Roadmap for the European Fertilizer Industry

Final version

Prepared for:

Fertilizers Europe

Fertilizers Europe

Submitted by:

Guidehouse Netherlands B.V.
Stadsplateau 15
3521 AZ Utrecht
Telephone +31 30 66 23 300
www.guidehouse.com
Simon.humperdinck@guidehouse.com
Michiel.stork@guidehouse.com
Marco.reiser@guidehouse.com
Matthias.schimmel@guidehouse.com

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Executive Summary

The European Fertilizer Industry[1], provides reliable supply of essential nutrients to European farmers, and thus contributes to food security in Europe. Nitrogen is one of the key nutrients; nitrogen fertilizers are based on ammonia. **The industry is committed to climate-neutral production of ammonia by 2050.**[2] The industry is transforming, and the sector has developed potential trajectories towards this goal. Multiple alternative technologies can eliminate the greenhouse gas (GHG) emissions from the industries' ammonia plants by 2050 and already significantly reduce them by 2030. This is necessary to mitigate climate change and meet the goals under the Paris Agreement.

This roadmap explores what is required to reach this 2050 target as well as what is required to reach the following intermediate milestones:

1. By 2030, reduce GHG emissions for ammonia production with 31%[3] (trajectory 1)
2. By 2030, produce 50% of production based on water-electrolysis[4] (trajectory 2)

This roadmap focuses on ammonia production from hydrogen and nitrogen, including the energy intensive production of the intermediate hydrogen, see Figure 1. Today the production of ammonia generates the largest share[5] of the GHG emissions from nitrogen fertilizer production, as (mainly by abating 94% of the sector's N_2O emissions from nitric acid production) the industry has already reduced the sector's scope 1 emissions with 49% between 2005 and 2020.[6]

[1] "The industry" refers to the European fertilizer industry in this report.

[2] Reducing greenhouse gas emissions as much as possible and compensating for any remaining emissions to achieve a net-zero emissions balance for the sector's production in line with Europe's target to strive towards climate neutrality in 2050. https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal_en

[3] In line with the interpretation of the decrease for the EU's industry sector's GHG emissions in EU's Emission Trading System aimed for in EU's Fit for 55 proposal, factoring in a reduction of European N-based fertilizer use of 5.7% in 2030, see chapter 2.

[4] In line with the current EU proposal for the Renewable Energy Directive; this alternative hydrogen production route eliminates most GHG emissions of the production of N-fertilizer.

[5] Part of the CO_2 generated during ammonia production is currently converted to urea. This CO_2 is subsequently emitted when applying urea on the field. EU's Emission Trading System considers this CO_2 as emitted during ammonia production. This approach has been followed in this report (rather than considering these emissions as part of the fertilizer producer's scope 3 emissions).

[6] Based on the scope 1 emissions under the EU-ETS from ammonia- and nitric acid production.

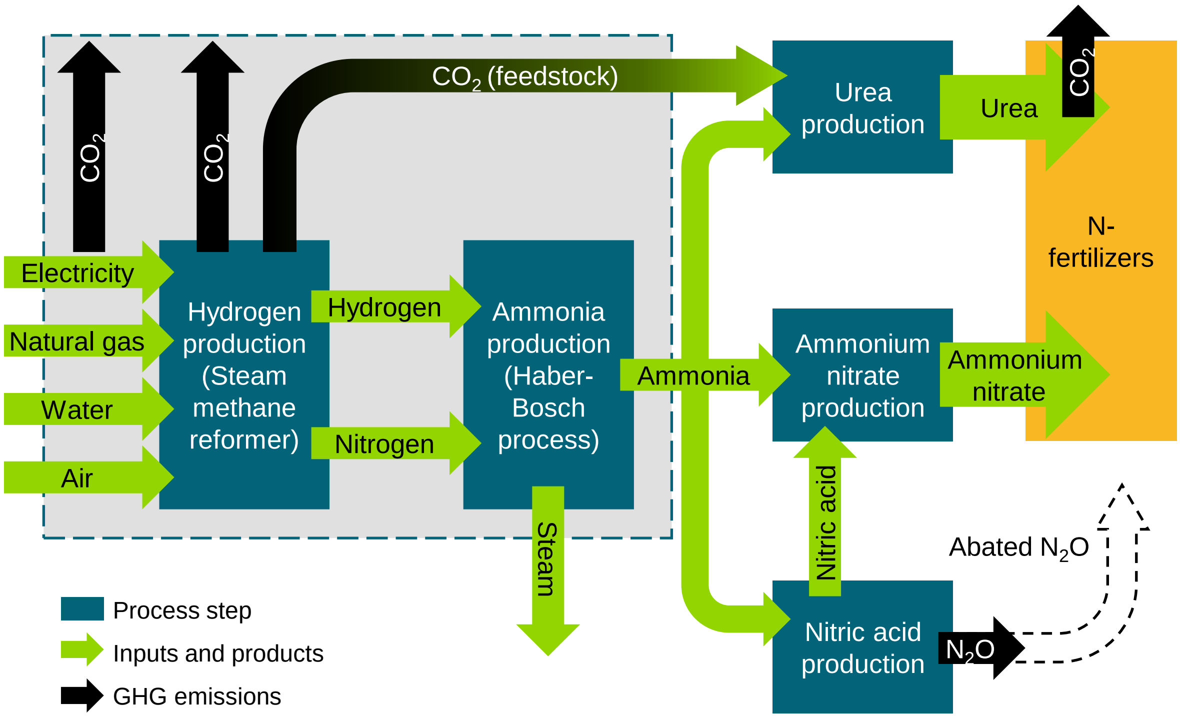


Figure 1: Conventional production of N-fertilizers

The vast majority of CO_2 emissions originate from the hydrogen production, and these can be reduced or eliminated via alternative production routes for hydrogen. These include electrolysis of water, capturing and storing of most CO_2 generated and replacing natural gas by biomethane. Many of these technologies are for the typical range of future prices of energy carriers more expensive than the current European production route.[7]

However, if these technologies are quickly implemented on a large-scale, scale effects are expected to make the new technologies cheaper than the fossil-based technologies. Attractiveness of technologies heavily depends on the future ratio between the natural gas price, the biomethane price and the cost to generate (renewable) electricity; there is significant uncertainty in this future ratio. Abundant availability of low-priced renewable energy is important for large-scale implementation.

The CO_2 the fertilizer industry needs to produce urea (see Figure 1) is, in this roadmap, either considered as emitted in the ammonia plants or will need to be zero-emission CO_2.

The industry will choose between the alternative routes based on the availability and cost of the required energy carriers, which will vary over the different regions, as will the national policy frameworks. These different circumstances are summarized into four archetypes via the key differentiators (see Figure 2):

- Archetype 1, Methane: a plant in this archetype has access to biomethane and/or CO_2 infrastructure and can thus generate hydrogen based on methane (or by gasification of other forms of biomass).
- Archetype 2, Hydrogen: A plant in this archetype has access to hydrogen, either from abundant competitively priced renewable electricity, or from a hydrogen pipeline grid.
- Archetype 3, Methane and Hydrogen: A plant in this archetype has all of the above, and thus most options to transition.

[7] Applies for natural gas prices from before Russia's invasion in Ukraine.

- Archetype 4, Limited possibilities: A plant in this archetype has none of the above, and thus least options to transition.

This illustrates that the availability of renewable energy is not equally distributed over Europe.

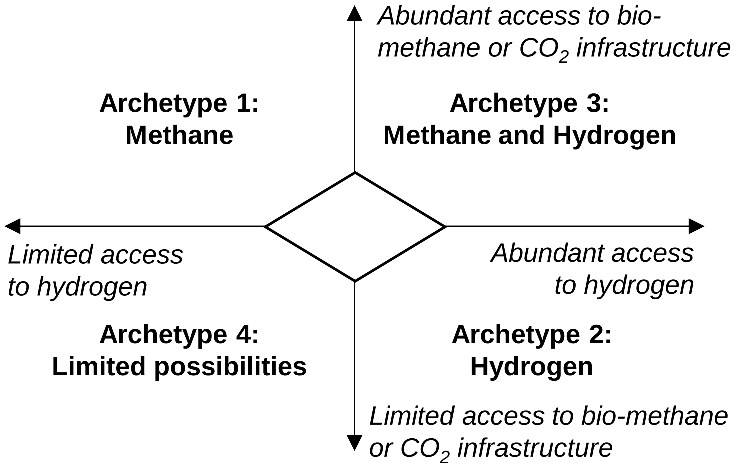
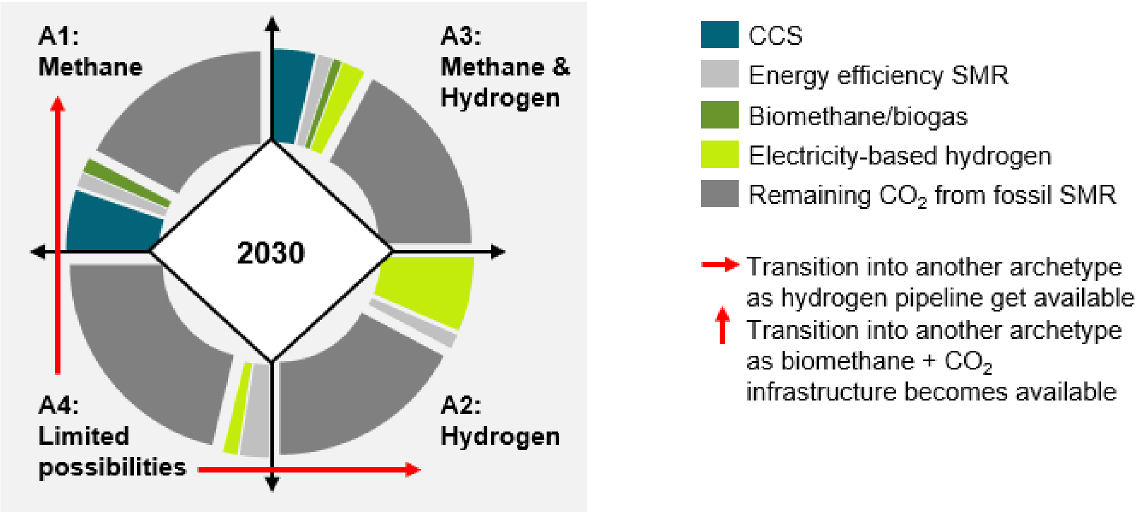
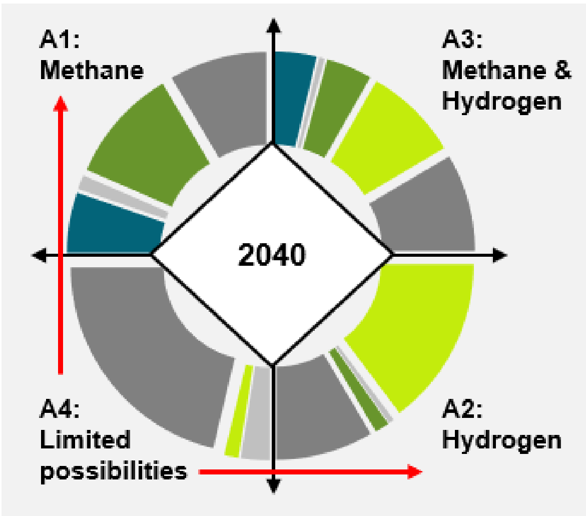


Figure 2: Four archetypes based on their access to biomethane or CO_2 infrastructure and access to hydrogen

The sectors transition pathway for these four archetypes delivering on trajectory 1 is visualised in Figure 3 below.



2030:
Emission intensity reduction of 31% to a scope 1 average of 1.26 $tCO_2/t\ NH_3$. Plants in Archetype 4 (A4) should try to get either get access to hydrogen via a backbone/ pipelines or to biomethane and therefore try to transition to another archetype.



2040:
Emission intensity reduction of 66% to a scope 1 average of 0.62 $tCO_2/t\ NH_3$. Plants in Archetype 4 (A4) either get access to hydrogen via a backbone/ pipelines or to biomethane and therefore transition to another archetype.

2050:
Emission intensity reduction of 100% to a scope 1 average of 0 $tCO_2/t\ NH_3$. Plants in Archetype 1 (A1) get access to hydrogen via a backbone/pipeline. Plants in Archetype 2 (A2) get access to biomethane. All plants have transitioned to clean ammonia.

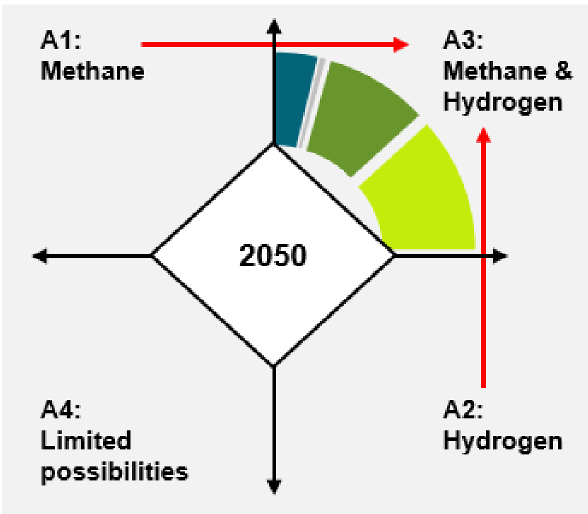


Figure 3: Transition pathways for trajectory 1

Note that this is a stylised representation from which no absolute numbers can be deduced.

The figure shows that for **trajectory 1**, the technology neutral emission reduction trajectory, a mix of solutions are implemented depending on the availability of infrastructure and energy carriers:

- In 2030, urea production is not significantly limited by the 31% emission intensity reduction target - sufficient CO_2 is still available[8]. Where available, relevant shares of carbon capture and storage (CCS) and electrolysis-based hydrogen are used.
- In 2040, having sufficient CO_2 available for urea is more challenging for those plants without access to sufficient biomethane - which is projected to be more widely available and cheaper in 2040. Where available, large amounts of electrolysis-based hydrogen are used.
- In 2050, all plants are assumed to be connected with infrastructure with all energy carriers and a mix of electrolysis-based hydrogen and biomethane is used.

Meeting **trajectory 2** depends solely on the use of hydrogen from electrolysis of water, creating a need for alternative sources of bio-CO_2 (or Direct Air Capture) for the production of urea.

The sector's transition towards climate-neutral production is part of a bigger transition:

- The volume of ammonia used in Europe will increase quickly due to new demand applying ammonia as energy carrier. Meanwhile there is an expectation of import of (electrolysis-based) ammonia to Europe.
- The sector will need to operate (part of) its plants (somewhat) flexibly to deal with the intermittency of generation of renewable electricity, with hydrogen and/or ammonia storage.
- When the sector would continue to use natural gas, the sector should increasingly map its upstream scope 3 emissions stimulating its suppliers to detect leaks via satellites and with early failure detection and monitoring, and to then terminate leaks. *Meanwhile, the sector should aim at sourcing it from suppliers with low upstream GHG emissions.*
- The sector will need to deeply reduce the GHG emissions during the application of its fertilizers on the field by improving farming practices, integrating waste/nutrient sources in its fertilizer production and optimising soil quality and its products' functionality. *As part of the efforts, building on its ongoing cooperation with farmers, the sector should enhance developing and supporting implementation of farming strategies.*

The associated investment costs are large: If, for example, by 2050 all ammonia production would be replaced by electrolysers running on offshore wind, the total investment would be 17 billion EUR for electrolysers. This compares to yearly investments of 1.2 billion EUR[9] for the sector. In addition, the required investments outside the sector are around 3 billion EUR for a hydrogen pipeline network[10] and 64 billion EUR for offshore wind parks. The lead time of the sector's investments can be up to 7 years from start of planning to start of operation and sometimes longer for the generation of energy carriers or the infrastructure to bring

[8] Although this might go at the expense of supplying CO_2 to the Food & Beverage industry.

[9] Fertilizer Industry Facts & Figures, 2021, investment from the mineral fertilizer industry, https://www.fertilizerseurope.com/wp-content/uploads/2021/07/Industry-Facts-and-Figures-2021-1.pdf

[10] Assuming a 5% share of total cost for European hydrogen backbone would be attributed to European Fertilizer production.

these to the sites. *The sector should cooperate with all stakeholders to reduce these lead times.*

To take the investment decisions, companies need to be reasonably certain that energy carriers will in time be available on their site, that there is a policy level playing field with countries outside the EU, and that the investments are sufficiently attractive. Coordination and speed are thus essential to ensure that all stakeholders involved contribute in time. *Each ammonia / fertilizer plant in the EU needs to soonest have a masterplan outlining how it will eliminate the GHG emissions from ammonia production and what would need to be in place by when. These masterplans need to be discussed with key stakeholders soonest.*

The sector is already working on a voluntary label/certification system for clean fertilizer and ammonia.

Policy levers the European Commission could take that would support the industries' transition include:

- Ensuring timely and effective Carbon Border Adjustment measures to avoid an unfair competitive advantage for non-European producers;
- Stimulating demand for climate friendly produced fertilizers with a label system followed by a mandatory consumption target for all consumption in EU;
- Using policy levers to drive investment, closing a remaining gap between the cost of the alternative routes and the current production route (e.g., CAPEX and OPEX support). To give a first rough indication, for trajectory 2, assuming 50% electricity-based ammonia in 2030, the difference in production cost would be 1.2 billion EUR.[11] This is even more important in view of the large uncertainty in future prices of the various energy carriers, like natural gas.

What about much higher natural gas prices?
As a consequence of Russia's invasion in Ukraine, the natural gas price had skyrocketed. A higher natural gas price favors electricity-based ammonia production routes at equal electricity price[12]. It is possible that at some point, generating demand and investment support for climate friendly produced fertilizer would no longer be needed. Getting sufficient renewable and low-carbon electricity quickly would then be the challenge. Meanwhile, when the natural gas price is much higher in Europe than in other parts of the world, this jeopardises the competitiveness of the natural gas based European fertilizer production.

The industry has a fantastic opportunity to be a front runner in the transition towards a climate-neutral economy by 2050 and be a workhorse of the European hydrogen economy. Implementation will be region- and product-specific. To be successful in its transition, the industry will need to cooperate with a wide variety of European and regional stakeholders.

[11] Based on 7.5 Mt of ammonia production, no changes at all in the other 50%, ignoring investments in the Haber Bosch plants (other than in the ASU), ignoring subsidies for the generation of renewable electricity or any other policy support, using a natural gas price of 37 EUR/MWh (including network cost and taxes and levies) and an LCOE of renewable electricity of 39 EUR/MWh (based on average offshore; refer to Annex 2) and including the full impact of a CO_2 price of 100 EUR/tCO_2. Numbers are based on average literature values and should only be seen as a first impression. The design, and the amount of funding needed, should be based on more detailed and plant-specific data. Even then, the strong dependence on the future cost of energy carriers should be kept in mind.

[12] Note that the market price for grid electricity increased in Europe too.

1. Introduction

The European Fertilizer Industry provides reliable supply of essential nitrogen (N)-nutrients to European farmers, contributing to food security in Europe. Ammonia is an essential building block for N-fertilizers. This roadmap will tell you how the sector hopes to change its ammonia plants in order to eliminate their greenhouse gas emissions. This is necessary to limit climate change and to reduce reliance on natural gas. The latter is important as recent geopolitical developments have shown the risks associated to relying on imported gas. This chapter characterises the industry today.

1.1 The European Fertilizer Industry today

Figure 4 schematically characterises the industry today. The sector produces N-fertilizers based on ammonium nitrate and/or urea, the two key N-fertilizers used in Europe. Ammonia provides the nitrogen to both products and forms the heart of the industry. It is produced by combining hydrogen with nitrogen in the Haber-Bosch process. The hydrogen is currently typically made from natural gas in a Steam Methane Reformer (SMR).

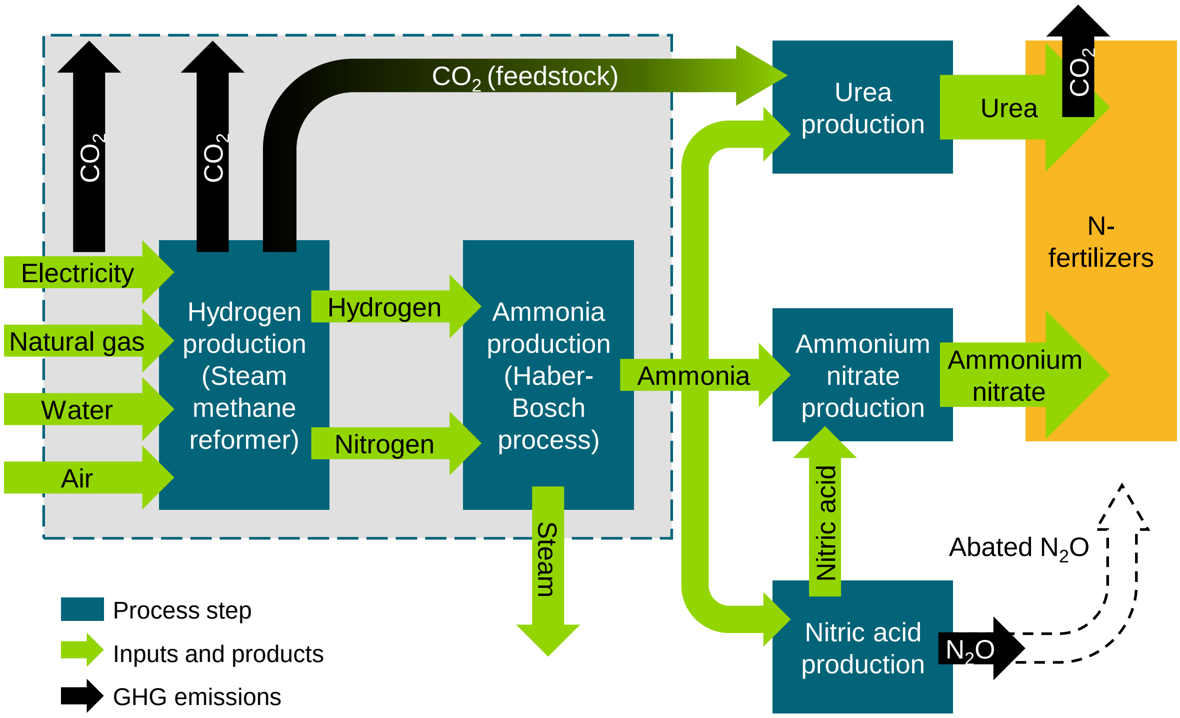


Figure 4: Conventional production of N-fertilizers

Figure 4 illustrates that:

- Greenhouse gas CO_2 is formed during the production of hydrogen. Part of this CO_2 is emitted, another part of this CO_2 is converted into **urea**, and then released when the urea is used on the field. Due to the strong interconnectivity between the SMR process and the CO_2 emissions from urea on the field[13], these CO_2 emissions are included in this

[13] EU's Emission Trading System considers this CO_2 as emitted during ammonia production. This approach has been followed in this report (rather than considering these emissions as part of the fertilizer producer's scope 3 emissions).

roadmap. Another part of the CO_2 formed during production of hydrogen is used in the food & beverage sectors.[14]

- **Ammonium nitrate** is formed converting intermediate nitric acid. During the production of **nitric acid** from ammonia, N_2O - a powerful greenhouse gas - is formed. The European fertilizer sector has reduced the associated N_2O emissions with 94% between 2005 and 2020, reaching 0.34 kg N_2O/t HNO_3, corresponding to 1.8 $MtCO_2eq$ in 2020[15] (5% of the sectors total scope 1 emissions in 2020).

After N-fertilizers (urea and ammonium nitrate) have been produced, they are applied in their pure form or blended with other nutrients - depending on the fertilisation needs of the field.

This roadmap focuses on European production of ammonia, the key building block for N-based fertilizers, with the highest energy consumption.

1.2 Current and Future European Fertilizer production

The table below summarises the current production levels of ammonia, nitric acid and urea.

What:	***2020 production (Mt of substance)*** [16]***:***	***2020 production (Mt of N-equivalent)*** [17]***:***
Ammonia	15.8	13.0
Nitric acid	20.1	7.0
Urea	≈8.7	≈4.1

Historic ammonia production in Europe has been relatively constant. The International Energy Agency (IEA) doesn't expect material changes in the European ammonia and urea production until 2050[18]. Fertilizer Europe expects the European consumption of fertilizers to decrease with 5.7% between 2020 and 2030[19]. This roadmap report assumes that:

- The European production of ammonia, nitric acid and urea is 5.7% lower in 2030 (than in 2021[20]) and remains constant afterwards.

- This share stays the same, but chapter 8 gives more background on the likeliness of imports.

[14] Several GHG abatement options do not produce CO_2 (from biological origin), implying that over time, the food & beverage sectors would need to find other sources of CO_2 for their products – this is not further explored in this roadmap.

[15] This estimate is based on an average emission of 0.34 kg N_2O/t HNO_3 [info from Fertilizer Europe], a global warming potential of 265 [IPPC, Fifth Assessment Report (AR5), 2014] and an estimated European nitric acid production of 20.1 Mt/year in 2020 in Europe (EU-27 plus Iceland, Liechtenstein and Norway – scope of the EU-ETS in 2021)

[16] Ammonia and nitric acid amounts are estimated based on preliminary free allocation covered by benchmark in 2021, benchmark and – for ammonia – correction factor for electricity exchangeability (data obtained from EC benchmark curves and key parameters, link to source https://ec.europa.eu/clima/system/files/2021-10/policy_ets_allowances_bm_curve_factsheets_en.pdf, electricity exchange factor from EU ETS revision, link to source https://ec.europa.eu/info/sites/default/files/revision-eu-ets_with-annex_en_0.pdf). The amount of urea has been estimated by Fertilizer Europe.

[17] Nitrogen-equivalents: 1 ton of ammonia corresponds to 0.82 ton N-equivalents, 1 ton of urea corresponds to 0.47 ton N-equivalents, and 1 ton of ammonium nitrate corresponds to 0.35 ton N-equivalents (based on rounded mol masses; N has an atomic mass of 14, ammonia a mol mass of 17, urea a mol mass of 60 and ammonium nitrate a mol mass of 80).

[18] IEA (2021), Ammonia Technology Roadmap, IEA, Paris https://www.iea.org/reports/ammonia-technology-roadmap, License: CC BY 4.0

[19] Based on https://www.fertilizerseurope.com/wp-content/uploads/2021/12/Forecast-2021-31-Studio-final-web.pdf; this roadmap assumes that the same 5.7% decreases applies to EU *production* of N-based fertilizers.

[20] In this roadmap, 2020 production numbers have been estimated based on 2021 production data, as only 2021 production was available.

2. Speed for decarbonisation for scope 1 and 2

With the European Green Deal the EU announced a target to be climate-neutral by 2050. An economy with net-zero greenhouse gas (GHG) emissions is in line with the EU commitment under the Paris Agreement. In the stakeholder process leading to this roadmap, it became clear that Fertilizers Europe and its members are **committed to climate-neutral production of ammonia by 2050.**[21] This roadmap intends to paint the road to get there, establishing what needs to happen to deliver the speed EU policymakers aim at for the production of clean ammonia.[22]

The sector has already achieved a 49% reduction of its plants' scope 1 GHG emissions intensity between 2005 and 2020 (see Annex 1: Background on emission reduction trajectories), to a very large extent as a consequence of GHG emission abatement in the production of nitric acid, where the sector has eliminated 94% of its N_2O emissions. The scope 1 emission reduction for its ammonia production was much lower than the EU ETS average.

Scope 1 emissions

To better understand the consequences of the course of the emission reduction the EU policymakers aim at, this roadmap looks at two trajectories for scope 1 emissions based on existing European GHG reduction scenarios from the European Commission's Fit for 55-package (see the table below). While the first trajectory expresses the steps in GHG emission reduction without preference for certain emission reduction technologies[23], the second trajectory focuses on renewable fuels of non-biological origin (RFNBO) for hydrogen used in the sector's production and therefore focuses on RFNBO-compliant hydrogen as the only emission reduction lever.

[21] Reducing greenhouse gas emissions as much as possible and compensating for any remaining emissions to achieve a net-zero emissions balance for the sector's production in line with Europe's target to strive towards climate neutrality in 2050. https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal_en

[22] The term "clean ammonia" in this document covers renewable ammonia, which is produced by renewable electricity or based on biomethane, as well as low-carbon ammonia, which is produced by electricity from nuclear sources or using CCS technologies.

[23] Technology agnostic.

Table 1: Trajectories based on existing EU GHG reduction scenarios for scope 1 emissions from the European Commission

Trajectory #	Basis for Trajectory	Milestone for 2030	Exploration for 2040	Target for 2050
1	EU ETS proposal[24]	-35% of EU ETS emissions (absolute), compared to 2020 Average scope 1 production emission intensity 1.26 tCO_2e/t NH_3[25]	-68% of EU ETS emissions (absolute)[26], compared to 2020 Average scope 1 production emission intensity 0.62 tCO_2e/t NH_3[27]	-100% of EU ETS emissions Average production emission intensity: 0 tCO_2e/t NH_3
2[28]	2021 RED proposal[29] [30]	RFNBO contribute to 50% of hydrogen	-75% of fossil-based CO_2 compared to 2020, RFNBO's form vast majority of hydrogen	-100% of scope 1 emissions, RFNBO's form vast majority of hydrogen

Table note: 2030 based on Guidehouse interpretation of European Commission proposals, 2040 based on interpolation as an exploration, 2050 based on the desire to have completely eliminated all the emissions from the sector's plants. *Source: EC, Fertilizers Europe, Guidehouse calculations.*

The scope 1 emission intensity reduction in the trajectories is not much different from these in IEA's Sustainable Development and Net Zero Emissions scenarios (refer to Annex 1).[31]

Scope 2 emissions

For the speed of decarbonisation of scope 2 emissions this roadmap report assumes that emissions from existing electricity purchases will decrease in line with the EU average GHG emission intensity of electricity generation (see Annex 1). For new electricity consumption (e.g., for electrolyser or air separation unit) the report assumes zero scope 2 emissions as this could be supplied via power purchasing agreements for renewable electricity. There is additional potential from energy efficiency. Consequently scope 2 emissions decrease steeper than scope 1 emissions.[32]

Aim of this roadmap

This roadmap neither attempts to establish a (most) realistic scenario nor to predict the future, but the trajectories elaborated above help to explore possible futures that are

[24] Based on EU-ETS directive proposal from 14.7.2021, COM (2021) 551 Commission Proposal: Revision of the EU Emissions Trading System. Link to source: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52021PC0551

[25] Based on an average scope 1 production emission intensity in 2020 of 1.93 * ±0.95 = ±1.83 tCO_2e/t NH_3 (Fertilizers Europe) and assuming that the European production of ammonia is 5.7% lower in 2030 (than in 2020) and remains constant afterwards, based on Fertilizers Europe: forecast of food, farming and fertilizer use in the European Union 2021-2031

[26] Based on a 66% intensity decrease compared to 2020 (refer to Annex 1)

[27] Based on 1.93 * ±0.95 * 0.34

[28] The reduction of greenhouse gas emissions in the Haber Bosch process has not been modelled for electricity based hydrogen (assumed to be all electricity as well (albeit – see chapter 3 – grid electricity))

[29] Based on Renewable energy directive (RED) proposal from 14.7.2021, COM (2021) 557, Article 22a. Link to source: https://eur-lex.europa.eu/resource.html?uri=cellar:dbb7eb9c-e575-11eb-a1a5-01aa75ed71a1.0001.02/DOC_1&format=PDF and European Parliament proposal from 14.9.2022 (https://www.europarl.europa.eu/doceo/document/TA-9-2022-0317_EN.pdf)

[30] In the provisional agreement of RED III, concluded on March 30, 2023, an RFNBO-share of 42% of the H_2 used in industry in 2030 and 60% by 2035 was agreed.

[31] Based on the scope 1 emission intensity reduction for European ammonia production (see Annex 1). Note that 43 countries are included in the IEA's definition for Europe (see further details here: https://www.iea.org/regions/europe) while this roadmap only covers ammonia production in the European Union (EU-27).

[32] The individual speed of decarbonization of scope 2 emissions at plant level depends on the structure of electricity generation in the country where the plan is located.

compatible with the European Union's targets. Meeting these trajectories will be a different challenge in each member state. This roadmap aims to:

- Provide a common understanding of the implications, needs and many dependencies to meet each of these trajectories and thus deliver on the European Union's targets.
- Inform the policy debate.
- Provide clarity to many other stakeholders, as meeting these trajectories will require cooperation with other, new, players in (new) value chains.

While this roadmap focuses on the scope 1 and 2 emissions from ammonia production, the sector's scope 3 emissions are - as for many sectors - larger than the scope 1 and 2 emissions[33]. Without attempting to be complete, this roadmap will introduce some of the key options for reducing scope 3 emissions (see chapter 5).

[33] As noted in Fertilizer Europe's 2015 roadmap, Michiel Stork and Charles Bourgault, Fertilizers and Climate Change, Looking to 2050, 2015 (figure 6).

3. Ammonia production technologies

Currently the sector produces the vast majority of ammonia from natural gas using Steam Methane Reforming. However, several clean ammonia production technologies have become available, while others are still being developed. This chapter describes various relatively mature ammonia production technologies, focused on their ammonia production cost. These depend mostly on three factors:

- The cost of energy carriers
- The efficiency of generating hydrogen from these energy carriers
- The conversion of hydrogen to ammonia

These factors are described in the three paragraphs below.

3.1 Relative cost of energy carriers

The production cost for hydrogen depends to a large extend on the energy sources used, and their cost. Current fertilizer production depends to a large extend on the price of natural gas, the current feedstock/fuel for the production of hydrogen. In the future, alternative production routes can also be based on biogas/biomethane, and on electricity. Their relative cost has recently changed drastically, and will likely continue to change drastically, heavily impacting the relative attractiveness of the various production routes. The cost of emitting CO_2 (in Europe's Emission Trading Scheme) has increasingly become a relevant factor in production cost. This section summarises the assumptions taken on these for this report (more details in Annex 2).

The production cost estimates are based on cost assumptions displayed in Figure 5 and Figure 6 for these resources. Due to the uncertainty of the future market development, a price range is given.

In the past years, **natural gas** (NG) prices in the EU have skyrocketed, due to the decreasing supply from Russia. While the natural gas price has since decreased significantly, in the medium to long term, factors such as Europe's increased reliance on LNG imports[34], will determine the price. While future price projections come with significant uncertainty, this roadmap assumes future natural gas prices ranging between 20 and 40 EUR/MWh (excl. CO_2 price), to which network cost and taxes have been added. The projected increasing cost of CO_2 emissions will increase the cost of using natural gas[35]. However, as the past years have illustrated, the future development of prices of energy carriers is uncertain, the remainder of this chapter also shows the consequences of significantly different natural gas prices.

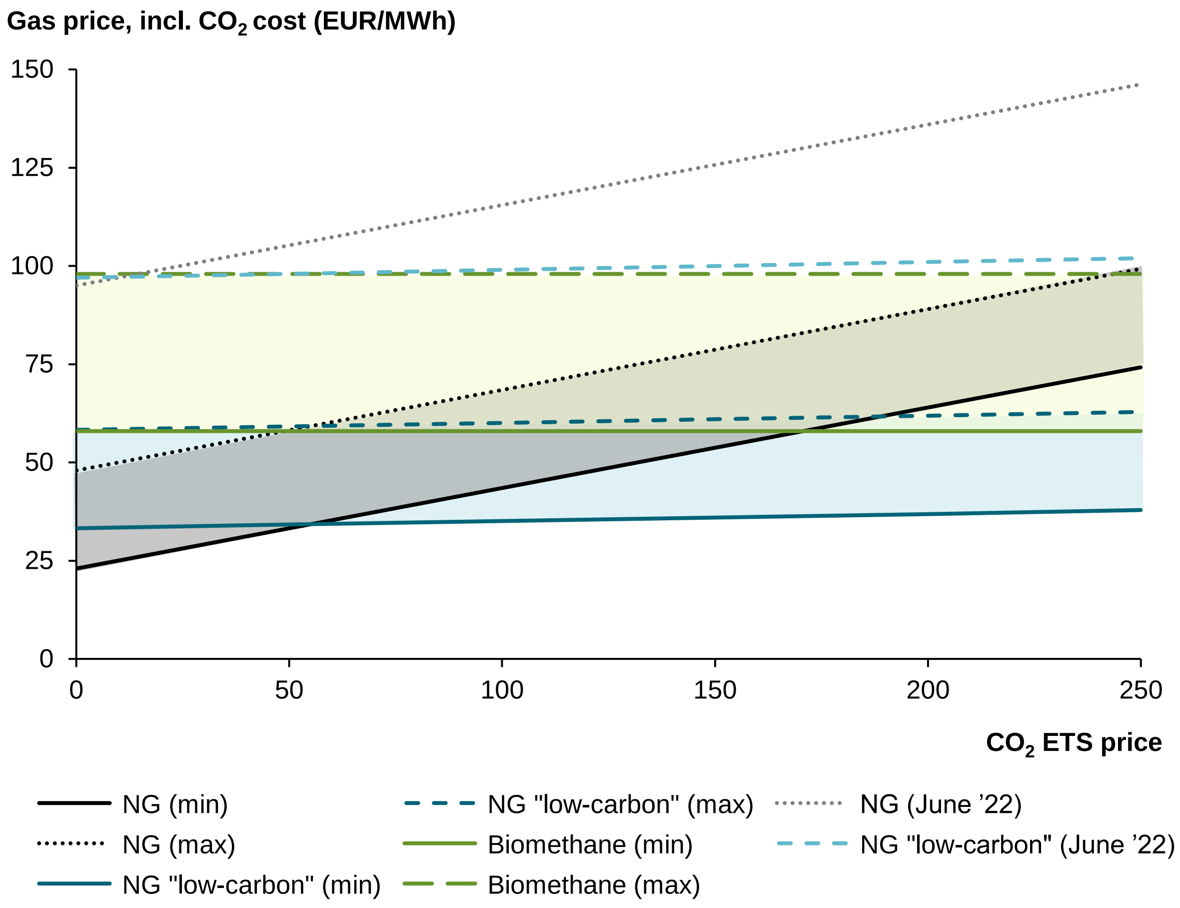
As an alternative for natural gas, biogas[36] and/or **biomethane** could be used. The European Commission has set the target to increase EU production capacity from today's 10 TWh/year up to 350 TWh/year by 2030. Today's levelised cost of biomethane of 86 EUR/MWh (range: 57 to 95 EUR/MWh), is projected to decrease to 46 to 75 EUR/MWh by 2040 and around 50 EUR/MWh (range: 40 to 60 EUR/MWh) by 2050. It is to consider, that the biomethane market price is very unlikely to fall below the market price for natural gas (incl. EU ETS CO_2

[34] LNG import requires energy (due to the required cooling to liquify the natural gas) and import of LNG is thus expected to be more expensive and exposed to global market impacts than historic pipeline imports from (non-liquified) natural gas from Russia.

[35] When discussing CO_2 cost throughout this report, impact of free allocation of allowances is ignored, to reflect the impact that carbon cost have on the marginal cost of emitting an additional ton of CO_2.

[36] Biogas is not purified yet and contains significant amounts of CO_2; biomethane is purified.

cost), even if its levelised cost would be lower. It is more likely it will be either depending on its production cost (LCOB) or the natural gas price (incl. EU ETS CO_2 cost).



Notes: NG = Natural gas; NG (min) = 15 EUR/MWh, NG (max) = 40 EUR/MWh; Biomethane (min) = 50 EUR/MWh, Biomethane (max) = 86 EUR/MWh; NG (June '22) = average NG price in June 2022 of 87 EUR/MWh; NG "low-carbon": ATR with 91% capture rate; All without CAPEX or carbon capture cost; All including 8 EUR/MWh network and taxes; Cost for CO_2 transport & storage is 50 EUR/t_{CO_2}

Figure 5: Range of gas prices used in this study, depending on feedstock, technology, application of CCS and the CO_2 EU ETS price

Electricity:

At the same time renewable electricity production costs from all major sources are decreasing drastically (see Figure 6). In Spain, the auctions in January 2021 were awarded at an average price of 25 EUR/MWh for onshore wind and 24 EUR/MWh for solar PV.[37]

According to cost prognoses, the levelised cost of electricity (LCOE) from wind offshore can be produced at 38 EUR/MWh by 2030 and 30 EUR/MWh by 2050 and onshore wind generated electricity at 29 EUR/MWh in 2030 and 21 EUR/MWh in 2050. The significant reduction of LCOE results from various factors, like the improvements in the technologies (larger wind turbines, more efficient PV collectors), even higher production scales with

[37] https://www.evwind.es/2021/12/11/the-return-of-renewable-energy-auctions-in-the-spanish-electricity-market/83759

renewable energies being more and more installed across the globe and learning curves in project realisation, esp. for offshore wind projects.

Electricity network cost (EU average 8 EUR/MWh), and the level of taxes and levies (EU average 15 EUR/MWh) are higher than for gas, but for electricity there is the option to set up the electrolyser next to the renewable electricity generation - thus not using the public network, eliminating the need to pay network cost and taxes. Therefore, both options are listed in the graph below - although electrolysers could well be mostly set up next to the renewable electricity generation (refer to the next paragraph).

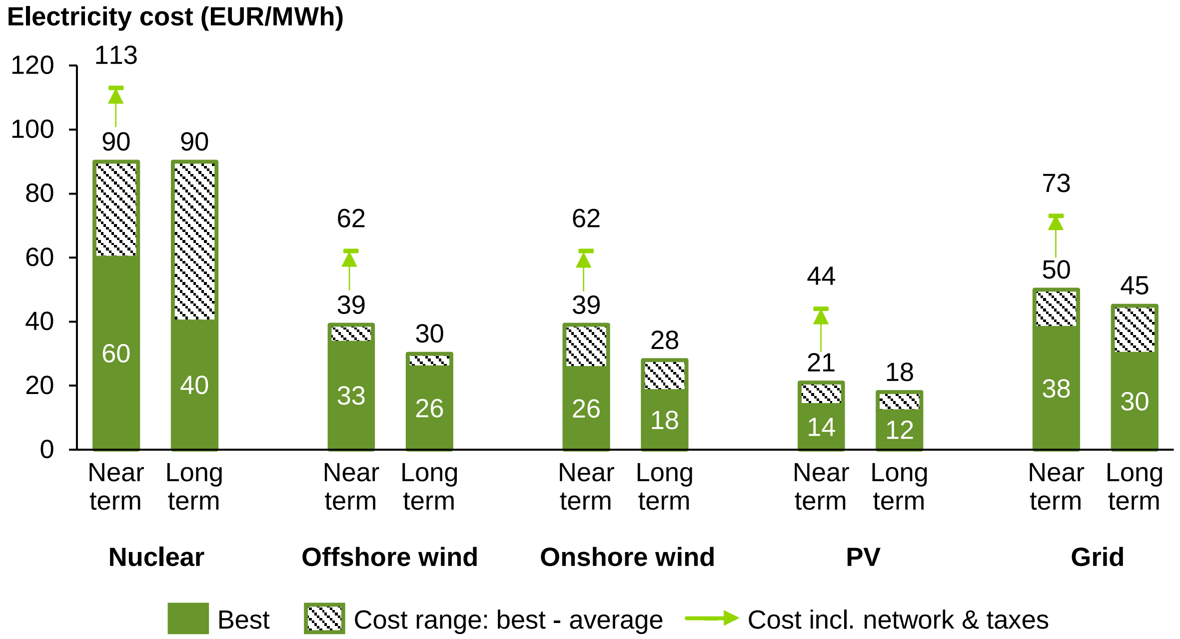


Figure 6: Levelised cost of electricity production for different generation types in the EU as range of best to average location in the near and long term[38]

Huge capacities of additional renewable energies are needed to supply the necessary amount of renewable electricity. Besides the investment cost (shown in section 4.1), large areas are needed for these capacities. The current average ammonia plant with a production capacity of around 490 kt NH_3 per year[39] would need a photovoltaic area of 48-72 km² or an onshore wind farm with 29 to 49 km².[40] This is more than the size of the EU capital Brussels (33 km²) or about 0.15% of total Belgium. The largest ammonia plants, producing up to 1,700 kt NH_3 per year, would need over three times of this area to produce ammonia from RFNBO.

[38] Near term grid costs are based on the marginal price in the electricity market in 2025 for national trends, as published by TYNDP in April 2022. Current costs are significantly higher. Long term: the final development stage of the technology is reached; production levels are at large scale and strong competition and experience in the project implementation is realized (expected around 2040 – 2050). Near term marks an intermediate step, with significant improvements in production and technology compared to today. Depreciation rate for renewable energies is 5% with 20 years lifetime and for nuclear it is 7% with 40 years lifetime, to reflect the fact that renewable electricity projects have easier access to finance, but nuclear power plants longer lifetimes.

[39] https://ec.europa.eu/docsroom/documents/4166/attachments/1/translations/en/renditions/pdf

[40] PV: 1,000 – 1,500 FLH assumed, and 16 m²/kWp; Wind onshore: 2,300 – 2,500 FLH assumed, and 40 – 62 MW/km² assumed, depending on local circumstances and climate

3.2 Generating hydrogen

There are various ways to produce hydrogen, based on methane (the main component of natural gas) or using electricity. Historically, the fertilizer industry has produced hydrogen using methane as this was the most cost-effective route, with low natural gas prices and high costs for electricity. As shown in the previous section, these circumstances will change significantly over the coming decades with a projected significant further decrease of the cost of renewable electricity – as already occurred in 2021/2022.

Methane-based hydrogen:

Currently, the European fertilizer industry produces almost all hydrogen from methane in **SMR**. In the reforming section natural gas reacts with steam under high pressure and is turned into process gas (a mixture of hydrogen and carbon monoxide); the process gas is cooled and fed into water gas shift reactors where the carbon monoxide is converted to carbon dioxide and hydrogen through the addition of steam. At least 60% from the CO_2 formed can be removed easily as it is almost pure CO_2. Most of the remaining CO_2 can be extracted from the flue gas with amine absorption (a well-established technology), or pressures swing adsorption (PSA). Most SMR have already a H_2-PSA but would need an additional CO_2-PSA to extract carbon dioxide.[41]

Alternatively, methane can also be converted to hydrogen in an **Auto Thermal Reformer** (ATR). Oxygen (which is separated from air using electricity), steam, and methane react to produce process gas. The partial oxidation reaction provides the heat needed for the reforming reaction. The produced process gas is further converted, and subsequently split in a hydrogen flow and a CO_2 flow. ATR is always considered to have a CCS or utilisation unit in this report.[42]

In general, 85% (for a retrofitted SMR) **to 90 to 95%** (for a new built ATR) **of CO_2 can be captured**. Even higher CCS shares are technically possible, but they are less economic. The CCS rate is significantly higher than the current application of CO_2 for conversion to urea. This additional CO_2 is available for CCS, or other (long-lived) Carbon Capture & Utilisation (CCU) applications.

Biomethane or biogas can be used instead of natural gas making the production process carbon neutral. The production process remains largely unchanged, although there currently is a technical limitation for the share of biomethane/biogas that can be used[43]. Biomethane availability is currently supply constrained and costs are higher compared to natural gas. The availability of biogas/biomethane varies greatly across Europe as a result of differences in policy support. In its recently published RePowerEU plan, the European Commission set out a European biomethane production target of 35bcm by 2030. If this target is achieved at attractive cost, biomethane could become a more widely adopted transformation pathway for the fertilizer industry. By using biogas (rather than biomethane) or by upgrading the biogas close to the fertilizer plant, the CO_2 content of the biogas becomes available for conversion to urea.

Production costs for methane-based hydrogen are based on:

- Projected cost for natural gas (as a natural gas market exists), considering the EU ETS CO_2 price.
- Levelised cost for biomethane cost, with the natural gas market price as lower cost limit.

[41] https://www.digitalrefining.com/article/1001013/options-for-co2-capture-from-smr#.YxtFNXZByHs
[42] https://www.sciencedirect.com/science/article/pii/S0196890422000413
[43] Based on interviews with Member Companies.

Electricity-based hydrogen:

Hydrogen can also be produced by splitting water into hydrogen and oxygen in electrolysers using electricity; the most developed type of electrolysers are proton exchange membrane electrolyser (PEM) and alkaline electrolyser (ALK); another promising technology that is under development is the solid oxide electrolyser (SOEC). The used electricity can be from renewable origin (like onshore or offshore wind, or like solar PV), or nuclear[44]. As nuclear-based hydrogen is not considered an RFNBO regarding the criteria set by the EC, hydrogen produced based on nuclear electricity does not count towards the 50% hydrogen target in industry by 2030 (trajectory 2).

As it could be expected that electrolysers will mostly[45] be set up next to renewable electricity generation (not using the electricity network). Cost of electricity are thus approximated by its levelised cost (per generation technology). This is in line with the proposition of the European Commission on temporal correlation of clean electricity and clean hydrogen production (on hourly basis). However, with an amendment of the European Parliament[46] the temporal correlation needs to be only balanced on quarterly basis until 2029 and afterwards the suggestion is to assess if monthly, quarterly, or yearly basis is the best. Since the regulation on the rules for producing RFNBOs are not clear as to date, the option of grid fed electrolyser to produce renewable hydrogen in the near and long term is considered too.

Besides the regulatory aspects, there are various reasons to produce hydrogen next to the renewable electricity generation plant (direct coupling) or use grid electricity.

Direct coupling of electrolyser and electricity generation:

- Allows for cheaper electricity cost, since there is no need to use the power network (assumption: no grid fees or taxes need to be paid - see Annex 2); This reduces the levelised cost of hydrogen significantly, with electricity price being the major cost driver.
- Is also less exposed to electricity markets: It is less of an option for the renewable electricity to be sold to the market instead or sell electricity to the market price; especially if the electricity generation is owned/operated by the hydrogen producer.
- When renewable energy generation is not fed to the grid, but used directly onsite, this adds to the power grid stability and decreases potential congestions from regions with high renewable resources to demand centres.
- Direct coupling guarantees the immediate correlation of renewable electricity and hydrogen production, which is the proposed criteria by the European Commission.
- Transport and storage of hydrogen is a lot more flexible and economic - once a hydrogen backbone is in place - than for electricity. It can be more effective and cheaper to convert on electricity to hydrogen close to its generation rather than using the power grid too extensively (also regarding long timelines for power grid extensions).
- Potential drawbacks are that either the Haber-Bosch process needs to be operated flexibly, in sync with renewable electricity production, which is already in the R&D

[44] Although grid-based electricity allows for high load factors of the electrolyser, it is unlikely to be a cost-competitive case (compared to renewable, fossil or low-carbon ammonia). According to the IEA (2021, Ammonia Technology Roadmap, IEA, Paris https://www.iea.org/reports/ammonia-technology-roadmap, License: CC BY 4.0), the price for grid electricity would need to be at or below around 40USD/MWh for most of the year – which is realistic in very few markets across the world only.

[45] Over time, as the share of renewable electricity in the grid increases, there might also be electrolysers connected to the grid. This roadmap did not factor this in.

[46] https://www.europarl.europa.eu/doceo/document/TA-9-2022-0317_EN.pdf

pipeline (refer to paragraph 7.2). Alternatively, a hydrogen storage might be needed[47] or potentially multiple renewable electricity sources (wind and solar) could be combined.

Grid connected electrolysers:

- Can be operated almost the entire year, which decreases the influence of the electrolyser CAPEX on the hydrogen cost; This might be especially relevant in the near term, when electrolysers are still comparatively expensive.
- Allow adjacent process where hydrogen is needed (Haber-Bosch) to operate as well throughout the year, without the need of (expensive) hydrogen storages.
- Do not need to wait for hydrogen transport infrastructure, but the electrolyser can be set up close to the application of hydrogen; Risk factor is, however, the build out of power grid infrastructure.
- PPAs could potentially be used to produce renewable hydrogen.[48]
- Using the grid electricity to feed the electrolyser, needs either a grid mix with high shares of renewable energies (grid emissions <60g/kWh_{el})[49] or PPAs purchased renewable electricity. Most EU countries will in the long-term have high renewable shares in the electricity mix.
- Can be used much more (high amount of full load hours) - due to the balancing by the grid, the electrolysers can operate (almost) continuously.
- Disadvantages are the network tariffs and potential taxes that need to be paid on top of the electricity price, the dependency on the electricity network (congestion are expected to increase) and missing the opportunity to directly profit from the low LCOE from renewable energies.

In conclusion to that, both set ups have their advantages and could be, depending on local, political, and individual circumstances, the more beneficial option. Dedicated set ups are likely to be the cheaper option, especially in the long term. However, this is not always an option and needs, depending on the case, a hydrogen transport network plus either the ability of Haber-Bosch process to operate flexible or hydrogen storage capacities.

Nuclear power generation is further discussed in section 4.3. The lifetime extension of existing plants leads to comparatively low electricity generation cost. However, for hydrogen production mainly new build power generation capacities would be needed. Regarding new power plants, it has the widest spread of projected cost, due to the high uncertainty of investment costs, lead times and technology development. New advanced small modular reactors are promising electricity generation cost of around 40 EUR/MWh, but there is no plant yet commercially running (TRL 9 not reached, yet).[50] On the other hand, current projects being developed in Europe have very long lead times and are over their planned budgets.[51]

Additional to consider to the levelised cost of hydrogen (LCOH) are the **hydrogen** transport costs. These are considered for direct coupled electrolyser and electricity generation, which is usually a set-up further away from the ammonia production plant. Within Europe, a

[47] Cost of hydrogen storage are not included in the technology cost presented in this roadmap

[48] Commission Delegated Regulation C(2023) 1087. Link to source: https://energy.ec.europa.eu/system/files/2023-02/C_2023_1087_1_EN_ACT_part1_v8.pdf

[49] For the hydrogen to meet the EU taxonomy limit of 3 kg CO_2 per kg of hydrogen, with electrolyser efficiency of 67%. Link to source: https://www.fortum.com/about-us/forthedoers-blog/hydrogen-legislation-needs-acknowledge-regional-differences

[50] https://www.world-nuclear.org/information-library/nuclear-fuel-cycle/nuclear-power-reactors/small-nuclear-power-reactors.aspx

[51] https://news.sky.com/story/hinkley-point-c-nuclear-power-station-delayed-again-and-at-further-3bn-cost-12617273

network of dedicated hydrogen pipelines on the transmission system level is envisaged. Therefore, expected cost to transport the hydrogen via these pipelines is from 13 to 16 UR/t NH_3/1,000 km if repurposed gas pipelines can be used or 31 to 60 EUR/t NH_3/1,000 km if new pipelines need to be built.[52] The ranges result from different cost for different pipe diameters. The distances from electrolyser to ammonia plant will be very site-specific. Therefore, this roadmap considered additional cost to transport the hydrogen via 500 km of the European Hydrogen Backbone in average (15 EUR/t NH_3) in its calculations for all technologies. For offshore wind, these costs will be increased (to 31 EUR/t NH_3) since they might need additional subsea pipelines to connect to the shore.

Details on the cost of these hydrogen generation technologies can be found in Annex 3.

3.3 Generating ammonia

The fertilizers industry converts hydrogen to ammonia using the Haber-Bosch process. This process generates heat, and no greenhouse gases are directly emitted by this process step[53]. The industry thus does not foresee a need for replacement of these[54], as it foresees for the plants generating hydrogen (see the previous paragraph). Thus, the ammonia production costs are based on:

- The cost to generate hydrogen using the various options discussed in the previous paragraph and
- The OPEX of the Haber-Bosch process, and the CAPEX of a new ASU, no further CAPEX (ignoring other changes required by lack of data on required investment cost[55]).

For ammonia production, based on renewable electricity it is assumed that the electrolyser is at the location where the renewable electricity is generated (no network cost and no taxes/levies). The hydrogen is transported via (short) pipelines from the electrolyser to the ammonia plant using line pack capabilities to compensate for differences between production and consumption. The report, however, also shows ammonia production cost based on hydrogen produced from grid electricity.

Results:

Figure 7 shows the ammonia production costs for SMR based hydrogen production (for plants with new SMRs and plants continuing to use their existing SMR). The figure shows two CO_2 price levels to give an indication for the cost in the near term (100 EUR/tCO_2) and potential long term (200 EUR/tCO_2). The real cost experienced by the ammonia producers are somewhere between the cost with and without the CO_2 price component, as a consequence of free allocation of allowances. In further graphs only options including the

[52] https://ehb.eu/files/downloads/EHB-Analysing-the-future-demand-supply-and-transport-of-hydrogen-June-2021-v3.pdf
[53] https://ec.europa.eu/clima/system/files/2016-11/bm_study-chemicals_en.pdf (page 30).
[54] Currently, the Haber Bosch process is typically strongly (energy) integrated with the SMR process (based on member interviews):
- SMR's produce the nitrogen needed in the Haber Bosch process; in the absence of a Haber Bosch process, nitrogen would need to be produced in an Air Separation Unit.
- Residual heat from SMR's flue gas is used to produce steam for some pre-heating and to drive steam turbines, with some SMRs also exporting steam to other plants.

Investments are needed in Haber-Bosch plants when more than around 15% of the hydrogen supply doesn't come from an integrated SMR anymore (based on member interviews). Costs for the new Air Separation Unit that is needed when switching from SMR to an electrolyser are included, but no other adjustment costs. Production losses as a consequence of adjusting the Haber Bosch process further contribute to costs (not included).
[55] This implies that potential investments to make the Haber Bosch process more flexible are not included.

impact of full CO_2 cost are shown, even though EU ETS has not (yet) been designed along these lines[56].

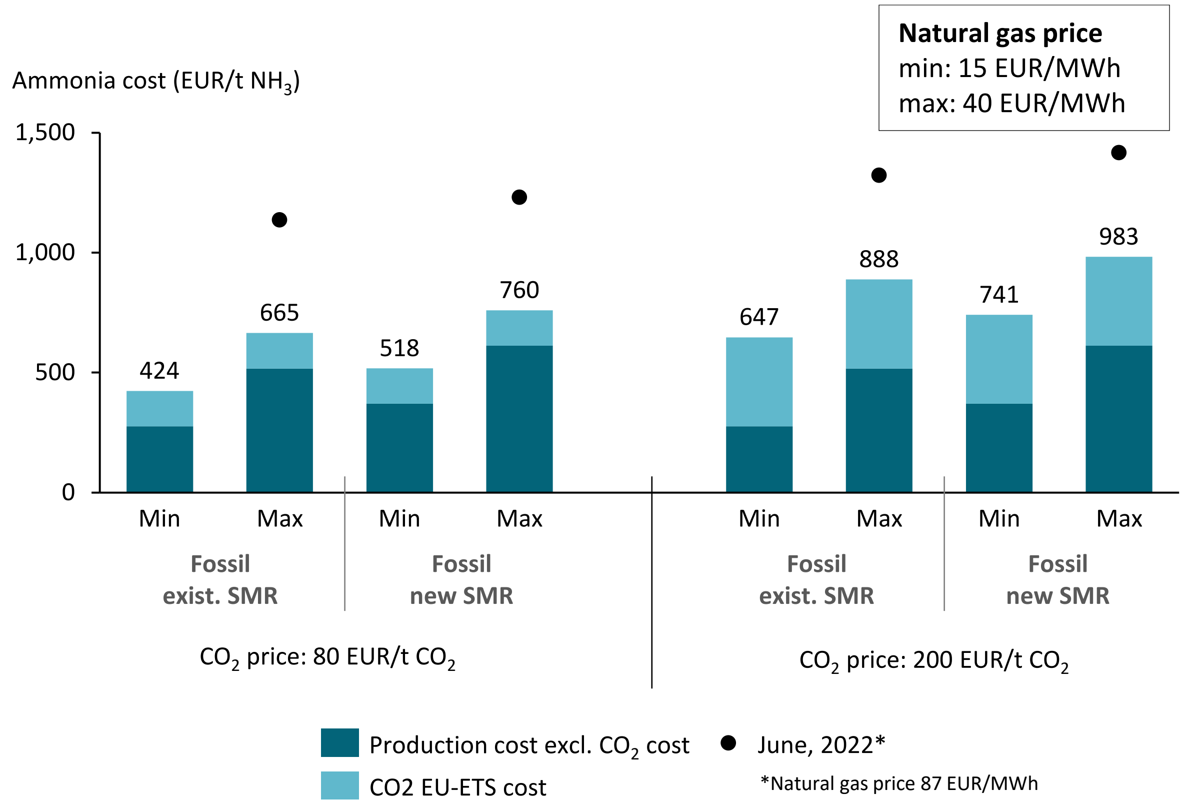


Figure 7: Ammonia cost based on natural gas with and without CO_2 costs (in EUR/t NH_3)[57]

Figure 8 below shows the cost of producing ammonia based on methane:

- From natural gas without CCS (as in the figure above)
- From natural gas with CCS
- From biomethane.

The figure shows, for example, that:

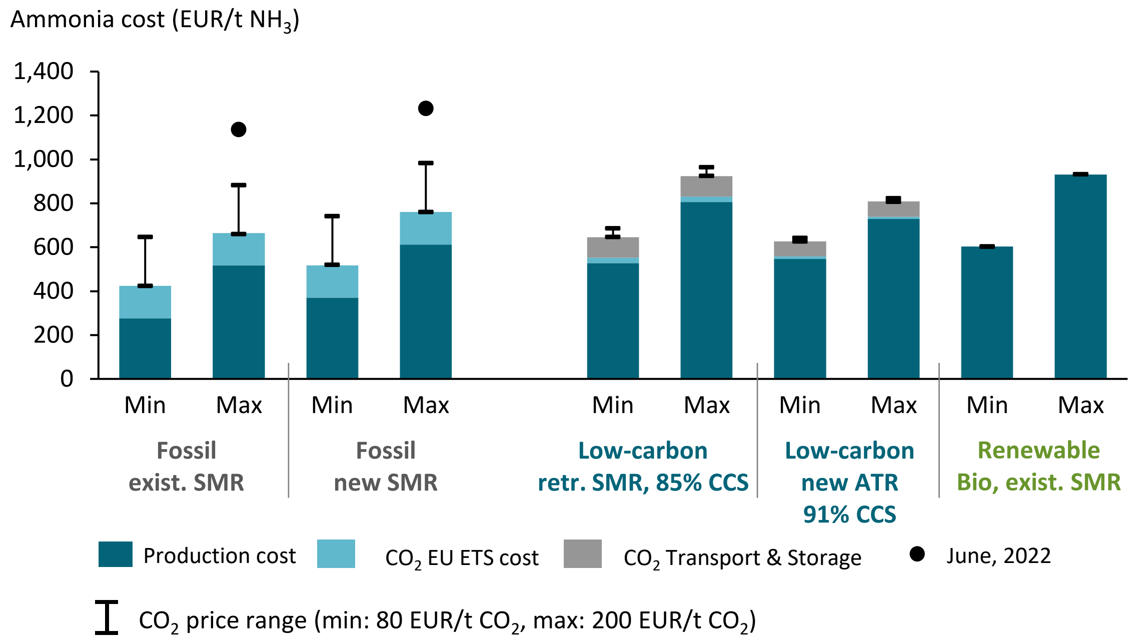
- ATR *vs* SMR:
    - At a natural gas price of 15 EUR/MWh, *new built* ATR can compete with *existing* SMRs at CO_2 cost of around 200 EUR/tCO_2 or higher, while *new built* ATR can already be more economic than *new built* SMRs at CO_2 cost of around 150 EUR/tCO_2;
    - At a natural gas price of 40 EUR/MWh, *new built* ATR can compete with *existing* SMRs at CO_2 cost of around 150 EUR/tCO_2 or higher;

[56] This would assume that the free allocation of allowances would not change when investing in clean production, so that the full impact of the CO_2 cost is taken into consideration in the investment decision. This is currently not the case, as a consequence of the impact of the interchangeability of electricity in the product benchmark – refer to chapter 9.

[57] When speaking about CO_2 capturing & storage for SMR and ATR, the assumption is that the CO_2 currently used for urea production (or alternative short-lived applications) is priced as if it was still emitted, thus effectively the cost of conventional ammonia apply even though CO_2 is captured.

- Retrofitting SMR to capture 85% of CO_2:
    - Capturing the concentrated emissions[58] doesn't require much additional energy, but transport and storage of CO_2 still cost.
    - Capturing more (85%) CO_2 requires additional energy. This roadmap assumes this energy is generated with natural gas, adding cost and emissions. In case low-grade residual heat would be available, both the natural gas consumption and the associated CO_2 emissions can be reduced (Uni Alberta, 2022).
    - The cost for retrofitting SMRs to capture more CO_2 can thus not be expressed in a single cost per ton of CO_2.
- Assuming a biomethane price of around 90 EUR/MWh and considering only CO_2 cost up to 200 EUR/tCO_2, biomethane is not competitive when natural gas cost are 15 EUR/MWh, and becomes competitive at CO_2 cost of 180 EUR/tCO_2 when natural gas cost are 40 EUR/MWh. Its competitiveness increases at higher natural gas prices (as seen in the past years due to the supply limitations of Russian gas as a consequence of Russia's invasion in the Ukraine).
    - At future (2040-2050) biomethane cost around 40-60 EUR/MWh, this route will become competitive to the low-carbon SMR and ATR options with CCS - depending on the CO_2 EU ETS and natural gas price. Especially since existing SMR infrastructure can be used.
    - It is to consider, that the biomethane market price is unlikely to fall below natural gas price (incl. CO_2 cost). It is more likely it will be either depending on its production cost (LCOB) – accounting for subsidies - or the natural gas price (incl. CO_2 cost).
    - On top of this, the biomethane route generates CO_2-from-renewable-source-by-product that can be used in urea production (not considered here). Further upward potential for the business case comes from the possibility of using biogas rather than biomethane (generating more CO_2-from-renewable-source-by-product at lower cost).

[58] Typically more than 60%; refer to chapter 6.



Notes: Natural gas: Min = 15 EUR/MWh, Max = 40 EUR/MWh; Biomethane: Min = 50 EUR/MWh, Max = 86 EUR/MWh; Transport & storage cost of 50 EUR/t CO_2 assumed for low-carbon hydrogen; June 2022 indicates the price level in this month of 87 EUR/MWh for natural gas and 80 EUR/t CO_2 from EU ETS. The biomethane option is based on production costs (LCOB). It is to consider, that the biomethane market price is very unlikely to fall below the market price for natural gas (incl. EU-ETS CO2 cost), even if its levelized cost would be lower.

Figure 8: Ammonia cost based on conventional and low-carbon based hydrogen (in EUR/t NH_3)

Figure 9 shows the cost of ammonia using different renewable electricity generation technologies and nuclear electricity, in comparison with ammonia generation cost for natural gas-based ammonia without CCS. For each technology production cost are shown in a range with.[59]

- A best case, reflecting an ideal location within the EU for the generation of electricity with this technology (e.g., PV in Spain) or ideal other conditions (e.g., nuclear in France).
- An additional average case, reflecting good locations for the generation of electricity (e.g., PV in Germany); countries with average cost could - depending on their alternatives - well apply the technology later.

Since these generation technologies are still further developed and scaled up, costs at two moments are shown:

- Near term marks an intermediate step, with significant improvements in production and technology compared to today (around 2030).
- Long term: the final development stage of the technology is reached; production levels are at large scale and strong competition and experience in the project implementation is realised (expected around 2040-2050).

[59] Note that this report does not show the highest cost (for example the cost in the country with the highest levelized cost for electricity from PV), as it would be counter-intuitive to assume these routes to be built.

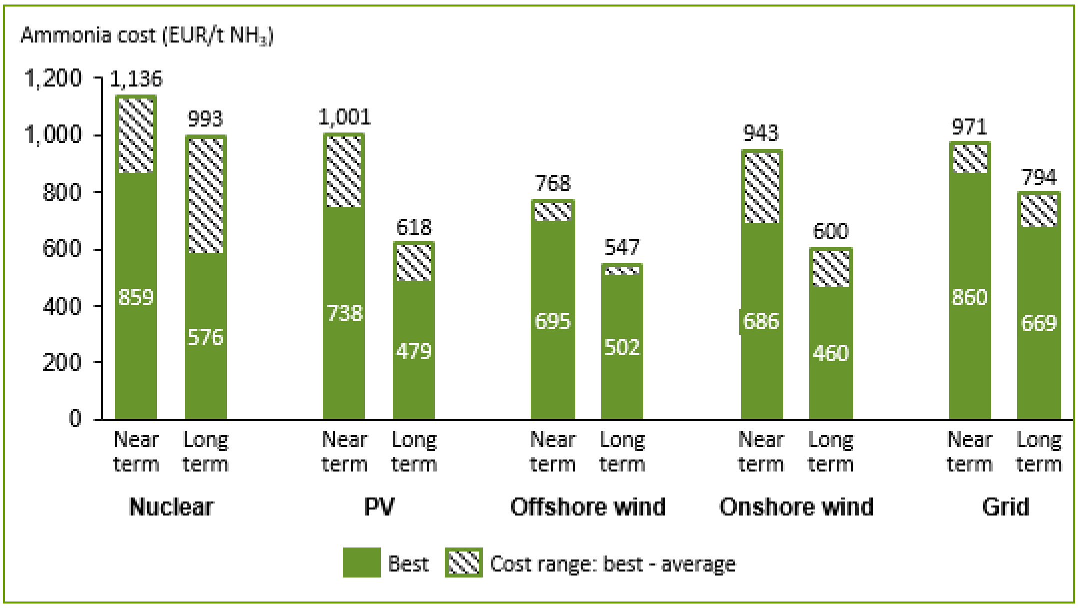


Figure 9: Ammonia cost based on renewable and nuclear electricity-based hydrogen, with best case and average as upper and lower boundary (in EUR/t NH_3)[60]

Onshore wind has in the near and long term the lowest cost projections and lowest delta between the best and an average location within Europe. Especially in the near term its low LCOE, combined with reasonable capacity factor for the electrolyser (30%) leads to the lowest ammonia cost. Offshore wind and solar also seem to be economic options in the long term. For nuclear-based ammonia production, it depends largely on the evolution of the technologies currently being developed. If the promised low electricity cost is reached, it is economic, while, with more conservative assumptions, it seems to stay the most expensive option.

The electrolyser has, depending on its electricity generation source, different capacity factor (see Table 10 in Annex 3). Electrolyser operated with lower capacity factors (less full load hours) need more installed capacity to produce the same amount of hydrogen per year. The higher capacity needs, lead consequently to higher investment cost, as shown in Figure 9.

Figure 10 and Figure 11 below compare the ammonia production cost for key hydrogen generation routes described above - in the near term and long term.

How to read the graphs?
The x-axis displays the energy cost in EUR/MWh while the resulting ammonia cost are shown on the y-axis in EUR/t NH_3. Each line in the graph represents one hydrogen generation technology, further distinguished by the type of gas or electricity generation technology. The graph shows the dependency between the cost of gas or electricity and the resulting ammonia cost for each technology. To check what energy cost levels must be to produce ammonia at a certain price, one could draw a horizontal line at the considered price level. The intersections of this horizontal and the technology lines indicate the gas or electricity cost needed to produce ammonia at this price.

[60] Near term grid costs are based on the marginal price in the electricity market in 2025 for national trends, as published by TYNDP in April 2022. Current costs are significantly higher.

To give the reader an indication how to interpret these price levels typical gas and electricity cost ranges[61] for each technology have been indicated below the chart.

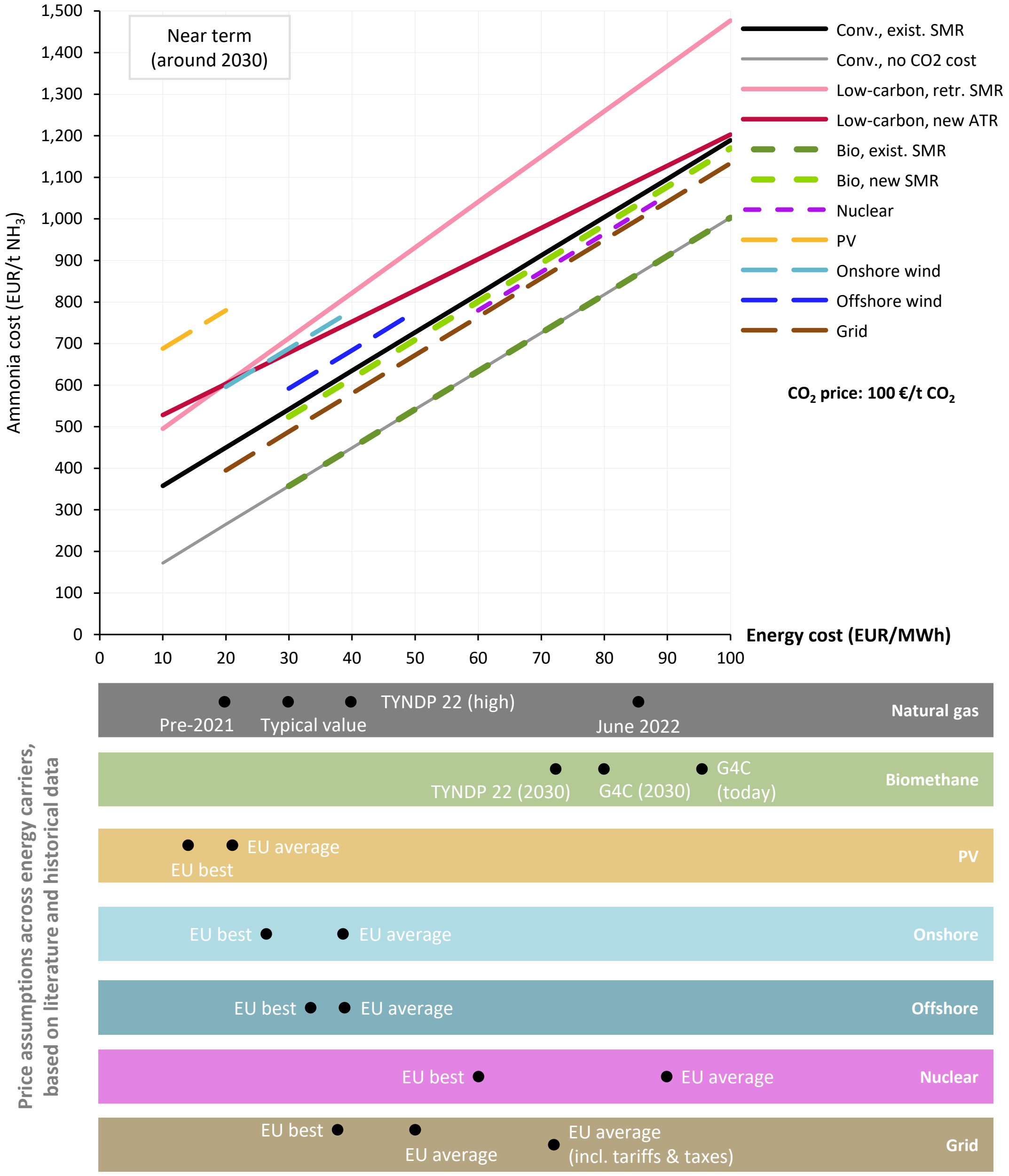


Figure 10: Ammonia cost comparing all hydrogen options (in EUR/t NH_3) in the near term (around 2030)[62]

[61] Note that the projected 2030 cost for grid electricity have been used for the electricity consumption of the plant producing the ammonia (2.32 MWh/t NH_3) throughout these graphs. Should, for example, the price of the cheapest on shore electricity (26 rather than 72 EUR/MWh in 2030) have been used for this share of the electricity, then ammonia production cost would have been 107 EUR/t NH_3 cheaper.

[62] Current grid costs are significantly higher.

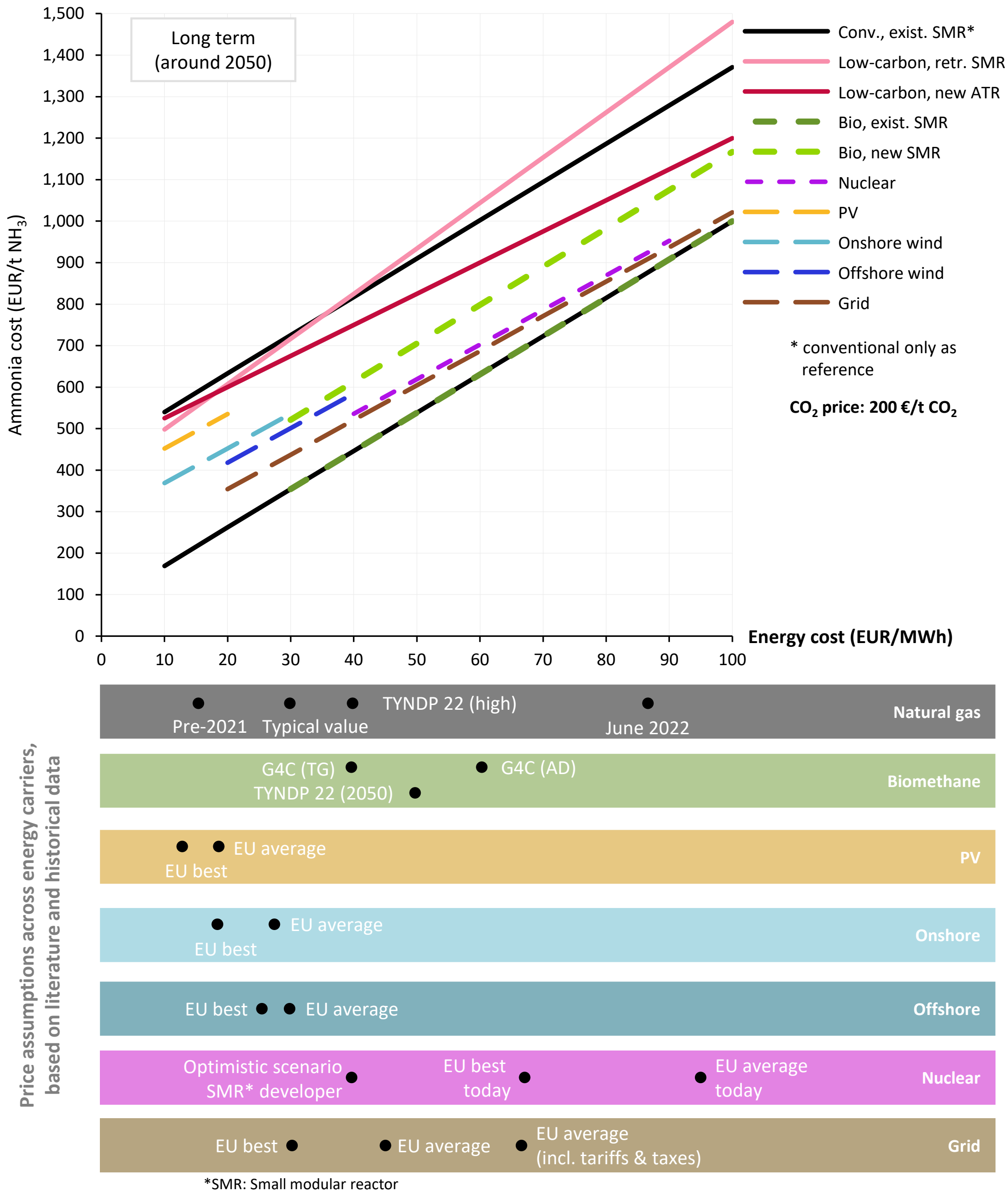


Figure 11: Ammonia cost comparing all hydrogen options (in EUR/t NH_3) in the long term (around 2050)[63]

What about much higher natural gas prices?
As a consequence of Russia's invasion in Ukraine, the natural gas price had skyrocketed. A higher natural gas price favors electricity-based ammonia production routes at equal electricity price[64]. It is possible that at some point, generating demand and investment support for climate friendly produced fertilizer would no longer be needed. Getting sufficient renewable and low-carbon electricity quickly would then be the challenge. Meanwhile, when the natural gas price is much higher in Europe than in other parts of the world, this jeopardises the competitiveness of the natural gas based European fertilizer production.

[63] Current grid costs are significantly higher.
[64] Note that the market price for grid electricity increased in Europe too.

4. Context

In this chapter, further context on the previous chapter's findings is given regarding:

- The overall cost of this transition (in comparison with the sectors current Gross Value Added)
- The extent to which the required new energy carriers (and CO_2 storage capacity) is available in Europe
- Pros and cons of use of nuclear electricity
- Other - innovative - technologies that are currently being developed.

4.1 Investment cost for the transition

There is a massive additional investment in clean hydrogen and electricity generation capacity needed. Figure 12 provides an overview on the total investments that would be needed to generate all hydrogen required for European ammonia production (assumed to be 14.9 Mt/year[65]) with only one technology. This is not a realistic scenario but gives an idea what investment cost such a transformation implies and shows the differences between the technologies. This compares to yearly investments of 1.2 billion EUR for the sector.[66]

For the electrolyser investment cost in this section, the year 2035 is assumed as reference year. This is because, electrolysers would need to be build prior to 2040, but there will be still new ones added by 2040. The investments differ as well, depending on the renewable source. Since PV has lower load factors than wind, the investment costs are higher, while for nuclear it is the other way around[67]. For the other technologies, investment costs are assumed constant over time (see Annex 3).

Note that the impact of changes in OPEX (including the price of energy carriers) comes on top of this.

[65] 15.8 Mt/year * (100% - 5.7%)

[66] Fertilizer Industry Facts & Figures, 2021, investment from the mineral fertilizer industry, https://www.fertilizerseurope.com/wp-content/uploads/2021/07/Industry-Facts-and-Figures-2021-1.pdf

[67] Assumed load factors: 18% for PV, 30% for onshore wind, 50% for offshore wind and 90% for nuclear

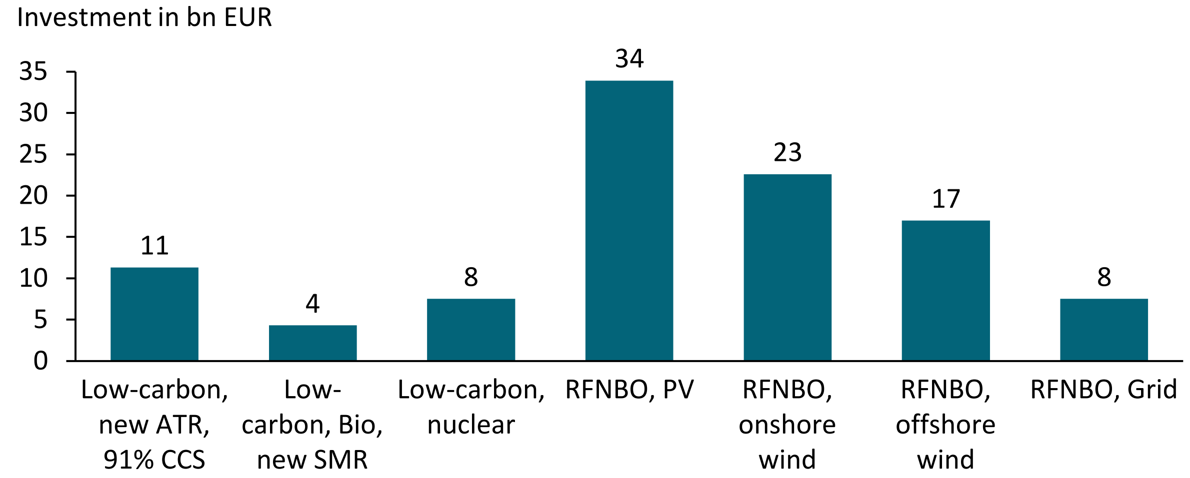


Figure 12: Total investment in hydrogen production technology (SMR, ATR, electrolyser, excl. generation of electricity) cost if one technology would provide all the hydrogen needed[68]

Additional cost components are the hydrogen transport infrastructure and the electricity generation which both need significant investments, too. The European Hydrogen Backbone initiative estimates the cost for the European hydrogen network around 23-63 billion EUR. The European Fertilizer industry would need about 5% of the European hydrogen (see Annex 5: Need for and availability of RFNBO in the form of hydrogen. Therefore, 5% of the hydrogen infrastructure cost are accounted for to the fertilizer sector, which is about 3 billion EUR.

The investments for renewable generation are in the same range and higher as the electrolyser investment cost. For PV, additional 73 GW would be needed which cost around 26 billion EUR. Additional 49 GW wind onshore are needed, which cost around 43 billion EUR and the 37 GW offshore wind result in about 64 billion EUR.[69] For nuclear power plants, the additional 16 GW would cost around 77 billion EUR.[70]

For low-carbon methane-based options additional investments in CCS infrastructure are necessary.

4.2 Needs for and Availability of energy carriers

The transformation of the European fertilizer production needs, besides other components, large amounts of clean energy carrier, electricity or carbon storage. In order to understand the magnitude of resources needed, this section will give an overview, depending on the transformation pathway. While later in the study several more hybrid greenhouse gas emission reduction pathways are given, here the (hypothetical) transformation using only one energy resource is analysed. There will be severe competition from other sectors for renewable electricity/hydrogen, biogas, and CCS capacity. This roadmap has explored to which extent each of the energy carriers would be available sufficiently. Despite the large

[68] Using the average CAPEX numbers between 2030 and 2040, and only including the hydrogen production cost (not the cost of production of biomethane, renewable or low-carbon electricity, any hydrogen or CO_2 transport infrastructure, any investment in CO_2 storage and any adjustment to the Haber Bosch process/in the ASU); cost to generate electricity are not included but addressed in the running text.

[69] The investments for renewable generation are excluding changes required for the Haber-Bosch process and based on the projected price level of 2035.

[70] Investment cost are based on the average of 2030 and 2040 CAPEX for renewable energies (G4C) and average of today's cost for nuclear power plants in the US, South Korea and eastern Europe (WNA).

scale of the fertilizer industry, the conclusion is that none of the technological options would seem impossible based on (future) availability of the required energy carriers. As there will be fierce competition from other resources, it will be essential to continuously find the optimal application for each of the energy carriers. More details can be found in Annex 5 to 8.

4.3 Nuclear electricity

Electricity-based options can be powered by renewable electricity, but also by nuclear electricity. Nuclear electricity has some advantages that renewable energies are not able to deliver, e.g., base load profile. However, there are also drawbacks, especially around economics and the question of sustainability. Below in Table 2, an overview of arguments pro and contra the use of nuclear electricity is given relative to renewable electricity.

Table 2: Overview of arguments for (Pro) and against (Contra) the use of nuclear power for hydrogen production compared to renewable electricity

Pro	Contra
Operates 24/7 which delivers base load to the electricity grid, but also an efficient load profile to the electrolyser	High upfront capital cost. Currently, LCOE of newly built is more expensive than most renewables are already today or projected to be by 2030
No operating CO_2 emissions	Flexibility of policies could lead to hydrogen from nuclear being classified different then hydrogen from renewable electricity in the future
Generates process steam	Currently, very long lead time to build a new nuclear plant (10 to 12.5 years)[71]
In principle very high capacities can be built, with a fraction of the land use renewable installations need	The spent nuclear fuel must be managed
Option for countries with poor RES availability aiming to develop own low-carbon generation hydrogen capacity	

Economics of new nuclear power plants

There are many uncertainties around the economics of new build nuclear power plants, especially for Europe or the USA, since not many power plants have been newly built in the past decade. Most of the existing plants have been operating for 30 years or longer. New small modular reactors (<300 MW) which are currently under development promise cheaper constructions with less risk of escalating cost and construction time. However, they are still in the development phase and have yet to prove themselves in the field. Additional uncertainties result from the financing situation of these projects. Since around 50% or even more of the LCOE are CAPEX, the technologies generation cost is very sensitive to capital cost.

[71] https://web.mit.edu/kshirvan/www/research/ANP193%20TR%20CANES.pdf

While today's LCOE can be derived from the few power plants being built and range from around 70 to 102 USD/MWh[72] (depreciation rate of 7%, 40 years lifetime), outlooks are more complex due to the above-mentioned reasons. A study published 2018 by a consortium of manufacturers working on new small-scale reactors[73], indicates future LCOE from 36 to 90 USD/MWh, with 60 USD/MWh as best guess. A report published 2022 by the MIT[74] states that large-scale Generation III/III+ power plants (AP1000) will have LCOE around 60 USD/MWh, although a long lifetime of >40 years could reduce the LCOE to 30 USD/MWh. Their conclusion was that small modular reactors will not be cheaper in operation then the mentioned large-scale GEN III/III+.

Keeping in mind the relatively high cost to produce nuclear electricity in case new capacity would need to be built, lifetime extension of existing nuclear production facilities seems to offer the best/only potential.

4.4 Innovations

The technologies described so far, have all - in essence - achieved a high Technology Readiness Level - although further innovative developments will likely improve their efficiency and decrease their cost. Other technologies are currently still being invented, including innovations like[75]:

- **Methane pyrolysis**, using an electrical plasma to split methane into solid carbon (C) and H_2. The solid carbon can be used in certain carbon black applications. When the carbon black is combusted at the end of its lifetime, the indirect emissions are similar to the natural gas-based production[76]. The technology is at demonstration scale (TRL 7).
- **Biomass gasification**, in which various biomass (or waste) sources are gasified producing syngas. The technology still needs further development (TRL 5[76]).
- **Photocatalytic production of hydrogen**, directly converting water using sun light.
- **Electrified SMR**[76], producing hydrogen using a combination of natural gas for feedstock - for which the process emissions are more easily captured - and electricity to provide process heat.
- **Biological enzymes** replacing the Haber-Bosch process with biological enzyme catalysts that produce ammonia directly from water and nitrogen in the air.
- **Hydrogen production from biomass through integration of anaerobic digestion and biogas dry reforming**.[77]

Further, many **new CO_2 capture technologies, electrolyser or (thermo-)electrochemical** processes to produce hydrogen are explored.

Finally, **producing hydrogen from biogas while capturing CO_2 is explored**[78]. This could deliver an effective alternative to feeding biomethane to SMRs, producing hydrogen and climate-neutral CO_2 for urea production.

[72] IEA (2020), Projected Costs of Generating Electricity 2020, IEA, Paris https://www.iea.org/reports/projected-costs-of-generating-electricity-2020, License: CC BY 4.0

[73] https://www.innovationreform.org/wp-content/uploads/2018/01/Advanced-Nuclear-Reactors-Cost-Study.pdf

[74] https://web.mit.edu/kshirvan/www/research/ANP193%20TR%20CANES.pdf

[75] Illustrative, non-complete, list intended to show the variety of developments.

[76] IEA (2021), Ammonia Technology Roadmap, IEA, Paris https://www.iea.org/reports/ammonia-technology-roadmap, License: CC BY 4.0

[77] https://www.sciencedirect.com/science/article/abs/pii/S0306261921016676#

[78] https://www.sciencedirect.com/science/article/abs/pii/S0016236120314757

5. Reducing scope 3 emissions

Without attempting to be complete, this chapter provides brief context on two of the emission hotspots in scope 3 of the fertilizer value chains:

- The upstream emissions from fossil methane.
- The emissions from the field when applying fertilizers.

5.1 Upstream emissions of methane

Methane emissions occur across the entire supply chain of natural gas. Data variability and differences between countries make it difficult to establish accurate emission factors. The typical order of magnitude lies between 2% and 65% of the GHG emissions related to the incineration of methane (see Annex 9 for more details), thus upstream emissions from methane can be very meaningful[79].

Therefore, when fertilizer producers would continue to use natural gas, the sector should increasingly map its upstream scope 3 emissions stimulating its suppliers to detect leaks via satellites and with early failure detection and monitoring, and to then terminate leaks[1]. Meanwhile, the sector should aim at sourcing it from suppliers with low upstream GHG emissions.

5.2 Emissions from the field when applying fertilizers

Like the fertilizer industry is facing a transition, also its customers, the farmers, are facing an equally challenging transition towards significantly more circular, climate-neutral farming. The fertilizer industry wants to be their pro-active partner in this transition. This delivers, or contributes to:

- Improved, healthy soil quality.
- A strategy that significantly reduces the GHG emissions from using fertilizers[80] on the field. This is key, as the GHG emissions from fertilizers when applied on the field are (markedly) higher than those from the production plants.[81]
- No excess-nitrogen in nature areas, preventing loss of biodiversity.[82]
- Carbon sequestration.

This roadmap can build on the European Commission's Farm-to-Fork strategy's aims to reduce nutrient losses in 2030 by 50%.[83]

[79] As these emissions fall under scope 3, these are not included in the sector's scope 1 and 2 emissions discussed so far.

[80] The sector's fertilizers, but also organic fertilizers and manure, emit GHGs from the field.

[81] N_2O and for urea CO_2 as well; based on https://issuu.com/efma2/docs/ecofys_fertilizers_and_climate_chan (figure 6) and https://www.youtube.com/watch?v=gFQLndYlLRA (slide 7, and slide at 28:55).

[82] While nitrogen is an essential nutrient for crops, plants that thrive on nitrogen-rich soil can overgrown other plants when there is too much nitrogen in the soil in nature reserves (from ammonia and NO_x emissions elsewhere). Remkes (https://open.overheid.nl/repository/ronl-e1d98609-6f59-4245-8758-ec00da553db5/1/pdf/niet%20alles%20kan%20overal.pdf) reports that, for the Netherlands:

- 9% of the NH_3 emissions from agriculture (~94-114 kt N) is related to the use of fertilizers.
- The (~13 kt) NO_x emissions from agriculture are also mainly related to the use of fertilizers.

The report recommends modernizing the use of animal manure and fertilizers, with a demand-driven and improved use of animal manure, reducing the need for fertilizer.

[83] https://eur-lex.europa.eu/resource.html?uri=cellar:ea0f9f73-9ab2-11ea-9d2d-01aa75ed71a1.0001.02/DOC_1&format=PDF

To get there, the industry should actively develop and support implementation of farming strategies based on:

- *A nutrient strategy optimising presence of all nutrients complimenting organic nutrients with mineral fertilizers.*
- *Recycling organic fertilizers (such as manure, crop residues and waste streams) and optimising the N-efficiency of N-fertilizers.*
- *Increase soil organic matter growth using the right balance of manure, and inorganic fertilizers.*[84]
- *Carbon farming.*[85]

The industry already:

- Aims to equip farmers with knowledge, advice, tools and technology to produce sustainably and optimise yields.
- Is a member of the alliance offering the Cool Farm Tool, which farmers can use to assess and reduce their GHG emissions.
- Supports farmers to optimise application of fertilizers, for example by advising on the ideal dosage[86] by using drones and by using inhibitors or other solutions controlling the release of N-nutrients.
- Is a partner in FERTIMANURE, which develops, integrates, tests and validates innovative Nutrient Management Strategies to efficiently recover mineral nutrients and other relevant products with agronomic value from animal manure. The project aims to achieve a zero-waste manure management approach and obtain reliable and safe fertilizers able to compete in the European fertilizer market.

All Fertilizers Europe members participate in the sector's Product Stewardship Programme, under whose umbrella the Fertilizer Carbon Footprint Calculator has been developed. This tool enables the calculation of direct and indirect GHG emissions related to the production of a wide range of selected fertilizer products.

The sector should expand its activities based on the 4R principle (right time, right place, right amount and right type of fertilizers). This 4R principle can be expanded to cover the combination between organic and mineral fertilizers.

The above will reduce the demand *in tonnes* for mineral fertilizer products[87]. Optimal application of the industries' products and services as part of a more circular and climate-neutral agriculture is essential from a sustainability - as well as from a business-perspective.

[84] Soil organic matter improves the soil quality by contributing to an active and diverse soil life and improving the structure and the fertility of the soil; https://www.meststoffennederland.nl/dossiers/voeding-van-de-plant/effect-kunstmest-op-organische-stof-en-bodemleven

[85] https://www.cleanenergywire.org/factsheets/carbon-farming-explained-pros-cons-and-eus-plans

[86] Overdosage increases N_2O emissions from the field.

[87] Potential impact of further reduction of use of fertilizers (than indicated in chapter 2) on the transition of ammonia production has not been explored in this roadmap.

6. Transition pathways

The location of current plants is mainly based on the availability of natural gas, raw materials to mix in the fertilizers, good logistics (railways, rivers) and proximity to markets. For the sector's transition, the availability of sufficient competitively priced clean electricity, biomethane or hydrogen or CO_2 infrastructure is key, proximity to ports (for ammonia imports), and availability of nutrients for recycling, as well as access to water, are key factors too[88]. Not all current plants have equal access to these. This chapter presents the sector's transition pathways for typical plants (archetypes) in various situations, in the following four steps:

- Introducing the archetypes
- Presenting general starting points for the production of urea and the use of biomethane, and regional policies
- Discussing the transition for each of the two trajectories defined in chapter 2 (trajectory 1 reducing emissions technology agnostic, and trajectory 2 with an increasing share of RFNBO-based hydrogen)
- Commenting on the transition

Introduction archetypes:

The figure below shows the four archetypes, based on two axes:

- A plant in archetype 1 has access to biomethane and/or CO_2 infrastructure and can thus generate hydrogen based on methane (or by gasification of other forms of biomass).
- A plant in archetype 2 has access to hydrogen, either from abundant competitively priced renewable electricity, or from a hydrogen pipeline grid.
- A plant in archetype 3 has all of the above, and thus most options to transition.
- A plant in archetype 4 has none of the above, and thus least options to transition.

This illustrates that the availability of renewable energy is not equally distributed over Europe.

[88] Based on interviews with Fertilizer Europe members.

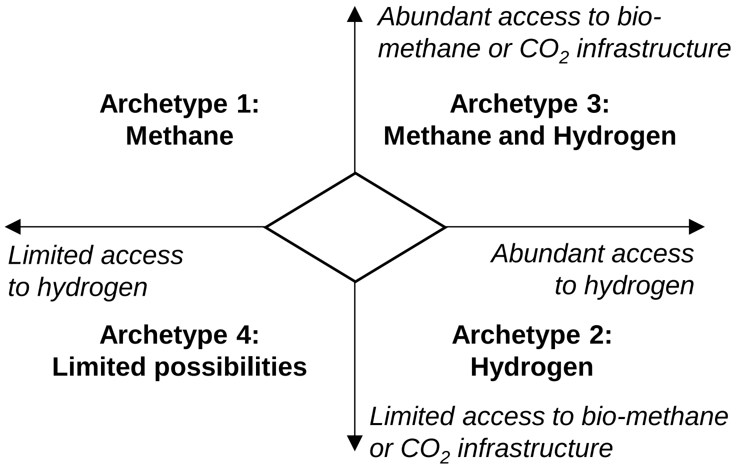


Figure 13: Four archetypes based on their access to biomethane or CO_2 infrastructure and access to hydrogen

Starting points:

Some overarching points are relevant for all archetypes:

1. A relevant share of N-fertilizers currently contains urea. The production process step converting ammonia to **urea needs CO_2 as feedstock**. Currently, this CO_2 is produced in the SMRs producing ammonia. For new production routes not producing CO_2 as by-product, such as electricity-based hydrogen, another source of CO_2 would be needed[89]. This means that:

    a) Urea production will over time be partially replaced by ammonium nitrate production[90]:

    - Fertilizer Europe has reported that under normal European growing conditions, ammonium nitrate has lower emissions in the use phase than urea[91]. This however depends amongst others on the exact conditions and the question whether inhibitors are used.

    - The application in diesel (AdBlue) will be phased out with the phasing out of diesel-use for road transport, and application in DeNOx will be reduced with the phasing out of fossil fuels. Urea will still be required for industrial applications (like melamine).

    b) Alternative sources of CO_2 need to be used:

    - Biomass used for the production of hydrogen (biomethane or biogas fed to SMRs/ATRs, or biomass (a. o. from waste) gasification)

[89] CO_2 from SMR's is not just used to produce the urea, but also to produce other chemical compounds for example in the caprolactam production chain and oxo-alcohols. This leads to similar considerations as presented for urea.

[90] Based on interviews with Fertilizer Europe members. The IEA (2021), Ammonia Technology Roadmap, IEA, Paris https://www.iea.org/reports/ammonia-technology-roadmap, License: CC BY 4.0 also indicates a decrease in the European urea production relative to ammonia production (after 2030).

[91] Based on Christensen, Brentrup, Six, Pallière and Hoxha, Assessing the carbon footprint of fertilizers at production and at full life cycle, Paper presented to the International Fertilizer Society at a Conference in London, UK, on 3rd July 2014, Annex 1 – Fertilizer Use, corrected for nutrient content.

- Biogenic CO_2 emitted by other plants:
  - Power plants
  - Incineration of bio-waste
  - Excess CO_2 from gasification of biomass to produce fuels
  - Fermentation
- Direct Air Capture (DAC - which concentrates the CO_2 from atmospheric air): Currently DAC is expensive and uses a significant amount of energy, although the cost estimates range widely but can decrease by scaling up[92]. This report assumes DAC is too expensive in the short term but could become an option towards 2050[93].

2. **Biomethane** can replace natural gas in currently used SMRs. It can be taken from the grid, where a certification system could prove the (fossil or bio) origin of the methane[94]. Alternatively, **biogas** can be used, which has significant advantages:

   a) Biogas is formed in anaerobic digestion (for example at farms) and contains around 35% CO_2[95]. Currently the biogas is either used at the location of generation (for example to produce power), or it is upgraded to biomethane and fed to a grid. However, up to 30% of biogas can be fed directly to SMRs (in combination with 70% natural gas - for the 'feedstock part')[96], eliminating the need for upgrading and providing additional bio-CO_2 for conversion to urea (see above). To illustrate, large-scale digestion of animal manure[97] can produce biogas, thus coupling organic and mineral fertilizers. In case the applicability of biogas in SMRs/ATRs could be increased (preventing contamination of catalysts and creating the logistic to feed large amounts of biogas to the ammonia plants), this would provide a cheaper alternative for the use of biomethane while at the same time enabling higher urea production.

3. The potential to transition quickly for plants in all archetypes is not just determined by the availability of resources (as in the Figure above), but also by **the presence of**

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[92] Based on:
- IEA (2021), Direct Air Capture, IEA, Paris https://www.iea.org/reports/direct-air-capture, License: CC BY 4.0: As the technology has yet to be demonstrated at large scale, the future cost of DAC is uncertain, with capture cost ranging widely from USD 100/tCO_2 to USD 1,000/tCO_2.
- Capture costs of USD 94/tCO_2 to USD 232/tCO_2 can be achievable depending on financial assumptions, energy costs and specific plant configuration (https://www.sciencedirect.com/science/article/pii/S2542435118302253?via%3).
- WRI: Cost are currently USD 250 to 600/tCO_2 and could fall to around USD 150 to 200/tCO_2 in 5 to 10 years, and reports an aim to reduce these to USD 100/tCO_2 until 2033 for largescale gigaton projects (https://www.wri.org/insights/direct-air-capture-resource-considerations-and-costs-carbon-removal#:~:text=The%20range%20of%20costs%20for,less%20than%20%2450%2Ftonne)
- Global CCS Institute explores scenarios based on low cost of 137 USD/tCO_2 and high cost of 412 USD/tCO_2 quoting a range of USD 100-300 based on IPCC 2022 (https://www.globalccsinstitute.com/wp-content/uploads/2022/07/Economics-of-DAC_FINAL.pdf).

If the DAC cost (including transport and storage) would be lower than the carbon price there could be an incentive case to apply DAC followed by storing the captured CO_2, delivering negative emissions.

[93] To express the cost of DAC for use in urea production in EUR/t ammonia, multiply the cost in EUR/tCO_2 by 1.29 (Based on $2\ NH_3 + 1\ CO_2$ --> $H_2O + (NH_2)CO$), using mol masses of 17.03 respectively 44.01.

[94] In Germany Dena has already set up a certification system.

[95] https://www.eesi.org/papers/view/fact-sheet-biogasconverting-waste-to-energy#:~:text=Biogas%20contains%20roughly%2050%2D70,trace%20amounts%20of%20other%20gases.

[96] Based on one interview with a Fertilizer Europe member.

[97] This example only applies to the part of animal manure that cannot be directly applied as nutrient due to thresholds in its application on the land.

organisations developing infrastructure, the knowledge about the transition and associated technologies in the region, local support policies (see chapter 9.4) and **the speed of permitting** (see chapter 9.3).

Trajectory 1: Reducing the emission intensity

In 2030, the emission intensity of ammonia production is reduced with 31%, by:

1. Increasing the energy efficiency: For current SMR's, investments in energy efficiency (before 2030) reduce the natural gas use and thus the associated CO_2 emissions with around 5%[98] - delivering an impact for as long as they are operated. This report assumes mostly that on average half of this will be delivered, due to the switching to other technologies.
    - Note that the energy efficiency of newly built plants can be optimised further over time too, but as this has limited CO_2 emission impact and for the sake of simplicity, this has not been incorporated.
2. In case transport and storage infrastructure is available close by (archetypes 1 and 3), capturing and storing of CO_2 is possible for any remaining concentrated CO_2 emissions not yet converted to urea or used for other applications (like carbonated drinks). The current scope 1 emission intensity is ±1.83[99] $tCO_2/t\ NH_3$ - at least 60% of these CO_2 emissions are concentrated[100] (at least 1.10 $tCO_2/t\ NH_3$):
    - In case almost all ammonia would be converted to urea, all concentrated CO_2 would already be converted to urea, and no concentrated CO_2 would be available anymore.[101]
    - In the extreme case that none of this CO_2 is currently used (no urea is produced and no sales for other applications), capturing and storing the concentrated CO_2 could deliver a CO_2 emission saving of >60%.
3. Capturing more CO_2, also from the diluted CO_2 stream: This option is more expensive than capturing the CO_2 from the concentrated stream but increases the total capture rate to 85% in SMRs and is also available for sites where almost all ammonia is converted to urea. Alternatively, ATRs can be newly built, producing significantly less CO_2 due to their higher efficiency, of which 91% can be captured.

[98] Based on the current average emissions (1.93 * ±0.95 = ±1,83 t $CO_2/t\ NH_3$, see Annex 1), which converts to ±32.6 GJ natural gas/t NH_3 (conversion factor 0.0561 tCO_2/GJ natural gas). As Dechema indicates a retrofit potential energy use of 30.8 GJ natural gas/t NH_3 (32 GJ overall/t NH_3 - 1.2 GJ electricity/t NH_3), this boils down to 1.8 GJ/t NH_3 less natural gas use, corresponding to 5%. For further perspective: the average GHG emissions of the 10% most efficient installations in 2016/2017 was 12% lower (1.604 $tCO_2/t\ NH_3$), corresponding to 28,6 GJ natural gas / t NH_3, see EC benchmark curves and key parameters, (https://ec.europa.eu/clima/system/files/2021-10/policy_ets_allowances_bm_curve_factsheets_en.pdf). And ATR's can operate at 80% efficiency while SMRs operate at 65% efficiency (refer to Annex 3).

[99] Factoring in that ≈5% of emissions are electricity related (refer to Annex 1).

[100] IEA (2021), Ammonia Technology Roadmap, IEA, Paris https://www.iea.org/reports/ammonia-technology-roadmap, License: CC BY 4.0: In the SMR route, typically more than 60% of the natural gas inputs are used as feedstock, resulting in a concentrated CO_2 stream, which CO_2 only needs to be compressed. A Fertilizer Europe member indicated in an interview that even 70% of the natural gas input results in this concentrated CO_2 stream.

[101] To convert 1 ton of ammonia to urea, around 1.29 ton of CO_2 is required (based on $2\ NH_3 + 1\ CO_2 \rightarrow H_2O + (NH_2)CO$ (https://dechema.de/dechema_media/Downloads/Positionspapiere/Studie+Ammoniak.pdf), using mol masses of 17.03 respectively 44.01).

- To illustrate, for a site where almost all (±77%) ammonia is converted to urea, the target emission reduction can be delivered with fossil-based methane in combination with (SMR) CCS[102].

4. Electricity-based hydrogen can replace SMRs without limitation for sites not producing urea. Sites producing urea still need a source of CO_2 and would likely limit the switch to electricity-based hydrogen:

   - To illustrate, for a site where the full 31% emission reduction would be delivered by switching to electricity-based hydrogen:

     - At least 59% of produced ammonia could be converted to urea just using concentrated CO_2;

     - When the share of captured CO_2 would be increased to 85% (applying carbon capture also to diluted CO_2 streams), even 83% of produced ammonia could be converted to urea[103].

     This calculation is intended to give an example of the CO_2 needs for urea production only. In reality it could be unlikely that the production of one SMR plant would be reduced with 31%; sites with multiple SMR plants have more options.

   - Urea plants (exceeding these ratios) would use biomethane (if available) or electricity-based hydrogen with other bio-sources (if available). If no other bio-sources are available, electricity-based hydrogen can be combined with CO_2 from DAC in archetype 2, but this is expected to be costly in 2030.

5. Some biomethane/biogas will replace natural gas, at locations where it is cheaply available.

For archetype 4 focusing on energy efficiency is obvious and replacing SMRs by ATRs – even without CCS - would reduce the energy consumption already with 19%. Further nuclear electricity might make low CO_2 production of hydrogen possible in this trajectory. However, investments for this archetype come with considerable uncertainty, and Figure 14 thus shows a more limited decrease of the intensity (not meeting the 2030 target). To enhance the transition and to generate more options to meet the 2030 target (and to enable meeting targets for subsequent years), all efforts possible thus need to be undertaken to get access as quickly as possible to external hydrogen (hydrogen pipeline), CO_2 infrastructure (for CCS) and biomethane, biogas or other biomass options – after which they become another archetype. Alternatively, innovative technologies (refer to chapter 4) might offer a solution.

[102] The target emission intensity is 1.93 * ±0.95 * (1-0.31) = ±1.27 $tCO_2/t\ NH_3$. SMR captures 85% and thus still emits 15% * ±1.83 = ±0.28 $tCO_2/t\ NH_3$. Thus, ±0.99 $tCO_2/t\ NH_3$ can be used for urea. As around 1.29 ton of CO_2 is required to convert 1 ton of ammonia to urea (based on $2\ NH_3 + 1\ CO_2 \rightarrow H_2O + (NH_2)CO$, using mol masses of 17.03 respectively 44.01), this means that 1.04/1.29= ±77% of the ammonia can be converted to urea. Note that when assessing the amount of CO_2 available to convert ammonia into urea, any additional natural gas use has – differently than when assessing the cost in chapter 3 and the Annexes – not been taken into account in this report (conservative; assuming presence of residual heat); in the absence of presence of residual heat, more natural gas would be needed, thus more CO_2 would be emitted and captured, and thus more urea could be produced.

[103] Assuming 31% of current SMR capacity is replaced by electricity-based hydrogen, not generating CO_2. Remaining concentrated CO_2 is at least 60% * (1-0.31) * 1.93 * ±0.95 = ±0.76 $tCO_2/t\ NH_3$, enabling conversion of 59% of ammonia to urea. In case further CCS would be applied to the remaining SMR capacity (85% capture rate), the amount of CO_2 available would be 85% * (1-0.31) * 1.93 * ±0.95 = ±1.08 $tCO_2/t\ NH_3$, enabling conversion of 83% of ammonia to urea.

In **2040**, the emission intensity of ammonia production is reduced with **66%**, which implies:

1. Sites converting a large share of ammonia to urea can now no longer rely on just CCS.
    - To illustrate, when the only abatement measure would be to apply 85% CCS to natural gas-based SMR, then only 27% of the ammonia can be converted to urea[104] while staying within the constraints of the 66% emission reduction target.
2. Urea producers will increasingly move to biomethane/biogas, or bio-gasification, and in case these are not available, try to source bio-based CO_2 from other installations. DAC may well still be too expensive but may be used here and there.
    - The biomethane/biogas could also be used in new ATR's or retrofitted 85% SMRs, offering the potential to produce bio-CO_2 or negative emissions.
3. Ammonium nitrate producers rely mainly on renewable electricity-based hydrogen, and potentially to some extent nuclear, electricity, if available. Alternatively, they would use biomethane/biogas or increasingly apply CCS.

In **2050**, the emission intensity of ammonia production is reduced with **100%**, by:

1. Producing ammonium nitrate mainly based on electricity-based hydrogen, produced locally, or supplied from a grid.
2. Producing urea based on biomethane/biogas (or biomass gasification) as source for the CO_2. Biomethane / biogas (and biomass for gasification) are expected to be widely available by this time, and alternatively CO_2 from other plants (CO_2 from biological origin) or Direct Air Capture (in case its cost would reduce sufficiently) can be used in combination with electricity-based hydrogen.
3. Continuing to operate some investments in CCS, partially in combination with biomethane/biogas.

In 2050 all infrastructure (CO_2 and hydrogen) is expected to be available to all (remaining) plants/archetypes.

[104] The target emission intensity is 1.93 * 0.95 * (1-0.66) = 0.62 tCO_2/t NH_3. SMR captures 85% and thus still emits 15%*1.93 * 0.95= 0.28 tCO_2/t NH_3. Thus, 0.35 tCO_2/t NH_3 can be used for urea. As around 1.29 ton of CO_2 is required to convert 1 ton of ammonia to urea (based on 2 NH_3 + 1 CO_2 --> H_2O + $(NH_2)CO$, using mol masses of 17 respectively 44), this means that 0.35/1.29= 27% of the ammonia can be converted to urea.

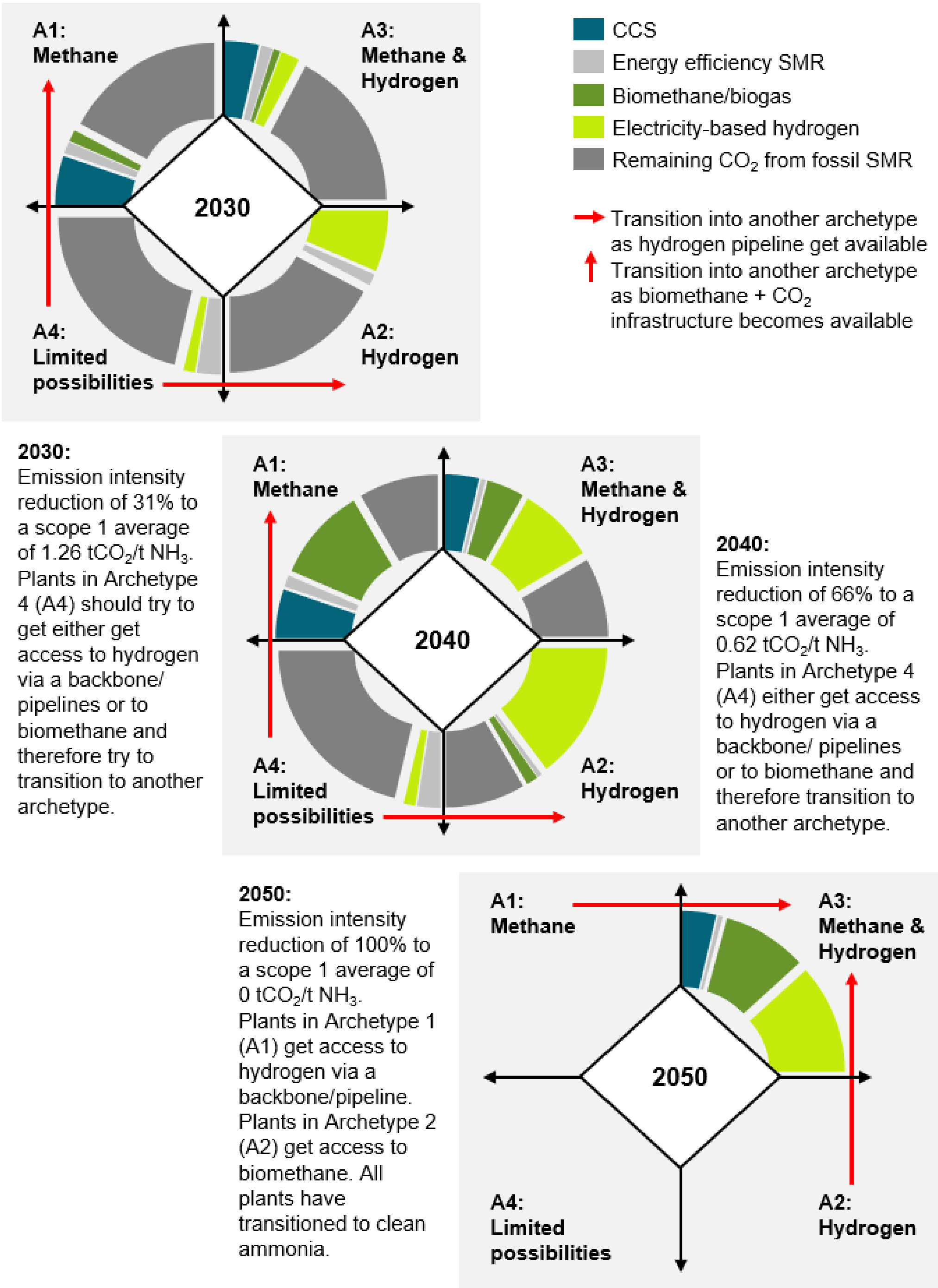

Figure 14: Transition pathways for trajectory 1

Note that this is a stylised representation from which no absolute numbers can be deduced. The relative share of abatement options depends heavily on the prices of the various energy carriers[105]*.*

[105] For example on the ratio between prices for the "natural gas + CO_2 cost *or* CCS" and the price of electricity (Archetype 3), the ratio between prices for biomethane and "natural gas + CO_2 cost *or* CCS" (Archetypes 1 and 3). For electricity cost, the levelized cost of generation have been considered producing this figure.

Trajectory 2: Increasing the share of electricity-based hydrogen:

This trajectory just focuses on increasing the share of electricity-based hydrogen. Energy efficiency improvements and applying CCS can be cost-effective measures to take, but they compete with using RFNBO-based hydrogen, and are not considered in this - stylised - description.

- Current SMR capacity is replaced over the years by either self-produced electricity-based hydrogen, or by renewable hydrogen from a pipeline.
- This option is feasible for plants in archetypes 2 and 3. Plants in archetypes 1 and 4 will need to find access to renewable electricity or a hydrogen pipeline as soon as possible.
- Urea producers will need to find plants producing CO_2 to use as feedstock:
  - Towards 2040 this will increasingly need to be bio-CO_2. Towards 2050 DAC might become cost-effective.
- The share of electricity-based hydrogen is 50% in 2030, 75% in 2040 and 100% in 2050.

This trajectory would require in total 86 TWh of electricity 2030, 122 TWh in 2040 and 159 TWh in 2050 (Annex 8) and would require investments of 63-88 billion EUR depending on the chosen electricity generation technology[106].

Making the transition:

Electricity-based hydrogen will play a key role in the sector's transition, from 2030, but even more so afterwards in view of its projected cost reduction. Access to hydrogen, or (renewable) electricity is thus key and it thus needs to be assured that the ammonia plants are connected with a hydrogen backbone as soon as possible, so that all plants are either in archetype 2 or in archetype 3. In the beginning these pipelines are connecting production to consumption sites, in a later phase these pipelines can connect to form a transnational and European pipeline system, with underground hydrogen storages connected. Some ammonia producers might generate the electricity-based hydrogen ourselves, others might procure it from other producers.

On the short term, up to around 2030, there could be investments in CCS, which requires CO_2 transport (pipeline or shipping) infrastructure and storage projects. Later, the logic of storing CO_2 decreases with the demand for CO_2 as feedstock for urea production, and in view of the continued decrease of cost of electricity-based hydrogen.

Both options however do not enable production of clean urea. For this, a biomass-based route is needed, either in the sector's ammonia plants, or in plants nearby delivering bio-CO_2. The sector thus needs to quickly scale up its efforts to increase the availability of sustainable biomass sources, like biomethane, biogas and others - for use in other technologies. If the processibility of biogas in SMR's would be increased, then considerably less biomethane would be able to provide sufficient CO_2 feedstock for urea production. Production of urea appears to be better enabled in trajectory 1 than in trajectory 2.

[106] Refer to chapter 4.1 (CAPEX only): 63 billion EUR includes 26 billion EUR for PV electricity generation, 3 billion EUR for hydrogen pipelines and 34 billion EUR for the electrolysers. 88 billion EUR includes 77 billion EUR for nuclear electricity generation, 3 billion EUR for hydrogen pipelines and 8 billion EUR for the electrolysers. Values for onshore/offshore wind can be derived similarly and fall in this range.

7. The interplay with ammonia as energy carrier

This chapter explores the growth in the production of ammonia due to new applications of ammonia as energy carriers, and how the sector can contribute to stability in the electricity grid when producing ammonia (with electrolysis).

7.1 Use of ammonia as energy carrier

Today, ammonia is largely used to produce fertilizers, and other chemicals. However, the IEA's Ammonia Roadmap (2021)[107] projects the majority of ammonia to be used as energy carrier in a decarbonising energy system in 2050[108], generating a significant additional demand for ammonia.

Ammonia can be used as energy carrier for:

- ***Power and heat generation***, replacing coal and natural gas in both baseload applications and peaker plants to provide stability in the grid with a high penetration of intermittent solar and wind power. This can reduce greenhouse gas emissions. This application is being scaled up for increasing ammonia concentrations, with formation of NO_x and stable operation being relevant attention points.

- ***High temperature heat in industrial processes***, as for example the German company Aurubis is currently exploring the use of ammonia for the production of copper in the anode furnace displacing natural gas.[109]

- ***Shipping fuel***: Ammonia, next to renewable methanol, is proposed to replace heavy fuel oil and LNG as a marine fuel for international shipping. With around 95% of all freight transport taking place at sea, consuming around 10% of the total transport energy worldwide and accounting for 2.6% of GHG emissions, recent outlooks estimate a demand for ammonia as a marine fuel ranging from 100 Mt to more than 1,000 Mt of ammonia by 2050.

- ***As transport vector for hydrogen:*** The emergence of the hydrogen economy has sparked a debate on how hydrogen can best be transported across large distance. While pipelines seem the most cost-efficient option to transport hydrogen, shipping can be an option where pipeline routes are not possible and for hydrogen derivatives such as ammonia. As chapter 8 elaborates, ammonia can be an effective medium to ship hydrogen. Furthermore, there may be situations where storage of ammonia is cheaper and easier than storage of hydrogen. When hydrogen is the desired final energy carrier, the ammonia needs to be split into nitrogen and hydrogen, which can be done via catalytic cracking or via plasma decomposition - requiring at least 13% of the energy contained in the ammonia. Ammonia crackers are being scaled up.

As a consequence of these developments, the European production of ammonia may well increase, and the European fertilizer sector may transform into producers of ammonia for all these markets.

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[107] IEA (2021), Ammonia Technology Roadmap, IEA, Paris https://www.iea.org/reports/ammonia-technology-roadmap, License: CC BY 4.0

[108] NZE scenario

[109] https://www.wiwo.de/unternehmen/industrie/kupferproduzent-aurubis-die-voellige-umstellung-auf-wasserstoff-ist-mittelfristig-moeglich/28238848.html

7.2 Flexible production of ammonia

When operating electrolysers in direct connection to the generation of renewable electricity, or when the sector would contribute to grid stability, it would need to operate flexibly. The sector's potential to do so is visualised in Figure 15.

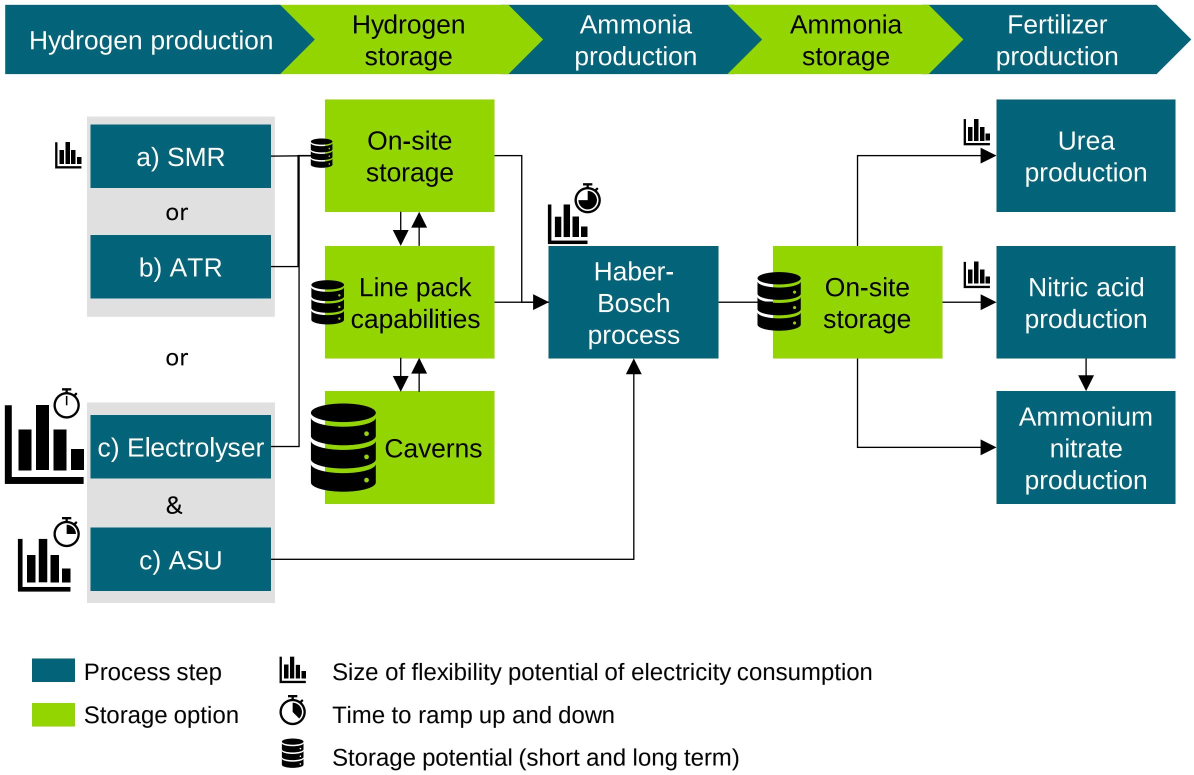

Figure 15: Visualisation of the potential to flex in the sector's production processes[110]

Hydrogen can be stored by using line pack capabilities[111], or - for larger volumes and extended periods - in natural reservoirs[112] (when available and connected with pipelines), or - much more expensive - in special tanks. Storage of hydrogen in natural reservoirs already exists today, e.g., in Texas (US) or Teesside (UK).[113] Storage of ammonia in tanks is generally cheaper, as ammonia can be liquified at relatively mild temperatures (-33°C versus -253°C for hydrogen) and can thus be stored at relatively limited cooling cost.

While SMRs can – to some extent – be operated flexibly[114], their electricity consumption is relatively limited (in relation to its gas consumption), so the impact would be relatively limited.

In case the sector would operate the electrolysers with a 1:1 connection with the generation of renewable electricity, or in case the sector would contribute to grid stability, the electrolysers will clearly need to operate flexibly - which they can. Buffer capacity can be either provided with hydrogen, or with ammonia as the Haber-Bosch process can also be

[110] Based on interviews with Fertilizer Europe members, and on Air Liquide, Air separation Unit: Flexibility & Energy Storage, https://ieaghg.org/docs/General_Docs/OCC2/Abstracts/Abstract%20OCC2%20ASU%20Air%20Liquide.pdf.
[111] Storing gas in a pipeline by compressing it (increasing the pressure)
[112] Like salt caverns, depleted gas fields, aquifers and hard rock caverns
[113] https://energnet.eu/wp-content/uploads/2021/02/3-Hevin-Underground-Storage-H2-in-Salt.pdf
[114] To which extent ATR's can be operated flexibly has not been explored.

operated flexibly to quite some extent - as well as the ASU needed in case electrolysers are used.

As ammonia can be stored relatively easily and cheaply, the sector doesn't see a need to flex the production of urea and nitric acid, and its subsequent processes.

8. Ammonia imports and the value of domestic fertilizer production

Ammonia and/or hydrogen can be produced in Europe but can alternatively be imported from outside Europe. However, there are multiple benefits in having a domestic fertilizer, including ammonia, production. This chapter:

1. Explores the best way to transport hydrogen for ammonia production
2. Compares the cost of imported ammonia with the cost of ammonia produced in Europe
3. Discusses the value of domestic fertilizer, including ammonia, production

8.1 Transporting hydrogen from outside Europe for ammonia production

The two visuals below show the energy use and the cost of shipping hydrogen (either liquified or on an organic hydrogen carrier), or ammonia:

- When hydrogen is liquified, it needs to be deep-cooled (requiring much energy[115]) prior to shipping, and re-gasified after arrival.
- When hydrogen is transported on a liquid organic hydrogen carrier (e.g., benzyl toluene), it first needs to absorb on this carrier[116], and then needs to be desorbed after arrival - while the absorption process generates heat, the latter step requires substantial energy input.
- When ammonia is shipped for the purpose of using it as ammonia, there is no need for conversion and reconversion for the sake of transporting the ammonia; the ammonia needs to be produced anyhow, and no reconversion is needed.[117]

[115] Part of this energy can be regained on arrival in case there is an application requiring cooling.

[116] Part of this energy can be regained in the form of heat in case there is an application requiring heating.

[117] This would be different in case the ammonia would be shipped for reconversion to hydrogen, in which case the conversion of hydrogen to ammonia and the reconversion back to hydrogen would need to be considered in the comparison. If the ammonia imported at a terminal is re-converted to hydrogen before further use, it needs to be cracked at 600 to 800°C first. First largescale ammonia crackers are expected in Rotterdam by 2026 (1 Mt H_2/a (33.33 TWh/a)) and in Wilhelmshaven by 2028.

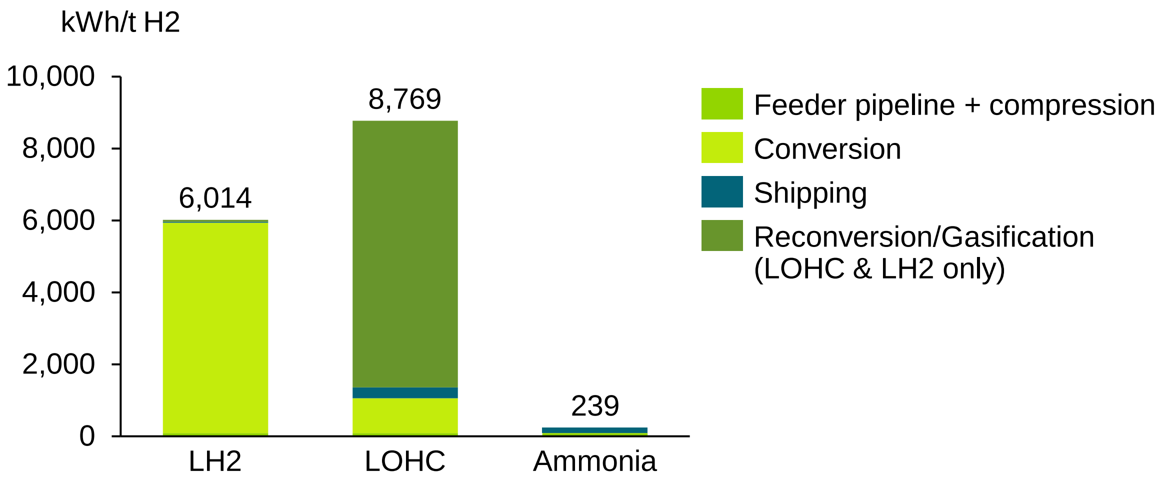

Figure 16: Overall energy consumption of shipping for various transport modalities of hydrogen: Liquified (LH_2), on an organic hydrogen carrier (LOHC) and as ammonia (for use as ammonia)[118]

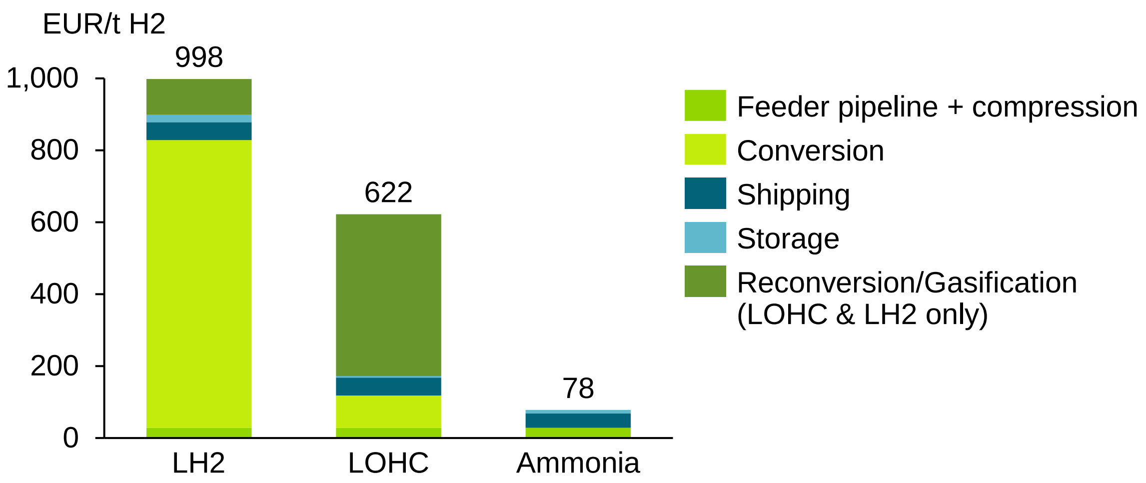

Figure 17: Overall cost of shipping for various transport modalities of hydrogen: Liquified (LH_2), on an organic hydrogen carrier (LOHC) and as ammonia (for use as ammonia)[119]

The figures clearly show that when hydrogen is imported to Europe by ship for application as ammonia, shipping it in the form of ammonia is by far the most efficient shipping option.

Alternatively, hydrogen can be transported by pipeline as well. Where feasible, pipelines are the most economical way to transport large volumes of hydrogen, as this eliminates the need for conversion and reconversion of hydrogen required for shipping. Two existing pipelines from Africa could be repurposed[120] for hydrogen imports - as envisioned by the REPowerEU

[118] The above comparison serves as a stylized example. The actual vessel types, sizes and tanker designs, and the actual form of the LOHC can lead to different numbers. Figure is based on transport from Saudi Arabia to Sicily (feeder pipeline 300 km, shipping distance 2,300 km).

[119] The above comparison serves as a stylized example. The actual vessel types, sizes and tanker designs, and the actual form of the LOHC can lead to different numbers. Figure is based on transport from Saudi Arabia to Sicily (feeder pipeline 300 km, shipping distance 2,300 km). HFO is assumed as shipping fuel. Cost of energy carriers significantly impact these numbers.

[120] The cost of repurposed pipelines can be as low as one-third the cost of new pipelines.

plan[121] as well as the European Hydrogen Backbone[122] for 2030/2035 - and new pipelines could be built. As it is to be expected that the hydrogen import pipeline transport capacity will be scarce in the decades to come, and as no (re)conversion is needed when shipping ammonia for application as ammonia, shipping ammonia is the logical import modality for ammonia imports - given the necessary import infrastructure exists. However, when shipping ammonia, safety should be considered.

However, ammonia has been traded by road, train, ship and pipeline for many decades. Storage, transport, and distribution technologies, as well as training, industry codes and standards, and safety regulations are well-established. In total, around 25 to 30 Mt of ammonia are transported annually around the globe, of which around 18 to 20 Mt are transported by ship. Around 170 ships are in operation that can carry ammonia, of which 40 carry ammonia on a continuous basis[123]. Further additional ammonia import capacity could come from the LNG terminals multiple EU countries (for example Germany) are building now as a result of the Russian invasion of Ukraine. These newly constructed LNG terminals can at a later stage - at cost[124] - be converted to ammonia terminals and are thus in practice “ammonia-ready”.

8.2 Cost of imported ammonia

The figure below compares expected cost of imported ammonia from UAE and Australia with the European production options assessed in chapter 3[125]. For Europe, the range of the best

[121] European Commission: REPowerEU Plan (2022) – https://eur-lex.europa.eu/resource.html?uri=cellar:fc930f14-d7ae-11ec-a95f-01aa75ed71a1.0001.02/DOC_1&format=PDF

[122] European Hydrogen Backbone (2022) https://ehb.eu/files/downloads/EHB-Supply-corridor-presentation-Full-version.pdf

[123] https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2022/May/IRENA_Innovation_Outlook_Ammonia_2022.pdf

[124] These modification costs are estimated to constitute up to 20% of the LNG import facility CAPEX. https://guidehouse.com/insights/energy/2022/imports-germanys-hydrogen-demand?lang=en

[125] For all cases on the basis of existing Haber Bosch plants – ignoring the need to adjust these towards the needs of processing electricity based hydrogen. New ammonia plants imply a new Haber Bosch plant is also needed.

case to less favourable production options is shown. The first graph shows the situation in 2030, and the second by 2040.[126]

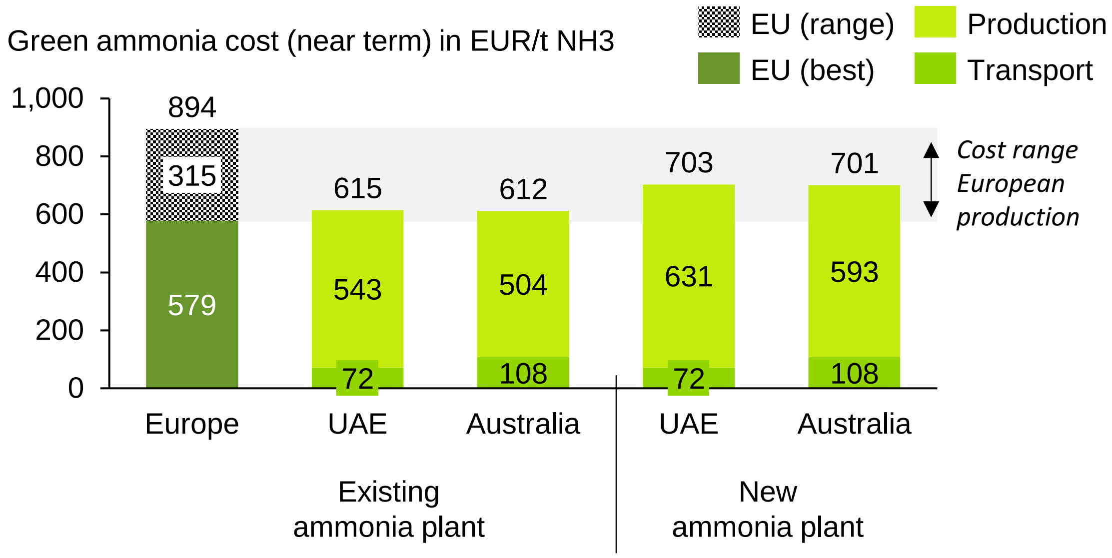

Figure 18: Comparison of expected cost of European ammonia production from RFNBO with imported ammonia from UAE and Australia for 2030

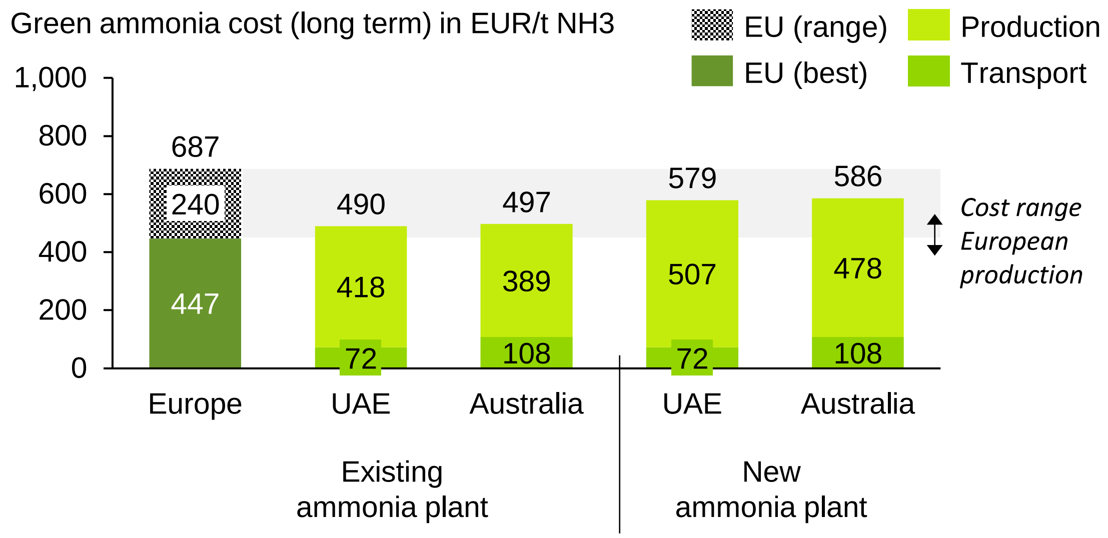

Figure 19: Comparison of expected cost of European ammonia production from RFNBO with imported ammonia from UAE and Australia for 2040

[126] The visuals are based on equal CAPEX, efficiency, OPEX and annualization factors, and different levelized cost of electricity, full load hours and depend significantly on assumed cost for energy carriers. Electricity cost for imports is shown in Annex 2, and full load hours are shown in Annex 3. Transport costs are only added for imported ammonia. The electricity consumption for the Haber Bosch is assumed to be the same. Differently than in chapter 3 it has been assumed all electricity to be supplied through 1:1 connection (no grid fees and no grid prices, just levelized cost), for European production as well as for imports. Transport cost are included for hydrogen transport to ammonia plants in Europe via pipeline (corresponding to around 15 EUR/t NH_3), as well as ammonia transport from port to locations processing ammonia in central Europe by train (around 50 EUR/t NH_3) (both 500 km). In case the ammonia plant would be located in the harbour receiving imported ammonia or hydrogen based on offshore wind, these transport cost would not apply and the business case for imported ammonia would slightly improve.

8.3 The value of domestic fertilizer production

This paragraph summarizes the arguments heard during discussions with Fertilizer Europe and its members during the preparation of this roadmap:

The EU needs a strong fertilizer industry to continue producing food and in the long-run help develop the European hydrogen economy by using clean ammonia supplied by us, because:

- Europe is largely self-sufficient for many agricultural products[127]. Fertilizers contributing to food security in Europe and beyond.[128]
- The Russian invasion into the Ukraine and fertilizer export bans in third countries has shown that dependence on material imports from external actors can pose a substantial risk.
- The European fertilizer industry produces about 40% of the total of European hydrogen as raw material of ammonia production.[129] It is therefore also uniquely placed to contribute to the objectives of the EU Green Deal and the development of a hydrogen economy in Europe.
- The sector is well-positioned to tailor (local) production to the (new) needs of farmers, cooperating over the local value chains.

European Commission initiatives such as REPowerEU are a crucial reminder that action needs to be taken to safeguard European autonomy. Less dependence on external actors will contribute to stable local fertilizer production, securing existing and creating new jobs, and long-term food security.

8.4 Conclusion

The expansion of the European ammonia import infrastructure could - over time - lead to an increasing share of ammonia being imported into Europe, although the cost difference could well decrease over time. However, the current gas crisis is a significant reminder that relying on material imports could pose a substantial risk. Local fertilizer production can contribute to guarantee long-term food security.

The next chapter will elaborate on the transition of the industry and discuss implications regarding timing and investment needs.

[127] https://ec.europa.eu/commission/presscorner/detail/en/ip_22_1963, also stating that while the EU is a net food exporter, EU's agricultural sector is a net importer of specific products, for example feed protein.

[128] https://www.fertilizerseurope.com/gas-prices-2/

[129] AFRY MANAGEMENT CONSULTING, Hydrogen Development in Europe and Middle East, 2021.

9. The sector's transition

This chapter present:

- The sector's transition in a bigger perspective
- The challenges to be overcome
- For the transition to eliminate greenhouse gases in the production of ammonia:
    - The timing
    - Making investments happen

This chapter describes actions the sector should take, as well as actions others could take and how policy makers can help. A summary of policy recommendations can be found in Annex 12.

9.1 The overall transition

The sector's transition is bigger than "just" eliminating the GHG emissions from its ammonia plants. As indicated in chapter 5, there also is a need to develop new farming strategies with a different fertilizer strategy - focusing further on delivering functionality and considering the role manure and other waste streams can play more integrally.

The sector should - together with its clients (the farmers) - make a plan to significantly reduce the fertilizers' scope 3 emissions from the field, embedded in such a new farming strategy optimising products' functionality.

Meanwhile, most of the sector's plants have been built around 50 years ago, and afterwards quite a lot of further investments have been made in them. Nevertheless, significant maintenance will be needed in the not too far away future[130]. Each company not having an integral transition plan should soonest develop and publish one. *Companies should be eager to deliver on the full transition in Europe thus contributing to food security, generating jobs and facilitating the hydrogen economy across Europe.*

The sector should never take its position for granted and needs to work on and communicate about the broader overall transition. However, the remainder of this chapter focuses on the transition to eliminate the greenhouse gas emissions from the sector's ammonia plants.

9.2 Challenges to be overcome

To be successful in this transition, key challenges will need to be overcome:

1. The need for profitable business cases for the investments required.
2. The need to scale up the technologies and to learn how to operate these new technologies (at scale), so that their cost decrease.
3. The lead times for investments, in combination with the current uncertainty about the (future) business case.
4. Dealing with the intermittency of generation of renewable energy.

[130] Based on interviews with a member.

Overcoming the first two challenges will be discussed in section 9.4. Section 9.3 sets the stage discussing the lead times of investments, while the fourth challenge has been discussed in section 7.2.

9.3 Timing for the transition to eliminate scope 1 and 2 emissions

The investment projects will require new energy carriers (like renewable electricity), new infrastructure (like a strengthened electricity grid, and hydrogen, CO_2 and biogas pipelines), and new and/or adjusted plants (like electrolysers and modifying the existing Haber-Bosch process). All of these need to be finished before operation of new plants can start. Companies want to be reasonably sure that all of these will be in place when the new plant is ready to be operated already when taking the investment decision. Uncertainties in policy design, timely availability of new energy carriers and/or new infrastructure adds to the uncertainty in investment decisions and delays taking these.

Figure 20: Stylised exemplary project timeline with certainty requirements for final investment decision (start of operation in 2028)Figure 20 shows typical lead times for ammonia plants, the associated infrastructure, and for policy implementation. It also indicates how the moment of the final investment decisions depend on these elements. To make the final investment decision, companies need to be reasonably certain that when the investment (plant or modification) is ready for use:

- There is sufficient of the energy carrier available (generated, and transported to the plant)
- There is a fair amount of certainty that the business case is positive, which includes clarity on policies, and clarity on potential support.

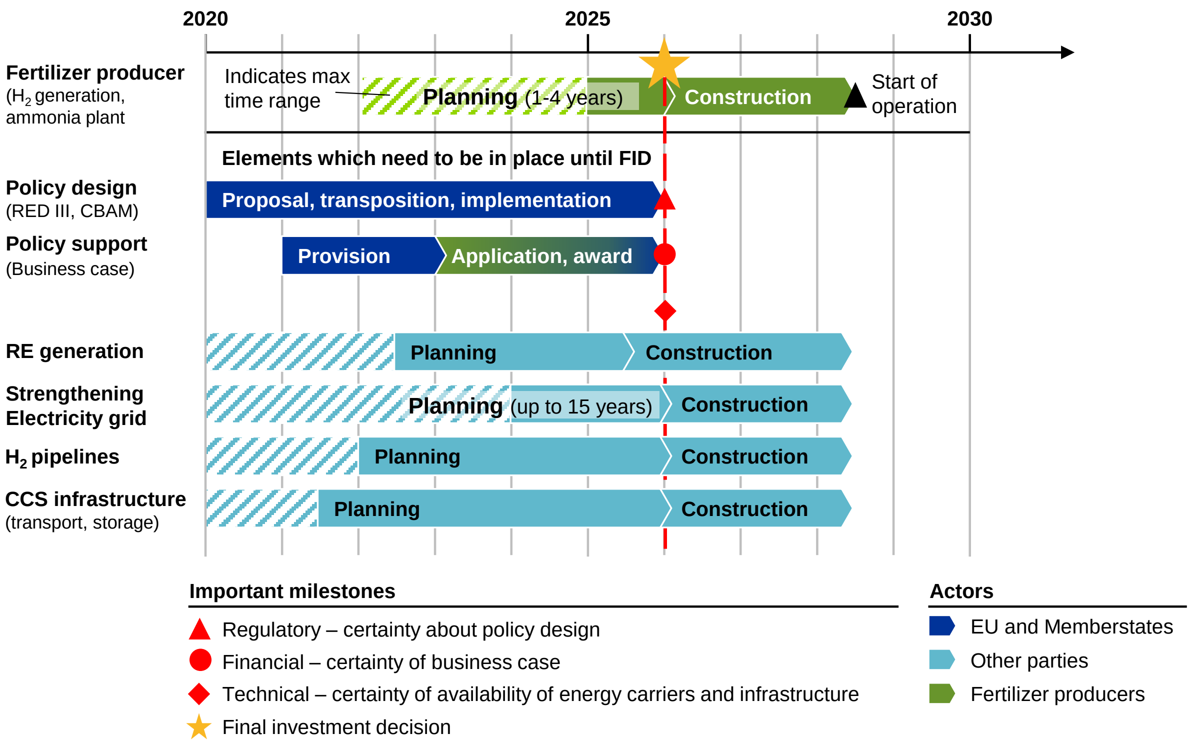

Figure 20: Stylised exemplary project timeline with certainty requirements for final investment decision (start of operation in 2028)

As all these processes have long lead times, it is imperative to plan ahead and start in time. Figure 21 shows how this process plays out between for projects with the Final Investment Decision taken in several years before 2030.

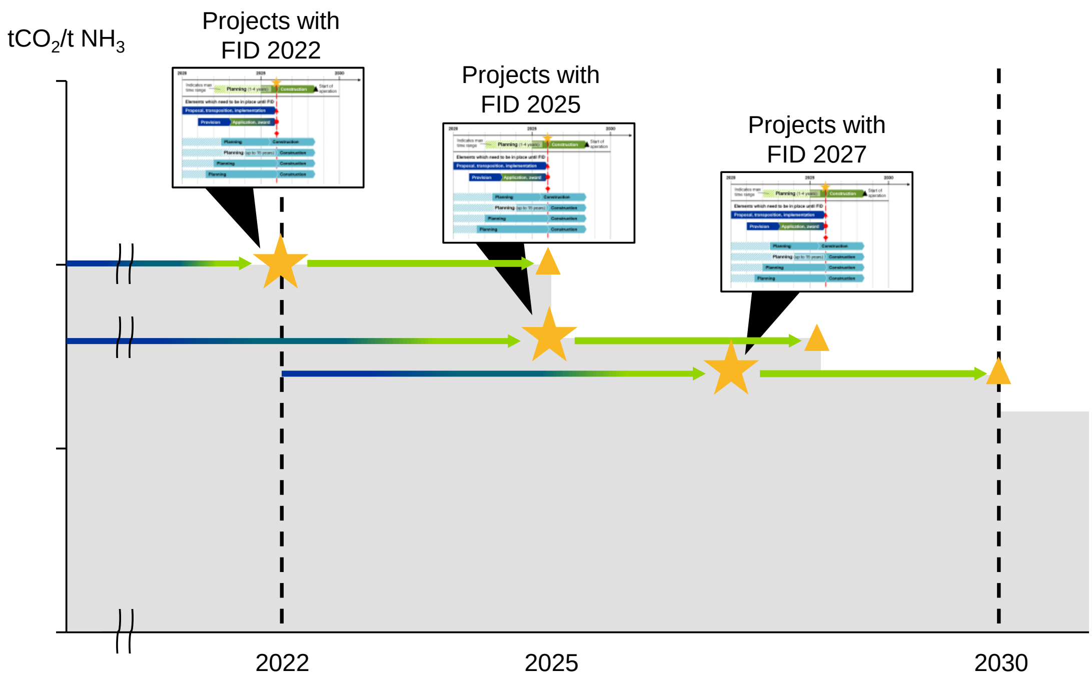

Figure 21: **Exemplary Emission reduction via different projects until 2030**[131]

[131] A similar line of reasoning applies towards 2040 and 2050.

The figure shows that:

- Some companies already have developed advanced projects. If these have taken the investment decisions in 2022, these could get on stream in 2025. This would require reasonable clarity on future policies, and reasonable certainty on the availability of energy carriers.
- Final Investment Decisions taken on 1st of July 2027 can deliver new plants operating as of 1st of January 2030 - the last moment to deliver on 2030 targets.

This leads to the conclusion that the next years are crucial for the delivery of emission reduction until and by 2030. The earlier plans are made, the shorter lead times are, and the earlier, together with the stakeholders involved (see Annex 11), sufficient clarity can be accomplished, the more emission reduction the sector will be able to deliver. The next years will be crucial.

It will be key to reduce lead times *and* ***the sector will need to do its best to reduce lead times*** and ask other stakeholders to do the same. This is addressed in the remainder of this paragraph.

Accelerate the processes for public funding and the permitting process:

Chapter 9.3 elaborates on the need of support for investments. While there should be fair and proper processes to award public funding, these processes - and associated uncertainty - also take lead time: Some calls are only open at distinct moments and deciding on who to award support takes time. The pursuit of public funding can take up to 3 years (in parallel)[132].

Furthermore, while permitting processes serve an important purpose, these processes take time for investments in plants, but also for additional generation of renewable electricity, and for additional infrastructure, thus adding to the lead time and uncertainty for the sector's investment decisions.

The sector should cooperate with the European Commission and with Member States to accelerate the processes for public funding and the permitting process - while maintaining their quality.

The sector should also track the debate on Carbon Capture & Use, to ensure it is up-to-speed with the requirements when using fossil-based CO_2 from other plants in combination with electricity-based hydrogen to produce urea.

Ensure timely delivery of required engineering from licensors:

The sector is facing significant investments, in plants that are customised towards the local situation, and adjusted and optimised over their often long lifetime. Adjusting these plants to new clean plants will thus require engineering from licensors. When the licensors would not have the capacity to timely deliver the engineering, this could delay investments. The same applies to the availability of sufficient technical people to build or adjust (new) plants.

[132] Based on an interview with one of the sector's members.

Fertilizer Europe should give more background and details to licensors about the timing and planning of the sector's transition.

Accelerate the development of future-proof and adequate infrastructure:

Timely presence of infrastructure and renewable energy sources is essential for the investment decisions, for which significant investments are needed. These investments cannot be made by the fertilizer producer but should be made by infrastructure companies with support from Member States and the EU.

Policy makers could help by implementing the right frameworks to accelerate the development of future-proof and adequate infrastructure. While the European Commission has published multiple relevant proposals recently to facilitate infrastructure deployment (e.g., renewable gas package, REPowerEU, delegated acts on renewable hydrogen, REDIII) and while progress is being made, quick implementation is key, so that fertilizer producers can take their investment decisions with certainty about availability of infrastructure.

Compile plant-specific masterplans for the transition:

Each ammonia / fertilizer plant in the EU needs to soonest have a masterplan outlining how it will eliminate the GHG emissions from ammonia production and what would need to be in place by when. These plans can serve as a basis to discuss the (timing of) required infrastructure, renewable energy carriers, clarity on policies and support with the European Commission, the relevant policymakers in the Member States, and with the relevant infrastructure stakeholders and energy generators, including potential suppliers of climate-neutral CO_2. These masterplans need to be discussed with key stakeholders soonest.

Ensure sufficient biogas and biomethane are available:

The fertilizer industry can provide demand for biogas and/or biomethane, enabling increasing its (large scale) production.

9.4 Making investments happen

Chapter 3 shows that ammonia production cost using most of the new technologies generating less or no greenhouse gas emissions are for the typical range of prices of energy carriers higher than producing ammonia based on hydrogen from fossil-based existing SMR, also when current carbon cost are included.

But the costs for new technologies are expected to decrease sharply over time while their efficiency increases, making them cheaper than the current production process; for example, CAPEX and the efficiency of renewable electricity generation and electrolysers are expected to decrease sharply (64% until 2050 for the average levelised cost to generate offshore wind, and even 77% for the investment in electrolysers[133]).

As a society, postponing investing in clean technologies to wait for the cost decreases would be ineffective, as cost reductions are the result of projected implementation and the associated learnings. In other words, if all would wait, the cost of the low greenhouse gas technologies will not decrease that fast, emission of greenhouse gases would continue too long.

As the sector also needs time for its own transition, it should do all it can to invest soonest. To enable the sector to do so as quickly as possible in a competitive world, a supportive policy framework can help; it would:

1. Ensure that there will be a policy level playing field for carbon cost between producing fertilizer in Europe vs import from outside Europe, in order not to add to the impact of any differences for energy prices between the EU and for example the US and the Middle East (for example for natural gas)
2. Stimulate the demand for clean ammonia
3. Timely use policy levers to drive investment, closing any remaining gap in the production cost of new technologies versus fossil hydrogen

Creating a policy level playing field:

Carbon Border Adjustment Mechanism (CBAM)

Currently, the sector pays for the CO_2 their plants emit in the EU's Emission Trading Scheme through CO_2 allowances. To avoid distortion of competition with areas outside the EU ("carbon leakage"), the sector receives free allocation of CO_2 allowances. As part of the Fit For 55 package, the European Commission has proposed in July 2021 to replace the system of free allocation of allowances by a CBAM for - amongst others – fertilizers and ammonia. A CBAM imposes carbon cost equal to these in EU ETS on imports from countries with significantly lower carbon cost than Europe. Thus, a CBAM creates a level playing field on carbon cost for the production of ammonia based on fossil SMR.[134] The effectiveness of the CBAM in practice depends on the design details. The provisional agreement on the CBAM does not cover exports, which may open-up an export-related carbon leakage channel.

Timely completion of the development and implementation of CBAM are relevant for the sector.

Stimulate the demand for clean fertilizer and ammonia:

The market for clean fertilizer and ammonia can be accelerated and turned into a scalable mass market with comprehensive and integrated actions to stimulate their demand.

In the first place, labelling of clean fertilizer and ammonia can help consumers and institutional purchasers to quickly and easily identify those products that meet specific environmental performance criteria and are therefore deemed "environmentally preferable". The sustainability criteria should ideally be co-developed by the sector and policy makers

[133] Refer to Annex 2 for the underlying numbers.

[134] A CBAM thus doesn't create a level playing field between imports of ammonia based on natural gas based SMR vs European production meeting a 50% electricity-based hydrogen target – as in trajectory 2. This is addressed further on.

(e.g., the European Commission) with input from civil society (e.g., NGOs). Such labelling provides clarity to customers and stimulates market entry for clean fertilizer and ammonia.

Secondly, a mandatory quota for the consumption of clean fertilizer and ammonia could be envisioned. The provisional agreement on the RED III mandates that by 2030, 42% of all hydrogen used in the European industry should be RFNBO. This would increase the production cost for European production of fertilizers (see chapter 3), without applying to imported ammonia and fertilizers. CBAM would not fix the resulting price difference between European production and imports (see above). In contrast, a consumption quota for fertilizer and ammonia would apply to domestically produced and imported products and can have various forms. To allow for innovation and competition amongst the different clean technologies presented in chapter 3, setting a maximum average greenhouse gas emissions associated with the production of ammonia - in line with the European Commission's Renewable Energy Directive requirements for fuels would be most appropriate.

The above needs to be done in parallel with supply-side policies (see next section). The coordination of 'demand pull' and 'supply push' policies at both EU and national levels is essential.

The sector is already working on a voluntary label/certification system for clean fertilizer and ammonia and looks forward to cooperating on the detailed design of such schemes with the European Commission. It could start campaigns promoting European production of green food and the use of clean fertilizer and ammonia and reach out to financial institutes to stimulate them to consider optimal use of fertilizers (right fertilizer ant right time, pace and crop) and use of climate friendly produced fertilizers when financing farmers.

The sector should also contribute to biomethane certification schemes, so that the origin of the biomethane used can be verified.

In the pursuit of clean fertilizer, the sector will need to increasingly map the upstream scope 3 emissions for its natural gas consumption, stimulating its suppliers to detect leaks via satellites and with early failure detection and monitoring, and to then terminate leaks.[135] Meanwhile, it should aim at sourcing it from suppliers with low upstream GHG emissions.

Timely use policy levers to drive investment, closing any remaining gap in the production cost of new technologies versus fossil hydrogen:

There are several ways the remaining gap in the production cost of clean fertilizer can be closed by reducing their production cost:

- Capturing opportunities from the broader energy transition
- Contracts for Difference
- Investment support
- Ensuring EU ETS stimulates electrification

[135] IEA (2021), Ammonia Technology Roadmap, IEA, Paris https://www.iea.org/reports/ammonia-technology-roadmap, License: CC BY 4.0: 75% of oil and gas methane emissions can be abated with existing technologies, often at relatively low cost – with an estimated 50% without net cost because the value of the captured methane is sufficient to cover the costs of the abatement measure.

Capturing opportunities from the broader energy transition:

The energy transition offers the sector broader opportunities:

- *The sector should contribute to the stability of the electricity network by flexing its production[136] (refer to chapter 7.2)*
- *The sector could integrate its ammonia production for fertilizers with the ammonia production for application as energy carrier (see chapter 7.1)*

These actions could already contribute somewhat to the business case of investments, somewhat reducing the need to de-risk these.

Carbon Contract for Difference (CCfD):

In a CCfD governments would pay companies investing the difference between the market price for CO_2 emission allowances in the EU ETS and the price that enables investing in a clean production technology, for a certain period. This mechanism de-risks clean investments and covers an important gap in the funding landscape, as many new technologies fail in the phase between research and funding and large-scale commercial application (also known as the Valley of Death). This instrument can help with large-scale commercialisation and bring promising technologies to market, such as the rapid implementation of electricity-based hydrogen.

In its RePowerEU plan, the European Commission proposed a roll-out of CCfD to support a full switch of the existing hydrogen production in industrial processes from natural gas to renewables.

Quick clarity on the design, the availability of sufficient funding, and implementation timeline is relevant for the sector.

How much funding would be needed?
The difference in production cost between natural gas SMR based ammonia and electricity-based ammonia depends strongly on the cost of energy carriers. To give a first rough indication, for trajectory 2, assuming 50% electricity-based ammonia in 2030, the annual difference in production cost would be 1.2 billion Euro[137]. Stimulating demand for clean fertilizer could stimulate electricity-based ammonia production similarly.

Investment support

Substantial investments (CAPEX) in new technologies are needed, e.g., for electricity-based hydrogen production or carbon capture. As an alternative to a CCfD, additional funds directly

136 Note that current thinking assumes that the by far largest share of the sector's electricity consumption would come from a 1:1 connection with the generation.

137 Based on 7.5 Mt of ammonia production, no changes at all in the other 50%, ignoring investments in the Haber Bosch plants (other than in the ASU), ignoring subsidies for the generation of renewable electricity or any other policy support, using a natural gas price of 37 EUR/MWh (including network cost and taxes and levies) and an LCOE of renewable electricity of 39 EUR/MWh (based on average offshore; refer to Annex 2) and including the full impact of a CO_2 price of 100 EUR/tCO_2. Numbers are based on average literature values and should only be seen as a first impression. The design, and the amount of funding needed, should be based on more detailed and plant-specific data. Even then, the strong dependence on the future cost of energy carriers should be kept in mind.

supporting (e.g., through grants or subsidies) investments in clean technologies can be set up. Today, on a European level, only the Innovation Fund provides such support to industry, but its success rate is relatively low (12% in the second call for large-scale projects)[138] and only first deployment of a technology is supported. In addition, Member States can also provide investment support.

Policymakers are encouraged to explore and establish ways to facilitate investments aiming at decarbonising ammonia production, e.g. dedicated funds providing grants or low interest loans, within state aid limitations.

An example of support outside Europe:[139]
Countries around the globe are ramping up their efforts to meet the targets under the Paris Agreement. The Russian invasion of the Ukraine has further strengthened this trend. In August 2022, the US implement the Inflation Reduction Act which earmarked USD 369 billion for investments in energy security and climate change provisions, including new and critical ones for hydrogen and fuel cells. The creation of the new Clean Hydrogen Production Tax Credit (H2PTC) is the centrepiece of the hydrogen provisions, providing USD 13 billion in value across the industry for the next 10 years. The H2PTC is a new ten-year tax credit that provides up to 3.00 USD/kg of hydrogen produced at a given facility, based on the carbon intensity of production, or offers a similarly scaled investment tax credit (ITC) up to 30% for new facilities. The US could also become a major exporter of (subsidised) hydrogen (likely in the form of ammonia), which would compete with ammonia produced in Europe.

Stimulating electrification in EU ETS:

Under the current EU ETS rules an electricity exchangeability correction factor is applied when establishing product benchmarks, aiming to compare real energy performances of plants. However, when an ammonia plant would now electrify its production processes, its free allocation of allowances could decrease. This reduces the incentive EU ETS gives ammonia producers to switch from fossil-based SMR to electricity driven production of ammonia, e.g., via switching from natural gas-based to renewable hydrogen. As free allocation for the production of ammonia will continue until 2025 as it currently is and will gradually phase out due to CBAM from 2026 until 2034, additional measures to incentivise electrification should be added for the production of ammonia.

Fertilizer Europe should discuss alternative ways with the European Commission to balance the calculation of future product benchmarks maintaining free allocation of allowances for natural gas-based production with ensuring EU ETS provides an incentive for electrification based on renewable electricity.

[138] Based on the share of successful applications (https://ec.europa.eu/clima/eu-action/funding-climate-action/innovation-fund/large-scale-calls_en)

[139] https://www.fchea.org/transitions/2022/8/5/how-the-inflation-reduction-act-of-2022-will-advance-a-us-hydrogen-economy#:~:text=The%20H2PTC%20is%20a%20new,to%2030%25%20for%20new%20facilities.

Annex 1: Background on emission reduction trajectories

Table 3: Historic GHG emission intensity and absolute GHG emission reduction of between 2005 and 2020

Parameter	Unit	2005	2020
Average emission intensity nitric acid	$tCO_2e/t\ HNO_3$	1.61	0.09
Average emission intensity ammonia[140]	$tCO_2e/t\ NH_3$	1.99	1.93
Average emission intensity reduction Nitric acid compared to 2005	%	-	-94%
Average emission intensity reduction ammonia compared to 2005	%	-	-3%
Production volume nitric acid	$Mt\ HNO_3$		20.1
Production volume ammonia	$Mt\ NH_3$		15.8
Emissions nitric acid based on 2020 production levels	$MtCO_2e$	32.3	1.8
Emissions ammonia based on 2020 production levels	$MtCO_2e$	31.5	30.6
Sum of emissions from nitric acid and ammonia based on 2020 production levels[141]	$MtCO_2e$	63.8	32.4
Average emission reduction nitric acid and ammonia compared to 2005	%	-	-49%

Based on average nitric acid and ammonia emission intensities for 2005 and 2020[142] as well the production volumes[143] the absolute emissions for nitric acid and ammonia for 2005 and 2020 are calculated. The average emission reduction compared to 2005 is derived from the sum of emissions in 2005 and 2020.

Conclusion: The sector has reduced its production related GHG emission intensity by 49% between 2005 and 2020. The 94% reduction of N_2O emissions from nitric acid production was the main contributor to this.

[140] This number includes scope 1+2, with electricity related emissions estimated to be around 5% (source: Fertilizer Europe).
[141] The 2020 production levels are also used for 2005 to provide a consistent basis to calculate the overall emission intensity decrease.
[142] Source: Fertilizers Europe
[143] Derived via preliminary free allocation 2021 divided by benchmark value 2021 to 2025 (source EC benchmark curves and key parameters, https://ec.europa.eu/clima/system/files/2021-10/policy_ets_allowances_bm_curve_factsheets_en.pdf); Electricity exchange factor of 0.963 for ammonia from https://ec.europa.eu/info/sites/default/files/revision-eu-ets_with-annex_en_0.pdf

Trajectory 1: based on Fit for 55's EU ETS proposal - underlying assumptions and calculations

The current proposal for the revision of the EU ETS from the EC, as part of the Fit for 55 package, allows for two interpretations of the required greenhouse gas emission reduction for **scope 1** between 2020 and 2030, which lead to a similar trajectory for nitrogen-based fertilizer production in Europe:

- The first interpretation takes the **proposal's new overall target of 61% reduction by 2030, compared with 2005**[144] as starting point (became 62% in the final agreement).[145] This reduction covers ETS aviation and the integrated ETS shipping and the EU ETS target in line with Fit for 55. From 2005 until 2020 industrial installations[146] have already achieved an emission reduction of 42%[147]. This results in a further need to reduce emissions with 33% between 2020 and 2030 for all industrial installations[148] (including European fertilizer installations under the EU ETS), assuming that all industrial installations (activities 21 to 99) reduce their emissions with the same rate (burden sharing).
- In the second interpretation, the **proposed 49% reduction of the EU ETS's emissions cap for stationary installations from 2021 (1,572 $MtCO_2e$) until 2030 (794 $MtCO_2e$) is taken as starting point**[149]. As in 2020 actual emissions[150] were well below the 2021 cap, a reduction of only 37% compared to 2020 would be needed to reach this new 2030 cap[151]. This perspective is only forward looking without considering past achievements and assuming that the actual emissions and the emission cap will converge until 2030 as well as that all stationary installations reduce their emissions with the same rate (burden sharing).

Both interpretations lead to emission reduction targets between 33 to 37% for the European fertilizers industry (between 2020 and 2030), with 35% being the average. Considering the 5.7% decrease in European production of ammonia, nitric acid and urea during the same time period (see chapter 1.2), this leads to an emission intensity reduction target of ~31%.[152]

[144] EEA, The EU Emissions Trading System in 2021: trends and projections. Link to source: https://www.eea.europa.eu/publications/the-eu-emissions-trading-system-2

[145] In the final agreement, it was agreed to increase the reduction target. With Directive (EU) 2023/959, the EU has therefore set a reduction target for the EU ETS sectors of 62% compared to 2005 (https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=OJ:L:2023:130:FULL).

[146] All industrial installations, Activities 21-99, excluding aviation and combustion of fuels

[147] Emissions under the current scope of the EU-ETS from industrial installations decreased from 853 $MtCO_2e$ in 2005 to 498 $MtCO_2e$ in 2020. "Verified emissions" and numbers from "Estimate to reflect current ETS scope for allowances and emissions" were considered for "all countries" minus "UK", Source: EEA. Link to source: https://www.eea.europa.eu/data-and-maps/dashboards/emissions-trading-viewer-1

[148] The target of 61% reduction by 2030, compared with 2005 (853 $MtCO_2e$) results in 333 $MtCO_2e$ in 2030, which is 33% below the 498 $MtCO_2e$ in 2020.

[149] Climact 2022, is the EU ETS proposal fit for 55% (https://climact.com/wp-content/uploads/2022/01/Climact-ETS-report-220125.pdf)

[150] 1,258 $MtCO_2e$ Verified Emissions according to https://ercst.org/wp-content/uploads/2021/08/20210414-2021-State-of-the-EU-ETS-Report-vfinal-1.pdf

[151] Necessary emission is lower than cap reduction as the cap was not reached in 2020 and 2021

[152] Resulting in an average scope 1 production emission intensity of 1.26 $tCO_2e/t\ NH_3$

For **2040**, the Fit for 55 proposal gives less guidance. An interpolation between 2030 and 2050 leads to a 66% emission intensity reduction in 2040[153] (compared to 2020). This would be a more or less linear reduction until zero-emissions in 2050 from 2020.[154]

Trajectory 2 - based on RED proposal from 14.7.2021

The RED proposal from the EC, as another part of the Fit for 55 package, provides the basis for the second trajectory. Article 22a, “mainstreaming renewable energy in industry”, specifies that RFNBO shall contribute to 50% of the hydrogen used in industry by 2030 on a member state level.[155] The European Commission has called for an even higher target of 78%[156] in its REPowerEU plan, however, the European Parliament has confirmed the 50% target from Fit for 55.[157] That is why this roadmap explores what would be needed for the European Fertilizer Industry to reach the 50% RFNBO quota for hydrogen in 2030. The insights generated will also be useful for a potential future 78% target. Note that in the provisional agreement of RED III, concluded on March 30, 2023, an RFNBO-share of 42% of the H_2 used in industry in 2030 and 60% by 2035 was agreed. Trajectory 2 in this roadmap is thus more ambitious than the provisional agreement.

Similar to the first trajectory, there is not yet a basis for an intermediate emission reduction value (in 2040). To show the impact of a more ambitious trajectory, this trajectory aims at a 75% reduction of fossil-based CO_2, with the vast majority via hydrogen as RFNBO, by 2040 already (depending on the availability of alternative renewable-CO_2-sources for the production of urea). In 2050, scope 1 emissions shall be net-zero and RFNBO’s contribute to the vast majority of hydrogen used in industry, regardless of how urea would be produced.

Text Box: Comparison of trajectories considered in this roadmap with IEA scenarios[158]
- In 2030: Trajectory 1 is reduces the emission intensity of ammonia production somewhat quicker than IEA’s Sustainable Development and Net Zero Emissions scenarios, while trajectory 2 reduces this emission intensity significantly quicker. - In 2040: Trajectory 1 reduces this emission intensity comparable to IEZ’s Net Zero Emissions scenario and quicker than its Sustainable Development scenario, while Trajectory 2 is quicker than both. - In 2050: Trajectory 1 and 2 assume 0 emissions from ammonia production while (some) emissions remain in IEA’s Sustainable Development and Net Zero Emissions scenarios.

[153] Considering the 5.7% decrease in European production of ammonia until 2030 and assuming a constant production volume until 2040 and after, this would boil down to an 68 decrease of absolute scope 1 emissions.
[154] An alternative approach would assume a continuation of the decrease of the cap after 2030 with the same speed as proposed for 2021 to 2030. This would lead to zero emissions already before 2050. As the proposal for the reduction of the gap only covers the period until 2030 this has not been considered.
[155] RED proposal, COM (2021) 557, Article 22a. Link to source: https://eur-lex.europa.eu/resource.html?uri=cellar:dbb7eb9c-e575-11eb-a1a5-01aa75ed71a1.0001.02/DOC_1&format=PDF
[156] Working Document, Implementing the REPowerEU Action plan, SWD (2022) 230, link to source https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52022SC0230&from=EN
[157] European Parliament proposal from 14.9.2022. Link to source: https://www.europarl.europa.eu/doceo/document/TA-9-2022-0317_EN.pdf
[158] Based on an interpretation of European data – with assumptions – and adjusting for CO_2 used in urea. For trajectory 2 the scope 1 emission reduction percentage is assumed to be equal to the share of green hydrogen (thus just focusing on the production of hydrogen), which would imply that all emissions from the related Haber Bosch process should be eliminated as well (despite the loss of integration with the SMRs that are replaced).

Scope 2 emissions:

Scope 2 emissions from purchased electricity use related to ammonia production are considered. Scope 2 emissions for steam/heat are not considered as ammonia producers typically do not procure these.

For the average electricity consumption for ammonia production with SMR in 2020 0.61 MWh/t NH_3[159] is used, which results in 0.14 tCO_2/t NH_3 (using the EU-27 average carbon intensity of electricity generation in 2020 (see Table 4)).

Table 4: EU-27 average carbon intensity of electricity generation

Parameter	Unit	2020	2030 *(Projected)*	2040 *(Projected)*	2050 *(Projected)*
Carbon intensity[160]	gCO_2e/kWh	229[161]	92	53	1
Carbon intensity reduction compared to 2020	%	-	-60%	-77%	-100%

While energy efficiency improvements may reduce the scope 2 emissions slightly, most of their decrease originates from the reduction of the emission factor as indicated in the table above. By 2050, they are projected to be zero[162]. Note further that consequently the scope 2 emissions decline quicker than the scope 1 emissions.

[159] Dechema, 2022: Perspective Europe 2030

[160] Future Projections are based on TYNDP 2022. Numbers for 2030 and 2040 are from the "National Trends" scenario. Number for 2050 is from the "Distributed Energy" scenario, which has a steeper decrease for 2030 and 2040 carbon intensities. Link to source: https://2022.entsos-tyndp-scenarios.eu/wp-content/uploads/2022/04/TYNDP2022_Joint_Scenario_Full-Report-April-2022.pdf

[161] EEA, Greenhouse gas emission intensity of electricity generation in Europe. Link to source: https://www.eea.europa.eu/ims/greenhouse-gas-emission-intensity-of-1#ref-zF_FD

[162] Note that until 2050 the sector's electricity consumption can increase very significantly as a consequence of producing hydrogen based on electricity. For these routes 1:1 connections between the renewable energy parks and the electrolysers have however been assumed, so this additional electricity use would have an emission factor zero. In case of electricity from nuclear power plants the related CO_2 emissions over their life cycle are considered as comparable to those from renewable energy sources, https://ec.europa.eu/commission/presscorner/detail/en/QANDA_22_712

Annex 2: Cost of energy carriers

Table 5: Energy carrier cost: natural gas, biomethane, CO_2

Energy Carrier	*Current cost (Euro/MWh)*	*Projected 2030 cost (Euro/MWh)*	*Projected 2040 cost (Euro/MWh)*	*Projected 2050 cost (Euro/MWh)*	*Sources used/ Background*
Biomethane[163]	86	72	61	50	TYNDP[164] 2022 Guidelines, Table 7
	95			40-60	G4C (2019)[165]
	57-92		46-75		IEA 2020 p. 35, 36[166]
Natural gas	15 - 25 (pre-crisis)	14-40	14-40	14-40	TYNDP 22 - High LNG price
	19	19	19	19	Dechema (pre-crisis)
		18-36			CE Delft, 2022 p.43
	87				June 2022 (average)
CO_2 cost (in EUR/tCO_2)	40	78	123	168	TYNDP 22, Guidelines
	78-87	122			GH internal analysis
		53-85			CE Delft, 2022 p.43
	35	100	200	300	Dechema
CO_2 transport & storage cost	**80**	**60**	**50**	**50**	G4C, 2019 (Range as described in the following text)

[163] Reflects the production cost, not necessarily the market price which relies also on natural gas and CO_2 market. Biomethane cost highly depend on local situation and feedstock available. This is shown by an IEA study on different feedstocks potentials and cost ranges. Potential 2018: Wood (35 Mt), Municipal waste (2 Mt), Municipal solid waste 19 Mt, Animal manure (32 Mt), Crop residues (26 Mt). Biomethane cost (excl. feedstock): 30-52 EUR/MWh (small – large Biodigester) (IEA (2020), Outlook for biogas and biomethane: Prospects for organic growth, IEA, Paris https://www.iea.org/reports/outlook-for-biogas-and-biomethane-prospects-for-organic-growth, License: CC BY 4.0, page 28). Feedstock cost today: Municipal waste: 7-40 EUR/MWh, Crops: 23-52 EUR/MWh, Animal manure: 23-65 EUR/MWh (IEA (2020), page 30). Feedstock cost 2040: Municipal waste: 7-36 EUR/MWh, Crops: 23-56 EUR/MWh, Animal manure: 16-56 EUR/MWh (IEA (2020), page 32).

[164] ENTSOG and ENTSO-E benchmark their assumptions against other key sources, reflecting averages and conservative approaches. Therefore, the TYNDP 22 conclusion is often taken as the base for assumptions.

[165] G4C numbers consider Anaerobic digestion for today's cost and 2050 the anaerobic digestion for higher value and thermal gasification for lower value.

[166] IEA (2020), Outlook for biogas and biomethane: Prospects for organic growth, IEA, Paris https://www.iea.org/reports/outlook-for-biogas-and-biomethane-prospects-for-organic-growth, License: CC BY 4.0

Network tariff and taxes:

Network tariffs and taxes are country specific cost elements added to the natural gas price that differ significantly across the EU[167]:

- Network costs range from 0.2 to 2.5 EUR/MWh, the average is 1.5 EUR/MWh
- Taxes and levies range from 1.5 to 8.7 EUR/MWh, the average is 5.5 EUR/MWh

Average network cost and taxes/levies have been added to the natural gas and biomethane price in the calculations.

Table 6: Levelised cost of electricity[168] for different technologies, based on literature values

Energy Carrier	*Current cost (EUR/MWh)*	*Projected 2030 cost (EUR/MWh)*	*Projected 2040 cost (EUR/MWh)*	*Projected 2050 cost (EUR/MWh)*	*Sources used/ Background*
Nuclear	67 New build (7% DR) 71 ($ France) 102 ($ Slovakia)		60		IEA, 2020[169]
			60 $/MWh (GEN III)		MIT, 2022
			36-90 $/MWh (small modular reactors)		Innovation-forum, 2017 WNA
Offshore wind	84 (78-109 $/MWh)				IEA, 2020[169]
	65 (45-90 $/MWh)				OECD, 2020
		33-39	30-35	26-30	Gas for Climate North Sea - average EU (e.g., PL)
			24-34		TYNDP, 2022
Onshore wind	47 (37-62 $/MWh)				IEA, 2020[169]

[167] https://ec.europa.eu/eurostat/databrowser/view/nrg_pc_203_c/default/table?lang=en, based on large industrial (I6) gas price break-down in cost components (not all countries report on I6 natural gas prices in Eurostat).

[168] Costs for energy carriers are based on utility depreciation rates and capital cost assumptions (30 years, 5%), unlike the investments for ammonia plants and hydrogen generation in industry.

[169] IEA (2020), Projected Costs of Generating Electricity 2020, IEA, Paris https://www.iea.org/reports/projected-costs-of-generating-electricity-2020, License: CC BY 4.0

Energy Carrier	*Current cost (EUR/MWh)*	*Projected 2030 cost (EUR/MWh)*	*Projected 2040 cost (EUR/MWh)*	*Projected 2050 cost (EUR/MWh)*	*Sources used/ Background*
	25 (23-25 $/MWh)				OECD, 2020
	83	69	55	41	Dechema[170](region 4 HU)
	35 $/MWh	20 $/MWh			IEA, 2021, p.98[171]
			20-30		TYNDP, 2022
		26-39	21-33	18-28	Gas for Climate Norway - average EU (e.g. PL)
Solar PV (Europe)	50 (40-80 $/MWh)				IEA, 2020[169]
	40 (34-44 $/MWh)				OECD, 2020
	144	35	26	17	Dechema[172] (region 1 ES)
	35 $/MWh	20 $/MWh			IEA, 2021, p.98[171]
			19-26		TYNDP 2022
		14-21	13-19	12-18	Gas for Climate ES/PO - average EU (e.g. GER)
Solar PV (outside of Europe)	N/A	12-13	11-12	10-11	UAE/North-Africa (2020 N/A, today no import)
Electricity cost H_2 generation		30-40			CE Delft, 2022 p.43[173]
Electricity grid cost	38[174]	45-50	45-60	55	Marginal price in market, TYNDP 22, Figure 44
		38-63	34-56	30-50	EHB, 2022; based on CE Delft, 2021

170 Dechema, 2022 used a factor of 1.5 on top of LCOE, which this report does not consider – this report just uses the LCOE.

171 IEA (2021), Ammonia Technology Roadmap, IEA, Paris https://www.iea.org/reports/ammonia-technology-roadmap, License: CC BY 4.0

172 Dechema, 2022 used a factor of 1.5 on top of LCOE, which this report does not consider – this report just uses the LCOE.

173 The report doesn't specify the source of the electricity.

174 Marginal price in the electricity market in 2025 for national trends, as published by TYNDP in April 2022. Current costs are significantly higher.

Table 7: Summary of energy carrier cost: renewable and low-carbon electricity[175]

Energy Carrier	*Current cost (EUR/MWh)*	*Projected 2030 cost (EUR/MWh)*	*Projected 2040 cost (EUR/MWh)*	*Projected 2050 cost (EUR/MWh)*
Nuclear				
Best[176]	67	60	40	40
Average	90	90	90	90
Offshore wind				
Best	60	33	30	26
Average EU	84	39	35	30
Onshore wind				
Best	45	26	21	18
Average EU	60	39	33	28
Solar PV				
Best	40	14	13	12
Average EU	50	21	19	18
PV outside Europe	(30)	16	13	12
Grid electricity	38[177]	50	50	45

[175] Cost to generate electricity heavily depend on the local circumstances (how much wind/sun?). The table therefore gives cost on an illustrative favourable location as well as EU average cost.

[176] For nuclear the current cost is derived from actual projects. Outlook for small modular reactor and large-scale reactors have similar average best guess (60 USD/MWh) but range defined by SMR with optimistic 36 USD/MWh as "best"

[177] Marginal price in the electricity market in 2025 for national trends, as published by TYNDP in April 2022. Current costs are significantly higher.

Network tariff and taxes:

Network tariffs and taxes are country specific cost elements added to the electricity price that differ significantly across the EU[178]:

- Network costs range from 3 to 16 EUR/MWh, the average is 7.6 EUR/MWh
- Taxes and levies range from 0 to 49 EUR/MWh, the average is 15 EUR/MWh

The EU average network cost and taxes/levies have only been added to the electricity price for the current electricity use, and in case of the production of electrolysis-based hydrogen where the grid is used (not in case of a direct connection - where these are assumed not to apply - although there might be exceptions in specific Member States).

[178] https://ec.europa.eu/eurostat/databrowser/view/NRG_PC_205_C__custom_3209719/default/table?lang=en, based on large industrial (IG) electricity price break-down in cost components (not all countries report on IG electricity prices in Eurostat).

Annex 3: Hydrogen generation cost assumptions

The levelised cost[179] of hydrogen (LCOH) for ammonia production, i.e., the production cost plus potential transport and storage costs, have been considered, as there is no uniform hydrogen market price in the short term (in the absence of a hydrogen market with scale) and forecasting potential market dynamics beyond afterwards would come with significant uncertainties.

The LCOH are calculated based on:

- The investment costs (CAPEX) of the SMR, ATR or electrolyser, considering a depreciation time of 15 years[180] and weighted average cost of capital (WACC) of 10% - resulting in a simple payback period of around 8 years.
- Operational costs (OPEX) consist of fixed operational costs, which are expressed as percentage of CAPEX (depending on technology), and
- Variable costs, that depend on the energy carriers used and CO_2 emitted. Carbon cost, if relevant, are considered as EUR/tCO_2 on top of the levelised cost. In their calculation, the impact of free allocation of allowances, as well as their potential reduction as a consequence of for example electrification (refer to chapter 9.3), have been ignored.

The table below lists values for CAPEX (over time) and the “selected values” that form the basis of the cost as presented in chapter 3.

Table 8: CAPEX assumptions for different hydrogen generation technologies (excl. renewable power generation)

Technology	Today	2030	Ultimate	Source/Comments
SMR (no CCS) in EUR/kW H_2	550	500	450	EC, 2020 (E3)
	470-850			IEA, 2019[182]
	340			Dechema, 2022
	397[181]			Uni Alberta, 2022
	400	400	400	Selected values
SMR retrofit CCS in EUR/kW H_2 to 85% CR[183]	700			ASSET study 2019, p.37
	505[184]			Uni Alberta, 2022
	500	500	500	Selected values
ATR new CCS in EUR/kW H_2[185]	950-1,500			ASSET study 2019 (based on IEA)
	1,011[186]			Uni Alberta, 2022

[179] Consistent with the approach for biomethane and renewable electricity generation.

[180] Note the technical lifetime is likely longer.

[181] Excl. H_2 storage, CO_2 pipelines and sequestration

[182] IEA (2019), The Future of Hydrogen, IEA, Paris https://www.iea.org/reports/the-future-of-hydrogen, License: CC BY 4.0

[183] CR = Capture rate of carbon

[184] Excl. conventional SMR parts and H_2 storage, incl. CO_2 separation, pipeline, and sequestration

[185] There are many ATR suppliers and markets, while still not as established as SMR. Therefore, wide range of cost assumptions. Learning and improvements are to be expected but that not known and thus didn’t factor in – a conservative approach thus.

[186] Excluding hydrogen storage, including CO_2 separation, pipeline, and sequestration

Technology	Today	2030	Ultimate	Source/Comments
	800-1,080			H2 vision, 2019 (large scale >1 GW H_2)
	1,050	1,050	1,050	Selected values
Electrolyser in EUR/kWe[187]		500	250	G4C (G4C, 2020) OPEX: 5% of CAPEX
Electrolyser in EUR/kW H_2		770	345	G4C (G4C, 2020) OPEX: 5% of CAPEX
		600-1,500		CE Delft, 2022 p.43 OPEX: 5.8% of CAPEX for 3,000 FLH per year
Electrolyser PEM large in EUR/kW H_2	1,610 (72%)	740 (84%)	200 (85%)	EC, 2020 (E3)
Electrolyser ALK large in EUR/kW H_2	1,265 (72%)	600 (79%)	180 (85%)	EC, 2020 (E3)
Electrolyser SOEC large in EUR/kW H_2	3,332 (35%)	1,421 (45%)	600 (96%)	EC, 2020 (E3)
Electrolyser efficiency	65%	65%	72%	G4C (G4C, 2020) (Selected values)

[187] Since PAM and ALK are already developed technologies, they are assumed to be used over the next decade well then also SOEC is becoming a relevant technology when being cost competitive.

Table 9 below characterizes various hydrogen generation technologies (including the "selected values" as presented in the table above).

Table 9: CAPEX and efficiency assumptions for different hydrogen generation technologies (excl. renewable power generation)[188] [189]

SMR new, no CCS	2020	2030	2040	2050	Unit
CAPEX[190]	1,522	1,522	1,522	1,522	EUR/t H_2
OPEX	59	59	59	59	EUR/t H_2/a
Efficiency[191] ($H_{2\ out}$/ natural gas used)	65%	65%	65%	65%	
Electricity needed (SMR)	0.17	0.17	0.17	0.17	MWh/t NH_3/a
Electricity needed (ammonia prod.)[192]	0.44	0.44	0.44	0.44	MWh/t NH_3/a
CO_2 emitted	1.86	1.86	1.86	1.86	tCO_2/t NH_3/a

SMR retrofit,w CCS - 85%	2020	2030	2040	2050	Unit
CAPEX	1,902	1,902	1,902	1,902	EUR/t H_2
OPEX	74	74	74	74	EUR/t H_2/a
Efficiency[193] ($H_{2\ out}$/ natural gas used)	55%	55%	55%	55%	
CC rate	85%	85%	85%	85%	
Electricity needed (SMR)	0.8	0.8	0.8	0.8	MWh/t NH_3/a
Electricity needed (ammonia prod.)[194]	0.44	0.44	0.44	0.44	MWh/t NH_3/a

[188] Sources: CAPEX as stated in table before; Efficiency, electricity need are based on Uni Alberta, 2022 and ASSET study 2019, CO_2 emitted is based on own calculations; Electrolyser data as stated in table before; OPEX only considers maintenance & replacements, no energy carrier cost. Original cost in EUR/kW H_2 and transformed in EUR/t H_2 with 100% full load hours assumed.

[189] Sense check: The IEA (2021), Ammonia Technology Roadmap, IEA, Paris https://www.iea.org/reports/ammonia-technology-roadmap, License: CC BY 4.0, table 1.2, has comparable cost assumptions and comes to similar conclusions. Natural gas use is slightly lower (65% conversion vs. 67% in IEA (2021) Ammonia Technology Roadmap) but only BAT is considered there. The electricity use for methane based hydrogen, however, is assumed to be lower (around 50%) in IEA (2021) Ammonia Technology Roadmap than the average in this study. There is no specific CAPEX outlined for SMR and ATR, but IEA (2019), The Future of Hydrogen, IEA, Paris https://www.iea.org/reports/the-future-of-hydrogen, License: CC BY 4.0, is one of the sources taken into consideration above. Furthermore, the same conclusion is drawn: SMR with CCS is slightly more expensive than a new build ATR with CCS. On electrolysers, the efficiencies are almost equal, but investment cost range is assumed higher in IEA (2021) Ammonia Technology Roadmap (550 to 2,300 EUR/kW H_2) than in this study (350 to 1,500 EUR/kW H_2). Again, the conclusion that direct connected renewable electricity-based ammonia can be competitive is drawn in both studies, as well as that grid-connected electrolyser is most likely to expensive looking at electricity market prices.

[190] CAPEX represents the total (not annualized) investment.

[191] No significant improvements in technology, hence efficiency assumed in future; Reference to LHV; based on Uni Alberta (2022). IEA (2021), Ammonia Technology Roadmap, IEA, Paris https://www.iea.org/reports/ammonia-technology-roadmap, License: CC BY 4.0, (p. 33) indicates 67% (BAT)

[192] Based on Uni Alberta (2022). IEA (2021), Ammonia Technology Roadmap, IEA, Paris https://www.iea.org/reports/ammonia-technology-roadmap, License: CC BY 4.0, (p. 33) indicates 0.1 MWh/t NH_3/a for total electricity used – a relatively large difference.

[193] Based on Uni Alberta (2022) and ASSET 2019. As the potential for future efficiency improvements was not known, the efficiency has been kept constant over time. Note that chapter 6 factors in some efficiency improvements.

[194] Based on Uni Alberta (2022). IEA (2021), Ammonia Technology Roadmap, IEA, Paris https://www.iea.org/reports/ammonia-technology-roadmap, License: CC BY 4.0, (p. 33) indicates 0.3 MWh/t NH_3/a for total electricity used

ATR new, CCS	2020	2030	2040	2050	Unit
CAPEX	3,995	3,995	3,995	3,995	EUR/t H_2
OPEX	156	156	156	156	EUR/t H_2/a
Efficiency[195] ($H_{2\ out}$/ natural gas used)	80%	80%	80%	80%	
CC rate	91%	91%	91%	91%	
Electricity needed (ATR)	0.65	0.65	0.65	0.65	MWh/t NH_3/a
Electricity needed (ammonia prod.)[196]	0.44	0.44	0.44	0.44	MWh/t NH_3/a

Electrolyser	2020	2030	2040	2050	Unit
CAPEX	5,707	2,930	2,121	1,313	EUR/t H_2
OPEX	223	114	83	51	EUR/t H_2/a
Efficiency ($H_{2\ out}$/ electricity used)	65%	65%	70%	72%	
Electricity needed (ammonia prod.)	2.32	2.32	2.32	2.32	MWh/t NH_3/a

Table 10: Capacity factors of electricity generation technologies used for full load hours calculation of electrolyser in direct set-up

Technology	Capacity factor
PV	18%
PV (imported)	25%
Offshore	50%
Onshore	30%
Nuclear	90%
Grid	90%

Cost on carbon transport and storage:

As the sector will likely not build transport- and storage infrastructure, no CAPEX costs, but only CO_2 transport and storage as service in terms of Euro per tonne of CO_2 transported and stored, have been assumed. For **CO_2 transport:**

- **Pipeline costs** are proportional to the distance transported since more than 90% of the pipeline costs relate to CAPEX. For the transport of CO_2 over distances between 10 km-

[195] No significant improvements in technology, hence efficiency assumed constant in future; Reference to LHV; Efficiency based on Uni Alberta (2022). IEA (2021), Ammonia Technology Roadmap, IEA, Paris https://www.iea.org/reports/ammonia-technology-roadmap, License: CC BY 4.0, (p. 33) indicates 78%. As the potential for future efficiency improvements was not known, the efficiency has been kept constant over time. Note that chapter 6 factors in some efficiency improvements.

[196] Based on Uni Alberta (2022). IEA (2021), Ammonia Technology Roadmap, IEA, Paris https://www.iea.org/reports/ammonia-technology-roadmap, License: CC BY 4.0 (p. 33) indicates 0.4 MWh/t NH_3/a for total electricity used

1,500 km, onshore pipeline costs can range between EUR 0.1 to 16/tCO_2, whereas offshore pipelines costs can vary between EUR 2 to 29/tCO_2.[197]

- **Shipping costs**, on the other hand, are marginally influenced by the distance as CAPEX has a significantly lower contribution to the total annual costs. Costs for ship transport vary between EUR 10 to 20/tCO_2 and this method is usually preferable when small volumes (2.5 MtCO_2) need to be transported over long distances (>180 km).[198]

Economies of scale effects are considerable in pipeline transport, while this effect is less significant for ship transport.

Costs for **CO_2 storage** can vary widely and are sensitive to various factors such as the type of storage, field capacity and well injection rate, amongst others. Onshore storage is usually less costly compared to offshore storage. Moreover, it is cheaper to store CO_2 in depleted oil & gas fields than in saline aquifers due to pre-existing infrastructure. Costs for storage can vary between EUR 1 to 13/tCO_2 onshore, and between EUR 2 to 22/tCO_2 offshore.[198]

These costs vary significantly depending on the individual situation, i.e., the distances, type of transport (pipe or ship) and storage (on- or offshore) as well as the capacity transported and stored. In the following ranges are given depending on these factors. The above is summarised in the table below.

Table 11: carbon transport and storage cost based on Gas for Climate[199]

In EUR/tCO_2	Onshore	Offshore
Transport	0.1-16	2-29 (pipeline) 10-20 (shipping)
Storage	1-13	2-22
Total	**1-29**	**4-51**

In this roadmap, based on this table, constant cost of EUR 50/tCO_2 transported and stored are assumed.

[197] The ranges are estimated for transported volumes of 2.5, 10, and 20 MtCO_2/year. The first two flow rates assume a one-on-one, point-to-point connection between a source and a sink. The last scenario, with the flow rate of 20 MtCO_2/year, considers a large-scale integrated network of CO_2 sources connected to multiple storage sites.

[198] G4C, 2019 (page 120 f.)

[199] https://gasforclimate2050.eu/wp-content/uploads/2020/03/Navigant-Gas-for-Climate-The-optimal-role-for-gas-in-a-net-zero-emissions-energy-system-March-2019.pdf

Annex 4: Hydrogen production cost

The results shown in this annex are based on the assumptions elaborated in Annex 2 and Annex 3, for different natural gas prices and renewable and low-carbon electricity sources/time scales. Resulting ammonia production cost are shown in chapter 3.

Table 12: Levelised cost of hydrogen, produced from methane

Technology	Natural gas price: 15 EUR/MWh CO_2 price: 50 EUR/tCO_2	Natural gas price: 30 EUR/MWh CO_2 price: 100 EUR/tCO_2	Natural gas price: 40 EUR/MWh CO_2 price: 200 EUR/tCO_2	Unit
SMR exist., no CCS (no CO_2 cost)	1.2	1.9	2.3	EUR/kg H_2
SMR new, no CCS (no CO_2 cost)	1.4	2.1	2.5	EUR/kg H_2
SMR exist., no CCS (incl. CO_2 cost[200])	1.7	2.9	4.4	EUR/kg H_2
SMR new, no CCS (incl. CO_2 cost)	1.9	3.1	4.6	EUR/kg H_2
SMR exist., retrofit 85% CCS	2.7	3.5	4.2	EUR/kg H_2
ATR, new	2.4	2.9	3.3	EUR/kg H_2

Table 13: Levelised cost of hydrogen, produced from electricity

Technology	Variant	Near term*	Long term*	Unit
Nuclear	Best	3.7	2.2	EUR/kg H_2
	Average	5.2	4.5	EUR/kg H_2
Offshore wind	Best	2.8	1.8	EUR/kg H_2
	Average	3.2	2.0	EUR/kg H_2
Onshore wind	Best	2.7	1.5	EUR/kg H_2
	Average	4.1	2.3	EUR/kg H_2
PV	Best	3.0	1.6	EUR/kg H_2
	Average	4.5	2.4	EUR/kg H_2
Grid[201]	Best	3.7	2.7	EUR/kg H_2
	Average	4.3	3.4	EUR/kg H_2
Import, (incl. transport)	Pipeline**	2.9	1.7	EUR/kg H_2

*Long term: the final development stage of the technology is reached; production levels are at large scale and strong competition and experience in the project implementation is realised (expected around 2040 to 2050). Near term marks an intermediate step, with significant improvements in production and technology compared to today.

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[200] The CO_2 cost are added to the natural gas cost.

[201] Based on marginal price in the electricity market in 2025 for national trends, as published by TYNDP in April 2022. Current costs are significantly higher.

**Reflects cost of hydrogen, produced in Northern Africa (based on PV), and transported as hydrogen, via pipeline, to southern Europe and additional 500 km transported within central Europe.

Table 14 summarizes the decrease of the emissions associated with the production of grey ammonia (without CCS) and of green ammonia, just as a consequence of the decrease of the emission factor of the grid as listed at the end of Annex 1 (assuming grid electricity is only used for the Haber Bosch process, not for the production of hydrogen). Emissions for grey ammonia (without CCS) in 2020 are only slightly higher than indicated in Annex 1 based on actual plant data[202], confirming the applicability of the theoretical assessment in Annexes 2-4.

Table 14: Overview of scope 1+2 emissions for the production of ammonia

	2020	2030	2040	2050	
Grey (no CCS)	1.99	1.91	1.89	1.86	t CO_2/t NH_3
Green Ammonia	0.53	0.21	0.12	0.00	t CO_2/t NH_3

[202] 1.99 (Annex 2-4) vs 1.93 (Annex 1) t CO_2/t NH_3 for scope 1 and 2, and 1.86 (Annex 2-4, which doesn't assume energy efficiency improvements for SMRs) vs ±1.83 (Annex 1, considering ±5% of current emissions are from electricity use) t CO_2/t NH_3.

Annex 5: Need for and availability of RFNBO in the form of hydrogen[203]

Table 15: Amount of RFNBO needed for ammonia production to meet trajectory 2[204]

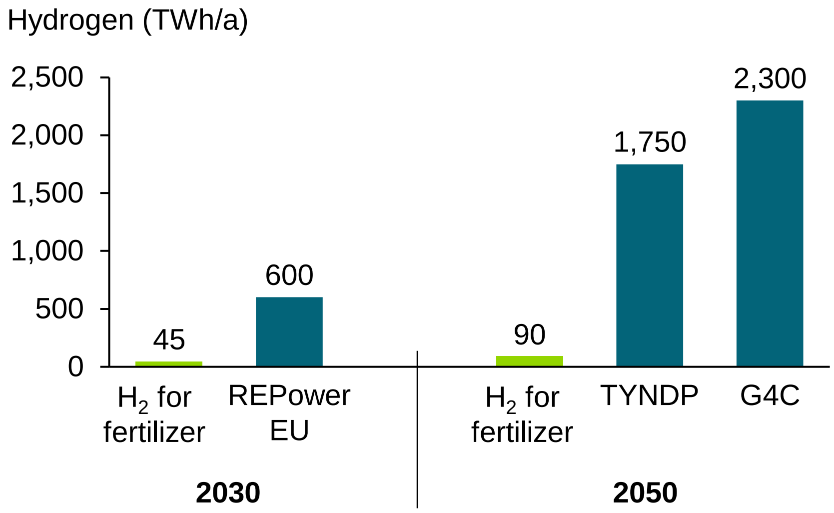
Parameter	2020	2030	2040	2050	Unit
Ammonia from RFNBO	0	7.5	11.2	14.9	Mt NH_3
RFNBO in the form of hydrogen	0	45	67	90	TWh/a
RFNBO in the form of hydrogen	0	1.3	2.0	2.7	Mt H_2

The European Commission aims at a supply of over 600 TWh of hydrogen by 2030 (RePowerEU) and sees sectors currently consuming fossil-based hydrogen as first to transition[205]. The Figure below shows that less than 10% of the REPowerEU hydrogen supply target for 2030 and 5% of the prospected hydrogen supply by 2050 would be needed for the production of RFNBO-based fertilizer.

[203] In the provisional agreement of RED III, concluded on March 30, 2023, an RFNBO-share of 42% of the H_2 used in industry in 2030 and 60% by 2035 was agreed. This Annex is based on the – more ambitious – shares in trajectory 2.

[204] Can be either produced using renewable electricity or be imported

[205] The EC's Hydrogen Strategy states for example: "*An **immediate application in industry is to reduce and replace the use of carbon-intensive hydrogen in refineries, the production of ammonia**, and for new forms of methanol production, or to partially replace fossil fuels in steel making. In a second phase, hydrogen can form the basis for investing in and constructing zero-carbon steel making processes in the EU, envisioned under the Commission's new industrial strategy.*"



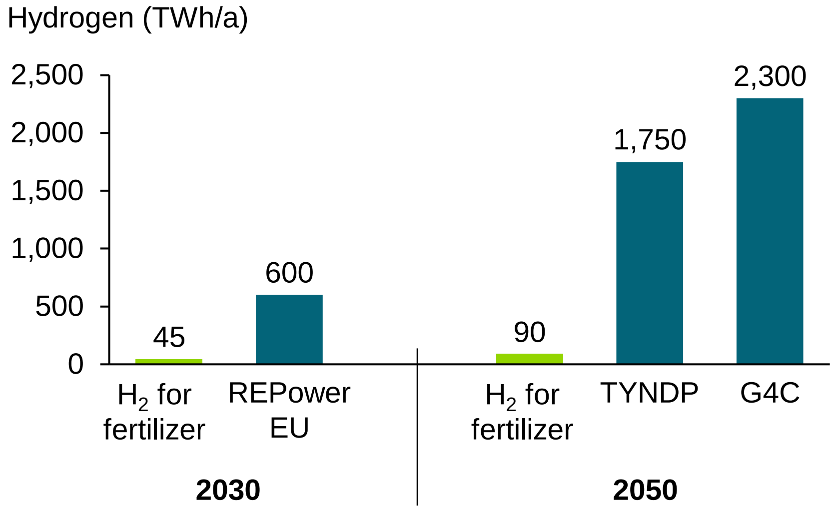


Figure 22: Hydrogen demand for fertilizers compared with supply projections from REPowerEU[206] in 2030 and TYNDP[207] and Gas for Climate[208] in 2050

[206] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52022DC0230&from=EN

[207] Ten-year network development plan (TYNDP) 2022: https://2022.entsos-tyndp-scenarios.eu/wp-content/uploads/2022/04/TYNDP2022_Joint_Scenario_Full-Report-April-2022.pdf

[208] https://gasforclimate2050.eu/wp-content/uploads/2020/04/Gas-for-Climate-Gas-Decarbonisation-Pathways-2020-2050.pdf

Annex 6: Needs for and availability of low-carbon hydrogen from natural gas

The table below shows the amount of natural gas, renewable electricity and CO_2 storage needed by 2050 in case all ammonia production would be 100% based on low-carbon hydrogen from natural gas, produced with ATRs. Low-carbon ammonia share increases according to trajectory 1. RE is increasing since it is needed for low-carbon ammonia production in the ATR. Fossil ammonia is produced via natural gas-based SMR (before 2050).

Table 16: Amount of natural gas, carbon storage and renewable electricity needed

Parameter	2020	2030	2040	2050	Unit
Fossil ammonia	15.8	10.3	5.1	0	Mt NH_3
Low-carbon ammonia	0	4.6	9.9	14.9	Mt NH_3
Natural gas	146	130	121	112	TWh
Renewable electricity[209]	0	5	11	16	TWh
CCS	0	7	15	23	$MtCO_2$

To set the needed CCS capacity into perspective, studies on total CCS availability in the EU are compared. The European Commission's Impact Assessment for Fit for 55 does not provide any figures for the total potential for CCS, but TYNDP[210] does, comparing other studies on European CCS capacity available or needed by 2050. These range from 50 $MtCO_2$ to over 1,000 $MtCO_2$ per year, but the major literature sources, i.e., from IEA[211] and TYNDP 2022, conclude around 600 $MtCO_2$/a is available by 2050. The following figure shows that in case the fertilizer industry would produce all its hydrogen as low-carbon hydrogen from natural gas (with 100% of the CO_2 formed being stored[212]), less than 5% of European carbon storage capacity would be needed by 2050.[213]

[209] Low-carbon ammonia needs to use renewable electricity for the ammonia production processes. Fossil ammonia also needs electricity for production, but not necessarily renewable.

[210] TYNDP 22, https://2022.entsos-tyndp-scenarios.eu/wp-content/uploads/2022/04/TYNDP2022_Joint_Scenario_Full-Report-April-2022.pdf, Figure 59

[211] IEA (2021), Net Zero by 2050, IEA, Paris https://www.iea.org/reports/net-zero-by-2050, License: CC BY 4.0

[212] Thus, no CO_2 converted to urea.

[213] Storage options outside Europe are not considered in this calculation.

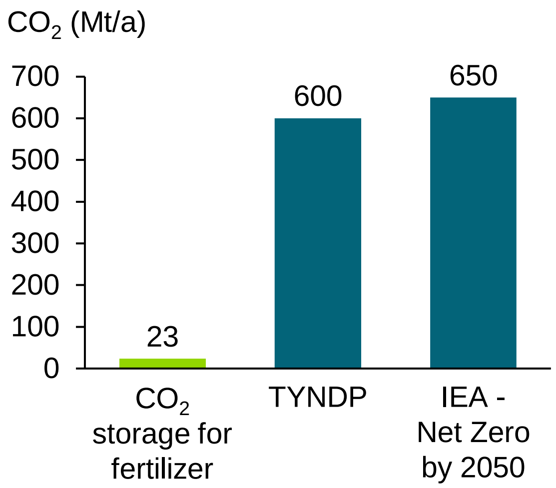


Figure 23: Carbon storage needed for fertilizer by 2050 and the available capacity forecasted by TYNDP 2022 and IEA[214]

[214] IEA (2021), Net Zero by 2050, IEA, Paris https://www.iea.org/reports/net-zero-by-2050, License: CC BY 4.0

Annex 7: Needs for and availability of biomethane

The table below shows the amount of biomethane, and renewable electricity, needed to produce all ammonia based on biomethane by 2050 with SMRs. Until then biomethane is used to deliver the trajectory 1 target.

Table 17: Amount of natural gas, carbon storage and renewable electricity needed

Parameter	2020	2030	2040	2050	Unit
Fossil ammonia	15.8	10.3	5.1	0	Mt NH_3
Renewable ammonia	0	4.6	9.9	14.9	Mt NH_3
Biomethane	0	43	91	138	TWh
Renewable electricity[215]	0	3	6	9	TWh

To bring it into context, literature values for total biomethane availability and the needed amount for fertilizer is compared. The TYNDP 2022 sees around 1,000 to 1,200 TWh of biomethane by 2050 and an additional 250 to 400 TWh of synthetic methane, while there will be almost no natural gas use (0 to 250 TWh)[216]. The Fit for 55 impact assessments see 700 to 800 TWh biomethane, 250 to 400 42TWh synthetic methane and still 1,000 to 1,200 TWh natural gas by 2050. However, they all were conducted before the Ukraine crisis and the REPower EU announcements.

Figure 24 shows that around 10 to 15% of the available biomethane would be needed for the fertilizer industry. It is not unrealistic that the fertilizer industry gets a significant share, however, biomethane will be used in many other sectors as well and the economics will mostly decide where it is applied.

[215] Low-carbon ammonia needs to use renewable electricity for the ammonia production processes. Fossil ammonia also needs electricity for production, but not necessarily renewable.

[216] TYNDP 22, https://2022.entsos-tyndp-scenarios.eu/wp-content/uploads/2022/04/TYNDP2022_Joint_Scenario_Full-Report-April-2022.pdf, Figure 55

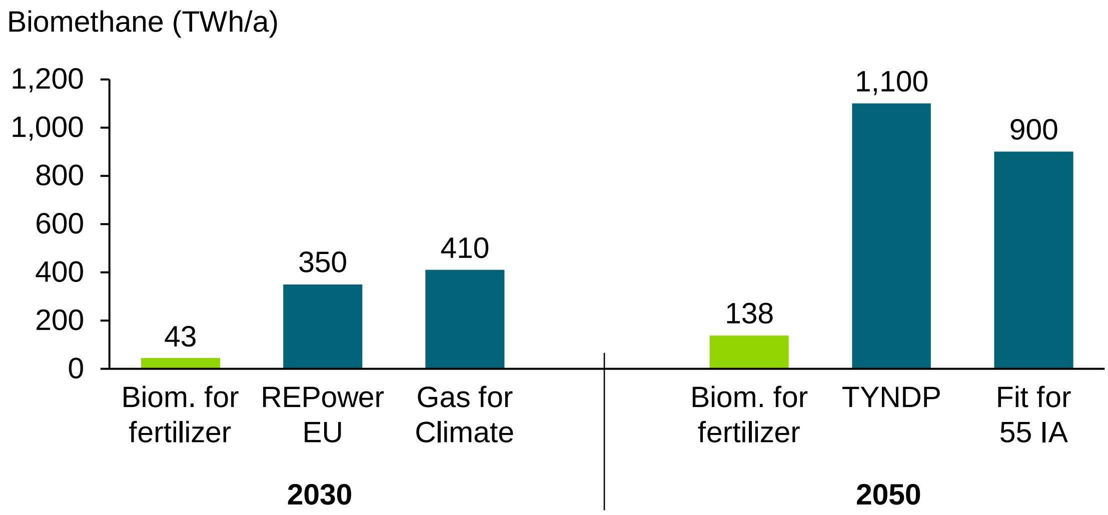


Figure 24: Biomethane demand for fertilizer in 2030 and 2050 compared to availability according to REPowerEU[217], Gas for Climate[218], TYNDP 2022[219] and EU Fit for 55 Impact Assessment[220]

217 https://energy.ec.europa.eu/system/files/2022-05/SWD_2022_230_1_EN_autre_document_travail_service_part1_v3.pdf

218 https://gasforclimate2050.eu/wp-content/uploads/2022/07/GfC_national-biomethane-potentials_070722.pdf

219 https://2022.entsos-tyndp-scenarios.eu/wp-content/uploads/2022/04/TYNDP2022_Joint_Scenario_Full-Report-April-2022.pdf

220 https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:52020SC0176&from=EN

Annex 8: Needs for and availability of renewable electricity

The table below shows the amount of renewable electricity needed in case all the ammonia from RFNBO indicated above would be produced in Europe using renewable electricity (to generate RFNBO in the form of hydrogen). The renewable electricity needed is depicted according to trajectory 2 as the amounts of renewable electricity are needed earlier as in trajectory 1.

Table 18: Amount of renewable electricity needed[221]

Parameter	2020	2030	2040	2050	Unit
Renewable electricity (H_2 production)	0	69	96	124	TWh/a
Renewable electricity (other)	0	17	26	35	TWh/a
Renewable electricity (total)	0	86	122	159	TWh/a

If the renewable hydrogen would be produced from renewable energies in Europe, 159 TWh of electricity would be needed per year. This is about 7% of the total renewable energy production forecasted in the EU by 2050, according to the TYNDP 2022[222] and the impact assessment for Fit for 55.[223]

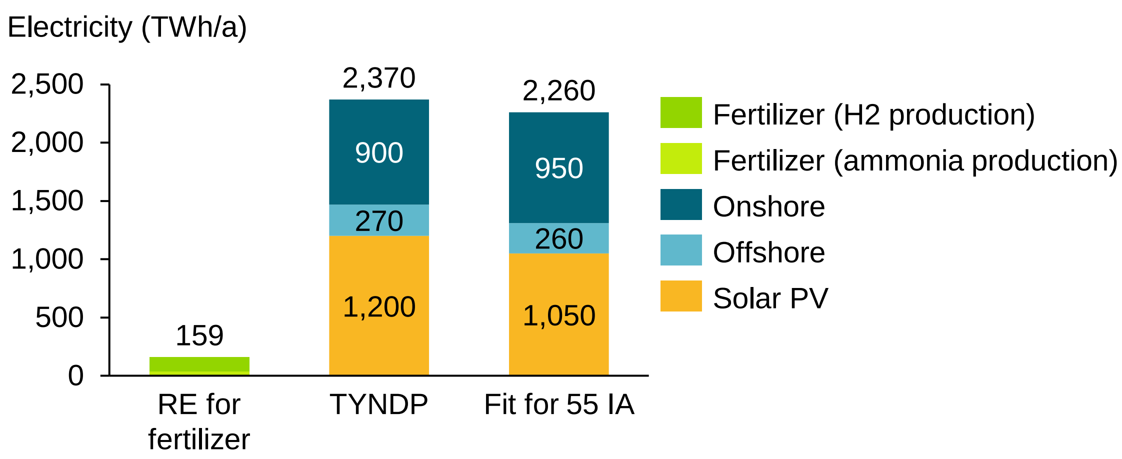


Figure 25: Electricity demand of fertilizer industry in 2050 (100% electricity-based hydrogen production) compared to available renewable electricity according to literature

[221] Electricity for hydrogen production is to feed electrolyser. “Other” for further ammonia production (e.g., air capture, compressors)
[222] TYNDP 22, https://2022.entsos-tyndp-scenarios.eu/wp-content/uploads/2022/04/TYNDP2022_Joint_Scenario_Full-Report-April-2022.pdf, Figure 53
[223] https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:52020SC0176&from=EN

Annex 9: Upstream emissions of methane

Country:	***Share of EU's natural gas demand in 2021 (BP, 2021)[224]:***	***Methane emissions rate:***
Russia	Almost 40%	- >2% (Bauer et al., 2022[225], for the production, processing, transportation to Europe) - 5%-7% (Abrahams, 2015[226], for the production, processing, transportation to Europe)
Norway	Around 25%	- 0.0175% (DBI, 2021[227], for the production and processing of natural gas that is transported to Germany). - These values corresponded to values published by Equinor, who exports 80% of its natural gas to Europe (Equinor, 2021[228]) The Norwegian upstream emissions are best case in the world, requiring full implementation of best practices and very good regulatory and monitoring oversight.[229].
USA	Together with Qatar and Algeria, the USA delivers LNG imports which represent around 25% of EU demand for natural gas	- 1.3%, of which 64% occurs within the production and processing step (Thinkstep, 2017[230], for the production, processing, LNG conversions and transportation to Rotterdam) - 2.3% across the US's oil and gas supply chains (Alvarez, 2018[231], based on meta-analysis of field data on the production, processing and domestic transportation/distribution) - 1.5%-4.9% (Klemun et al., 2019[232]; for fossil gas used in US power sector, production, processing and domestic transportation/distribution)

The emissions shown in this table are only the upstream emissions. Even the Norwegian gas (best case) likely adds ~0.2% leakage[233] before it reaches the end-use at best, and there can also be methane emissions in the sector's ammonium plants (methane slip).

224 https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2021-full-report.pdf
225 https://pubs.rsc.org/en/content/articlelanding/2022/se/d1se01508g
226 https://pubs.acs.org/doi/pdf/10.1021/es505617p
227 https://www.dbi-gut.de/files/PDFs/Dokumente/61_Gasnetze/61_CFNG1.1_Report_ENG.pdf
228 Equinor, 2021. Greenhouse gas and methane intensities along Equinor's Norwegian gas value chain.
229 Guidehouse expert opinion.
230 https://globallnghub.com/wp-content/uploads/attach_380.pdf
231 https://pubmed.ncbi.nlm.nih.gov/29930092/
232 https://iopscience.iop.org/article/10.1088/1748-9326/ab2577/pdf
233 TSO level infra (0.05%; https://www.marcogaz.org/wp-content/uploads/2021/04/WG-ME-17-09.pdf), DSO level infra (0.1-0.2%; https://www.marcogaz.org/wp-content/uploads/2021/04/WG-ME-17-25.pdf), Storage (0.01%; https://www.marcogaz.org/wp-content/uploads/2021/04/WG-ME-17-19.pdf)

Using a Global Warming Potential of 25 for methane[234], the table above including the above-mentioned ~0.2% leakage corresponds to GHG emissions of 0.054 to 1.8 tCO_2e per tonne of methane.

The GHG emissions of stoichiometric combusting CH_4 are 2.75 $tCO_2/t\ CH_4$[235].

This means that the upstream GHG emissions from methane are 2 to 65% of the GHG emissions from the combustion of methane. The IEA's Ammonia Roadmap[236] estimates that the methane emissions attributable to the fuel inputs for ammonia production are equivalent to 15% of the CO_2 directly emitted during production on average, noting it is complex to allocate methane emissions to specific end-use like ammonia production.

[234] Global warming potential of methane used by the EU, according to https://www.europarl.europa.eu/RegData/etudes/BRIE/2022/729313/EPRS_BRI(2022)729313_EN.pdf

[235] CH_4 (M = 16) + 2 O_2 --> CO_2 (M = 44) + 2 H_2O

[236] IEA (2021), Ammonia Technology Roadmap, IEA, Paris https://www.iea.org/reports/ammonia-technology-roadmap, License: CC BY 4.0. This roadmap has a global scope and the estimate likely also includes methane emissions during coal mining.

Annex 10: Ammonia production cost

Technology	Today	2030	Ultimate	Source/Comments
CAPEX Ammonia plant new (1,500 t NH_3/day)[237]	500-650	500-650	500-650	Dechema, 2022 (standard to BAT)
	550	**550**	**550**	Selected values
CAPEX ASU (in EUR/t NH_3)[238]	**90**	**90**	**90**	Dechema, 2022

[237] Haber Bosch, excluding generation of hydrogen.
[238] Only necessary for ammonia production based on hydrogen generated via electrolysis

Annex 11: Lead times for investments in ammonia plants

Figure 26 shows typical lead times for investment in ammonia plants, the associated infrastructure, and for when policies impacting the business case need to be implemented. It also indicates how the moment of the final investment decisions depend on these elements.

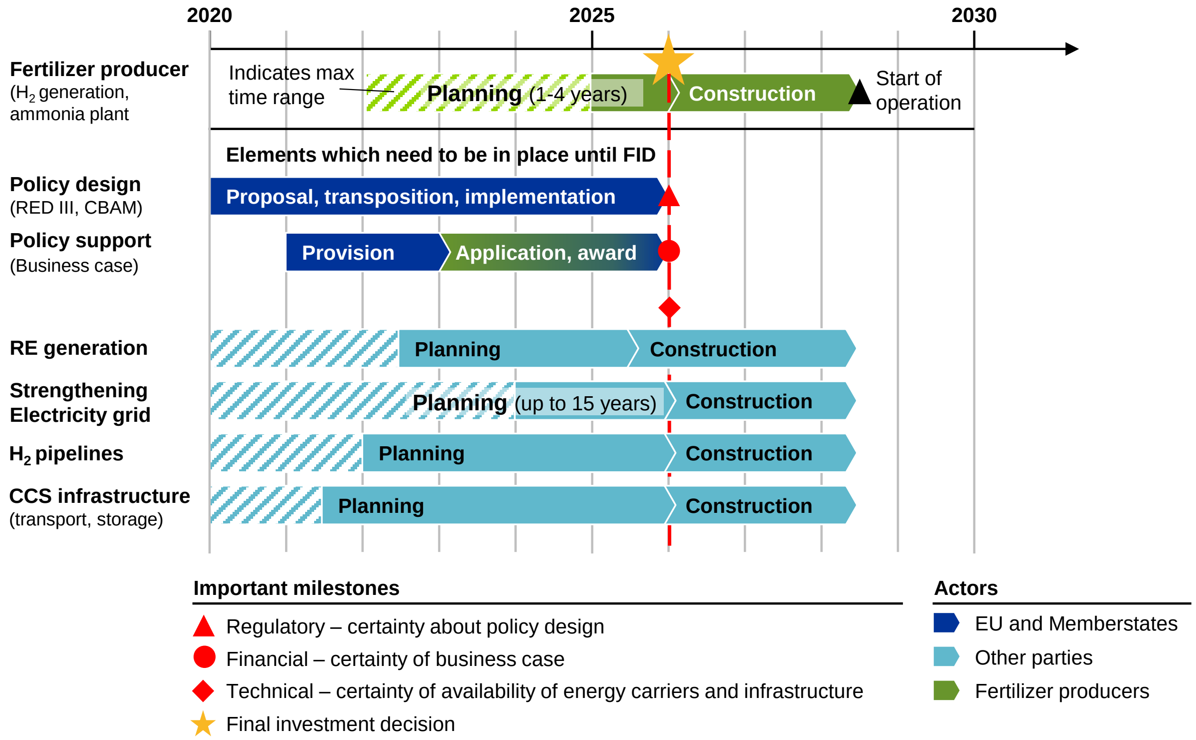


Figure 26: Stylised exemplary project timeline with certainty requirements for final investment decision (start of operation in 2028)

Lead time for fertilizer plants (incl. hydrogen generation): Building a new plant or significantly changing an existing plant takes four to seven years, more in case of a new location.[239] Around half of this time is during the planning phase before the final investment decision, half of this time is for the construction phase afterwards.[240] The planning phase takes between one and four years and includes studies, business case development, engineering, permitting, contractor selection, funding. The construction phase takes between 2 and 3 years and includes procurement and construction. The lead time between ordering and delivery of some critical parts can take up to 2 years.

To make a final investment decision, ammonia producing companies need to have reasonably certainty on all of the following three things:

1. **Certainty about policy design**: Clear market conditions for clean ammonia production and consumption should provide clarity on supply, demand and regulation. Important policies like RED III and CBAM should be quickly adopted without possible adaptions to provide certainty for companies' planning.

[239] Based on several interviews with members, and in line with https://assets.vnci.nl/p/32768/none/PDF Docs/VNCI_Lancering_R2R_.pdf?_gl=1*11dd7xo*_ga*Mzk4MDMzODgwLjE2NDEyMzMyNjM.*_ga_Q5F11Z5K6N*MTY1MTQ5NDQ5NC42LjEuMTY1MTQ5NDYwOS4w.

[240] https://assets.vnci.nl/p/32768/none/PDF Docs/VNCI_Lancering_R2R_.pdf?_gl=1*11dd7xo*_ga*Mzk4MDMzODgwLjE2NDEyMzMyNjM.*_ga_Q5F11Z5K6N*MTY1MTQ5NDQ5NC42LjEuMTY1MTQ5NDYwOS4w

2. **Certainty of business case**: clarity on policy incentive schemes and subsidy programmes which are needed to create a positive business case.
3. **Certainty of availability of energy carriers and infrastructure**: There is sufficient of the energy carrier to be consumed (it is generated and transported to the plant) or sufficient CCS infrastructure.

To have this certainty, apart from the lead time for the sector's own investments' preparation, several elements need to be in place which need to be established timely in cooperation with other stakeholders:

- **Policy design:** Design of key policies takes multiple years from proposal to implementation. Following final adoption of RED III in summer 2023, member states will transpose the individual targets into national policies and regulations, creating certainty on market conditions.[241]
- **Policy support:** The time from application until award for different grant schemes can take up to two to three years, while the design of the policy scheme can take for example 2 years.
- **Renewable energy generation:** Building renewable energy generation capacity takes around 6 years or more.[242] The first half of this time is needed for the planning phase and the second half of is needed for the construction phase.
- **Strengthening the electricity network** takes between 2.5 years up to 15 years.[243] In case network reinforcements are required the time span is seven to ten years with a potential delay of 5 years.[244] If network reinforcements are needed and the process has not yet started it could already be impossible to start commercial operation before 2030.
- **Hydrogen infrastructure:** the lead time of new hydrogen pipelines is around 6 years.[245] This can be faster for repurposed pipelines. The planning phase takes around four years and includes business case development, design, contractor selection, permitting, funding, planning. Permitting may take up to 10 years in the worst case. This will be faster for an existing corridor. The construction phase takes around 2.5 years and includes financial arrangements, procure materials and components, construction.
- **CCS infrastructure:** Large-scale infrastructure projects like Porthos often have a lead time of roughly five years up to ten years, depending on the location.[246] Half of this period is required for preparations, half for realising the planned system and taking it into operation. Porthos itself will be operational after six to seven years after the feasibility study.[247]

[241] https://cedelft.eu/wp-content/uploads/sites/2/2022/03/CE_Delft_210426_50_percent_green_hydrogen_for_Dutch_industry_FINAL.pdf
[242] Based on a detailed planning discussed with one of the members.
[243] https://assets.vnci.nl/p/32768/none/PDF Docs/VNCI_Lancering_R2R_.pdf?_gl=1*11dd7xo*_ga*Mzk4MDMzODgwLjE2NDEyMzMyNjM.*_ga_Q5F11Z5K6N*MTY1MTQ5NDQ5NC42LjEuMTY1MTQ5NDYwOS4w
[244] https://cedelft.eu/wp-content/uploads/sites/2/2022/03/CE_Delft_210426_50_percent_green_hydrogen_for_Dutch_industry_FINAL.pdf
[245] Based on Guidehouse expert opinion (6-8 years), validated in an interview with a member (5 years). Shorter for repurposing of pipelines. https://assets.vnci.nl/p/32768/none/PDF Docs/VNCI_Lancering_R2R_.pdf?_gl=1*11dd7xo*_ga*Mzk4MDMzODgwLjE2NDEyMzMyNjM.*_ga_Q5F11Z5K6N*MTY1MTQ5NDQ5NC42LjEuMTY1MTQ5NDYwOS4w.
[246] https://www.globalccsinstitute.com/wp-content/uploads/2021/11/Global-Status-of-CCS-2021-Global-CCS-Institute-1121.pdf
[247] https://www.porthosco2.nl/en/project/

Annex 12: Policy Asks

Policy Asks
Accelerate public funding & permitting process
Accelerate development of infrastructure
Timely completion of CBAM implementation
Timely use policy levers to drive investment, closing any remaining gap in the production cost of new technologies versus fossil hydrogen: - Provide clarity on the design of CCfD - Set up alternative ways for investment support - Stimulate electrification in EU ETS

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