hydrogen applications, such as transport, household applications and industrial feedstocks, have unique quality requirements with regard to purity and pressure that have an impact on infrastructure configuration and cost. The majority of the assessed analyses, however, focus on a single market, like passenger cars, thus omitting possible network synergy effects with other markets, such as stationary applications, commercial vehicles and heavy industry [94, 115, 215-217, 219, 221, 257].

The more detailed development of demand is generally modeled in three distinct ways: using a bottom-up approach via agent-based modeling (ABM) or by applying a top-down approach that utilizes either the system dynamics (SD) technique or, alternatively, planning tools that apply detailed spatial distribution to an exogenous demand scenario (see Table 11). The choice of the approach depends mainly on the stated research question, as all three methodologies have strengths and weaknesses. In comparison to the ABM and SD approaches, the planning tool models anticipate early markets and their development by incorporating a broader set of geospatial statistical data, thus focusing more firmly on the spatial component of the demand.

Table 11. Features of ABM, SD, and planning tools.

	Agent based models	**System dynamics**	**Planning tools**
Demand perspective	Bottom-up	Top-down	Exogenous
Demand scope	Single market	Single market	Broad set of markets
Model interactions	Interaction amongst agents	Interaction amongst system components	Interaction of demand and supply
Spatial scope	City to a region	Region to a country	City to a country
Spatial resolution	Single agents or agent groups	Limited to a few regions	High granularity of disaggregation
Technological scope	Limited to refueling stations	Limited to refueling stations	Broad set of technologies
Technological detail	Limited to costs	Limited to costs	High level of detail

Representative models for the ABM approach include those by Stephan and Sulivan [258], Schwoon [259] and the H2CAS Model [260]. Stephan and Sulivan's model considers a stylized environment of an inner-city with fixed, randomly-generated travel routes by the agents. Amongst the main recommendations of the analysis is the clustering of hydrogen refueling stations along main roads. Furthermore, the authors conclude that market segments with regular travel routes such as commuters are favorable toward initial hydrogen infrastructure development [258]. The H2CAS model also considers inner-city infrastructure but is developed in a more realistic urban environment. Here as well, randomly generated travel routes are applied to determine the associated hydrogen demand. The H2CAS model stands out in light of its high level of detail of individual agent characteristics. Moreover, the agents are enabled to learn from their environment, as well as to act in anticipation of future hydrogen market development, which is modeled with the standard Bass approach [107]. One of the main results from the project is that market penetration during the first 10 years can be alleviated if the stakeholders do not engage in strictly profit-maximizing behavior [260]. In contrast to the described models, the model by Schwoon focuses on the inter-urban perspective of hydrogen demand. It applies the gravitation model to determine the relevant inter-urban transport and hydrogen demand of the agents. One of the key insights from this work is the central role of "don't worry distance" (DWD), which describes the perceived travel distance between hydrogen refueling stations. It was shown that at a DWD as small as 50 km, the sales of hydrogen significantly deteriorate, thus leading to the conclusion that broad countrywide coverage is necessary for successful hydrogen market development [259].

In terms of the required modeling aspects, the described ABM approaches lack the associated supply chain infrastructure, as these models focus solely on the consumer and supplier interaction at the refueling station. As a result, the models lack the technical detail required to support strategic infrastructure development to supply hydrogen to the refueling station. The described ABM models primarily emphasize the passenger car market while neglecting all other promising markets for cost-effective initial infrastructure roll-out. Additionally, despite their intensive focus on the car, the listed models do not combine inner and inter-city transportation demand. With sufficient knowledge regarding the potential of infrastructure-related synergies between markets and neighboring regions, the ABM method could be extended with local interactions amongst agents from different markets, but at the current state, the described ABM models lack the necessary functionality to fulfill the stated model requirements.

The SD approach is used by Meyer and Winebrake [261] in the HyDive [262] and UniSyD models [263-265]. While the former focuses on the design of feedback loops, the latter models also introduce spatial considerations. To analyze the chicken-egg problem of hydrogen market development, HyDive models decision-making in 2D pixels of the potential vehicle buyers and refueling station operators. Core feedback loops in the model consider the interrelationship between refueling infrastructure and demand for fuel cell vehicles, station profitability and station crowding, which increase waiting times at refueling stations and refueling coverage. The main result of the analysis for the case of California was the high impact of refueling security, representing refueling availability for successful infrastructure roll-out. Furthermore, it was shown that hydrogen demand tends to be clustered in urban areas [262]. UniSyD is a multiregional partial equilibrium SD model that computes market equilibria for electricity, natural gas, hydrogen and vehicle sales. The model is structured on fuel demand, infrastructure, energy supply and energy pricing modules that are connected through variables such as fuel cost, fuel availability, fuel demand and sufficient fuel production. The key insights of this model are, amongst others, the positive impact of infrastructure development, high carbon tax and rapid development of hydrogen production technologies on FCEV purchasing decisions [263-265].

Similar to the drawbacks of the described ABM models, HyDive primarily investigates the interaction between drivers and hydrogen refueling station operators, omitting the associated infrastructure required to supply hydrogen. Furthermore, such a strong focus on this interaction is associated with a neglect of alternative markets for infrastructure development, such as commercial vehicles, industry and public transport, as these markets have divergent infrastructure requirements. Due to its focus on the general aspects and hydrogen’s role in the energy system, UniSyD incorporates the full costs of the hydrogen supply chain. The strengths of this model include its capacity to represent the independent hydrogen markets and to implement consumer preference characteristics for endogenous vehicle purchases. However, the detailed vehicle choice model is limited to the passenger car market. Furthermore, the aggregated nature of the model obscures the infrastructure-related characteristics of alternative markets, such as the geospatial location of refueling stations, hydrogen delivery routes, the scaling effects of the components and the network effects that occur. Like the ABM, with sufficient data on infrastructure synergies between different market segments, SD models could be extended with interactions amongst markets, thus enabling them to more closely evaluate market development dynamics. However, in the current state, the described SD models do not fulfill the stated model requirements.

A similar but somewhat different perspective on demand development can be found in models, CHIT [266], HIT [267] and SERA [268], which focus more on geospatial demand distribution and infrastructure capacity planning. CHIT is a tool used by the California Air Resources Board to identify strategic areas for the development of a hydrogen refueling station network in California. This tool seeks to identify potential hydrogen demand, evaluate current infrastructure and its coverage, as well as prioritize emerging markets for subsequent infrastructure buildup. It uses financial, educational indicators as well as green and general vehicle trends to localize the early adopter market. The assessed market and commuter traffic data are compared to the existing regional coverage of hydrogen refueling stations to determine the coverage gap and required additional refueling station capacity. The underlying assumption is that coverage is defined as 15 minutes of driving distance to households, thus implying hydrogen refueling near homes. Thus, the CHIT tool balances the inter-city and inner-city perspectives for infrastructure demand assessment [266]. In comparison, the HIT model encompasses an improved infrastructure analysis but reduces the geospatial scope of the assessment. It incorporates linear infrastructure costs, transport demand at road intersections and socio-economic data to determine the required refueling station capacities. Moreover, it uses fixed delivery distances from centralized production units to an analyzed city and minimum spanning tree algorithm to design inner-city infrastructure locations. In the example of a case study of Beijing, it was found that infrastructure introduction should commence with forecourt SMR hydrogen refueling stations that would subsequently be replaced with GH2 trailers and pipelines [267]. In contrast to HIT, the SERA model focuses primarily on a national hydrogen strategy development for the US and applies local early adoption scenarios to generate nationwide technology adoption. It utilizes comparable approaches to CHIT and HIT to localize and size hydrogen refueling stations. Similar to HIT, SERA also computes the required delivery and production infrastructure. However, due to the high spatial scope of the model, infrastructure is determined via direct lines between production and demand centers. The analysis of countrywide hydrogen introduction in the US highlighted that the central SMR with subsequent pipeline or trailer delivery would dominate the system. Furthermore, it was also shown that from the initial market introduction, the system would require seven years to reach the cash flow break-even point [268].

While the described planning tools offer valuable functionalities for infrastructure planners, they do not combine the defined components necessary for the analysis. As the CHIT tool limits itself to the detailed capacity planning of hydrogen refueling stations, it omits all other supply chain infrastructure that is essential to strategic planning. The HIT model alleviates this issue by incorporating various supply chain pathways into the analysis, but its technical scope would be increased by reducing the spatial scope to a single urban area. Thus, the HIT model can provide valuable information on only a comparably small regional scale. In comparison to the former models, the SERA model combines the strengths of both models to conduct a countrywide demand analysis with subsequent infrastructure assessment. However, due to the broad spatial scope of the USA, the modeling of the infrastructure is significantly simplified by the omission of technical and spatial details. Similar to the ABM and SD models, all three planning tools focus only on the passenger car market, thus neglecting alternative markets. However, the high emphasis on the technical detail and infrastructure development, as well as lower structural complexity of the models, indicates that this approach can be more easily expanded with additional markets, thus enabling the investigation of available synergies and network effects across the different hydrogen markets.

In summary, it can be stated that the approach of planning tools provides superior functionalities over ABM and SD in representing hydrogen markets according to the modeling requirements of a high spatial resolution, broad market spectrum and high technical detail. The main drawbacks of ABM and SD are the focus on local and global interactions on the demand side rather than the market-specific spatial representation of the infrastructure requirements. Therefore, the planning tools approach is identified as an appropriate representation of demand for the envisaged strategic infrastructure development analysis.

2.3 Deriving the Modeling Approach

As previously stated, this work aims to investigate the question of suitable infrastructure and demand-side strategies for facilitating a cost-optimized hydrogen infrastructure for the transportation and industrial sectors in Germany. This question was then divided into four distinct sub-questions covering various aspects of the main research aim, which in turn define the specific requirements for the chosen modeling approach.

The **first sub-question**, concerning promising markets with anticipated precipitation of hydrogen adoption and relevant infrastructure options, is primarily addressed in the strategic environment analysis (see Sub-chapter 2.1). For hydrogen demand, the following markets must be incorporated into the model: local buses, non-electrified trains, passenger cars, freight trucks, forklifts, steel and the chemical industry, including refineries, ammonia, and methanol. It was found that for the supply chain, the following technologies are especially relevant in the short to medium term: electrolysis and SMR for domestic hydrogen production, as well as the import of green and blue hydrogen. For the storage of hydrogen, selected alternatives are salt caverns, GH_2 and LH_2 tanks. Amongst the selected hydrogen processing and conditioning technologies are compressors, liquefaction and evaporation units, as well as TSA and PSA purification components. The chosen hydrogen delivery options encompass GH_2 and LH_2 trailers, as well as new and reassigned hydrogen pipelines. Congruent to the selected markets and hydrogen delivery options, 350 and 700 bar refueling station designs for trailer and pipeline delivery are also considered in this work.

Consequently, the model must incorporate a sufficient level of technical detail to differentiate between different qualities of hydrogen (pressure, purity, physical state) and encompass a broad spectrum of demands (**requirement I**). The **second sub-question** regarding the positive effects attained by the utilization of the existing infrastructure requires in-depth data gathering and high-level representative infrastructure characteristics to be considered in the model (**requirement II**). Hence, aspects of the existing infrastructure such as location and availability of post-EEG wind power plants, as well as technical potential for pipeline reassignment for hydrogen delivery are incorporated in the approach

Addressing the **third research question**, concerning the features facilitating the low-cost introduction of infrastructure while aligning development towards an optimized system in the long-term, requires cost-optimization of the model. Moreover, in order to address the infrastructure and market development, spatial and temporal features of technology and market growth must be considered (**requirement III**). Additionally, characteristic features of the individual supply chain components enable simulation of the technology behavior and optimization of only the most uncertain parameters such as delivery pathways and the capacity placement of the refueling stations.

In order to address the **fourth research sub-question** on the market-specific infrastructure requirements and attainable synergy effects, a detailed consideration of the individual hydrogen markets characteristics is required. Spatial demand distribution, as well as market-specific characteristics such as the location of the station, output pressure, refueling time and refueling quantity (**requirement IV**), must be taken into account. Consequently, for a broad set of different hydrogen markets with varying speeds of market adoption as well as the detailed modeling of supply chain components, the incorporation of scaling and learning effects is necessary. The nature of these requirements places a large focus on the spatial and technical detail for both the infrastructure and demand representation, indicates a need for multiple smaller models operating within different spatial and technical dimensions rather than a large homogenous model.

To comply with the stated model requirements and address the described research gap, a **Hydrogen Market & Infrastructure Development** (**H2MIND**) model was developed that incorporates the missing aspects required to assess hydrogen introduction strategies. As previously observed, the stated overarching research question regarding the infrastructure and demand-side strategy can be subdivided into a demand and infrastructure assessment that is characteristic of complementary goods [261].

On the demand side, in order to access relevant markets and synergy effects amongst different market segments, the model encompasses a broad range of hydrogen and fuel cell markets that have high hydrogen demand or feature a large number of commercialization projects (**requirement I**). Furthermore, to model the transitive nature of the markets, similarly to the H2CAS scenario approach [260], the model was extended with a specific methodology by Cerniauskas et al. [68] to derive market penetration curves for specific markets by using the Bass model. The regional distribution of the single market was modeled by using multi-criteria disaggregation methods [68] applied in the simulation models of Robinius and Reuß [10, 11], as well as planning tools such as CHIT [266]. Furthermore, within regions, the placement of refueling stations was achieved using the MILP program, which was also used by Cerniauskas et al. [68] and which operates with a similar logic to that applied in CHIT [266] and SERA [268]. Accordingly, the spatial and temporal assessment of hydrogen demand development facilitates the meeting of stated **requirements III and IV**.

On the supply side, the utilization of the existing infrastructure was assessed with a detailed infrastructure modeling tool that was developed by extending the work of Reuß and the associated model family [9 - 11, 179]. Accordingly, this approach enabled consideration of the necessary components for **requirement I**. H2MIND includes already existing hydrogen infrastructure (**requirement II**), such as for production, demand and related infrastructural components, as well as electrolysis and fuel cell commercialization projects that are in operation or planned to commence operation by 2025. Additionally, short- to medium-term hydrogen production from post-EEG non-repowerable onshore wind plants [50], with the associated placement of electrolysis plants, is considered in the modeling approach. Furthermore, the assessment of natural gas pipeline reassignment for hydrogen delivery by Cerniauskas et al. [173], as well as the continuous transition from GH2 trailer to pipeline delivery, are incorporated into the model. Moreover, in order to differentiate between the hydrogen markets (**requirement IV**), the models of HRSAM and HDRSAM for the representation of refueling stations [248-252] were extended and incorporated into the model. Finally, in order to prioritize the analyzed strategies, the model derives not only consumer-specific hydrogen costs but also assesses hydrogen cost-competitiveness with fossil fuel benchmarks. Further aspects such as infrastructure costs, CO_2 emissions and domestic energy demand were derived by extending the HyInfraGis model [11].

This approach can be structured into five steps, as displayed in Figure 12. **First**, hydrogen demand potential is evaluated based on the existing commercialization activities and presented literature. **Second**, exploratory market penetration scenarios are computed based on available hydrogen scenario data. **Third**, a market-specific regionalization of demand and hydrogen refueling stations is conducted. **Fourth**, the hydrogen supply chain is designed and analyzed. In this step, the integration of the hydrogen infrastructure, such as PtG plant operation with retiring post-EEG wind turbines, natural gas pipeline reassignment, and the extensive utilization of hydrogen refueling stations, is evaluated. Also within this step, the network effects of trailer and pipeline delivery, as well as market-specific infrastructure costs, are investigated. In the **fifth** step, based on the selected infrastructure roll-out pathway, the hydrogen supply chain's development is examined.

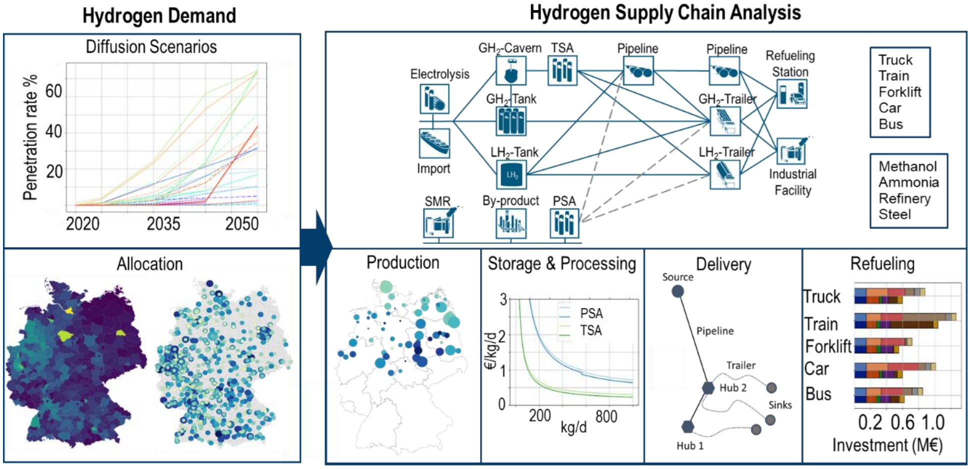

Figure 12. Overview of the developed modeling approach in H2MIND.

3 Methodology and Features of Strategy

The following chapter presents the designed modeling approach for investigating the transition of the hydrogen supply chain (see Figure 12). **First**, to investigate the transformation of the market, an approach to modeling anticipated hydrogen penetration in a given market and associated spatial distribution of the demand is presented. **Second**, aspects and considerations regarding short- and long-term hydrogen sources are conveyed. **Third**, relevant techno-economic aspects of storage and hydrogen processing are discussed. Accordingly, the reconfiguration of production and storage is taken into consideration. **Fourth**, to account for the evolution of hydrogen delivery, the designed methods to assess natural gas reassignment for hydrogen transport, as well as a continuous shift from the GH2 trailer to pipeline transport, are presented. Lastly, in the **fifth** step, an approach to the design refueling stations for different hydrogen markets will be conveyed. They hence shed light on the anticipated changeover of hydrogen refueling infrastructure.

3.1 Hydrogen Demand

The strategic planning process for the hydrogen infrastructure necessitates an estimation of the overall size and regional occurrence of hydrogen demand in order to anticipate the transformation of the hydrogen market. To address this issue, the following chapter describes the developed methodology to derive market diffusion scenarios of FCEV and green hydrogen applications, as well as the associated regional distribution of demand.

3.1.1 Anticipated Market Development

Given the described limitations of the standard Bass model to incorporate initial market penetration, an omission of future technology generations, as well as challenges in modeling technologies at a very early stage, this chapter presents the developed methodology by addressing these issues and deriving exploratory scenarios.

As was formerly described, a critical aspect of the Bass model is the elimination of the integration constant in its initial formulation, leading to a starting penetration of zero [107, 108]. This creates a challenge in incorporating the historical data, which is especially important in the case of the early adoption phase. Moreover, due to the pilot and pre-commercial deployments of the technology, the zero-initial level condition leads to problems with defining the starting point of the market introduction of the technology. These challenges can be addressed by incorporating an integration constant into the Bass model [110]:

$$N(t) = m\frac{c(p+q)+pe^{-(p+q)t}}{c(p+q)-pe^{-(p+q)t}} \text{ with } c = \frac{N_0 q - p}{p+q}\cdot\frac{1}{N_0 - 1} \quad (1)$$

where N represents penetration function into the market, N_0 the initial penetration, t the time step, m the size of the market and p and q define values for innovators and imitators. Another challenge with the Bass differential equation is the neglected lifetime of the product, as only first time adopters are considered, thus overlooking different product generations and the resulting frequency of purchasing decisions [107]. This issue is especially critical in the case of durable technologies such as vehicles and industrial equipment, as it diminishes the speed of novel technology adoption. To alleviate this problem, the Markov chain approach can be employed by incorporating factors from different product generations into the Bass diffusion model.

After initial adoption of the product, all consumers are subject to a repurchase probability (consumer loyalty) and a return to the product's probability for those adopters who did not own the product in the last time step. In this manner, the product introduction and retraction after the end of its lifetime are considered (see Table 12). This model is then used to generate exploratory scenarios in the context of the scenario data gathered for each market. Nevertheless, before investigating the resulting scenarios, the underlying properties of the constructed market adoption model will be presented.

Table 12. Assumed application technical lifetime in each market [68].

Application	Car	Bus	Train	Truck	Forklift	Industry [1] (Equipment)
Lifetime (Years)	12	10	30	10	5	20

[1]Ammonia, methanol, refineries, and the steel industry

The underlying structure of the model can be highlighted by applying a theoretical example of a simplified market penetration limited to two product generations with a lifetime of 20 years during the period from 2020 to 2050. First, in Figure 13, with the example of the base scenario, it can be determined that the ratio of products that are abandoned or replaced after the end of their lifetime is governed by the predefined consumer loyalty. Therefore, the overall market adoption reaches a plateau somewhat below the first adoption line. Secondly, one can observe the flexibility in setting up the starting point, which is set in this example to 5% in 2020. The parameter variations displayed on the right indicate the model's sensitivity to technology lifetime and probability that the technology is not abandoned after the end of its lifetime. In the first case, it can be observed that, due to the shorter technology lifetime, the products need replacement twice as often, thus leading to a larger impact of consumer loyalty and slower market adoption that plateaus even further below the original first adopter level. Given the fact that a shorter technology lifetime enables an additional adoption cycle over the set time-frame, this effect would be even more pronounced if a third repurchase level was added. Lastly, consumer loyalty, governing the repurchasing of technology at the end of its lifetime, is varied. It can be observed that despite the growing number of first adopters, after 2040, overall technology adoption begins to abate, thus enabling the modeling of scenarios with an initial peaking and subsequent diminishing adoption of technology.

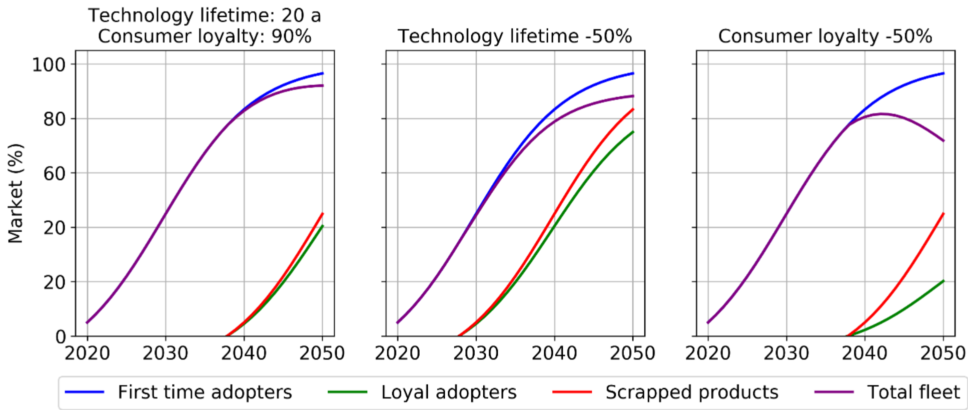

Figure 13. Variation in model parameters and the resulting impact on the market penetration.

It must be added that such high model flexibility not only adds parameters to improve the fit to the data but also to model the underlying nonlinearities of the internal market structure with respect to new vehicle efficiency. Such information would be lost if a simple logistic regression to the market adoption data was applied. Figure 14 displays the comparison between the assumed new vehicle fuel demand and the resulting mean fleet fuel demand based on the final market penetration and acts as a proxy for the adoption speed. As can be expected, in a market dominated by a large amount of older vehicles with higher fuel demand, the average fleet demand is approximately 5% to 25% lower than the assumed new vehicle fuel demand for that year. A specific case is modeled for 10% market penetration where, due to its slow growth rate, the market penetration curve is close to linear behavior. Such market adoption leads to an equal distribution of new vehicles and an associated reduction of fuel demand, resulting in a considerable overestimation of the mean fleet fuel demand. In the case of the development of the new vehicle, fuel demand is modeled in a non-linear manner, and these effects are expected to become even more pronounced. In summary, it was shown that simple linear computations, without any consideration of the market structure, lead to a substantial under- or overestimation of the resulting hydrogen demand of the fleet. However, the proposed modified Bass model encapsulates the market structure to assign weights to each efficiency and thus derives a much more consistent method for computing hydrogen demand.

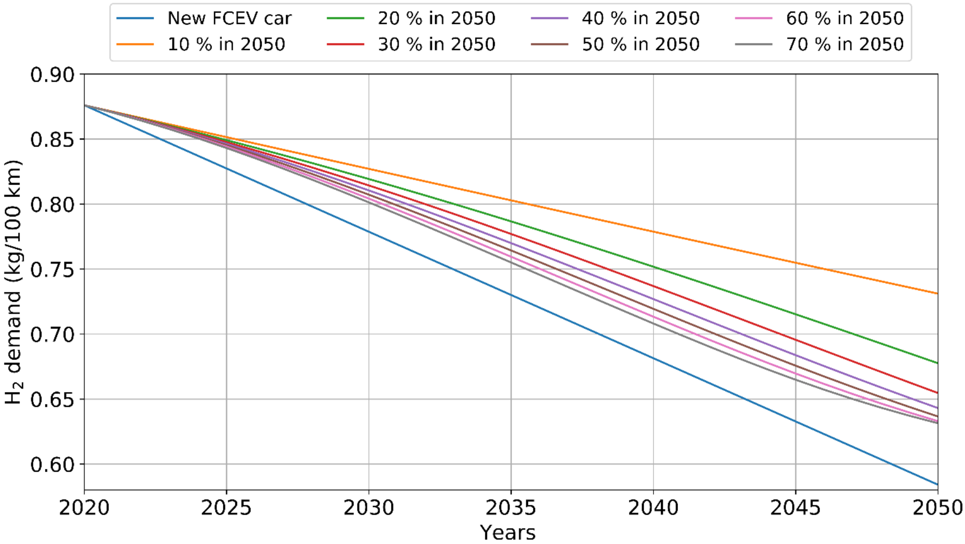

Figure 14. Non-linear impact of market diffusion on average fleet fuel consumption.

After consideration of the main features of the model, the extended Bass model is applied to derive exploratory market adoption scenarios for each analyzed market. Given the data scarcity and uncertainty regarding final market adoption, three different market adoption S-curves are derived to cover low, medium and high market diffusion in the year 2050. The resulting scenarios are displayed in Figure 15. It can be highlighted that only in the case of the high scenario is market saturation reached before 2050. Accordingly, low and medium scenarios would lead to substantial market diffusion beyond the analysis period. Thus, if no substantial fleet shares are reached by the years 2030 to 2035, the adoption is significantly delayed and one increasingly drifts towards a low overall market penetration in the year 2050 with higher penetrations that are beyond the scope of this analysis.

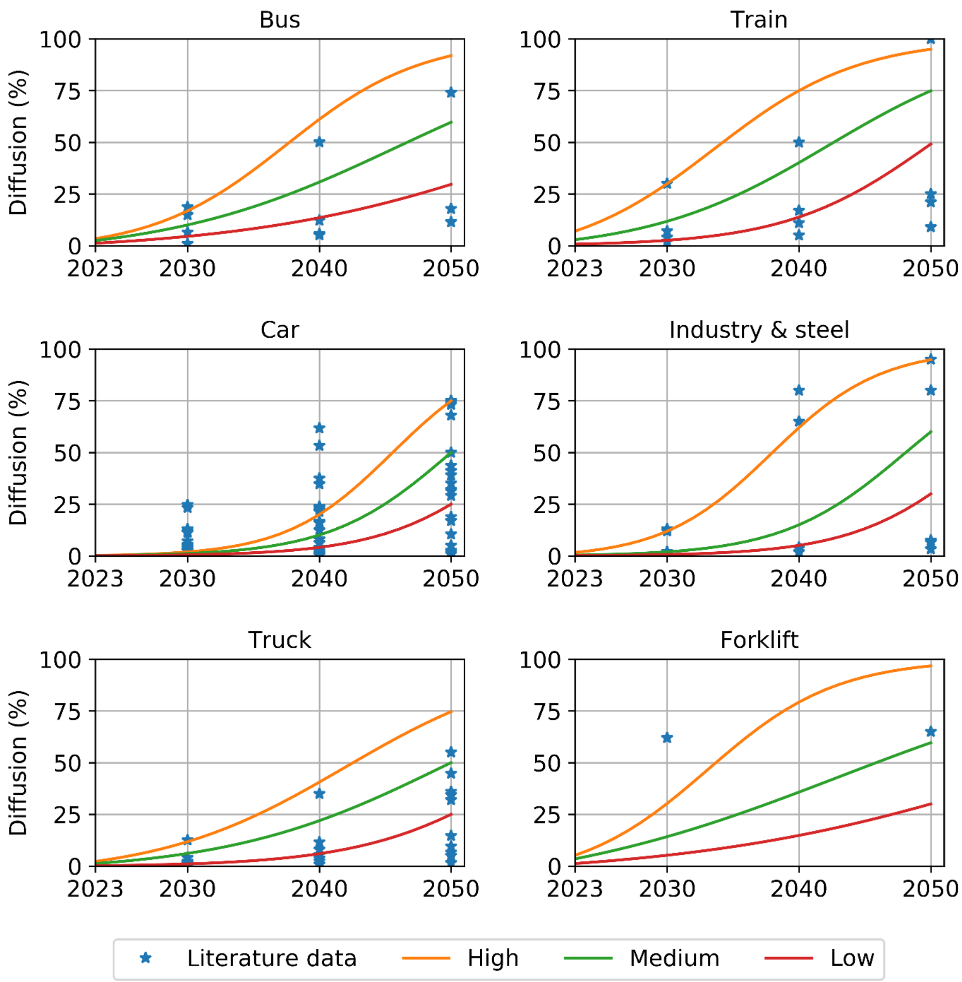

Figure 15. Overview of the derived market penetration scenarios for individual hydrogen markets from 2023 to 2050.

With the determined N and t values for individual market scenarios (see Eq. 1), the p and q values of the underlying extended Bass model can be fitted, and which govern the shape of the adoption curve (see Figure 16). These points show that the curves with a high p coefficient, in comparison to q, are more linear, especially at the beginning, as these markets are mainly driven by the first movers, which are less dependent on the overall market size. Examples for such behavior are the markets for forklifts, local buses, trains and freight vehicles. Alternatively, the data points clustered in the top left corner, such as for passenger cars and the industry, indicate substantially more inert markets that rely much more on market followers, i.e., imitators. Therefore, the development of these markets is initially prolonged until a sufficient level of market adoption is reached and a subsequent phase similar to exponential growth is commenced. Consequently, according to the derived scenarios, markets associated with a high number of first movers are expected to be the first to diffuse in the respective markets. These markets are then followed by the other markets, which are more inert and encompass a higher number of imitators.

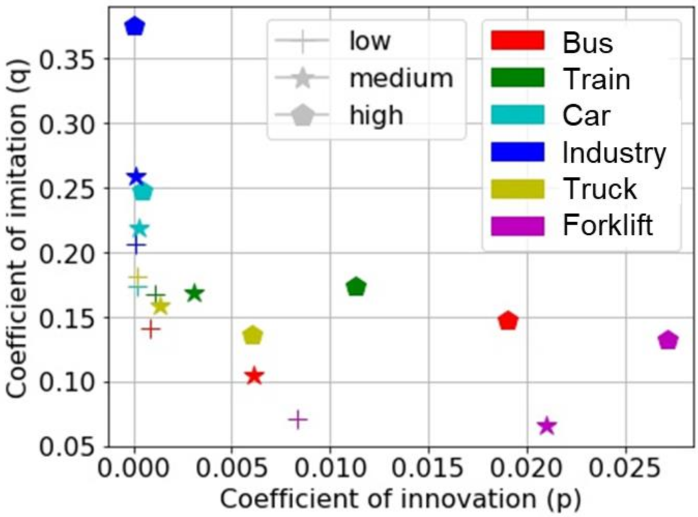

Figure 16. Derived innovation (p) and imitation (q) coefficients for each market scenario.

Lastly, the derived p and q coefficients can be compared with the other estimates in the literature. Due to the lack of literature regarding the smaller markets, only data for the passenger car market can be assessed in Figure 17. For this comparison, the estimates for drivetrains, as well as specific vehicle models, initiating particular technology adoption, are included in the comparison. One can observe a high variation in the parameters, indicating a high uncertainty regarding the overall market potential, as well as the form of adoption in the early stages of the technology diffusion. Furthermore, a high clustering of data points at a low coefficient of innovation can be observed, thus indicating the generally inert nature of the passenger car market. In comparison, the derived p and q values for FCEV adoption in the passenger car market are fairly conservative in comparison to the literature, thus indicating that the derived scenarios are in line not only with the underlying scenario data but are also an unalike technology adoption, as is often observed in the passenger car market. Based on this finding, it can be inferred that the same conclusion also holds for smaller market scenarios, thus enabling the use of these in this work for further analysis.

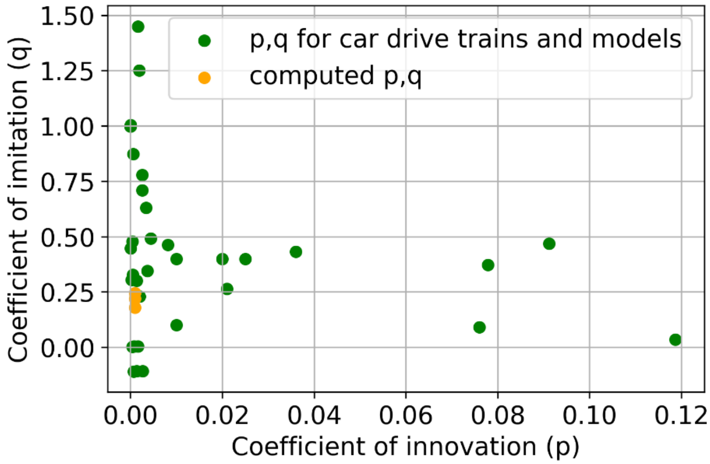

Figure 17. Comparison of computed p and q coefficients for FCEV passenger cars with literature data for the diffusion of drivetrains and specific vehicle models [269].

3.1.2 Anticipated Demand Distribution

After designing the methodology to investigate future market penetration scenarios, the representation of geospatial attributes of the demand will be described. The geospatial distribution of future hydrogen demand will be one of the critical variables determining infrastructure cost. Due to the high data availability and broad applicability, the nomenclature of territorial units for statistics (NUTS) is used to define the individual regions.

To determine the spatial allocation of local buses in NUTS3 areas, the factor of population was chosen to approximate the driven mileage and accompanying issues of nitrogen oxides and noise pollution, which can be alleviated with the deployment of FCEV buses. Moreover, the mean available income correlates with the existing pilot projects and associated federal subsidies for low-emission transport. In the case of trains, the allocation of FCEV trains is determined by weighting the federal states (NUTS1) according to the length of non-electrified train lines, federal support for regional development, and train mileage at the federal state level. Subsequently, the individual NUTS3 areas are weighted according to the number of existing refueling stations for diesel trains. As for cars, the approach of Robinius is applied to allocate FCEV demand according to population, population density, income and overall car fleet in the NUTS3 region. To determine the distribution of truck mileage, the number of registered vehicles and registered freight intensity is used, whereas freight intensity is estimated with the loaded and unloaded mass in the NUTS3 region. For the allocation of forklifts, the freight intensity data is extended with an area of logistical buildings, thus assuming a correlation between the size of the forklift fleet and size of the logistical area. The chosen weights for the relative geospatial hydrogen demand distribution can be observed in Table 13. A more detailed description of data sources can be found in Cerniauskas et al. [68].

Table 13. Criteria for geospatial hydrogen demand distribution on a NUTS3 level.

Bus	Train	Car	Industry [1]	Truck	Forklift
Population	Diesel train lines	Population	Plant capacity	Loaded freight mass	Loaded freight mass
Income	Federal support	Population density		Unloaded freight mass	Unloaded freight mass
	Diesel train mileage	Income		Fleet size	Logistic space
	Refueling stations	Fleet size			

[1] Steel, ammonia, methanol, petrochemical industry

Figure 18 demonstrates the resulting geospatial distribution of demand for each market when all mentioned weighting criteria are taken into account. It can be perceived that passenger cars are significantly more equally distributed across the regions than commercial vehicles and industrial plants. Accordingly, countrywide coverage of passenger car demand necessitates a larger number of hydrogen distribution links and refueling stations than is the case for local buses or non-electrified trains. The former is primarily concentrated in larger metropolitan and suburban areas, which is in line with the anticipated FCEV bus deployment in larger suburban areas [192]. The latter is profoundly affected by existing train refueling stations, as this exhibits the prominence of rail traffic hubs. The concentration of demand indicates that even though FCEV trains are expected to be deployed on less frequented non-electrified lines, the trains would be refueled in rail hubs, which are often located in the vicinity of population centers.

Despite the common influencing factor of freight intensity, the allocation of forklifts is more evenly distributed than in the case of trucks, indicating differences between the allocation of truck registration and logistical space. Lastly, the distribution of hydrogen demand for industry showcases the most important centers of heavy industry in the Ruhr, Rhineland, Ludwigshafen and Central Germany.

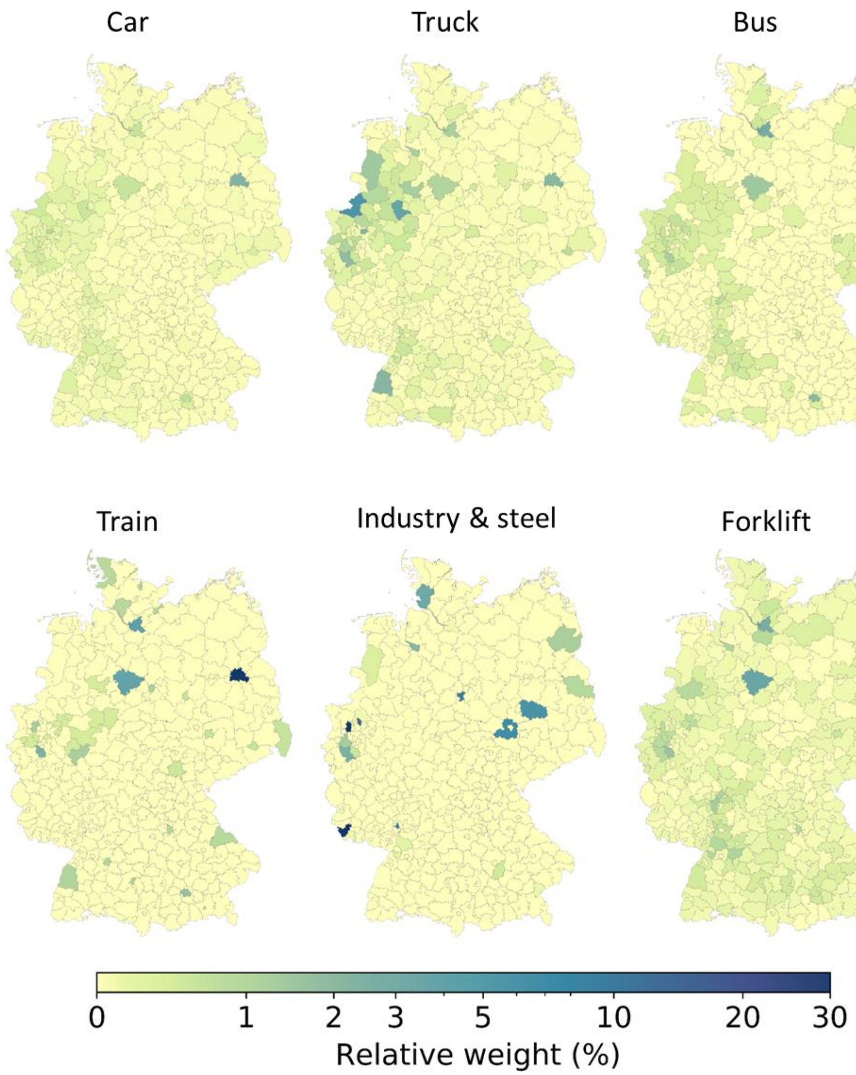

Figure 18. Geospatial allocation of hydrogen demand for each hydrogen market in Germany.

After the countrywide allocation of demand on the NUTS3 level, hydrogen demand is subsequently appointed to single sinks within each individual NUTS3 region. The chosen approach differentiates whether the demand is associated with publicly available and non-public infrastructure, the latter relating to commercial vehicle fleets and industry. In the case of the public refueling infrastructure, for every region a MILP problem is solved to determine the optimal number of refueling stations to supply the necessary demand. A key aspect is that the model is constrained to build only small-sized refueling stations (S: 212 kg/d) if a certain percentage of the existing stations within the NUTS3 area are yet not equipped with hydrogen dispenser. This assumption draws on other literature that investigates the necessary minimal size of the station network for providing sufficient geographical coverage during the introduction phase [77, 261, 270]. Moreover, in accordance with the strategy proposed by a joint venture installing hydrogen refueling stations in Germany [26], the refueling stations are first constructed along the highways, which are then followed by main and rural roads. Similarly, the construction of captive refueling station is also limited to the relevant existing infrastructure, such as commercial sites and depots. Due to the variability of the daily refueling patterns and associated uncertainty, the utilization rate of a public refueling station is set to 70% [11]. In contrast, non-public stations can be designed according to the relevant captive fleet demand, enabling a close to 100% utilization rate. However, in order to include a more realistic non-public infrastructure adoption, a minimum size of the fleet is required before it can actually be adopted and an associated non-public refueling station point is created. In cases where the minimum fleet size is not reached, the vehicles are distributed amongst regions meeting this criterion. This simplified approach allows us to better differentiate the key characteristics of public and non-public infrastructure by enabling a larger concentration of vehicles at a single refueling point. In future work, this approach could be extended by enabling the refueling of smaller fleets of passenger cars, trucks and buses at publicly available refueling stations, thus considering the initial test phase of the vehicles by fleet operators. Table 14 summarizes the used data and applied methods for the capacity allocation. In comparison with the overall data points, the currently installed 86 refueling stations in Germany (see Section 2.1.1) is a negligible number, and therefore, these stations are not explicitly considered in this work.

Table 14. Criteria for the geospatial allocation of station capacity within a NUTS3 region.

Type	Public		Non-Public					
Application	Car	Truck	Bus	Train	Industry	Forklift	Car	Truck
Max. number of sinks	9800	8000	402	170	90	10,000	7150	2340
Capacity distribution in a region	MILP		Equally among the sinks		Max capacity	Logistic area	Commercial area	Commercial area
Constraints	S if <10%	S if <5%	Fleet > 25	Fleet > 5	-	Fleet > 70	Fleet > 50	Fleet > 20

3.2 Hydrogen Production

The following section describes the applied methodology to incorporate technologies and locations for hydrogen production in Germany into the model. Due to the transitive nature of infrastructure introduction, the importance of various hydrogen sources will vary in different phases of infrastructure development. Accordingly, a reconfiguration of hydrogen production must be taken into account. To address this issue, hydrogen sources are differentiated into short- and long-term production.

Short-term hydrogen production is defined as hydrogen generation capacity that is either currently existing or planned to be implemented by 2025, or which is closely linked to the existing energy infrastructure, thus alleviating the challenges associated with the implementation of new infrastructure (see Table 15). Available SMR capacity from currently underutilized units and by-product hydrogen are considered for existing production. Thus, it is assumed that no new reformer capacities will be installed. Furthermore, currently implemented and planned electrolyzer commercialization projects are also considered for short-term hydrogen production, and therefore these projects fall to both categories of existing and planned production by 2025. Lastly, to account for the fact that currently anticipated projects represent a lower bound for anticipated hydrogen production in the future, the further expansion of electrolytic hydrogen production is considered for existing wind power plants, thus enabling the implementation of short-term hydrogen production. Industrial hydrogen production and electrolyzer commercialization project data (see Section 2.1.3) are used herein to represent existing production and commercialization projects.

Table 15. Short-term hydrogen sources considered in this work.

Existing production	Planned production by 2025	Production linked to current energy infrastructure
Underutilized SMR	Electrolyzer commercialization projects	Electrolyzers at post-EEG onshore wind parks (off-grid)
By-product hydrogen	-	-
Existing electrolyzers	-	-

The cost of grey hydrogen is computed within the given techno-economic parameters (Appendix B) and using a unit scaling function, provided below, thus accounting for different sizes of industrial facilities in Germany. Due to data availability limitations regarding the techno-economic parameters of by-product hydrogen, its costs are estimated to be the same as for SMR, which is the dominant technology for hydrogen production in Germany. In the case of electrolytic hydrogen production, a differentiation is made between production sites related to commercialization projects and anticipated off-grid hydrogen production from onshore wind.

To determine viable off-grid hydrogen production options, the following steps are necessary: the determination of suitable electrolyzer locations, computing of the available renewable energy potential at the site and, finally, performing techno-economic modeling of each system. Firstly, the approach to determining viable electrolysis locations is described. The criteria to identify suitable electrolysis locations are based on the discussion of current commercialization projects and literature regarding relevant aspects for electrolysis placement (see Section 2.1.3).

For electrolyzers, which are both useful for the electricity grid system and remain an economically-viable technology, it is necessary to balance the short- and long-term perspectives for the placement criteria (see Figure 19). From the short-term perspective, relevant factors are proximity to high voltage (HV) substations and installed variable renewable energy (VRE) capacity, which enables minimization of the necessary electrical infrastructure and provides an opportunity to harvest peak generation from VRE. Moreover, as VRE is often connected to the HV or placed in the vicinity of these points, the electrolyzer can be assumed to be placed at the HV substation. Such an approach, from the medium- to long-term perspective, would likewise enable the utilization of the surplus or green baseload electricity from the grid. Further placement criteria become increasingly important in the medium- to long-term, as these are crucial for successful downstream hydrogen storage and delivery infrastructure. With increasing hydrogen production, the vicinity to natural gas infrastructure opens possibilities to easily connect to reassigned natural gas pipelines or, in the case of new pipeline construction, to utilize the existing pipeline routes. Similarly, with growing green hydrogen production, low-cost seasonal storage becomes increasingly essential for the viability of the system. As was previously discussed (see Sub-section 2.1.5.2), salt caverns offer an attractive solution for the challenge of seasonal hydrogen storage. As the disposal of brine is challenging in the interior of the country and is preferably performed at sea, an additional criteria of proximity to navigable waterways as a proxy for rivers with sufficient water flow is considered. These rivers can then be used to cost-efficiently remove the brine by a calibrated injection into the river.

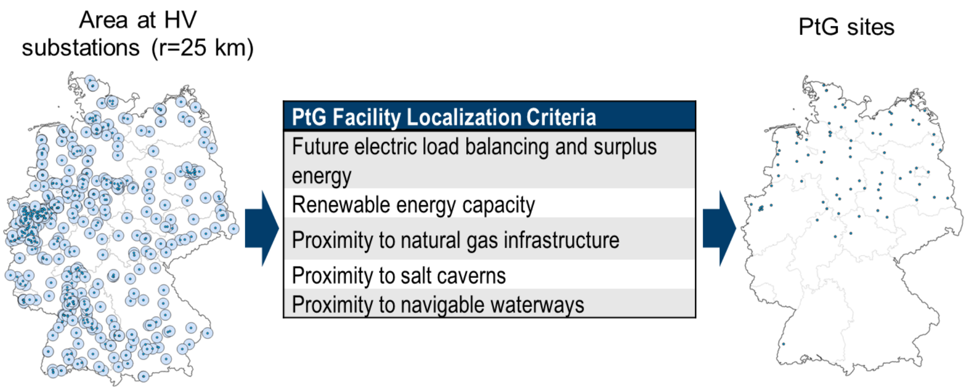

Figure 19. Methodology to select PtG sites for generation from post-EEG plants.

Figure 20 presents the impact of each individual criterion on the overall number of available sites with the required distance to the substation location. It can be observed that current open-field PV sites are clustered around approximately 50% of the substations. Therefore, after a sufficient radius is considered, the number of sites is reduced in order to avoid the double counting of available renewable energy capacity. Furthermore, it can be determined that, due to the uneven distribution of salt deposits for caverns, this criterion is the most restricting one, limiting the number of available sites to a maximum of 110 at a distance to substations of 25 km. To maximize the number of potential sites, the distance of 25 km will be used in the following analysis. In total, due to the exclusivity of the criteria, more than 80 potential electrolyzer sites were identified.

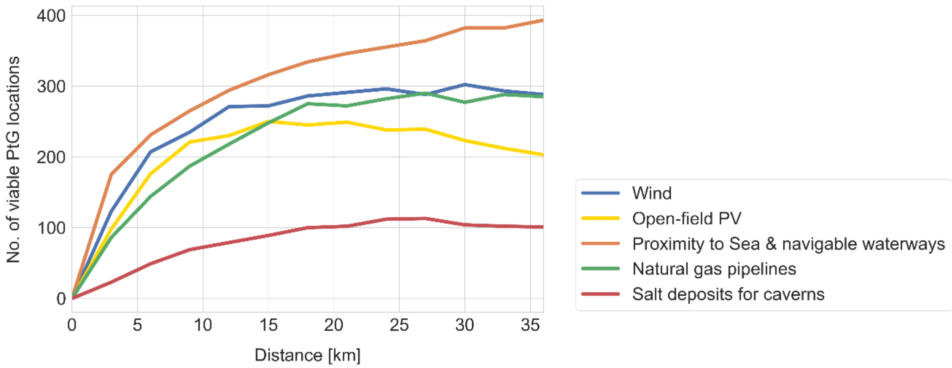

Figure 20. The individual impact of the criterion on the number of potential PtG plant sites.

After identifying the suitable locations for short- to medium-term hydrogen production, the associated renewable energy potential and hydrogen production capacity must be estimated. Due to currently unfavorable regulations and high CO_2 intensity in the German electricity mix, it can be estimated that hydrogen production with direct coupling with renewable sources provides the most feasible short- to medium-term option for green hydrogen production. In parallel, in 2020, the first aging renewable plants are beginning to fall out of the EEG feed-in tariff scheme, and their operators are confronted with the decision to either continue to operate the plants or decommission them. In order to make the further operation of onshore wind economically attractive, the operators can either opt for power purchasing agreements (PPAs), the reconstruction of wind parks by repowering them, or supply an electricity consumer through a direct connection, i.e., an electrolyzer. However, due to the fact that approximately 50% of the relevant wind turbines cannot be repowered, as they lie outside of current land-eligible areas, the economic potential for repowering is highly constrained, leaving half of the turbines for the other two options. This finding is in line with a recent bottom-up investigation published by the German environmental agency, which indicated that approximately 47% of currently installed wind turbines lie outside of applicable land eligibility criteria [50]. Therefore, the following methodological framework was designed to identify aging wind turbines that are not repowerable. This methodological approach will help to locate the sites, derive the available hydrogen production potential and associated hydrogen cost. To identify non-repowerable post-

EEG wind turbines, the GLAES model [271] for the assessment of land eligibility was calibrated with federal state-specific criteria for onshore wind. Subsequently, the data on currently installed wind power plants were screened with respect to their age and location in non-eligible areas (see Figure 21). For the applied criteria and results for the individual federal states until 2035, see Appendix C.

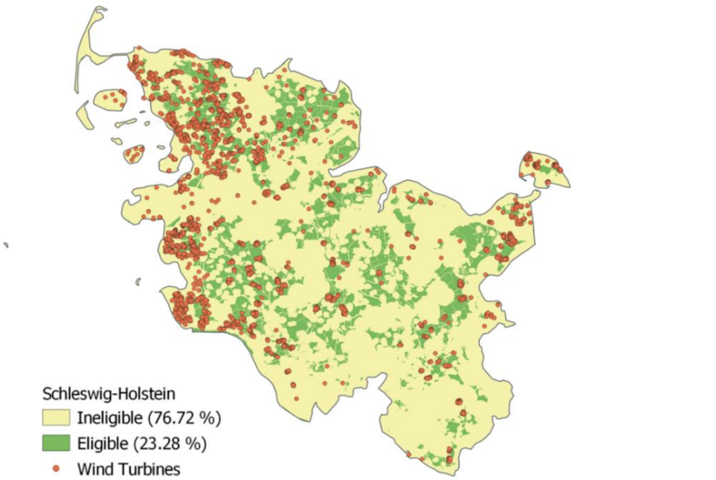

Figure 21. Identified land eligibility for the case of Schleswig-Holstein and currently installed onshore wind power plants.

Based on the data regarding current wind turbine design and their locations, the techno-economic modeling of wind power generation is computed with the RESKit model by Ryberg [272], and provides electricity production times series and production costs for each turbine location. Furthermore, to account for the operation of aging turbines, additional considerations with regard to efficiency degradation, maintenance cost and profitability margin are also included [52]. The results show that the derived average levelized cost of electricity (LCOE) values of 3.83 ct/kWh are close to the PPA prices for 2023 [51], thereby supporting the validity of the implemented LCOE calculation. Additionally, in the event of an appropriate regulatory framework, PPAs allow for the avoidance of adverse lock-in effects on electrolyzer plants following the technical lifetime of post-EEG wind power plants. Associated hydrogen production costs, depicted in Figure 22, indicate that in the short term, green hydrogen costs lie mostly in the range of 4 €/kg to 5 €/kg (1000 €/kW_{el} and efficiency of 65% of the electrolyzer).

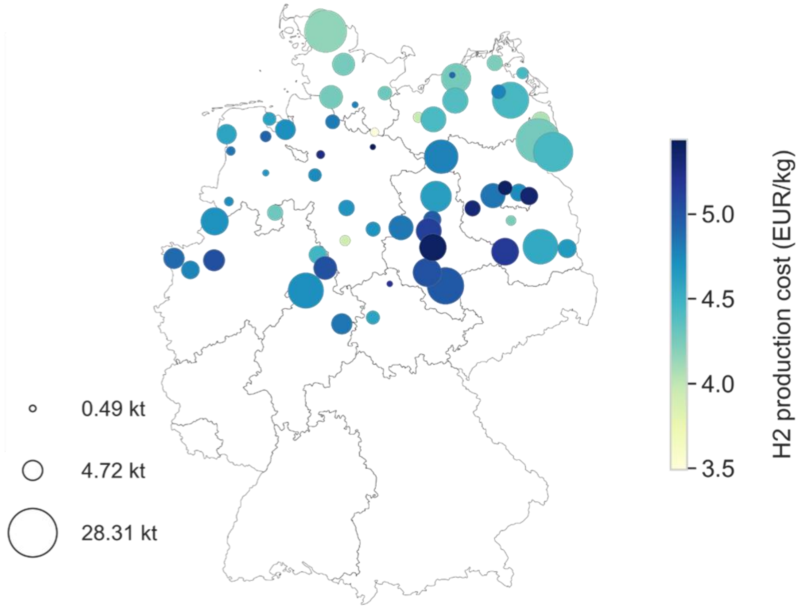

Figure 22. Results for hydrogen production capacity and cost based on non-repowerable post-EEG wind power plants in Germany.

The computed equivalent full load hours (FLH) reach, on average, 3700. This value is also used to model the production of the announced electrolyzer projects and large-scale centralized electrolyzers as well. Moreover, as is shown in Figure 22 the determined production is widely distributed, thus providing relatively dense coverage for the entirety of northern Germany. Consequently, hydrogen production from post-EEG wind power plants can be seen as a viable short-term bridge towards centralized large-scale hydrogen production.

From a long-term perspective, the import of hydrogen and large centralized electrolyzers in the coastal regions of Germany, which are designed to utilize the available surplus energy, will be the primary hydrogen sources [10, 11]. The placement of centralized electrolyzers is considered in terms of a long-term scenario in the electricity sector, dominated by a substantial renewable energy expansion in northern Germany, with a production capacity of up to 3.1 Mt p.a. [10]. Furthermore, hydrogen imports can be taken into account if the domestic hydrogen production potential is overreached. Drawing from the methodology of Heuser et al., the estimated hydrogen import cost at port in Germany is set to 3.9 €/kg_{H2} [135]. To align short- to medium-term infrastructure development with the long-term requirements of a hydrogen infrastructure, long-term hydrogen sources are included in the design of the system as soon as the capacity of short-term hydrogen production is exceeded. This enables a gradual transition from decentralized and small-scale production to increasingly centralized hydrogen generation.

3.3 Hydrogen Storage and Processing

After describing the chosen representation of hydrogen production, the methodological aspects of hydrogen storage and processing will be presented in the following sections. Considerations regarding storage duration and cost are outlined to represent the transition from small- to large- scale hydrogen storage. Thereafter, the considered purification costs for PSA and TSA processes and their impact on infrastructure introduction are discussed.

3.3.1 Hydrogen Storage

As is presented above (Sub-section 2.1.5.2) salt caverns offer a superior option for long-term hydrogen storage. However, it is less certain when and in what capacity such storage would be required before the year 2050. This uncertainty has manifold consequences for infrastructure development. As previously stated, the smallest caverns discovered in Germany, with a working volume of 70,000 m^3 at a nominal pressure difference of 150 bar, can be assumed to establish the smallest size of salt caverns for hydrogen storage, and thus smaller storage capacity would be facilitated by GH2 tanks. Based on these assumptions and the stated cost parameters, Figure 23 depicts the storage transition from the GH2 tank to the cavern. Firstly, it can be shown that by increasing the required storage length and thus the storage capacity, the initial storage costs of GH2 tanks are substantially increased and the construction of caverns is accelerated. Moreover, it can be determined that at fixed minimal size of the cavern, the salt caverns are a viable storage option for electrolyzers of approximately 100 to 250 MW_{el}, which is on the same order of magnitude as electrolyzer commercialization projects [46, 48] that also discuss the construction of salt cavern hydrogen storage. Thirdly, a comparison of the computed areas under the curve (AUC) shows that the transition costs from GH2 tanks to caverns are only slightly higher for more extensive storage periods. However, as AUC implies a linear capacity growth, a more substantial increase in the cumulative cost can be expected for extended storage periods. Thus, in order to consider both centralized hydrogen production and smaller decentralized units, two storage lengths are defined.

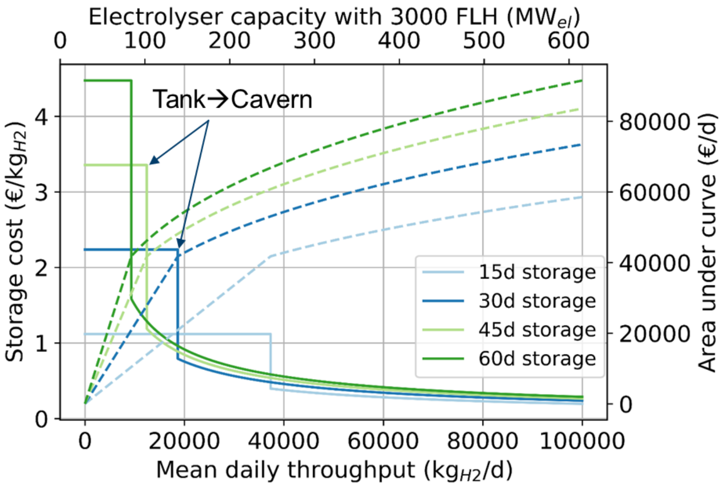

Figure 23. Storage cost comparison for different storage durations of 15, 30, 45 and 60 days. Assumed minimal size of the cavern is 70,000 m3 at nominal pressure difference of 150 bar. For detailed techno-economic assumptions please refer to Appendix B.

In the case of large production sites with more than 100 MW_{el} that have high relevance for supply security, a storage period of 60 days is selected [11]. Conversely, in the case of small production units of less than 100 MW_{el}, a storage time of 15 days is assumed, as it enables the lowest storage cost for a small electrolysis plant. In case of smaller working volumes than now fixed 70,000 m3, such as partially filling the cavern with water, the necessary electrolyzer capacity can be reduced, but a 50% reduction of cavern capacity would lead to approximately doubling of the specific-cost leading to comparable cost as now suggested 15 days of storage in tanks and then 60 days of storage in caverns. Due to the long construction of the salt caverns, the current set-up essentially uses the tank storage during the initial ramp up of the electrolysis capacity so that the salt cavern is ready for operation when electrolyzer reaches the 100 MW_{el} mark. Detailed values of the storage cost can be found in the appendix B.

3.3.2 Hydrogen Processing

In the case of components related to the state and pressure change of hydrogen, the modeling approach developed by Reuß is used for the subsequent computations in this work [11]. As previously discussed, the diverse hydrogen purity requirements of supply chain components and demand applications require consideration of hydrogen purification technologies. Based on the described costs and impurity levels in different links of the supply chain, the purification costs for PSA and TSA technologies can be derived in accordance with Cerniauskas et al. [68, 173] (see Figure 24).

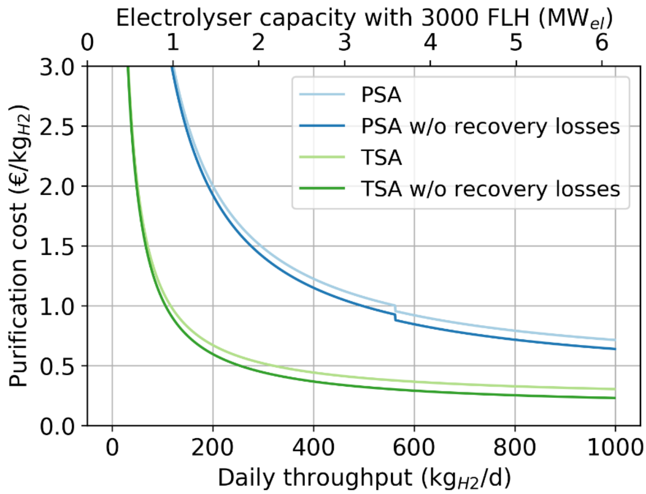

Figure 24. Cost comparison of purification methods for PSA and TSA. For detailed techno-economic assumptions please refer to Appendix B.

It can be observed that both purification options reach low-cost levels at already minimal hydrogen production capacities, thus making it a less critical component during the initial infrastructure development. However, even for larger systems, purification has a non-negligible impact on the system costs, ranging from 0.3 €/kg to 0.6 €/kg. Furthermore, the impact of hydrogen recovery losses on operational cost must be highlighted, as it becomes one of the main cost components for larger purification systems. The underlying techno-economic parameters are listed in Appendix B. In the following sections, based on the described characteristics of the purification methods (see Sub-section 2.1.5.3), it is assumed that PSA is used for hydrogen purification following hydrogen production via SMR and by-product hydrogen. Correspondingly, TSA is assumed to purify hydrogen after its storage in salt caverns. For detailed techno-economic assumptions please refer to Appendix B.

3.4 Hydrogen Delivery

To assess the anticipated evolution of the hydrogen delivery infrastructure, the following chapter presents the methods applied in this work to represent trailer- and pipeline-based hydrogen delivery. As discussed earlier, the current energy infrastructure must be utilized if a low-cost hydrogen infrastructure is to be introduced. In the case of delivery, the potential reassignment of natural gas transmission pipelines for hydrogen transport is assessed. Similarly, for hydrogen production from electricity generated by aging wind turbines, the goal is to make use of underutilized and potentially stranded assets. Subsequently, a newly-developed method for combined pipeline and trailer delivery is presented that enables the modeling of a continuous shift from trailer to pipeline transport.

3.4.1 Natural Gas Pipeline Reassignment

In this section, based on an earlier literature discussion (see Sub-section 2.1.5) techno-economic parameters for the pipeline without modification (PWM) and inhibitor pipeline reassignment are investigated. Then, the costs of both options are compared to determine the most viable reassignment option to be used in the subsequent analysis. Furthermore, pipeline reassignment potential is assessed on the basis of the relevant pipeline material and structural data of the representative natural gas transmission network for Germany.

In order to derive the cost of the PWM reassignment, the associated pipeline capital and operational costs will be incorporated. It is assumed that, due to the pipeline reassignment, no capital cost for the pipeline itself is required and that only new compressor and gas pressure regulation stations that are compatible with the hydrogen environment are installed. No capital cost for the exchange of deteriorated valves and fittings is considered, as these measures are independent of the pipeline reassignment. Furthermore, no change in the maximum operating pressure of the pipeline is assumed. Table 16 presents the cost components entailed by PWM reassignment.

Table 16. The cost structure of pipeline without modification (PWM) option for pipeline reassignment.

Components	CAPEX	OPEX
Pipeline	No	Yes
Compressor stations	Yes	Yes
Gas pressure regulation	Yes	Yes

As is discussed above, PWM reassignment accelerates pipeline material degradation, which in turn increases the O&M costs of the pipeline. To quantify this effect, the operation costs of a comparable new hydrogen pipeline are assumed. To account for the increased operational costs due to hydrogen embrittlement, conservative factors are considered for compressor and gas pressure regulation stations, which are placed in the pipeline grid every 250 km [9]. The associated capital cost of the compressor station is estimated according to the hydrogen compressor cost and scaling data presented by Reuß et al. [148]. Thereafter, the base compressor station capacity is set to 10 t/d while operating in the range of 70-100 bar. As for the gas pressure regulation stations, under the assumption that such a device is almost equivalent to that for natural gas, the capital costs were derived from estimates in the German natural gas grid development plan [7].

In the case of the inhibitor admixture to the hydrogen stream, the cost of inhibitors and their subsequent removal prior to the further processing of hydrogen is also taken into account. Furthermore, for the consistency of the analysis, an additional compressor is considered that is required to reach the minimum transmission pipeline operating pressure of 70 bar, given the low purification output pressure of 40 bar [163, 164]. An overview of all cost components of the inhibitor reassignment cost can be observed in Table 17.

Table 17. The cost structure for inhibitor admixture option for pipeline reassignment.

Cost component	**CAPEX**	**OPEX**
Pipeline	No	Yes
Compressor stations	Yes	Yes
Inhibitor	No	Yes
Purification	Yes	Yes
Compressor at purification facility	Yes	Yes
Gas pressure regulation	Yes	Yes

The costs of the analyzed pipeline reassignment options are evaluated and the countrywide cost effects for the preselected options are assessed. Three distinct pipeline availability scenarios are defined and compared with respect to the cost-sensitivity of the hydrogen supply chain. Finally, hydrogen pipeline reassignment is compared to other hydrogen supply chain pathways.

Figure 25 displays the resulting total yearly pipeline costs of the analyzed pipeline reassignment alternatives at typical transmission pipeline diameters. In addition, new hydrogen pipeline costs with compressor and gas pressure regulation stations every 250 km are presented [9, 188]. It can be observed that not all reassignment options deliver lower costs than new hydrogen pipelines, whereas CO and SO_2 admixtures are the least competitive options. The significantly lower cost of the O_2 admixture closely corresponds to the lower inhibitor cost and, most notably, the very small required quantity of inhibitor that additionally reduces purification costs. However, due to the purification costs, the O_2 inhibitor admixture does not provide any cost reduction in comparison to new hydrogen pipeline construction.

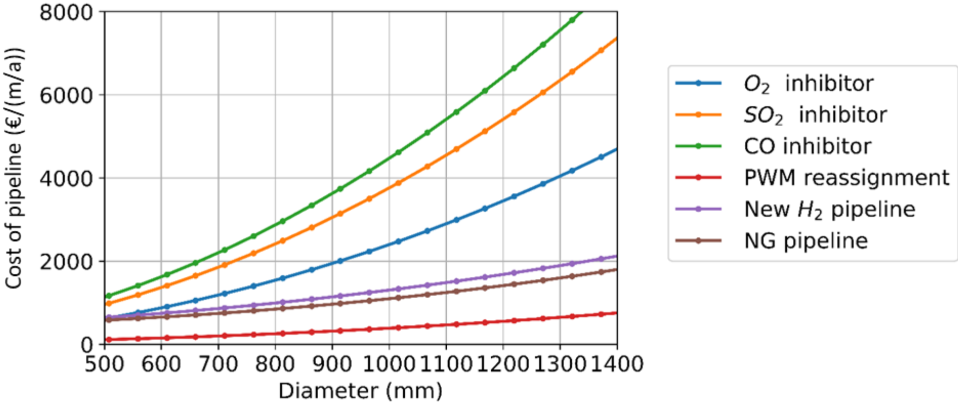

Figure 25. Cost comparison of the pipeline reassignment alternatives and new H2 pipelines. For detailed techno-economic assumptions please refer to Appendix B.

Significant cost reductions are observed in the case of the PWM pipeline reassignment that is found to be, on average, one order of magnitude less costly than the O_2 inhibitor admixture. The main reason for such a difference is that, for the PWM approach, no hydrogen purification is required for further hydrogen processing and use. Furthermore, due to its low CAPEX and fixed OPEX, the PWM reassignment was found to be at least 60% less expensive than building a new hydrogen pipeline. Nevertheless, it should be kept in mind that our cost estimates are based on material tests of small-diameter pipelines in comparably low-pressure conditions. Moreover, the crack growth acceleration is estimated for cases of static pipeline load operation, which is facilitated by long-term and buffer hydrogen storage capacities. However, the high intermittency of renewable energy sources may require more flexibility in the pipeline network, which would increase the number of load cycles and, in turn, accelerate material degradation. Thus, larger tests under more realistic transmission pipeline operation scenarios are required in order to gather more accurate results.

Figure 26 displays the specific cost savings of pipeline reassignment for the two least expensive options in comparison to a new pipeline with small diameters of below 250 mm. Pipelines are generally associated with comparably large initial capital investment that is independent of their capacity and thus has a negative impact on specific costs. As the capacity increases, the specific CAPEX of the new H_2 pipeline delivery falls rapidly; therefore, increasing hydrogen throughput diminishes specific cost savings. Furthermore, the negative impact of low pipeline capacity utilization during the initial pipeline reassignment can be observed. In cases where the available NG pipeline capacity is insufficient, no reassignment can be applied and thus no cost comparison to the construction of a new hydrogen pipeline is apparent. Due to the high expenses of purification and inhibitors, inhibitor reassignment is more affected by the increasing pipeline throughput and low pipeline utilization. However, as PWM reassignment costs are mostly governed by the fixed operating costs caused by accelerated crack growth, pipeline throughput has a lower impact on the pipeline cost. For these reasons, PWM generally offers superior features for cost-efficient hydrogen delivery over O_2 inhibitor admixtures.

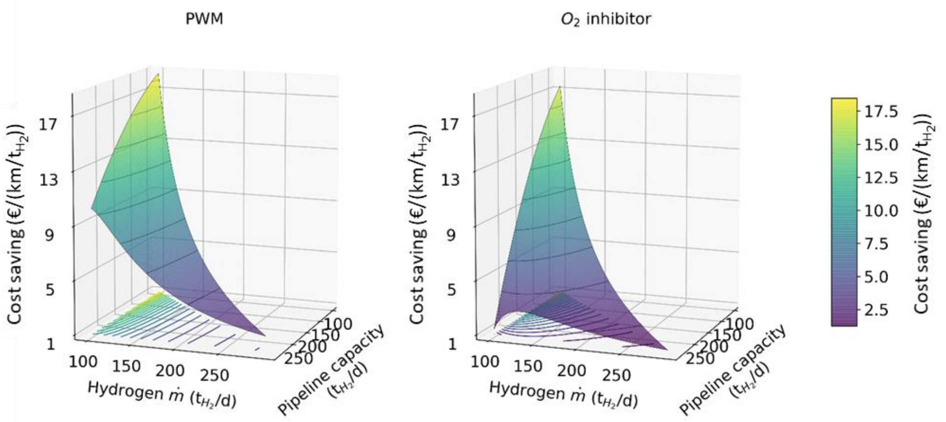

Figure 26. Cost savings by pipeline reassignment alternatives in comparison to a newly build H2 pipeline.

Based on the aforementioned variables of pipeline reassignment, the data on the pipeline material, minimal pipeline pressure and the number of parallel pipelines, as well as age, are determined to be representative of the German NG transmission grid. Table 18 presents an overview of pipeline characteristics concerning the number of pipelines, operational pressure and material. For a more detailed description of the publicly available data assessment, please see Cerniauskas et al. [173].

Table 18. Constraints of pipeline reassignment technical potential in Germany.

	Number of pipelines	Operation Pressure	Material	Percentage of total length	Total
Reassignable for hydrogen transport	1	> 70 bar	X70	42.96%	81.9%
	2	> 70 bar	X70	25.89%	
	3	> 70 bar	X70	13.11%	
Non-Reassignable for hydrogen transport	1	< 70 bar	X60	10.72%	18.0%
	1	< 70 bar	X70	0.90%	
	1	> 70 bar	X60	0.17%	
	2	< 70 bar	X70	1.41%	
	2	> 70 bar	X60	2.44%	
	3	> 70 bar	X60	2.40%	

Based on this data, the considered reassignable and non-reassignable pipelines for hydrogen transmission are classified. From the results yielded, it can be inferred that the material requirement has a limited effect on the overall potential, as X70 steel is estimated to constitute almost 85% of the analyzed pipelines. On a comparable scale, the technical potential is affected by the minimum pressure requirement, which limits the technical potential to 87% of the overall pipeline length. Furthermore, it can be observed that the number of parallel tranches, which are used as a proxy for compatibility with the further operation of the NG system, has a decisive effect on pipeline availability. More than half (57%) of the reassignable pipelines correspond to segments with only one additional parallel tranche. Therefore, with the requirement of continued NG transmission through the region, the reassignment potential is diminished by half, to 39% of the total transmission pipeline length. Consequently, to account for successful hydrogen system integration, only pipelines with multiple parallel tranches will be considered for reassignment.

3.4.2 Trailer and Pipeline Routing

The approach applied in this work to derive the spatial and capacity values of the supply from sources to sinks is based on earlier work by Reuß [9]. This method employs nodes and edges linking different nodes to represent viable streets and pipeline routes as a graph (see Figure 27). To implement such a graph, the underlying data on pipelines and streets are divided into nodes set 1 km apart and the distances between nearest-neighbor nodes are computed. Subsequently, additional points such as sources and sinks are connected to the network via the shortest Euclidian distance.

Edges are also weighted to account for detours. Then, with a set node and sink capacity, i.e., production and demand potential, an optimal flow problem is solved to attain a global optimum for flow routes and capacities. Due to the complexity of the problem, pipeline routing alternatives are also constrained with a minimum spanning tree algorithm, ensuring the minimum sum of weights for network edges.

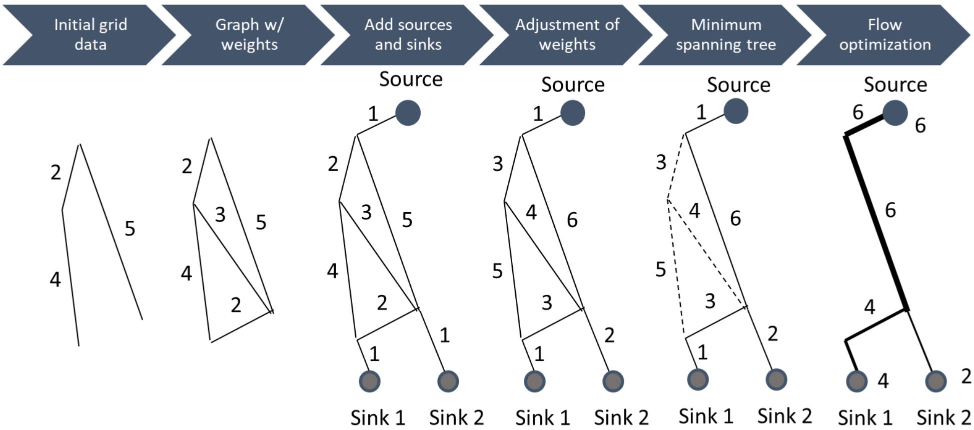

Figure 27. Workflow to determine the supply capacities and routes between sources and sinks in the case of a pipeline.

As shown by Reuß, this approach can also be applied to the modeling of hybrid delivery pathways, such as pipeline transmission with subsequent trailer distribution. Furthermore, it was highlighted that the selection of the number and locations of hubs, where the trailer is connected to the pipeline, has a substantial impact on system costs [9]. In the case of a high number of hubs, the transmission pipeline dominates the costs of transport, by reducing the number of hubs, the costs of the pipeline, as well as of the hub, begin to decrease as the pipelines' length is decreasing while the respective capacity is increasing. In contrast, however, the delivery distances for distribution by trailer increase as do their specific costs. From the perspective of infrastructure introduction, this effect has even greater importance, as a continuous development of the pipeline would change the optimum in each analysis step, leading to many iterations until a new optimum number of hubs is computed.

To address the described issue and simplify the analysis, in this work a method is designed to balance the number of hubs with trailer and pipeline delivery costs. The underlying idea of the approach is that non-linear systems can be described linearly on a sufficiently small scale. Applied to the pipeline and trailer routing problem, this results in a comparison of the specific delivery costs for each edge of the network (see Figure 28). However, as pipelines and trailers do not share the same routes, a threshold value is introduced to determine the maximum allowable specific cost of a pipeline edge between two nodes. After the flow optimization for pipelines, all edges with costs exceeding the threshold value are discarded and hubs with the capacity of the first removed edge are implemented at each switchover. Then, optimization of trailer distribution takes place under the reconfigured sources and hubs to supply the sinks.

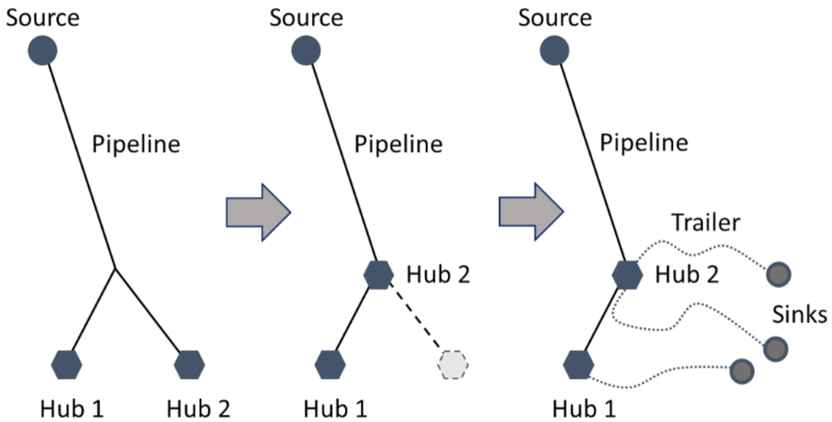

Figure 28. Interlinking of pipeline and trailer routing optimization by discarding pipelines exceeding the threshold value and reconfiguring hub locations.

In this work, it is argued that the selection of the threshold value for determining the considered pipeline edges is key to the pipeline network's design. This value is especially relevant for small pipeline throughputs, which lead to low pipeline utilization, as the minimum diameter of a transmission pipeline is set to 100 mm [9]. Thus, the threshold value can also be interpreted as a minimum acceptable pipeline utilization rate. Figure 29 displays the impact of pipeline utilization on new and reassigned pipeline costs and compares the resulting costs with GH2 trailer transport. From the figure, it can be determined that a threshold value of 0.01 €/(kg/km) is comparable with specific trailer costs per kilometer. However, due to the fact that, depending on the type of area, the individual pipeline routes are subjected to the readjustment of weights, the threshold value is reduced to 0.003 €/(kg/km). In such a case, only edges with utilization of more than 6% and 1.5% for new and reassigned pipelines are available for pipeline delivery. Such low minimal utilization rates lead to twofold conclusions. First, pipelines require only minimal utilization to become a valuable alternative to GH2 trailers, thus indicating a need for the early development of the hydrogen pipeline network. Secondly, due to the fact that very low utilization is excluded, only very expensive pipeline edges, which are unlikely to actually be implemented, are omitted from the design. Based on these considerations, a threshold value of 0.003 €/(kg/km) is selected for further analysis.

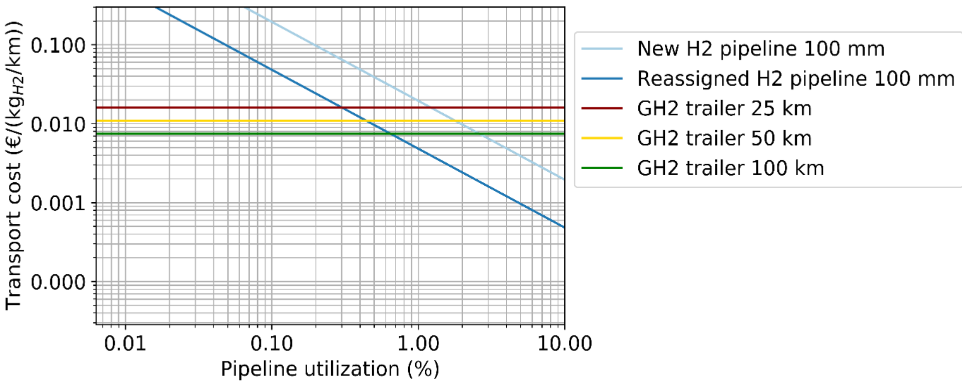

Figure 29. Impact of utilization on specific pipeline costs per kilogram and kilometer and comparison with GH2 trailer delivery for different transport distances.

3.5 Hydrogen Refueling

Following the description of the production, storage, purification and delivery of hydrogen, the following section outlines the methods applied to assess the changeover of hydrogen refueling stations during the transition to a large-scale countrywide system. To begin with, the modeling approach, underlying assumptions and model's comparison with the literature are presented. Subsequently, the scaling and most suitable designs of hydrogen refueling stations for passenger cars are evaluated. Based on these findings, investment costs and the scaling of refueling stations for different vehicle markets are assessed.

3.5.1 Modeling Approach

The representation of hydrogen refueling stations herein was developed based on models for passenger cars (HRSAM, Reuß) and freight vehicles (HRDSAM) from the literature [9, 249, 250]. The goal of the newly developed model was to combine both of these models in order to enable the flexibility to model a refueling station while simultaneously supplying different hydrogen market segments, i.e., at 350 bar and 700 bar. Furthermore, the different nature of public and non-public refueling stations requires additional consideration of refueling uncertainty and its impact on the required refueling station capacity. While public refueling stations must account for high demand fluctuations, thus leading to excess capacity, non-public refueling stations can be designed according to the requirements of a particular vehicle fleet. Consequently, the characteristic demand time series for each vehicle market are taken into account. Lastly, due to the fact that non-public refueling stations are designed according to the requirements of a particular fleet, the design of components must be sufficiently flexible to accommodate a wide range of refueling station sizes.

In the first step of the new model, the scope of the hydrogen refueling stations is extended by additional components enabling the supply of both 350 bar and 700 bar demand. Furthermore, markets have unique refueling-related characteristics, such as typical refueling amount, the size of a single tank and required refueling time that also affect hydrogen refueling station design. Table 19 and Figure 30 present selected assumptions to differentiate amongst various fuel cell vehicles. It should be pointed out that, for larger commercial vehicles, the overall refueling amount differs significantly from the individual tank capacities. Therefore, differentiation between refueling amount and the size of a single tank is necessary to determine the required cooling capacity, which is also affected by the refueling time. Moreover, varying temporal distribution and time between refueling events has a significant impact on cascade size and the capacity of the compressor or cryogenic pump. Here, the time between refueling events represents the minimum time between back to back refueling events and encompasses the necessary time to park the vehicle, get out and into it, connect and disconnect the dispenser, and time spent during the payment procedure. In particular, trains have a large gap between refueling, as rearranging of the vehicle is estimated to take approximately 15 minutes [193].

Table 19. Refueling related features for individual FCEV markets considered in this work.

Feature	Car	Truck	Bus	Train	Forklift
Pressure (bar)	700	350	350	350	350
Refueling amount (kg)	3.5	35-40	35-40	170	3.2
Single tank (kg)	3.5	8	8	8	3.2
Next refueling (min)	3	5	5	30	1
Refueling time (min)	3	10	10	30	1
Source	[194, 197]	[199, 207]	[199, 207]	[83, 193]	[55, 198, 205]

For this analysis, the publicly-available refueling profiles for passenger cars and freight trucks were used. In the case of trains and buses, it was assumed that vehicle refueling takes place in the late evening and early morning before the start of daily operations, thus enabling maximum operational flexibility for these vehicles. Finally, a forklift was assumed to be utilized in a typical two-shift operation, leading to a refueling peak at midday and a more even refueling overnight.

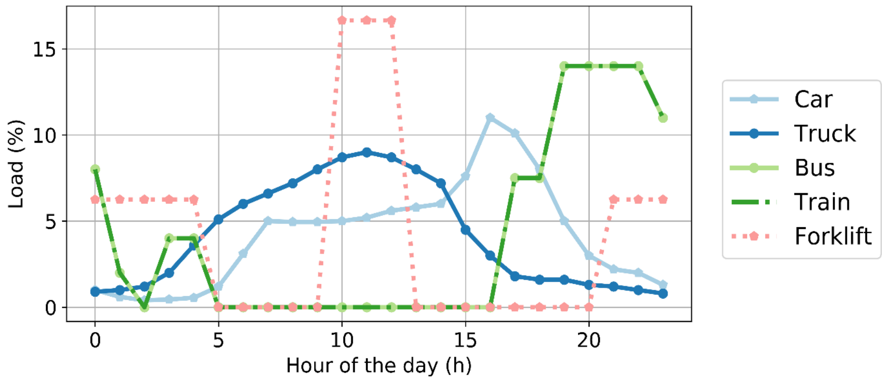

Figure 30. Assumed hydrogen refueling time series for different FCEV markets [200, 201, 203, 204].

In accordance with the described approach, the modeling results of a passenger car refueling station are compared with those from both of the underlying approaches derived by Reuß [11] and the H2A model family (HRSAM, HRDSAM) [249, 250]. To begin with, it should be highlighted that all three models employ very similar underlying cost assumptions. Thus, substantial cost differences are primarily due to the different choices of underlying modeling approach. Nevertheless, even though these models use assumptions derived from the state-of-the-art components and include 30% installation overhead, the resulting cost of a specific project can still substantially deviate from the computed cost due to component redundancy or project inefficiencies. However, both aspects are expected to diminish in the future with better refueling station availability and experience of how to implement such projects efficiently. In Figure 31, it can be noted that the investment costs from the HRSAM model are consistently lower than in the case of other models because the costs from the daily storage are omitted for GH2 delivery. Nevertheless, the difference between the approach of Reuß and HRSAM cannot be explained by only the cost of daily storage. On the one hand, further cost differences arise from a more conservative compressor design that is based on back-to-back refueling and approximation of the cooling capacity by Reuß. On the other hand, HRSAM compensates a lower compressor capacity with larger cascade systems. In comparison, the derived modeling method of HRSAM offers a consistently lower cost than both of the other models (without daily storage) in all three capacity categories. The main reasons for this are optimization of the compressor and cascade capacity, as well as a more detailed design of the cooling and dispenser capacities. For detailed techno-economic assumptions please refer to Appendix B.

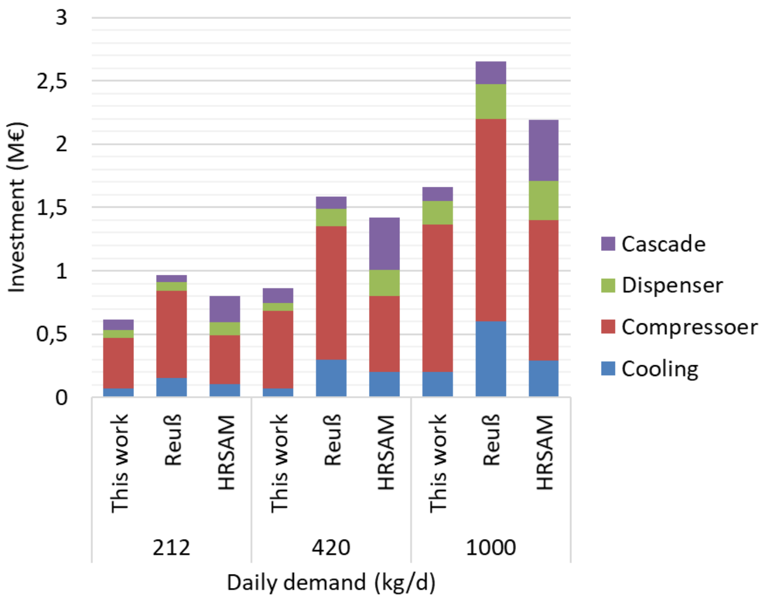

Figure 31. Comparison of model results with the models from the literature [11, 250].

3.5.2 Market-Specific Cost of Hydrogen Refueling Stations

This section aims to identify the most promising station design in the case of GH2 and LH2 delivery for each FCEV market considered. This is facilitated by applying the model for the example of a passenger car refueling station, as it has the highest requirements regarding output pressure and time between refueling events. Based on these findings and market-specific refueling features, the refueling station costs for both designs are compared across different FCEV markets, enabling the identification of potential design preferences for each market.

Figure 32 depicts a comparison of investment costs amongst various hydrogen refueling station designs derived from the hydrogen refueling station model developed in this work (see the Appendix B). It can be perceived that a tenfold increase in capacity, from 200 kg/d to 2000 kg/d, leads to a specific investment reduction of at least 50%, thus highlighting the benefits of larger-scale infrastructure. Consequently, when comparing the results with the contour lines, it can be noted that the smallest stations can be built for approximately 1 million €, whereas large stations of 2000 kg/d would cost between 3 and 5 million €. Moreover, it is apparent that for LH2 options, the cryogenic pump design is the lowest cost option, as it is 10% to 40% less capital intensive than a compressor design. In the case of the GH2 supply, it can be noticed that cascade the design is 5% cheaper than the booster design for both trailer and pipeline delivery, which is in accordance with other estimates in the literature [148]. Thus, the cascade design can be slightly more favored than the booster one. In the case of LH2 stations, most of the other estimates also find LH2 stations to be 30% to 50% less expensive than their GH2 counterparts [210, 250-252]. However, some estimates hint towards more conservative LH2 station costs, being approximately equal to those of GH2 stations [179]. Notwithstanding some differences in the literature values, it can be concluded that the selection of the hydrogen delivery option and underlying station design can have a significant impact on the required investment cost, which is especially relevant during the market introduction phase, as it is associated with high uncertainty and low infrastructure utilization.

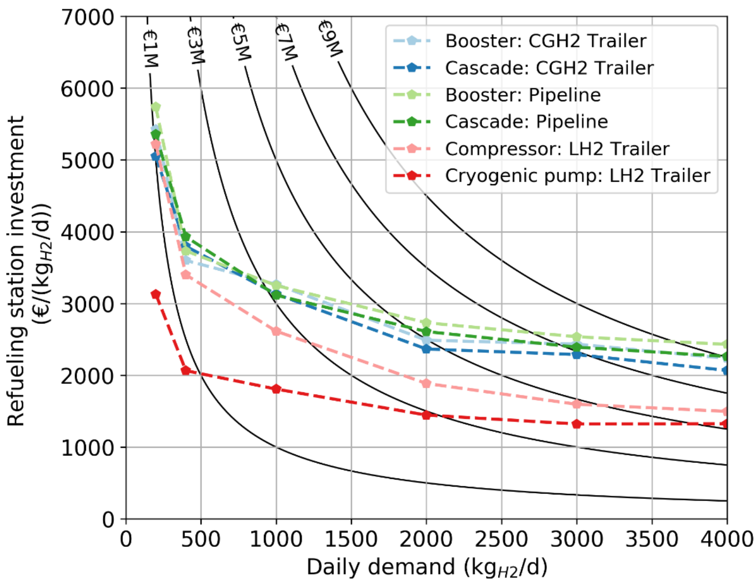

Figure 32. Comparison of the specific-investment cost of refueling stations for passenger cars of different designs and capacities, which are derived from the refueling station model developed for this work. The contour lines indicate various levels of the overall investment cost. For detailed techno-economic assumptions please refer to Appendix B.

From Figure 33, it is apparent that diminishing specific costs for the compressors, LH2 storage and auxiliaries, such as controlling and electrical installations, are primarily responsible for the observed cost reductions. However, it should be pointed out that the model derived in this work implies sufficient space for the associated infrastructure. Depending on the local conditions of the refueling station, it is possible that, at a certain point, additional gains from component scales are outweighed by the drawbacks of the loss of the available area at the refueling station. Another issue is the implied standardization of components. Accordingly, stations of different capacities should retain their main design features and be easily expandable. Both of these requirements are satisfied by the model, as consistently favorable station designs were identified, and core components, such as LH2 tanks and compressors, are available across a broad capacity spectrum.

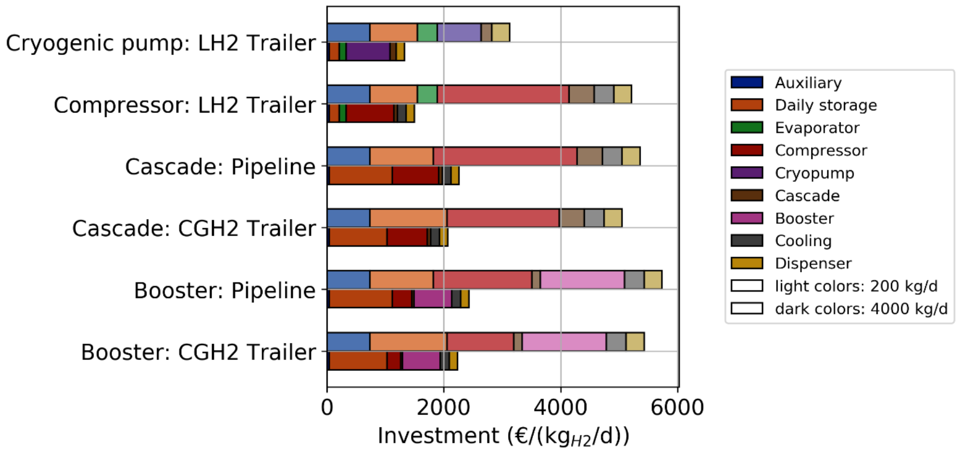

Figure 33. Comparison of investment cost structure for various refueling station designs for a capacity of 200 kg/d and 4000 kg/d.

Thus, the cryogenic pump and cascade designs were selected for the further investigation of hydrogen refueling station costs for different FCEV vehicle markets. In Figure 34, it can be observed that, in line with the findings mentioned earlier, LH2 stations are up to 40% less expensive than compressed gaseous hydrogen (CGH2) ones. The highest cost reductions by switching from HG2 to LH2 are attained in the case of passenger car and truck refueling, which both have assumed lower daily refueling peaks but also a lower average utilization of 70% [194]. Moreover, a reduction of pressure from 700 bar to 350 bar can lower refueling station costs by at least 20%, thus enabling the gap between GH2 and LH2 stations to be minimized. Nevertheless, an increase in the cascade cost with the growing refueling volume can also be observed, which is primarily expressed in the case of trains. Consequently, the investment cost for a 350 bar train station is higher than that for a 700 bar passenger car station. However, a 200 kg/d case represents a situation where only a single train is refueled, which is not representative for fleets beyond the initial pilot projects. Conversely, forklift refueling stations with refill amounts of 3.2 kg require only marginal cascade systems and almost no cooling, thus leading to the highest cost reduction in comparison to refueling stations for passenger cars.

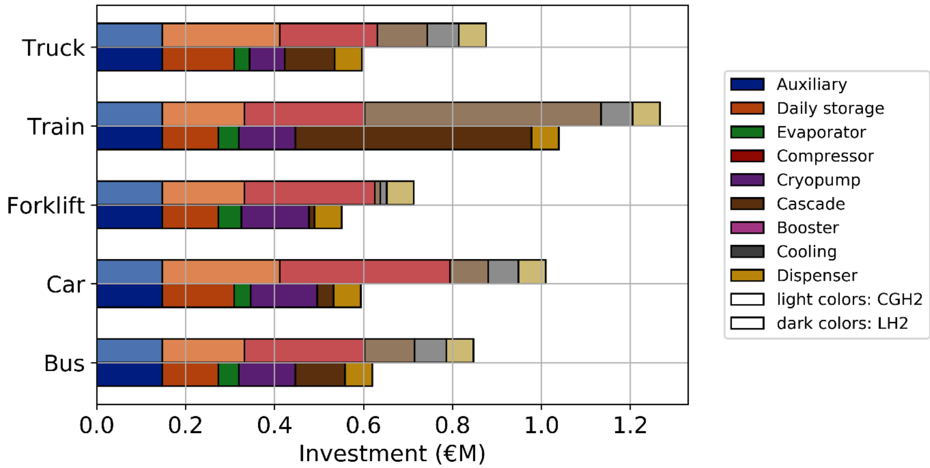

Figure 34. Comparison of investment cost structure between CGH2 and LH2 designs amongst various different hydrogen markets for the capacity of 200 kg/d.

To quantify the station scaling effects, Figure 35 depicts the specific costs of the refueling station along with the increasing station capacity. In accordance with the previous findings for a passenger car station, with a capacity increase from 200 kg/d to 4000 kg/d, the specific station cost can be reduced by up to 50%. These results are in line with recent estimates of the economies of scale for hydrogen refueling stations in California, indicating a cost reduction potential of 30%, from 250 kg/d to 1000 kg/d [252]. The results indicate that LH2 stations tend to be less expensive and that their cost variation is lower than in the case of CGH2 stations. Nevertheless, the impact on large-scale station costs varies across different applications. Stations for passenger cars and freight trucks, which are amongst the most expensive, benefit the most from switching to an LH2 supply, whereas bus and forklift station costs are only marginally affected.

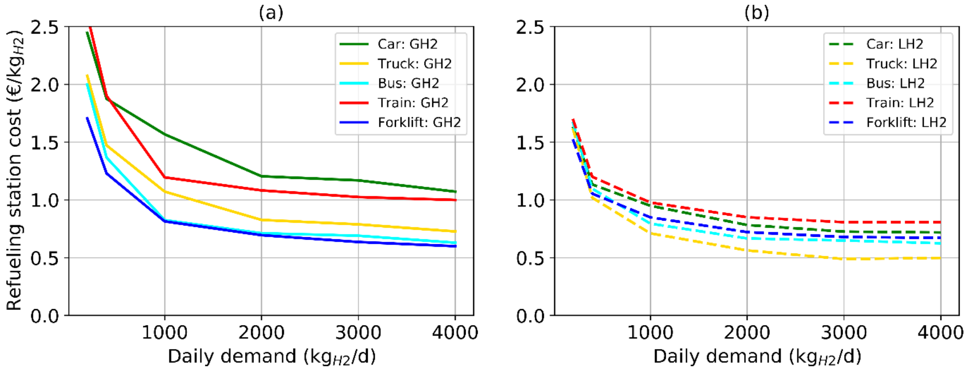

Figure 35. Impact of refueling station capacity on refueling costs for different markets; (a) CGH2 refueling station; and (b) LH2 refueling station design.

Consequently, these results indicate a substantial cost-reduction potential for larger vehicle fleets, as even 1000 kg/d non-public refueling stations can be operated with a cost between 0.7 €/kg and 1.2 €/kg. To put it into perspective, Table 20 compares an estimated number of vehicles to fully utilize a 1000 kg/d station and fleet sizes from most significant commercialization projects in Europe. Thereafter, it can be observed that fleets tend to grow towards the indicated size of the fleet, thus showing that such large fleets are a viable proposition. Furthermore, given the ever-increasing fleet sizes of the projects and the fact that one of the main reasons provided for fleet expansion is a better utilization of the refueling infrastructure, it can be argued that described cost reduction effects are comparable to the ones observed by the industry.

Table 20. Estimated fleet size required to reach 1000kg/d and already operating or planned fleets in Europe [54, 55, 195, 196, 202].

	Taxi	**Freight truck**	**Bus**	**Train**	**Forklift**
Fleet with 1000 kg/d	650	45	70	14	150
Operating fleet size in 2020	600	50	34	15	137

By employing the methodology for the modeling of hydrogen refueling stations (see Sub-chapter 3.5), cost savings for individual market pairs were computed for demands ranging from 100 kg/d, which lies below the smallest public refueling station capacity and, therefore represents an underutilized station, to 1000 kg/d, which depicts a large refueling station (see Figure 36). From the figure, it can be noted that multiple-use refueling stations have a positive overall effect on refueling costs, thus outweighing the additional investment costs associated with the expansion of station capacity and equipment, such as dispensers and high-pressure storage. Nevertheless, the observed cost-saving ranges from 1 €/kg to more than 5 €/kg, indicating high variation between the specific cases.

A comparison of median cost-savings indicates that the multiple utilization of a refueling station for 350 bar and 700 bar technologies provides ~10% higher median cost savings than a combination of two 350 bar vehicles. In the case of only 350 bar vehicles, the cost savings are primarily caused by the larger scale and better utilization of the station. However, in the event of supplying different pressure levels, the cost savings are also affected by the higher costs of the 700 bar stations, thus enabling more substantial cost reductions through the use of the shared components, such as daily storage, the main compressor and cascade system. More efficient utilization of the cascade system is also the main reason for the highest cost savings being associated with the train refueling station. This finding is in line with the previously observed results, which show that the costs of train refueling stations are profoundly affected by the costs of the cascade system, which is required to provide 170 kg of hydrogen per individual refueling event (see Section 3.5.2).

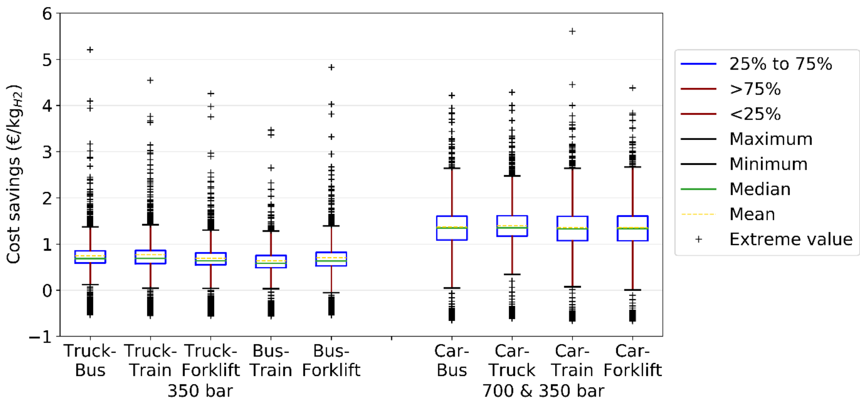

Figure 36. Cost savings of the multiple use of refueling stations (cascade design) compared to two separate facilities. Demand ranges from 100 kg/d to 1000 kg/d.

Notwithstanding the high-cost savings for pairs containing trains, due to the more significant market volume and extensive station distribution, the highest system-wide savings are expected to be achieved by multiple station utilization for cars and trucks. Accordingly, only multiple station utilization for cars and trucks will be considered in this work.

3.6 Summary

To derive the **anticipated hydrogen demand**, extensions of the applied Bass model and its resulting features are presented. The model is then applied to exploratory diffusion scenarios for each market encompassing low, medium and high penetration in 2050. The evaluation of the scenarios indicates that commercial vehicle fleets, such as local buses, non-electrified trains and forklifts, are associated with the highest innovation coefficients. Subsequently, the factors applied to determine the geospatial distribution of the demand are discussed. The **spatial distribution of the demand** scenario is conducted in two steps. First, each German NUTS3 region is weighted according to the defined criteria for each market, whereas each criterion is weighted equally, as the actual impact by each factor remains to be quantified. Second, after deriving the demand for each market in each county, the number of required hydrogen refueling stations is determined by applying optimization and linear disaggregation methods.

By investigating suitable **criteria for electrolyzer placement**, such as proximity to the electricity grid and other infrastructure assets, renewable energy installations and viable areas for salt cavern construction, more than 80 potential sites in Germany were identified. **Post-EEG wind turbines** were investigated to derive a short-term option for green hydrogen production and thus to bridge the gap towards large-scale green hydrogen production from surplus energy in the future. Firstly, it could be verified that approximately 50% of existing wind power plants stand outside of the newest land eligibility criteria, thereby creating an opportunity for hydrogen production if these power plants are not decommissioned. Secondly, the derived electricity costs for the relevant post-EEG wind power plants were validated with PPA contract futures for the year 2023, resulting in an average electricity cost of 38 €/MWh_{el}. The short-term green hydrogen costs were then found to range from 4€/kg to 5€/kg in the year 2025.

From the discussion of the required minimum storage length, it was shown that to facilitate a low-cost **transition from tank to cavern storage**, production sites should be differentiated between ones with less than 100 MW_{el} with tank storage for 15 days and larger electrolyzers, which are accompanied by 60 days of cavern storage. Based on the developed model for purification technologies, it could be demonstrated that for electrolyzer capacities of less than 10 MW_{el}, these technologies reach a sufficient scale to provide **low specific purification costs**, thus limiting their impact during the introduction phase. However, driven by recovery losses during purification, long-term purification costs of 0.3 €/kg to 0.6 €/kg have a non-negligible impact on the final hydrogen costs.

The techno-economic assessment of **pipeline reassignment** methods conveys that pipeline without modification offers superior properties over inhibitors, enabling costs to be reduced by more than 60% in comparison to a newly constructed hydrogen pipeline. Thereafter, based on a representative natural gas transmission network for Germany, it was determined that technical reassignment potential reaches more than 80% of the analyzed pipelines. Subsequently, a method for **combined pipeline and trailer delivery** is proposed. It was argued that by limiting pipeline utilization to more than 1% of their capacity, specific pipeline costs could be capped to a level comparable to GH2 trailers, thus facilitating a smooth switchover from trailer to pipeline delivery.

Additionally, it was found that the **selection of the hydrogen delivery option and underlying station design** could have a significant impact on refueling station investment, indicating the capability of a GH2 cascade and LH2 station designs to alleviating the market introduction associated with high initial costs and low utilization of the refueling stations. Based on these findings, **refueling station costs** for other considered FCEV markets are investigated. The comparison of station costs for **700 bar passenger cars and 350 bar commercial vehicles** generally leads to a cost reduction of at least 20%, thus highlighting lower operational requirements for the 350 bar stations. A notable exception is a refueling station for trains, for which costs remain in a similar range to passenger cars due to the required high cascade capacity. Evaluation of the most significant FCEV commercialization projects in Europe indicates that modeled scaling effects are observable in actual implementation, leading to fleet demands of approximately 1000 kg/d, which corresponds to modeled refueling costs of 0.7 €/kg to 1.2 €/kg.

4 Strategy Implementation and Evaluation

In this chapter, the implementation strategy for a hydrogen infrastructure is evaluated from the perspective of the anticipated transition to a countrywide hydrogen supply chain system encompassing **four main pillars:** market structure; production and storage; delivery infrastructure; and refueling stations. First, the transformation of the **hydrogen market (1)** is outlined by discussing the market's structural changes and **National Hydrogen Strategy of Germany**. It is initially dominated by demand from commercial vehicles as well as industrial markets, while later on, it will be primarily governed by demand from passenger cars and industrial consumers. Moreover, associated spatial features of the market transition are discussed, which arise as a result of the shift from commercial fleets towards passenger cars. After the demand scenario is defined, an overview of the resulting cost and infrastructure development is provided. Then, against the background of the overall infrastructure development, the reconfiguration of **production and storage (2)** is presented to highlight the shift from small and decentralized production encompassing SMR, by-product hydrogen and off-grid electrolysis from post-EEG wind, and small initial imports into a system that is characterized by centralized, large-scale hydrogen generation and large volumes of hydrogen imports. Moreover, storage, comprising medium- and long-term solutions, is evaluated. Based on these results, the evolution of the hydrogen **delivery infrastructure (3)**, which connects production and demand, will be scrutinized. Different supply chain pathways are analyzed in terms of their evolution, from connecting small-scale regional generation with a sparse network of refueling stations towards a large-scale infrastructure, delivering from centralized production facilities to highly concentrated demand in industrial centers, as well as to the densely populated countrywide network of refueling stations. Then, the changeover of the hydrogen **refueling infrastructure (4)** will be investigated. This changeover takes place as the refueling infrastructure shifts away from a sparse network of small-scale stations to a dense station infrastructure with a high specific throughput of individual facilities. Additionally, the beneficial features of multiple utilization refueling stations in the introduction phase are assessed.

On the basis of the presented results, the derived hydrogen introduction strategy is evaluated with respect to its cost-competitiveness, with **benchmark fuels** for individual markets. Subsequently, the resulting costs of the supply chain are assessed in the framework of the **current carbon tax** policy in Germany in order to derive the cumulative cost gap of the introduction strategy that is also required to reach a cost-competitive level for individual consumers. The discussion is concluded with a sensitivity analysis of the main input parameters.

4.1 The Transformation of the Hydrogen Market

The following section assesses the transformation of the hydrogen market, focusing primarily on the structural and spatial developments of market introduction. First, drawing on the National Hydrogen Strategy of Germany [5], the overall market growth scenario and its structure are evaluated. Then, the spatial distribution of demand at different stages of market introduction is investigated and the demand regions identified, at which point a detailed demand structure for these is evaluated for the year 2030.

As previously noted, the National Hydrogen Strategy places a large focus on the transportation and industrial markets, especially steel, ammonia, methanol and refineries. Consequently, the total hydrogen demand is anticipated to grow by 35 to 55 TWh (1.05 to 1.65 Mt) through 2030. However, this growth also incorporates fuel production for aviation, which is not considered in this work. Hence, the demand for externally supplied hydrogen, which substitutes SMR and supplies FCEVs, must be lower than 35 TWh (1.05 Mt) in 2030. Based on Figure 15, the high and medium market penetration scenarios are selected for industry and transportation, respectively, in order to represent the goals of the National Hydrogen Strategy. This scenario yields an external hydrogen demand of 27 TWh (0.81 Mt) in 2030. The demand encompasses the substitution of SMR in the chemical industry (0.165 Mt) and new demand for steel (0.195 Mt) and transportation (0.45 Mt).

Figure 37 depicts the accumulated hydrogen demand for the selected market penetration scenario in the analyzed hydrogen markets, including for FCEVs and externally supplied hydrogen, which substitutes incumbent production by SMR. Note that no behavior changes due to autonomous driving or evolution regarding vehicle mileage and the total fleet size of vehicles or industrial stock production are assumed. However, the green hydrogen demand potential in refineries is dynamically adapted to conventional fuel substitution in the relevant market penetration scenario. The total demand is relatively balanced between industry and transportation, as the chemical and steel industries encompass between 42% and 62% of the overall demand.

Nevertheless, the structure of hydrogen demand for transportation significantly evolves from 2023 to 2050. From 2023 to 2030, hydrogen demand is driven mainly by captive fleet vehicles in public transportation, such as regional non-electric trains, local buses and other commercial fleets, such as forklifts and especially trucks. During the time-frame beyond 2030-2035, the green hydrogen market for the transport sector is increasingly dominated by passenger vehicles, which make up the most sizable fraction of overall demand by the year 2050 (28%).

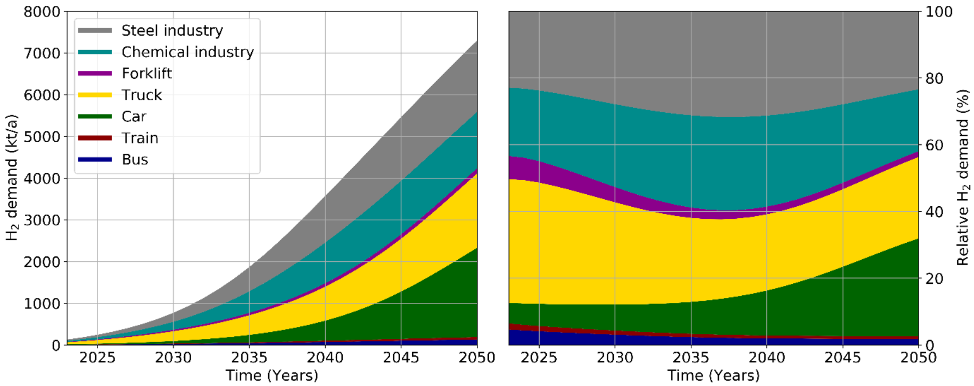

Figure 37. Derived temporal development of the cumulative hydrogen demand and demand structure in Germany up to the year 2050.

To investigate the spatial transition of demand, Figure 38 displays the hydrogen demand distribution for the years 2025 to 2050. Similar distribution patterns can be observed in both early market development during the years 2025 to 2030 and the more extensive market adoption in 2050. One of the main reasons for this stability is a consistently high fraction of hydrogen demand for the steel and chemical industries, which in turn creates highly concentrated hydrogen sinks, around which a regional infrastructure can be developed. The regions dominated by these industries, such as the Rhineland, Ruhr, and the Central German chemical triangle, stand out as early as the years 2025 and 2030. Additionally, as previously observed due to similar features of demand distribution, hydrogen consumption for trucks and cars provides a good fit between the regions, hence concentrating demand in the main population centers (see Figure 18). Consequently, major urban centers such as Berlin, Hamburg, Cologne and Munich act as major hydrogen sinks from the beginning of the market introduction phase. Non-electrified trains, buses and forklifts comprise only up to 15% of the market during the analysis period, and therefore do not affect the overall demand distribution in a substantial way. However, as was previously discussed, the relatively even distribution of these markets across the regions may be beneficial by providing additional load for infrastructure between the core demand areas and by being able to utilize more decentralized hydrogen production (see Section 3.1.2). The potential benefits of these smaller commercial vehicle markets will be further outlined in the following chapters.

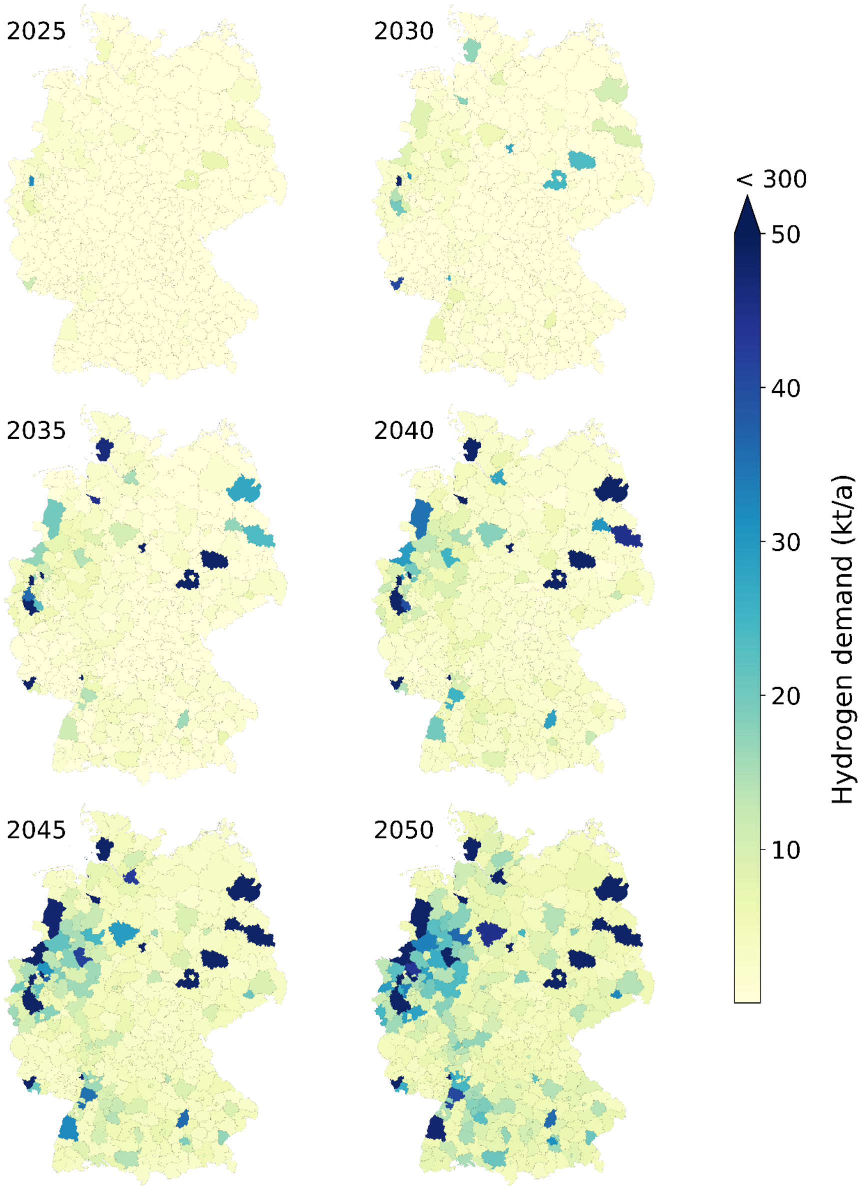

Figure 38. Distribution of the derived hydrogen demand scenario in Germany from 2025 to 2050.

To highlight the underlying structural differences of hydrogen demand amongst the regions, Figure 39 depicts the fractions of hydrogen demand for the steel and chemical industries, as well as transportation for individual NUTS3 regions. As was previously mentioned, the limited color scale is applied in order to improve the interpretability of the regions with minimal hydrogen demand. Detailed market-specific demand in each NUTS3 region is provided in Appendix D.

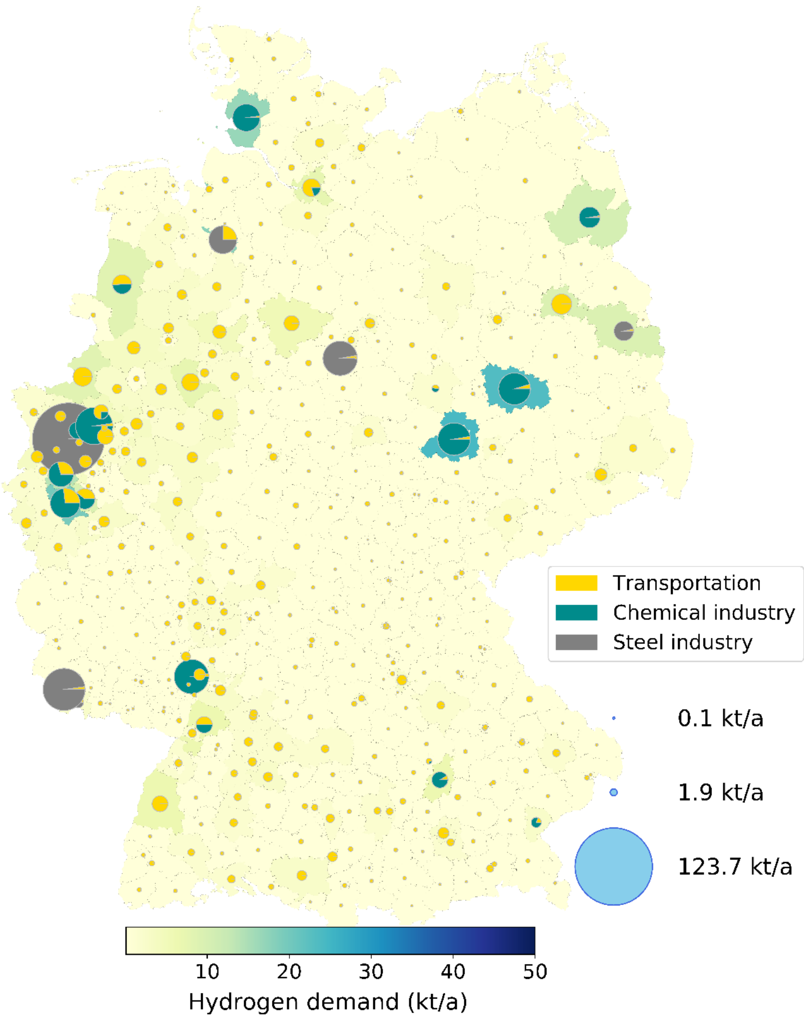

Figure 39. Derived hydrogen demand distribution and structure in Germany for the year 2030.

Figure 40 displays the structure of the hydrogen market for North-Rhine Westphalia for the year 2030. As previously noted, the Ruhr region (Duisburg, Gelsenkirchen) is highly dominated by industrial consumption, whereas the Rhineland area (Neuss, Cologne, Rhine-Erft) is characterized by a high fraction of both industrial and transport demand. Due to the high concentration of demand, these regions would be the primary drivers of pipeline infrastructure dedicated to hydrogen delivery. Regional population centers, such as Wuppertal, Dortmund and Unna, encompass a high diversity of the markets in the transportation sector, as none of the markets account for more than 60% of the consumption. Despite the high industrial demand, the Cologne region also shares a highly diverse hydrogen market, as the fraction of industrial entities is over 55%. Such a diversity of consumption makes these regions attractive for the initial market development, as the region's delivery infrastructure can be utilized by a broad set of potential consumers, allowing the distribution infrastructure to be optimized. More rural areas, such as Steinfurt, Borken and Gütersloh, are highly dominated by trucks, which account for over 75% of regional demand. The sparse distribution of population and the high fraction of hydrogen consumption for trucks in these areas underlines that these regions would especially benefit from the potential to utilize truck refueling stations for passenger cars, thus enabling the alleviation of the low initial utilization of hydrogen refueling stations. Furthermore, similar rural areas might benefit from the vicinity of renewable energy resources and associated decentralized hydrogen production from post-EEG wind power plants, whereas more urban areas must rely on either hydrogen delivery, locally-generated by-product hydrogen or available SMR capacities during the initial system development until the year 2030.

To summarize, this section outlined the development and distribution of hydrogen demand up to the year 2050. The market scenario is characterized by a balance between demand in industry and transportation, as both sectors remain within 40% to 60% of the overall market. Transportation demand exhibits an extensive transition, from considerable reliance on commercial captive vehicles and trucks in the initial years to a market structure dominated by passenger cars that provides 50% of hydrogen demand for transportation in 2050. Despite this shift in hydrogen demand for transportation, the overall distribution of the hydrogen market is only marginally affected, especially because approximately 50% of industrial consumption remains stable over time. Amongst the key observations is the potentially unique role of the regions combining high industry and transport demand, as these regions would benefit the most from the network effects of hydrogen delivery

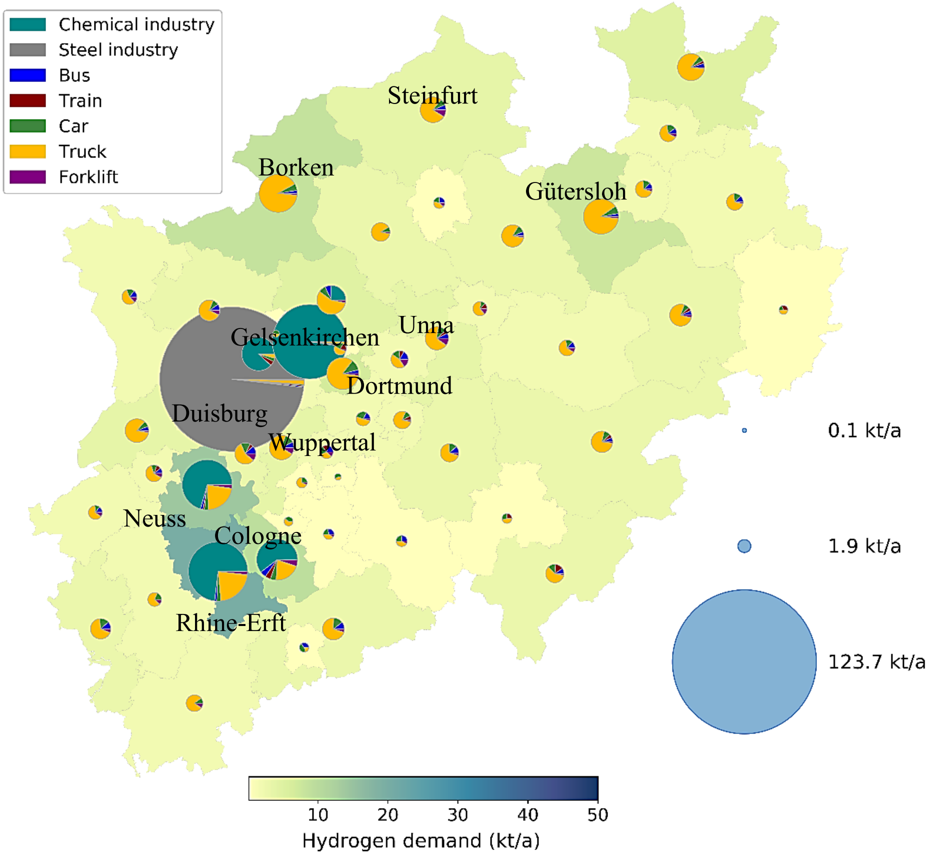

Figure 40. Derived hydrogen demand distribution and structure in North-Rhine Westphalia for the year 2030.

4.2 Infrastructure Implementation

Following the detailed evaluation of the hydrogen market transformation, the overall costs of the hydrogen introduction strategy are evaluated. Figure 41 demonstrates the development of the total hydrogen supply chain's cost for the analyzed pathways, including GH2 and LH2 trailers, as well as combined pipeline and trailer delivery. Substantial cost reductions of 30% to 40% can be observed in both cases of the LH2 truck and combined pipeline and trailer delivery supply chains, as hydrogen demand develops over time. Conversely, the cost of the supply chain with delivery by GH2 trailers increases, as the stable cost of delivery does not compensate for the increasing costs of supply caused by the declining fraction of SMR and by-product in the overall supply. In the following years, between 2030 and 2035, the GH2 trailer supply is surpassed by LH2 trailers, as well as combined pipeline and trailer delivery as the most cost-effective hydrogen supply option due to the increased utilization of the liquefaction units and pipelines.

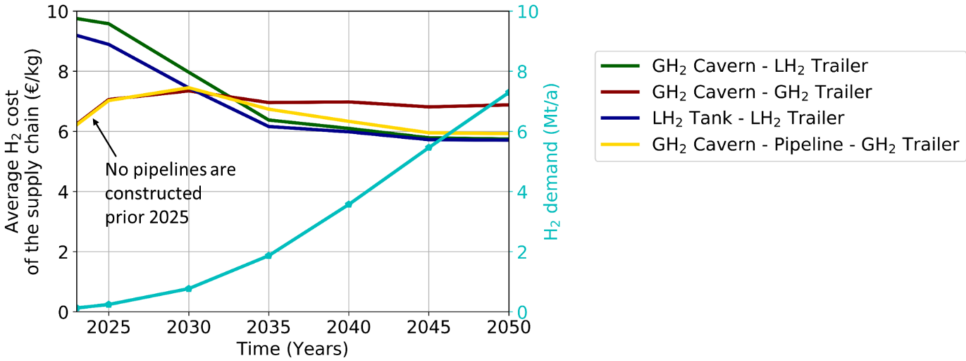

Figure 41. Comparison of the overall costs of the GH2 and LH2 hydrogen supply chains in Germany from 2023 to 2050. Including production, storage, processing and conditioning, transport, and refueling stations. Pipeline construction already includes an optimized reassignment of suitable pipelines.

Consequently, it can be noted that LH2 trailer delivery, as well as combined pipeline and GH2 trailer transport, offers the lowest long-term hydrogen delivery costs of 5.7 €/kg and 5.9 €/kg, respectively. In contrast, GH2 trailer delivery entails long-term costs of 6.9 €/kg, and so it is not cost-competitive with other alternatives. Comparable analyses of countrywide hydrogen delivery costs yield the results of 5.3 to 6.6 €/kg, showing that a combined GH2 pipeline and trailer transport and LH2 trailer delivery pathways are amongst the most cost-efficient [94, 179]. The main reasons for the observed deviation are different methodological approaches and the incorporation of hydrogen purification into the supply chain analysis, as well as the broader scope of analyzed consumer applications, thus leading to a significantly greater number of refueling stations, which affects the length and cost of the distribution. It should be noted that the long-term costs are essentially reached from 2030 to 2035, with the overall demand of 2 Mt p.a. thus requiring only 27% of the total anticipated demand of 7.5 Mt p.a. in 2050. The year 2030 is also characterized by the phased-out SMR units and the high concentration of supply at the import and centralized electrolysis locations. Hence, with a sufficiently high concentration of hydrogen supply, as well as the scaling of the delivery and refueling infrastructure, the loss of limited low-cost hydrogen production via SMR can be compensated.

The primary reason for the cost-effectiveness of the LH2 pathway is the increasing scale of the liquefaction units at the centralized hydrogen production sites and the growing amount of LH2 imports that do not require domestic liquefaction, which is cost- and energy-intensive. Furthermore, the aforementioned low costs of the LH2 refueling stations also increase the cost-effectiveness of the LH2 pathway. Alternatively, the combined GH2 pipeline and trailer pathway draws upon the pipeline transmission between the main supply and demand areas, as well as industrial sites, whereas smaller demands, such as refueling stations and less densely populated regions, are supplied by means of GH2 trailers. As the compression of hydrogen to the required pipeline pressure is less cost-intensive than liquefaction, this pathway is less affected by the increasing fraction of imports in the overall hydrogen supply.

The described cost effects can also be evaluated from the perspective of energy demand (see Figure 42). First, the impact of hydrogen imports can be observed, as by the year 2028, the domestic energy demand for hydrogen provision diminishes by more than 50%, from 51-58 kWh/kg to 24-25 kWh/kg. Furthermore, the remaining domestic hydrogen demand is primarily governed by hydrogen production from natural gas and renewable electricity, which is responsible for 80-90% of the supply chain demand. Consequently, the domestic energy demand is mainly determined by the development of the supply structure. Due to the energy-intensive liquefaction process, considerable differences in grid electricity consumption can be observed between GH2 and LH2 pathways, leading to an overall higher energy demand for the LH2 delivery system. However, with an increasing fraction of LH2 imports, this effect is significantly diminished.

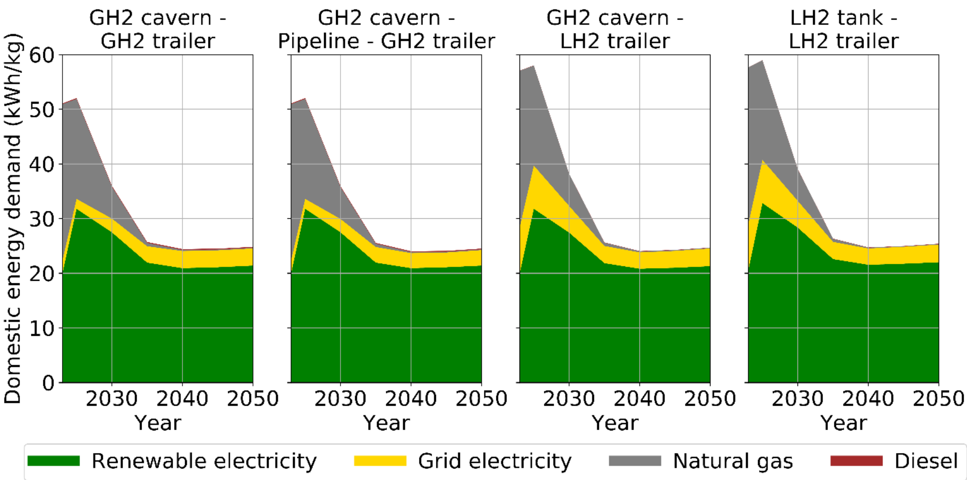

Figure 42. Domestic energy demand of the hydrogen supply chains in Germany from 2023 to 2050.

Consequently, the superior long-term results of LH2 delivery must be weighted against the substantially higher short-term cost of 9 to 9.8 €/kg, whereas GH2 delivery enables final hydrogen costs of 6 to 7.5 €/kg from 2023 to 2030. Thus, the LH2 pathway includes additional risks regarding the assumed boundary conditions' development and requires substantially higher foresight during the planning process. In contrast, through the continuous expansion of the pipeline network, GH2 enables more myopic infrastructure development by better optimizing the initial infrastructure introduction costs.

4.3 The Reconfiguration of Hydrogen Production and Storage

After the analysis of the development of hydrogen demand and the overall transition of the infrastructure, the following section describes the transition from the initial state of hydrogen production to a large and centralized supply by the year 2050. Furthermore, due to the interlinked requirements of the seasonal storage with domestic hydrogen production from intermittent renewable energy, this chapter explores the development of the medium-term and seasonal storage capacity.

As was previously stated for the domestic hydrogen generation pathways of electrolysis, SMR and by-product hydrogen were considered in this study (see Sub-chapter 3.2). While the potential of the domestic hydrogen production is derived from Robinius, the intermediate capacities for 2030 (5 GW_{el}) and 2040 (10 GW_{el}) are derived on the basis of the National Hydrogen Strategy of Germany [5]. From this potential, the estimated capacity of the stated electrolyzer projects is subtracted in order to determine the available potential for the optimization of the electrolysis capacity allocation between small- to medium-scale plants in post-EEG wind power plants and for large-scale central electrolysis. As for SMR and by-product hydrogen, the respective capacity is limited by the estimated potential of current generation (see Sub-chapter 3.2). The imports supply the remaining hydrogen demand, which cannot be covered by domestic production.

To begin with, Figure 43 depicts the overall transition of hydrogen production during the analysis period. In the initial phase, the supply of hydrogen is dominated by the existing and currently noted hydrogen productions, as well as available by-products and SMR hydrogen. Together, these sources account for up to 2/3 of the overall hydrogen production, whereas approximately 1/2 of the production relates to SMR and by-product hydrogen, thus underlying the importance of utilizing the existing industrial production capacity. However, these results indicate that existing and planned hydrogen capacity is not sufficient to cover the short-term demand for this scenario and that additional production capacities must be installed. This result is highlighted by the high initial fraction of decentralized production from post-EEG wind power plants, which contribute to 20% to 30% of the total hydrogen production. Thus, utilization of the otherwise unprofitable post-EEG power plants can offer a good opportunity for green hydrogen production in the short- to medium-term. By 2025, the gap between the existing energy infrastructure and increasing hydrogen demand begins to widen and must be closed by the new centralized electrolysis projects. Hydrogen imports start to play a more critical role in the hydrogen supply only as the overall installed capacity of electrolyzers reaches the 5 GW_{el} mark by the end of the 2020s, thus highlighting the role of domestic hydrogen production during the initial market introduction phase. These results are congruent with the neighboring countries, as the first hydrogen pipelines to Germany are planned in the Netherlands after the year 2026 [6]. Nevertheless, as the national hydrogen strategy of Germany assumes 30% to 50% higher demand by 2030 than this demand scenario [5], hydrogen imports might already be required in the earlier stages of market introduction.

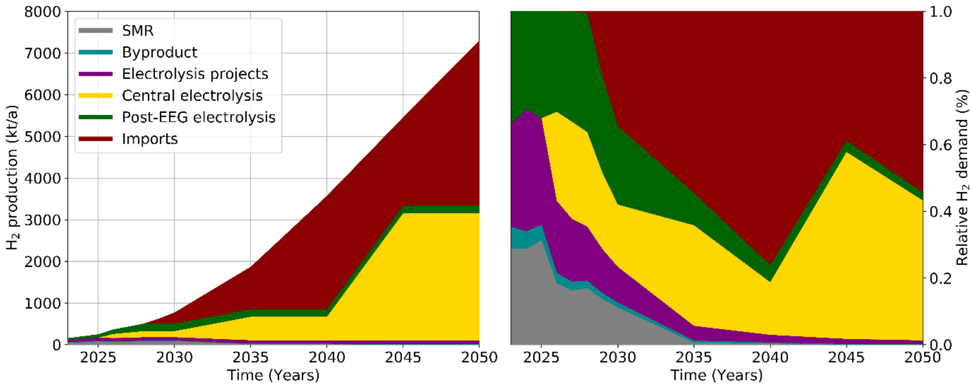

Figure 43. Development and structure of hydrogen production in Germany up to the year 2050.

Such significant changes in the production structure have a major impact on the spatial allocation of the production regions. Figure 44 displays the distribution of the hydrogen supply during the years 2025 to 2050. First, it can be observed that the rate of relative diversity of the hydrogen production results in a highly decentralized supply structure in 2025. The production is relatively evenly distributed among the regions in northwest and northeastern Germany, as well as industrial plants in North Rhine-Westphalia, Central German chemical triangle and Ludwigshafen. Accordingly, south German regions play only a minor role in production with hydrogen as the only by-product, and SMR hydrogen is produced in these regions. Despite the broad distribution of production, the impact of major electrolysis commercialization projects, such as Element Eins [46] and Hybridge [48], is clearly visible, as both of these projects are located in the northwestern areas of Germany. A similar picture can also be observed for the year 2030, which is characterized by the expansion of hydrogen production with additional electrolysis plants and hydrogen imports at planned LNG terminal locations, as well as hydrogen pipelines from the Netherlands. However, increasing the capacity of centralized electrolysis and imports also leads to a substantially larger concentration of production. In subsequent years, the growing, centralized electrolysis capacity and imports increase the trend of the supply concentration on the coast and in the northwestern areas near the border with the Netherlands. At the same time, decentralized generation and post-EEG sites remain relatively stable, and hydrogen production in industrial areas declines after the phase-out of SMR production in 2030. These results are in accordance with the findings from the literature that show an increasing centralization of production over time [254, 255].

Secondly, despite the described structural changes in the hydrogen supply, except for SMR, the capacities in the individual regions are either stable or steadily growing, as indicated by the darker coloring of the regions between the time steps. This fact has twofold implications for the development of the hydrogen delivery infrastructure. First, the stability of electrolyzer locations and core production centers alleviate the associated risk of long-term planning and implementation of the pipelines, as well as the storage infrastructure. Secondly, distributed hydrogen generation from post-EEG wind power plants makes a substantial contribution not only in the short term, but also to allow the diversification of production in the mid-term (see Appendix C).

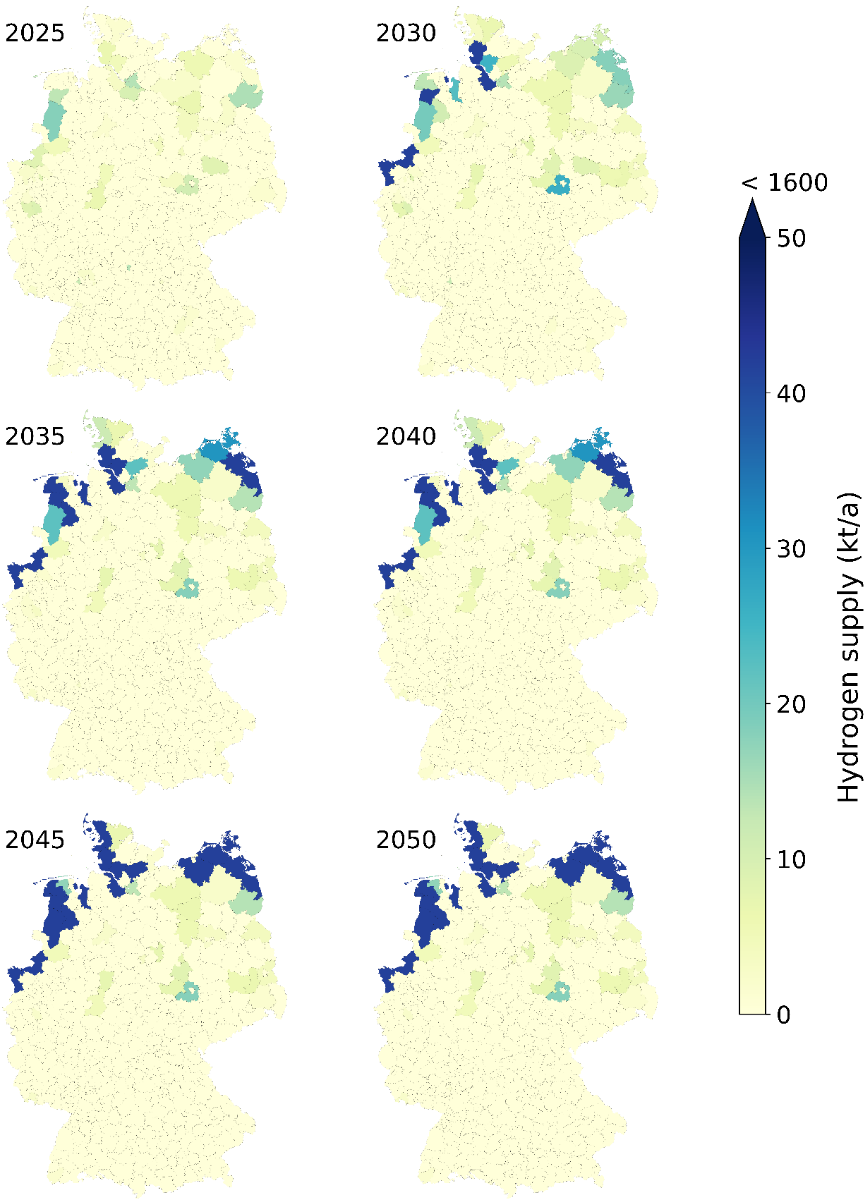

Figure 44. Derived spatial development of hydrogen production in Germany from 2025 to 2050. Includes SMR and by-product, post-EEG non-repowerable wind power, electrolysis projects and imports. Renewable energy surplus of wind onshore and off-shore after Robinius [10].

Figure 45 shows the cost development of the previously described structure of the hydrogen supply. It can be observed that the total cost of supply remains relatively stable over time. The initially elevated green hydrogen production cost is balanced by the high fraction of low-cost by-product and grey hydrogen, thus enabling a hydrogen supply of 3.3 €/kg in the initial years. Similar to these results, other studies have also shown a positive effect of SMR during the introduction phase [233, 273]. Furthermore, it should be noted that the hydrogen cost remains stable between 2025 and 2030, despite the diminishing fraction of SMR, thus indicating a substantial cost reduction for electrolytic hydrogen production. After that, with the phasing out of SMR in 2030 and the limited potential of by-product hydrogen, the cost of supply is being governed by electrolytic and imported hydrogen, thus leading to a hydrogen supply cost of 4.0-3.7 €/kg. These results are more conservative than findings reported in the literature, which estimate a cost parity between SMR and electrolytic hydrogen production by 2030 [233].

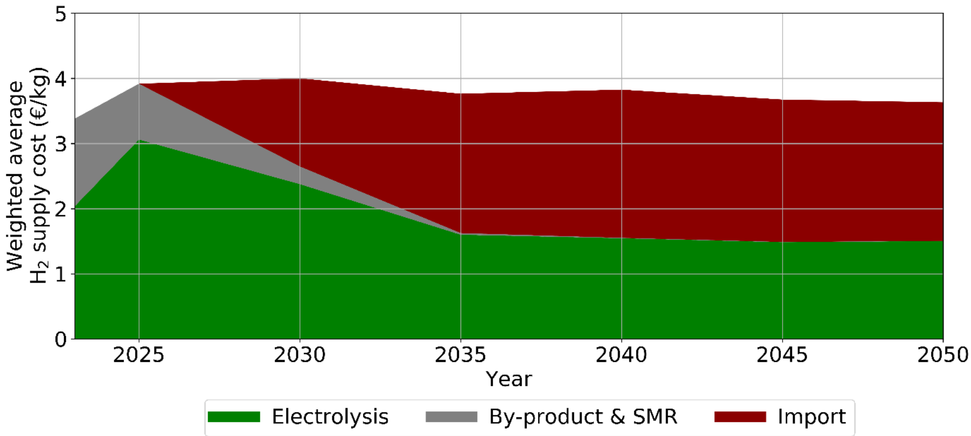

Figure 45. Structure of the hydrogen supply and the resulting weighted average hydrogen cost from 2023 to 2050.

Figure 46 displays the allocation of different hydrogen supply options for the year 2030, which is characterized by the highest diversity of hydrogen. As was previously observed, the large fraction of centralized electrolysis and hydrogen imports concentrate supply in the border regions to the Netherlands and the coast. Hydrogen generation from post-EEG wind power plants is very prominent in the eastern areas. Accordingly, post-EEG generation creates the possibility to balance the supply concentration in the northwest areas and enables production to be shifted closer to the demand centers, thus reducing the delivery distances.

Hydrogen production from SMR is concentrated in the regions with a large chemical industry presence, such as the Rhineland, including Cologne and Rhine-Erft Kreis, Gelsenkirchen, Ludwigshafen and the Central German chemical triangle areas, thus enabling hydrogen production in the western and central regions of the country. By-product hydrogen only makes up a small fraction of the overall supply and is distributed similarly to SMR but is more concentrated in the regions in the Rhine-Ruhr area, Ludwigshafen, Stade and the Central German chemical triangle region. It can be concluded that SMR and by-product hydrogen only marginally alleviate the low production capacity in the southern regions of the country, as only Ludwigshafen could offer more substantial hydrogen production (14.4 kt/a). Similarly to the regions in the south of Germany, SMR and by-product hydrogen are essential sources of local hydrogen production in North Rhine-Westphalia. Moreover, these sources add flexibility in the regions that feature a broad set of production options types, such as the Central German chemical triangle and Heide, thus facilitating their role as key hydrogen supply centers. For more detailed assessment of the production structure in the year 2025 please see Appendix E.

In accordance with the structure of the hydrogen supply, the capacity for short-term and seasonal storage capacity is expanded at the locations of the sources on the basis of the assumed 15 d and 60 d storage duration (see Section 3.3.1). From Figure 47, it can be noted that, in line with the observed concentration of production, by 2031, the individual supply points reach the assumed necessary capacity for the smallest salt cavern construction of 1.9 TWh. The construction of seasonal storage substantially increases the overall storage capacity, which is used for the storage of both domestic and import hydrogen. When compared with Figure 43, it is apparent that the year 2031 is the first time step after the available capacity of SMR is abandoned for hydrogen production. Thus, the earlier shift from SMR towards electrolyzer-based production and imports can lead to the earlier development of salt caverns. Salt cavern construction can potentially be accelerated by connecting multiple sources to a single storage site in order to increase the overall throughput. By the year 2050, the total storage capacity will reach 38 TWh, resulting in the storage of 16.4% of overall demanded hydrogen.

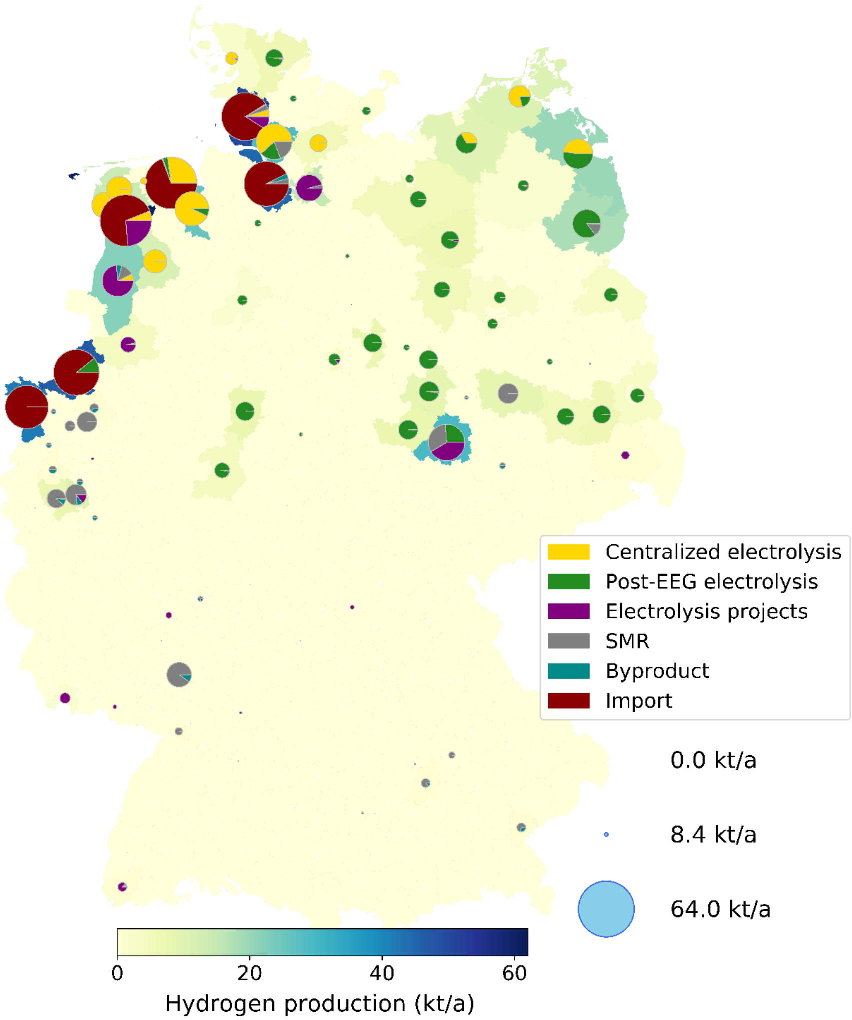

Figure 46. Distribution and structure of hydrogen production in Germany in the year 2030. Includes SMR and by-product, post-EEG non-repowerable wind power, electrolysis projects and imports. Renewable energy surplus of wind onshore and off-shore after Robinius [10].

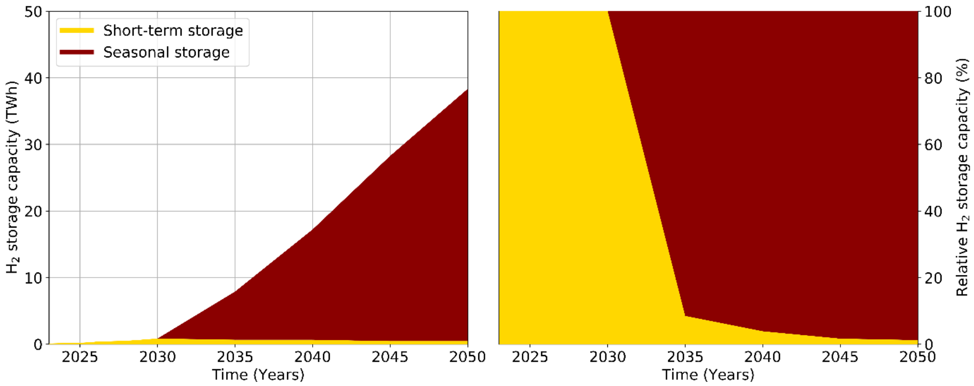

Figure 47. Development of the derived capacity and structure of hydrogen storage from 2023 to 2050. Short-term storage of 15 days in tanks and seasonal storage of 60 days in salt caverns. The assumed minimal size of the salt cavern is 70,000 m3 with 150 bar.

From Figure 48, it can be determined that, in line with the supply concentration in the northwest parts of the country, salt caverns are constructed for seasonal storage along the North Sea coast and the border regions to the Netherlands. The comparison of locations with the sites of the existing salt caverns shows that potentially underutilized salt caverns could be reassigned for hydrogen storage with only minimal implications for the delivery infrastructure, as both types of storage sites lie in relative vicinity to each other. Furthermore, such a reassignment of salt caverns could potentially accelerate the implementation of hydrogen storage, as it could rely on already existing caverns. However, a more detailed analysis of the natural gas market and the availability of salt caverns would be required to incorporate the reassignment of existing salt caverns into the introduction strategy of the hydrogen infrastructure.

In summary, the imports of hydrogen only start to play a more critical role in the hydrogen supply as the overall installed capacity of electrolyzers reaches the 5 GW_{el} mark by the end of the 2020s, thus highlighting the role of domestic hydrogen production during the initial market introduction phase. Moreover, hydrogen production from non-repowerable, post-EEG wind power plants is a significant contributor to the initial hydrogen generation, providing 20% to 30% of the overall supply prior to 2030. The low-cost by-product and grey hydrogen can absorb the initially elevated green hydrogen production cost, thus enabling average hydrogen supply costs of between 3.2 €/kg and 3.7 €/kg before grey hydrogen is phased out in 2030. However, due to the limited available capacity, it was concluded that SMR and by-product hydrogen only marginally alleviate the low hydrogen production level in the southern regions of the country. With respect to storage, seasonal storage, such as salt caverns, were constructed in the early 2030s when the individual supply points reached the assumed necessary capacity for the smallest salt cavern construction of 1.9 TWh. However, an earlier shift away from SMR towards centralized, electrolyzer-based production and imports can lead to the earlier development of long-term storage units.

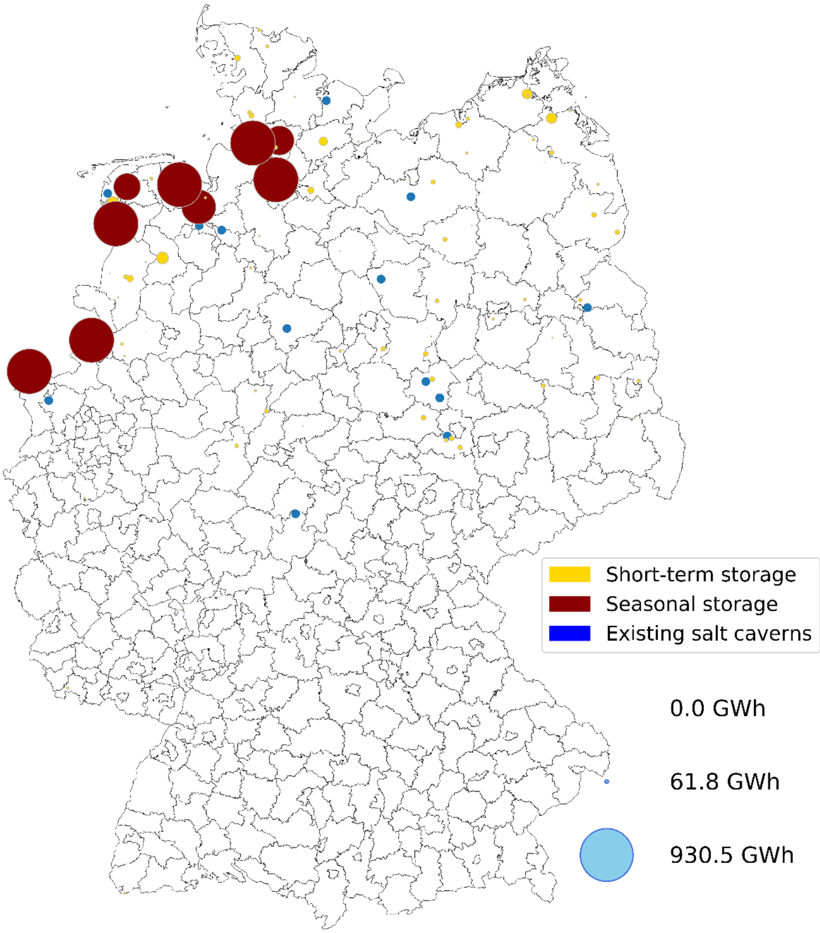

Figure 48. Distribution of hydrogen storage capacity in the year 2035 and positions of currently existing salt cavern sites.

4.4 The Evolution of the Hydrogen Delivery Infrastructure

In this section, the development of the hydrogen delivery infrastructure connecting the described sources and sinks is compared for LH2 and GH2 trailers, as well as GH2 pipeline pathways (see Figure 11). First, the development of the individual cost components for each of the supply chains is investigated. Close links between the chosen storage and delivery options, as well as the necessary processing steps, require consideration of all of these elements in a single analysis. Furthermore, as the chosen delivery option has an impact on the refueling station cost (see Section 3.5), the costs of refueling are also taken into account. Therefore, the assessment encompasses all elements of the supply chain except the supply, the costs of which are not influenced by the delivery pathway and were separately derived in Sub-chapter 4.3. Secondly, the derived cost results for individual supply chains are discussed against the backdrop of the visualized supply chain maps, depicting infrastructure development during the years 2023 to 2050. Finally, this section is concluded with a detailed assessment of the core characteristics of the respective supply chains, such as the required number of delivery trucks and pipeline length, as well as the maximum capacity of an individual trailer and pipeline route.

From Figure 49, it can be determined that both pathways for LH2 trailer delivery, including GH2 and LH2 storage options, provide substantial cost reductions from the introduction phase until the year 2050. The delivery cost for both pathways diminishes from 5.8 €/kg and 6.4 €/kg to 2.1 €/kg over the period from 2023 to 2050. A comparable cost reduction of 50% within 10 years for hydrogen supply chain components was also discussed in the literature; however, these estimates also include the reduction of electrolysis costs [233]. The cost reduction of production for both options indicates that despite the scale effects, the cost of LH2 storage increased until 2030 to 2035. This result was caused by the observed reconfiguration of hydrogen production, which increasingly shifted from SMR and by-product hydrogen production without storage to import and electrolyzers associated with storage units. From the comparison of both GH2 and LH2 storage options, it is apparent that LH2 storage offers a low-cost storage option over the entire period of the analysis. While salt caverns are the superior storage option for long-term storage (see Sub-section 2.1.5.2), the significant number of smaller production sites does not reach the capacity criterion for salt cavern construction, leading to medium-term storage in GH2 tanks during the initial phase. As previously mentioned in Sub-section 2.1.5.2, the GH2 tank is amongst the most expensive storage options, hence leading to a situation in which a minority of the storage capacity (see Figure 23) drives the majority of the storage costs of GH2 storage. Conversely, LH2 storage is more versatile with respect to the capacity of the storage and, therefore, is less affected by the fragmented production structure.

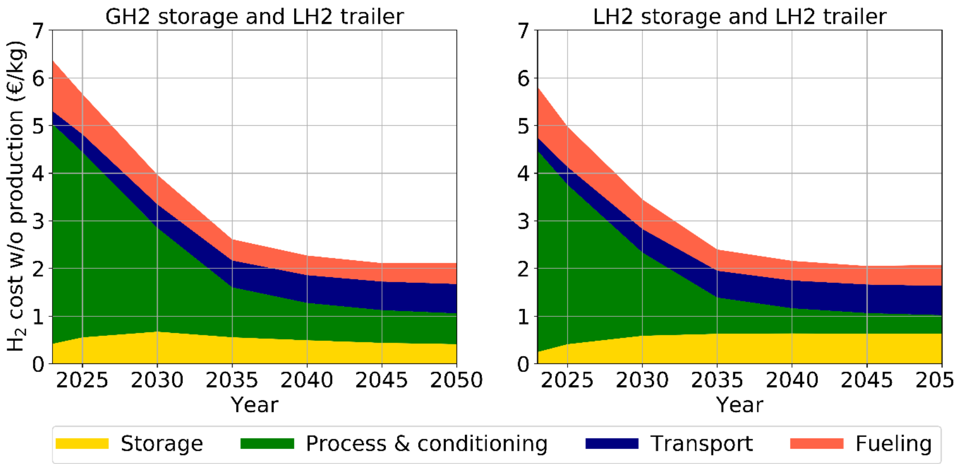

Figure 49. Costs of the hydrogen supply chain for LH2 delivery pathways without production costs in Germany from 2023 to 2050.

Nevertheless, the main component defining the cost of both pathways is the processing and conditioning of hydrogen. In the case of non-seaborne delivery from abroad, hydrogen liquefaction is required, thus adding additional costs to the supply chain. The diverse production patterns during the initial market introduction years of 2023 to 2030 and the limited capacity of the individual liquefaction units at the sites of production lead to exceptionally high processing and conditioning costs. Then, as the concentration of hydrogen production to a smaller number of large-scale units advances further, the costs of processing and conditioning rapidly decline until they reach 0.4 €/kg, which is primarily driven by the increased scale of the liquefaction plants and the inclining fraction of imports in the overall hydrogen supply. As previously discussed, one of the primary reasons for the increasing supply concentration is the phase out of SMR units after 2030. Hence, the short investment horizon in these locations diminishes the feasibility of LH2 delivery, as liquefaction units at SMR sites would cease to operate after 2030.

Other components of the supply chain, such as LH2 delivery and refueling stations, remain the same for both pathways, but exhibit features that characterize LH2 delivery. First, similarly to LH2 storage, the delivery of LH2 trailers offers a cost-effective delivery option during the early introduction phase for 0.3 €/kg. However, as demand increases the number of delivery destinations and hence the overall delivery distance, the average cost of LH2 delivery grows to 0.6 €/kg in 2050. Conversely, the learning and scaling effects of refueling stations observed in Section 3.5.2 lead to the average cost of refueling stations declining from 1.1 €/kg in 2023 to 0.44 €/kg in 2050. Consequently, the increasing cost of delivery is overcompensated by the diminishing expenditures at refueling stations, leading to an overall cost reduction for delivery and refueling of 0.3 €/kg. However, it must be pointed out that these average costs of refueling are diluted by approximately 50% of demand in industry, which does not require any refueling stations. Hence, the average refueling costs for the transportation sector are approximately 2.2 €/kg and 0.88 €/kg in 2023 and 2050, respectively.

Alternatively to LH2 delivery, hydrogen can be transported via GH2 trailers and pipelines. Furthermore, as discussed in Sub-chapter 3.4, the use of GH2 pipeline pathway allows us to consider the reassignment of existing natural gas pipelines, thus additionally reducing the cost of delivery. Figure 50 compares the transmission cost for the identified reassignment options of pipeline without modification (PWM) and O2 inhibitor (see Section 3.4.1) with a new hydrogen pipeline for different levels of overall demand. In order to ensure comparability amongst the options, the pipeline grid's composition is set as fixed, as otherwise the methodology for the positioning of hubs for trailer delivery (see Section 3.4.2) would result in different geometries for the three cases.

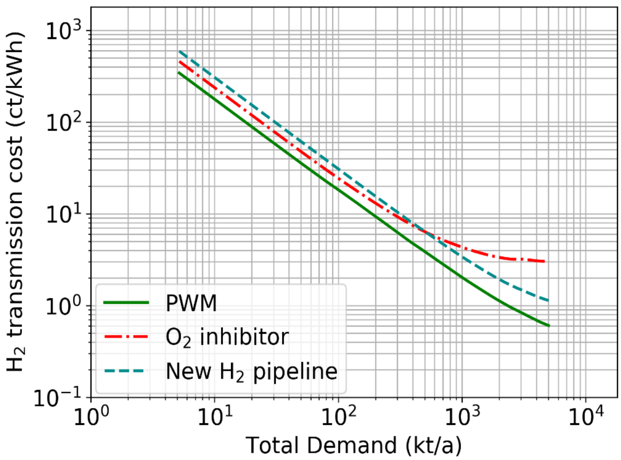

Figure 50. Comparison of hydrogen transmission costs for the PWM, O2 inhibitor, and a new pipeline for a fixed pipeline grid connecting all regions.

The results indicate rapid cost reduction in a countrywide H_2 pipeline system with increasing demand showing that, with sufficient market size, competitive network costs of 0.6-1 ct/kWh can be achieved. However, the cost reduction effects observed earlier are diminished by 50% due to the limited pipeline availability for reassignment and the methodological requirement to connect county centers with new hydrogen pipelines. Furthermore, these results confirm the positive effect of PWM reassignment, as the system-wide costs are consistently lower than in the case of a new pipeline system. An O_2 inhibitor and PWM reassignment lead to cost reductions of up to 20% and 60%, respectively. In accordance with earlier observations, we find that for small overall hydrogen demand (< 250 kt p.a.), an O_2 inhibitor provides a good pipeline reassignment option, but the low pipeline utilization significantly diminishes its cost reduction potential. At larger throughputs, due to the rapidly increasing operating costs at an overall demand of 500 kt p.a., the O_2 inhibitor reaches the cost of the entirely new hydrogen pipeline system. Consequently, only PWM will be further assessed for a countrywide hydrogen system analysis.

Figure 51 presents the cost development for both GH2 delivery pathways, encompassing GH2 truck transport and pipeline transmission with GH2 truck distribution. Both pathways have the same cost structure during the 2023-2025 period, as no hydrogen pipelines are employed before 2025, and hence only truck-based hydrogen transport takes place. The cost development of hydrogen storage observed for GH2 storage with LH2 delivery is also replicated in this case, and is thus primarily governed by the cost of medium-term storage in GH2 tanks at the smaller supply facilities. Accordingly, due to the growing fraction of hydrogen production associated with storage, the cost of storage increases up until 2030. After that, the increasing concentration of production and construction of salt caverns leads to substantial cost reductions for hydrogen storage. The processing and conditioning costs for GH2 hydrogen provision are significantly lower than was previously observed for LH2 pathways, diminishing from 0.6 €/kg in 2023 to 0.33 €/kg in 2050. The main reason for this difference is that the compression of hydrogen is associated with significantly lower investment costs than liquefication and hence is less affected by the smaller unit scale, associated with the fragmented production structure observed during the initial period of market introduction (see Figure 46). The cost of refueling stations for GH2 delivery are observed to fall from 1.2 €/kg in 2023 to 0.6 €/kg in 2050, and so are in line with the previous observation regarding higher station costs for GH2 than LH2 delivery (see Sub-chapter 3.5). As for LH2, the average cost of refueling is diluted by industrial demand, and hence the actual refueling costs for the transportation sector are, on average, approximately 2.4 €/kg and 1.2 €/kg in the years 2023 and 2050. The cost of hydrogen distribution experiences a sharp increase of 40% during the period 2023-2025, from 0.65 €/kg to 1 €/kg, as the number of delivery destinations grows. After that, the pace of increasing costs decelerates until the average cost of GH2 trailer delivery reaches 1.9 €/kg in 2050. Accordingly, the GH2 trailer is subject to much higher sensitivity to the number of destinations, which impacts the delivery distance and un-/loading time of the trailer, than its LH2 trailer counterpart. The main reason for this difference is the lower energy density of the 500 bar trailer, making it less suitable for high-throughput delivery in a large grid of hydrogen sinks required in the later years of market development. This effect is partially balanced out by the declining cost of refueling and storage, as well as processing and conditioning, such that the overall cost of the pathway is only marginally changed, from 2.9 €/kg in 2023 to 3.1 €/kg in 2050. They therefore provide a strong contrast to LH2 delivery, which encompasses significantly higher initial costs, while also offering 35% lower long-term costs.

In the case of combined pipeline and trailer delivery, the transport costs begin to deviate from GH2 trailer delivery with the construction of the first pipelines between 2025 and 2030. With the implemented methodology of subsequent pipeline deployment (see Section 3.4.2), these pipelines not only absorb the highly concentrated demand at the core demand areas but also provide the hubs from where subsequent trailer distribution is carried out. Therefore, pipeline construction enables the observed rise in the trailer delivery cost to be limited to less than 1.2 €/kg in 2030. Subsequently, this period is then followed by a further decrease in the cost of trailer delivery, reaching 0.6 €/kg in 2050, which is on par with the value for 2023. Based on these results, it can be concluded that pipeline transmission can successfully alleviate the drawbacks of GH2 trailer delivery associated with high throughput and a growing network of refueling stations. However, this measure comes at the cost of facilitating a pipeline network dedicated to hydrogen delivery. It can be observed that, during the initial years 2023-2035, despite its positive effect on trailer distribution, the introduction of pipelines increases the overall cost of hydrogen transport. The main reason for this is that, up to 2030, SMR production in industrial areas diminishes the local hydrogen demand concentration. Nevertheless, as consumption at the demand clusters increases after the SMR phase out in 2030, the combination of pipeline and trailer delivery surpasses the cost of GH2 trailer transport as the more cost-effective delivery option and yields costs for pipeline transmission of 0.26 €/kg in 2050. The cost of refueling develops along the lines observed for GH2 trailers, falling from an average cost of 1.2 €/kg in 2025 to 0.6 €/kg in 2050.

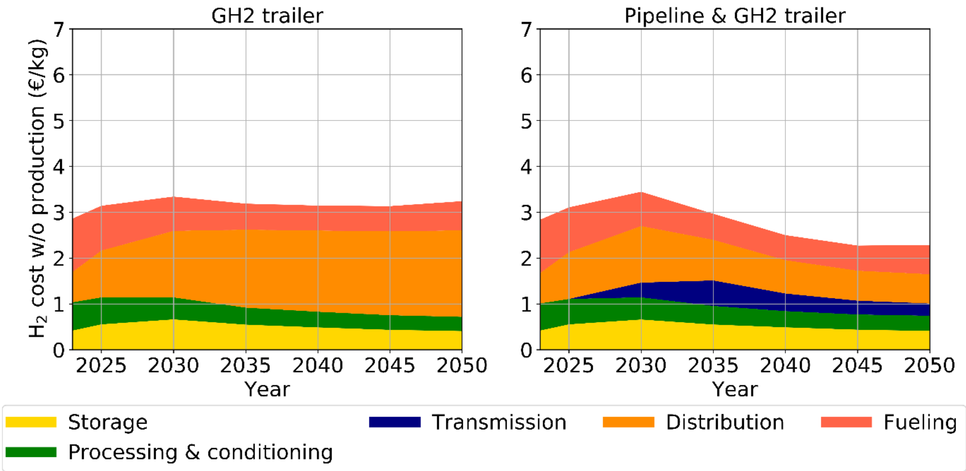

Figure 51. Costs of the hydrogen supply chain for GH2 delivery pathways without production cost in Germany from 2023 to 2050.

To explore the impact of the increasing demand and associated number of refueling stations mentioned above, Figure 52 depicts the required number of trailers and the length of pipeline for the investigated GH2 and LH2 pathways. From the comparison of the cases where only trailers are applied, approximately three times more GH2 (55,000) than LH2 (16,600) trailers are required in order to facilitate hydrogen transport. The ratio of refueling stations is smaller than that between the transport capacity of GH2 and LH2 trailers because of the negative impact of the increased loading and unloading times associated with a higher number of destinations. Consequently, a delivery relying solely on GH2 trailers would, therefore, increase the number of trucks on the streets by more than 27%, as there are less than 200,000 registered semi-trucks in Germany [182]. In comparison, the combined pipeline and GH2 trailer delivery require approximately the same number as in the case of LH2 trailers (19,500). The main reasons for such a reduction of trailers are the supply of highly concentrated demand areas via pipelines, whereas trailers are applied to the supply of sparse demand regions, as well as for the final distribution of hydrogen from the pipeline hubs. Hence, such a method enables the impact of gaseous hydrogen delivery on road transport to be limited. This can be achieved by the construction of up to 4150 km of pipelines by 2050, which is shorter, by almost a factor of 10, than the current network of natural gas transmission pipelines in Germany of approximately

40,000 km [187], which includes a substantially higher level of redundancies. Such findings were also confirmed by other analyses in the literature that showed preferable pipeline supply lines to the major demand centers, whereas GH2 trailers are more optimally applied to supplying smaller cities [154, 273]. Furthermore, the fact that approximately 1/4 of that pipeline length would be required already by 2030 indicates the need for extensive efforts to facilitate the required pipeline projects on time. However, the reassignment of natural gas pipelines can not only reduce the pipeline cost (see Section 3.4.1) but also enable pipeline implementation to be accelerated, thus shortening the required project time and reducing the risk. Hence the reassignment of natural gas pipelines is a key component for the initial development of the hydrogen pipeline infrastructure.

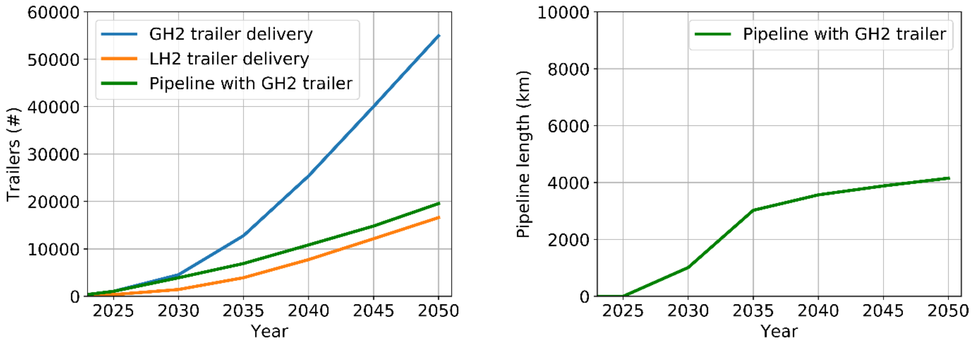

Figure 52. Development of the required trailers and pipeline length for pipeline transmission for the GH2 and LH2 pathways in Germany from 2023 to 2050.

To better comprehend the discussed features of supply chain development, Figure 53 and Figure 54 depict the spatial evolution of delivery based solely on trailers and a combination of pipelines and trailers. In Figure 53, one can observe the increasing number of refueling stations and associated delivery routes from the individual source locations. Furthermore, the growing concentration of trailers along the transportation routes from north to south indicates the consequences of concentrated hydrogen production in coastal regions. In 2050, the high capacity of trailer delivery is closely associated with demand at the industrial sites, such as in North Rhine-Westphalia, Ludwigshafen, as well as in the Central German chemical triangle. In the case of the Hamburg, Berlin, Rhein-Main, Stuttgart and Munich areas, the urban population centers lead to a more concentrated trailer flow. Consequently, in the case of GH2 delivery, this increases the overall number of semi-trucks by more than 27%, which would place a substantial strain on the traffic and road infrastructure around the population centers, especially in the event of high industry concentration, as is the case for the Ruhr and Rhineland regions in North Rhine-Westphalia. As was previously noted, a combination of pipeline and trailer transport can reduce the required number of GH2 trailers by more than 60%, thus reaching a comparable number of trailers as required for LH2 delivery. Hence, it can be argued that pipeline transport is crucial for viable implementation if the pathway for GH2 supply is chosen. Additionally, it has to be noted that the current assessment does not consider LH2 transport via trains or domestic waterways that could further reduce the number of required trailers and thus the delivery cost.

Figure 54 displays the evolution of such a combined pipeline and trailer delivery system. By exploring the different time steps, it can be determined that, due to the applied methodology, pipeline delivery only becomes viable after 2025. By 2030, the pipeline system is substantially developed and connects the major industrial and population centers in North Rhine-Westphalia with the centralized sources at the North Sea coast and imports from the Netherlands. According to the applied methodology (see Section 3.4.1), more than 50% of pipeline throughput is facilitated by reassigned natural gas pipelines. For more detailed maps see Appendix E.

By 2050, the hydrogen pipeline network connects almost all regions in Germany and supplies over 95% of the demand emanating from the industrial sector. Moreover, the hubs along the pipeline routes provide the necessary supply for local hydrogen distribution in the region. Therefore, no trailer flow to the industrial hubs is observed and the importance of urban population centers, such as Rhine-Ruhr, Berlin and Rhine-Main, is relatively diminished. Nevertheless, as the less urbanized areas have an insufficiently concentrated level of consumption to justify pipeline delivery, trailer supply from the coast to central Germany can still be practiced. The eastern part of the country can be characterized by a substantial number of smaller hydrogen sources at post-EEG wind locations that are connected to the pipeline system to supply the regional demand centers in the Central German chemical triangle, as well as Berlin, thus highlighting the impact of the fractured nature of the hydrogen supply in that region. The general nature of the network differs from the current natural gas system, as no transit flows to neighboring countries and imports from the eastern border, which are an essential feature of the current natural gas system, were considered in this assessment.

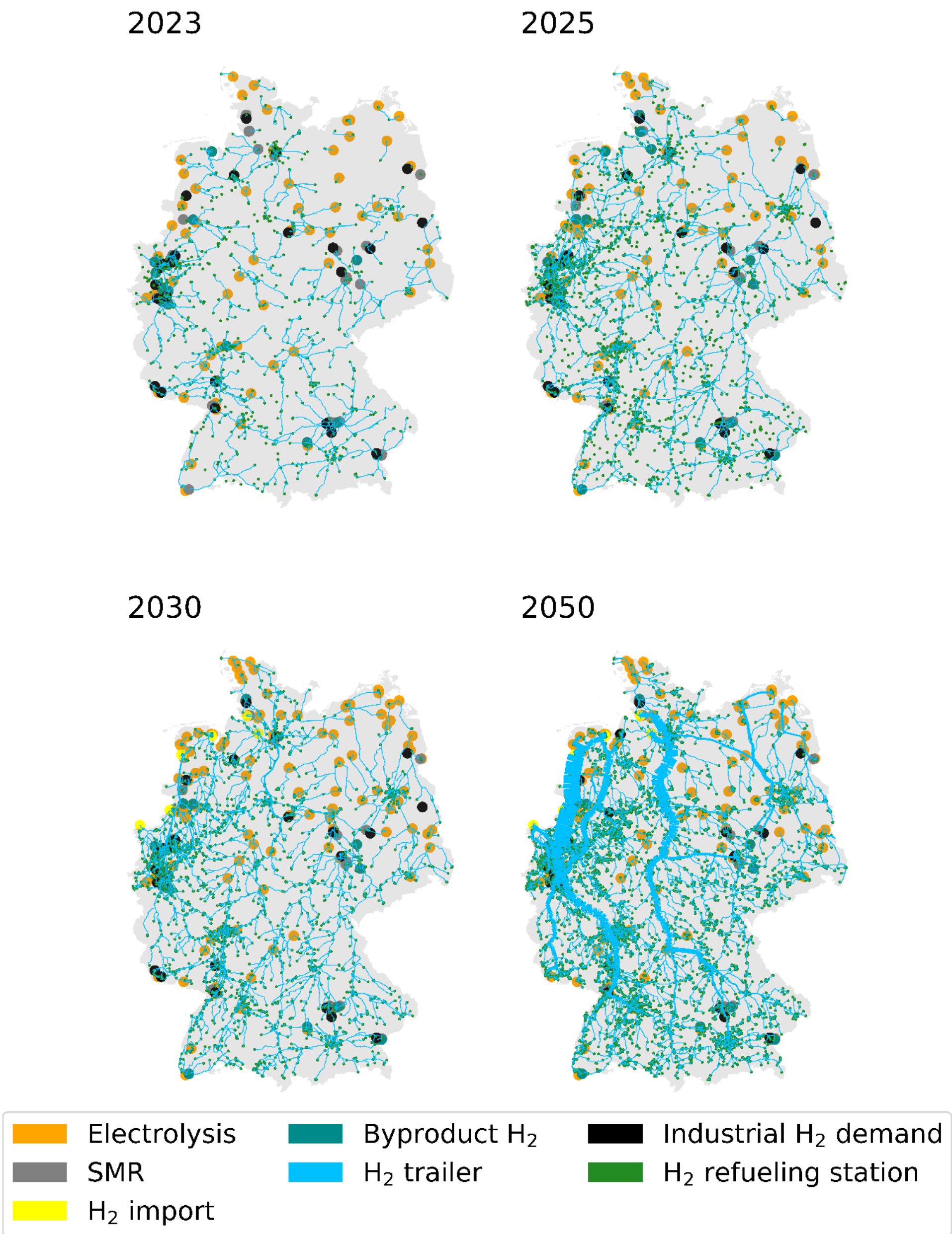

Figure 53. Infrastructure development of GH2 and LH2 trailer delivery in Germany from 2023 to 2050.

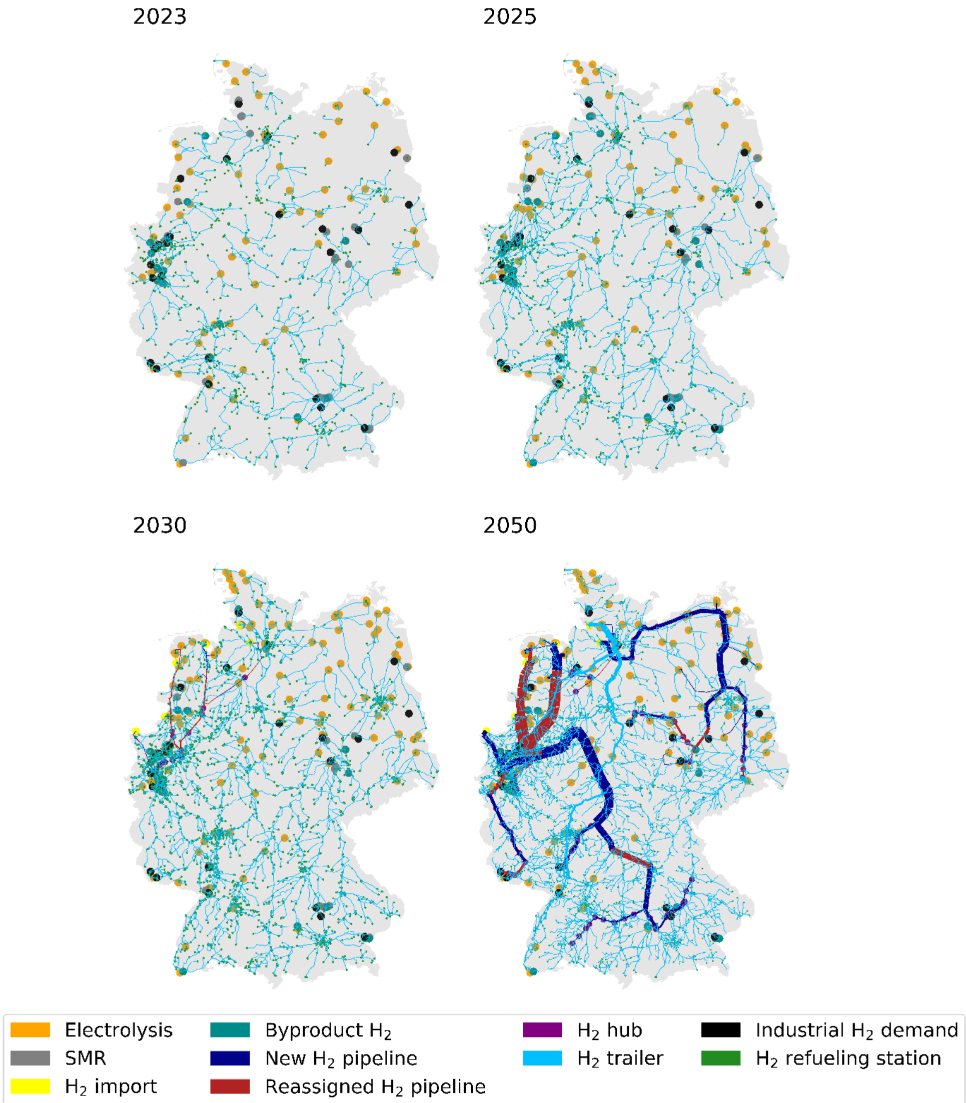

Figure 54. Infrastructure development of pipeline and GH2 trailer delivery in Germany from 2023 to 2050.

When these results are compared to the recently proposed European hydrogen backbone network [8] and the draft of the German gas network development plan 2020-2030 [7], several key features can be observed. First, both assessments and this study identify the same regions in the north and west of the country as being the frontrunners regarding the development of a dedicated hydrogen pipeline infrastructure. All three studies envision a connection between the industrial and population centers in North Rhine-Westphalia with the coastal regions on the North

Sea. Furthermore, all three studies indicate a high percentage of reassigned pipelines in the initial hydrogen grid by 2030. Despite the identified similarities, different methodologies lead to some deviations regarding the actual routes of the hydrogen pipelines. The European perspective and consideration of the selected projects to connect industrial hubs in Europe led to substantially more pipeline connections from east to west, thus linking industrial sites in northwestern Germany to northern France, Belgium and the Netherlands. The drafted German gas network development plan is similar to the approach of this study, as it also considers hydrogen production and demand projects, hydrogen production from post-EEG wind onshore plants and import from the Netherlands. However, in this case, only a pipeline-based hydrogen delivery or admixture to natural gas is assessed. Based on these results, the gas flow simulation is facilitated. Consequently, due to the differences regarding the underlying data and the modeled reduction of low calorific gas (L-gas) flows, the proposed hydrogen grid consists primarily of unused L-gas pipelines. Nevertheless, given the intense focus on L-gas pipelines, thus increasing both the network length and the fraction of reassigned pipelines, the general features of the pipeline network, with its total length of 1300 km and 88% reassigned pipelines, are comparable to this work (950 km and 51% reassigned pipelines).

In summary, it was shown that the long-term costs for supply chains without production reach 2.3 €/kg and 2.1 €/kg for GH2 and LH2, respectively. The limited capacity of individual liquefaction units at the sites of production during the initial market introduction years 2023 to 2030 leads to high processing costs, which result in LH2 pathway costs without production of 6.4 €/kg to 3.5 €/kg between 2023 to 2030. The initial pipeline development for the combined pipeline and GH2 trailer delivery surpasses GH2 trailer delivery after 2030 as the most cost-effective GH2 delivery option. The maximum additional cost for pipeline implementation is 0.1 €/kg across all GH2 trailer delivery. Therefore, it was concluded that hydrogen pipelines could already be cost-efficiently implemented between the years 2025 and 2030. Furthermore, comparing the determined initial hydrogen pipeline grid of 950 km in 2030 with other recent assessments showed that all assessments identify the same regions in the northwest of the country as frontrunners in the development of a dedicated hydrogen pipeline infrastructure. Furthermore, all three studies indicate a high percentage (over 50%) of reassigned pipelines in the initial hydrogen grid by 2030.

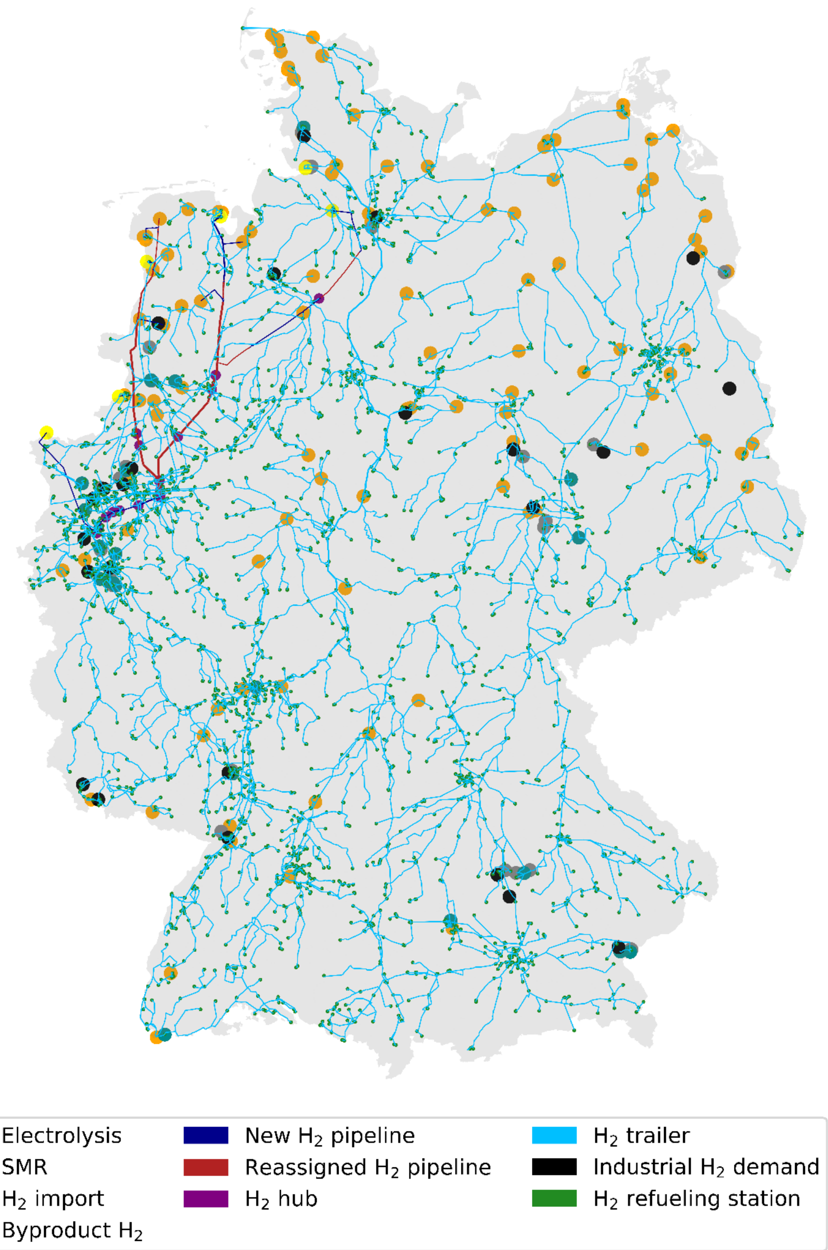

Figure 55. Infrastructure of pipeline and GH2 trailer delivery in Germany in 2030.

4.5 The Changeover of the Hydrogen Refueling Infrastructure

In close coordination with the hydrogen demand transition, the hydrogen refueling infrastructure is evolving from a sparse collection of small refueling stations into a dense network of large-scale stations. This projected transition can be observed in Figure 56 and Figure 57 for passenger cars and trucks, respectively. As previously discussed (see Section 3.1.2), the capacity allocation of the public refueling stations in the NUTS3 regions is governed by an optimization problem with constraints pertaining to 10% and 5% station coverage for cars and trucks, respectively, before stations with capacities larger than 212 kg/d can be constructed. The resulting long-term composition of the overall refueling infrastructure is similar for cars and trucks, with the largest refueling stations dominating the infrastructure with more than 60% of the overall throughput. Nevertheless, the transition pathways of both cars and trucks highlight some key differences between these markets.

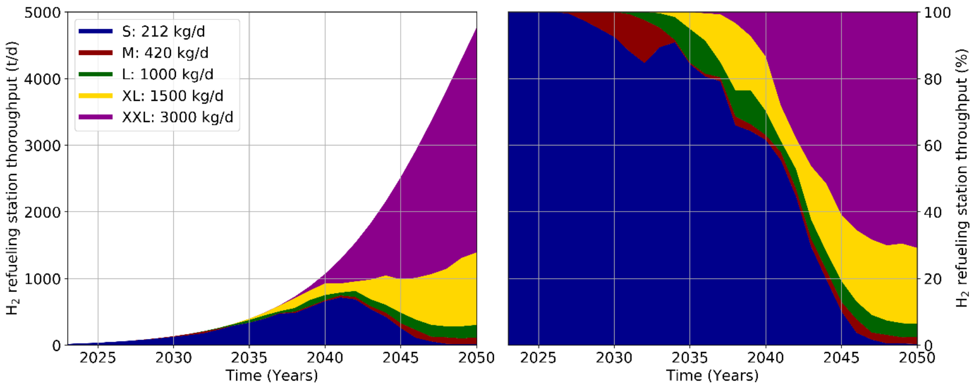

Figure 56. Development of different size classes for public passenger car refueling stations in Germany from 2023 to 2050.

First, as previously discussed, the truck market is anticipated to be dominated by the early adopters of fuel cell vehicles, whereas the passenger car market encompasses a larger set of imitators, thus resulting in lagging adoption of fuel cell vehicles (see Section 3.1.1). Together with a different specific fuel demand of vehicles, these adoption rates translate into a substantially deviating development of hydrogen throughput in the respective refueling stations. Secondly, differences regarding the distribution of various station size classes arise because of distinct attributes of spatial distribution and assumed minimal station coverage, which governs the minimal number of smallest stations before more extensive refueling facilities can be deployed. Given the different overall throughput in a given year, these spatial and coverage factors lead to the significantly later construction of larger refueling stations for passenger cars than for trucks. Accordingly, due to there being a high number of rural areas with relatively low hydrogen demand (see Figure 39), even by the year 2040, 60% of the station throughput for passenger cars is facilitated in small stations. In contrast to passenger cars, the throughput of the smallest truck stations already drops below 50% by 2025, as larger stations are increasingly deployed from the start of the analysis period.

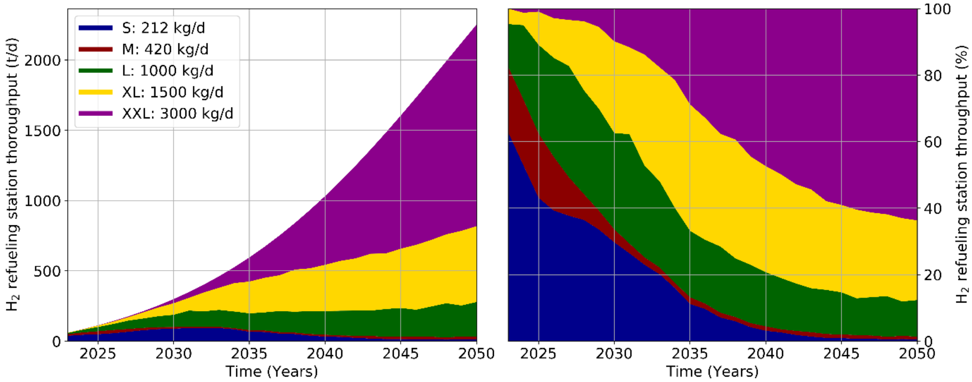

Figure 57. Development of different size classes for public truck refueling stations in Germany from 2023 to 2050.

The dominance of the smallest refueling stations for passenger cars and a large number of refueling stations dedicated to trucks offers an opportunity to reduce the costs of the overall system by enabling the multiple utilization of a single refueling station for both markets. In such a case, the station coverage would not be affected, while the total investment costs could be significantly reduced. In Figure 58, it can be observed that the highest cost savings observed above are primarily associated with small-scale demand for both pairs of the combination, thus highlighting the cost-benefits of avoided small individual refueling stations. Consequently, as scale effects enable a reduction in the specific station costs (see Sub-chapter 3.5), the cost savings diminish with the increasing station capacity. The extreme cases of supplying small and large demand and the observed cost savings offer only marginal cost savings as an additional investment cost, and the complexity of the refueling station is not justified by a minimal increase in onsite demand. A comparison of both extreme cases indicates that small truck stations would benefit more from multiple utilization. The main reason for this finding is that small truck stations can piggyback on larger car refueling stations with only minimal additional costs, as 700 bar car stations have among the highest investment costs for refueling stations (see Sub-chapter 3.5). Alternatively, in the case of a small car refueling station attached to a larger truck station, aside from the dispenser, additional investments for high-pressure cascades are required, hence undermining the cost-saving potential.

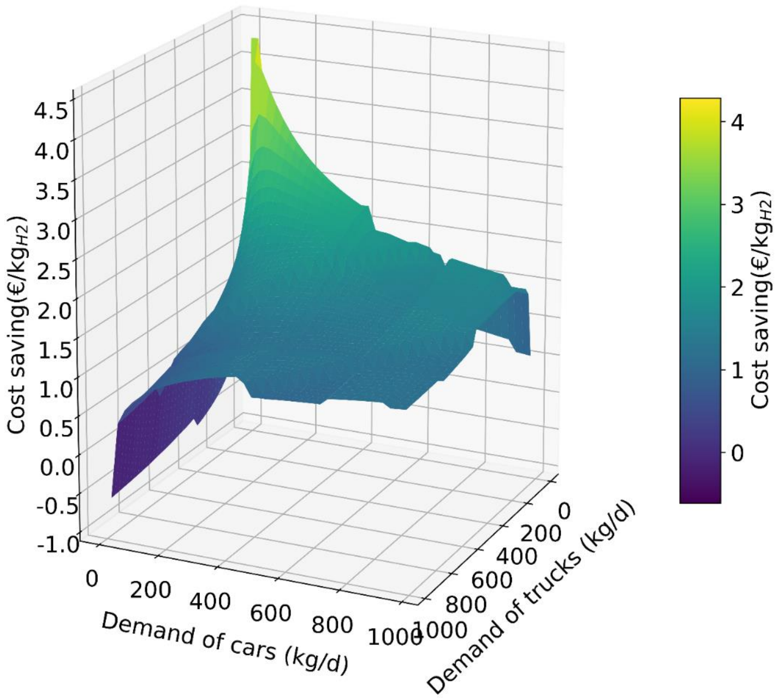

Figure 58. Cost savings for the multiple use of a refueling station (cascade design) for passenger cars and trucks. Demand ranges from 5 kg/d to 1000 kg/d.

Such a refueling station, which substitutes two separate car and truck stations, should ideally be located in close proximity to the original station locations so that the station's coverage in the region, as well as the prioritized placement of refueling stations on the main roads, are not affected. Thus, only locations selected for both truck and car station implementation are considered for further analysis. When the demand distributions of the generated refueling station data (see Figure 59) are compared, it can be observed that the results correspond to the previously discussed structure of station size classes (Figure 56). Hence, the majority of car stations are smaller than 212 kg/d (S-size class). Accordingly, a substantial number of multiple-use hydrogen refueling stations (HRS) gravitate towards an unfavorable configuration of a medium to large truck station with very little car demand. The positive relationship between the amount of hydrogen demand for cars at the multi-use of HRS and the achieved cost savings indicate that, due to the broader spectrum of station sizes for trucks (see Figure 57), demand for cars is the defining parameter for beneficial multi-use HRS design. From the spatial placement of the multi-use HRS, it can be deduced that positive cost savings correlate not only with demand for cars but also with urban centers, as these are more likely to contain larger refueling stations for cars. Thus, it can be concluded that highly diverging speeds of market adoption for cars and trucks will substantially limit the general cost-savings potential of multi-use HRS during the introduction phase. Thus, the accelerated adoption of cars and further region-specific assessments are necessary in order to optimally apply the multi-use HRS strategy.

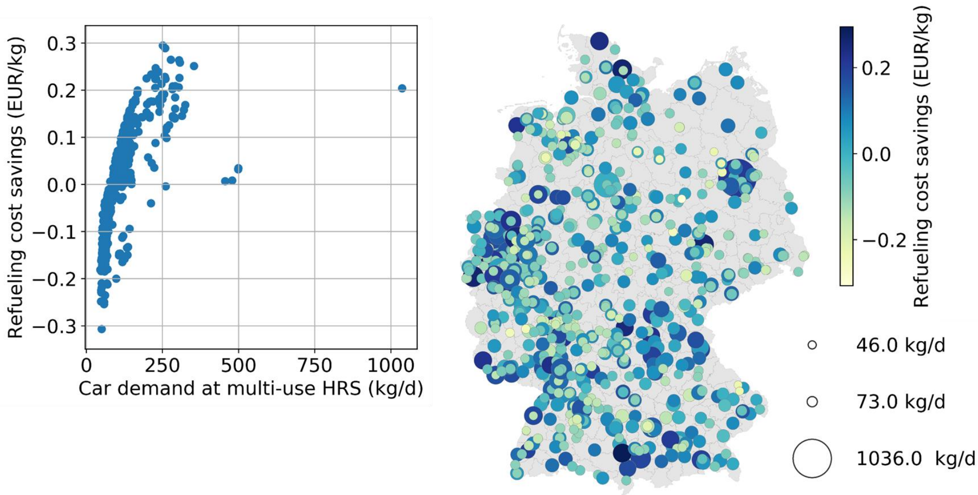

Figure 59. Refueling cost savings and hydrogen demand for cars at multi-use hydrogen refueling station for cars and trucks in 2030.

To summarize, in this section the transition of the refueling infrastructure was analyzed, which is characterized by a shift from a sparse network of small stations to a large grid of high throughput stations. First, structural differences in the refueling infrastructure for cars and trucks are observed, as large truck stations are deployed significantly earlier than is the case for their counterparts for passenger cars. Consequently, the passenger car refueling infrastructure is dominated by the smallest refueling stations through the year 2040. Second, given this finding and the extensive refueling infrastructure for other vehicle markets, the cost-benefits of utilizing a refueling station to supply two different markets were assessed. As was previously identified in sub-section 3.5.2, the highest cost savings, from combining two refueling stations, are observed in the case of combination pairs containing 350 bar and 700 bar vehicles (10% higher mean savings), as 700 bar stations have a higher technical complexity and specific investment costs (see Section 3.5.2). Accordingly, the features of multi-use HRS were assessed for the two most important applications in the transport sector – trucks and cars. It was shown that cost savings are achieved in the case of both applications having a comparable demand at the level of multi-use HRS, with the smallest demands offering the highest cost-savings of up to 4-5 €/kg. The main reason for this finding is the cost of the market-specific extensions of refueling stations that reconfigure the optimal design of the cascade and main compressor. In the case of an insufficient utilization of the additional components, the overall design of multi-use HRS becomes more expensive than two separate stations. When the multi-use HRS concept was applied to the generated station data for 2030, it was found that, due to the diverging speeds of market penetration for cars and trucks, a substantial number of car stations are too small to justify the additional complexity of multi-use HRS. Hence, while still providing an attractive cost-saving option in the long-term, multi-use HRS does not have a meaningful impact on overall costs during the introduction phase.

4.6 Strategy Evaluation

Given the long-term parameter uncertainties and difference of long-term costs of less than 4% between LH2 trailers and combined pipelines and GH2 trailer pathways, no clear preference of one pathway over the other can be stated. Therefore, the resulting cost gap between the hydrogen pathways and the benchmark costs for transportation and industry until 2030 are evaluated. Furthermore, relevant environmental policies, such as the National Emissions Trading System (NETS), renewable energy targets for grid electricity and prices for European Emission Allowances (EUA) are also considered for evaluating the final hydrogen and benchmark costs. Note that the following evaluation does not include substantial R&D expenditures, which are necessary to achieve the assumed technology improvements. Table 21 describes the definition of the benchmark costs for hydrogen alternatives in transportation and industry. The assumed pre-tax cost, conversion efficiency and CO_2-intensity are then applied to the policy measures to compute the final benchmark costs.

Table 21. Definition of benchmark costs for transport and industry sectors [68].

Parameter	Transportation	Industry	Comments
Energy carrier	Gasoline	Grey hydrogen	SMR for the industry sector
CO_2 intensity	73.1 tCO_2/TJ	56.1 tCO_2/TJ [1]	Diesel: 74.1 tCO_2/TJ
Pre-tax cost	0.069 €/kWh [2]	0.06 €/kWh	Diesel: 0.064 €/kWh [2]
Conversion efficiency	-	73%	SMR for the industry sector
Energy efficiency factor	2.1	-	$\eta_{gasoline}$ = 69 kWh/100km [2] η_{diesel} = 67 kWh/100km [2] η_{FCEV} = 33 kWh/100 km

[1] Natural gas; [2] 10-year mean.

Due to the similar CO_2 footprints of gasoline and diesel, we select the former as being a representative benchmark for transportation. To account for the actual quality of the provided service, the calculated gasoline benchmark is also corrected by the comparison of internal combustion vehicle (ICV) and FCEV real-world efficiencies. Due to the high uncertainty regarding future ICV hybridization and efficiency development, it is assumed that the future of both ICV and FCEV efficiency develops at the same pace. In the case of industrial hydrogen feedstock, natural gas-based steam methane reforming is used as the reference benchmark.

Figure 60 depicts the values considered for the EUA prices, carbon tax and the anticipated CO_2 intensity of the German electricity mix up until the year 2030. The EUA prices are derived from the mid-term EUA price trajectory of 23 and 28 €/t CO_2 in 2025 and 2030, respectively [14]. The CO_2 prices in NETS are set to 55 €/t CO_2 in 2025, with an introduction of auctions in a price range of 55-65 €/t CO_2 in the subsequent years [16]. For the purposes of this study, the price development is extrapolated to 2030 based on the CO_2 price slope from 2021 to 2025. Finally, the emission intensity of the electricity mix is derived from the -55% GHG emission reduction target in 2030 by the German Federal Government, which leads to a reduction in emissions from 764 g/kWh_{el} in 1990 to 344 g/kWh_{el} in 2030 [3, 15]. Against the backdrop of these policies, the pathway costs of the hydrogen supply chains and benchmark costs are then computed.

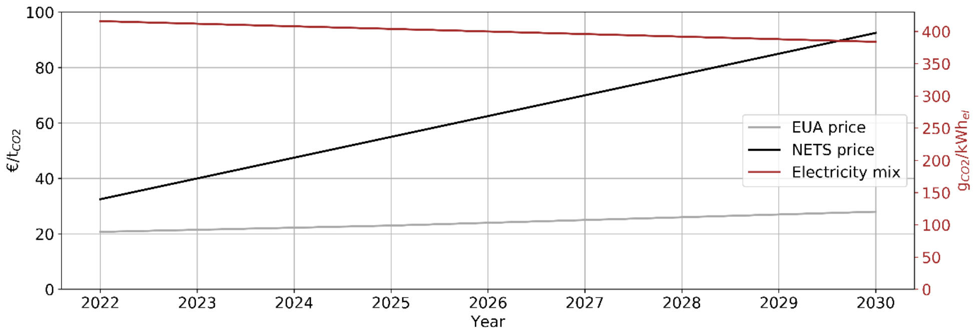

Figure 60. Considered values for policy measures of ETS, carbon tax, and CO_2 intensity of the electricity grid through 2030 resulting from emission reductions goals by the German Federal Government.

Figure 61 (a) portrays the development of the resulting costs of hydrogen and the respective benchmark cost from 2023 to 2030. It can be perceived that over the observation period, the average costs of hydrogen are higher than the pre-tax benchmark costs, indicating that currently implemented planed NETS CO_2 costs are insufficient to provide a pre-tax cost parity with hydrogen fuel. Nevertheless, the diminishing costs of the hydrogen supply chains lead to a marginal cost difference to gasoline benchmark of 2.7-4.6 ct/kWh in the year 2030. These findings are more conservative than in the literature, which showed break-even cashflows seven years after the introduction of the infrastructure [268]. As was previously observed, long-term hydrogen costs are estimated to reach 5.7 €/kg to 5.9 €/kg (17.1 – 17.7 ct/kWh), providing long-term cost benefits compared with the gasoline benchmark in 2030. The same cannot be said about the natural gas benchmark derived from the EUA price corridor for natural gas, which lies significantly below the final hydrogen cost in 2030, as well as the observed long-term costs. This fact highlights the substantial economic challenge of hydrogen adoption in the industrial sector. When fuel and energy taxes are also considered for the benchmarks, it is apparent that gasoline, primarily because of lower engine efficiency, becomes a more expensive fuel than hydrogen. Accordingly, temporally-limited tax breaks can be applied to hydrogen fuel to provide cost-parity for consumers. Similarly, as before, a different picture is observed in the case of the natural gas benchmark. Current energy taxes are insufficient to bridge the gap between the benchmark and hydrogen costs. As a result of the observed cost differences to the pre-tax benchmark costs, a cost-gap for the consumer is established that can be reduced by tax breaks for hydrogen or alternative incentive measures.

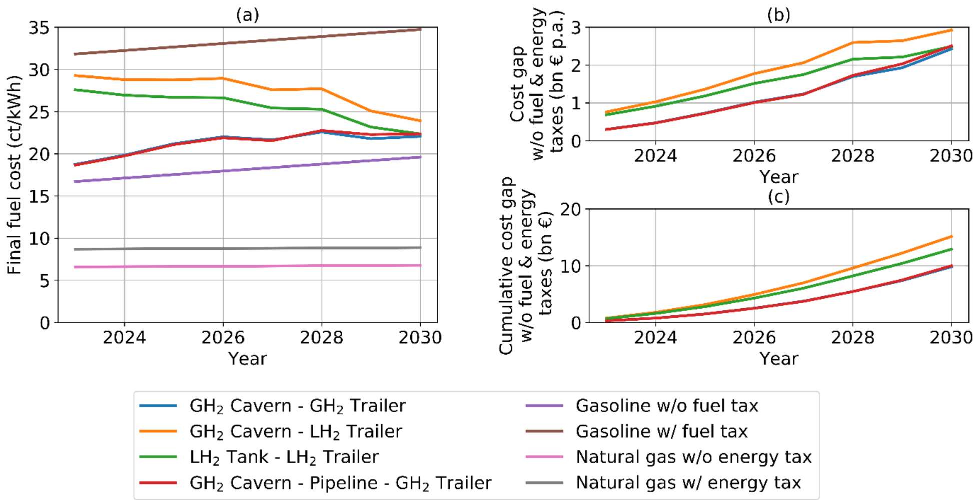

Figure 61. Comparison of the final fuel cost of hydrogen with the benchmark cost and the resulting cost gap in Germany from 2023 to 2030.

Figure 61 (b) and (c) depict the yearly and cumulative cost-gap appearing for each of the hydrogen supply chains, respectively. With the increasing demand and diminishing cost difference between the hydrogen and benchmark costs, the yearly gap increases until the year 2030. Therefore, the yearly cost gap reaches its maximum value of 2.4 to 2.9 bn. € p. a. These results account for approximately only a third of the currently implemented tax breaks for diesel fuel, leading to the estimated cost of 7.75 bn € p.a. in 2014 [17][5] and indicating that the cost can be covered by reducing the subsidies for diesel instead of raising or creating new taxes. Consequently, due to the positive yearly gap, the additional cumulative cost of hydrogen increases to an overall expenditure of between 9.8 and 15.1 bn €, with the GH2 pathways having the lowest introduction costs. These are 40% to 115% higher than the overall domestic expenditures planned in the National Hydrogen Strategy of 7 bn € through 2030 [5], indicating the need for additional support measures, especially as the costs related to the fuel switch in transportation and industry are not considered in this work.

To better assess the structure of the estimated additional costs, Figure 62 displays the disaggregated cost gap for transportation and industry benchmarks, where the different infrastructure requirements, such as refueling stations for transport, are considered. In the case of transportation, the yearly cost gap for each pathway reaches

[5] Aggregated cost of energy tax for diesel, including commercial road freight transport and passenger cars in comparison to the energy tax levels for gasoline.

its peak in the period of 2028 to 2030 at expenditures of 0.6 to 1 bn € p.a., with the pathway of GH2 caverns with LH2 trailer delivery being consistently the most expensive. Consequently, the cumulative cost gap reaches 3.2 to 5.7 bn € in 2030, where LH2 delivery is consistently more expensive than the GH2 pathways. The combined pipeline and trailer pathway is only marginally more expensive (+0.08 bn €) than hydrogen transport via GH2 trailers, thus offering the cost-effective introduction of a superior delivery option in the long term. Furthermore, these costs stand against the 75% lower number of required GH2 trailers, thus alleviating the burden on road traffic, especially in urban and industrial areas. In the case of industry, despite the omission of costs for refueling stations, the yearly cost gap reaches its peak in 2030 between 1.8 and 2.1 bn € p.a. Accordingly, the additional cumulative expenditures reach 6.5 to 9.4 bn €, leading to significantly higher introduction costs. It can be concluded that, regardless of the chosen supply pathway, industry accounts for approximately two thirds of the overall gap, whereas transportation causes only one third of the additional expenditures. In light of the fact that transportation and industry have roughly equal market shares (58% and 42% in 2023 and 49% and 51% in 2030, respectively), this finding highlights the economic challenge of extensive hydrogen introduction in the industry sector. Alternatively, it can be argued that a parallel adoption of fuel cell vehicles in the transport sector is essential for the introduction of hydrogen in industry, as it creates flexibility for sharing the initial burden of infrastructure introduction.

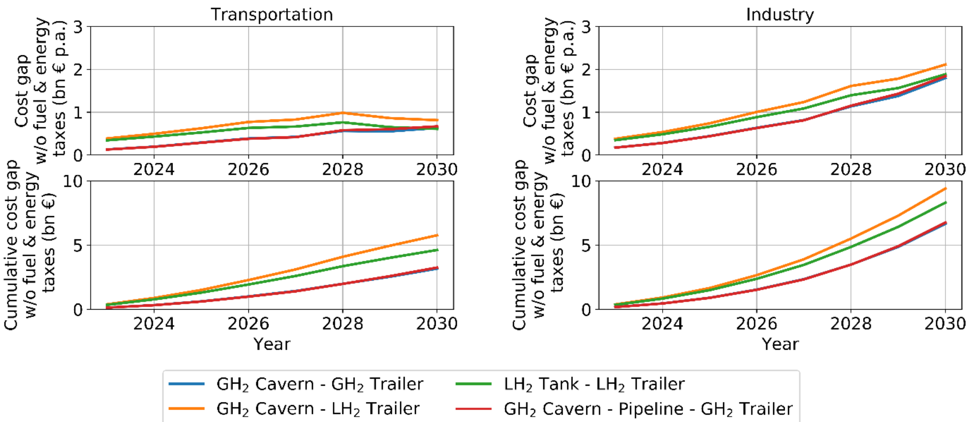

Figure 62. Resulting yearly and cumulative cost gap between hydrogen and benchmark cost for transportation and industry in Germany from 2023 to 2030.

4.7 Sensitivity Analysis

In order to assess the robustness of the derived cost gap occurring between 2023 and 2030, a sensitivity analysis of the main assumptions is conducted. Figure 63 depicts the resulting cumulative cost gap in the case of the introduction of only transportation or industry, thus discarding any synergy effects of the infrastructure between these markets. It can be perceived that, in line with the previous observations, LH2 delivery pathways are substantially more sensitive to market size which, in the case of an equal hydrogen provision structure, has an impact on the scale and utilization of the liquefaction units. Accordingly, in the case of a single market introduction, the LH2 cost gap would increase by 1.3 to 1.4 bn € and 1.1 to 1.2 bn € for separate market introduction strategies for transportation and industry, respectively. In the case of the GH2 pathways with 0.06 to 0.38 bn €, the value of synergies is smaller because the scale effects are counteracted by the increased delivery distances and costs (see Figure 51). Thus, the impact on industry is 30% to 60% higher than on transportation, as it relies more on the scaling of the pipeline network.

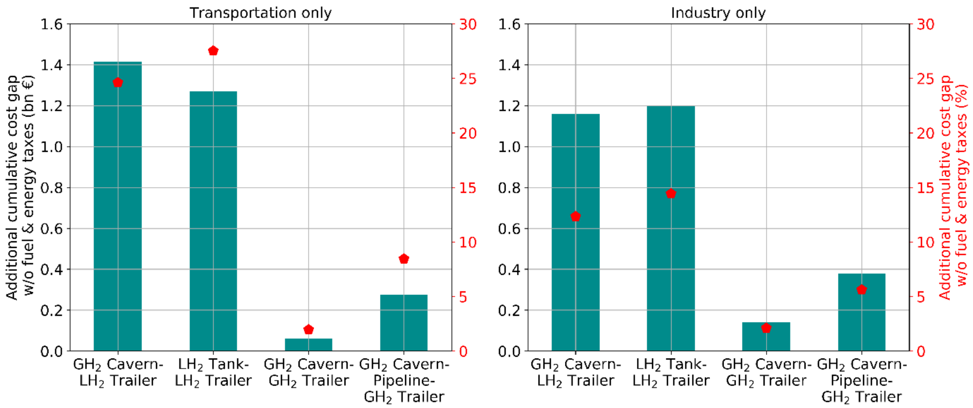

Figure 63. Value of synergy effects - additional cumulative cost gap between hydrogen and benchmark cost in case of single market introduction through 2030.

Figure 64 portrays the resulting cumulative cost gap after the parameter variation for each pathway in comparison to the base case. It can be perceived that across all four analyzed pathways, the weighted average cost of capital (WACC) and investment costs for electrolysis had the highest impact on the additional expenditures. In the case of a WACC reduction by 25% (from 8% to 6%), the introduction of GH2 and LH2 pathways incurred additional expenditures of 5.8-6 bn € and 9.2-10 bn €, respectively. Similarly, a WACC of 10% can raise the cost gap to 12.5 and 15.6-17.6 bn € for GH2 and LH2 pathways. Consequently, the WACC shows a comparable impact on the computed cost gap to the choice between GH2 and LH2 pathways itself. The assessment of WACC for wind onshore across the EU in 2016 showed 3.5% and 12% WACC, with the reliability and credibility of government policy being the main influencing factor for the perceived investment risk [18]. Accordingly, a reliable and credible policy regarding the use of the hydrogen market is necessary for low-cost capital provision to infrastructure development projects.

LCOE costs of 4.75 and 7.5 ct/kWh (base case assumption: 6 ct/kWh) lead to a cost gap of 8.2-11.5 bn € and 11.4-16.7 bn € for the GH2 and LH2 pathways, respectively. The high impact of LCOE variation, as for electrolysis investment cost, stems from the high fraction of electrolytic hydrogen production in the base scenario. The assumed system efficiency of 63% to 65% from 2023 to 2030 for electrolysis units indicates that the computed LCOE’s impact on the cumulative cost gap might additionally increase if R&D and system-scale effects are insufficient to attaining the target system efficiency [127].

One of the main reasons for the high impact of the WACC on the resulting cost gap is the high fraction of the overall cost dedicated to electrolysis investment. Hence, a variation in the electrolysis investment costs accounts for a large portion of the cost variation observed for WACC. The country-wide learning effects (see Sub-section 2.1.5.1) lead to a reduction in the investment costs from 1500 €/kW to 600 €/kW in 2030, thus indicating the same cost level as the anticipated costs for AEL and PEMEL [127, 132]. An even faster cost reduction might also be possible, but would then also require a substantially greater R&D investment [127]. The overall cost gap could potentially be diminished by only applying the AEL technology, but the absence of AEL plants showcasing direct coupling with renewables does not allow one to determine whether AEL technology could be applied to the more decentralized and smaller plants that will be the primary sites for electrolytic production. As stated above, by the end of the 2020s, PEM electrolyzers are projected to reach similar investment costs as AEL, thus substantially limiting cost-savings due from the use of AEL technology.

A similar impact is seen in the variation of CO_2 costs. The increase in CO_2 costs by 25% reduces the cost gap to 9.4 bn € and 12.33 to 14.6 bn €. This highlights the positive impact of more progressive environmental policies. However, the positive effect is limited by the fact that the cost of CO_2 emissions affect both the benchmark costs and CO_2 emissions of hydrogen delivery, which is characterized by a substantial natural gas demand up until the year 2030. Hence, the benefits of higher benchmark costs are partially canceled out by the higher costs of industrial hydrogen.

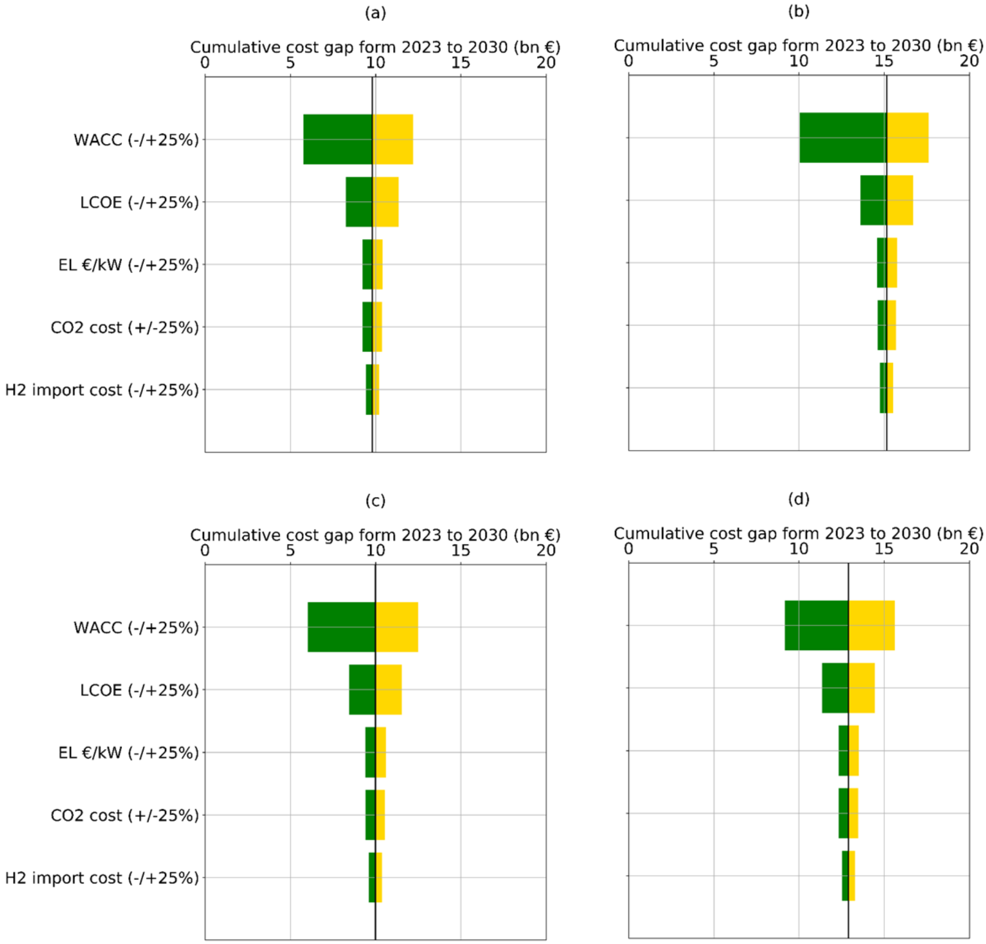

Figure 64. Sensitivity analysis of the cumulative cost gap between hydrogen and benchmark cost between 2023 to 2030 for: (a) GH2 caverns-GH2 trailers; (b) GH2 caverns-LH2 trailers; (c) GH2 caverns- pipeline-GH2 trailer; (d) LH2 tanks-LH2 trailers.

Even though hydrogen will only be imported by the year 2028 (see Figure 43), the costs of imported hydrogen have significant implications for the additional costs of the hydrogen introduction strategy. For GH2 and LH2 pathways, a reduction of import costs by 25% leads to an overall cost gap of 9.4-9.6 and 12.5-14.8 bn €. Accordingly, tapping low-cost hydrogen sources and importing it can have important implications for the early development of cost-competitive hydrogen provision. As previously stated, the import cost of 3.9 €/kg assumed for the base case is derived from the cost analysis of fully renewable hydrogen importing in 2050. From a short- to mid-term perspective, this import cost could be undercut by the imports of blue or yellow hydrogen, offering production costs of 2-3 €/kg (see Sub-section 2.1.5.1). However, a significant challenge for international supply chain development is the creation of sufficient pull in the home market and to rapidly create an international supply chain infrastructure. The first demonstration projects for international supply chains, initiated by Japan in Brunei and Australia, point to a pilot phase after the project's commencement of 3 to 4 years before first hydrogen shipments of 3 to 210 t p.a. are to be facilitated [19-21]. If this analogy were also to hold for Germany, the first and initially tiny import shipments could only be facilitated after 2025. This shows the limited feasibility of anticipations for the rapid growth of hydrogen imports. Alternatively, hydrogen imports could be sought from the European countries already supplying Germany with natural gas, such as Norway, the Netherlands or Russia, as this would allow existing commercial relationships and delivery infrastructure to be drawn upon if pipelines could be reassigned. The most promising options appear in the Netherlands, where the available L-gas pipelines could be used for hydrogen delivery to Germany. However, similar timelines are also observed in this case, as the first deliveries are anticipated to take place beyond the year 2026 [6]. Accordingly, the observed cost reductions can be achieved with low-cost hydrogen imports; however, as in the base scenario, even if sufficient hydrogen imports are achieved, these can only impact the hydrogen supply by the end of the decade.

Due to the high cost-sensitivity of industry and the observed economic challenge concerning cost-competitive hydrogen delivery for industrial consumers, it can be concluded that individual measures are insufficient to reach satisfactory cost levels in this market. To address this issue, Figure 65 and Figure 66 showcase the cumulative impact of the favorable scenarios from the sensitivity analysis of the industry cost gap (see Figure 62). Accordingly, as the transportation sector can reach a cost-competitive level independently of industry, all gains from the occurring cost savings are accounted for in that sector.

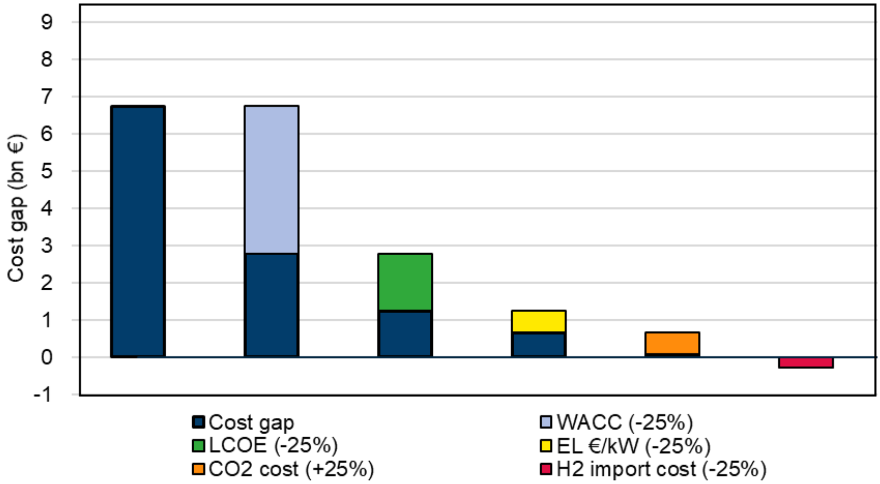

Figure 65. Impact of the sensitivities on the reduction of cost-gap between hydrogen and benchmark cost for industry in the case of the GH2 cavern - pipeline - GH2 trailer pathway.

From these figures, three main results can be noted. First, due to the comparably low cost-gap of the GH2 pathways to the benchmark cost, the best-case scenario, which combines all favorable sensitivity cases, allows reduction of the cost-gap to zero and even generates a minor surplus of 0.3 bn € through 2030. However, the cost-gap of the LH2 pathway is too extensive to be covered, even in the best-case scenario, limiting the industrial gap to 1.5 bn € through 2030. Second, both examples highlight the key role of the transport sector for cost-competitive hydrogen delivery for industry, as it allows sharing of the initial burden of infrastructure introduction. Thirdly, as in the case of the sensitivity analysis, the introduction cost of the hydrogen infrastructure shows a high sensitivity for parameters independent of the development of the hydrogen market, such as WACC and LCOE, as well as CO_2 costs. Hence, infrastructure development is confronted with a substantial level of risk regarding the stability and future development of these parameters, as they cannot be significantly influenced by the hydrogen industry alone. Accordingly, policy measures are required to limit the risk of the long-term development of these factors.

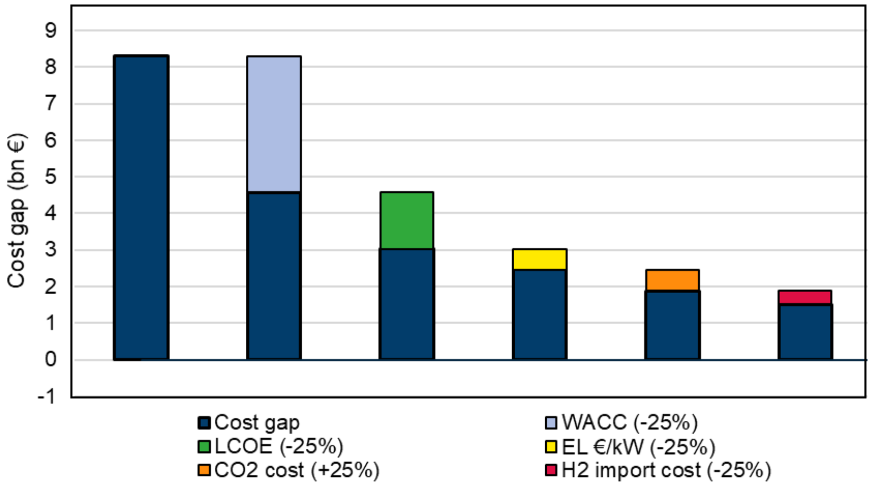

Figure 66. Impact of the sensitivities on the reduction of cost-gap between hydrogen and benchmark cost for industry in the case of the LH2 tank - LH2 trailer pathway.

In light of these results, a general strategy for the introduction of the hydrogen infrastructure can be derived (see Figure 67). Given the fact that the necessary boundary conditions for cost-efficient LH2 delivery, such as a high concentration of hydrogen production and LH2 imports, are not to be expected until the late 2020s, a GH2 pathway is the more favorable choice for the initial infrastructure introduction in Germany. Consequently, the decentralized production of hydrogen as it is now pursued in different commercialization projects should be accelerated in order to shorten the hydrogen delivery distances. Furthermore, demand clusters should be created that ideally combine transportation and industrial demand, such as Rhine-Ruhr, Hamburg and the Central German chemical triangle, hence enabling the optimal utilization of the occurring synergies within these demand clusters. Additionally, SMR and by-product hydrogen can be utilized to locally supplement renewable hydrogen deliveries. In these demand clusters, captive vehicle fleets of passenger cars, trucks and forklifts, as well as buses and trains, should be developed to minimize the risk of low station utilization.

The public refueling station network can then be expanded according to the car and truck fleet requirements with multi-functional 350 bar and 700 bar stations, thus maximizing the scaling effects of the refueling stations and improving the station coverage of public refueling stations. The initially developed public station network can then accelerate the adoption of private passenger cars and trucks requiring public refueling stations. With growing demand, by the mid 2020s these clusters can be connected with the larger production centers via preferably reassigned natural gas pipelines, thus creating the initial backbone of the hydrogen pipeline network, while smaller cities located not too far from the pipeline routes can be supplied by the GH2 trailers. Such an approach would be consistent other studies that report a similar division between pipeline and trailer delivery [253, 273]. Given the changeover from L-gas in northwestern Germany and North Rhine-Westphalia, these regions are the first-order choices for the initial development of the pipeline network. Potential hydrogen imports form the Netherlands can then be integrated into that network by the end of the 2020s. From then on, in the 2030s, the pipeline network can be expanded to connect the salt caverns and demand centers in Rhine-Main, the Saarland and Ingolstadt with Munich, as well as to connect the Central German chemical triangle and Berlin with hydrogen production along the Baltic and the North Sea coasts.

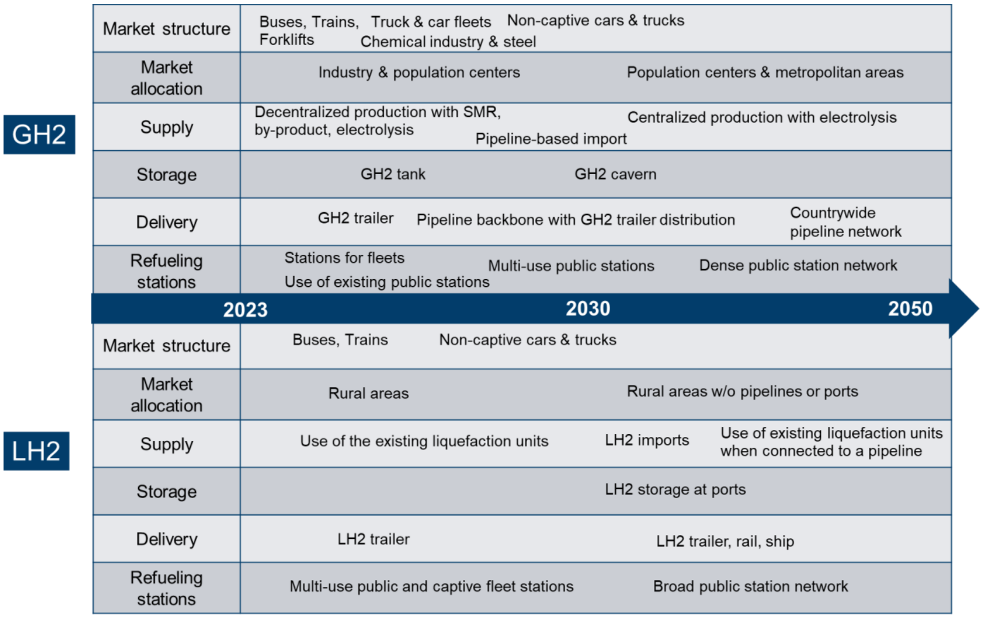

Figure 67. Overview of the proposed introduction strategy for the GH2 and LH2 hydrogen infrastructure in Germany.

Until the end of the 2020s, LH2 delivery should be expanded to maximize the utilization of existing liquefaction capacity. LH2 stations should be primarily installed in locations that are not expected to have regional hydrogen production, do not feature major industrial centers and which are not expected to be crossed by hydrogen pipelines. Similar findings can also be observed in other studies, indicating the cost-effectiveness of LH2 delivery to rural areas [253, 273]. Exemplary regions with these features are in

Thuringia and low to medium urbanized regions in southern Germany. LH2 trailers can then be used for deliveries to these more remote regions. The development of the transport market in these more rural regions could then rely primarily on trains and buses. Additionally, the lower investment costs for the LH2 stations would enable accelerated reliance on public stations for passenger cars and trucks, as these regions feature only limited numbers of larger captive fleets. Car OEMs located in southern Germany can also draw on their appeal to accelerate the adoption of FCEVs in these areas. Subsequently, with the increasing seaborne imports in the 2030s, the further expansion of LH2 stations can also be assessed according to the coverage of the pipeline network in rural areas and relevant ports in order to optimally utilize the LH2 imports. From the ports, LH2 can then additionally be transported by rail or ships to optimize LH2 delivery to southern Germany. Depending on LH2 demand, storage can then be erected in the vicinity of importing ports. If necessary, the existing liquefaction units at industrial sites that are connected to the pipeline network, such as Leuna in the Central German chemical triangle, can be used to supply additional LH2 demand. Hence, the construction of the new liquefaction units should be weighted against the availability and costs of LH2 imports.

In summary, by comparing the overall costs of the hydrogen supply chains, it was found that LH2 trailer delivery, as well as combined pipeline and GH2 trailer transport, offer the lowest long-term hydrogen delivery costs of 5.7 €/kg and 5.9 €/kg, respectively. For large market penetrations, no substantial differences for LH2 delivery with previous LH2 tank storage or GH2 cavern storage were observed. In contrast, delivery utilizing only GH2 trailers provides long-term costs of 6.9 €/kg, and so it is substantially more expensive than other alternatives. Thereafter, the development of domestic energy demand for each supply chain pathway is assessed. It was concluded that the energy demand for the supply chains is primarily driven by hydrogen production, as well as processing and conditioning.

Accordingly, domestic energy demand resembles the development of the supply structure, where electrolytic and industrial hydrogen will dominate the supply until SMR is phased out in 2030. Additionally, due to the energy-intensive liquefaction process, LH2 requires more energy per unit of hydrogen. Nevertheless, this effect is diminishing in the long term with the growing fraction of LH2 imports. The observed long-term costs of the supply chains are reached in the period of 2030 to 2040 and, given the long-term uncertainties about the underlying assumptions, the 4% cost difference between the LH2 and combined pipeline and GH2 trailer delivery does not imply a clear preference of one introduction pathway over another. Consequently, the cost gap for consumers from 2023 to 2030 is calculated to derive additional costs of infrastructure introduction for each pathway.

It was determined that by 2030, the calculated supply chains do not reach the gasoline or natural gas benchmark pre-tax costs, with a cost-gap to the gasoline of 2.7 to 4.6 ct/kWh and to natural gas of more than 15 ct/kWh. Accordingly, the cumulative cost gap for the period 2023 to 2030 ranges from 9.8 and 15.1 bn € for GH2 and LH2 pathways, respectively. This result has twofold implications. First, after consideration of energy taxes, it could be shown that gasoline benchmark costs are higher than the computed hydrogen delivery costs. Thus, limited tax brakes would be sufficient to finance the pre-tax cost gap in order to provide an equal energy cost for consumers. The cost parity can be reached with tax breaks of 2.4 to 2.9 bn € p.a. Such costs for federal budgets are found to be on the same scale as the currently implemented tax breaks for diesel costing yearly, of approximately 7.75 bn €. A different picture is observed in the case of industry, where energy taxes are insufficient to close the gap to hydrogen costs, hence indicating the requirement of additional support measures. Second, after the comparison of the market-specific cost gaps for industry and transportation, it can be concluded that fuel cell vehicles in the transport sector are essential for the introduction of hydrogen in industry, as this creates flexibility to share the initial burden of the infrastructure introduction, as two thirds of the cost-gap stem from the industry sector.

During the sensitivity analysis regarding market choice, it was shown that the value of synergies between industry and transportation markets is 1.1 to 1.4 bn € and 0.06 to 0.38 bn € for LH2 and GH2 pathways, thus highlighting the dependency of LH2 pathways on large-scale hydrogen production. In the case of GH2, the synergy effects are balanced by the increasing delivery distances associated with higher demand. Additionally, it was shown that the industry market introduction strategy is more sensitive to synergy effects, as industrial consumers rely more on the scaling of the pipeline network.

During the variation in the input parameters of 25%, the highest sensitivity was observed for WACC, LCOE and electrolysis investment costs, thus showcasing the importance of these parameters for the additional cost of hydrogen infrastructure introduction. With the correct measures in place, it was argued that a 25% smaller value for WACC and import costs could be attained, thus individually reducing the cost gap to 5.8 bn € and 6 bn € for GH2 pathways. In the case of LH2 pathways, the occurring cost-gap could be diminished by reducing the WACC down to 9.2 bn € and 10 bn €. The CO_2 cost has a limited effect on the overall cost-gap, as the impact on the benchmark fuel cost is partially balanced out by the increased cost of the SMR and by-product hydrogen from industry.

Based on the evaluation of infrastructure development and the sensitivity analysis, a generalized introduction strategy for the hydrogen infrastructure was derived. The main theme of the strategy was that GH2 trailers and pipelines should be used to establish the backbone of the hydrogen supply to the main industrial and population centers, while LH2 could be used to optimize the utilization of the existing liquefaction units and LH2 imports, as well as to supplement the infrastructure in LH2-importing ports and in less densely-populated regions without anticipated hydrogen pipelines.

5 Summary and Conclusions

In this chapter, the key results of this study are summarized. In **sub-chapter 5.1**, the aim and the research questions of the thesis are collated. Then, **sub-chapter 5.2** describes the results of the strategic environment analysis and literature review that inspired the modeling approach taken herein. Based on these outcomes, in **sub-chapter 5.3**, key aspects of the methodology are selected to depict the supply chain components and the market evolution is outlined. After that, in **sub-chapter 5.4**, the primary outcomes of the strategy design and evaluation are recapitulated. Finally, in **sub-chapter 5.5**, the main conclusions of this work are drawn.

5.1 Aim and Approach

The current GHG abatement targets require deep emissions cuts in the transport and industrial sectors, especially in the chemical and steel industries. Hydrogen is seen as a key element of the defossilized energy system of the future, as it supports the tackling of both issues, enabling a transformation of drivetrains to more efficient, zero-emission FCEVs, as well as to diminish process-related emissions in industry. However, there is increasing interest by stakeholders from the industrial and political fields in developing hydrogen infrastructure tools to map the strategic options and evaluate the impact of individual strategies.

The goal of this work was to extend the strategy development process by means of a computer model-based assessment of the infrastructure and demand strategies that promote the implementation of a hydrogen infrastructure to supply the transportation and industry sectors in Germany. More specifically, this study has aimed to investigate the synergy effects across industry and transportation markets, as well as the key features of infrastructure pathways, enabling the existing infrastructure to be utilized and aligning the initial development with an optimized supply chain in the long term.

To achieve these goals, in **Chapter 2**, a review of the most attractive hydrogen market and infrastructure alternatives was conducted. Furthermore, based on these findings and a literature review, an appropriate modeling approach was derived for this study. Then, **Chapter 3** provided a detailed depiction of the applied methods to represent the demand, production, storage, processing and conditioning, delivery and refueling of hydrogen. Subsequently, **Chapter 4** constructed a demand scenario based on the German national hydrogen strategy and the transition to the hydrogen system, including an evaluation of the transformation of the hydrogen market, the changeover of refueling stations, production and storage reconfiguration and the evolution of the delivery infrastructure.

5.2 Literature

In **Chapter 2**, a strategic environment analysis was conducted in order to assess current and anticipated hydrogen market development in the future, as well as the key technologies and their characteristics for market introduction. It was found that local buses, non-electrified passenger trains, freight trucks, passenger cars and forklifts, as well as industry, including methanol, ammonia, refining and steel, were the most attractive markets for the introduction of hydrogen. Furthermore, key technologies and their associated features for the supply chain's components were selected. Production via PEMEL and SMR, as well as by-product hydrogen, were identified as being the most suitable options during the introduction phase. For subsequent delivery, GH2 trailers and pipelines, as well as LH2 trailers, were concluded to be the most attractive transport options. Accordingly, GH2 caverns, as well as GH2 and LH2 tanks, were selected as the most promising storage options during the introduction phase. Purification via PSA and TSA was also considered to ensure sufficient hydrogen quality for subsequent supply chain components and hydrogen consumers. Based on these findings, the relevant scientific literature was reviewed to identify a suitable modeling approach for use in this work. It was determined that an approach that combines several individual simulation and planning tools, operating in different spatial and technical dimensions, would be the most feasible choice to represent the relevant energy installations and map the introduction strategies for a hydrogen infrastructure.

5.3 Methods

Building on previous findings and the derived methodology, in **Chapter 3**, the individual components of hydrogen provision systems were assessed to derive the critical features of the infrastructure introduction strategy. To determine the anticipated hydrogen demand, the Bass model was extended to incorporate exploratory diffusion scenarios for each market. The evaluation of the scenarios indicated that commercial vehicle fleets, such as local buses, non-electrified trains and forklifts, are associated with the highest innovation coefficients. Subsequently, a two-step spatial distribution of demand was conducted, which contains top-down demand allocation among the NUTS3 regions and an optimized capacity allocation of the stations within each region.

Thereafter, by developing a set of criteria for electrolyzer placement, such as proximity to the electricity grid and other infrastructure assets, renewable energy installations and viable areas for salt cavern construction, more than 80 potential sites at high voltage substations in Germany were identified. Additionally, by investigating post-EEG wind turbines, short-term hydrogen costs in the range of 4 €/kg to 5 €/kg in the year 2025 were identified. In the discussion of the required minimum storage length, it was shown that to facilitate a low-cost transition from tank to cavern storage, production sites should be differentiated to those with less than 100 MW_{el} with tank storage for 15 days and larger electrolyzers that are accompanied by 60 days of cavern storage.

A method for investigating the feasibility of pipeline reassignment alternatives of PWM and inhibitors was developed to investigate techno-economic potential for Germany. The assessment of the pipeline reassignment methods indicates that PWM offers superior properties over inhibitors, enabling cost reductions by more than 60% in comparison to a newly constructed hydrogen pipeline. Thereafter, based on gathered data for the representative natural gas transmission network for Germany, it was found that technical reassignment potential reaches 80% of the analyzed pipelines. Subsequently, a novel two-step optimization method for combined pipeline and trailer delivery was proposed, which enables an increase in the pipeline network while continuously substituting trailer delivery, hence providing a more realistic representation of infrastructural development.

Finally, the optimized design and scale of the hydrogen refueling stations were investigated by implementing a novel model for station representation. Accordingly, a novel approach to model stations for a broad set of vehicle types was developed that accounts for varying technical (350 and 700 bar, as well as the fueling amount) and operational requirements, such as refueling times and characteristic loads at refueling stations. Based on these results, with the help of the developed approach to combine the refueling of different vehicle types, it could be shown that median cost-savings achieved with a multi-utilization refueling station for 350 bar and 700 bar technologies provides ~10% higher median cost savings than a combination of two 350 bar vehicles.

5.4 Results

In the **Chapter 4**, the four main pillars of the hydrogen transition to a countrywide supply chain were evaluated: the transformation of the hydrogen market, reconfiguration of production and storage, the evolution of the hydrogen delivery infrastructure, as well as the changeover of the refueling infrastructure. These are the most critical findings observed during the transition towards a large-scale countrywide supply system.

The market scenario is characterized by a nearly equal balance between demand in the industry and transportation sectors. Transportation demand exhibits an extensive transition from considerable reliance on commercial captive vehicles and trucks in the initial years to a market structure dominated by passenger cars, which account for a 50% in hydrogen demand for transportation in 2050. The most promising regions for the initial infrastructure development are areas where population centers are located and which are associated with high transportation demand and industrial centers for the chemical and steel industry. These regions include Rhine-Ruhr, Hamburg, Ludwigshafen and Central German chemical triangle.

Considering the overall cost of the hydrogen supply chains, it was found that LH2 trailer delivery, as well as combined pipeline and GH2 trailer transport, provide comparably low long-term hydrogen delivery costs of 5.7 €/kg and 5.9 €/kg, respectively. Hydrogen delivery utilizing only GH2 trailers entails long-term costs of 6.9 €/kg, and so is substantially more expensive than other alternatives. However, these results must be weighted against the substantially higher LH2 delivery pathways of 10 to 8 €/kg, whereas GH2 delivery enables final hydrogen costs of 7 to 8 €/kg from 2023 to 2030. Thus, the LH2 pathway provides the most cost-efficient delivery medium in the long term at the cost of additional risk during the introduction phase. In contrast, with the continuous expansion of the pipeline network, GH2 enables a more myopic infrastructure that better optimizes the costs of the initial infrastructure introduction.

The assessment of the resulting reconfiguration of production and storage showed that the import of hydrogen is only required as the overall installed capacity of electrolyzers reaches the 5 GW_{el} mark and hydrogen demand outstrips production by the end of the 2020s. This finding highlights the role of domestic hydrogen production during the initial market introduction phase. Moreover, it was found that hydrogen production from non-repowerable, post-EEG wind power plants is a significant contributor to the initial hydrogen generation, providing 20% to 30% of the overall supply before 2030. The resulting cost increase due to the elevated electrolysis investment costs can be successfully balanced by SMR and by-product hydrogen production, limiting the cost to less than 3.3 to 3.9 €/kg. However, due to the limited available capacity, it was concluded that SMR and by-product hydrogen only marginally alleviate low hydrogen production in the southern regions of the country. Moreover, the short investment horizon diminishes the feasibility of LH2 delivery, as liquefaction units at SMR sites would cease to operate after 2030. The first use of seasonal storage, such as a salt cavern, was observed in the early 2030s when the individual supply points reached the assumed necessary capacity for the minimal salt cavern construction of 1.9 TWh. However, an earlier shift away from SMR towards centralized, electrolyzer-based production and imports would lead to a higher storage capacity with an earlier development of salt caverns, and so to additional costs during the introduction phase.

The analysis of the evolution of the hydrogen delivery infrastructure showed that the long-term costs for supply chains without production reach 2.3 €/kg and 2.1 €/kg for GH2 and LH2, respectively. The limited capacity of the individual liquefaction units at the sites of production during the initial market introduction years of 2023 to 2030 leads to high processing costs, which result in LH2 pathway costs without production of 6.4 €/kg to 3.5 €/kg between 2023 and 2030. The initial pipeline development for the combined pipeline and GH2 trailer delivery surpasses sole GH2 trailer delivery after 2030 as the most cost-effective GH2 delivery option. The maximum additional cost for pipeline implementation is 0.1 €/kg with GH2 trailer delivery alone. Therefore, it was concluded that hydrogen pipelines could already be cost-efficiently implemented between the years 2025 and 2030. A comparison of the determined initial hydrogen pipeline grid of 950 km in 2030 with other recent assessments identified the same regions in the Northwest of the country as the frontrunners regarding the development of a dedicated hydrogen pipeline infrastructure. Furthermore, all of the investigated studies point to a high percentage (over 50%) of the reassigned pipelines entering the initial hydrogen grid by 2030.

A changeover in the refueling infrastructure was observed, and is characterized by a shift from a sparse network of small stations to a large grid of high-throughput ones. A comparison of public refueling stations for cars and trucks showed that large truck stations were deployed significantly earlier (2025-2030) than was the case for car stations, which are dominated by the smallest refueling stations up until 2040. It was shown that the cost savings of a multi-use HRS are achieved in the case of both trucks and cars having comparable demand at multi-use HRS, with the smallest levels of demand providing the highest cost savings of up to 4-5 €/kg. When the multi-use HRS concept was applied to the generated station data for 2030, it was found that, due to the diverging speeds of market penetration for cars and trucks, a substantial number of car stations would be too small to justify the additional complexity of multi-use HRS.

In order to assess the impact of the relevant policy background for the infrastructure introduction, the cost gap for consumers from 2023 to 2030 was calculated for each pathway. It was determined that by 2030, the calculated supply chains would not reach the gasoline or natural gas pre-tax benchmarks, having a cost gap with gasoline of 2.7 to 4.6 ct/kWh and natural gas of more than 15 ct/kWh. Accordingly, the cumulative cost gap during the period 2023 to 2030 ranges from 9.8 and 15.1 bn. € for the GH2 and LH2 pathways, respectively.

An assessment of the after-tax gasoline benchmark costs showed that limited tax breaks would be sufficient to finance the pre-tax cost gap in order to provide an equal energy cost for consumers. The cost parity can be reached with tax breaks of 2.4 to 2.9 bn. € p.a., which are on the same scale as the currently implemented tax breaks for diesel which cost approximately 7.75 bn € annually. In the case of industry, the current energy for natural gas is insufficient to close the gap with hydrogen costs, thus indicating the requirement for additional support measures in this market.

It was shown that fuel cell vehicles in the transport sector are essential for the introduction of hydrogen in industry by creating the flexibility to share the initial burden of the infrastructure in its early stages, as two thirds of the cost-gap stems from the industry sector. Accordingly, the industry market's introduction strategy is more sensitive to synergy effects, as industrial consumers rely more on the scaling of the pipeline network. The value of synergies between the industry and transportation markets is 1.15 to 1.4 bn € and 0.06 to 0.38 bn € for the LH2 and GH2 pathways, respectively. Accordingly, a market introduction without transportation would increase the cost-gap for industry by 12% to 14% and 2.5% to 6 % in case of the LH2 and GH2 pathways, respectively.

With the correct measures in place, it was argued that a 25% smaller value for WACC and import costs could be attained, thus individually reducing the cost gap from 9.8 to 5.8 bn € and 6 bn € for the GH2 pathways. In the case of the LH2 pathways, the occurring cost gap could be diminished by the reduced WACC from 13 to 15.1 bn € down to 9.2 to 10 bn €. CO_2 costs had a limited impact on the overall cost-gap, as the impact on the benchmark fuel cost was partially balanced out by the increased cost of the SMR and by-product hydrogen.

On the basis of the evaluation of the infrastructure development and sensitivity analysis, a generalized introduction strategy for the hydrogen infrastructure was crafted that combines the observed strengths and weaknesses of GH2 and LH2 delivery. Both the GH2 and LH2 delivery pathways offer cost-competitive hydrogen delivery options over the long-term. However, the concentration of demand and supply has a different impact on these respective pathways. On the one hand, LH2 delivery favors the clustering of supply, as the level of centralization and diversity found in the supply structure strongly affects the scale of the liquefaction units. Consequently, the more decentralized the production is, the more costly is the phase change to LH2. At the same time, GH2 delivery, by combining pipeline and trailer transport, is more flexible to cost-efficiently accommodate various degrees of supply concentrations. Due to the large fraction of anticipated hydrogen imports in the long-term, the import structure concerning seaborne LH2 and pipeline-based GH2 import must additionally be taken into consideration if a countrywide LH2 delivery system is to be implemented. On the other hand, GH2 delivery favors the concentration of demand, as pipeline development is facilitated to connect industrial and population clusters. In contrast, GH2 trailers provide transport to low-density demand regions and final distribution from pipeline hubs to refueling stations. Conversely, hydrogen delivery via LH2 trailers is less sensitive to demand concentrations, enabling cost-efficient transport to both demand centers and rural areas. Thus, the key outcome of the strategy is that GH2 trailers and preferable reassigned pipelines should be used to create the backbone of hydrogen supply to the main industrial and population centers by 2030, while LH2 can be used to optimize the utilization of the existing liquefaction units and, by the end of the 2020s, to use LH2 imports to supplement the infrastructure in LH2-importing ports and in less densely populated regions that lack hydrogen pipelines.

5.5 Conclusions

Within the framework of this study, the process of strategy design was extended by numerical modeling and a novel approach for the analysis of introduction strategies for a hydrogen infrastructure was developed that takes into account a broad spectrum of technologies and hydrogen consumers, and enables the evaluation of various strategic options by considering the country-specific context. In light of the results discussed herein, the following overarching conclusions can be drawn.

Utilization of the existing infrastructure offers substantial cost-saving potential and should be pursued where possible. The cases of post-EEG wind power plants and the reassignment of natural gas pipelines demonstrated significant cost benefits. However, they can also enable an accelerated infrastructure transition by reducing the lead time and diminishing the space requirements, thus making them key strategies for infrastructure introduction. The assessment of multi-use of hydrogen refueling stations for trucks and cars has a positive long-term impact, but under the assumed scenario the large difference in market adoption speed limits the positive effects during the introduction phase.

From an infrastructure perspective, a better **alignment of the adoption speeds across the markets** and quality requirements, such as the required output pressure of refueling stations, is necessary in order to maximize the synergies enabled by the scaling and network effects of the refueling infrastructure. Such an adjustment and standardization of the output pressure across all vehicle classes would enable us to serve various markets with a marginal cost at the refueling station, thus diminishing the risks and associated costs of the public refueling station network.

The flexibility of the GH2 pathways to cost-efficiently accommodate both the centralized and decentralized supply, as well as demand, makes it the superior option over LH2 delivery. Accordingly, **GH2 pipeline and trailer delivery should be the main focus of infrastructure development, while LH2 transport is better used as a supplementary alternative** to optimize the utilization of the existing LH2 infrastructure and seaborne imports. Consequently, the accelerated creation of **demand clusters encompassing industrial and commercial vehicle** fleet demand should be pursued in order to facilitate a sufficient concentration of consumption for cost-effective pipeline network development. Furthermore, prior to 2030, pipeline-based imports should be prioritized over the development of seaborne ones, as these are better scalable due to existing energy import systems and can be more efficiently integrated into the expanding hydrogen pipeline network. Given the availability of industrial and transport demand, as well as reassignable pipelines and potential pipeline-based imports from the Netherlands, North Rhine-Westphalia and the coastal regions of the North Sea should be the primary target regions for the accelerated development of a hydrogen infrastructure prior to 2030. Conversely, in order to improve the conditions for infrastructure development in eastern Germany, the rapid expansion of renewable and electrolysis capacity, as well as higher availability of pipelines for reassignment, is required. Moreover, the question of the potential import of hydrogen from the Baltic Sea region and Russia would need to be solved in order to reduce uncertainty for the long-term planning of hydrogen pipelines.

The **broad market adoption of hydrogen in transport** and potentially other sectors is required if a cost-competitive hydrogen delivery for industry is to be achieved. Not unlike the current energy systems, where industrial consumers for electricity and natural gas pay substantially smaller grid fees than households or small commercial facilities, such a system would allow the distribution of infrastructure costs amongst consumer groups and could be especially relevant in regions that feature both high industry and transport demand.

In light of the observed synergies amongst hydrogen markets and the anticipated technological development of hydrogen systems, policy-related measures such as a tax on hydrogen and regulatory investment risks, as well as the existing energy-related partnerships, are some of the main points of leverage that define the costs of a hydrogen infrastructure. Accordingly, the **redirection of tax subsidies from fossil to renewable fuels**, the design of a clear and consistent regulatory framework, as well as the creation of a hydrogen import roadmap with current gas supplier countries, are fundamental measures for the successful and cost-efficient introduction of a hydrogen infrastructure.

Hiermit versichere ich, dass ich die vorliegende Arbeit selbständig verfasst und keine anderen als die angegebenen Quellen und Hilfsmittel verwendet habe.

Köln, den 21. Januar 2021

(Unterschrift des Verfassers)

Appendix A

In this appendix the project related data of relevant fuel cell vehicle and electrolysis commercialization projects at the state of the year 2019 are presented.

Table A1: Project data for fuel cell buses in Germany.

NUTS 3 Region	# of vehicles	Status
Bielefeld	4	planed
Darmstadt	1	operating
Düsseldorf	10	planed
Frankfurt am Main	7	operating
Frankfurt am Main	3	operating
Heidelberg	40	planed
Karlsruhe	2	operating
Köln	4	operating
Köln	30	planed
Mainz	4	operating
Münster	2	operating
Münster	6	planed
Nordfriesland	2	planed
Rheinisch-Bergischer Kreis	15	planed
Stuttgart	4	operating
Wiesbaden	4	operating
Wuppertal	10	planed

Table A2: Project data for fuel cell trains in Germany.

NUTS 3 Region	# of vehicles	Status
Steinfurt	3	planed
Rotenburg (Wümme)	14	planed
Rotenburg (Wümme)	1	operating

Table A3: Project data of hydrogen refueling stations for fuel cell buses in Germany.

NUTS 3 Region	Status	Latitude	Longitude
Berlin	operating	52.370213	13.527239
Bielefeld	planed	52.042625	8.606584
Düsseldorf	planed	51.225629	6.822998
Frankfurt am Main	operating	50.080319	8.545024
Hamburg	operating	53.545997	10.003105
Karlsruhe	operating	49.099055	8.432104
Köln	planed	50.870717	7.140734
Münster	operating	51.939592	7.644504
Münsters	operating	51.892498	7.584140
Nordfriesland	planed	54.786810	8.825836
Nordfriesland	planed	54.485364	9.053816
Rhein-Erft-Kreis	operating	50.865651	6.824442
Rheinisch-Bergischer Kreis	planed	51.130071	7.201345
Rhein-Sieg-Kreis	planed	50.628028	7.010225

Steinfurt	planed	52.274454	7.733470
Stuttgart	operating	48.693035	9.198797
Stuttgart	operating	48.724164	9.130991
Wiesbaden	operating	50.069611	8.247776
Wuppertal	planed	51.225112	7.142186

Table A4: Project data of hydrogen refueling stations for fuel cell trains in Germany.

NUTS 3 Region	Status	Latitude	Longitude
Rotenburg (Wümme)	planed	53.486737	9.125156
Steinfurt	planed		

Table A5.:Project data for electrolysis projects in Germany.

Name	NUTS 3 Region	Latitude	Longitude	Power (kW_{el})
Exytron Zero-Emission-Wohnpark	Alzey-Worms	49.748056	8.106059	62,5
Exytron Klimafreundliches Wohnen Augsburg	Augsburg	48.369054	10.894767	62,5
RefLau	Bautzen	51.522786	14.370415	10000
Multi-energy fueling station H2BER	Berlin	52.370213	13.527239	500
Morbach	Bernkastel-Wittlich	49.831940	7.107785	25
MVA Bielefeld-Herford GmbH	Bielefeld	52.042625	8.606584	
H2-Researchcentre BTU	Cottbus	51.767129	14.326636	145
Wind to Gas	Dithmarschen	53.912359	9.158804	2400
ReWest100 (Reallabor der Energiewende)	Dithmarschen	54.158226	9.077827	30000
HYPOS rSOC	Dresden	51.027692	13.786617	180
Sunfire Power-to-Liquids	Düren	50.904944	6.418857	150
Sunfire Research project	Düren	50.904944	6.418857	10
HPEM2Gas	Emden	53.364113	7.210494	180
PtG for the refining process Lingen	Emsland	52.561465	7.308480	6000
Audi e-gas	Emsland	52.870004	7.672360	6000
F&E Windpark Fehndorf-Lindloh	Emsland	52.761084	7.177862	2000
Hybridge	Emsland	52.725900	7.463166	100000
MethFuel	Frankfurt am Main	50.096395	8.537678	1000
Strom zu Gas - Demonstrationsanlage	Frankfurt am Main	50.108519	8.675946	300
Solar hydrogen filling station Freiburg	Freiburg	48.009600	7.833980	30
SEE	Freiburg	48.009164	7.834613	6
Exytron Bestands- und Neubauten Bernsteinsee	Gifhorn	52.560140	10.669890	52
H&R Ölwerke Schindler	Hamburg	53.514445	9.952373	5000
Power-2-Hydrogen-Tankstelle Hamburg	Hamburg	53.573444	9.919291	185

Hydrogen refuelling station HafenCity	Hamburg	53.546029	10.002846	600
100 MW Elektrolyseur	Hamburg	53.507163	9.967809	100000
HyFLEET:CUTE Hamburg	Hamburg	53.549280	9.993588	390
WindGas Hamburg	Hamburg	53.467204	10.137463	1000
Power-to-Gas Haßfurt	Haßberge	50.029541	10.524994	1250
E2Fuel	Haßberge	50.029541	10.524994	1250
H2Orizon	Heilbronn	49.282756	9.375070	1000
Methanation at Eichhof 2nd	Hersfeld-Rotenburg	50.843148	9.681396	50
Integrated High-Temperature Electrolysis and Methanation for Effective Power to Gas Conversion	Karlsruhe	49.097839	8.431432	15
ELEMENT EINS	Diele	53.125381	7.308344	100000
H2Mobility - Karlsruhe	Karlsruhe	48.985730	8.447464	9,4
bioCONNECT / bioCO2nvert	Lippe	52.016086	8.904856	
Flagship project: Power-to-Gas Baden-Württemberg	Lörrach	47.538823	7.707856	1300
H2 Whylen	Lörrach	47.538823	7.707856	10000
Industriepark Hanau	Main-Kinzig-Kreis	50.121016	8.970469	30
Energiepark Mainz	Mainz	49.944946	8.256607	6000
RH2-WKA	Grapzow	53.712673	13.289346	1000
eFARM	Nordfriesland	54.828374	8.751246	225
eFARM	Nordfriesland	54.742723	8.794013	225
eFARM	Nordfriesland	54.543152	8.968454	225
eFARM	Nordfriesland	54.861561	8.678579	225
eFARM	Nordfriesland	54.629597	8.896537	225
Wasserstofftankstelle und Elektrolyseur	Nordfriesland	54.885539	8.975900	
Infinity 1	Pfaffenhofen a. d. Ilm	48.520777	11.510075	
Energy park Pirmasens-Winzeln	Pirmasens	49.178271	7.566541	2500
Hybrid power plant Falkenhagen - STORE&GO Germany	Prignitz	53.199517	12.233650	2000
H2Herten	Recklinghausen	51.572645	7.148670	280
HydroHub	Saarbrücken	49.248641	6.879391	17500
ALIGN-CCUS	Rhein-Erft-Kreis	50.992021	6.667123	65
MefCO2	Rhein-Erft-Kreis	50.990086	6.667802	600
REFHYNE	Rhein-Erft-Kreis	50.855182	6.976746	10000
CO2RRECT	Rhein-Erft-Kreis	50.992021	6.667123	300
Exytron demonstration project	Rostock	54.092459	12.129232	21
HYPOS Megalyseur	Saalekreis	51.328738	12.005968	2000
EnergieparkBL	Saalekreis	51.392428	11.820367	35000
GreenHydroChem Mitteldeutsches Chemiedreieck	Saalekreis	51.328738	12.005968	50000
GrInHy 2.0	Salzgitter	52.161074	10.431907	720
Salzgitter Clean Hydrogen	Salzgitter	52.161074	10.431907	2000
GrInHy	Salzgitter	52.161074	10.431907	150
Windgas Haurup	Schleswig-Flensburg	54.717935	9.315934	1000

Power to Gas at Eucolino	Schwandorf	49.302584	12.081319	108
Power-to-Gas Anlage Heubisch	Sonneberg	50.306609	11.245553	
Altenberge Muelldeponie	Stade	52.069551	7.431094	8000
Green MeOH	Stade	53.635041	9.503881	
RWE demonstration plant	Steinfurt	52.276340	7.716930	150
Ibbenbueren	Steinfurt	52.274454	7.733470	
Innogy SE & Westnety GmbH	Steinfurt	52.170680	7.215980	100
Metelen-Umspannwerk	Steinfurt	52.170680	7.215980	10000
Saerbeck-Bioenergiepark	Steinfurt	52.198112	7.628708	
Steinfurt-Hollich – Buergerwindpark	Steinfurt	52.170111	7.387759	17500
Power to Gas Biogasbooster	Straubing	48.900486	12.624529	10
PtG 250	Stuttgart	48.738140	9.107880	250
Hydrogen filling station Stuttgart	Stuttgart	48.782567	9.210660	400
ENERTRAG Hybrid power plant Prenzlau	Uckermark	53.338337	13.894298	500
STEAG	Unna	51.614792	7.478164	1000
Hochschule Stralsund, Institut für Regenerative Energiesysteme	Vorpommern-Rügen	54.339324	13.076353	20
BioPower2Gas	Waldeck-Frankenberg	51.028543	8.675875	1100
Viessmann microbial methanation	Waldeck-Frankenberg	51.028543	8.675875	275
Smart Grid Solar	Würzburg	49.786341	9.967511	75

Appendix B

This chapter presents the underlying techno-economic data for each hydrogen supply chain component, which were used to derive the presented results. First the general assumptions are presented, followed by hydrogen production, import, storage, conditioning, processing, trailer and pipeline delivery as well as hydrogen refueling stations.

Table B 1. General assumptions.

WACC (%)	LCOE (€/kWh)	Diesel cost (€/l)	Electrolysis FLH (h p.a.)	Natural gas cost (€/kWh)	Water cost (€/m3)
8	0.06	1.2	3700	0.04	4

Table B 2. Assumptions for hydrogen production.

System	Outlet (bar)	O&M %	Lifetime (a)	Investment (€/kW)	Scaling factor (%)	Learning factor (%)	n_{LHV} in 2023 (%)	n_{LHV} in 2050 (%)
Electrolysis	30	3	10	1500	0.925*	16.8 %**	63	70
SMR	30	5,14	20	170	0.7	1	73	73

*Up to 20 MW unit size; **Average for the whole system

Table B 3. Assumptions for hydrogen import infrastructure.

System	O&M (%)	Lifetime (a)	Investment (€/kW)	Electricity demand (kWh/kg)
GH2	3	10	33,000	0.7
LH2	3	10	30,000	0.1

Table B 4. Assumptions for hydrogen storage.

System	Pressure (bar)	O&M (%)	Lifetime (a)	Investment	Scaling factor %	Losses (%/d)
GH2 Tank	150	2	20	250 (€/kg)	-	0

GH2 Cavern	150	2	30	$a*(vol./b)^{scale}$ (€) a=81000000 b=500000	0.28	0
LH2 Tank	1	2	20	30 (€/kg)	-	0.03

Table B 5. Assumptions for hydrogen conditioning.

System	**Outlet (bar)**	**O&M (%)**	**Lifetime (a)**	**Investment (€/kW) : $a+b*Q/n_{H2}$ (Q: flow, n_{H2}: mole fraction)**		**Recovery rate (%)**
PSA	40	4	20	a=664864	b=16537771	97.5
TSA	40	4	20	a=197707	b=23430	97.5

Table B 6. Assumptions for hydrogen processing.

System	**Outlet (bar)**	**O&M (%)**	**Lifeti-me (a)**	**Investment (€/kW)**	**Scaling factor (%)**	**Electricity demand (kWh/kg)**	**Loss (%)**
Compressor	variable	4	15	15000	0.6089	-	0.5
Liquefaction	-	8	20	105000000 +50000	0.66	6.78	1.65
LH2 pump	variable	3	10	30	1	0.1	0
Evaporator	10	3	10	3	1	0.6	0

Table B 7. Assumptions for tractor.

System	Investment (€)	Lifetime (a)	Utilization (h/a)	O&M (%)	Speed (km/h)	Diesel demand (l_{Diesel}/100km)
Truck	160,000	8	2000	1	50	1.5

Table B 8. Assumptions for hydrogen trailer.

System	Pressure (bar)	Investment (€)	Lifetime (a)	Utilization (h/a)	O&M (%)	Loading time (h)	Capacity (t)
GH2	500	660,000	12	2000	2	1.5	1.1
LH2	30	860,000	12	2000	2	3	4.3

Table B 9. Assumptions for hydrogen pipeline.

System	Pressure range (bar)	Investment (Mio. €): a*diammeter^2+b*diameter+c			Min diameter (mm)	Lifetime (a)
Pipeline*	70-100	a=2.2e-3	b=0.86	c=247.5	100	40

*Including recompression and gas pressure regulation every 50 km

Table B 10. Assumptions for hydrogen refueling station.

Component	Cost	Unit
Dispenser	57500	€/unit
Cooling unit	$14000 * \left(\frac{28.43 * \mathrm{P_{ref}}[\mathrm{KW}]}{T_{max}[°\mathrm{C}] + 273.15}\right)^{0.8579} + 35000 * (\frac{m_{HX}[kg]}{1000})^{0.9}$	€/unit
LP storage	645	€/kg
MP storage	822	€/kg
HP storage	1190	€/kg

LH_2-Tank	$991.89 * m_{capacity}[kg]^{0.692}$	€/unit
Compressor	$40528 * P_{comp}[KW]^{0.4603}$ [for 350 bar] $40035 * P_{comp}[KW]^{0.6038}$ [for 700 bar]	€/unit
Cryogenic pump	$4250 * m_{pump}[\mathrm{kg/h}]$ [for 350 bar] $7000 * m_{pump}[\mathrm{kg/h}]$ [for 700 bar]	€/unit
Evaporator	$m_{evap}[kg] * 1000 + 15000$	€/unit
Booster-Compressor	$6000 * P_{booster}[KW]$	€/unit
Control system	180000	€
Instalation factor	1.3 for all components	-

Table B 11. Storage cost for 15, 30, 45 and 60 days of storage. Assumed minimal size of the cavern is 70,000 m3.

Mean daily throughput (kgH2/d)	15d Storage	30d Storage	45d Storage	60d Storage
1	1.11809	2.23618	3.35427	4.47236
2001	1.11809	2.23618	3.35427	4.47236
4001	1.11809	2.23618	3.35427	4.47236
6001	1.11809	2.23618	3.35427	4.47236
8001	1.11809	2.23618	3.35427	4.47236
10001	1.11809	2.23618	3.35427	1.506706
12001	1.11809	2.23618	3.35427	1.321366
14001	1.11809	2.23618	1.091044	1.182566
16001	1.11809	2.23618	0.991039	1.074172
18001	1.11809	2.23618	0.910465	0.986839
20001	1.11809	0.75338	0.843956	0.91475
22001	1.11809	0.703417	0.787986	0.854085
24001	1.11809	0.660703	0.740136	0.802222
26001	1.11809	0.623704	0.698689	0.757298
28001	1.11809	0.591298	0.662387	0.717951
30001	1.11809	0.562644	0.630288	0.683159
32001	1.11809	0.537098	0.601671	0.652142
34001	1.11809	0.514159	0.575974	0.624289
36001	1.11809	0.493429	0.552752	0.599119
38001	0.390868	0.47459	0.531648	0.576245
40001	0.376697	0.457383	0.512373	0.555352

42001	0.363694	0.441595	0.494686	0.536183
44001	0.351714	0.42705	0.478392	0.518521
46001	0.340636	0.413598	0.463324	0.502189
48001	0.330356	0.401117	0.449342	0.487034
50001	0.320788	0.389499	0.436327	0.472928
52001	0.311856	0.378654	0.424178	0.45976
54001	0.303496	0.368504	0.412808	0.447435
56001	0.295653	0.35898	0.402139	0.435872
58001	0.288277	0.350024	0.392106	0.424997
60001	0.281325	0.341584	0.382651	0.414749
62001	0.274761	0.333614	0.373723	0.405072
64001	0.268552	0.326075	0.365277	0.395918
66001	0.262668	0.31893	0.357273	0.387243
68001	0.257082	0.312148	0.349676	0.379008
70001	0.251772	0.305701	0.342454	0.37118
72001	0.246717	0.299563	0.335578	0.363727
74001	0.241898	0.293711	0.329023	0.356622
76001	0.237297	0.288125	0.322765	0.34984
78001	0.232901	0.282787	0.316785	0.343358
80001	0.228694	0.277679	0.311063	0.337156
82001	0.224664	0.272786	0.305582	0.331215
84001	0.2208	0.268094	0.300325	0.325518
86001	0.21709	0.26359	0.29528	0.32005
88001	0.213527	0.259263	0.290433	0.314796
90001	0.210099	0.255102	0.285771	0.309743
92001	0.206801	0.251097	0.281285	0.30488
94001	0.203623	0.247238	0.276963	0.300196
96001	0.20056	0.243519	0.272796	0.295679
98001	0.197605	0.23993	0.268776	0.291322

Appendix C

The following appendix presents the underlying data used to assess the non-repowerable post-EEG wind power plants for hydrogen production. First the criteria for selection of land availability for wind onshore in each federal state is presented. These criteria are used to filter the exsting wind power plants to identify sites that are located outside of currently defined wind areas.

Table C 1: State specific criteria identify available land area for wind onshore in 2019.

Criterion	Subcriterion
Settlement Areas	General and pure residential areas
	Individual residential buildings and splinter settlements
	Campsites
	Trade and industrial zones
	Areas for tourism, leisure/ recreation
	Natural monuments and protected ensembles
Nature and landscape conservation	Wildlife sanctuaries
	National parks
	Protected landscapes
	Protected forests
	SPA areas
	Biosphere reserves
	Bird corridors
	Water bodies (> 10 ha)
	Slope
Other	Airports and air fields
	Raw material hedging
	Streets
	Highways
	Railway lines
	Transmission lines
	Wind frequency

In the second step, the identified sites are filtered after the respectice construction date to derive the available capacity of the post-EEG wind power plants for each time step. Figure E1 presents the temporal evolution of the post-EEG capacity in each federal state. Overall a stable growth of the capacity can be observed, indicating the viability of the hydrogen production from post-EEG wind power plants in the medium term.

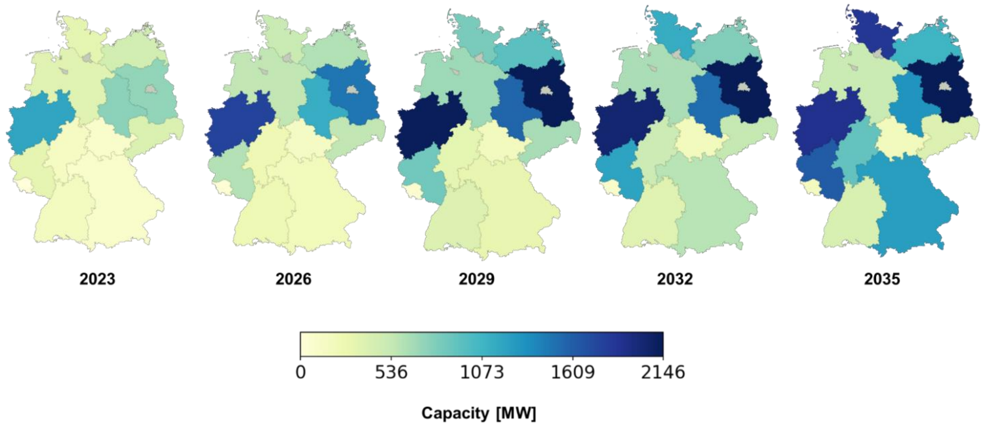

Figure C 1: Capacity development of the non-repowerable post-EEG wind power plants in each federal state.

Appendix D

The following Table F1. gives a detailed overview of the anticipated hydrogen demand in individual NUTS3 regions in Germany in the year 2050. In addition to the overall demand, market specific consumption for trains, buses, chemical industry, steel, passenger cars, trucks and forklifts is provided.

Table D 1: Hydrogen demand in individual NUTS3 regions of Germany in the year 2030.

Key	Total (kt/a)	Train (kt/a)	Bus (kt/a)	Industry (kt/a)	Steel (kt/a)	Car (kt/a)	Truck (kt/a)	Forklift (kt/a)
01001	0,489	0,000	0,000	0,000	0,000	0,130	0,286	0,073
01002	0,893	0,226	0,178	0,000	0,000	0,123	0,204	0,000
01003	1,367	0,226	0,000	0,000	0,000	0,080	0,944	0,063
01004	0,552	0,000	0,000	0,000	0,000	0,111	0,368	0,073
01051	17,952	0,000	0,000	17,585	0,000	0,063	0,143	0,039
01053	0,400	0,000	0,000	0,000	0,000	0,078	0,133	0,070
01054	0,535	0,226	0,000	0,000	0,000	0,071	0,117	0,055
01055	0,338	0,000	0,000	0,000	0,000	0,079	0,125	0,041
01056	0,858	0,000	0,269	0,000	0,000	0,169	0,146	0,113
01057	0,168	0,000	0,000	0,000	0,000	0,064	0,082	0,000
01058	0,730	0,000	0,183	0,000	0,000	0,074	0,184	0,126
01059	0,399	0,000	0,000	0,000	0,000	0,077	0,137	0,088
01060	1,835	0,000	0,178	0,000	0,000	0,128	1,225	0,254
01061	0,595	0,226	0,000	0,000	0,000	0,065	0,229	0,054
01062	0,654	0,000	0,000	0,000	0,000	0,076	0,198	0,206
02000	7,723	0,560	0,771	1,568	0,000	0,279	1,444	0,687
03101	1,087	0,268	0,200	0,000	0,000	0,107	0,196	0,138
03102	28,283	0,000	0,000	0,000	27,469	0,065	0,640	0,087
03103	2,353	0,000	0,000	0,000	0,000	0,360	1,853	0,139
03151	0,301	0,000	0,000	0,000	0,000	0,071	0,105	0,065
03152	0,890	0,000	0,176	0,000	0,000	0,068	0,387	0,098
03153	0,487	0,000	0,000	0,000	0,000	0,065	0,296	0,000
03154	0,236	0,000	0,000	0,000	0,000	0,057	0,121	0,039
03155	0,396	0,000	0,000	0,000	0,000	0,066	0,244	0,000
03156	0,258	0,000	0,000	0,000	0,000	0,054	0,186	0,000
03157	0,472	0,000	0,000	0,000	0,000	0,068	0,302	0,079
03158	0,166	0,000	0,000	0,000	0,000	0,064	0,080	0,000
03241	5,561	0,537	0,525	0,000	0,000	0,399	2,145	0,791
03251	1,824	0,000	0,000	0,000	0,000	0,146	1,364	0,079
03252	0,654	0,000	0,000	0,000	0,000	0,070	0,525	0,000
03254	0,804	0,000	0,187	0,000	0,000	0,074	0,209	0,105
03255	0,264	0,000	0,000	0,000	0,000	0,054	0,155	0,037
03256	0,462	0,000	0,000	0,000	0,000	0,061	0,220	0,043
03257	0,439	0,000	0,000	0,000	0,000	0,075	0,150	0,086
03351	0,552	0,000	0,000	0,000	0,000	0,072	0,370	0,050

03352	0,987	0,000	0,000	0,000	0,000	0,077	0,722	0,066
03353	1,250	0,000	0,173	0,000	0,000	0,120	0,403	0,362
03354	0,167	0,000	0,000	0,000	0,000	0,046	0,068	0,037
03355	0,438	0,000	0,000	0,000	0,000	0,071	0,214	0,059
03356	0,156	0,000	0,000	0,000	0,000	0,065	0,052	0,000
03357	0,407	0,000	0,000	0,000	0,000	0,072	0,168	0,039
03358	0,454	0,000	0,000	0,000	0,000	0,064	0,179	0,080
03359	0,760	0,000	0,000	0,000	0,000	0,079	0,498	0,050
03360	0,250	0,000	0,000	0,000	0,000	0,055	0,116	0,000
03361	0,531	0,000	0,000	0,000	0,000	0,142	0,169	0,091
03401	0,262	0,000	0,000	0,000	0,000	0,117	0,145	0,000
03402	0,239	0,000	0,000	0,000	0,000	0,072	0,167	0,000
03403	0,487	0,000	0,000	0,000	0,000	0,093	0,287	0,046
03404	0,953	0,000	0,000	0,000	0,000	0,085	0,553	0,098
03405	0,272	0,000	0,000	0,000	0,000	0,069	0,180	0,000
03451	1,373	0,000	0,000	0,000	0,000	0,066	1,141	0,046
03452	0,256	0,000	0,000	0,000	0,000	0,074	0,117	0,000
03453	1,322	0,000	0,000	0,000	0,000	0,067	0,924	0,054
03454	8,756	0,000	0,205	4,331	0,000	0,191	3,522	0,063
03455	0,232	0,000	0,000	0,000	0,000	0,061	0,112	0,000
03456	0,475	0,000	0,000	0,000	0,000	0,063	0,167	0,123
03457	0,286	0,000	0,000	0,000	0,000	0,069	0,127	0,000
03458	0,390	0,000	0,000	0,000	0,000	0,106	0,131	0,039
03459	2,580	0,000	0,228	0,000	0,000	0,169	1,463	0,188
03460	2,262	0,000	0,000	0,000	0,000	0,129	2,054	0,057
03461	0,344	0,000	0,000	0,000	0,000	0,055	0,120	0,088
03462	0,114	0,000	0,000	0,000	0,000	0,049	0,049	0,000
04011	18,586	0,000	0,303	0,000	14,011	0,240	3,537	0,396
04012	1,043	0,000	0,000	0,000	0,000	0,117	0,686	0,000
05111	2,676	0,144	0,320	0,000	0,000	0,256	1,081	0,291
05112	123,748	0,288	0,286	0,000	121,477	0,144	0,607	0,327
05113	1,214	0,000	0,302	0,000	0,000	0,160	0,430	0,182
05114	1,023	0,000	0,193	0,000	0,000	0,112	0,248	0,163
05116	1,648	0,144	0,175	0,000	0,000	0,114	0,907	0,138
05117	1,084	0,000	0,000	0,000	0,000	0,114	0,862	0,048
05119	6,645	0,288	0,000	5,856	0,000	0,128	0,283	0,000
05120	0,247	0,000	0,000	0,000	0,000	0,143	0,105	0,000
05122	0,667	0,000	0,000	0,000	0,000	0,110	0,457	0,041
05124	1,027	0,144	0,218	0,000	0,000	0,142	0,190	0,119
05154	1,351	0,000	0,192	0,000	0,000	0,169	0,408	0,174
05158	3,603	0,000	0,265	0,000	0,000	0,345	2,367	0,315
05162	14,887	0,144	0,243	10,517	0,000	0,291	2,883	0,338
05166	3,344	0,000	0,190	0,000	0,000	0,203	2,609	0,087
05170	2,589	0,000	0,251	0,000	0,000	0,181	1,634	0,178
05314	0,524	0,000	0,188	0,000	0,000	0,134	0,054	0,000
05315	9,983	0,432	0,487	6,030	0,000	0,265	1,450	0,512

05316	0,466	0,000	0,000	0,000	0,000	0,117	0,287	0,000
05334	2,471	0,000	0,284	0,000	0,000	0,290	1,638	0,148
05358	1,131	0,000	0,000	0,000	0,000	0,161	0,792	0,128
05362	20,920	0,000	0,254	15,309	0,000	0,372	4,112	0,362
05366	1,642	0,000	0,000	0,000	0,000	0,139	1,169	0,153
05370	1,139	0,000	0,171	0,000	0,000	0,076	0,632	0,110
05374	0,730	0,000	0,178	0,000	0,000	0,144	0,193	0,057
05378	0,669	0,000	0,185	0,000	0,000	0,092	0,236	0,059
05382	2,858	0,000	0,305	0,000	0,000	0,306	1,808	0,130
05512	0,270	0,000	0,000	0,000	0,000	0,128	0,142	0,000
05513	32,984	0,000	0,170	32,202	0,000	0,138	0,364	0,036
05515	0,759	0,000	0,190	0,000	0,000	0,094	0,226	0,084
05554	8,681	0,000	0,218	0,000	0,000	0,414	7,412	0,130
05558	2,078	0,000	0,000	0,000	0,000	0,129	1,729	0,059
05562	4,976	0,000	0,316	1,278	0,000	0,298	2,470	0,157
05566	3,934	0,000	0,241	0,000	0,000	0,260	2,661	0,352
05570	2,942	0,000	0,178	0,000	0,000	0,249	2,076	0,070
05711	1,703	0,000	0,205	0,000	0,000	0,184	1,181	0,070
05754	7,372	0,000	0,210	0,000	0,000	0,443	6,140	0,123
05758	1,687	0,000	0,172	0,000	0,000	0,234	0,938	0,130
05762	0,462	0,144	0,000	0,000	0,000	0,067	0,230	0,000
05766	1,643	0,000	0,205	0,000	0,000	0,176	0,993	0,052
05770	4,363	0,144	0,197	0,000	0,000	0,228	3,342	0,072
05774	2,877	0,144	0,192	0,000	0,000	0,169	1,981	0,103
05911	6,053	0,000	0,225	0,000	0,000	0,550	4,906	0,116
05913	1,778	0,144	0,305	0,000	0,000	0,156	0,429	0,283
05914	1,846	0,144	0,000	0,000	0,000	0,141	1,448	0,057
05915	1,193	0,144	0,000	0,000	0,000	0,071	0,627	0,159
05916	0,871	0,144	0,000	0,000	0,000	0,141	0,463	0,048
05954	1,168	0,000	0,199	0,000	0,000	0,267	0,461	0,044
05958	2,717	0,144	0,177	0,000	0,000	0,211	1,811	0,046
05962	2,005	0,000	0,240	0,000	0,000	0,225	1,094	0,094
05966	0,580	0,144	0,000	0,000	0,000	0,145	0,178	0,000
05970	2,011	0,288	0,191	0,000	0,000	0,210	0,951	0,062
05974	1,502	0,000	0,197	0,000	0,000	0,154	0,671	0,134
05978	3,246	0,144	0,229	0,000	0,000	0,305	1,661	0,324
06411	0,301	0,000	0,000	0,000	0,000	0,135	0,110	0,055
06412	1,951	0,000	0,360	0,000	0,000	0,190	0,860	0,400
06413	0,334	0,000	0,000	0,000	0,000	0,124	0,108	0,037
06414	0,989	0,000	0,190	0,000	0,000	0,114	0,448	0,084
06431	0,886	0,000	0,191	0,000	0,000	0,134	0,180	0,215
06432	1,123	0,000	0,187	0,000	0,000	0,133	0,445	0,212
06433	1,405	0,000	0,183	0,000	0,000	0,122	0,329	0,458
06434	1,052	0,000	0,000	0,000	0,000	0,262	0,710	0,000
06435	1,883	0,000	0,236	0,000	0,000	0,170	1,015	0,226
06436	1,022	0,000	0,170	0,000	0,000	0,212	0,418	0,120
06437	0,141	0,000	0,000	0,000	0,000	0,061	0,060	0,000

06438	1,193	0,000	0,218	0,000	0,000	0,259	0,194	0,315
06439	0,220	0,000	0,000	0,000	0,000	0,066	0,054	0,037
06440	0,771	0,000	0,190	0,000	0,000	0,082	0,179	0,153
06531	0,889	0,000	0,173	0,000	0,000	0,074	0,332	0,145
06532	1,294	0,000	0,000	0,000	0,000	0,174	0,734	0,160
06533	0,354	0,000	0,000	0,000	0,000	0,079	0,136	0,041
06534	0,820	0,000	0,171	0,000	0,000	0,068	0,392	0,037
06535	0,276	0,000	0,000	0,000	0,000	0,061	0,194	0,000
06611	1,359	0,000	0,000	0,000	0,000	0,171	1,131	0,000
06631	0,912	0,000	0,000	0,000	0,000	0,067	0,427	0,128
06632	0,766	0,000	0,000	0,000	0,000	0,064	0,524	0,157
06633	0,623	0,000	0,000	0,000	0,000	0,113	0,195	0,148
06634	0,608	0,000	0,000	0,000	0,000	0,076	0,205	0,124
06635	0,443	0,000	0,000	0,000	0,000	0,071	0,128	0,130
06636	0,271	0,000	0,000	0,000	0,000	0,058	0,151	0,041
07111	0,527	0,000	0,000	0,000	0,000	0,122	0,260	0,145
07131	0,275	0,000	0,000	0,000	0,000	0,069	0,120	0,000
07132	0,275	0,000	0,000	0,000	0,000	0,069	0,107	0,039
07133	0,435	0,000	0,000	0,000	0,000	0,073	0,251	0,086
07134	0,170	0,000	0,000	0,000	0,000	0,058	0,093	0,000
07135	0,195	0,000	0,000	0,000	0,000	0,054	0,122	0,000
07137	0,700	0,000	0,000	0,000	0,000	0,070	0,518	0,065
07138	0,983	0,000	0,000	0,000	0,000	0,067	0,660	0,097
07140	0,252	0,000	0,000	0,000	0,000	0,063	0,082	0,057
07141	0,216	0,000	0,000	0,000	0,000	0,068	0,125	0,000
07143	0,574	0,000	0,000	0,000	0,000	0,069	0,205	0,077
07211	0,412	0,000	0,000	0,000	0,000	0,110	0,302	0,000
07231	0,463	0,000	0,000	0,000	0,000	0,066	0,194	0,061
07232	0,317	0,000	0,000	0,000	0,000	0,059	0,238	0,000
07233	0,297	0,000	0,000	0,000	0,000	0,053	0,189	0,037
07235	0,261	0,000	0,000	0,000	0,000	0,072	0,115	0,051
07311	0,149	0,000	0,000	0,000	0,000	0,054	0,041	0,000
07312	0,448	0,000	0,000	0,000	0,000	0,074	0,271	0,079
07313	0,141	0,000	0,000	0,000	0,000	0,085	0,056	0,000
07314	28,461	0,000	0,000	27,637	0,000	0,115	0,362	0,048
07315	0,569	0,000	0,000	0,000	0,000	0,123	0,243	0,138
07316	0,193	0,000	0,000	0,000	0,000	0,087	0,106	0,000
07317	0,160	0,000	0,000	0,000	0,000	0,087	0,072	0,000
07318	0,435	0,000	0,000	0,000	0,000	0,254	0,112	0,069
07319	1,960	0,000	0,000	0,000	0,000	0,136	1,658	0,141
07320	0,124	0,000	0,000	0,000	0,000	0,080	0,045	0,000
07331	0,361	0,000	0,000	0,000	0,000	0,071	0,194	0,073
07332	0,267	0,000	0,000	0,000	0,000	0,075	0,075	0,066
07333	0,265	0,000	0,000	0,000	0,000	0,056	0,126	0,063
07334	0,604	0,000	0,000	0,000	0,000	0,072	0,355	0,153
07335	0,174	0,000	0,000	0,000	0,000	0,063	0,089	0,000
07336	0,128	0,000	0,000	0,000	0,000	0,056	0,053	0,000

07337	0,299	0,000	0,000	0,000	0,000	0,068	0,119	0,090
07338	0,327	0,000	0,000	0,000	0,000	0,117	0,157	0,054
07339	0,629	0,000	0,000	0,000	0,000	0,122	0,141	0,215
07340	0,172	0,000	0,000	0,000	0,000	0,063	0,049	0,039
08111	1,733	0,263	0,315	0,000	0,000	0,198	0,201	0,159
08115	1,124	0,000	0,218	0,000	0,000	0,225	0,218	0,212
08116	2,105	0,000	0,262	0,000	0,000	0,304	1,020	0,175
08117	0,779	0,000	0,175	0,000	0,000	0,080	0,286	0,076
08118	1,834	0,000	0,284	0,000	0,000	0,178	0,359	0,404
08119	1,829	0,000	0,242	0,000	0,000	0,231	1,076	0,098
08121	1,500	0,000	0,000	0,000	0,000	0,196	1,155	0,149
08125	1,357	0,000	0,233	0,000	0,000	0,238	0,327	0,241
08126	0,389	0,000	0,000	0,000	0,000	0,068	0,198	0,101
08127	0,655	0,000	0,000	0,000	0,000	0,079	0,437	0,113
08128	0,451	0,000	0,000	0,000	0,000	0,107	0,228	0,052
08135	0,455	0,000	0,000	0,000	0,000	0,069	0,259	0,103
08136	1,453	0,000	0,204	0,000	0,000	0,083	0,788	0,161
08211	0,208	0,000	0,000	0,000	0,000	0,067	0,119	0,000
08212	1,657	0,000	0,190	0,000	0,000	0,187	1,095	0,120
08215	6,388	0,000	0,237	3,235	0,000	0,317	1,910	0,371
08216	1,335	0,000	0,000	0,000	0,000	0,157	0,946	0,182
08221	0,207	0,000	0,000	0,000	0,000	0,139	0,068	0,000
08222	3,121	0,000	0,186	0,000	0,000	0,253	2,315	0,297
08225	0,271	0,000	0,000	0,000	0,000	0,068	0,102	0,043
08226	2,623	0,000	0,280	0,000	0,000	0,237	1,249	0,273
08231	0,230	0,000	0,000	0,000	0,000	0,128	0,102	0,000
08235	0,294	0,000	0,000	0,000	0,000	0,074	0,127	0,068
08236	0,347	0,000	0,000	0,000	0,000	0,071	0,111	0,058
08237	0,314	0,000	0,000	0,000	0,000	0,065	0,176	0,051
08311	0,384	0,000	0,000	0,000	0,000	0,092	0,188	0,043
08315	0,719	0,000	0,171	0,000	0,000	0,072	0,196	0,109
08316	0,285	0,000	0,000	0,000	0,000	0,074	0,096	0,057
08317	6,003	0,263	0,222	0,000	0,000	0,278	4,516	0,233
08325	0,336	0,000	0,000	0,000	0,000	0,072	0,121	0,055
08326	1,128	0,000	0,000	0,000	0,000	0,115	0,752	0,102
08327	0,314	0,000	0,000	0,000	0,000	0,071	0,148	0,072
08335	1,470	0,000	0,171	0,000	0,000	0,172	0,787	0,138
08336	0,435	0,000	0,000	0,000	0,000	0,071	0,135	0,087
08337	0,368	0,000	0,000	0,000	0,000	0,074	0,215	0,054
08415	0,632	0,000	0,000	0,000	0,000	0,080	0,306	0,090
08416	1,325	0,000	0,000	0,000	0,000	0,137	1,068	0,041
08417	1,510	0,000	0,000	0,000	0,000	0,113	1,189	0,059
08421	0,940	0,263	0,000	0,000	0,000	0,125	0,405	0,148
08425	0,745	0,000	0,000	0,000	0,000	0,079	0,416	0,224
08426	0,575	0,000	0,000	0,000	0,000	0,120	0,315	0,113
08435	0,709	0,000	0,000	0,000	0,000	0,110	0,431	0,063
08436	2,322	0,000	0,179	0,000	0,000	0,141	1,511	0,090

08437	0,321	0,000	0,000	0,000	0,000	0,066	0,189	0,044
09161	0,791	0,000	0,000	0,192	0,000	0,081	0,377	0,087
09162	2,938	0,345	0,635	0,000	0,000	0,329	0,587	0,255
09163	1,210	0,230	0,000	0,000	0,000	0,198	0,782	0,000
09171	2,466	0,000	0,000	1,999	0,000	0,112	0,290	0,044
09172	0,228	0,000	0,000	0,000	0,000	0,060	0,148	0,000
09173	0,172	0,000	0,000	0,000	0,000	0,068	0,081	0,000
09174	0,388	0,000	0,000	0,000	0,000	0,074	0,161	0,128
09175	0,395	0,000	0,000	0,000	0,000	0,073	0,150	0,146
09176	0,385	0,000	0,000	0,000	0,000	0,065	0,218	0,080
09177	0,425	0,000	0,000	0,000	0,000	0,069	0,214	0,119
09178	0,839	0,000	0,000	0,000	0,000	0,077	0,525	0,211
09179	0,346	0,000	0,000	0,000	0,000	0,124	0,124	0,098
09180	0,121	0,000	0,000	0,000	0,000	0,056	0,045	0,000
09181	0,402	0,000	0,000	0,000	0,000	0,159	0,150	0,070
09182	0,151	0,000	0,000	0,000	0,000	0,066	0,063	0,000
09183	0,301	0,000	0,000	0,000	0,000	0,064	0,159	0,057
09184	1,290	0,000	0,202	0,000	0,000	0,334	0,142	0,235
09185	0,438	0,000	0,000	0,000	0,000	0,125	0,241	0,051
09186	6,103	0,000	0,000	5,582	0,000	0,068	0,318	0,112
09187	0,595	0,000	0,000	0,000	0,000	0,077	0,397	0,069
09188	0,210	0,000	0,000	0,000	0,000	0,113	0,051	0,000
09189	0,397	0,000	0,000	0,000	0,000	0,076	0,135	0,068
09190	0,323	0,000	0,000	0,000	0,000	0,069	0,184	0,047
09261	0,225	0,000	0,000	0,000	0,000	0,111	0,115	0,000
09262	0,212	0,000	0,000	0,000	0,000	0,068	0,121	0,000
09263	0,923	0,000	0,000	0,000	0,000	0,069	0,762	0,069
09271	1,382	0,000	0,000	0,000	0,000	0,136	1,178	0,046
09272	0,194	0,000	0,000	0,000	0,000	0,054	0,081	0,041
09273	0,381	0,000	0,000	0,000	0,000	0,065	0,257	0,037
09274	0,470	0,000	0,000	0,000	0,000	0,073	0,121	0,189
09275	0,527	0,000	0,000	0,000	0,000	0,078	0,207	0,062
09276	0,151	0,000	0,000	0,000	0,000	0,053	0,060	0,000
09277	0,295	0,000	0,000	0,000	0,000	0,065	0,163	0,046
09278	0,279	0,000	0,000	0,000	0,000	0,060	0,140	0,059
09279	0,587	0,000	0,000	0,000	0,000	0,105	0,278	0,184
09361	0,187	0,000	0,000	0,000	0,000	0,113	0,049	0,000
09362	0,619	0,000	0,000	0,000	0,000	0,096	0,216	0,081
09363	0,171	0,000	0,000	0,000	0,000	0,087	0,083	0,000
09371	0,310	0,000	0,000	0,000	0,000	0,061	0,168	0,061
09372	0,939	0,230	0,000	0,000	0,000	0,066	0,568	0,054
09373	1,445	0,000	0,000	0,000	0,000	0,127	1,253	0,043
09374	0,330	0,000	0,000	0,000	0,000	0,078	0,200	0,051
09375	0,538	0,000	0,000	0,000	0,000	0,080	0,170	0,156
09376	0,555	0,000	0,000	0,000	0,000	0,069	0,205	0,080
09377	0,238	0,000	0,000	0,000	0,000	0,073	0,054	0,058
09461	0,996	0,000	0,000	0,000	0,000	0,124	0,872	0,000

09462	0,283	0,000	0,000	0,000	0,000	0,114	0,169	0,000
09463	0,220	0,000	0,000	0,000	0,000	0,153	0,067	0,000
09464	0,569	0,000	0,000	0,000	0,000	0,069	0,476	0,000
09471	0,367	0,000	0,000	0,000	0,000	0,072	0,117	0,092
09472	0,263	0,000	0,000	0,000	0,000	0,062	0,116	0,065
09473	0,294	0,000	0,000	0,000	0,000	0,064	0,140	0,069
09474	0,343	0,000	0,000	0,000	0,000	0,068	0,122	0,130
09475	0,507	0,000	0,000	0,000	0,000	0,061	0,335	0,091
09476	0,205	0,000	0,000	0,000	0,000	0,058	0,128	0,000
09477	0,239	0,000	0,000	0,000	0,000	0,058	0,162	0,000
09478	0,245	0,000	0,000	0,000	0,000	0,055	0,112	0,059
09479	0,196	0,000	0,000	0,000	0,000	0,056	0,121	0,000
09561	1,006	0,000	0,000	0,000	0,000	0,104	0,883	0,000
09562	0,437	0,000	0,000	0,000	0,000	0,136	0,203	0,098
09563	0,437	0,000	0,000	0,000	0,000	0,108	0,217	0,057
09564	2,379	0,230	0,271	0,000	0,000	0,150	1,236	0,362
09565	0,144	0,000	0,000	0,000	0,000	0,109	0,035	0,000
09571	0,655	0,000	0,000	0,000	0,000	0,077	0,213	0,182
09572	0,311	0,000	0,000	0,000	0,000	0,079	0,118	0,087
09573	0,151	0,000	0,000	0,000	0,000	0,076	0,050	0,000
09574	0,367	0,000	0,000	0,000	0,000	0,054	0,138	0,048
09575	0,415	0,000	0,000	0,000	0,000	0,060	0,142	0,119
09576	0,295	0,000	0,000	0,000	0,000	0,069	0,109	0,037
09577	0,222	0,000	0,000	0,000	0,000	0,059	0,143	0,000
09661	0,412	0,000	0,000	0,000	0,000	0,121	0,219	0,072
09662	0,276	0,000	0,000	0,000	0,000	0,125	0,151	0,000
09663	0,649	0,000	0,000	0,000	0,000	0,084	0,433	0,000
09671	0,549	0,000	0,000	0,000	0,000	0,067	0,180	0,168
09672	0,273	0,000	0,000	0,000	0,000	0,062	0,109	0,044
09673	0,185	0,000	0,000	0,000	0,000	0,057	0,109	0,000
09674	0,331	0,000	0,000	0,000	0,000	0,058	0,197	0,057
09675	0,441	0,000	0,000	0,000	0,000	0,061	0,177	0,094
09676	0,302	0,000	0,000	0,000	0,000	0,070	0,112	0,058
09677	0,328	0,000	0,000	0,000	0,000	0,067	0,113	0,066
09678	0,356	0,000	0,000	0,000	0,000	0,066	0,184	0,084
09679	0,394	0,000	0,000	0,000	0,000	0,075	0,139	0,081
09761	1,104	0,000	0,186	0,000	0,000	0,126	0,440	0,170
09762	0,140	0,000	0,000	0,000	0,000	0,106	0,034	0,000
09763	0,467	0,000	0,000	0,000	0,000	0,114	0,353	0,000
09764	2,230	0,000	0,000	0,000	0,000	0,221	1,940	0,069
09771	0,842	0,000	0,000	0,000	0,000	0,071	0,690	0,058
09772	1,128	0,000	0,173	0,000	0,000	0,075	0,342	0,235
09773	0,341	0,000	0,000	0,000	0,000	0,062	0,186	0,072
09774	0,425	0,000	0,000	0,000	0,000	0,068	0,150	0,079
09775	1,707	0,000	0,000	0,000	0,000	0,156	1,391	0,117
09776	0,160	0,000	0,000	0,000	0,000	0,063	0,075	0,000
09777	0,345	0,000	0,000	0,000	0,000	0,068	0,128	0,059

09778	0,541	0,000	0,000	0,000	0,000	0,071	0,181	0,153
09779	0,577	0,000	0,000	0,000	0,000	0,069	0,217	0,106
09780	0,278	0,000	0,000	0,000	0,000	0,071	0,098	0,051
10041	2,968	0,000	0,211	0,000	2,033	0,164	0,402	0,102
10042	0,216	0,000	0,000	0,000	0,000	0,084	0,132	0,000
10043	0,227	0,000	0,000	0,000	0,000	0,054	0,089	0,000
10044	42,257	0,000	0,171	0,000	41,330	0,188	0,222	0,075
10045	0,520	0,000	0,000	0,000	0,000	0,171	0,174	0,062
10046	0,163	0,000	0,000	0,000	0,000	0,068	0,072	0,000
11000	9,777	1,230	1,436	0,000	0,000	0,691	3,843	1,109
12051	1,944	0,000	0,000	0,000	0,000	0,128	1,799	0,000
12052	0,108	0,000	0,000	0,000	0,000	0,069	0,017	0,000
12053	0,106	0,000	0,000	0,000	0,000	0,072	0,034	0,000
12054	0,144	0,000	0,000	0,000	0,000	0,114	0,029	0,000
12060	0,164	0,000	0,000	0,000	0,000	0,070	0,053	0,000
12061	0,378	0,000	0,000	0,000	0,000	0,068	0,054	0,179
12062	0,129	0,000	0,000	0,000	0,000	0,056	0,054	0,000
12063	0,325	0,000	0,000	0,000	0,000	0,065	0,083	0,126
12064	0,290	0,000	0,000	0,000	0,000	0,072	0,066	0,106
12065	0,345	0,000	0,000	0,000	0,000	0,075	0,071	0,150
12066	0,211	0,000	0,000	0,000	0,000	0,058	0,067	0,044
12067	9,024	0,000	0,000	0,000	8,687	0,070	0,090	0,123
12068	0,156	0,000	0,000	0,000	0,000	0,053	0,064	0,000
12069	0,278	0,000	0,000	0,000	0,000	0,077	0,074	0,076
12070	0,101	0,000	0,000	0,000	0,000	0,049	0,036	0,000
12071	0,154	0,000	0,000	0,000	0,000	0,060	0,074	0,000
12072	0,535	0,000	0,000	0,000	0,000	0,124	0,120	0,204
12073	10,462	0,000	0,000	10,172	0,000	0,166	0,105	0,000
13003	0,613	0,000	0,000	0,000	0,000	0,079	0,481	0,000
13004	0,173	0,000	0,000	0,000	0,000	0,070	0,080	0,000
13071	0,538	0,000	0,170	0,000	0,000	0,054	0,172	0,072
13072	0,200	0,000	0,000	0,000	0,000	0,075	0,041	0,059
13073	0,224	0,000	0,000	0,000	0,000	0,074	0,067	0,058
13074	0,164	0,000	0,000	0,000	0,000	0,063	0,040	0,040
13075	0,175	0,000	0,000	0,000	0,000	0,074	0,026	0,050
13076	0,340	0,000	0,000	0,000	0,000	0,076	0,044	0,181
14511	0,508	0,000	0,000	0,000	0,000	0,090	0,308	0,050
14521	0,516	0,000	0,215	0,000	0,000	0,085	0,064	0,075
14522	0,616	0,000	0,189	0,000	0,000	0,122	0,110	0,105
14523	0,333	0,000	0,000	0,000	0,000	0,067	0,143	0,059
14524	1,388	0,000	0,201	0,000	0,000	0,169	0,839	0,084
14612	3,551	0,183	0,296	0,000	0,000	0,305	2,478	0,046
14625	1,394	0,000	0,189	0,000	0,000	0,157	0,849	0,084
14626	0,590	0,183	0,174	0,000	0,000	0,067	0,057	0,044
14627	0,485	0,000	0,000	0,000	0,000	0,136	0,133	0,102
14628	0,280	0,000	0,000	0,000	0,000	0,114	0,052	0,051
14713	1,111	0,183	0,295	0,000	0,000	0,136	0,110	0,254

14729	0,520	0,000	0,185	0,000	0,000	0,071	0,103	0,079
14730	0,381	0,000	0,000	0,000	0,000	0,074	0,115	0,127
15001	0,106	0,000	0,000	0,000	0,000	0,059	0,028	0,000
15002	0,446	0,000	0,000	0,000	0,000	0,108	0,214	0,068
15003	0,814	0,181	0,000	0,000	0,000	0,087	0,401	0,087
15081	0,254	0,000	0,000	0,000	0,000	0,092	0,107	0,000
15082	0,366	0,000	0,000	0,000	0,000	0,068	0,131	0,076
15083	0,633	0,000	0,000	0,000	0,000	0,071	0,417	0,121
15084	0,508	0,000	0,000	0,000	0,000	0,071	0,196	0,095
15085	0,416	0,000	0,175	0,000	0,000	0,077	0,103	0,000
15086	0,184	0,000	0,000	0,000	0,000	0,054	0,082	0,000
15087	0,194	0,000	0,000	0,000	0,000	0,063	0,081	0,000
15088	25,005	0,000	0,000	24,341	0,000	0,122	0,404	0,113
15089	1,204	0,000	0,000	0,666	0,000	0,140	0,186	0,073
15090	1,399	0,000	0,000	0,000	0,000	0,101	1,279	0,000
15091	24,137	0,000	0,000	23,003	0,000	0,060	1,052	0,000
16051	0,562	0,000	0,000	0,000	0,000	0,072	0,345	0,097
16052	0,179	0,000	0,000	0,000	0,000	0,069	0,087	0,000
16053	0,543	0,000	0,000	0,000	0,000	0,104	0,439	0,000
16054	0,098	0,000	0,000	0,000	0,000	0,073	0,026	0,000
16055	0,180	0,000	0,000	0,000	0,000	0,065	0,093	0,000
16056	0,181	0,000	0,000	0,000	0,000	0,053	0,111	0,000
16061	0,253	0,000	0,000	0,000	0,000	0,057	0,177	0,000
16062	1,912	0,000	0,000	0,000	0,000	0,121	1,774	0,000
16063	0,364	0,000	0,000	0,000	0,000	0,063	0,217	0,063
16064	0,224	0,000	0,000	0,000	0,000	0,054	0,151	0,000
16065	0,175	0,000	0,000	0,000	0,000	0,050	0,054	0,000
16066	0,253	0,000	0,000	0,000	0,000	0,062	0,170	0,000
16067	0,557	0,000	0,000	0,000	0,000	0,063	0,183	0,177
16068	0,309	0,000	0,000	0,000	0,000	0,066	0,131	0,112
16069	0,156	0,000	0,000	0,000	0,000	0,051	0,089	0,000
16070	0,267	0,000	0,000	0,000	0,000	0,057	0,191	0,000
16071	0,163	0,000	0,000	0,000	0,000	0,053	0,093	0,000
16072	0,188	0,000	0,000	0,000	0,000	0,067	0,082	0,039
16073	0,424	0,166	0,000	0,000	0,000	0,057	0,182	0,000
16074	0,491	0,000	0,000	0,000	0,000	0,054	0,354	0,066
16075	0,392	0,000	0,000	0,000	0,000	0,053	0,276	0,044
16076	0,316	0,000	0,000	0,000	0,000	0,058	0,238	0,000
16077	0,267	0,000	0,000	0,000	0,000	0,056	0,193	0,000

Appendix E

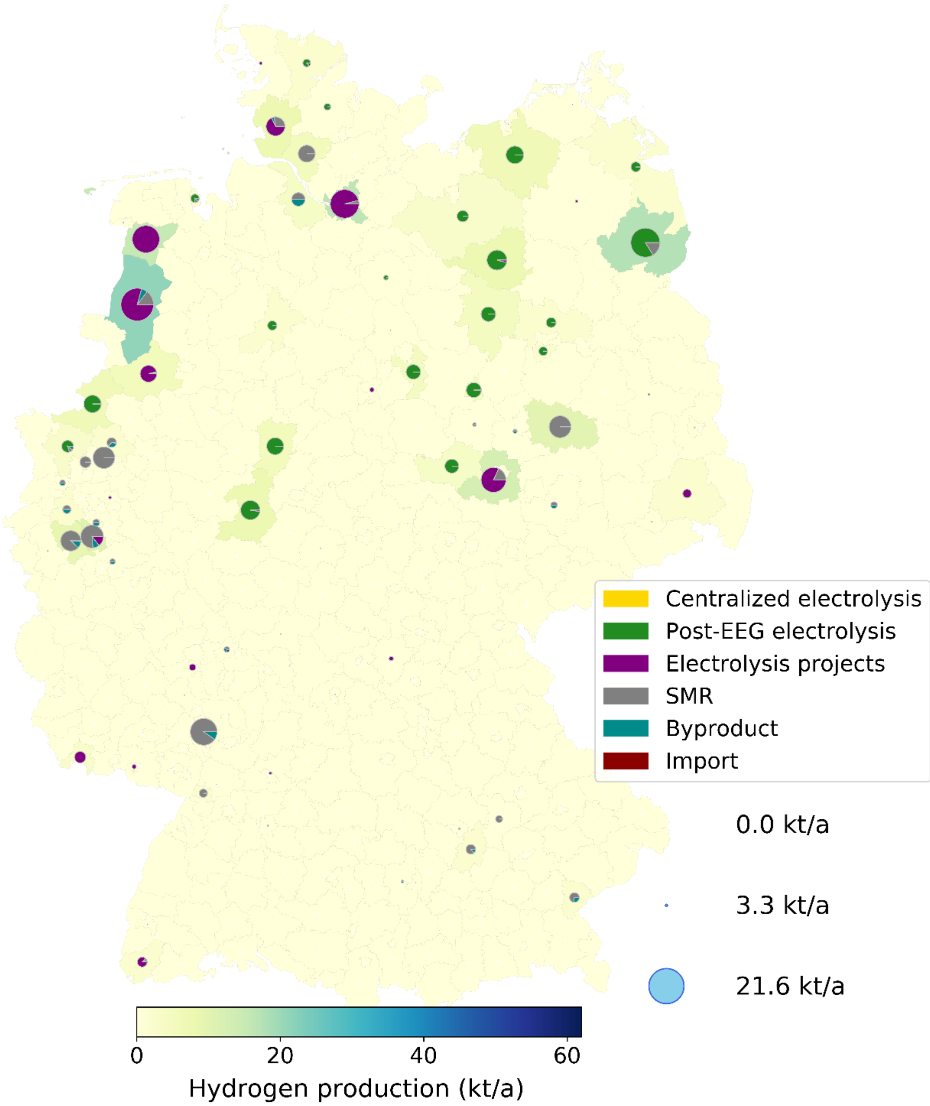

Figure E 1. Hydrogen production distribution and structure in the year 2025.

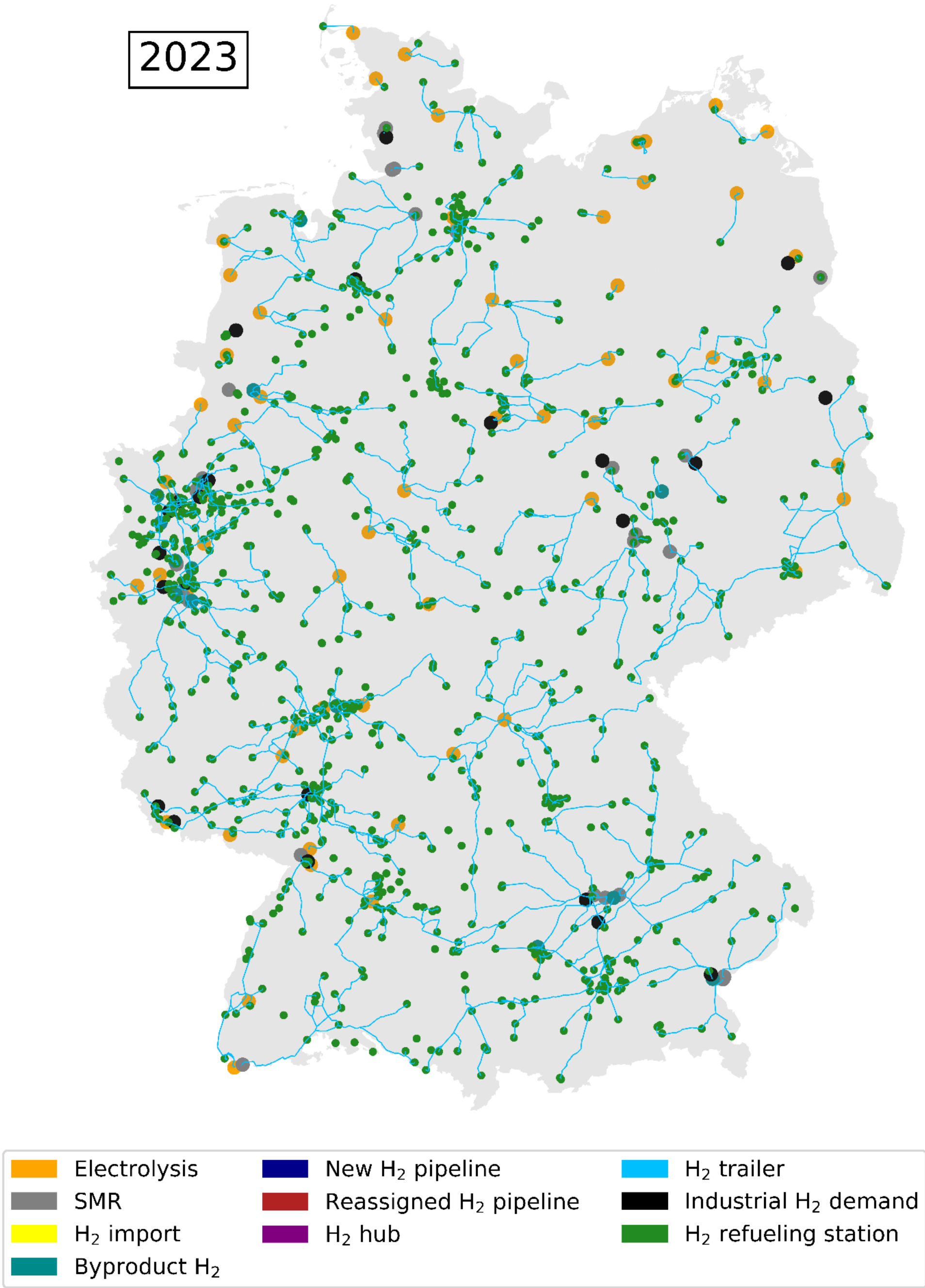

Figure E 2. Combined pipeline and GH2 trailer hydrogen supply chain in Germany in the year 2023.

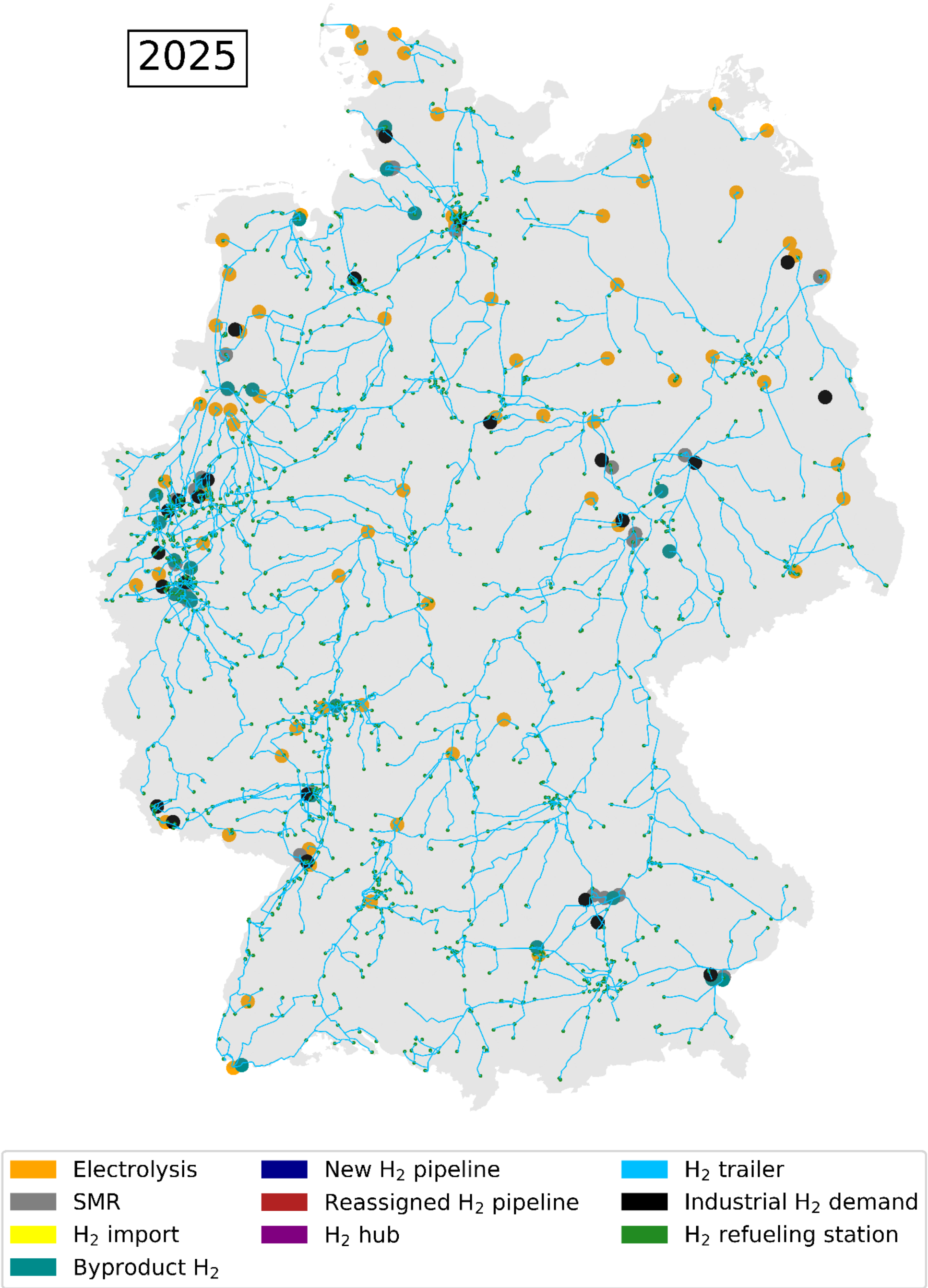

Figure E 3. Combined pipeline and GH2 trailer hydrogen supply chain in Germany in the year 2025.

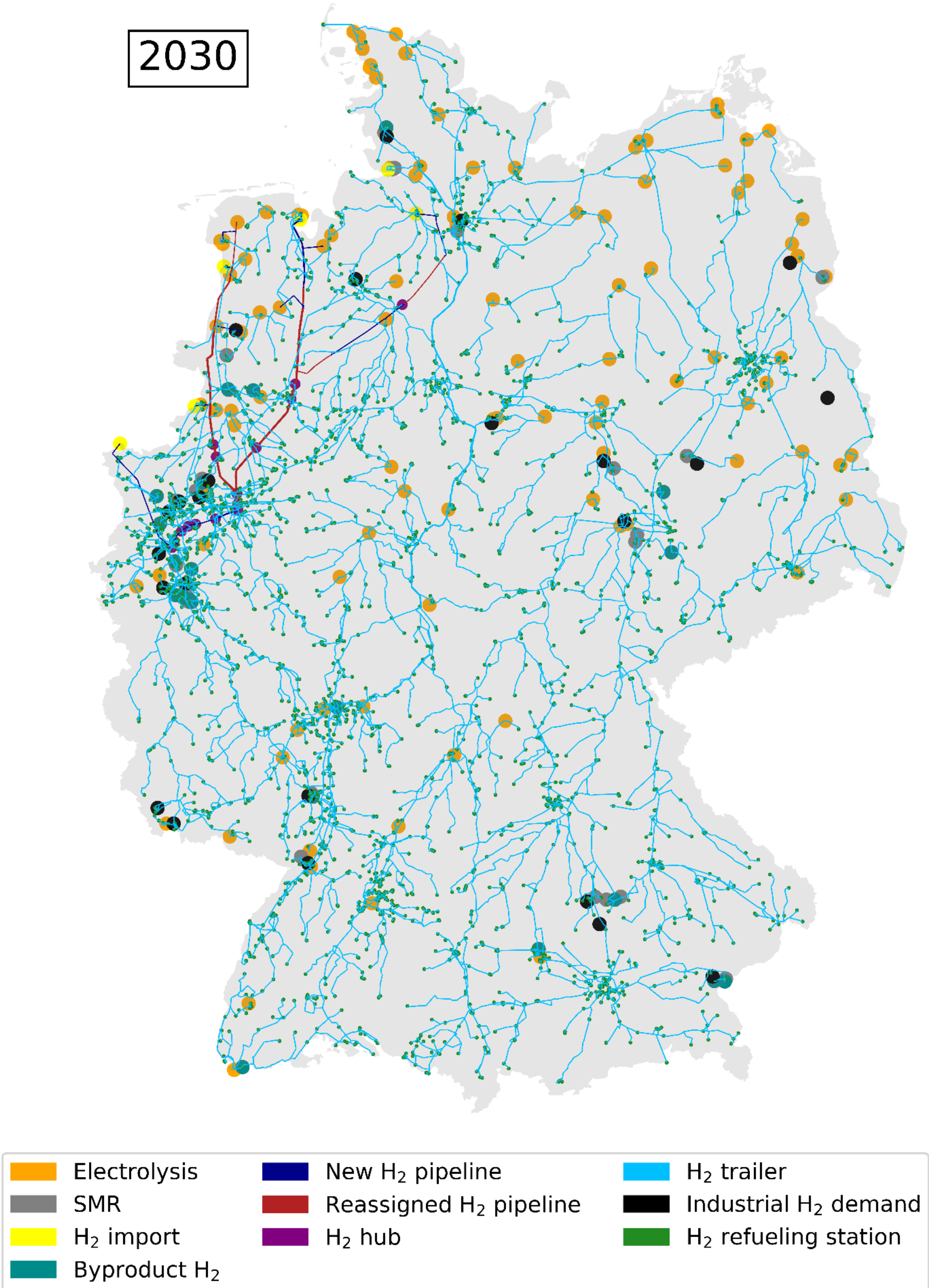

Figure E 4. Combined pipeline and GH2 trailer hydrogen supply chain in Germany in the year 2030.

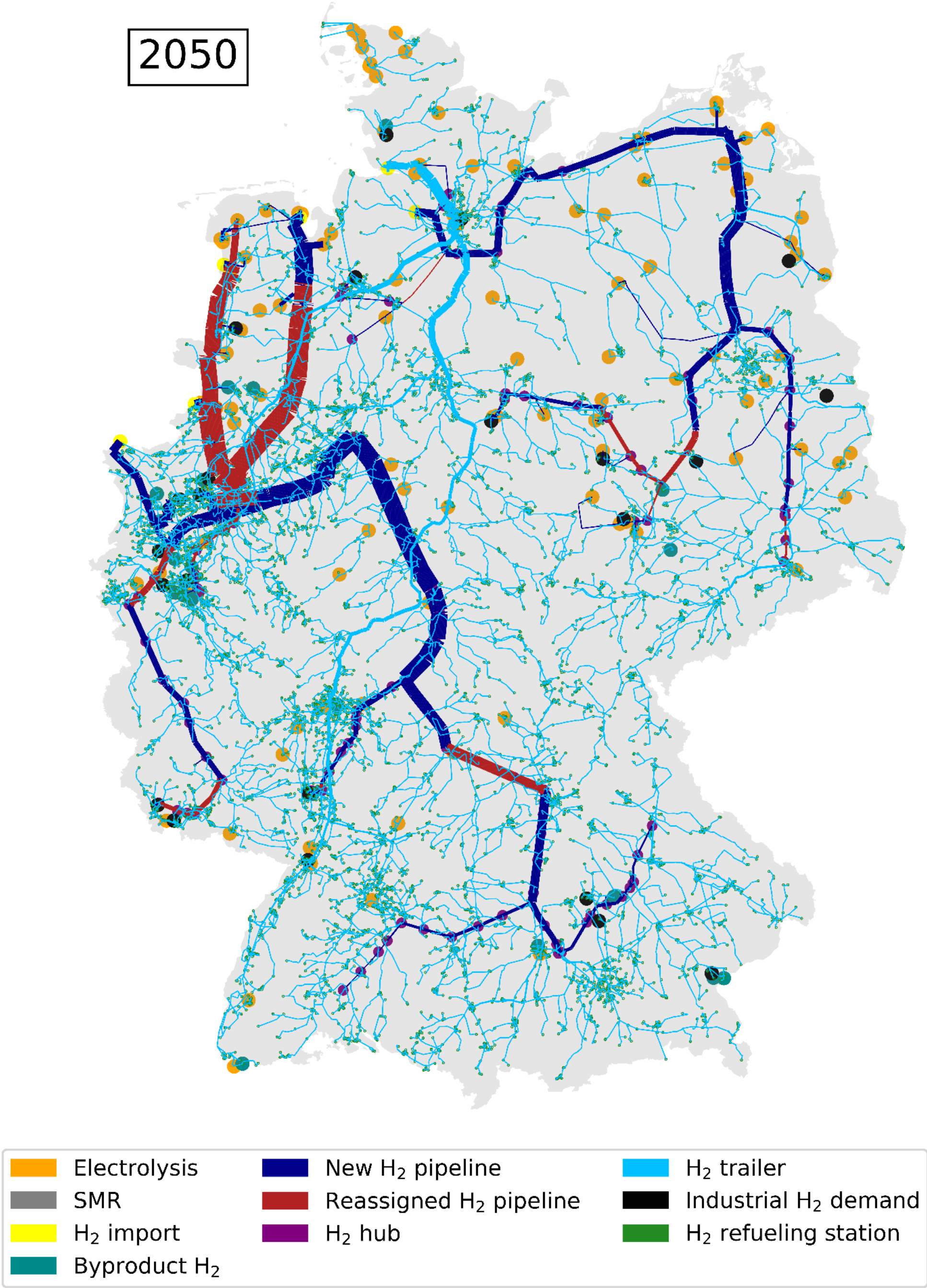

Figure E 5. Combined pipeline and GH2 trailer hydrogen supply chain in Germany in the year 2050.

Nomenclature

Acronyms and Abbreviations

ABM	*agent-based modeling*
AEL	*alkaline electrolysis*
AUC	*area under the curve*
BALMOREL	*Baltic Model of Regional Energy Market*
BoP	*balance of plant*
CAPEX	*capital expenditure*
CCS	*carbon capture and storage*
CGH2	*compressed gaseous hydrogen*
CO	*carbon monoxide*
CO2	*carbon dioxide*
DWD	*don’t worry distance*
EEG	*Renewable Energy Act*
EL	*electrolysis*
EU	*European Union*
EUA	*European Emission Allowances*
FCEV	*fuel cell electric vehicle*
FLH	*full load hours*
GH2	*gaseous hydrogen*
GHG	*greenhouse gas*
H2	*hydrogen*
H2A	*Hydrogen Analysis*
H2MIND	*Hydrogen Market & Infrastructure Development*
H2O	*water*
HDRSAM	*Heavy-duty refueling station analysis model*
HDSAM	*Hydrogen delivery systems analysis model*
HRS	*hydrogen refueling station*
HRSAM	*Hydrogen refueling station analysis model*
HV	*high voltage*
HyDS ME	*Hydrogen deployment system modeling environment*
Hytrans	*Hydrogen Transition*
ICV	*internal combustion vehicle*
LCOE	*levelized cost of electricity*
L-gas	*low calorific gas*
LH2	*liquid hydrogen*
LHV	*lower heating value*
LNG	*liquefied natural gas*
LOHCs	*liquid organic hydrogen carriers*
LR	*learning rate*
MILP	*mixed-integer linear program*
NETS	*National Emissions Trading System*
NG	*natural gas*
NUTS	*Nomenclature of territorial units for statistics*
O&M	*operation and maintenance*
O2	*oxygen*
OEMs	*original equipment manufacturers*
OPEX	*operational expenditures*

PEMEL	*polymer electrolyte membrane electrolysis*
PEMFC	*proton-exchange fuel cell*
PPAs	*power purchase agreements*
PSA	*pressure swing adsorption*
PtG	*power-to-gas*
PV	*photovoltaic*
PWM	*pipeline without modification*
R&D	*research and development*
SD	*system dynamics*
SMR	*steam methane reforming*
SO2	*sulfur dioxide*
SOEL	*solid oxide electrolysis*
TRL	*technology readiness level*
TSA	*temperature swing adsorption*
USA	*United States of America*
VRE	*variable renewable energy*
WACC	*weighted average cost of capital*

Symbols

η	*efficiency*
N	*market penetration*
p	*innovator coefficient*
q	*imitator coefficient*
t	*time*

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