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Utilization potentials for offshore PtX products using the example of industrial application field

Universität Stuttgart

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Abbreviations & Units

BF-BOF = Blast Furnace-Basic Oxygen Furnace

BTX = Benzene, Toluene, Xylene (Aromatics)

CCS = Carbon Capture and Storage

CCUS = Carbon Capture Utilisation and Storage

CO_2 = Carbon Dioxide

CO_2eq. = Carbon Dioxide equivalent

EAF = Electric Arc Furnace

FT = Fischer Tropsch

GDP = Gross Domestic Product

GHG = Greenhouse Gases

H_2 = Hydrogen

HVC = High Value Chemical

kt = Kilo tonne

LHV = Lower Heating Value

MNC = Multi National Corporation

Mt = Million/Mega tonne

MtA = Methanol-to-Aromatics

MtG = Methanol-to-Gasoline

MtJ = Methanol-to-Jetfuel

MtO = Methanol-to-Olefins

MtX = Methanol-to-X

NG = Natural Gas

NWS = German National Hydrogen Strategy

PtX = Power-to-X

SAF = Submerged Arc Furnace

SME = Small and Medium Enterprises

SMR = Steam Methane Reforming

TIMES = The Integrated MARKAL-EFOM System

TRL = Technology Readiness Level

WAG = Works-Arising-Gases

WGS = Water Gas Shift

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Kurzfassung

Der deutsche Industriesektor ist stark von fossilen Brennstoffen wie Erdgas abhängig, was zu erheblichen CO_2-Emissionen führt. Prozessbedingte Emissionen, die durch spezifische industrielle Prozesse entstehen, machen es schwer, diesen Sektor zu dekarbonisieren. Wasserstoff bietet aufgrund seiner Vielseitigkeit eine potenzielle Lösung zur Deckung des Energie- und Rohstoffbedarfs. Verschiedene Studien prognostizieren einen erheblichen Wasserstoffbedarf in allen deutschen Endverbrauchssektoren, insbesondere in der Industrie und im Verkehr, um Netto-THG-Neutralität zu erreichen. Trotz erheblicher Unterschiede zwischen den Studien liegt der durchschnittliche industrielle Bedarf zwischen 40 TWh H_2 (~1.2 Mt H_2) im Jahr 2030 und etwa 200 TWh H_2 (~6 Mt H_2) im Jahr 2045. Langfristig wird eine maximale Gesamtnachfrage von etwa 517 TWh H_2/a (~15.5 Mt H_2/a) erwartet. Wichtige Teilsektoren, die diese Nachfrage antreiben, sind die Grundstoffchemie, die Eisen- und Stahlindustrie sowie der Raffineriesektor. Auch der Lebensmittelsektor bietet potenzielle Anwendungen, um die Nachfrage zu steigern. Eine statische Analyse der aktuellen Strukturen und Bedarfswerte zeigt ein theoretisches maximales Nutzungspotenzial von etwa 965 TWh H_2/a (~29 Mt H_2/a) in den Industriebranchen, wobei ca. 60% im Raffinerie- und 24% im Basischemiesektor nutzbar sind. Die Auswirkungen der Wasserstoffpreise auf die Nachfrage wurden in verschiedenen H2-Preisszenarien in einem kostenoptimalen Modellsystem unter Vorgaben zur Emissionsminderung untersucht. Die Gesamtnachfrage bleibt relativ stabil, wobei sich der Anteil des gekauften im Vergleich zum selbst erzeugten Wasserstoff verschiebt. Bei niedrigen Preisen wird fast die gesamte Wasserstoffnachfrage von etwa 250 TWh (~7.5 Mt H_2) im Jahr 2045 eingekauft, während in teureren Szenarien etwa die Hälfte selbst erzeugt wird. Da Deutschland voraussichtlich ein Nettoimporteur von Wasserstoff sein wird, sind die Preisabhängigkeit und Anwendbarkeit von großer Bedeutung.

Abstract

The German industry sector currently relies heavily on fossil fuels like natural gas for energetic and feedstock requirements resulting in substantial CO_2 emissions. Process-based emissions, inherent to the specific industrial processes further classify it as a hard-to-abate sector in terms of its emission reducibility. Hydrogen, with its versatility, offers a potential solution for providing energy as well as feedstock requirements. Various studies project significant hydrogen demand across German end-use sectors, particularly in industry and transport, to achieve net-GHG neutrality. Despite significant differences across the individual studies, average industrial demand ranges from 40 TWh H_2 (~1.2 Mt H_2) in 2030 to around 200 TWh H_2 (~6 Mt H_2) in 2045. The maximum total demand in industry for long-term aspects is observed to be around 517 TWh H_2/a (~15.5 Mt H_2/a). Key sub-sectors driving these demands include the basic chemical, iron & steel, as well as the refinery sector. The food sub-sector, although not a significant player, also has potential applications to further add to these demands. To analyse the theoretical maximum usage potential of hydrogen within these industrial sub-sectors, a static analysis considering the current structures and values demanded is carried out. This results in a maximum total hydrogen usability in the industrial branches of around 965 TWh H_2/a (~29 Mt H_2/a), of which around 60% and 24% is usable in the refinery and the basic chemical sectors respectively. The impact of hydrogen prices on demand was explored through various price scenarios in a cost-optimal industry-specific model. The total industrial demand under these conditions is seen to remain relatively stable over the different price scenarios, with shifts primarily in the proportion of bought versus self-generated hydrogen. Under low prices, almost all of the total demanded hydrogen of around 250 TWh (~7.5 Mt H_2) in 2045 is bought, while in the most expensive cases, around half is self-generated. Considering that Germany is expected to be a net-importer of hydrogen, the price-dependency and hence its applicability are of significant considerations.

1. Introduction

The German economic market depends significantly on the industrial sector in terms of its contribution to the national GDP (Gross Domestic Product). In 2021, it was the single highest contributing sector at 25% of the national GDP, followed by the public service sector at 19%, and trade and transport at around 16% (Destatis 2024). In terms of GHG emissions, the industry sector followed the energy generation sector and contributed to a similar 24% (182 Mt $CO_{2eq.}$) of the total 760 Mt $CO_{2eq.}$ emissions in 2021 (Umwelt Bundesamt 2023). These emissions result from the high dependence on coal and other fossil-based gases (54%) for the various processes involved to meet the required energy and feedstock demands (Rohde and Arnold-Keifer 2023). These factors of emission shares and fuel-use among the different industrial sub-sectors are shown through Fig. 1.

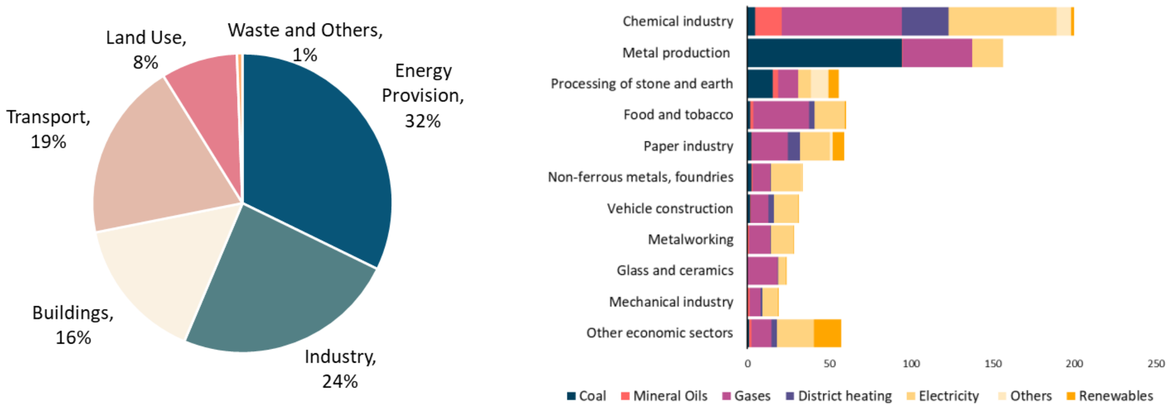

Fig. 1: Emission shares across economic sectors (left), and Fuel sources used among the industrial sub-sectors (right) in 2021. (Source: (Umwelt Bundesamt 2023), (Rohde and Arnold-Keifer 2023))

Since industrial applications require high temperatures and large quantities of energy, direct use of renewable sources is rather challenging (Neuwirth et al. 2022). However, hydrogen and PtX (Power-to-X) products are some low-carbon alternatives that could play a vital role in decarbonising the industrial sector in the long term (Staffell et al. 2019). As a result, both, the European hydrogen strategy, and the German national hydrogen strategy aim to promote applications of hydrogen in the end-use sectors of industry, transport, as well as for heating (European Commission 2020; BMWi 2020).

The German National Hydrogen Strategy, in its updated form, aims to establish 10 GW of domestic hydrogen generation capacity by 2030 to be able to produce 28 TWh (~0.84 Mt H_2) of hydrogen. At the same time, it also acknowledges a significant reliance on hydrogen imports to meet the projected hydrogen demands of 90 – 100 TWh (~2.7 – 3 Mt H_2) (BMWi 2020). The different studies considered agree for Germany that in the long-term, the highest utilisation potential for hydrogen lies in the industrial sector, closely followed by the transport sector, with also considerable demands in the energetic reconversion, and the building heat sectors. This can also be seen in Fig. 2 from the meta-analysis comparing different studies in terms of their sectoral final energy hydrogen demand. Among the studies considered, the scenarios from Ariadne (Pfluger et al. 2021) generally lead in terms of the total demanded hydrogen. For 2030, the total demand values of the H_2-imp scenario (scenario with high import potential and stronger direct usage of hydrogen for applications difficult to directly electrify) from Ariadne (Pfluger et al. 2021) are comparable to those from the BDI study (Burchardt et al. 2021) at around 100 TWh/a (~3 Mt H_2/a). However, the intrinsic demand among the sectors is different – the former has the majority demand in the industry sector, followed by the reconversion and the transport sectors respectively, while the latter has the majority demand in the industry sector, followed by the transport sector with no specific demand in the reconversion sector respectively. The lowest demand is observed from the TN-Strom scenario (scenario with strong direct electrification and use of hydrogen only as a raw material) of the ISI Langfrist scenario study on behalf of BMWK (Fleiter et al. 2021) with total demand nearing 20 TWh (~0.6 Mt H_2) with all of it being demanded from the industry sector. For 2045, the Efuel scenario (scenario with high import potential and usage of E-fuels along with direct electrification) from Ariadne (Pfluger et al. 2021) sees the highest uptake of hydrogen in the form of powerfuel (totalling around 960 TWh/a; ~28.8 Mt H_2/a), followed by the Ariadne H_2-imp scenario with the highest demand being in the industry sector, followed by the transport and energetic reconversion sectors respectively. The lowest demand reported in 2045, comes again from the ISI Long-term scenario study (Fleiter et al. 2021) at around 100 TWh (~3 Mt H_2) in the TN-Strom scenario, with all of it being similarly demanded in the industry sector. Another meta-study from the Fraunhofer institutes, which considered additional studies along with the ones covered here, came to the same conclusion in terms of sectoral hydrogen demand patterns (Wietschel et al. 2021).

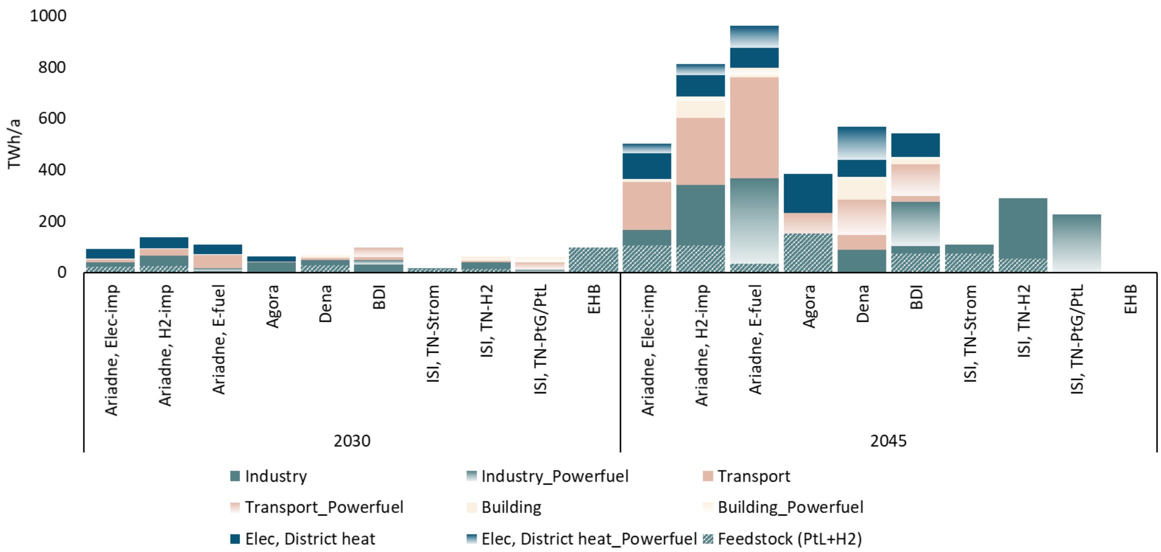

Fig. 2: H2 & Powerfuel (PtG/PtL) final energy demands across different studies for different end-use sectors of Germany. (Sources: (Pfluger et al. 2021; Prognos et al. 2021; Jugel et al. 2021; Burchardt et al. 2021; Fleiter et al. 2021; Wang et al. 2021))

Since the hydrogen demand considered across the studies is the highest in the industrial sector, analysing them in detail to understand which industrial sub-sectors drive these can be beneficial. This is briefly done in the following sections. First, a brief literature-based analysis of the hydrogen demand in the industrial sub-sectors is considered in section 2. Following this, a static analysis of the industrial sub-sectors and the theoretical amount of hydrogen usable under current structures is analysed in section 3. Finally, a dynamic analysis to represent the effect of hydrogen costs on the industrial demand is carried out in section 4.

2. Literature Analysis

In this section, the overall utilisation of hydrogen (including as powerfuels) in the industry sector for energetic as well as feedstock purposes is considered. The section follows from the previous mentioned meta-analysis, and considers the industry specific view in terms of hydrogen (and powerfuels) demanded, and further dives into the specific industrial sub-sectors contributing to this demand. Only a few sources provide detailed descriptions required for this analysis, restricting the scope to the amount of available data.

Fig. 3 shows the projected demand for hydrogen and powerfuels in the German industry sector from the studies considered in the previously mentioned meta-analysis. The industrial demand is already present in 2030 at an average of around 40 TWh/a with the highest requirement seen in the Ariadne H_2-imp scenario (Pfluger et al. 2021) at around 66 TWh, one-third of which results from feedstock requirements. By 2045, even though the shares of feedstock demand remain similar, the total industrial demand increases 5 folds, resulting in requirements of more than 340 TWh in the Ariadne E-fuel and H_2-imp scenarios. In terms of powerfuels, the average demand remains at around 240 TWh with the highest requirement seen in the E-fuel scenario of the Ariadne study at around 340 TWh (Pfluger et al. 2021), while the least demand is seen from the BDI study at around 170 TWh (Burchardt et al. 2021).

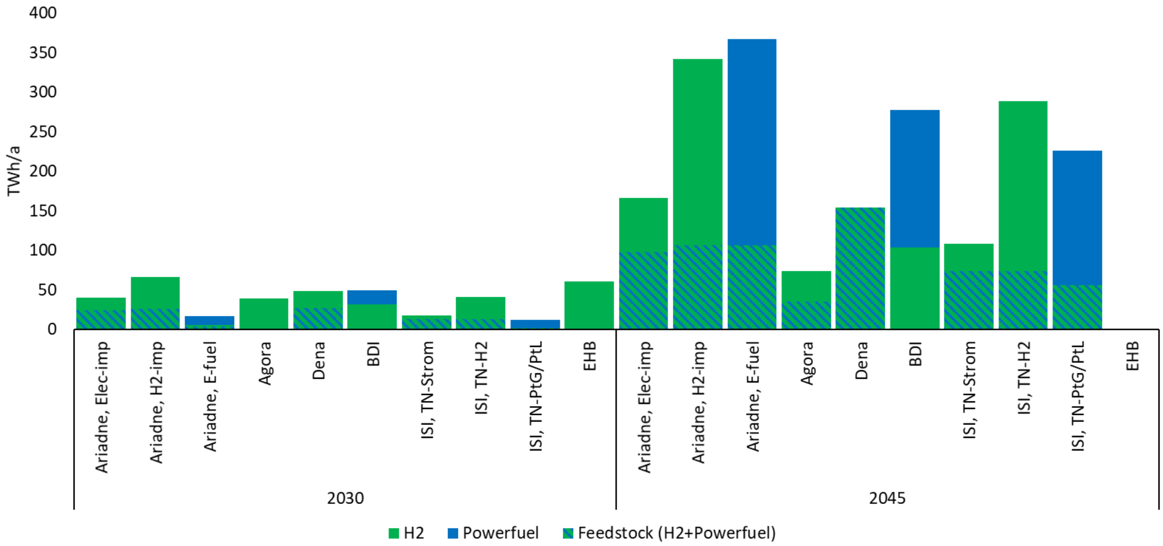

Fig. 3: H2 & Powerfuel (PtG/PtL) final energy demands in Industry sector across different studies for Germany. (Sources: (Pfluger et al. 2021; Prognos et al. 2021; Jugel et al. 2021; Burchardt et al. 2021; Fleiter et al. 2021; Wang et al. 2021)

The strong differences among the studies, which become more prominent in the long-term estimates, come from the different sets of assumptions considered (like GHG (Greenhouse Gas) reduction targets, Biomass and Renewable potentials, CO_2 costs, production values, etc.), as well as the differences in the model structure and methodologies (Wietschel et al. 2021). These differences are referred to and elaborated a bit further again in the later sections.

From the studies considered in (Wietschel et al. 2021), the authors concluded that across the scenarios for near- and long-term estimates, the chemical and the iron-&-steel industrial sub-sectors were responsible for the highest demand of hydrogen. At the same time, (Neuwirth et al. 2022) analysed the hydrogen usage potential in Germany for the industry sector and concluded that the production of basic chemicals, metals, and mineral processing have the highest future potentials in the energy-intensive industrial sub-sectors. These would correspondingly result in maximum demands of around 167.5, 75, and 30.7 TWh/a of hydrogen respectively. According to them, refineries have a hydrogen utilisation potential of around 18 TWh/a, however, they concede that if the production of methanol and further MtX (Methanol-to-X) synthesis is also considered, the corresponding final hydrogen requirement would increase significantly. In the non-energy-intensive industrial sub-sectors, food and vehicle production also show significant utilisation potentials at 36 TWh and 13 TWh respectively. The total hydrogen utilisation potential from their estimates amount to be in the range of 482 – 534 TWh/a (Neuwirth et al. 2022).

Resulting from this, for the scope of this report, while considering the role of hydrogen as a feedstock, reagent, and an energy carrier, the following industrial sub-sectors are considered and elaborated in the later sections:

- Among the energy intensive industrial sub-sectors:

   - Iron & Steel
   - Basic Chemicals
   - Refineries
- Among the non-energy intensive industrial sub-sectors:
   - Food

For reference, the final energy consumption of fossil and NG (Natural Gas)-based fuels in the respective industrial sub-sectors, and how they compare with the above referenced values is presented through Table 1 representing the Comparison of (final) energy consumption of German industrial sub-sectors (AGEB 2023; Rohde and Arnold-Keifer 2023) with maximum long-term hydrogen usage potentials from (Neuwirth et al. 2022). This table will be further expanded throughout this report as new values are discussed.

Table 1: Comparison of (final) energy consumption of German industrial sub-sectors (AGEB 2023; Rohde and Arnold-Keifer 2023) with maximum long-term hydrogen usage potentials from (Neuwirth et al. 2022).

	(Final) Energy Consumption (2021)			**H2 potential**
	Fossil			**Neuwirth et al. (2022)**
	Gas	**Liquid**	**Solid**	
	TWh/a			
Basic Chemicals	71	2	4	168
Iron & Steel	56	1	95	75
Food	34	2	2	36
Rest of Industry	111	8	24	158
Sum	**272**	**13**	**125**	**436**
Refinery (self-use)	32	58	1	18
Total	**304**	**71**	**126**	**454**

Since the basic chemical, iron & steel, and refinery sub-sectors are most commonly referred across the studies, they are briefly developed here further to represent their overall hydrogen demand ranges across the studies.

For the basic chemical sub-sector, the hydrogen demand values are wide-ranging. In the Agora study, the hydrogen demand for the chemical sector is at 15 TWh in 2030, which peaks at 50 TWh in 2040, and then decreases to 33 TWh in 2045 (Prognos et al. 2021). While in the Ariadne study these values range from around 5 – 30 TWh in 2030, to around 100 – 170 TWh in 2045 across the scenarios (Pfluger et al. 2021). For the bottom-up assessment done by (Neuwirth et al. 2022), future hydrogen demand for the chemical sub-sector is estimated at a total of 168 TWh/a, with olefins responsible for around 84% of it, and ammonia and methanol following at around 10% and 4% respectively. At the same time, among the studies compared by ACATECH and DECHEMA, hydrogen demand ranged between 21 – 50 TWh for 2030, and between 150 – 283 TWh for 2045 (ACATECH and DECHEMA 2023). The differences among the different studies depends on factors including, but is not limited to, the implementations of different applicable hydrogen-based technological alternatives, their availability, and also on the assumed rate of uptake of hydrogen (ACATECH and DECHEMA 2023).

For the iron & steel sub-sector, similar to the previous case, there is broad uncertainty about the amount of hydrogen that will be demanded across the years. In the Agora study, the demand for hydrogen in the steel industry increases from around 15 TWh in 2030, to 35 TWh in 2045 (Prognos et al. 2021). While in scenarios across the Ariadne study, this ranges between 2 – 20 TWh in 2030, and between 48 – 70 TWh in 2045 (Pfluger et al. 2021). In the Langfrist scenarios, however, the hydrogen dependence amounted to 10 TWh in 2030 and 45 TWh in 2050 (Fleiter et al. 2021). While in the studies compiled by (ACATECH and DECHEMA 2023), the hydrogen demands across the studies range between 0 – 26 TWh in 2030, and between 32 – 75 TWh in 2045.

Considering the refinery sub-sector, the Dena study projects demands of around 45 TWh for 2030 and around 160 TWh for 2045 (Jugel et al. 2021). While the Agora study, the demand increases slowly with 1 TWh in 2030 and reaching around 120 TWh in 2045 (Prognos et al. 2021). From the values compiled by (ACATECH and DECHEMA 2023), the total hydrogen demand in refineries for mineral oil processing and synfuel production lies in the range of 1 – 45 TWh for 2030 and between 1.3 – 159 TWh in 2045.

The overarching range of the demand estimates across the studies considered for the years of 2030 and 2045 under the focus sub-sectors of basic chemicals, iron & steel, and refinery are shown through Fig. 4.

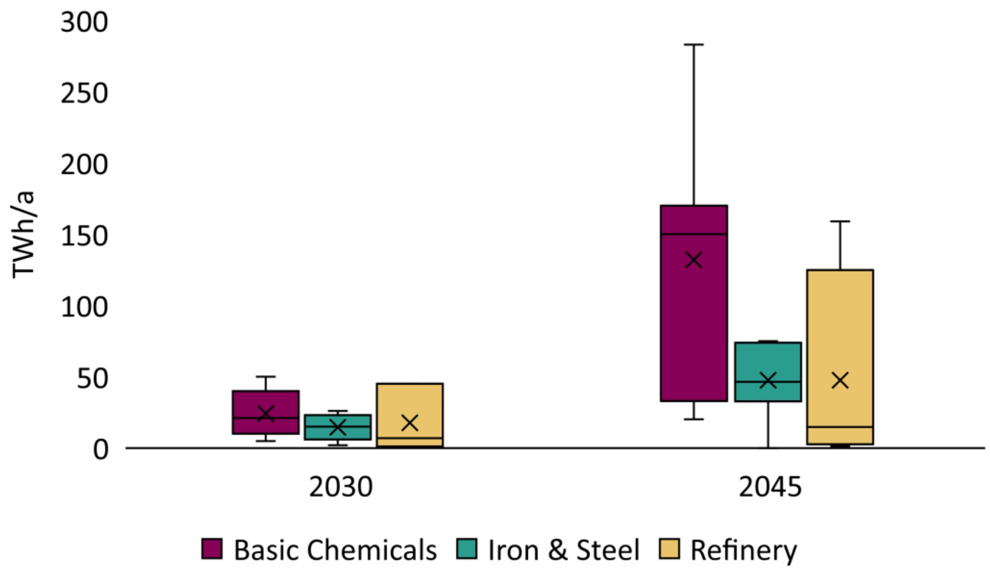

Fig. 4: Hydrogen demand ranges across studies for basic chemicals, iron & steel, and refinery industry sub-sectors for 2030 and 2045. (Source: own representation based on (Prognos et al. 2021; Pfluger et al. 2021; Neuwirth et al. 2022; ACATECH and DECHEMA 2023; Wang et al. 2021; Fleiter et al. 2021; Jugel et al. 2021))

Table 2 expands on Table 1 with the maximum ranges for the long-term estimates of hydrogen demand across the industrial sectors while considering the various studies.

Table 2: Comparison of maximum long-term hydrogen demand values across various studies for the industrial sub-sectors in consideration. (Source: (Prognos et al. 2021; Pfluger et al. 2021; Neuwirth et al. 2022; ACATECH and DECHEMA 2023; Wang et al. 2021; Fleiter et al. 2021; Jugel et al. 2021)

	(Final) Energy Consumption (2021)			**H2 potential**	
	Fossil			**Neuwirth et al. (2022)**	**Range from other literatures (maximum, long-term values)**
	Gas	**Liquid**	**Solid**		
	TWh/a				
Basic Chemicals	71	2	4	168	283
Iron & Steel	56	1	95	75	75
Food	34	2	2	36	-N/A-
Rest of Industry	111	8	24	158	-N/A-
Sum	**272**	**13**	**125**	**436**	**358**
Refinery (self-use)	32	58	1	18	159
Total	**304**	**71**	**126**	**454**	**517**

3. Current structures, volumes, and hydrogen opportunities

The different industrial sub-sectors are detailed in this section and the various products or options for the usage of hydrogen in them are further elaborated. The analysis of the amount of hydrogen that can be used in these sub-sectors is based on these usage options and is calculated in a bottom-up manner. This is done under considerations of replacing the current production methods completely with hydrogen-based alternatives to meet the current demand volumes of the considered end-products. As a result, this section provides a static analysis of the theoretical amount of hydrogen that can be used in each of the industrial sub-sectors under current structures, and does not consider any form of competition with other possible decarbonisation options (eg. electrification), as well as within the different products for hydrogen use.

3.1 Basic Chemicals

The products from the chemical industry are used widely across the different end-use sectors of the automotive, food, glass, as well as plastics industries, and also form an integral part of many value chains (Geres et al. 2019). These products range from basic chemicals like ammonia or methanol to components of clothing, cosmetics, etc. The chemical industry is a highly complex and integrated system with many internal transformation loops, and correspondingly, a segregated analysis of individual processes can lead to misrepresentations of the actual parameters (ACATECH and DECHEMA 2023). Nevertheless, these are considered here individually to showcase the usage potential for hydrogen.

The chemical industry relies heavily on fossil products for raw materials and energy provision. As of 2020, the chemical industry relied mainly on fossil-based raw materials like naphtha (14.3 Mt) and natural gas (2.8 Mt) which constituted around 85% of the total raw material used in the sector (20 Mt). Of the total energy required (215 TWh), the majority, at around 44% (94 TWh) was provided by natural gas, followed by electricity at 24.6% (53 TWh), and heat at around 13% (29 TWh) (ACATECH and DECHEMA 2023). Ensuing this, the chemical industry emitted around 113 Mt CO_{2eq} in 2020, of which the direct process-related emission (also known as scope 1 emissions) accounted for around 33 Mt CO_2, 23 Mt CO2 resulted from indirect energy sourcing (also known as scope 2 emissions), while the carbon content of the products explains the remaining emissions (also known as scope 3 emissions) (ACATECH and DECHEMA 2023). This heavy fossil reliance in the chemical industry also makes it difficult to decarbonise (Geres et al. 2019).

For decarbonisation in the chemical industry, technical solutions for replacing raw materials, as well as alternative process chains need to be developed. For their inclusion into the chemical industry, it is important to consider their availability, economic operability, emission reduction potentials, and the hurdles that need to be overcome to reach their full potential (Geres et al. 2019). Consequently, hydrogen could play a vital role here since it can be used as both a fuel and a feedstock source to provide the required energy as well as a material source respectively (Staffell et al. 2019).

In the following sub-sections, the focus lies on the chemical products driving these hydrogen demands, and hence is directed at the most energy- and feedstock-intensive products which consequently also release around two-thirds of the sectoral GHG emissions. This encompasses products like chlorine, ammonia, urea, methanol, and high-value chemicals of olefins and aromatics (Geres et al. 2019) which are discussed below. At the end, comparative plots of the total hydrogen and electricity demand under current end-product requirements, the current TRL of the involved hydrogen-based options, the stoichiometric amount of hydrogen required per unit of the end-product, as well as the total CO_2 that could avoided by employing the hydrogen options are depicted for the considered products through Fig. 11 – Fig. 14.

To improve the status of the low-carbon production routes for the various products considered, EU-level legislation, government support in the form of investment grants, demand incentives for alternative products, and adapting the planning and approval laws for faster inclusion of newer technologies can be favourable (ACATECH and DECHEMA 2023).

Chlorine

The majority of Chlorine produced in Germany is through the electricity-intensive Chloralkali process with different variations (Membrane, Diaphragm, Amalgam process). In 2017, Germany produced around 3.41 Mt of chlorine (Cl_2) (VCI 2022), resulting in hydrogen production of around 96.82 kt as a by-product, while consuming 8.08 TWh of electricity and emitting around 3.95 Mt CO_2 (Geres et al. 2019). As its production process is already heavily electrified, and hydrogen is a by-product of the process (under some process variants) rather than an input where it could play a vital role in its demand, this chemical product is not focussed on further in this study.

Ammonia (NH_3)

Ammonia is one of the most important chemicals and is used in large quantities for the production of fertilizers and nitric acid (ACATECH and DECHEMA 2023). It is generally produced through the Haber-Bosch process using hydrogen and nitrogen as the inputs in the presence of some catalysts at 150 – 350 bar and 450 – 550° C (Geres et al. 2019), the simplified production route is shown in Fig. 5, and the primary reaction through Equation (1).

$$N_2 + 3H_2 \leftrightharpoons 2NH_3 \qquad (1)$$

For its production in Germany, natural gas has been primarily used to source hydrogen through steam-reformation (NG-SMR) followed by WGS (water gas shift) reaction, while burning it under anaerobic conditions in the secondary reformer results in the provision of the required nitrogen. Ammonia synthesis takes place following the subsequent acid-gas scrubbing of these resultant products through the Haber-Bosch process (Geres et al. 2019). As a result of this natural gas reliance, around 2.5 t CO_2/t ammonia is subsequently produced (International Energy Agency- IEA 2022). In 2021, Germany produced around 2.4 Mt ammonia (VCI 2022), which would have resulted in emissions of around 6 Mt CO_2.

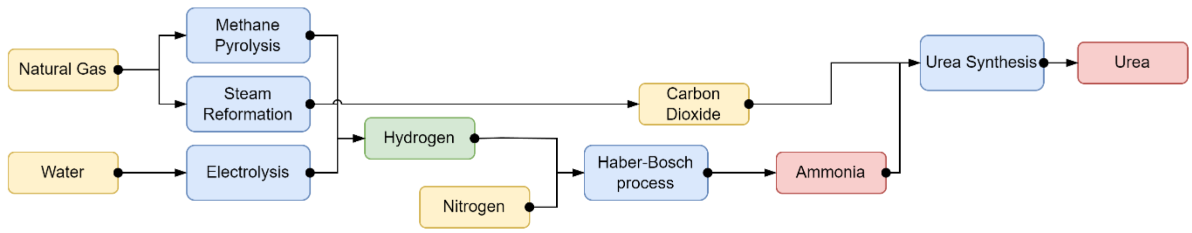

Fig. 5: Simplified representation of ammonia and urea production processes. (Source: own creation based on (Geres et al. 2019))

The emissions from ammonia synthesis can be reduced by alternative low-carbon production routes for its constituent hydrogen and nitrogen respectively. Hydrogen produced through either electrolysis or methane pyrolysis, and nitrogen provided through air separation units can significantly decrease the emission intensity of the resulting ammonia. By replacing the hydrogen with those from cleaner sources, energetic and feedstock emissions of around 1.2 t CO_2/t ammonia can be avoided. Stoichiometrically, there is a requirement of 177.5 kg H_2/t ammonia (Fleiter et al. 2021). However, the net demand for electricity for its production would also subsequently increase.

For ammonia production through water electrolysis, the total energy requirement amounts to around 10.89 MWh/t NH_3 (39.2 GJ/t NH_3), of which at least 80% (9.17 MWh/t NH_3) is required for electrolysis. The emissions in this case result from the electricity-based emissions used to produce the hydrogen. For the specific investment costs, a similar major contribution of the electrolyser unit is observed, with the total investment costs being 2.7 times higher than those for conventional systems (Geres et al. 2019). This production route already has reached TRL (Technology Readiness Level) of 9 (market uptake) and is used industrially (International Energy Agency- IEA 2022), although, production capacities are still under development and are 10 times lower than the current production routes. The cost-parity of these new routes to the conventional non-depreciated ones is expected to be reached around 2039, while for the conventional depreciated routes, parity is expected to be reached by 2048 (assumptions in A.2) (Geres et al. 2019).

In case hydrogen is supplied through methane pyrolysis, significantly higher total energy is required at 24.16 MWh (87 GJ), of which 3.4 MWh/t NH_3 are the electrical demands, and around 20.83 MWh (75 GJ) correspond to the energy content of methane as the feedstock. The CO_2 emissions are from the losses during the methane pyrolysis and are lower than for the conventional route. Stoichiometrically, there is a need for 1.5 t CH_4/t NH_3 to provide the required hydrogen, and the cost-parity of this alternative route compared to the conventional non-depreciated route is predicted to be reached after 2050 (Geres et al. 2019). The unit energy requirement comparisons among the electrolysis- and methane-pyrolysis-based ammonia production paths are shown in Fig. 6.

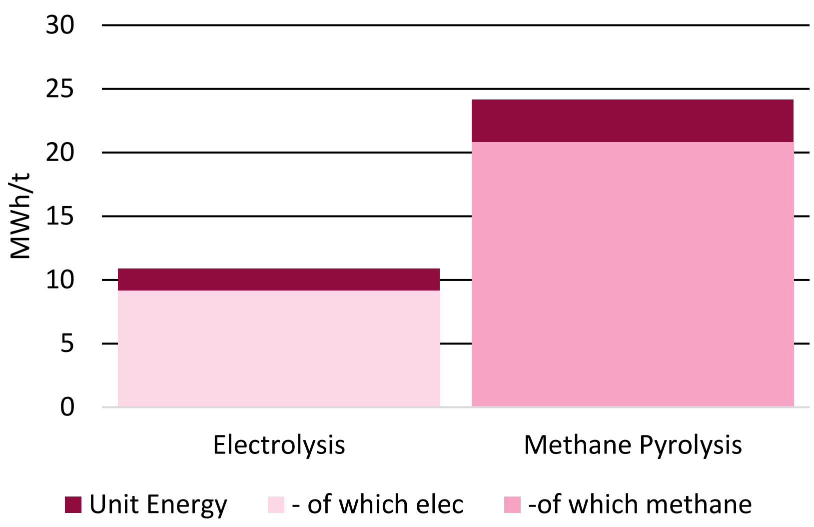

Fig. 6: Unit energy requirements for electrolysis- and methane pyrolysis-based ammonia production. (Source: own creation based on (Geres et al. 2019))

Under similar demand values for ammonia (2.4 Mt) in the future, the two alternatives of electrolysis- and methane pyrolysis-based hydrogen provision have the potential to save at least 6.11 Mt CO_2/annum and 6 Mt CO_2/annum by 2050 respectively, while resulting in additional electrical demands of around 21.29 TWh and 8.28 TWh. These parameters along with the cost-parity comparisons to conventional non-depreciated routes are shown in Fig. 9 together with values corresponding to methanol production. The hydrogen requirement would hence correspond to around 0.42 Mt, i.e. around 14.2 TWh (LHV). This value is comparable to the projected 15 TWh hydrogen demand for ammonia production in the Langfrist study scenarios for 2050 which refers to a demand of 2.56 Mt ammonia (LHV-based stoichiometric calculation) (Fleiter et al. 2021).

Urea ($CO(NH_2)_2$)

Urea is almost exclusively produced in Germany in combination with the ammonia synthesis through the process shown in Fig. 5 above. In 2021, Germany produced around 418 kt/a urea (Philipp Nimmermann 2023). For its production, a two-stage reaction of combining ammonia and CO_2 obtained from the conventional NG-SMR is required at high temperatures and pressures. The reaction forms ammonium carbamate as an intermediate product, which finally results in urea as shown through Equations (2), and (3) (Geres et al. 2019).

$$CO_2 + 2NH_3 \rightarrow NH_2COONH_4 \quad (2)$$

$$NH_2COONH_4 \rightarrow NH_2CONH_2 + H_2O \quad (3)$$

For low-emission urea production, the ammonia, and hence intrinsically the hydrogen should have lower associated emissions compared to the conventional route. This can be done through hydrogen production through either water electrolysis or methane pyrolysis. The urea synthesis process itself remains the same, only the provision of the source components needs to be changed. Following this, the CO_2 requirement of the urea production needs to be met through external sources instead of from the NG-SMR, and hence represents recycling of previously emitted CO_2 and avoiding new fossil carbon emissions (Geres et al. 2019). For their production, stoichiometrically, 0.73 t CO_2/t Urea is required, which remains in it as its carbon content and is released back at the end of its life. Additionally, the provision of heating energy which would otherwise be obtained from the SMR needs to be compensated through external low-carbon sources, preferably electric. This amounts to the requirement of an additional 3.29 GJ/t urea (0.91 MWh/t urea) for the steam generation.

Methanol

Methanol primarily serves as an intermediate product for the synthesis of various chemicals and fuels to be used in the different end-use sectors of construction, automotive, and consumer goods (International Energy Agency- IEA 2022). As a result, it is also considered to play an important role in decarbonising the chemical industry (ACATECH and DECHEMA 2023). In 2021, Germany produced around 1.3 Mt methanol (VCI 2022), of which 40% was produced through natural gas, and the rest through heavy oil processing (Geres et al. 2019). The basic production process is shown in Fig. 7. Syngas produced from either steam reforming of natural gas, partial oxidation of heavy oil, or through the gasification of biomass is sent through a water-gas-shift (WGS) reactor where it successively gets converted to a mix of hydrogen and CO_2 (Equation 4). This mix in the presence of a catalyst gets converted to methanol under physical conditions of 250 °C and 5 – 10 MPa (Equation 5), the overall reaction is shown through Equation 6. The heat produced from this exothermic reaction is used for further product processing (Geres et al. 2019).

$$CO + H_2O \rightleftharpoons CO_2 + H_2 \qquad (4)$$

$$CO_2 + 3H_2 \rightarrow CH_3OH + H_2O \qquad (5)$$

$$CO + 2H_2 \rightarrow CH_3OH \qquad (6)$$

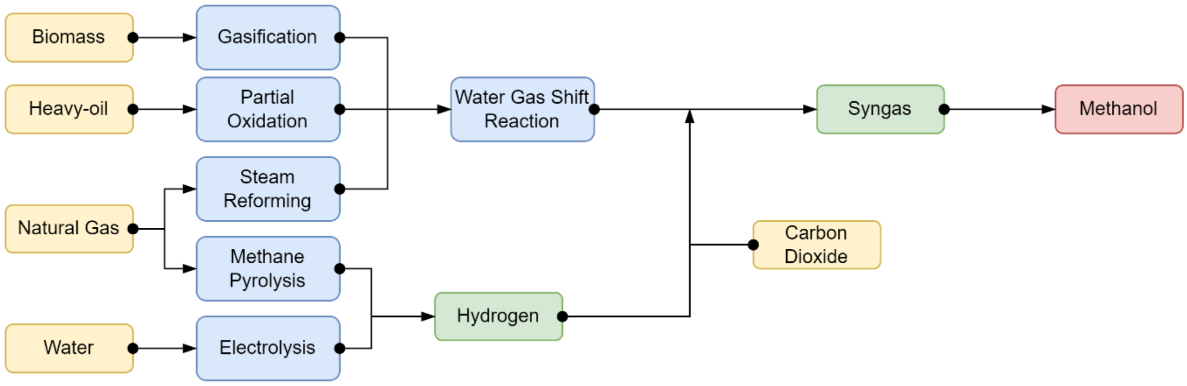

Fig. 7: Simplified representation of methanol synthesis. (Source: Own creation based on (Geres et al. 2019))

For low-carbon methanol production, hydrogen and externally sourced CO_2 can be reacted to form syngas, and consequently form methanol through the similar process described above. The process for electrolytic formation of methane is currently still in its demonstration phase (International Energy Agency- IEA 2022) while TRL of 9 is expected to be reached around 2033 (Geres et al. 2019). Alternatively, hydrogen can also be supplied through methane pyrolysis.

Stoichiometrically, there is a need of 1.37 t CO_2/t methanol which needs to be provided through external, preferably recycled sources to avoid creating new fossil emissions (Geres et al. 2019), and of about 187.5 kg H_2/t methanol (ACATECH and DECHEMA 2023). When the hydrogen provided is produced through water electrolysis, the specific energy required for the process is 11 MWh/t methanol (39.6 GJ/t methanol), of which around 85% corresponds to the demand of the electrolyser unit. Similarly, 80% of the total specific investment cost refers to the cost of the electrolyser, while the cost of this alternative production route is around 4 times that of the conventional route. The cost-parity of this production route compared to the conventional, non-depreciated systems is expected to be reached around 2044 (assumptions in A.2). The CO_2 emissions of the product and the process depend on the carbon content of the product at its stoichiometric value (1.37 t CO_2/t), and on the emission intensity of the electricity mix used for the electrolysis respectively (Geres et al. 2019).

If instead, the required hydrogen is to be provided through methane pyrolysis, the energy required for the whole process is 14.27 MWh/t methanol (51.4 GJ/t methanol), of which around 10.44 MWh/t methanol (37.6 GJ/t methanol) corresponds to the energy content of methane itself as the feedstock. As a result of the losses involved in methane pyrolysis, approximately 0.62 carbon is produced as a by-product. The production costs for this path correspond to around 1.3 times that of the conventional production route while also considering the cost of emitted carbon. Cost parity of this production route is foreseen to be reached by 2044 compared to the conventional, non-depreciated systems (Geres et al. 2019). The unit energy requirement for the two production paths is shown in Fig. 8.

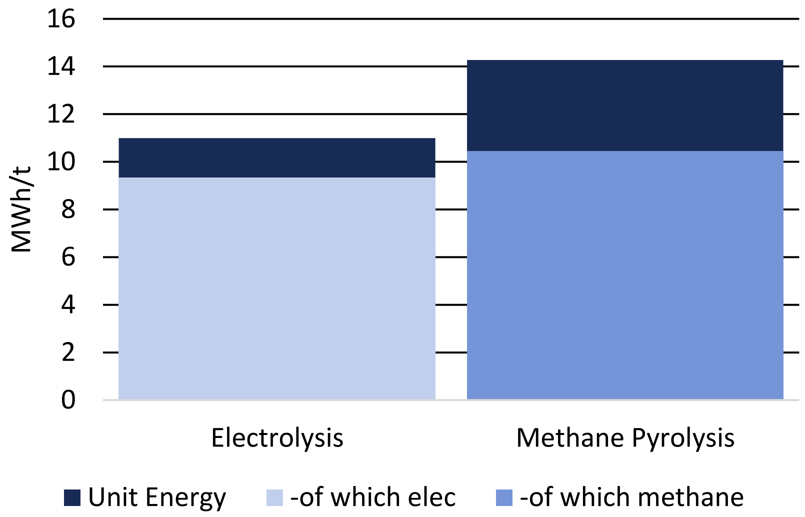

Fig. 8: Unit energy requirements for electrolysis- and methane pyrolysis-based methanol production. (Source: Own creation based on (Geres et al. 2019))

Under demands of 1.05 Mt methanol (as considered by Geres et al.) in the future, the two routes of electrolytic and methane pyrolysis provided hydrogen would result in CO_2 avoidances of 2.23 Mt/a and 2.18 Mt/a respectively, while also resulting in corresponding electrical demands of 11.6 TWh and 3.46 TWh by 2050 (Geres et al. 2019). These parameters are shown for both ammonia and methanol in Fig. 9 (a) and (b), while (c) shows the cost parity of these options compared to conventional non-depreciated systems. Under demands of 1.3 Mt methanol in the future, around 0.243 Mt hydrogen (8.01 TWh) of hydrogen (LHV) would be required. However, according to the Langfrist study scenarios, the projected demand of hydrogen for methanol production lies in the range of 101 TWh for 2050, which refers to a demand of around 16.32 Mt methanol (LHV) (Fleiter et al. 2021). The exceptionally high demand for methanol in this case results from the inclusion of its further downstream conversion to olefins and further MtX products.

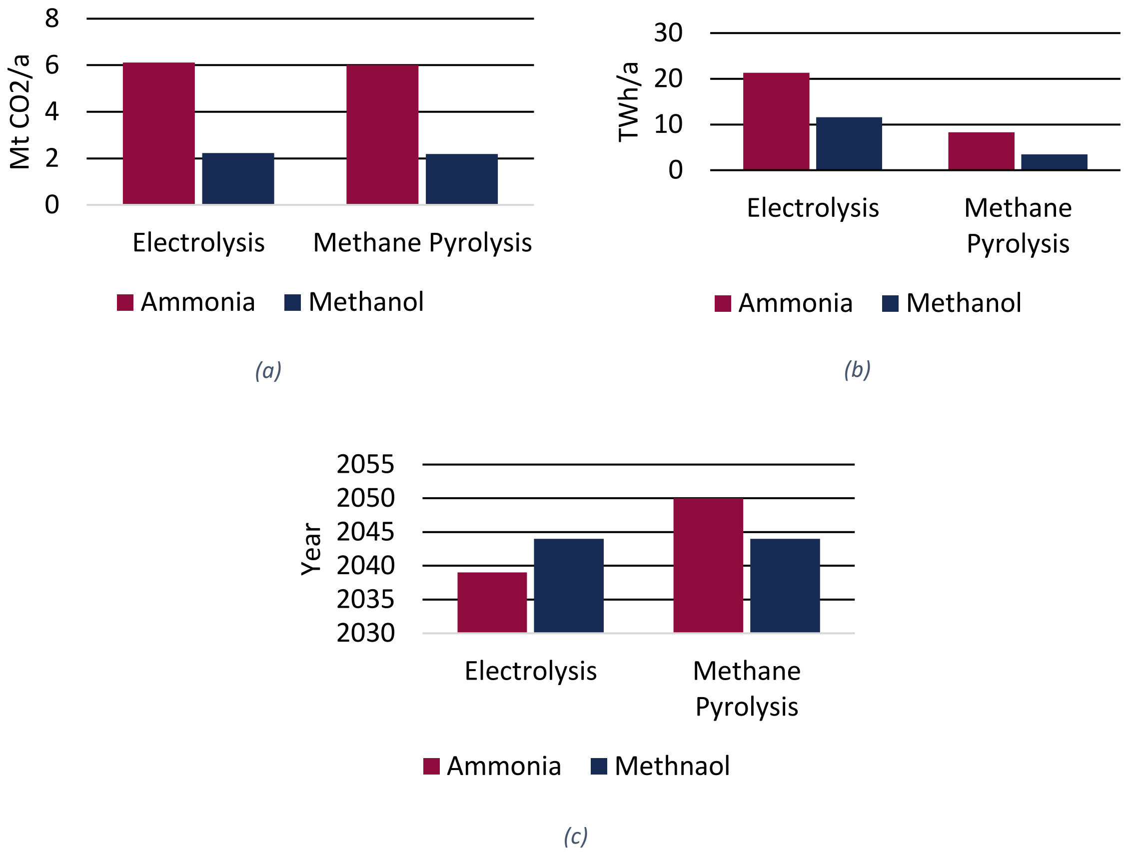

Fig. 9: (a) CO_2 avoided, (b) Electricity required, and (c) Cost-parity to conventional routes; of electrolysis- and methane pyrolsis-based ammonia and methanol production to meet current respective demands (Source: (a&b): Own calculations based on values from (Geres et al. 2019), (c): Own creation based on (Geres et al. 2019))

Olefins & Aromatics

Olefins are hydrocarbon chains like Ethylene, Propylene, Butylene, and Butadiene which are used extensively for plastic production (ACATECH and DECHEMA 2023). Among these, in 2021, ethylene led in production volumes at around 5.2 Mt, followed by propylene at around 3.6 Mt, and butylene and its isomers at around 2.2 Mt (VCI 2022). Aromatics like Benzene, Toluene, and Xylene (BTX) on the other hand, are used as polymer components and cosmetic ingredients (ACATECH and DECHEMA 2023). Among these, benzene had the highest production value at around 1.5 Mt, followed by toluene at 0.57 Mt in 2021, while xylene was only produced in quantities of around 0.4 Mt in 2019 (VCI 2022).

Conventionally, these olefins and aromatics have been produced through the thermal cracking of naphtha obtained from fossil oil refineries, of which around 14.3 Mt was used in Germany in 2023. The basic production process is shown in Fig. 10. As for the share of the resulting olefins and aromatics, this is dependent on the specific cracking setting and feedstock. These are nevertheless also commonly grouped under High-Value Chemicals (HVC), with energy requirements of around 16.5 GJ/t HVC (5.48 MWh/t HVC) for their production (Geres et al. 2019). The required heat for thermally cracking naphtha is obtained through the combustion of the process by-products (methane, hydrogen, and heavy oil) themselves, which also results in some related CO_2 emissions of around 0.87 t CO_2/t HVC (Geres et al. 2019).

Low-carbon HVCs can be produced either through the *electrical cracking* of *synthetic naphtha* or through the conversion of *methanol to olefins and aromatics*. These alternative production processes are also shown in Fig. 10 and are elaborated further below.

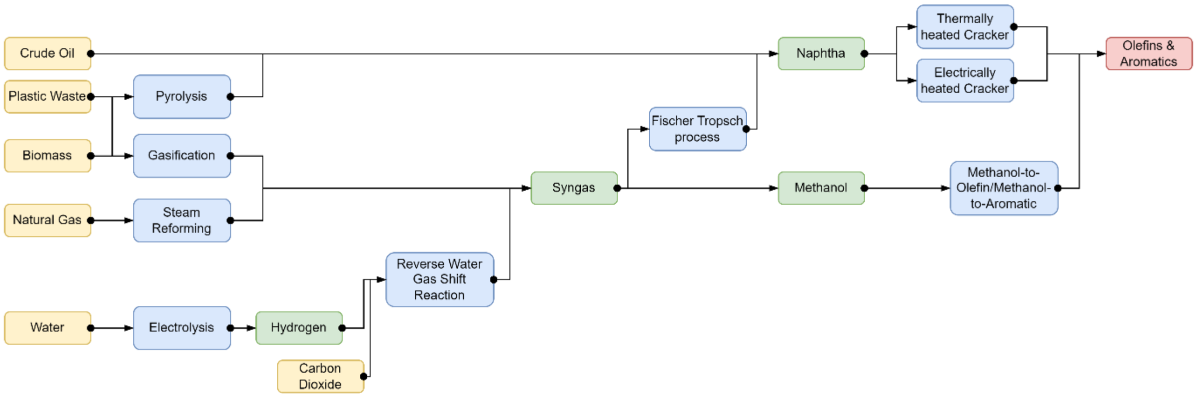

Fig. 10: Simplified representation of Olefin and Aromatics synthesis. (Source: Own creation based on (Geres et al. 2019))

<u>Synthetic naphtha</u> can be extracted through the separation and processing of the Fischer-Tropsch crude (FT-crude) products, which are generally a mix of gaseous and chemical compounds (crude gasoline or naphtha, gasoline, diesel, kerosene, as well as oils and waxes in the form of paraffin) (ACATECH and DECHEMA 2023). These products are formed as a result of the Fischer-Tropsch reaction, which is already at TRL of 9, wherein syngas is reacted to form a mix of long-chain aliphatic hydrocarbons and water (Geres et al. 2019). This reaction is also shown through Equation 7. The required syngas can be formed through the Reverse Water Gas Shift (RWGS) reaction (Equation 4) of hydrogen and CO2, which are obtained through various low-carbon means or as recycled/reused products in the case of CO2. If the hydrogen required is provided through water electrolysis, the electrolyser unit represents the highest share of energy demand at 34.16 MWh/t naphtha (123 GJ/t naphtha) of the total FT process' energy demand of 35 MWh/t naphtha (126 GJ/t naphtha) (Geres et al. 2019).

$$(2n+1)H_2 + nCO \rightarrow C_nH_{2n+2} + nH_2O \qquad (7)$$

Since the synthetic naphtha still has an inherent carbon content, this also represents the carbon emitted at the end of its life at 3.03 t CO_2/t naphtha, however compared to its original fossil route, synthetic naphtha would still result in avoidance of 4.27 t CO_2/t naphtha (ACATECH and DECHEMA 2023; Geres et al. 2019). The cost parity of this synthetic naphtha compared to the current fossil-refined naphtha is expected to be reached around 2079 (Geres et al. 2019). If the current demanded values of naphtha (14.3Mt) were to be provided entirely through electrolysis-based hydrogen, this would result in hydrogen requirements of over 200 TWh (ACATECH and DECHEMA 2023). Replacing fossil-produced naphtha with synthetic naphtha has the added advantages of continued use of existing infrastructures, large renewable energy import possibilities, and reduced dependency on fossil crude oil imports. However, the processing possibility of these synthetic naphtha to aromatics is still unclear and they may need other alternatives (ACATECH and DECHEMA 2023).

To convert the synthetic naphtha to the required HVCs, it needs to be thermally cracked as briefed earlier. For low-carbon products, this heat needs to be provided by an *<u>electric heater</u>*, while the by-products which were earlier combusted to provide this heat can now be used non-energetically in other processes to avoid the otherwise released CO_2 emissions (0.87 t CO_2/t HVC). Employing electric heaters can hence result in the avoidance of at least 90% of the fossil-based cracker emissions (ACATECH and DECHEMA 2023). The by-products can now also be converted back to synthetic gas through gasification and used again in the FT process (Geres et al. 2019). Currently, these electric crackers are still in the pilot and demonstration phase at TRL of 5 – 6, with a TRL of 9 only approximated for 2040. Since these are currently unavailable at industrial scales, and a significant dependency on them is foreseen in the future, these will be crucial in decarbonising the chemical sector. A significant increase in electrical demand is also expected when electrolyser-based synthetic naphtha is electrically cracked (ACATECH and DECHEMA 2023). For the current HVC demands, this would result in electricity requirements of around 595.5 TWh/a, if instead, conventional naphtha is cracked with an electric heater, this would result in electrical demands of around 69.8 TWh/a. These would then also result in CO_2 avoidance of around 51.1 Mt CO_2/a and 13.9 Mt CO_2/a respectively. Cost-parity compared to the conventional, non-depreciated cracker system is estimated to be reached around 2049 (assumptions in A.2) (Geres et al. 2019), while the specific costs differ by around 100 € at 900 – 950 €/t HVC (ACATECH and DECHEMA 2023). Considering the relevance and to avoid duplicity, the values relevant for synthetic naphtha are presented in the section dealing with the refinery sub-sector in this report, and are not represented here as part of the chemical sub-sector.

Another opportunity to obtain low-carbon HVCs is through the *Methanol-to-X* (MtX) conversion processes. Here, low-carbon methanol produced using hydrogen and CO_2 is converted to various products of fuels and aromatics and represents opportunities to replace fossil raw materials. These process products are dependent on the catalyst chosen and the process conditions. Methanol-to-Olefins (MtO) and Methanol-to-Aromatics (MtA) processes can respectively be used to produce the required olefins and aromatics discussed above. The yield of BTX from the MtA conversion is currently around 56% (ACATECH and DECHEMA 2023). MtO processes are already mature at TRL 9 and ready for industrial applications, while MtA processes are still under development and are currently at TRL 7 (Geres et al. 2019). Resulting from the dependence on Methanol for their production, its demand would increase significantly in a low-carbon future, which in turn results in increasing hydrogen and consequently the electrical demand. Stoichiometrically, around 2.8 t methanol/t olefin (ethylene and propylene) and around 4.3 t methanol/t aromatic (BTX) are required for the feedstock, while energetically around 26.52 MWh/t olefin (95.5 GJ/t olefin) and 48.89 MWh/t aromatic (176 GJ/t aromatic) is required for the processes of MtO and MtA respectively (Geres et al. 2019). This would then result in electrical demands of around 232 TWh and 124 TWh respectively if current values of olefins (ethylene and propylene) and BTX were to be produced through this method (ACATECH and DECHEMA 2023).

For methanol-based HVC production, certain advantages and disadvantages are present. Positively, the production facility is no longer limited to chemical industry sites with the availability of crackers and hence can be produced in a more distributed manner. However, when methanol availability is limited, competition may also arise for its use between the inherent MtX routes. Additionally, following the MtO process, further energy is required to purify and separate the ethylene and propylene mixture to obtain the required products (ACATECH and DECHEMA 2023). From an economic perspective, the production costs of MtO- and MtA-based olefins and aromatics are higher at around 680 – 1450 €/t olefin and 1,300 – 2,800 €/t BTX respectively compared to their conventional costs of around 816 €/t olefin and 680 €/t BTX (ACATECH and DECHEMA 2023).

By employing the MtX route, process-related emissions of 0.87 t CO_2/t HVC can be avoided, implying that the current process-related emissions of around 7.6 Mt CO_2 from propylene and ethylene, as well as around 2.14 Mt CO_2 from aromatics can be avoided. When considering also renewable hydrogen production and using captured CO_2, the CO_2 reduction can even amount to around 9.4 t CO_2/t H2 for olefins and around 8.4 t CO_2/t H2 for aromatics respectively (ACATECH and DECHEMA 2023). Accounting for the methanol requirement per unit olefin and aromatic, around 0.52 t H_2/t olefin and 0.8 t H_2/t aromatic would be required. For their current demands, this would resultantly refer to requirements of around 2.70 Mt H_2 (90 TWh H_2, LHV) for ethylene, followed by 1.87 Mt H_2 (62.33 TWh H_2, LHV) for propylene, and 1.97 Mt H_2 (65.60 TWh H_2, LHV) for aromatics.

In conclusion, the total amount of hydrogen as well as electricity required to meet the current end-product requirements through hydrogen-based options, as well as the resulting amount of total CO2 that could be avoided are represented through Fig. 11, Fig. 12, and Fig. 14 respectively. Fig. 13 represents the stoichiometric amount of hydrogen required per unit of the end-product.

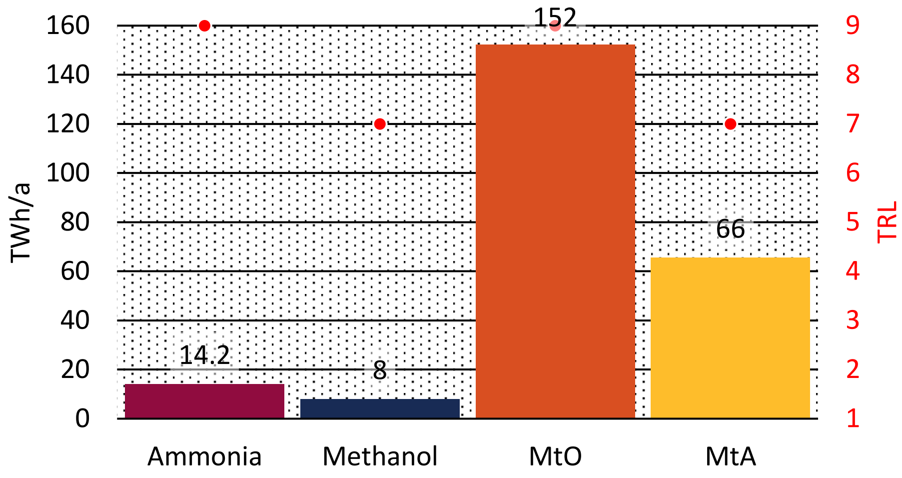

Fig. 11: Total H_2 demand for various chemicals considered under current end-requirements, red dots depict the current TRL of the hydrogen-alternative options. (Source: Own representation based on factors from (Geres et al. 2019; ACATECH and DECHEMA 2023))

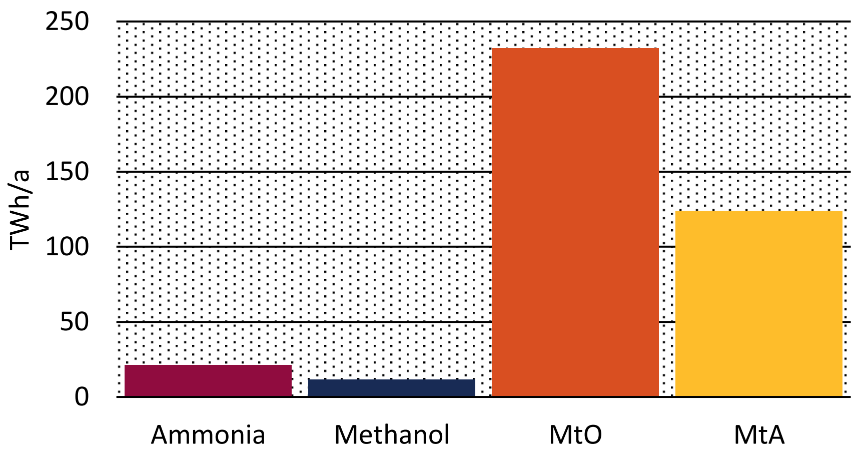

Fig. 12: Total Electricity demand for various chemicals considered when produced through electrolysis route under current end-requirements. (Source: Own represntation based on factors from (Geres et al. 2019; ACATECH and DECHEMA 2023))

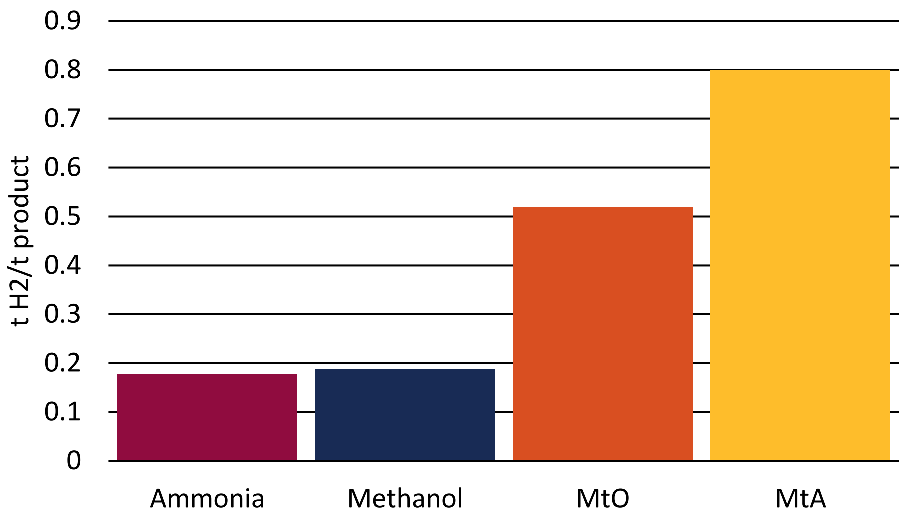

Fig. 13: Stoichiometric hydrogen requirement for various chemicals considered. (Source: Own representation bases on (Geres et al. 2019; ACATECH and DECHEMA 2023))

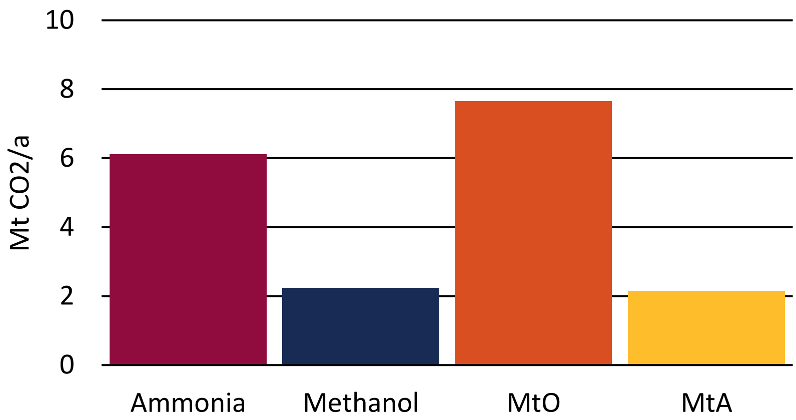

Fig. 14: Total CO_2 avoided through electrolytic hydrogen routes for various chemicals considered under current-end requirements. (Source: Own representation based on (Geres et al. 2019; ACATECH and DECHEMA 2023))

Other competitive technologies for a low-carbon future in the chemical industry, which could in turn also decrease the dependency on hydrogen, include electrification of process heat, as well as plastic recycling. For further information on these, the readers are referred to (ACATECH and DECHEMA 2023) and (Geres et al. 2019).

3.2 Iron & Steel

Steel is an important material with extensive application possibilities. It can be used across the sectors of building, transport, and power installations (ACATECH and DECHEMA 2023). In Germany, of the total 35.7 Mt steel produced in 2020, the majority was used in the building sector (35%), followed by the automotive sector (26%), and for the production of metal goods (12%) (Wirtschaftsvereinigung Stahl 2021).

Steel production processes can broadly be classified under two types, primary and secondary steel production. Primary steel production typically happens in a blast furnace-basic oxygen furnace (BF-BOF) using coal for smelting and reducing the iron ore to produce pig iron, which can then further be processed to yield crude steel. On the other hand, secondary steel production involves the melting of steel scraps to re-generate steel (Neuwirth et al. 2022); these steel production routes are also shown in Fig. 15. Of the total steel produced in Germany, around 70% was through the primary route, and only the remaining 30% was through the secondary route (Wirtschaftsvereinigung Stahl 2021).

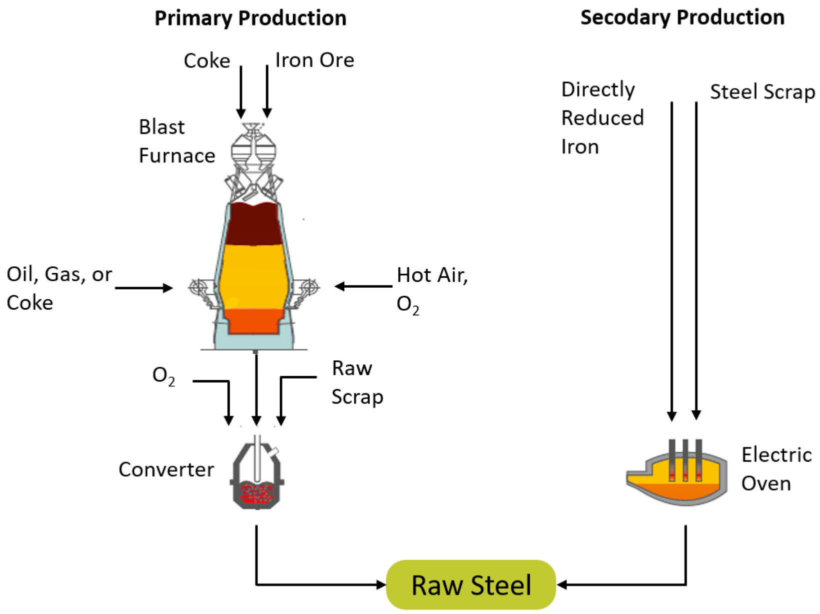

Fig. 15: Simplified representation of steel production routes and their shares. (Source: Self-representation based on (Wirtschaftsvereinigung Stahl 2021))

Steel production requires significant amounts of energy for the melting and reduction processes and resulted in total energy demands of around 146 TWh in 2019 (ACATECH and DECHEMA 2023), of which coal and coke provided the majority at around 97 TWh (Neuwirth et al. 2022). Due to this fossil dependency, around 52.6 Mt CO_2 was released representing around 31% of the total industrial, and around 6.5% of the total German GHG emissions (Wirtschaftsvereinigung Stahl 2021). Apart from the GHG emissions, the BF-BOF route also results in the formation of works-arising-gases (WAG), a mixture of gases including hydrogen and carbon monoxide, which can either be used within the steel industry itself or sold to other industries for further applications (International Energy Agency- IEA 2019).

Since steel demand is projected to increase even under improved material efficiencies, low-carbon steel provision would play an important role in reducing the related emissions (International Energy Agency- IEA 2019). Decarbonisation of steel production however represents a significant challenge given the inherent use of coke as a reducing agent for primary steel production. At the same time, secondary steel production through steel scraps has already been electrified by employing electric arc furnaces (EAF) (Neuwirth et al. 2022). To reach carbon neutrality, significant changes to the production routes are required, while CCUS (Carbon Capture Utilisation and Storage) applications can also be advantageous in reducing process-related emissions (Neuwirth et al. 2022). These production route changes, among others, can take the form of replacing blast furnaces with direct reduction methods and employing either hydrogen or methane for iron ore reduction. The methane-based direct reduction is already used in Germany to a certain extent, however, hydrogen can also play a significant role here in the production of primary steel (Fleiter et al. 2021). In addition to its usage for primary steel production, hydrogen can also be used for further steel processing through casting and rolling by converting conventional burners to hydrogen-based alternatives (Fleiter et al. 2021; Neuwirth et al. 2022).

The specific usage options of hydrogen for primary steel production through direct reduction of iron, and as an additive in the blast furnace to reduce coal dependence are briefly elaborated in the sections below. At the end, comparative plots for stoichiometric as well as the total amount of hydrogen that would be required to meet the current product demands through hydrogen-based options, the resulting amount of CO2 that could be avoided, as well as the TRL of these options are represented through Fig. 16 – Fig. 18.

To improve the status of low-carbon iron and steel production routes, support for demonstration projects through low-cost financing options to improve their scale-up possibilities, as well as incentivising demand for alternative products, can be favourable (International Energy Agency- IEA 2019). Similarly, policies encouraging green steel production with the inclusion of scope 3 emission targets for the resulting products and end-applications, as well as advancements towards hydrogen certifications can also be advantageous (ACATECH and DECHEMA 2023).

H_2-Direct reduction of iron (DRI)

Iron ore can be reduced using hydrogen instead of coal in this process, thus also avoiding the related CO_2 emissions and replacing it with water instead (Worldsteel association 2022). The involved reactions are shown through Equations 8, and 9.

$$Fe_2O_3 + 3H_2 \rightarrow 2Fe + 3H_2O \qquad (8)$$

$$FeO + H_2 \rightarrow Fe + H_2O \qquad (9)$$

The hydrogen used here needs to be produced externally and not as a co- or by-product from conventional fossil-based processes to ensure low-carbon steel production (International Energy Agency- IEA 2019). For the transitory period until large-scale availability of hydrogen is established, synthetic gas with higher shares of hydrogen, as well as biomethane can also be employed instead (ACATECH and DECHEMA 2023). Following the reduction of iron ore, the resulting pig iron can further be processed through different furnace options of EAF, BOF, or SAF (submerged arc furnace) (ACATECH and DECHEMA 2023).

The H2-DRI process is still in its prototype stage at TRL 7, while NG-based DRI is already in large-scale use at TRL 9. For the H2-DRI process, stoichiometrically around 0.067 t H_2/t crude steel is required and results in avoidances of around 1.88 t CO_2/t crude steel for primary steel production. Final energy requirements for these processes in terms of fuel are around 1.89 MWh/t crude steel and 2.69 MWh/t crude steel for the H2-DRI and NG-DRI processes respectively, while the latter has an additional electrical demand of around 75 kWh/t crude steel (ACATECH and DECHEMA 2023). Due to the high hydrogen and energy requirements, the costs of H2-DRI-produced steel are greatly influenced by energy and raw material costs which represent around 45% of the total production costs. Their cost estimates are hence broadly around 15 – 90% higher compared to the conventionally produced steel with inclusions of CCUS. As a result, H2-DRI would be competitive only in places with cheap and abundant access to renewable energy (International Energy Agency- IEA 2019).

If the total primary steel production was to be replaced by the H2-DRI process, this would result in hydrogen demands of around 56 TWh/a, which would also result in avoiding around 47 Mt CO_2/a of emissions.

Hydrogen injection in blast furnace

To reduce the amount of coal used in blast furnaces, hydrogen can be injected through the nozzles instead of coal dust; however, in this process, coke would still be required to reduce the iron ore (ACATECH and DECHEMA 2023). This process can hence provide a transitionary opportunity until large amounts of hydrogen are widely available.

The injection of hydrogen through nozzles into the blast furnace is still in its prototype stage at TRL 6 – 7, with fuel and electrical requirements of around 5 MWh/t steel and 0.4 MWh/t steel respectively. These electrical demands, however, have conventionally been met through self-generation at the plant sites locally. When replacing the conventionally injected coal dust with hydrogen, requirements of around 47 kg H_2/t pig iron are estimated, which results in avoiding emissions of around 0.37 – 0.51 t CO_2/t steel. From an economic perspective, under short-term considerations, continued usage of blast furnaces might be favourable against heavy investments for new processes, however, the CO_2 prices would also play a determining role (ACATECH and DECHEMA 2023).

Considering the total primary production to be replaced by hydrogen in the form of nozzle injection, electricity in the range of around 10 TWh/a would be required, which can fully be supplied internally (ACATECH and DECHEMA 2023). Consequently, total hydrogen demands would amount to around 39 TWh while resulting in emission avoidances of around 11 Mt CO_2/a.

In conclusion, the total amount of hydrogen required to meet the current demands through hydrogen-based routes and their respective TRLs are depicted through Fig. 16, followed by the resulting amount of CO_2 that could be avoided through Fig. 18. Fig. 17 shows the respective stoichiometric requirement of hydrogen under the hydrogen-based production options.

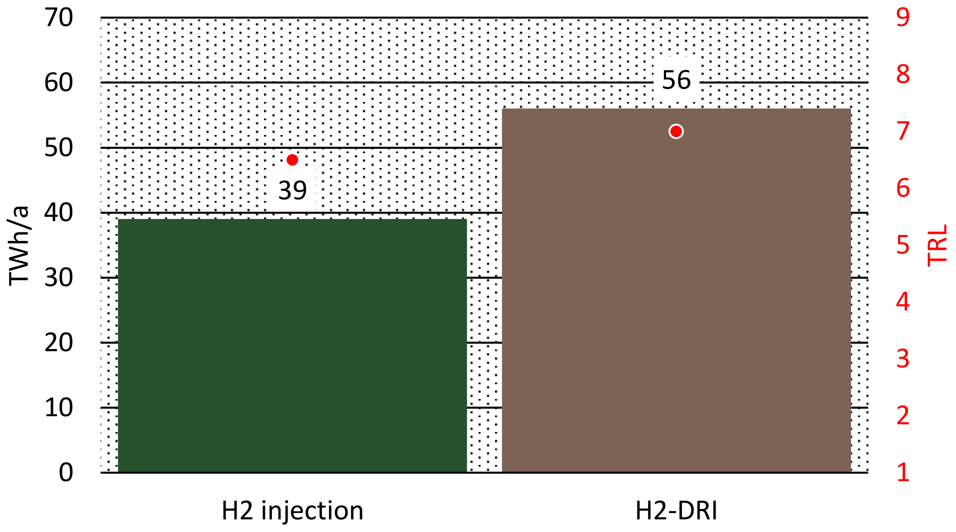

Fig. 16: Total H_2 demand for various primary iron & steel production routes considered under current end-requirements. The red dots depict the TRL of the hydrogen-alternative options. (Source: Own representation based on values from (ACATECH and DECHEMA 2023))

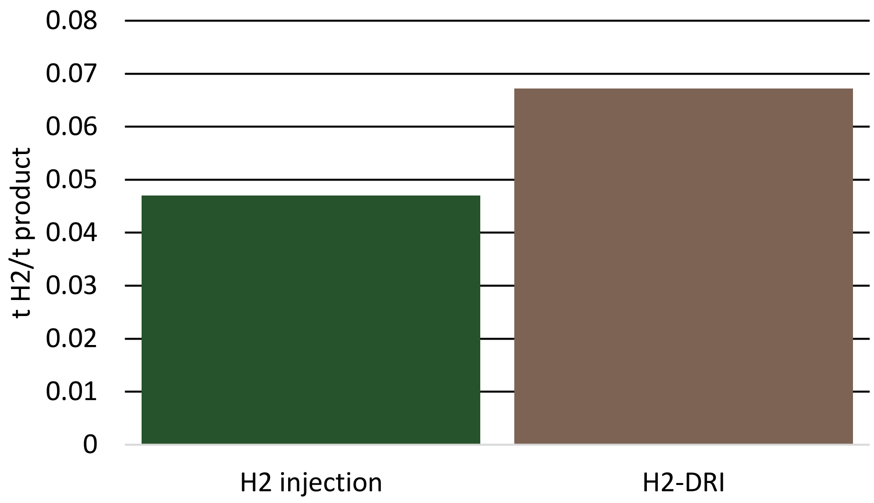

Fig. 17: Stoichiometric hydrogen requirements for various primary iron & steel production routes considered. (Source: Own representation based on (ACATECH and DECHEMA 2023))

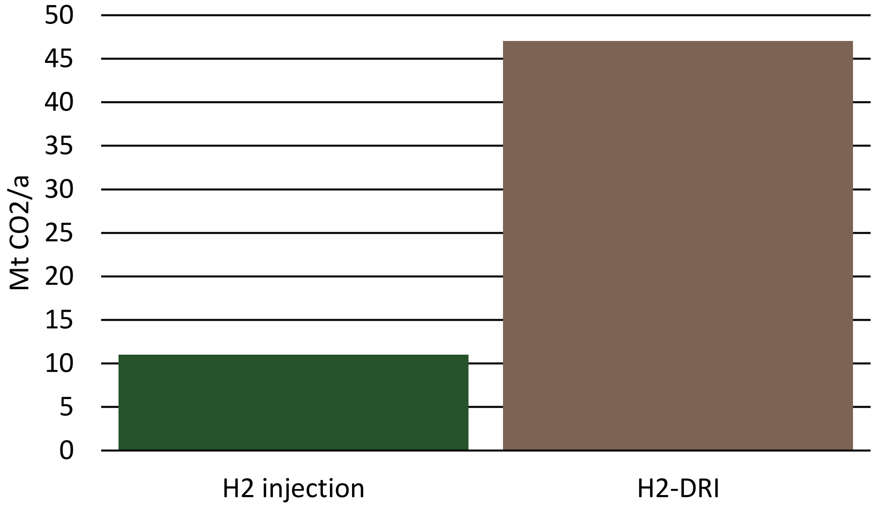

Fig. 18: Total CO_2 avoided for various primary iron & steel production routes considered under current-end requirements. (Source: Own representation based on (ACATECH and DECHEMA 2023))

3.3 Refinery

Crude oil is processed in refineries and results in multiple downstream products, of these, the high-value products can be traded for different applications. The remaining produce, however, can be recycled within the refinery to meet its own energetic and/or feedstock requirements, thus eliminating waste or residues. The traded high-value products include fuels and materials in the form of liquids and gases which can be used in sectors of power, transport, and heating, while also providing raw materials required for the chemical industry. A simplified representation of the process chains involved in refineries is shown in Fig. 19. In Germany, around 80% of the refinery products are currently used in the transport and heat sectors, while around 4% are reused in the refinery to meet its own energetic needs (ACATECH and DECHEMA 2023).

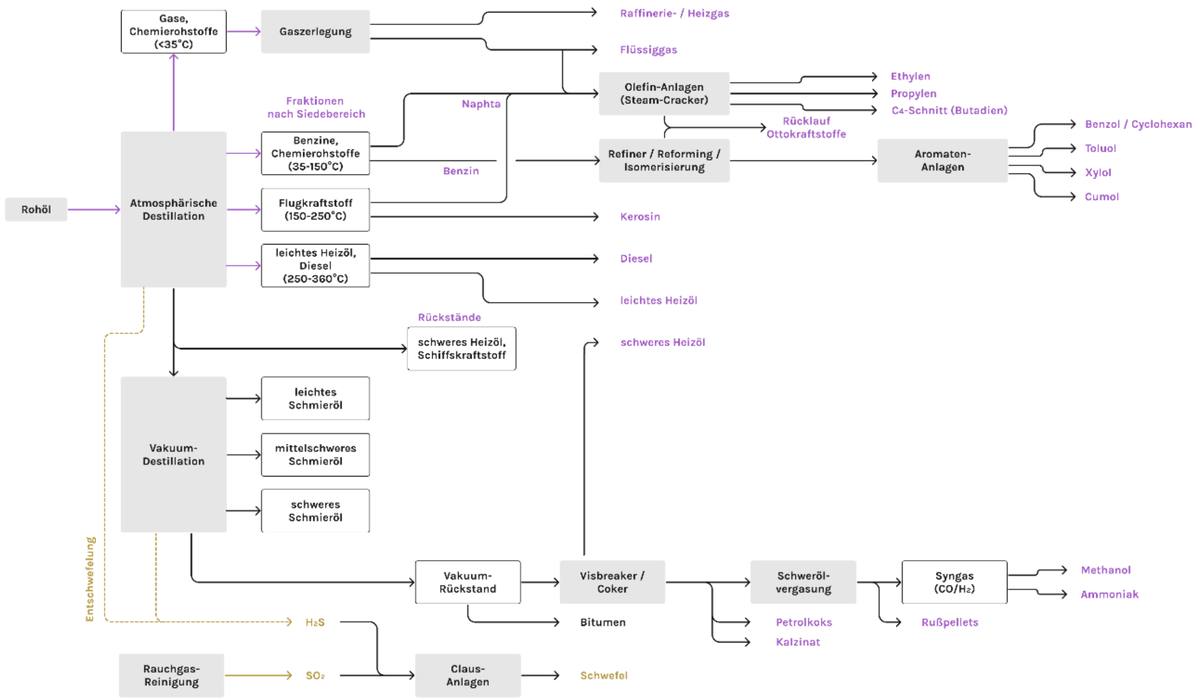

Fig. 19: Simplified representation of refinery process chains. (Source: (ACATECH and DECHEMA 2023))

Hydrogen is currently used in refineries for hydrotreatment and hydrocracking procedures to remove impurities from crude oil (desulphurisation), and to upgrade heavier crude to high-value oil products, respectively. Oil sands and biofuels can also be hydrotreated for their desulphurisation and to form diesel substitutes accordingly (International Energy Agency- IEA 2019). For the future uptake of hydrogen in refineries, competing assertions exist. On the one hand, higher restrictions on oil sulphur content and fundamental changes in the energy system through synthetic fuels, and increased domestic crude production would bolster the hydrogen requirements for the future. On the other hand, electrification and efficiency gains which result in a net decrease of future oil demands, would influence the hydrogen demand negatively (International Energy Agency- IEA 2019; Neuwirth et al. 2022).

Of the hydrogen required in the German refineries, around 78% is available from the refinery itself in the form of co- and by-products (which might even increase due to efficiency improvements), while the remaining 22% (0.15 Mt) is provided through NG-SMR (ACATECH and DECHEMA 2023; International Energy Agency- IEA 2019; Neuwirth et al. 2022). To reduce the carbon intensity of the hydrogen and hence also the refinery products, CCUS incorporation, as well as utilising green hydrogen can be favourable (Neuwirth et al. 2022; International Energy Agency- IEA 2019).

For the refinement of around 105 Mt crude oil in 2021 in Germany (en2x 2021), emissions of around 22.5 Mt $CO_{2eq.}$ were released, which represent around 18.7% of the total industrial emissions (Umwelt Bundesamt - DEHSt 2021). All the while, mineral refined oil, along with imports represented around 33.3% of the German final energy consumption (ACATECH and DECHEMA 2023). From the different studies compared by (ACATECH and DECHEMA 2023), the hydrogen demand across them ranges between 1 – 44.9 TWh for 2030, and between 1.3 – 159 TWh for 2045. The huge range among the studies result from the different assumptions considered for decreasing oil demands, increasing synfuel uptakes (which can no longer be produced from refinery co-produced hydrogen, and hence need to be sourced externally), as well as varying level of inclusion for downstream methanol conversions.

To reduce the emissions of the refinery sector, synthetic alternatives can be produced using hydrogen to provide products including Gasoline, Jet Fuel, and HVCs. These can be produced either through further processing of synthetic FT-crude or through methanol conversions; these options are briefly discussed in the sub-sections below. This synthetic provision can hence play a vital role in reducing the country's renewable energy gaps and reducing the import dependencies of mineral oil and natural gas (ACATECH and DECHEMA 2023). However, it should be noted that other co- and by-products of the refinery process (sulphur, bitumen, soot, coke, etc.), which already have further established value chains, would also need to be provided in a climate-friendly manner in the future and hence also require alternative production processes.

This refinery section ends with comparative plots (Fig. 20 – Fig. 23) for the total amount of hydrogen usable to meet the current end-product requirements, as well as the resulting electricity required along with the total amount of CO_2 that can be avoided through the different hydrogen-based options. The TRL as well as the stoichiometric requirements of hydrogen under the different options are also provided.

To improve the status of the synthetic FT and MtX products, EU-level legislation, cost reductions of the involved hydrogen, CO_2, and their derivatives, adapting the planning and approval laws for faster inclusion of newer technologies, as well as cooperation with other countries, and designing import criteria can be favourable (ACATECH and DECHEMA 2023).

FT-crude

As mentioned in the basic chemicals section for synthetic naphtha, FT-crude (a mix of hydrocarbons, chemical raw materials, liquid hydrocarbons, as well as oils and waxes) produced from the FT process can be used to produce synthetic fuels and chemicals. This FT-crude mix is similar to crude-oil composition and if produced in a climate-friendly manner, can be used to replace mineral oil, and can be adopted in the different end-use applications of transport, heating, and power through further processing (ACATECH and DECHEMA 2023).

The FT process itself is already mature at TRL 9 and widely used in the industry. For the low-carbon variant, however, production of the associated raw materials of hydrogen and carbon defines the readiness of the entire value chain which is consequently between TRL 6 – 9. Correspondingly, significant amounts of hydrogen (0.49 t H_2/t FT-crude), electricity (35 – 57 TWh/t FT-crude), and CO_2 are required for the production of low-carbon FT products and synthetic kerosene (0.42 t H_2/t kerosene). This refers to demands of around 200 TWh H_2 if the current naphtha demand is to be met completely through synthetic means, with additional demands in the range of 84 – 159 TWh H_2 and 3.9 – 5.7 TWh H_2 respectively for the production of alternative fuels and waxes & paraffin. As a result of this significant H_2 and electricity reliance, access to cheap renewable electricity is a fundamental prerequisite to the development of these low-carbon alternatives. A similar concern is also about the availability and storage of CO_2 (ACATECH and DECHEMA 2023).

Replacing crude oil through the FT-crude can help reduce the German fossil oil import dependence while also providing fuels with lower exhaust emissions, and allowing continued usage of the existing petroleum infrastructure. However, resulting from the large energetic requirements for their production, dependencies on imports of hydrogen or electricity would still remain and likely increase. Additionally, further energy-intensive processing of the FT-crude is required to obtain the individual products while alternative production methods might be required for the production of aromatics (ACATECH and DECHEMA 2023).

In terms of cost, FT-kerosene exceeds its conventional counterpart by at least a factor of 3 at 2 €/l kerosene depending on the costs of hydrogen and hence also the electricity available. Electricity and heat required are responsible for at least 65% of the total final cost and hence cheap renewable sources are critical for them to be competitive compared to the conventional kerosene. Other longer-chain hydrocarbons also see similar energy and hydrogen requirements and are more expensive than kerosene at 2.17 – 6.57 €/l. However, the synthetic variants of kerosene and naphtha result in CO_2 avoidances of around 3.15 t CO_2/t kerosene and around 4.27 t CO_2/t naphtha hence resulting in total avoidances of around 32 Mt CO_2/a and 61 Mt CO_2/a respectively for their current demand values (10 Mt Kerosene, 14.3 Mt naphtha) (ACATECH and DECHEMA 2023).

MtX (X = G, J, O, A)

MtX processes are those wherein the low-carbon methanol produced using hydrogen and CO_2 is converted to various products of fuels and aromatics. These represent opportunities for replacing fossil raw materials for the development of these products. For MtG and MtJ (Methanol-to-Gasoline, Methanol-to-Jet fuel) based gasoline and jet fuel production, methanol is first converted to olefin mixes (MtO) of ethylene and propylene. This mix is then consecutively processed to form the required gasoline and jet fuel. MtA on the other hand, is used to produce aromatics including BTX. The conversion of methanol to these products depends on the catalyst chosen and the process conditions (ACATECH and DECHEMA 2023).

In terms of commodity demanded in 2021, Germany used around 16.5 Mt gasoline (en2x 2021), which was mainly used in the transport sector. The future demand potential for it is still high given hybrid vehicle realisations and the need for high-density fuels for heavy freight transport. Owing to its high gravimetric and volumetric energy density, kerosene was used in the amounts of 10 Mt (ACATECH and DECHEMA 2023) for air travel, especially for long-haul flights. It will continue to play an important role in the future aviation sector due to its positive properties while also benefitting from the RefuelEU aviation regulation promoting climate-friendly synthetic fuels. Among the olefins, around 5.2 Mt of ethylene, and 3.6 Mt of propylene were demanded which provide raw materials for the chemical and plastic production sectors. Since the chemical industry, through its value-added products, is also closely linked with other industries (like automobile production), these products represent important opportunities for a climate-neutral supply security for Germany. Similarly, aromatics, which can also be used in a variety of applications such as solvents, adhesives, coatings, polymers, etc., represented demands of around 2.47 Mt of BTX (VCI 2022). Alternative production means of these also represent encouraging means for securing the German supply system (ACATECH and DECHEMA 2023).

Since the renewable energy generation potential in Germany is limited, this would result in reliance on regions with suitable conditions for their (MtX) production and exporting them to Germany. As a result of their higher energy densities and ease of storage, this would illustrate an opportunity for importing larger quantities of renewable energy from neighbouring regions (ACATECH and DECHEMA 2023).

The MtO and MtG processes are already mature at TRL 9 and 8 – 9 respectively and are industrially available. The MtJ process is still in development at TRL 7 – 9, while MtA is still at TRL 7. The production of hydrogen and CO_2 defines the TRL of the whole value chain and is between 4 and 5 for the entire MtJ process (ACATECH and DECHEMA 2023).

Stoichiometrically, there is a requirement of around 0.52 t H_2/olefin (propylene, ethylene), 0.43 t H_2/t gasoline, 0.42 t H_2/t kerosene, and 0.8 t H_2/t aromatic (ACATECH and DECHEMA 2023). The energy demand for the MtO process is around 1.4 MWh/t olefin, however considering the whole process chain, this value increases significantly to 26.5 MWh/t olefin. The majority of this corresponds to the energy required for methanol production through electrolysis-based hydrogen and externally acquired CO2. For the MtG and MtJ processes, the energy requirements amount to around 22.8 MWh/t gasoline, and 23.6 MWh/t kerosene respectively. For the MtA conversion, this value corresponds to 1.4 MWh/t BTX. However, considering the whole MtA process chain, similar to the case of olefins, the total process energetic requirement increases to around 48.9 MWh/t BTX (ACATECH and DECHEMA 2023).

Considering the costs of the products, MtG-produced gasoline compares well with its conventional counterparts and costs only around 5% more (at 1.88 €/l gasoline) under optimistic assumptions of electricity and CO_2 costs. For the MtJ-produced kerosene however, their costs are around 5 times (at 2.87 €/l kerosene) the conventionally produced kerosene and are in the range of FT-based kerosene costs (1.58 – 3 €/l kerosene). Following similar trends, the production costs of MtO- and MtA-based olefins and aromatics are also higher compared to their conventional complements by around 30% (at 680 – 1,450 €/t olefin) and 3 times (at 1,300 – 2,800 €/t BTX) respectively (ACATECH and DECHEMA 2023). These MtX routes with their higher costs however also result in CO_2 avoidances compared to the conventional routes when the required CO_2 is obtained externally and low-carbon hydrogen production technologies are used. This contributes to avoidances of around 3.2 t CO_2/t gasoline, 3.16 t CO_2/t kerosene (jet fuel), and 0.87 t CO_2/t HVC (propylene, ethylene, BTX) respectively. However, the combustion of these products would still result in the emission of these carbon amounts with the benefit being that no new emissions would result, since the carbon used for its production had to be captured from an already occurred emission (ACATECH and DECHEMA 2023).

Resulting from the heavy dependency on hydrogen and electricity for these methanol-based products, their economic viability relies heavily on the availability of these resources in large quantities as well as at competitive pricing. If the current demands for these products were to be met through these alternate routes, this would result in electrical demands of around 376 TWh, 236 TWh, 233 TWh, and 120 TWh for gasoline, jet fuel (kerosene), olefins (propylene, ethylene) and aromatics (BTX) respectively. Under similar contexts, the required hydrogen demands would subsequently amount to around 237 TWh, 140 TWh, 152 TWh, and 65 TWh respectively. Correspondingly, using hydrogen and external CO_2 would result in CO_2 avoidances of around 53 Mt CO_2/a, 32 Mt CO_2/a, 8 Mt CO_2/a, and 2 Mt CO_2/a respectively for the different products.

In conclusion, the total amount of hydrogen usable under current product end-requirements and their respectives TRL is shown through Fig. 20. Fig. 21 shows the resulting requirement of electricity while Fig. 23 shows the total amount of CO_2 that could be avoided through these hydrogen-based options. Fig. 22 shows the stoichiometric amount of hydrogen that is required for the different processes. To avoid duplicity and under considerations of relevance, the MtO and MtA options are only represented in the basic chemicals section (Fig. 11 – Fig. 14) and are not repeated here while the focus lies on the synthetic naphtha, as well as the MtG and MtJ options.

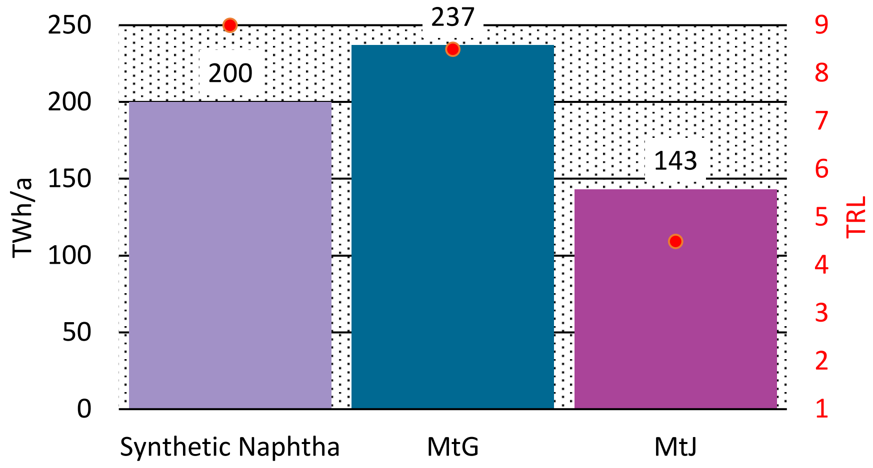

Fig. 20: Total H_2 demand for various refinery products considered under current end-requirements. The red dots depict the TRL of the hydrogen-alternative options. (Source: Own representation based on values from (ACATECH and DECHEMA 2023))

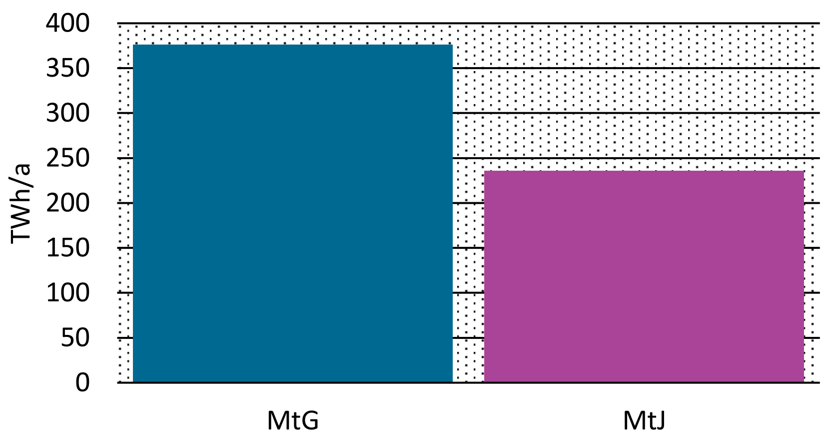

Fig. 21: Total Electricity demand for various refinery products considered under current end-requirements, when produced through electrolysis route. (Source: Own representation based on (ACATECH and DECHEMA 2023))

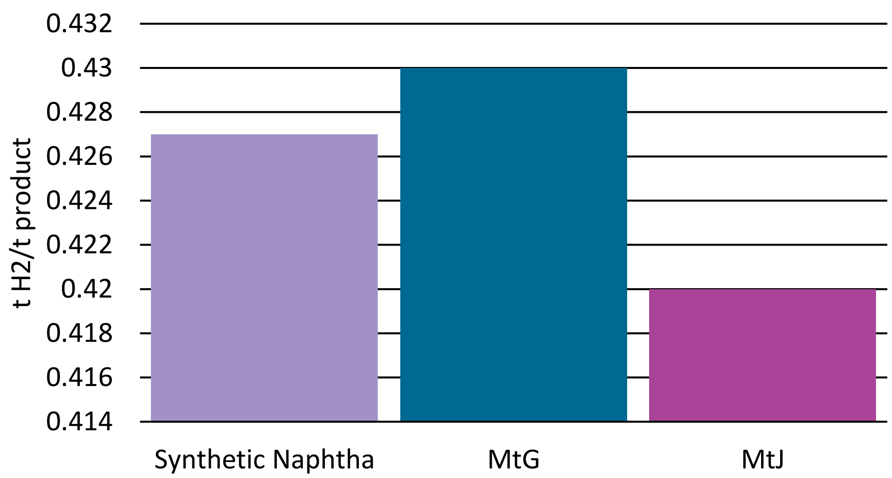

Fig. 22: Stoichiometric hydrogen requirement for various refinery products considered. (Source: Own representation based on (ACATECH and DECHEMA 2023))

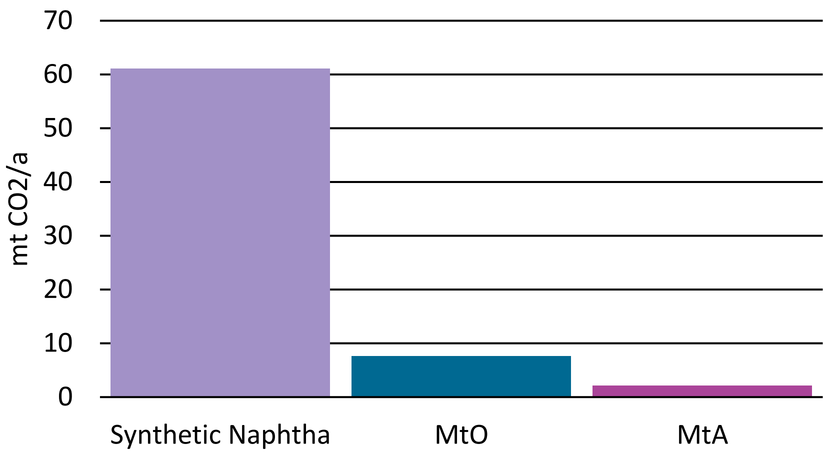

Fig. 23: Total CO_2 avoided through electrolytic hydrogen routes for various refinery products considered under current end-requirements. (Source: Own representation based on (ACATECH and DECHEMA 2023))

3.4 Food

So far, the food industry, because of it being classified as non-energy intensive, has not received much focus in studies researching end-use applications of hydrogen. However, this sector represents some distinguishing features compared to the sectors discussed above. These include high production volumes and distribution channels, different actors involved and their respective shares (MNCs (Multi-National Corporations) and SMEs (Small and Medium Enterprises)), numerous products used and sold (consequently also the involved supply chains), and the peculiar nature of food and drink products concerning their role in human survival (Sovacool et al. 2021). These aspects in addition to factors like highest land utilisation, long-term impacts of highly processed food on health, food waste, biodiversity loss, nutrient overloading, eutrophication, as well as the high energetic consumption in the value-chain and the related emissions all formulate the crux as to why the food industry should be imperatively considered while expanding comprehensive decarbonisation and sustainable development pathways (Sovacool et al. 2021). Here, the role that hydrogen, as well as other competing technologies, could play still needs to be researched and defined further.

(Sovacool et al. 2021) compiled a list of the energy-intensive processes in the complete food industry value-chain while considering material handling, size reduction, separation techniques, etc. for manufacturing; refrigeration, lighting, heating and cooling, etc. for distribution; as well as heating requirements for their final consumption and end-use. They further elaborate that among the European countries considered, the highest primary energy demand resulted from the branch of bakery products, followed by beverage and dairy products. Additionally, they identified products for their specific fuel and electricity consumptions (/t product), and found that for the meat sector, processed meat had the highest fuel consumption followed by rendering, while poultry products had the highest electricity consumption. Similarly, for the fisheries sector, fish meal products had the highest fuel and electricity consumption, followed by smoked and dried fish and prepared and preserved fish. Under the Fruits and vegetables sector, it was tomato juice with the highest fuel demand, followed by dried vegetables and fruits, while potato products and preserved mushrooms had the highest electricity consumption. Whey powder production from the dairy sector had the highest specific fuel and electricity demand across all the products considered, followed by milk powder, condensed milk, and cheese production. These factors along with the specific CO_2 emissions of select products are shown in Fig. 24.

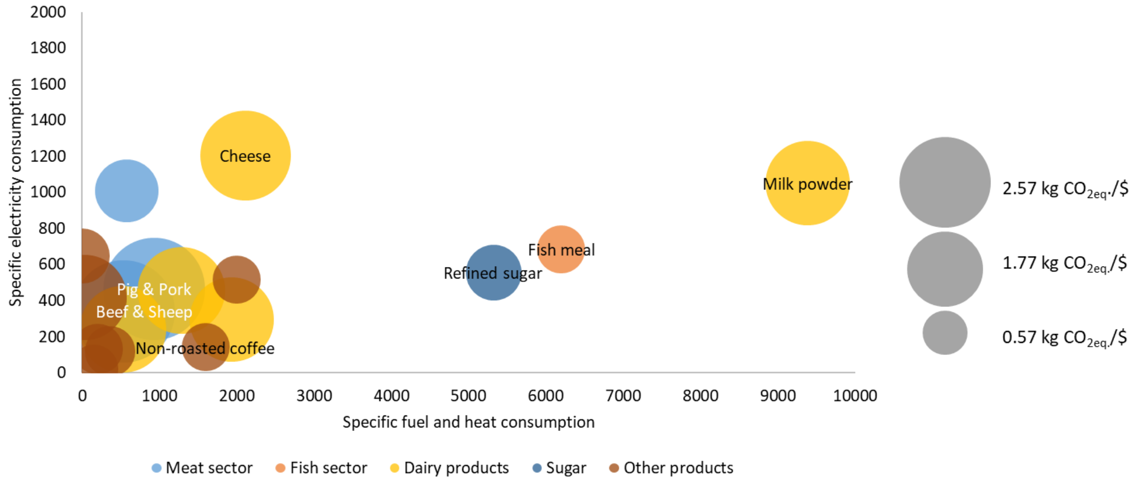

Fig. 24: Specific electricity vs heat consumption with CO_2-factors of select products. (Source: own representation based on (Sovacool et al. 2021))

In terms of the fuels used in the industrial sectors, as of 2022 in Germany, the food and tobacco sector ranked a close fourth at 44.7 TWh, following iron & steel (119.58 TWh), basic chemicals (87.8 TWh), and construction (44.67 TWh) (Rohde and Arnold-Keifer 2023). Of the total fuel used in the food sector, natural gas had the highest share at 75% (30.83 TWh) followed by coal and oil and was mainly used to provide the heat demand required for process heat, as well as room and water heating (98%, at around 30.3 TWh). At the same time, only a minimal amount (2%) of NG was used for providing the required mechanical energy in the food sector (Rohde and Arnold-Keifer 2023). These aspects are also shown in Fig. 25. This dependence on NG for heat provision in the food industry has been consistent throughout recent years. In terms of total industrial utilisation of NG, only the chemical industry supersedes the food and tobacco sector (Rohde and Arnold-Keifer 2023).

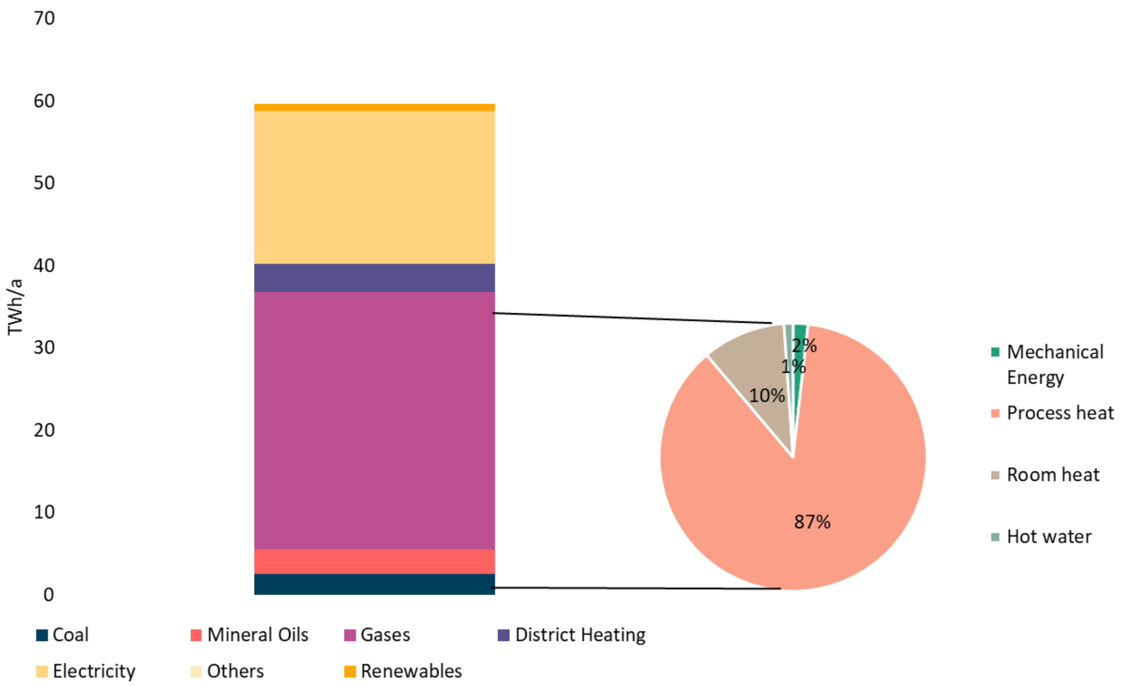

Fig. 25: Fuel use in the Food & Tobacco industry in Germany with the specific usage pathways of Natural Gas in 2022. (Source: Own representation based on (Rohde and Arnold-Keifer 2023))

Although there is a significant consumption of NG in the food industry, the CO_2 emissions from this sector cannot be directly attributed to them since CO_2 is also inherently used in the sector itself. This application of carbon dioxide comes in the form of refrigerants, carbonised beverages, deoxygenated water, casein precipitation, pre-treatment of olives, and use as an acidifier, as well as to prolong the shelf-life of certain fruits and vegetables. At the same time, the food industry is also responsible for the emission of short-lived GHG emissions in the form of methane and nitrous oxides through farming, poultry, and dairy applications (Sovacool et al. 2021). As of 2021, around 62 Mt CO_{2eq}. emissions of methane and nitrous oxides were released from the food industry, while accounting also the actual CO_2 emissions, the net GHG emissions would further increase significantly (Springmann 2023). This combination of high fossil-based NG consumption, along with the release of other significant GHGs represents a pivotal opportunity for the inclusion of renewable fuel sources, and to develop new technologies to bolster the industrial sector decarbonisation.

Different options exist for decarbonising the food industry in its complete value chain – for the agriculture and manufacturing processes, improved manure management systems, as well as improved nitrogen efficiency, along with the application of automation and robotics, and process management and optimisation could be beneficial. As for the retail and distribution channels, practices of energy efficiency, sustainable supply-chain management as well as minimising food waste can be valuable. Changes in the end-use through practices that minimise food waste like food-sharing, as well as promoting diet changes through plant-based diets can also significantly facilitate the reduction of related emissions (Sovacool et al. 2021).

For reducing energy-related emissions, electric heaters, as well as the use of waste heat could also be decisive. However, other options could also include the utilisation of hydrogen by modifying and retrofitting existing boiler and gas infrastructures. While electrical alternatives are readily available and can be used directly, information on hydrogen utilisations is sparse. (Abdalla et al. 2018) and (Parenteau 2023) refer to the usage of hydrogen in food processing for the hydrogenation of unsaturated fatty acids in vegetable oils, and also for the conversions of sugars to polyols, oils to fats, and tallow and grease to animal feed. (C. Conklin and Beresnyak 2023) however, provide options for hydrogen utilisation in food production, i.e. in the agriculture sector. These opportunities include using hydrogen for grain drying and cooling, as well as for fuel-cell-powered tractors, harvesters, irrigation systems, and greenhouses. (Sovacool et al. 2021) also express that decarbonising the food industry could result in savings in the form of energy, carbon, costs, along with environmental co-benefits, as well as improvements in the health and satisfaction of the employed workers.

If the heating demands currently met through NG were to be replaced completely with hydrogen, this would result in hydrogen utilisations of around 30 TWh/a, corresponding to a demand of around 0.9 Mt H2/a (LHV). Employing hydrogen would then also correspond to the avoidance of almost all process-related emissions of around 1.26 Mt CO_2/a (Neuwirth et al. 2022).

To improve the status of the various decarbonisation options, financial, organisational, and behavioural barriers need to be addressed. These respectively represent factors like additional costs towards decarbonisation, lack of investment and incentive towards research, as well as high meat consumption. These can be mitigated through measures like new finance and business models, as well as policy instruments. Some of these policies could be in the form of schemes including carbon emission trading, energy efficiency, as well as feed-in tariffs, regulation on potent emissions, etc. (Sovacool et al. 2021).

3.5 Summary

Fig. 26 shows the overall implications of the hydrogen demand under current structures for the considered industrial sub-sectors and the specific options driving it. While hydrogen use in refineries for gasoline production via MtG is expected to decline in future due to a shift towards electric transportation, the aviation sector will continue to require synthetic fuel from MtJ conversions. Correspondingly, since synthetic naphtha is primarily used for chemical production, the net usage potential of hydrogen would be the highest in the chemical industry.

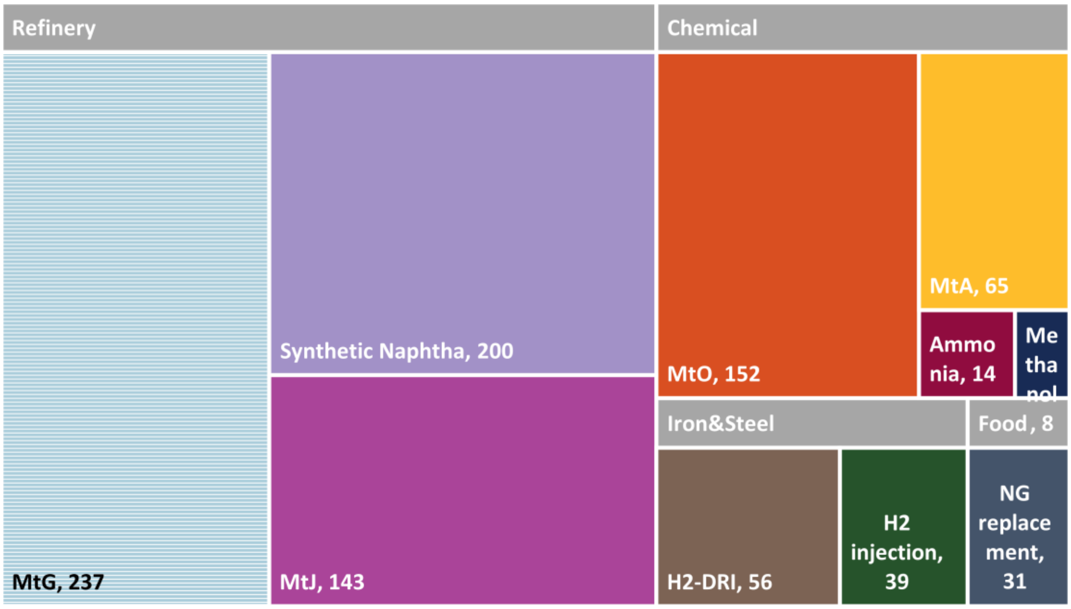

Fig. 26: Comparative plot of hydrogen usage potential for the different industrial sub-sectors and the options driving them under current end-product requirements. The shaded MtG portion represents an uncertain and decreasing future usage potential for gasoline production due to uptake of electric alternatives for transport. Since synthetic naphtha is primarily used further in chemical production, the chemical sub-sector represents the highest hydrogen utilisation potential. The values are represented in units of TWh/a. (Source: Own representation based on (Geres et al. 2019; ACATECH and DECHEMA 2023; Rohde and Arnold-Keifer 2023))

Table 3 expands further on Table 2 to include the values considered from the static analysis above to compare them with the previous considered ranges.

Table 3: Comparison of (final) energy consumption of German industrial sub-sectors with maximum long-term hydrogen demand values from studies and considered analysis under current and static structures.

	(Final) Energy Consumption (2021)			**H2 potential**		
	Fossil			**Neuwirth et al. (2022)**	**Range from other literatures (max, long-term values)**	**Static structure analysis**
	Gas	**Liquid**	**Solid**			
	TWh/a					
Basic Chemicals	71	2	4	168	283	240
Iron & Steel	56	1	95	75	75	95
Food	34	2	2	36	-N/A-	30
Rest of Industry	111	8	24	158	-N/A-	-N/A-
Sum	**272**	**13**	**125**	**436**	**358**	**365**
Refinery (self-use)	32	58	1	18	159	580
Total	**304**	**71**	**126**	**454**	**517**	**965**

4. Industrial hydrogen demand and cost dependence

Among the studies referred for estimates of hydrogen utilisation in the different industry branches, numerous differences exist. From their analysis of the different energy system models usually used for such estimates, (Quarton et al. 2020) and (Dodds et al. 2022) concluded that the models, as well as their results cannot be directly compared given the fundamental methodological, and architectural differences, as well as the disparities among the implemented assumptions. For the scope of hydrogen, these differences can derive from the different hydrogen-specific technologies considered, their assumed cost-developments, the respective diffusion rates, etc.

Another aspect which also plays an important role in regard to the demand of hydrogen is the price it is available at. Since there exists no current market for the trade of hydrogen, its cost estimates vary widely. (Michalski et al. 2017) provide estimates of around 1.3 – 3.4 €/kg H_2 (~30 – 100 €/MWh H_2), while (Busch et al. 2023) also provide costs for LH2 (Liquid Hydrogen) and state that hydrogen obtained from the MENA region would be available at around 2.10 €/kg H_2 (~60 €/MWh H_2). (Michalski et al. 2017) on the other hand, provide cost ranges of 2.8 – 3.9 €/kg H_2 (~80 – 110 €/MWh H_2) for its application specifically in the industry sector. (Kondziella et al. 2023) for their analysis however, consider two extreme prices of 100 €/MWh H_2 and 500 €/MWh H_2 to represent high- and low-cost values respectively in their sensitivity analysis. Since the assumed costs for hydrogen in the studies considering industrial demand ranges are generally not mentioned explicitly (as from studies in section 2 and 3), an analysis of the effect of different hydrogen costs and their growths on the industrial uptake is valuable and is inspected further in this section.

A total of 10 cost-growth paths are considered for hydrogen over the years of 2020 – 2060. The reference cost-growth considered is similar to the one used in (Harthan, Ralph O., Förster, Hannah et al. 2023), however further industrial specific mark-ups are also considered. Further 9 cost-pathways are developed to represent lower and higher price developments starting from 2030 which then remain constant until 2060. Linear interpolation is applied for the values between 2020 and 2030. These different scenarios for the distinct cost-growth values are represented in Table 4.

Table 4: Price-growth sensitivity scenarios

Scenario	Price-steps (€$_{2019}$/MWh)		
	2020	2030	2060
REF	217.4	110	56.3
P50	217.4	50	50
P60	217.4	60	60
P70	217.4	70	70
P80	217.4	80	80
P90	217.4	90	90
P100	217.4	100	100
P110	217.4	110	110
P130	217.4	130	130
P150	217.4	150	150

The demand comparisons in the industry along with insights into the specific industrial sub-branches among the above-mentioned price scenarios is done through the employment of the in-house developed model TAM-Industry (TIMES Actor Model – Industry), and is further elaborated in the further sections.

4.1 Total demand and cost-dependence

In this section, the overall impact of the price-growth on the industrial applications is considered. The employed TAM–Industry model is based on the TIMES (The Integrated MARKAL-EFOM System) energy system modelling framework and it focused on the Industry sector of the German energy system. It represents 10 different industrial sub-sectors and includes the value chains for each of them in detail, as- Automotive manufacturing (passenger car, light commercial vehicle, heavy commercial vehicle), Chemical (Ammonia, Chlorine, Methanol, Olefins, Aromatics and aggregated other chemicals), Cement Industry, Food and Tobacco, Iron and steel, Glass, Non-Ferrous Metal (Aluminium, Copper, and other nor ferrous metal), Paper, Other Non-metallic Minerals, and other industries (rest of the industries). The model is also calibrated to the base year of 2013 and again for 2015, with the whole model horizon until 2060. It develops on detailed technological representations within each industrial sub-sector with categorisation of the involved production processes. Furthermore, specific industrial sub-sectors (like Iron & Steel, Cement, and Glass) are further characterized by different actor groups representing disaggregated and divergent decision-making possibilities based on these specific branches. The model delivers cost-optimal investment decisions under conditions of industry specific GHG targets and CO_2 taxes. For more details regarding the model and its assumptions, the reader is directed to A.3.

Considering the total amount of hydrogen bought at the price within the industry, as can be seen from Fig. 27, it does not vary much in the years across the price scenarios. Overall, the P50 scenario sees the highest purchase of hydrogen by virtue of its lowest cost at around 1,532 TWh over the whole modelling horizon. The P60 and P70 scenarios follow closely at around total 1,520 TWh and 1,503 TWh respectively. The intermediate scenarios of P80 – P100 see values comparable to the REF scenario and are close to an average of 1,480 TWh. The effect of higher hydrogen costs is prominent in the P130 and P150 scenarios with the total amount bought being limited to 906 TWh and 554 TWh respectively. For 2030, with the price of hydrogen in the P50 scenario being less than half than in the REF scenario, its purchase is consecutively almost twice at around 67 TWh and is the highest of the year compared to 34 TWh in the REF. As the price of hydrogen increases, as in the P150 scenario, the amount bought decreases to around 23% of that of the REF scenario. By 2045, the values across all scenarios are comparable at around 260 TWh, except the most-expensive last two scenarios where purchase is lower by around 60 TWh and 116 TWh respectively. The situation continues in the year with slightly lower acquisitions overall resulting from previous investments and is on average around 240 TWh across the scenarios, here again the last two scenarios with the highest costs see significantly lower procurement by around 120 TWh and 170 TWh respectively.

Fig. 28 shows the trajectory of the hydrogen purchase for the scenarios across the years and shows that the P50 – P110 scenarios see comparable hydrogen acquirements to the REF scenario, while P130 and P150 have consistently significant lower values over the years.

An interesting aspect, shown through Fig. 29 is the impact of the hydrogen prices on the amount of hydrogen that is bought at the specific prices and the amount that is self-generated within the industry sector itself. In the REF scenario for 2030, around 28% of the total demanded hydrogen is self-generated, while the rest 72% is bought at the price. As the situation develops, only 1.6 – 1.7% is self-generated in the years of 2045 and 2060 respectively since its cheaper in this situation to buy it at the provided price. In the P50 scenario, the situation is similar for the latter years, however for 2030, the model decides to self-generate around 8% of the total demand since the price for its procurement is cheaper than if the hydrogen had to be produced within the industry. For the expensive scenarios however, the situation is different, self-generation represents the majority share for meeting the hydrogen demand. In the P150 scenario, for 2030, the self-generated amount of hydrogen corresponds to around 83% of the total demand, while it decreases to around 44% in 2045, however, it increases again to around 68% in 2060. Hence, it can be concluded from Fig. 27 – Fig. 29 that the total hydrogen demand does not depend significantly on the price of hydrogen since it requires them to meet its GHG targets, rather what differs is the amount of hydrogen that is bought at the price and the amount of hydrogen that is self-generated within the industry sub-sector. Fig. 29 also represents the amount of hydrogen that is required as feedstock in the industry sector, which is significant at around 80% for 2060, and hence is a major driver of hydrogen demand within the industry sector.

The comparative relation between price and hydrogen demand for the select years of 2030, 2045, and 2060 are shown in Fig. 30. This represents the change in hydrogen uptake (H_{Scen}/H_{Ref}) with respect to the change in price among (P_{Scen}/P_{Ref}) the different scenarios compared to the REF case along with their respective trendlines.

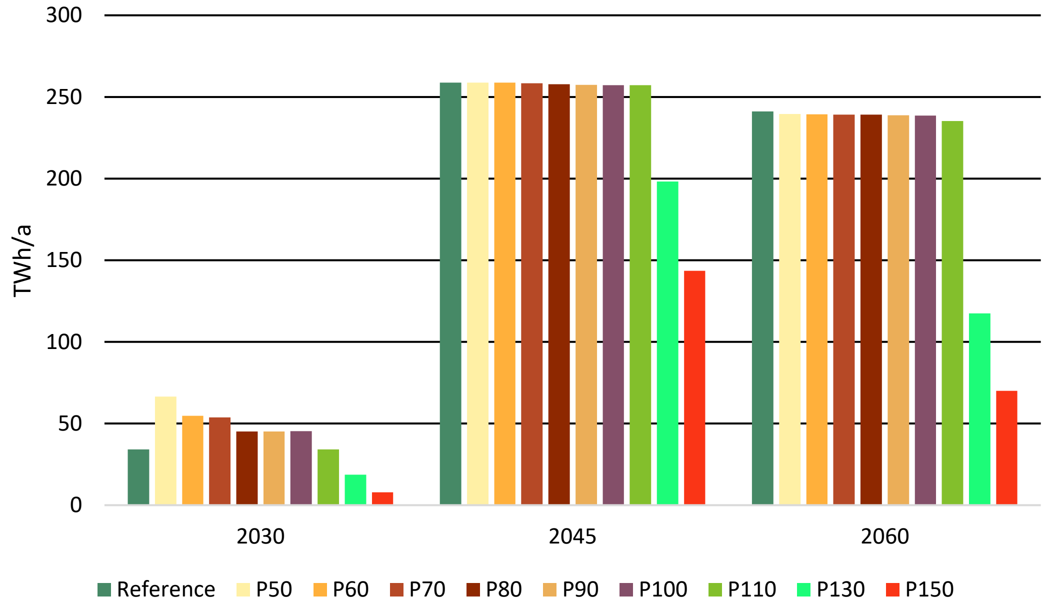

Fig. 27: Amount of hydrogen bought within the industry under different cost rates. (Source: Own representation)

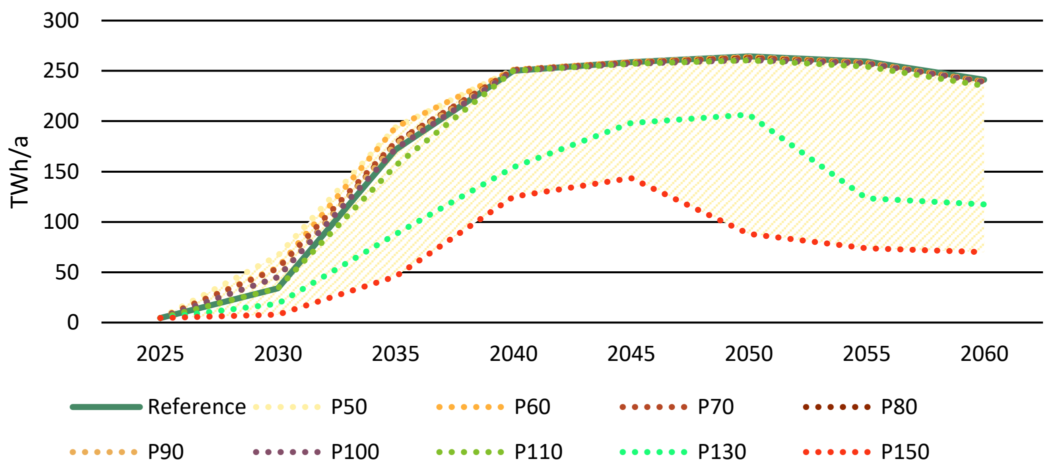

Fig. 28: Trajectory of amount of hydrogen bought within industry under different cost rates. (Source: Own representation)

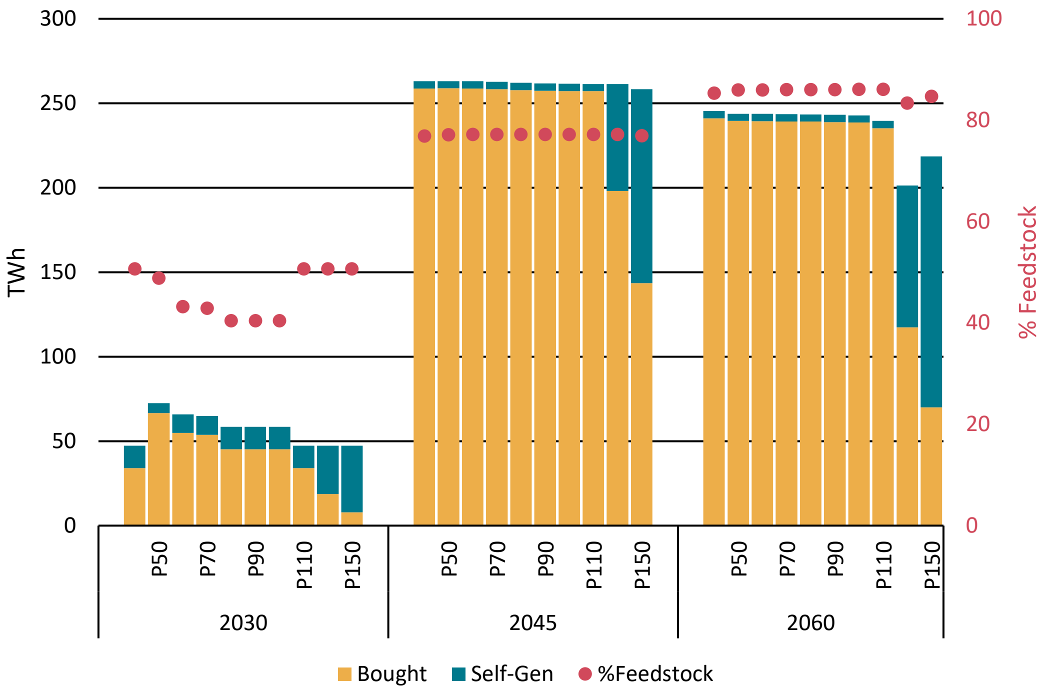

Fig. 29: Amount of hydrogen bought and self-generated within the industry sector. The total represents the total amount of hydrogen demanded within the industry sector. The red dots represent the % of hydrogen used as feedstock of the total demand. (Source: Own representation)

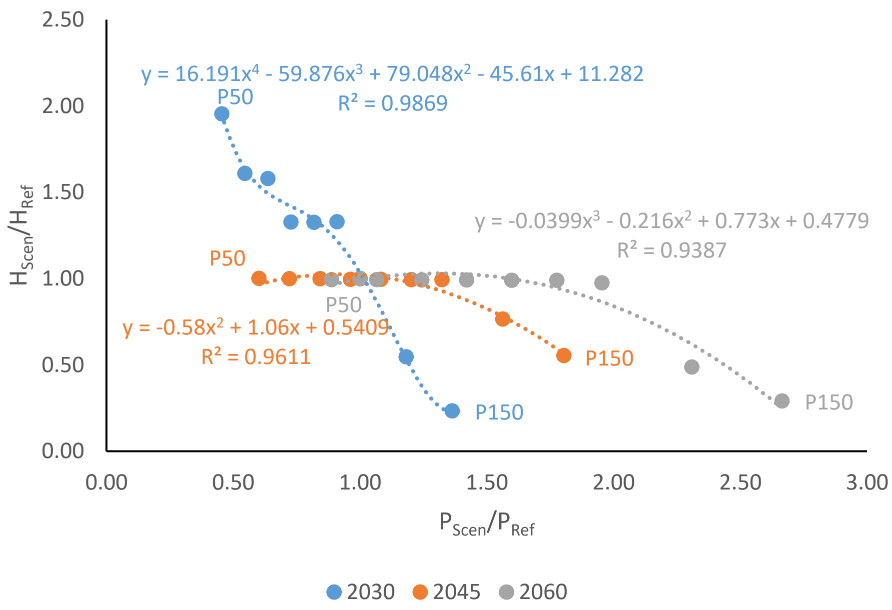

Fig. 30: Price vs hydrogen uptake compared to the REF scenario for different years. (Source: Own representation)

4.2 Sub-sectoral demand and cost-dependence

The uptake of hydrogen varies significantly among the industrial sub-sectors considered. This depends on the usability of hydrogen within each sub-sector and the implementation of these options within the model. In the TAM-Industry model, based on literature trends, hydrogen-based alternative options were mainly implemented for select sub-sectors of Basic Chemicals, Glass production, as well as Iron & Steel, while the model also has options for blending hydrogen with natural gas to maximum 20% by volume to reduce its GHG emissions across all the sub-sectors modelled. The sectoral division of hydrogen demand for the different scenarios across the years is shown through Fig. 31.

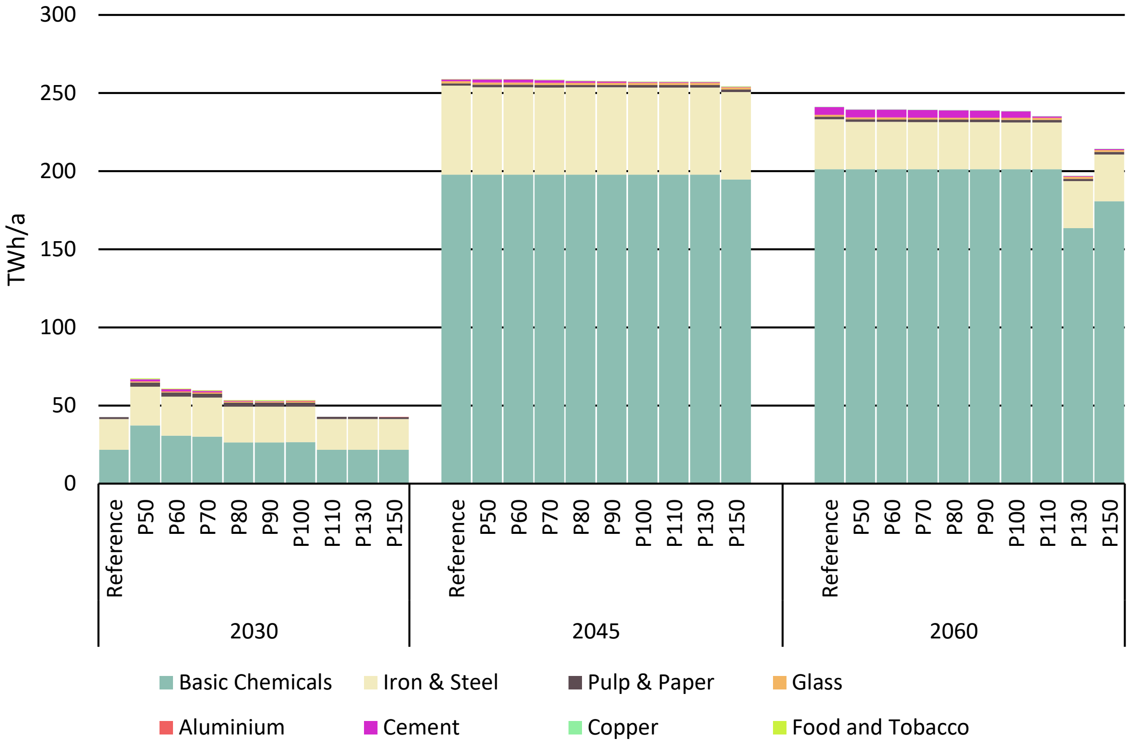

Fig. 31: Sectoral utilisation of hydrogen for select years among the different scenarios. (Source: Own representation)

The results show that the chemical and the iron & steel branches have the highest demands for hydrogen at the provided costs. The Basic Chemical sub-sector leads marginally to the Iron & Steel sub-sector with around 22 TWh demand in 2030 compared to 20 TWh in the latter for the REF scenario. However, in the P50 scenario, the demand increases to around 37 TWh and 25 TWh respectively for the chemical and the steel sub-sectors. The scenarios of P110 – 150 perform similar in terms of their demand among these two sub-sectors and have the same values as in the REF scenario. In 2045, the demand increases significantly for the basic chemicals to around 200 TWh in the REF scenario compared to 57 TWh for the iron & steel sub-sector. The demand here within the sub-sectors is the same across the scenarios with only a bit of decrease in the P150 scenario. In 2060, the overall demand sees a decrease (as also noted in Fig. 27), however the demand within the chemical sub-sector remains the same, while that in the steel sub-sector decreases to around 32 TWh in the REF scenario. The cement sub-sector also sees an increase in its hydrogen demand in this year and is around 5 TWh in the REF scenario. The situation for the sub-sectoral demands remains the same as in previous cases across the scenarios for the chemical sub-sector, however it sees a decrease by around 20 TWh in the P150 scenario. The iron and steel sub-sector however, sees a constant demand across the scenarios of P50 – P150 at around 30 TWh. For the cement sub-sector, the demand remains more or less similar across the scenarios (5 TWh) which decrease to below 1 TWh in P110 and further below 0.5 TWh in P130 and P150. Hydrogen demand in the other sectors is not seen as evidently, and is restricted to the hydrogen-usable options included in the model.

5. Conclusion

From the current analysis, it is evident that hydrogen is projected to play a crucial role in the industry sector. Its role varies within the industry branches to meet energetic as well as feedstock requirements. So far, the branches of basic chemicals, iron & steel, and refineries seem to be the forerunners in terms of hydrogen applicability. For the different products considered under the individual industry branches, if their current demands were to be met completely through hydrogen applications, the resulting hydrogen demands would be significant as seen through the static analysis. The chemical sub-sector would represent total demands of around 240 TWh H_2/a, with MtO and MtA responsible for around 63% and 27% of the total demand, followed by demands for ammonia and methanol respectively. The refinery sub-sector would represent significant demands at around 580 TWh H_2/a, of which around 41% results from the requirements for the production or conversion of methanol to gasoline and around 34% for the production of synthetic naphtha. The remaining amount is required for the conversion of methanol to jet-fuel (kerosene). Finally, the iron & steel sub-sector would result in lowest hydrogen demands totalling around 95 TWh H_2/a, of which around 56 TWh H_2/a would be required for H_2-DRI and the remaining for H_2-injetion into the blast furnace.

The usage of hydrogen for these products would also results in avoiding substantial amounts of CO_2 in a bid to reduce industrial GHG emissions. Around 90 Mt CO_2/a could be avoided if hydrogen was used for meeting the requirements for Synthetic Naphtha, while utilisations for Ammonia, MtO, Methanol, and MtA would amount to avoidances of 8 Mt CO_2/a, 7.6 Mt CO_2/a, 2.2 Mt CO_2/a, and, 2.14 Mt CO_2/a respectively. MtG and MtJ products from the refinery would subsequently result in avoidances of around 53 Mt CO_2/a and 32 Mt CO_2/a respectively. For the iron & steel sector, the CO_2 avoidances would amount to around 47 Mt CO_2/a and 10 Mt CO_2/a for H_2-DRI and BF-injection respectively. As a result, hydrogen will play a crucial role in decarbonising the industry sector, hence, further support for domestic hydrogen production, as well as strengthened cooperation for imports, are decisive to realise this potential.

So far, the food industry has been sidestepped in terms of hydrogen applicability. However, the distinctive nature of the industry not only in terms of energy and the related emissions but also in terms of land use, the impact of highly processed foods on health and economy, food waste, and biodiversity loss, all because of their necessity in terms of human survival, makes their consideration crucial in developing sustainable and decarbonisation pathways for the industry sector. If the dependency of NG in the food industry is replaced with H2 instead, this would result in requirements of around 0.9 Mt H2/a representing 30 TWh H_2/a. This would then also consecutively result in CO_2 avoidance of around 1.26 Mt CO_2/a.

These theoretical hydrogen demands based on literature and stoichiometry are however also dependent on the price at which it is available at. To take into consideration these cost-dependency aspects, scenario runs were done to compare the hydrogen demand in the industry sector under various prices using the TAM-Industry model. It was noted that the total demand for hydrogen within the years across the scenarios was not so sensitive to the price of hydrogen. The demand was more-or-less similar across the scenarios, and rather the impact the prices had was on the amount of hydrogen that was self-generated within the industry sector. When the price of hydrogen was high, the model compensated for it through increased self-generation and lower reliance on imports to meet its hydrogen demands. In 2030, the chemical and the steel sub-sectors had comparable demands of hydrogen at around 20 TWh/a which increased significantly in 2045 to around 200 TWh/a and 57 TWh/a respectively.

The comparative values from all the sections covered for the industrial sub-sectors for their hydrogen demand and the current energy consumption is represented through Table 5, which further expands on Table 3 with the values from the dynamic analysis.

Table 5: Comparison of (final) energy consumption of German industrial sub-sectors with hydrogen demand values from dynamic analysis under cost-scenarios.

	(Final) Energy Consumption (2021)			**H2 potential**					
	Fossil			**Neuwirth et al. (2022)**	**Range from other literatures (max, long-term values)**	**Static structure analysis**	**Dynamic analysis (cost-scenario ranges)**		
	Gas	**Liquid**	**Solid**				**2030**	**2045**	**2060**
	TWh/a								
Basic Chemicals	71	2	4	168	283	240	22 – 37	195 – 198	164 – 201
Iron & Steel	56	1	95	75	75	95	20 – 25	56 – 57	30 – 32
Food	34	2	2	36	-N/A-	30	-N/A-	-N/A-	-N/A-
Rest of Industry	111	8	24	158	-N/A-	-N/A-	-N/A-	-N/A-	-N/A-
Sum	**272**	**13**	**125**	**436**	**358**	**365**	**42 – 62**	**251 – 255**	**194 – 233**
Refinery (self-use)	32	58	1	18	159	580	-N/A-	-N/A-	-N/A-
Total Industry	**304**	**71**	**126**	**454**	**517**	**965**	**42 – 62**	**251 – 255**	**194 – 233**

Since the net demand in the industrial branches is not expected to change much over the years, higher advantages exist in improving industrial process efficiencies as well as decreasing their reliance on fossil sources. The final uptake of hydrogen in the industry branches depends not only on their market prices but also on political and social approvals. In this aspect, it is important to promote their acceptance through awareness programs, policies that promote alternative technologies through cost and risk aversions, faster approvals of these new technologies, as well as developing cooperations among different countries for an international hydrogen market.

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ANNEX

A.1

Technology Readiness Level (TRL) value descriptions (based on (ACATECH and DECHEMA 2023)).

TRL 1: Observation and description of the operating principle
TRL 2: Description of the application of a technology
TRL 3: Proof of functionality of a technology
TRL 4: Experimental set-up in laboratory environment
TRL 5: Experimental set-up in operational environment
TRL 6: Prototype in an operational environment
TRL 7: Prototype in use
TRL 8: Qualified system with proof of functionality in operational field
TRL 9: Qualified system with proof of successful use

A.2

Assumptions involved for cost-parity descriptions.

Ammonia

Fig. 32 from (Geres et al. 2019) shows the specific cost comparisons for ammonia production through the conventional (black) and electrolyser and ASU based production routes (red). These specific costs are considered for undepreciated (solid), i.e new, as well as depreciated (dashed), i.e already existing and old technologies. Additionally, the dotted lines represent the specific CO_2 emissions resulting from these two production options. The cost-decrease for the electrolyser-based route is considered to be around 20% over the first 9 years during 2031-2040 after reaching TRL 9 in 2031, after which until 2050, there is a further decrease in the specific costs by around 22%. In the same periods, the cost for the conventional option increases by around 3% each. By 2040 and 2048, the new electrolyser-based ammonia production route is seen to be more cost-efficient than the conventional non-depreciated and depreciated options respectively. For the CO_2 considerations, the development of the German electricity mix is considered and represents better opportunity for the electrolyser-based option already starting from 2035 onwards.

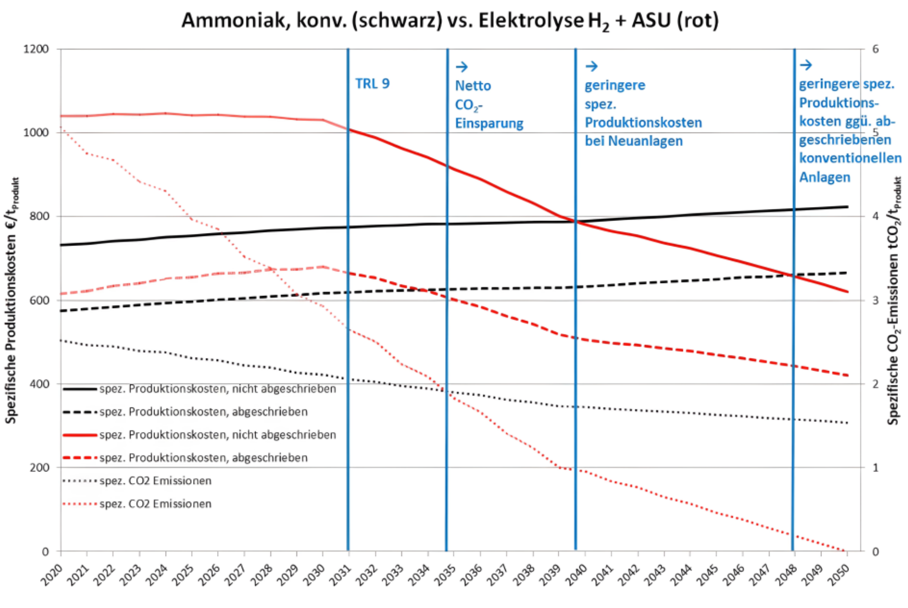

Fig. 32: Specific cost and CO_2-emission comparison of conventional ammonia production (black) with alternative electrolytic hydrogen and ASU based production (red). (Source: (Geres et al. 2019))

Methanol

Fig. 33 from (Geres et al. 2019) represents the specific cost comparisons for methanol production through the conventional (black) and electrolyser-based production routes (red). These specific costs are considered for undepreciated (solid), i.e new, as well as depreciated (dashed), i.e already existing and old technologies. Additionally, the dotted lines represent the specific CO_2 emissions resulting from these two production options. The cost-decrease for the electrolyser-based route is considered to be around 20% over the first 10 years during 2030-2040 after reaching TRL 9 in 2030, after which until 2050, the cost decrease continues at a further 20%. In the same periods, the cost for the conventional option increases by around 6% each. By 2044 and 2048, the new electrolyser-based methanol production route is seen to be more cost-efficient than the conventional non-depreciated and depreciated options respectively. For the CO_2 considerations, the development of the German electricity mix is considered and represents better opportunity for the electrolyser-based option already starting from 2034 onwards.

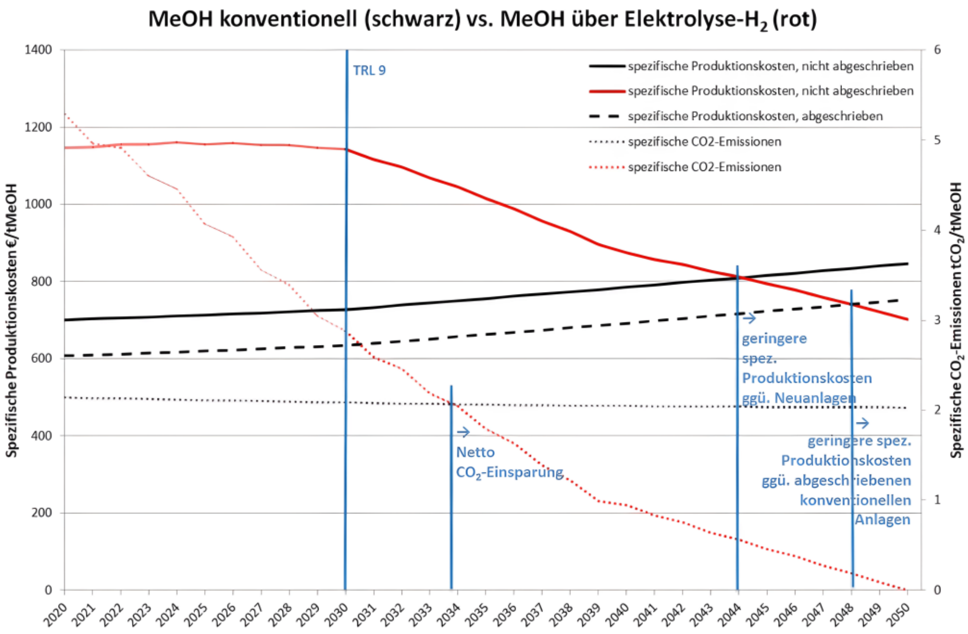

Fig. 33: Specific cost and CO_2-emission comparison of conventional methanol production (black) with alternative electrolytic hydrogen-based production (red). (Source: (Geres et al. 2019))

Naphtha Cracking

Fig. 34 from (Geres et al. 2019) shows the specific cost comparisons for naphtha cracking through the conventional (black) and electrolytic based routes (red). Additionally, the dotted lines represent the specific CO_2 emissions resulting from these two cracking options. The cost-decrease for the electric cracking is considered to be around 4% over the first 5 years during 2035-2040 after reaching TRL 9 in 2035, after which until 2050, there is a further decrease in the specific costs by around 3%. In the same periods, the cost for the conventional option increases by around 1% and 2% respectively. By 2049 the new electric cracking is seen to be more cost-efficient than the conventional cracking option. For the CO_2 considerations, the development of the German electricity mix is considered and represents better opportunity for electric cracking option already starting from 2035 onwards.

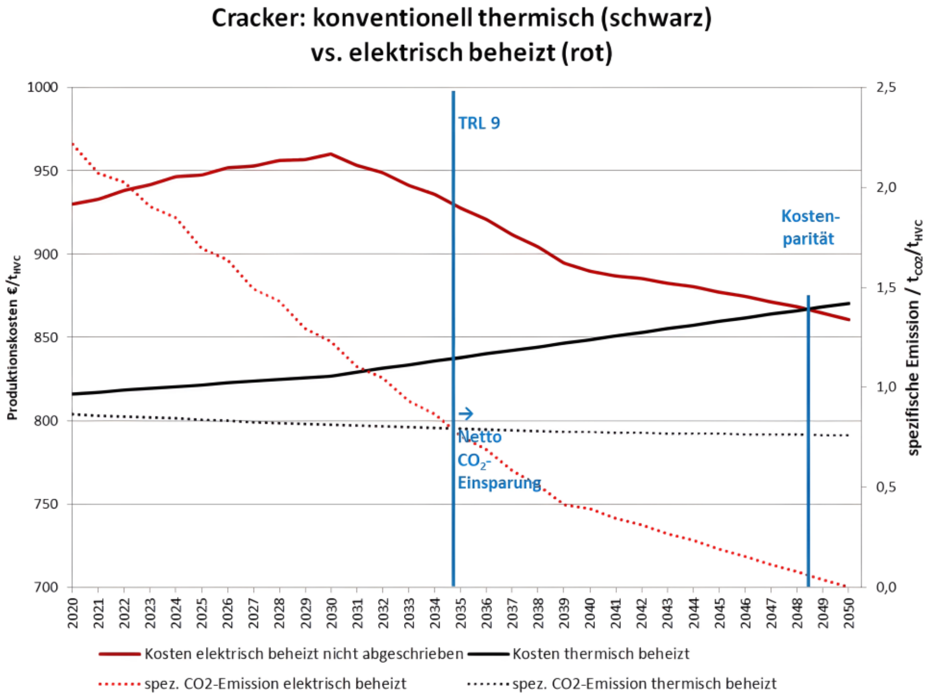

Fig. 34: Specific cost and CO2-emission comparison of conventional naphtha cracking (black) with alternative electric cracking (red). (Source: (Geres et al. 2019))

A.3

This section presents some of the assumptions and values implemented in the TAM-Industry model for better understanding of its workings. For more details, the readers are invited to contact the authors.

<u>Environmental & potential constraints</u> applicable to the overall model:

Parameter	Unit	2020	2025	2030	2035	2040	2045	2050	2055	2060
CO_2 Tax	M€/kt	0	0.055	0.08	0.1	0.1375	0.175	0.24	0.2625	0.302
CO_2 Bound	kt					20,371	8,023	8,023	8,023	8,023
CCS Bound	kt			16000	16000	16000	16000	16000	16000	16000
Biomass potential - Industry	PJ	221.5	285.7	350	350	350	350	350	350	350

Energy-Carrier prices for all the industrial sub-branches:

Energy Carrier	Unit	2020	2025	2030	2035	2040	2045	2050	2055	2060
Brown Coal	€/MWh	23.1	35.2	58.1	124.4	259.8	386.5	425.7	426.0	438.5
Coke	€/MWh	25.3	37.7	60.9	127.2	262.6	389.3	428.5	429.2	441.7
Hard Coal	€/MWh	23.3	35.5	58.4	124.7	260.0	386.7	425.9	426.3	438.7
Lignite	€/MWh	21.6	33.8	56.7	123.0	258.4	385.1	424.2	424.6	437.0
Elec. Grid	€/MWh	186.1	165.0	160.3	134.6	123.6	118.1	114.3	108.6	111.9
Coke Oven Gas	€/MWh	40.1	57.4	96.3	176.2	274.4	330.8	358.6	378.3	375.6
Methane	€/MWh	40.1	57.4	96.3	176.2	274.4	330.8	358.6	378.3	375.6
Natural Gas	€/MWh	40.1	57.4	96.3	176.2	274.4	330.8	358.6	378.3	375.6
High temp heat grid	€/MWh	33.5	58.3	85.9	95.4	94.2	83.5	74.8	80.1	86.5
Diesel	€/MWh	74.0	93.2	147.9	246.0	363.7	420.6	401.1	392.5	410.9
Gasoline	€/MWh	76.1	95.6	150.5	248.6	366.4	423.3	403.8	395.2	413.7
Heavy-fuel Oil	€/MWh	65.7	84.3	135.1	234.2	352.0	409.3	390.0	380.9	398.9
Kerosene	€/MWh	76.1	95.6	150.5	248.6	366.4	423.3	403.8	395.2	413.7
LPG	€/MWh	86.4	106.1	157.4	257.2	375.5	433.3	414.5	405.9	424.4
Naphtha	€/MWh	72.2	91.9	143.2	243.0	361.3	419.1	400.3	391.7	410.2
OILNEU	€/MWh	72.2	91.9	143.2	243.0	361.3	419.1	400.3	391.7	410.2
Other Oils	€/MWh	78.5	99.1	151.0	250.9	369.3	427.1	408.4	400.4	419.3
Refinery Gas	€/MWh	85.8	106.6	158.8	258.7	377.1	435.0	416.4	408.5	427.5

Final end-use demands:

Chemical sub-sector:

Product	Unit	2020	2025	2030	2035	2040	2045	2050	2055	2060
Chlorine	Mt	4.6	4.8	4.8	4.7	4.6	4.6	4.6	4.6	4.6
Methanol	Mt	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Ammonia	Mt	2.64	2.48	2.5	2.5	2.5	2.6	2.6	2.6	2.6
Olefins	Mt	5.1	5.4	5.5	5.6	5.7	5.8	6	6	6
Aromatics	Mt	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71

Iron & Steel and Food & Tobacco sub-sectors:

Product	Unit	2020	2025	2030	2035	2040	2045	2050	2055	2060
Iron & Steel	Mt	35	42.3	42.9	44.2	45.7	41.0	40.3	40.3	40.3
Food	PJ	207.3	207.5	207.4	207.2	207.0	206.8	206.6	206.6	206.6

Non-metallic mineral & Non-ferrous metal sub-sectors:

Product	Unit	2020	2025	2030	2035	2040	2045	2050	2055	2060
Non-metallic minerals	Mt	47.1	48.9	48.8	48.8	49.4	49.4	49.4	49.4	49.4
Non-ferrous metals	Mt	1.8	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0

Technology descriptions:

Electrolysers:

Type	CAPEX ($M€/GW\ H_2$)			Fixed O&M ($M€/GW\ H_2$)			Elec. Efficiency (%)	Lifetime (yrs)
	2020	2030	2050	2020	2030	2050		
Alkaline	625.9	377.2		40	26.2		67	40
PEM	1200	950	750	36	28.5	22.5	70	30
SOEC		1901	783	12	12	12	83	20

Ammonia, Methanol, MtO, MtA, electric cracking, and H2-DRI processes:

Technology	CAPEX (M€/ Mt product)	FOM (M€/Mt product)	Elec input (PJ/Mt product)
Ammonia synthesis	221.1	33	
Methanol synthesis	132	19.8	
Electric cracking (Olefins)	1400	70	16.92
Electric cracking (Aromatics)	1400	70	6.87
MtO	300	45	5
MtA	300	45	5
H2-DRI	400	10	0.7 (PJ/PJ)