Hydrogen4EU

CHARTING PATHWAYS TO ENABLE NET ZERO

Hydrogen for Europe study

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This study was designed and prepared by a research consortium composed of IFPEN, SINTEF and Deloitte Finance. The study was directed and managed by **Dr. Johannes Trüby**. **Sébastien Douguet** led the work on policies and coordinated the modelling and the drafting. **Dr. Manuel Villavicencio** designed the overall modelling framework and led the work on hydrogen imports from outside Europe. **Dr. Gondia Sokhna Seck** led the detailed energy system modelling, with essential contributions coming from **Dr. Emmanuel Hache** and **Jérôme Sabathier,** who also both worked on energy data and contributed to the drafting. **Dr. Gunhild A. Reigstad** led the work on the learning optimization model, with essential contributions coming from **Ove Wolfgang**, **Dr. Julian Straus** and **Dr. Jabir Ali Ouassou** who also all worked on energy data, drafting and technology analysis. **Dr. Mona J. Mølnvik** and **Florence Delprat-Jannaud** provided important guidance.

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Executive summary

1. The European Green Deal, published in December 2019 by the European Commission, strengthened the previously announced objectives in terms of sustainability, renewable energy deployment and reduction of greenhouse gas emissions. It sets unprecedented objectives for the decarbonization of the European Union, with a target of net-zero emissions by 2050 and an intermediary 55% reduction of emissions in 2030, compared to 1990.

2. Achieving net-zero emissions in the next thirty years represents a formidable challenge for the entire continent, and especially for its energy sector, which accounts for around three quarters of European greenhouse gas emissions today[1]. Under these climate ambitions, even the hardest-to-abate sectors are now confronted with the challenge of reducing their emissions to near net-zero. The transition towards a decarbonized European energy system needs to mobilize a wide range of solutions to ensure that energy supply remains secure and affordable for all European consumers. While renewables, electrification and energy efficiency are obvious and well-known contributors to a successful decarbonization, it is uncertain whether they are sufficient.

3. Promising technologies are renewable and low-carbon hydrogen; versatile and clean fuels that could be used across the energy supply chain: as energy carrier and as feedstock for other synthetic fuels and industry processes. Renewable hydrogen is produced from biomass or via electrolysis (powered by electricity from renewable sources), while low-carbon hydrogen is based on fossil fuels with low-emissions technologies like carbon capture and permanent storage (reformers with CCS) or pyrolysis. The potential and adaptability of renewable and low-carbon hydrogen have gained the interest of policy-makers and industrials. Not only can hydrogen help decarbonize the energy uses but it can also – together with electrification and renewables – foster energy system integration.

4. Few studies have addressed the potential of hydrogen in decarbonizing the European energy system in a holistic and detailed manner. The *Hydrogen for Europe* research project fills this gap. It is a scientific study based on a joint modelling effort from research centers IFPEN and SINTEF, led by Deloitte. The study delivers a comprehensive analysis regarding the dynamics of the European energy transition and the contribution of renewable and low-carbon hydrogen to the European climate objectives. It seeks to inform industrial players and policy-makers in fostering an optimal pathway to energy transition, that leverages the full potential of low-carbon and renewable technologies and allows to achieve net-zero emissions by 2050 at the least cost.

5. The study relies on a detailed model-based analysis with a full representation of the European energy system and its transition from 2020 to 2050. The modelling architecture combines *MIRET-EU* and *Integrate Europe*, two state-of-the-art partial-equilibrium models, enhanced specifically to tackle the objectives of this study. Both models are research-oriented tools, built on sound mathematical formulations, that have transparent modelling frameworks and deliver robust results. The *HyPE* model developed by Deloitte for this project is used to explicitly assess the potential of imports from neighboring regions, thus going further than what is usually represented in European hydrogen studies and reflecting the recent expectations on the role of imports.

6. This joint modelling effort is among the first to consider explicitly the latest European targets (e.g. the 55% CO_2 emissions reduction by 2030 and climate neutrality by 2050). It allows for an analysis of hydrogen's potential with a detailed technological, sectoral and geographic scope, including 27 European countries and considering the potential of hydrogen imports from North Africa, the Middle East, Russia and Ukraine. It considers the techno-economic parameters and drivers behind each main technology option. The modelling framework accounts for how investments lead to cost reductions through technology learning; an innovative approach typically not included in large-scale modelling of energy systems. Its energy system perspective also allows to represent, in detail, the interdependencies between the different sectors, assessing how to leverage the potential of energy system integration. Moreover, comprehensive data research has been carried out, not only relying on the existing literature, but also discussing with numerous experts and a wide range of hydrogen industry stakeholders to enhance data quality.

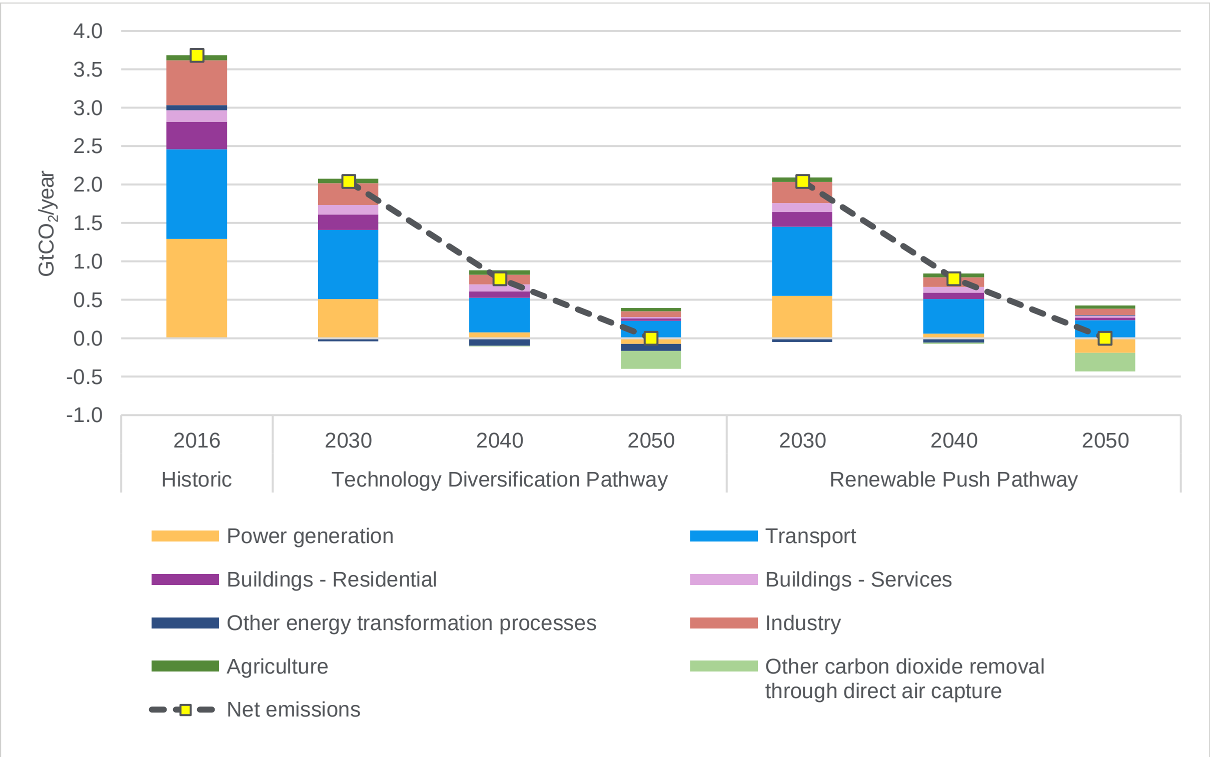
[1] European Environmental Agency, 2018.

7. The *Hydrogen for Europe* research project explores two pathways that lead to carbon neutrality. The "Technology Diversification" pathway provides insights into how an inclusive approach, that harnesses a wide-range of decarbonisation technologies, can help minimize the cost of the energy transition. The "Renewable Push" pathway examines the possible impact of a deliberate focus on renewable technologies; a prominent feature of the current policy debate. It differs from the other pathway by a series of targets on the share of renewables in gross final energy consumption, which is more ambitious for 2030 compared to today's policy (40% versus 32% in the Technology Diversification pathway) and includes binding targets for 2040 (at 60%) and 2050 (at 80%). Both pathways otherwise assume a level playing field between technologies.

8. Each of the two pathways presented in this outlook depicts an alternative future, a trajectory along which the European energy system could travel if its underlying economic, technological and regulatory assumptions unfold in a certain way, based on a least-cost optimization approach. They should neither be misinterpreted as forecasts nor misunderstood as the only viable pathways. The objective of our pathways is to stimulate debate and illuminate strategic decision-making, not to predict the future correctly or prescribe a certain evolution.

9. The two pathways follow a progressive trajectory towards deep decarbonization and achieve climate neutrality by 2050 (figure 1). By 2030, CO_2 emissions at European level are reduced by 55% compared to 1990 levels. This reduction is led by fuel switching in the power and industry sectors. CO_2 emissions then continue to decrease precipitously to reach net-zero emissions in 2050. The results suggest that the development of a fully operational CCUS value chain (including carbon capture and storage from fossil fuels and biomass and direct air capture) is indispensable for the success of the energy transition. Negative emissions from biomass and direct air capture with CCS serve to offset the residual emissions from the hard-to-abate sectors.

Figure 1. Evolution of CO_2 emissions by sector in the Technology Diversification and Renewable Push pathways, 2016 to 2050



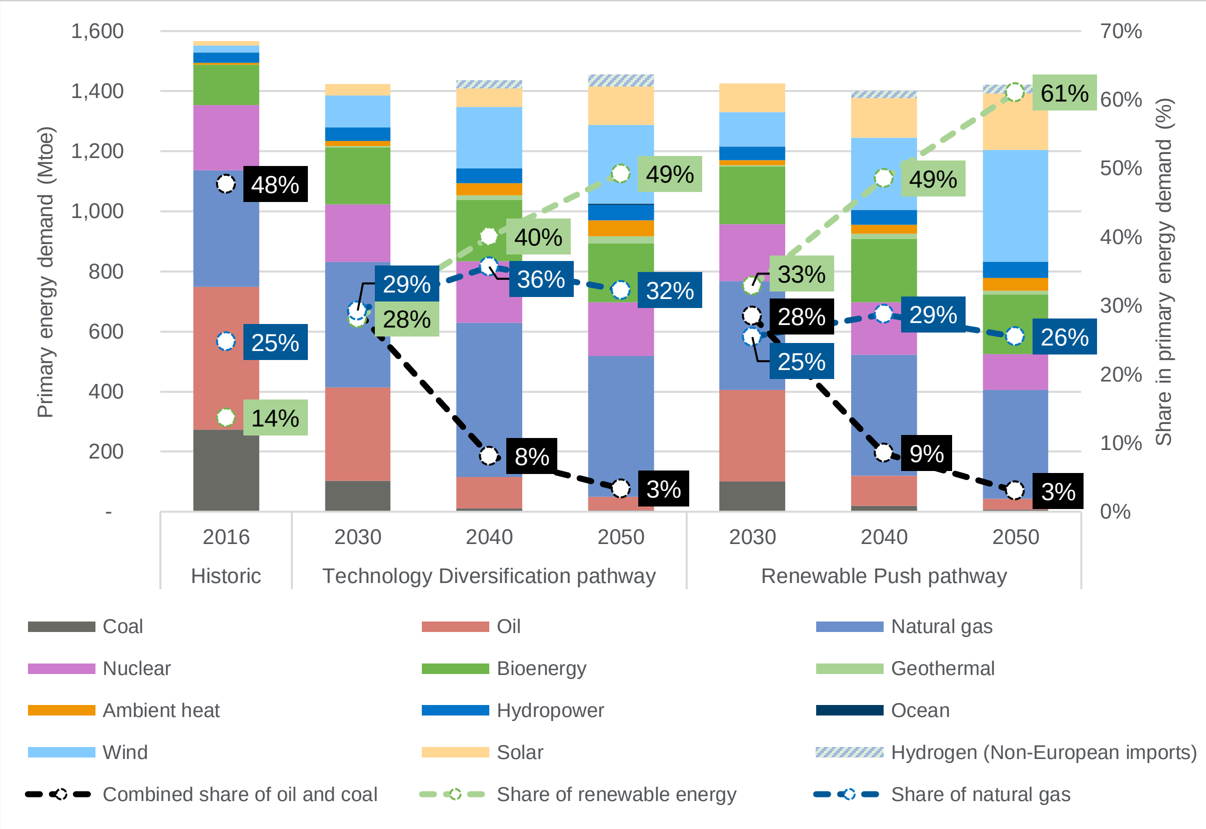
Other energy transformation processes include hydrogen production and refining.

Source : *Hydrogen for Europe* study

10. In achieving net-zero emissions, the primary energy mix is fundamentally reshaped in the two pathways (figure 2). Primary energy demand sees a pronounced shift to renewable energy. The share of renewable energy in primary energy demand reaches between 50% and 60% in 2050, sustained mostly by significant investments in wind and solar. This uptake is mirrored by a declining role of oil and coal, whose combined share in primary

energy demand drops to 3% in 2050. Natural gas is an element of continuity in the energy mix: use of natural gas remains resilient also in the Renewable Push pathway, where it provides important flexibility as a complement to renewables. Natural gas offers greatest benefits when coupled with CCUS. Much of its use is thus displaced from final energy consumption to transformation processes, e.g. for hydrogen production, where low-carbon hydrogen helps foster the growth of the hydrogen economy, or in power generation, where natural gas provides flexible power for load following and back-up generation.

Figure 2. Evolution of total primary energy demand in the Technology Diversification and Renewable Push pathways, 2016 to 2050



Source : Hydrogen for Europe study

11. At final consumption level, energy efficiency and electrification play their expected role in the transition to net-zero emissions. Final energy consumption is reduced by nearly a quarter in 2050 when compared to 2005, achieving along the way, the binding target of 32.5% reduction by 2030 (compared to a business-as-usual scenario) for the EU member states. Electricity's share in gross final energy consumption increases by almost 50% between today and 2050, with step changes observed in industry, transport and buildings. While this confirms the high expectations put on electrification, it also highlights the complementary roles played by molecules and other energy carriers to decarbonize end-use; also in the Renewable Push pathway that sees an acceleration of renewable deployment. As such, more than half of total gross final energy consumption is supplied by non-electrified technologies in 2050 in the two pathways.

12. Hydrogen plays a major role in the decarbonization of the energy sector. In light of the ambitious decarbonisation objectives, European hydrogen demand in our pathways exceeds 30 Mt by 2030, which is triple the current policy objective described in the EU hydrogen strategy. Demand for hydrogen ramps up substantially over the 2030s and 2040s and exceeds 100 million tons (Mt) by 2050 in both pathways. This is equivalent to more than 3,300 TWh or around 300 Mtoe (in lower heating value). The Renewable Push pathway, which shows a stronger deployment of renewable energy, demonstrates hydrogen's complementarity with renewable energies, helping to absorb, store and transport the bulk of the additional energy from renewable sources.

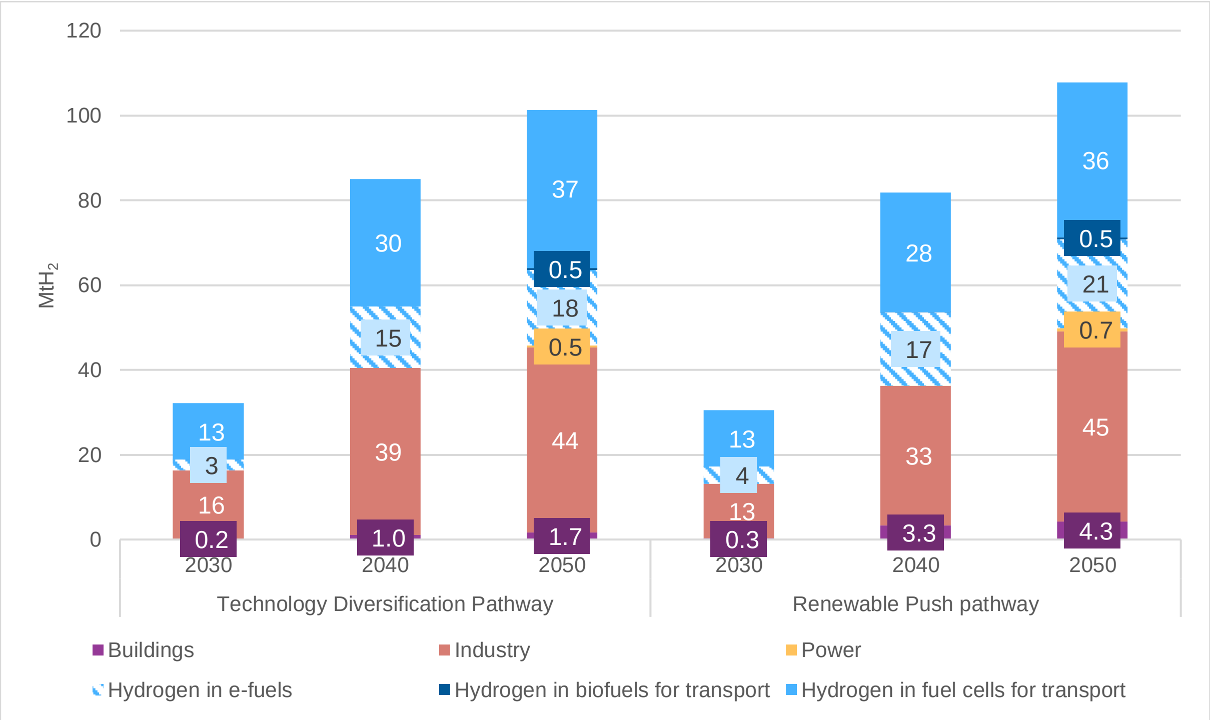
13. The sectoral breakdown of hydrogen demand confirms the versatility of hydrogen in decarbonizing the energy system (figure 3). Hydrogen can provide an answer to the challenges of deep electrification and the limits of energy efficiency improvements. It proves to be a cost-efficient solution for certain hard-to-abate energy uses in transport and industry.

a. More than half of hydrogen demand (above 50 Mt) comes from the transport sector, either for consumption in fuel cells, as intermediary feedstock for the production of synthetic fuels, or for use in biorefineries. By 2050, demand for hydrogen for e-fuels reaches around 20 Mt, with the majority being used in the transport sector and especially aviation. Hydrogen, e-fuels and other hydrogen-based solutions provide energy-dense fuels and gases to heavy and long-distance road transport, aviation and shipping, and thus address some of the limitations electric mobility faces in terms of energy density, weight, range and refueling.

b. Industrial hydrogen demand, primarily for energy, reaches some 45 Mt by 2050. Hydrogen is consumed in a diverse set of industrial sectors mainly to provide process heat and steam. Its potential is particularly high in the steel sector and in the chemical industry[2].

c. Hydrogen also contributes to emission reduction in buildings and power generation (with slightly greater use in those sectors in the Renewable Push pathway). Combined, buildings and power generation represent up to 5 Mt of hydrogen demand in 2050 in the Renewable Push pathway. This moderate uptake is notably due to trade-offs between a wide range of available options to decarbonize those sectors such as biogas, direct renewables, heat pumps and continued use of natural gas[3].

Figure 3. Evolution of hydrogen energy-related demand by sector in the Technology Diversification and Renewable Push pathways, 2030 to 2050



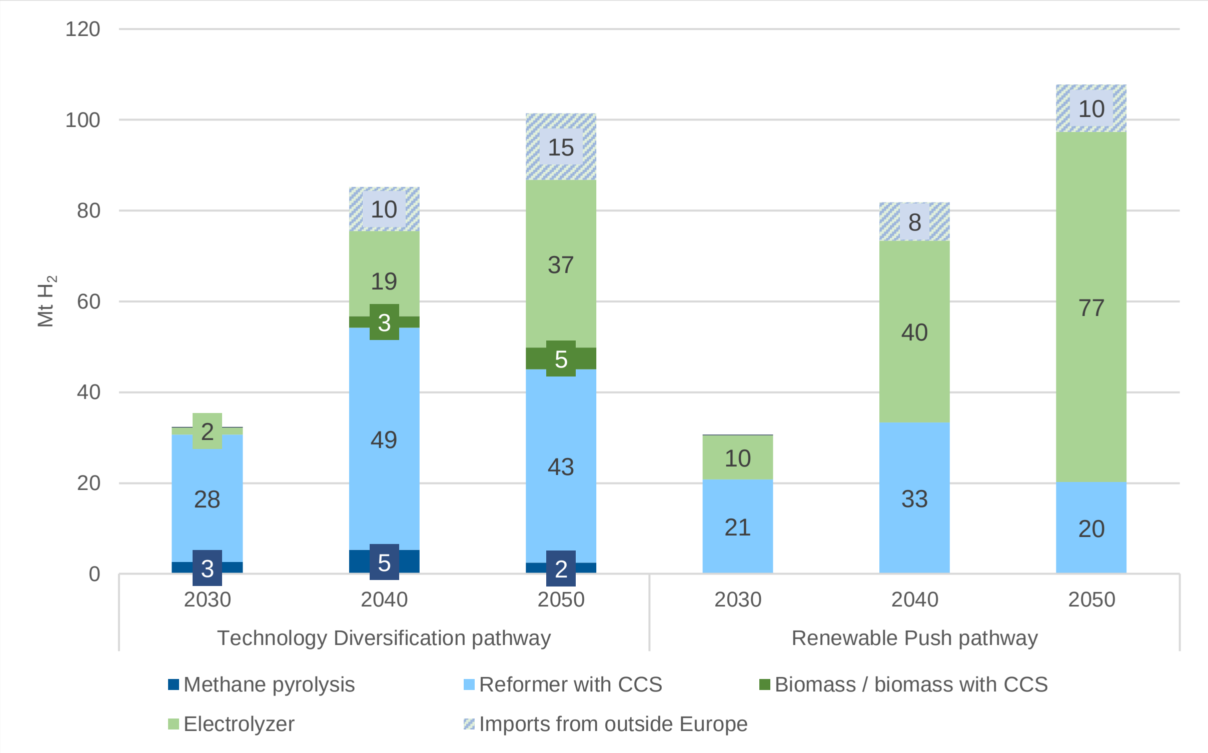
Source : *Hydrogen for Europe* study

[2] Note that consumption in refineries is attached to the transport sector and not to the industry sector.
The energy-related potential of hydrogen in industry should be supplemented by further assessment of the future hydrogen demand as a feedstock in chemical processes, which is out of the study's scope. This could mean that the potential of hydrogen for industry (both as a feedstock and as an energy fuel) in Europe is higher than what the Hydrogen for Europe's findings suggest.
[3] It should be noted that the inclusion of hydrogen turbine technologies in the energy system modelling scope could lead to higher hydrogen uptake in the power sector and is a subject for further studies. Likewise, constraints in the supply of renewable electricity and the conversion to heat pumps, efforts to protect the value of existing distribution grids and wider economic considerations, such as the creation of regional hydrogen ecosystems, could locally confer a more important role to hydrogen in buildings.

14. In the two *Hydrogen for Europe* pathways, European hydrogen production rises steeply over the next three decades, relying on a diverse production mix, comprising renewable and low-carbon technologies (figure 4). Hydrogen output in Europe soars to nearly 90 Mt in 2050 in the Technology Diversification pathway. Output increases markedly between 2030 and 2040, going from just over 30 Mt in 2030 to around 75 Mt in 2040, reflecting the accelerating uptake of the hydrogen economy after 2030. The pathways highlight the importance of keeping the momentum that is currently seen in Europe behind hydrogen production projects. Early investments are needed to increase the volumes of hydrogen production as soon as the next decade and create the necessary scale.

15. The pathways show the diversity of hydrogen production technologies and the complementarity between renewable and low-carbon routes. While low-carbon hydrogen plays a critical role in establishing a hydrogen economy in the first half of the outlook period, renewable hydrogen develops mainly in the second half of the outlook period and meets the bulk of the additional demand growth. In the Technology Diversification pathway, the production mix is balanced in 2050 with renewable and low-carbon sources both providing about half of the European output. In the Renewable Push pathway, underpinned by higher policy targets for renewable energy deployment, renewable hydrogen takes over during the late 2030s and becomes the biggest hydrogen production source by 2040. As in the other pathway, low-carbon hydrogen plays an important role to establish the hydrogen economy: it serves most of the demand in the first half of the outlook period.

Figure 4. Evolution of European hydrogen supply in the Technology Diversification and Renewable Push pathways, 2030 to 2050



Source : *Hydrogen for Europe* study

16. The development of low-carbon hydrogen and of other technologies such as biomass with CCS is highly dependent on the parallel deployment of the CCUS value chain and the ability of CO_2 storage capacities to grow rapidly over the next thirty years. The Technology Diversification pathway reaches an injection capacity limit of 1.4 Gt/year in 2050. This injection capacity has been derived as a reasonable estimate from a survey of existing literature and expert knowledge. However, the modelling also shows that higher levels of CO_2 injection capacities would allow for a bigger role for low-carbon hydrogen.

17. Achieving high levels of renewable hydrogen and renewable energy in the system, in the latter half of the period to 2050, requires significant investments, underpinned by accelerated deployment of renewable and electrolyzer supply chains and the optimal utilization of renewable energy potential in Europe. In the Renewable Push pathway, more than 1,800 GW of dedicated solar and wind capacities and more than 1,600 GW of electrolyzers need to be installed by 2050 to sustain the renewable hydrogen trajectory and get to over 75 Mt of output by 2050. The availability of bioenergy is another parameter that could shape the future European energy system and the prospects for renewable hydrogen. The modelling shows that a greater potential would lead to a more important role of biomass with CCS, contributing to hydrogen and power production and displacing direct air capture for negative emissions.

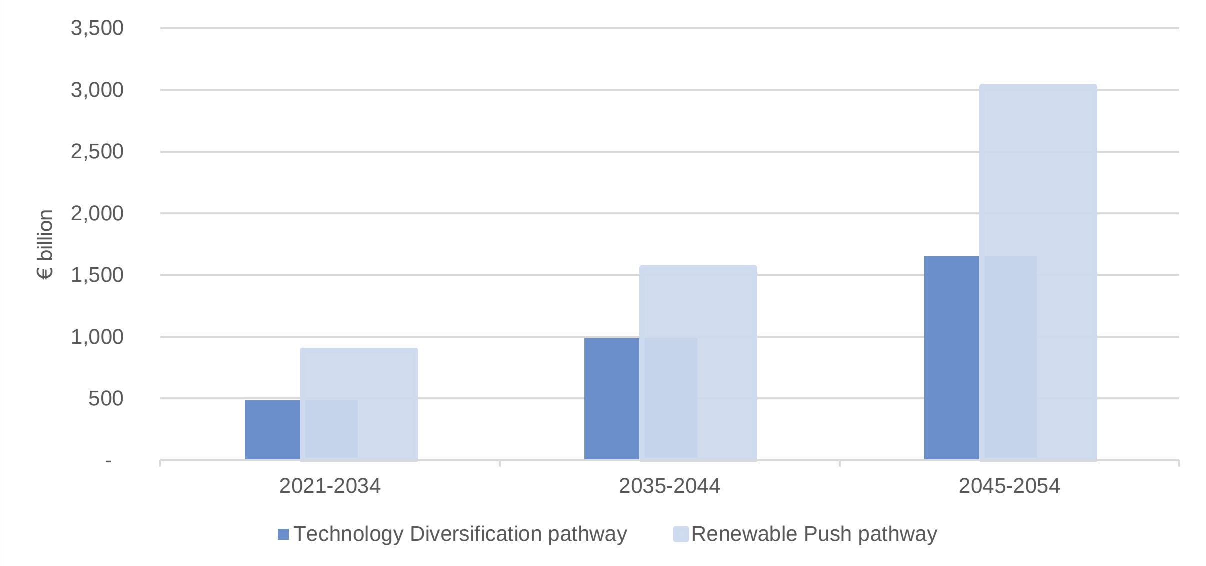
18. Part of the hydrogen needed in the transition to net-zero emissions is imported from outside Europe. The results show that imports of renewable and low-carbon hydrogen burgeon in the 2030s, including from North Africa, Russia, Ukraine and the Middle East. Imports play an important role in complementing European production of hydrogen and serving countries that have limited options for cost-efficient domestic hydrogen production. In the Technology Diversification pathway, up to 15 Mt of imports are able to compete on cost terms with domestic production, thus contributing nearly 15% to total hydrogen supply in Europe.

19. Trade between countries is needed to transport the hydrogen molecules from where they are produced to where they are consumed. Infrastructure, both cross-border and national, are developed progressively in the system to link demand to supply. The results underline the importance of repurposing existing natural gas infrastructure, protecting the value of the existing infrastructure and unlocking a lower cost option for hydrogen transportation. The pathways also show some potential for blending hydrogen with natural gas; with blending rates up to 15% in certain periods and in some countries. Blending with natural gas helps, in particular, to reduce emissions in the buildings sector and in industry.

20. Considering the hydrogen value chain as a whole, the results show that trillions of euros in investment are needed to leverage the full potential of hydrogen in the energy transition[4] (figure 5). These investments need to start in a timely manner to ensure demand and supply grow in lockstep, avoid technology lock-outs and mitigate risk of stranded assets. Investors need to start investing from the early 2020s in low-carbon hydrogen to take most advantage of their window of opportunity and avoid risk of becoming stranded as other sources become prominent or access to CO_2 storage becomes scarce. The difference of more than €2 trillion in capital spending between the two pathways demonstrates the higher capital intensity of a pathway focusing on renewable assets and electrolyzers. As such, one of the main challenges of the Renewable Push pathway is the ability to mobilize almost twice as much capital over the next thirty years to accomplish the hydrogen uptake.

[4] The time-steps in the planning period are: 2020 (today's system; no new investments), 2030, 2040 and 2050. Each period represents 10 years, e.g. 2045 – 2054 for 2050. The first day after the planning horizon is thus 2055.

Figure 5. Investments in the hydrogen value chain (including offgrid renewables) per period supply in the Technology Diversification and Renewable Push pathways, 2021 to 2054



Source : *Hydrogen for Europe* study

21. The Technology Diversification pathway underscores the value of adopting an agnostic approach with a level playing field between technologies and supply options and provides for a least-cost pathway to net-zero emissions. Compared to a pathway that focuses on acceleration of renewable energy deployment, it allows de-risking investments, relieving some of the financing and technological bottlenecks and enabling a more competitive and efficient energy system. In terms of total energy system costs, this approach would help save more than a trillion euros over the next thirty years, representing more than €70 billion of savings per year on average.

22. The trajectory drawn by the Technology Diversification pathway is founded on two principal paradigms: technology neutrality, assuming a comprehensive approach to decarbonization that includes the potential of all technologies, and reliability, transparency and effectiveness of the policy framework. It assumes that all barriers and uncertainties are addressed along the road by policy-makers and industrial leaders. In reality, despite some indisputable advances on the European policy and industrial fronts, much of the work is still lying ahead and the enablers identified in the *Hydrogen for Europe* study are not there yet to allow for an optimal contribution of hydrogen to the energy transition. The current regulatory and policy framework still lacks the tools and measures needed to stimulate hydrogen's upscaling, and more generally, to allow clean technologies to compete on a level playing field with existing CO_2-emitting solutions and to break even in the long term. The policy announcements and publications of the last year also put clear emphasis on certain technologies like renewable hydrogen, at the risk of creating a two-speed system and limiting the choice of available solutions.

23. The momentum built over the last few years thus needs to be followed by concrete actions to implement the building blocks of the European energy transition and of the hydrogen policy framework. The announced 'Fit for 55' policy package brings an opportunity to fundamentally reshape European energy policy. It is also the occasion to foster an optimal pathway to hydrogen deployment and emission reduction that complements the least-cost principle with other key policy considerations like energy security and social acceptance. The results of the *Hydrogen for Europe* study and their underlying assumptions can help inform the design of next policy packages and measures. The results can be used to better understand the gap between the current framework and the enablers of a least-cost pathway. In order to achieve the overarching policy objective of net-zero emissions by 2050, five main guidelines are proposed:

    1. Include externalities of CO_2 emissions in the economics of the energy system and incentivize CO_2 abatement technologies and uses: CO_2 pricing is today limited in scope and effect, which prevents renewable and low-carbon technologies from competing on a level playing field with emitting technologies. The reform of the EU-ETS and the reflections around a carbon border adjustment mechanism are

opportunities to address obstacles to coordinated and efficient CO_2 pricing and reflect the reinforced objectives of climate neutrality. There is possibly a need to complement them with other regulatory tools such as direct support, mandates or binding targets.

2. Design accounting rules for CO_2 content of energy: a common understanding on how to determine the CO_2 content of different forms of energy is crucial to compare their merits in achieving the transition. This is an important step in establishing a level playing field between technologies. European policy-makers have opportunities coming up to progress on CO_2 accounting e.g. the revision of the Renewable Energy Directive with regard to a EU-wide scheme of guarantees of origin, and the finalization of the EU Taxonomy, that should define a common CO_2 threshold applicable to low-carbon and renewable solutions.

3. Foster innovation and R&D to bring clean technologies to commercial viability: policy-makers need to create the right conditions for innovation to take place and give new clean technologies (e.g. renewables, CCS, electrolysis or pyrolysis) a hand so they can enter the market while keeping the virtuous learning-by-doing process for mature technologies going. The Horizon Europe program and the ETS-financed Innovation Fund are particularly well-suited for hydrogen technologies. National support schemes and State aid can also be used to support the uptake of less mature technologies and encourage learning-by-doing and cost decrease. Finally, the IPCEI (important project of common European interest) could be a powerful instrument to accelerate the roll-out of large-scale value chains and infrastructure.

4. Enable financing of investments: optimal timing of investments in the hydrogen value chain implies that all components need to anticipate demand growth and the establishment of a hydrogen market. Policy-makers can help mitigating the financing risks and open the door to low-cost financing. The upcoming ‘Fit for 55’ legislative package is important in alleviating uncertainty. Many public schemes and regulatory tools are, or could be, available to finance the European Green Deal and support innovation and competitiveness for low-carbon and renewable technologies, starting with the European and national Covid-19 recovery plans and the Just Transition Fund.

5. Ensure system integration and create a market: the upcoming framework for competitive decarbonized gas markets is expected to establish the foundation of the future internal market for hydrogen, which would enable trade of hydrogen within Europe. It should progressively establish an organized and liquid market for hydrogen that could be integrated within the existing gas market. It should also introduce a phased reform of gas infrastructure regulation, accommodating a full-fledged regulatory framework for hydrogen infrastructure. Taking a holistic perspective on the energy transition, the future hydrogen policy framework could be embedded in the European Commission’s efforts towards energy system integration.

Table of contents

Glossary

Term	Definition
Ambient heat	Energy captured from the air, the ground or water for use by heat pumps
BECCS	Bioenergy with carbon capture and storage
BEV	Battery Electric Vehicles
Biorefineries	Production process for first and second-generation biofuels
CCS	Carbon capture and storage
DAC	Direct air capture
DACCS	Direct Air Capture with permanent carbon dioxide storage
Decarbonized	Related to CO_2 emissions: from which CO_2 emissions have been removed
Distributed heat	Heat produced in a centralized way and distributed to final locations for end-use requirements
EC	European Commission
e-fuels	E-fuels are gaseous and liquid fuels such as hydrogen, methane, synthetic petrol, and diesel fuels generated from renewable electricity
Energy transformation process	(or energy conversion) Process to transform one form of energy to another. For example, solar irradiation is converted into electricity thanks to solar panels.
FCEV	Fuel Cell Electric Vehicle
Final energy consumption	Total energy consumed by end users, such as households, industry and agriculture. It is the energy which reaches the final consumer's door and excludes that which is used by the energy sector itself.
GHR/ATR	Gas Heated Reforming / Autothermal Reforming
Gross final energy consumption	The gross final energy consumption is the energy used by end-consumers (final energy consumption) plus grid losses and self-consumption of power plants. It also includes international aviation according to Eurostat definition but excludes maritime bunkers.
ICE	Internal Combustion Engine
IPCEI	Important Project of Common European Interest
LHV	Lower Heating Value. 1 Mt of hydrogen is equivalent to 120 PJ (around 33.3 TWh) in lower heating value.
Low-carbon hydrogen	Hydrogen produced from low-carbon energy sources such as nuclear or fossil fuels with carbon capture (e.g., reformers with CCS, pyrolysis)
$MtCO_2$	Unit of mass measurement of CO_2 (carbon dioxide): Million metric tons of CO_2
MtH_2	Unit of mass measurement of hydrogen: Million metric tons of hydrogen
Mtoe	Unit of energy measurement: Million metric tons of oil equivalent
Offgrid electrolyzer	Electrolyzer connected directly to renewable power plants for renewable hydrogen production
Ongrid electrolyzer	Electrolyzer withdrawing electricity from the main power grid for hydrogen production
PCI	Project of Common Interest
PHEV	Plug-in Hybrid Electric Vehicle
Renewable hydrogen	Hydrogen produced from renewable energy sources. It includes hydrogen produced from biomass or electrolysis, assuming that the electricity stems from renewable sources.
SMR	Steam Methane Reforming

From \ To	TWh	Mtoe	bcm	MtH_2	TBtu	EJ
TWh	1	0.086	0.094	0.03	3.41	0.004
Mtoe	11.63	1	1.1	0.35	39.68	0.042
bcm	10.6	0.91	1	0.32	36.30	0.038
MtH_2	33.33	2.87	3.14	1	113.7	0.120
TBtu	0.293	0.025	0.028	0.009	1	0.001
EJ	277.8	23.88	26.11	8.33	947.8	1

Note: lower heating value (LHV) is assumed for conversions to Mt H_2

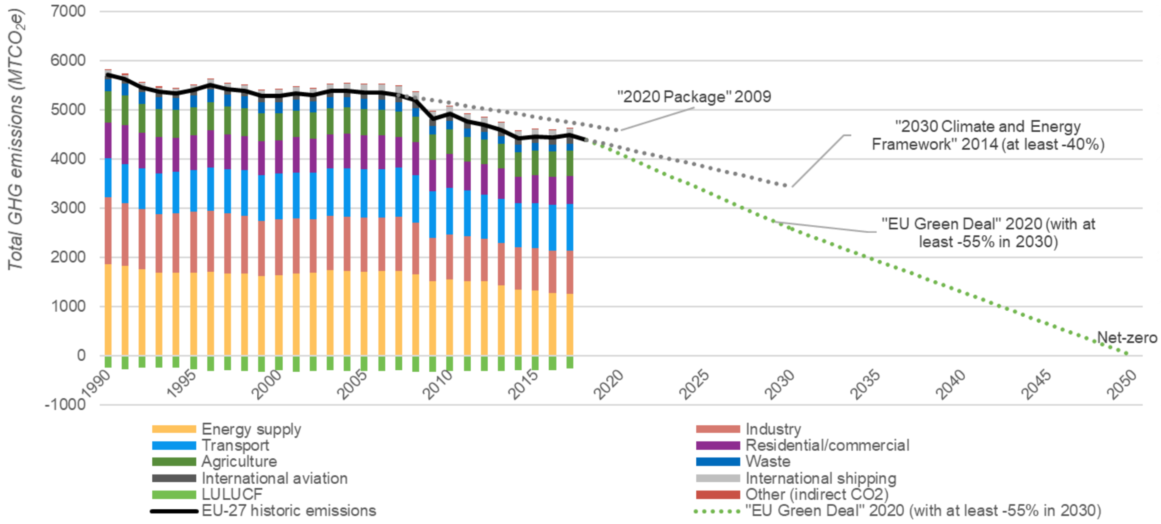
1 Introduction

1.1 Context of the study

24. Following the Paris Agreement, the European Union has committed to keeping the global temperature increase in 2100 to well below 2°C, with efforts to limit it to 1.5°C, and has set unprecedented ambitions in terms of sustainability, renewable energy deployment and reduction of CO_2 emissions (figure 6). The European Green Deal, published in December 2019 by the European Commission, aims at achieving climate neutrality by 2050 with the first European climate law. The Green Deal establishes a framework to achieve this objective, which has already led to reinforcing the 2030 EU targets for climate and energy. These now include a 55% cut in greenhouse gas emissions (compared to 1990 levels) by 2030, renewable energy reaching a share of 32% of gross final energy consumption and energy efficiency improving by 32.5% relative to a business-as-usual scenario[5]. With its Green Deal, the EU is a frontrunner in terms of decarbonization objectives and has actively started to develop policies and measures to achieve deep decarbonization.

25. In light of the emissions reductions over the past thirty years, achieving net-zero greenhouse gas emissions by 2050 represents a formidable challenge for the entire continent, and especially for the energy sector (figure 6). Since 1990, emissions have fallen by less than a quarter. Given that the last tons are typically the hardest to abate, it is clear that the European energy sector needs to significantly ramp up its efforts, based on adequate policy frameworks and regulations.

Figure 6. European energy transition and the policy challenges

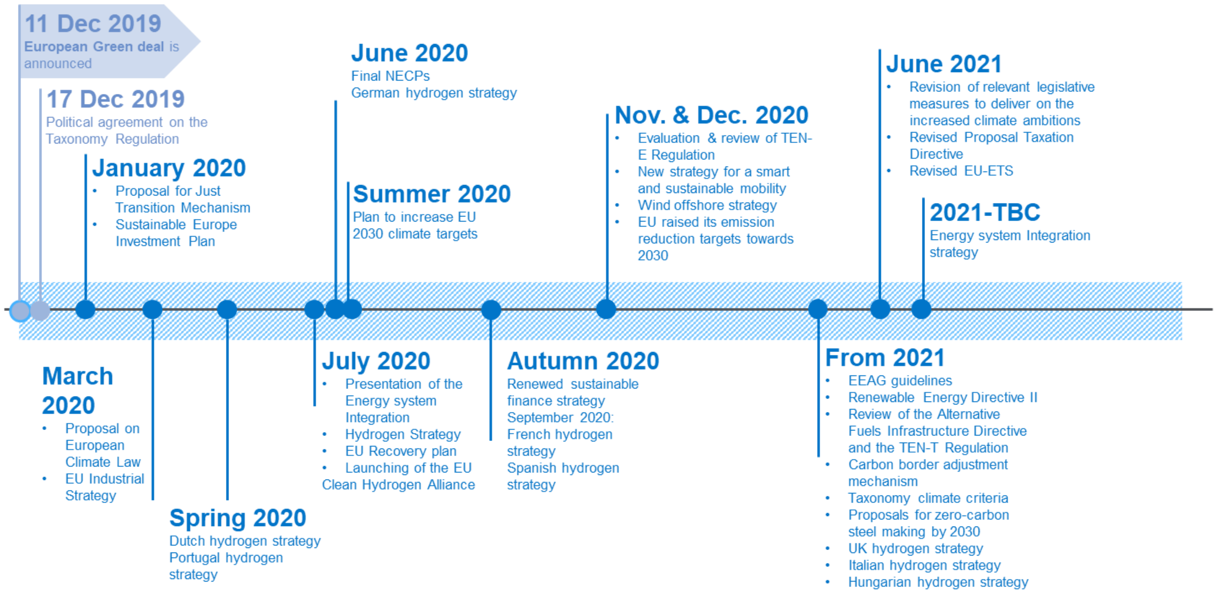


Source : *Hydrogen for Europe* study from data of the European Environment Agency

26. Following the publication of the Green Deal, national and European policy-makers have begun to develop decarbonization frameworks (figure 7). Several directive policy papers such as the industrial, renewable offshore, energy system integration, and smart and sustainable mobility strategies were published, each one focusing on a specific area of the EU economy and its role in the decarbonization process. Besides, policy-makers have reacted to the Covid-19 pandemic and the resulting economic crisis by focusing their recovery plan and the underlying funds on the transition towards carbon neutrality. The EU Covid-19 Recovery Fund, announced in May 2020, has a clear focus on the energy transition and implies that funding is available for the roll-out of clean technologies.

5 https://ec.europa.eu/clima/policies/strategies/2030_en

Figure 7. Timeline of main European policy milestones since 2019



Source : *Hydrogen for Europe* study

27. These high-level policy milestones lay the foundations of the future climate-neutral European economy, and will be followed by many specific regulations setting the rules and frameworks for each sector. Many of these are expected for release within 2021 in an "avalanche of regulations". These future regulations address several barriers that currently prevent the uptake of the key decarbonization solutions, with new measures and instruments.

28. In their work, policy-makers need to recognize and anticipate the transformation needs and potentials of the European energy system. The transition towards a decarbonized energy system needs to mobilize a wide range of technology options to ensure that energy supply remains secure and affordable for all European citizens. Tackling climate change is urgent and thus requires simultaneous (rather than consecutive) decarbonization of all end-use sectors. Restricted technology and fuel choices lead to bottlenecks, delaying the transition and increasing its cost. Promising technologies are renewable and low-carbon hydrogen; versatile and clean fuels that could be used across the entire energy supply chain: as energy carrier and as feedstock for other energy fuels and industry processes . The potential and adaptability of renewable and low-carbon hydrogen have gained the interest of policy-makers and industrials both to help decarbonize energy uses but also – together with electrification and renewables – to foster energy system integration. The value proposition of hydrogen is clear and is the foundation of this study:

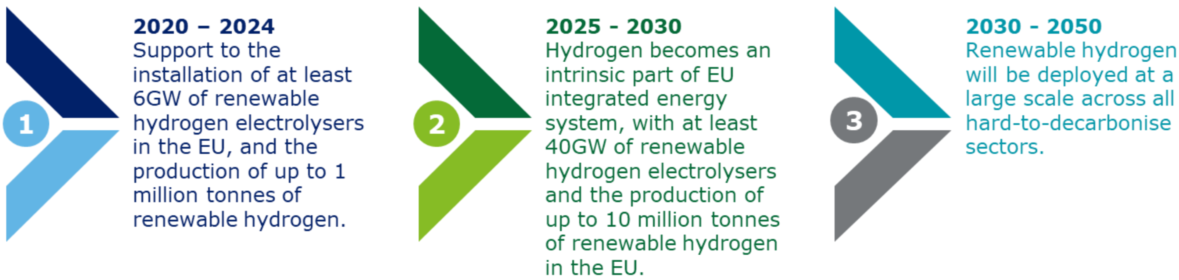
- Renewable and low-carbon hydrogen, produced from decarbonized electricity or from fossil fuels (combined with CCUS technologies or via pyrolysis), offer significant potential to reduce CO_2 emissions.
- Hydrogen offers a solution to support the energy transition in sectors that are technically difficult or particularly costly to decarbonize such as industry (e.g. process heat or steam) and freight transport, aviation or navigation.
- The different production routes of hydrogen offer bulk energy potential while the physical properties of hydrogen would allow it to use large parts of the existing gas infrastructure.
- Integrating renewable and low-carbon hydrogen in the energy system during the transition could help avoid stranded assets in the capital-intensive natural gas infrastructure sector. Hydrogen could allow decarbonizing parts of the natural gas sector with manageable adjustment and costs while mitigating the challenges and additional costs of a deep electrification.
- Hydrogen can relatively easily be stored and could thus play an important role in managing the seasonality of energy demand and the variability of weather-dependent sources of energy supply. It could also be the case in the power sector, where hydrogen could be used to balance intermittent and seasonally changing renewables.

- Finally, developing renewable and low-carbon hydrogen technology today opens the door for long-term options such as biomass with CCUS or pyrolysis of biomass to achieve negative emissions.

29. As such, hydrogen could be the missing piece in the European decarbonization puzzle. Over the past few years policy-makers have started preparing the ground for the uptake of hydrogen economy in the Europe. In this regard, the EU hydrogen strategy[6] of July 2020 makes it clear that hydrogen is part of the European strategy towards decarbonization. The strategy highlights the convictions of the European Commission regarding the role of hydrogen in the transition towards carbon-neutrality:

   - Hydrogen large-scale deployment is a key priority for achieving the EU's clean energy transition and reaching the ambition of carbon-neutrality in 2050;
   - Hydrogen produced from renewable energy sources takes highest priority within the strategy (see figure 8). However, other forms of low-carbon hydrogen[7] are not excluded. These forms of low-carbon hydrogen are needed in the short to medium term to reduce emissions from existing hydrogen production and complement renewable hydrogen until sufficient capacity is available to serve all demand.

Figure 8. The EU hydrogen strategy describes a three-step approach to establish renewable hydrogen at the heart of the hydrogen economy



Source : *Hydrogen for Europe* study

30. The momentum behind hydrogen is also visible at country level. Several EU Member States have already published their own national hydrogen strategies (the Netherlands, Germany, France, Spain, Portugal, Austria, and soon Italy or Hungary). Enthusiasm for hydrogen is also observable beyond the borders of the EU, for instance in Norway or the United Kingdom.

31. Policy-makers' enthusiasm is mirrored at industry level, with a clear uptake in hydrogen-related projects[8] and the growing membership of the European Clean Hydrogen Alliance.

32. Nevertheless, the current momentum behind hydrogen, both from governments and industry, should not conceal the many uncertainties and barriers that remain:

   - Existing mechanisms to mitigate the long-term financial risks of the large-scale investments are insufficient. Therefore, the conditions for innovation and deployment, leading to rapid cost decrease for hydrogen production technologies are still missing, or at least uncertain.
   - Benefits of renewable and low-carbon hydrogen are insufficiently recognized.
   - Despite a hike in the first quarter of 2021, current CO_2 prices do not yet send the appropriate price signals for technology deployment that is consistent with the net-zero objective.
   - Currently, there is no dedicated incentive scheme to support renewable and low-carbon hydrogen production.

[6] The strategy was published in parallel of the communication of the Energy System Integration Strategy, which describes a holistic approach for the decarbonization of energy systems in the EU (sector coupling).
[7] (including hydrogen produced from natural gas coupled with CCS, pyrolysis and hydrogen based on low-carbon electricity that is not 100% renewable)
[8] For instance, as of February 2021, more than 200 projects applied in Germany for hydrogen IPCEI status.

- On the infrastructure side, strategic choices are opening up, from blending hydrogen with natural gas to repurposing existing infrastructures or building a dedicated hydrogen transport network. However, little is known about the optimal development of the hydrogen-related infrastructure that is needed for the uptake of the European hydrogen economy.

33. Policy-makers should address these elements to ensure that hydrogen can unlock its full value in the energy transition. The European Commission already started the clarification process regarding its views on the future of the hydrogen economy. The recently published revision proposal of the TEN-E regulation enables hydrogen projects to apply for Project of Common Interest status, making them eligible to the Connecting Europe Facility. Policy-makers now intend to move forward with the future 'avalanche of regulations' from 2021 onward. This action plan should rely on sound analyses and a clear set of policy and economic criteria, in order to shape the future European hydrogen economy and allow for hydrogen's optimal contribution to the energy transition.

34. Studies (e.g., EC Clean Planet for all[9], Gas for Climate[10], Eurogas[11]) have looked at the decarbonization of the EU energy sector and presented insights on the future of hydrogen. However, no study has systematically analyzed the interactions between hydrogen and other technologies in the entire energy sector. Likewise, no published research has rigorously assessed the cost savings that low-carbon and renewable hydrogen could bring to the energy transition and the dynamic effects behind this mechanism.

35. In this context, there is value in an objective, comprehensive, and robust study on the role of renewable and low-carbon hydrogen in the European energy transition. The findings of this study can help policy-makers take a holistic approach to decarbonization and design a regulatory framework that leverages the benefits of all renewable and low-carbon technologies, including different types of hydrogen.

1.2 Objective of the study

36. The Hydrogen for Europe study is a research-based project that assesses how renewable and low-carbon hydrogen can contribute to the European energy transition. It is underpinned by a joint modelling effort from research laboratories IFPEN and SINTEF, which combine their respective MIRET EU and Integrate Europe models to deliver robust and comprehensive results regarding the optimal contribution of low-carbon and renewable hydrogen to the European climate targets. Together, the models enable to provide a holistic and detailed analysis of the hydrogen future development potential. They explore the detailed dynamics of the European energy transition until 2050 and the place of hydrogen within it.

37. The study seeks to inform industrial players and policy-makers in fostering an optimal pathway to energy transition, that leverages the full potential of low-carbon and renewable technologies and allows to achieve net-zero emissions by 2050 at the least cost. This objective is framed by a set of research questions that have underpinned the whole research project:

    a. **How can renewable and low-carbon hydrogen contribute to the European energy transition?** The study assesses the optimal role of low-carbon and renewable hydrogen in the energy transition using a least cost approach. It explores the mix of technologies, energy carriers and solutions that are needed to achieve net-zero emissions, with a comprehensive grasp on national and sectoral specificities and constraints. It shows how low-carbon and renewable hydrogen technologies can be progressively and complementarily developed to kick-start and sustain the development of the European hydrogen economy.

    b. **What decisions and pathways help to benefit from learning effects, bring down technology cost?** The study gives details on the industrial actions and investments that are needed to foster climate neutrality and the role of hydrogen technologies in this context. It gives insights on the development strategies, seeking specifically to optimize the deployment of technologies and assets in the system and leverage the

[9] European Commission, 2018. A clean planet for all.
[10] Guidehouse, 2020. Gas decarbonisation pathways 2020-2050 – Gas for Climate
[11] DNV-GL for Eurogas, 2020. European carbon neutrality: the importance of gas

benefits from learning effects. It also highlights how trade and infrastructure development can serve to leverage the role of hydrogen.

c. **What is needed at policy and regulatory level to foster the optimal contribution of hydrogen to climate neutrality?** The study looks at the measures and instruments that are available in the policy toolkit to spur technology development, bring the cost of low-carbon and renewable hydrogen down and foster their contribution to European energy transition. It describes how the announced policy roadmap could be clarified to address the hydrogen development challenges in the necessary timing, making the best use of existing facilities and regulations. It also highlights the current barriers that could prevent the realization of a least-cost pathway.

1.3 Methodology

1.3.1 Overview of the modelling scope

38. The *Hydrogen for Europe* study relies on energy system modelling that integrates a wide range of existing and future hydrogen technologies with the most up to date knowledge and data. The energy system modelling follows a least-cost logic and considers all the steps from primary resources to final consumption via transmission, distribution, conversion and storage, providing a detailed representation of technologies and energy carriers at each step of the value chain. All technologies compete over costs to meet the energy demand of all sectors. Table 1 provides a simplified overview of the main categories of technologies and end-uses that are represented in the models. The listed elements are disaggregated into more exhaustive components within the models according to the suitable level of detail.

39. The energy system modelling provides a comprehensive framework for assessing the potential role of hydrogen for serving energy demand across the entire European energy system. Hydrogen can also be used to produce ammonia as a shipping fuel, as a reduction agent in the iron and steel industry, and to produce e-fuels and e-gas. Other uses as feedstock, for example in the chemical sector, are beyond the scope of this study.

Table 1. Aggregated overview of the technological scope

Primary energy supply	Energy transformation	Final energy supply	End-use sector
Lignite (resources and import) Oil (resources and import) Coal (resources and imports) Natural gas (resources and imports) Bioenergy Solar energy Wind power	Electricity production CHP sector Electrolysis Biomass gasification Methane pyrolysis Methane reforming Liquefaction Coal processing Refineries Gas network …	Electricity Hydrogen Coal Natural gas Oil Bioenergy Other final RES	Residential Commercial Industry Transport (road, rail, aviation, maritime[12]) Agriculture
+ Representation of CCUS routes (direct air capture or carbon capture, CO_2 use and storage) + Representation of electricity, natural gas and hydrogen storage			

40. The *Hydrogen for Europe* study describes two scenarios denoted as the "Technology Diversification" and "Renewable Push" pathways. The first pathway is designed to provide insights into the most cost-efficient path for transformation of the European energy system until 2050[13]. The second pathway, in contrast, examines the

[12] Within Europe.
[13] The time-steps in the modelling framework are: 2020 (today's system; no new investments), 2030, 2040 and 2050. Each period represents 10 years, e.g. 2045 – 2054 for 2050. The first day after the planning horizon is thus 2055.

possible impact that an increased push for deployment of renewable energy could have on the hydrogen market size and development.

41. The modelling framework is aligned with the agenda of the European Green Deal and EU pillars and targets, incorporating the main targets for CO_2 emission reductions, share of renewable energy deployment, energy efficiency, and national decisions on the phasing out of coal and nuclear plants for power generation, among others. Nevertheless, the scenarios are not an attempt to forecast the actual development of the European energy system.

Box 1. Introduction to the *Hydrogen for Europe* pathways

Pathway 1: Technology Diversification

The Technology Diversification pathway assumes a perfect market where the European energy technology transition is underpinned by a Climate law in combination with already approved national targets as well as the overarching objectives for renewable energy share and energy efficiency. The markets are characterised by perfect foresight, meaning that investment decisions are made in each period with full knowledge of future developments. Further, deployment of technologies needed for decarbonization of the energy system occurs at the time of demand without any delays.

Pathway 2: Renewable Push

Using the same starting point with respect to currently implemented policies, policy announcements and overarching objectives, the Renewable Push scenario is set up to assess the consequences of a more favourable framework for investments in wind and solar energy. This is implemented in the form of a series of targets on the share of renewables in gross final energy consumption, which is more ambitious for 2030 compared to today's policy (40% versus 32% in the Technology Diversification pathway and includes binding targets for 2040 (at 60%) and 2050 (at 80%). The scenario also analyses the energy system under perfect foresight.

42. The energy policies are implemented as constraints in the models, forcing the solutions to reach all targets set. An overview of all implemented policies is provided in table 2, and table 3 provides a summary of the targets set at EU level for CO_2 emissions, energy efficiency and share of renewables in gross final energy consumption.

Table 2. Overview of implemented policies

Policy	Description
CO_2 targets	Under the EU's commitment to climate-neutrality by 2050, we model a 100% CO_2 emission reduction (compared to 1990 level) by 2050 at the European level, i.e., a collective constraint. The intermediate emission target for 2030 has also been implemented as they have been set as minimum binding legislation to achieve the transformation towards a low-carbon energy system.
EU Energy efficiency target	Energy efficiency measures and targets up to 2030 are a second strand of comprehensive measures in the policy of the European Commission. The amendment to the Directive on Energy Efficiency (2018/2002) targets a 32.5% improvement in energy efficiency by 2030 relative to a 'business-as-usual scenario'. This corresponds to a primary energy consumption around 1128 Mtoe (million ton of oil equivalent) or no more than 846 Mtoe of final energy consumption for the European Union in 2030[14].
Emission reduction targets for the transport sector	Regulation (EC) 443/2009 set mandatory emission reduction targets for new cars. The first target became operative in 2015 and a new target was phased in during 2020 and is fully implemented from 2021 onwards. The enforced 2021 target for the EU fleet-wide average

[14] Without the withdrawal of the UK these figures correspond to 1273 Mtoe (million tonnes of oil equivalents) of primary energy consumption and/or no more than 956 Mtoe of final energy consumption. Note that the target has been set for EU member states only (at the time of the directive) and thus does not include Norway and Switzerland, which are part of the modelling scope. Furthermore, no additional targets beyond 2030 have been assumed at EU level.

	emissions is set at 95 gCO_2/km. Furthermore, regulation (EU) 2019/631, adopted in 2019, sets CO_2 emission performance standards for new passenger cars and vans in the EU. The regulation maintains the former 2020-targets and adds new targets for 2025 and 2030.
Emission reduction targets for EU ETS sectors	The EU emissions trading system (EU-ETS) is a cornerstone of the EU's climate change policy and its key tool for reducing greenhouse gas emissions in a cost-effective way. Under Directive 2009/29/EC of the European Parliament and Council amending Directive 2003/87/EC; and under Directive (EU) 2018/410 of the European Parliament and Council amending Directive 2003/87/EC, emissions from the EU ETS sectors should be reduced by 21% in 2020 compared with the 2005 levels (including aviation), and by 43% in 2030.
Emission reduction targets for Non-EU ETS sectors	The Effort Sharing Regulation (ESR) defines legally binding national GHG emission targets in 2020 and in 2030 compared with 2005 for sectors not covered by the EU ETS excluding LULUCF, such as transport, buildings, agriculture. The national targets for 2020 are ranging between -20% (for the richest member states) and +20% (for the less wealthy countries) compared with 2005 levels to collectively achieve a reduction of 10% in total EU emissions (Decision No 406/2009/EC). The targets for 2030 will range between 0% and -40% compared with 2005 levels in order to achieve a collective 30% reduction of the total EU emissions of the non-EU ETS sectors (Regulation (EU) 2018/842)
Renewable energy directive (RED) target for final energy consumption	European Union Directive 2009/28/EC establishes binding renewable energy targets for each member state for 2020 that collectively amount to a share of renewables of 20% in the total gross final energy consumption by 2020. The revised renewable energy directive 2018/2001/EU established a new binding renewable energy target for the EU of 32% of the gross final energy consumption by 2030. This target was set in 2018 with a clause for a possible upwards revision by 2023[15]. Under the new Governance regulation (EU/2018/1999), EU member states have submitted their draft NECPs national contributions that are sufficient for the collective achievement of the Union's 2030 target.
Renewable energy directive (RED) target for transport sector	The RED sets targets specifically for use of energy from renewable sources in the transport sector. By 2020, at least 10% of the EU transport fuels (road and rail) must come from renewable sources. For the period 2030 to 2050 the target is set to 14%. The contribution of biofuels produced from food and feed crops (1st Generation) is capped at 7% of road and rail transport fuel in each member state from 2020 onwards. Furthermore, the contribution of advanced biofuels and biogas (2nd Generation) should be at least 0.2 % in 2022, at least 1 % in 2025 and at least 3,5 % in 2030 (as a share of the final consumption of energy in the transport sector).
National energy and climate plans (NECPs), climate and energy objectives established by Non-EU member states	National objectives for energy and climate sets targets for energy efficiency, share of renewable final energy consumption in general and for the transport sector, to comply with the targets set out by the RED, ESR, EU-ETS and EED, as described above. National objectives comprise targets for efficiency improvements in buildings and for heating and cooling. They also outline target dates for phasing out coal and nuclear energy, as well as limitations on nuclear production.

Table 3. Targets of main energy policies set at the European level

Target	Year	Technology Diversification pathway	Renewable Push pathway
CO_2 reduction with respect to 1990 levels	2030	- 55%	- 55%
	2050	Net-zero emissions	Net-zero emissions
Energy efficiency target with respect to business as usual	2030	32.5%	32.5%
Share of renewable energy supply in gross final energy consumption	2030	32%	40%
	2040		60%
	2050		80%

[15] The original target of 27% has been revised upwards.

43. Trajectories for the main macro-economic drivers, fossil fuel prices and energy demand are important input assumptions to the models. They rely on the following sources:

- The main macroeconomic drivers, population growth and GDP, have been collected from the JRC assumptions under the EU Reference 2016 scenario.
- Oil, natural gas and coal prices are according to the proposed trajectories from the EU Reference scenario 2016 as considered by the JRC in their energy models, modified to 2020 prices to consider the Covid-19 effect. The retained trajectories fall between the Sustainable Development (SDS) and Stated Policies (SPS) scenarios of the IEA World Energy Outlook, 2019 (WEO, 2019).
- Energy demand projections have been extracted from the JRC-EU-TIMES database.

44. Costs, technology assumptions, and limitations for deployment and resource availability for all included technologies are based on authoritative databases such as ENSPRESO, JRC-IDEES database, IEA database, and ENTRANZE. Notably, the potential for solar and wind follows the reference scenario of ENSPRESO, while the biomass potential is based on the JRC alternative BaU scenario[16]. To understand the impact of bioenergy availability on the results, a sensitivity analysis has also been carried out based on the ENSPRESO Reference Trajectory for biomass potential.

45. In a common effort with the project stakeholders, the dataset was strengthened for hydrogen production technologies to reflect the current state-of-the-art. The updated study database includes cost and performance data for new technologies such as molten media methane pyrolysis and combined gas heated/autothermal reformers with integrated capture of the produced CO_2, as well as modified data for existing technologies such as electrolysers and steam methane reformers with added CO_2 capture.

46. Furthermore, special constraints were implemented for the power sector, the deployment of CO_2 storage and the deployment rate of heat pumps in the residential sector:

- To ensure the reliability of the power grid in each country considered in the study, a restriction of minimum 20% back-up capacity from controllable electricity production within each country is applied.
- The available injection rates for CO_2 to permanent storage, measured in tonnes per year, has been restricted to 1.0 Gt per year from 2020 to 2040, 1.2 Gt per year in 2045 and 1.4 Gt per year in 2050. This injection capacity has been derived as a reasonable estimate from a survey of existing literature and expert knowledge.
- The potential of heat pumps has been implemented following the latest assumptions from the JRC heat pump analysis. Their techno-economic characteristics have been provided by the JRC database for residential and commercial services

47. The transition to climate-neutrality implies a significant change of pace in decarbonization efforts in the European energy system. Key technologies such as power production from wind and solar have seen a steady cost reduction, which to a large degree is a consequence of the increasing investments, a mechanism commonly denoted as the learning-by-doing effect in literature. Those effects pose two important challenges for detailed optimization models of large systems. Firstly, with technology learning, investment costs per MW becomes a variable instead of being a parameter. Hence, the calculation of investment costs in a year (cost per MW times MW invested) is a multiplication of two variables, which is a non-linearity. This is a challenge because detailed models of large-scale systems typically are based on linear programming (LP) – since very large numerical problems at acceptable computational times by use of LP. Secondly, one could try to solve that problem by iterating between the solution of a large-scale LP model and a technology learning-by-doing model. However, the solution would be biased in the direction of under-investing in technologies having high learning rates.

[16] The alternative BaU scenario from ENSPRESO is the latest trajectory released in the JRC database for EU28 bioenergy potential. It is an alternative to the JRC Reference trajectory and constitutes a more conservative assessment of the bioenergy potential. It assumes no major deviations from current market developments and utilization of forest resources, and forecasts a potential of bioenergy around 9,000 PJ in 2050. By contrast, the Reference trajectory from the JRC assumes added forestry potential, which lead a total bioenergy potential for 2050 of around 12,000 PJ. The assumption from the alternative BAU scenario of ENSPRESO has been considered a more conservative and adequate representation of bioenergy for the Hydrogen for Europe study. See (Ruiz et al., 2019) for more explanation on the ENSPRESO methodology.

48. Hence, in addition to a detailed energy system model (MIRET-EU) a dedicated learning optimization model (Integrate Europe) has been developed for optimizing the European energy system when accounting for endogenous learning (meaning calculated by the model) consistently in the optimization process. In addition, the study has carried out a comprehensive review of the learning-by-doing effects for the most important technologies in the transition to a net-zero emissions energy system for Europe by 2050. In the following we distinguish between 1) the learning-by-doing module, which is a quantification of learning-by doing effects based on a literature review, and 2) the learning optimization model, which optimize the energy system taking the results from the learning-by-doing module as an input.

Box 2. Representation of path dependencies and learning by doing

In the transition to climate neutrality, low-emission technologies will be needed in much larger quantities compared to today's deployment rates. As an example, electricity production from wind and solar has been present in the European energy system since the first decade of the 21st century. By 2050, the total production capacities could be in the range of 5 to 20 times higher than in 2016. The investment costs for these technologies are seen to decrease with increasing accumulative investments. This is called the learning-by-doing effect and is present for technologies related to energy supply, conversion and appliances. The effect could depend on both European and global investments.

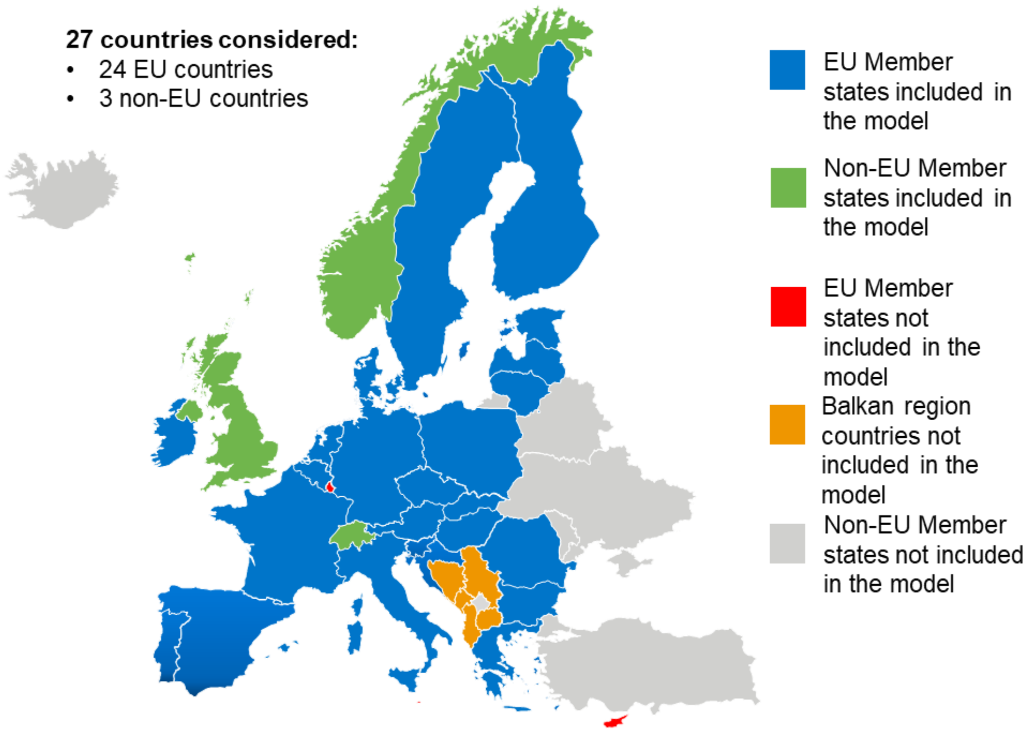
Economies of scale and network economies are also important to consider. Technologies such as electrolysers can be developed in a wide range of sizes. Small plants tend to have higher investment costs per capacity unit ($/MW) and lower energy efficiency than larger plants, but they can be placed close to consumption (a decentralized market configuration). Even if big plants might have a lower investment cost per capacity unit, they require associated transmission and distribution infrastructure to supply final energy needs (a centralized market configuration). Obtaining low-carbon hydrogen from fossil fuels through reforming also requires CCUS infrastructure development whose cost could depend on, for example, co-location with other stationary CO_2 emitters, distance to available transmission networks and locations for permanent storage. Therefore, the hydrogen supply chains are particularly affected by such scale and network considerations because they imply very capital-intensive technologies on the supply side and, due to the low energy-to-volume ratio of hydrogen, its transport and storage is far more cumbersome and costly than that of gases such as natural gas. Either a decentralized or a centralized market configuration might emerge entailing very different industrial and regulatory implications.

The complex interrelations opened by the learning-by-doing, economies of scale and network economies are not straightforward to model and are often disregarded in studies, however they encompass what is referred as “path-dependencies”. They are very relevant for assessing the future of hydrogen within the energy transition. What is at stake is that policies disregarding such externalities risk defining “winner technologies” too early. The *Hydrogen for Europe* study integrates part of this complexity into the modelling approach to determine the role of hydrogen in the European energy transition.

More precisely, The *Hydrogen for Europe* modelling approach makes it possible to represent a situation where there is complete awareness of the potential cost reductions due to learning-by-doing effects and other path dependencies, and to assess how they are affected by European strategies and policy decisions. While global learning rates are explicitly represented and based on figures reported in the most recent literature, the impact investment decisions have for inducing further cost reductions within Europe are optimized in the modelling framework. This means that it is possible to know now which technology and infrastructure investments in the 2020s and 2030s would lead to the least cost energy transition pathways when considering the entire period from today and until 2050.

To do this, energy supply and conversion technologies whose cost reductions depend entirely, or partly, on European development and investments are treated with special care to ensure that the applied cost profiles are consistent with the investments predicted and that economic gains of technology learning are accounted for when optimizing investments. Cost reductions expected to occur due to investments on a global level are incorporated exogenously using the same learning rate as for European investments to maintain consistency in the cost profiles. Economies of scale are captured by including a size-differentiated cost figures within the technology database for some of the technologies. Network effects are implicitly captured by the models within the energy value chain representation with investment and retirement decisions on both extremes (on the supply and demand sides). Such path dependencies are included in accordance with the principle of technology neutrality.

Figure 9. Geographic coverage of the *Hydrogen for Europe* project



Source : *Hydrogen for Europe* study

49. In total, 27 European countries have been included in the study, including 24 EU member states and 3 Non-EU countries (figure 9). Each country is represented by its own energy system, accounting for the main demand sectors and applying the high-resolution technology representation framework described earlier. Moreover, each country can trade petroleum products, electricity, natural gas and hydrogen. CO_2 can also be transported across borders. Such trade can occur in already existing trade routes such as pipelines, or new infrastructure can be built, assuming that the corresponding investment costs are known. For hydrogen, the possibility to re-purpose cross-border natural gas pipelines for hydrogen transport is also considered.

50. The possibility to import hydrogen from non-European countries is included in the modelling framework as well, through an import model developed by Deloitte. The import model follows an economic optimization logic, thus not constraining the uptake of hydrogen imports in Europe. The hydrogen importing prices have been estimated in the study using the principles of CO_2 neutrality of European energy imports and technology neutrality on the supply side. The hydrogen import option thus comprises hydrogen imported from North African countries, the Middle East and Russia and Ukraine, where the hydrogen can be produced both from renewable sources and from methane with abated CO_2 emissions.

Box 3. Technological boundaries of the models

The target of climate neutrality by 2050 sparked an acceleration in the development of technologies that can contribute to the transition of the energy system. The *Hydrogen for Europe* study included as many of these technologies as possible. The technologies were selected based on the availability of reliable data for cost and energy performance. Other technologies exist but are not considered, including the Allam cycle for electricity production from natural gas with integrated capture of CO_2, adsorption enhanced water gas shift processes for hydrogen production from natural gas or hydrogen rich off-gases from the industry, the Hazer pyrolysis process for production of hydrogen and carbon black from natural gas, pyrolysis processes with hydrogen- or electricity-fired reactors and hydrogen-fuelled open and closed cycle gas turbines among others. More research and data is needed before these technologies can confidently be included in future studies.

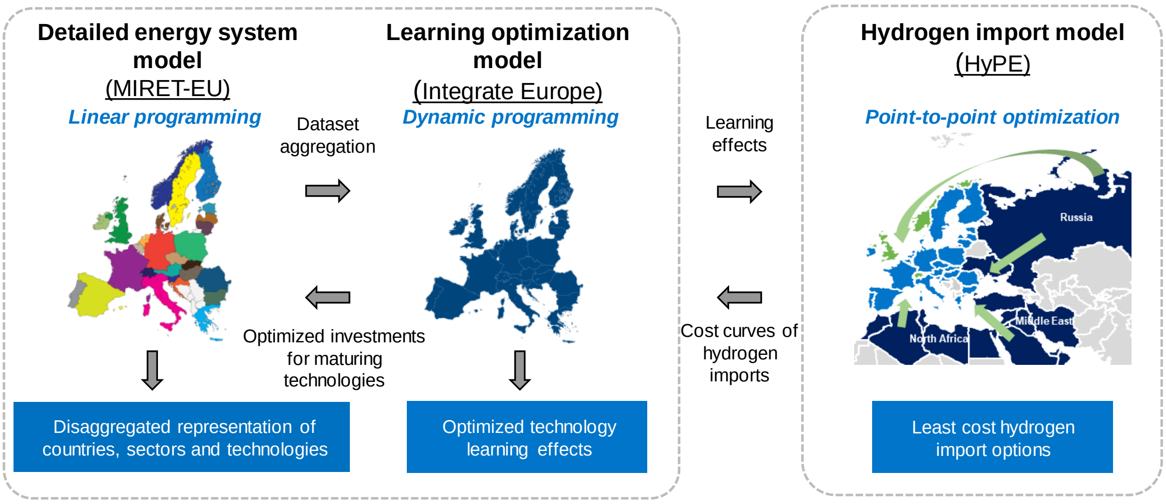
1.3.2 Presentation of the modelling framework

51. The modelling framework consists of a detailed energy system model (MIRET-EU), a dedicated learning optimization model (Integrate Europe) and a hydrogen import model (HyPE). The entire energy system with corresponding range of technologies, policy constraints and baseline assumptions are included in both the energy system and the learning optimization models. The detailed energy system model provides a robust and proven methodology based on linear programming for the representation of the energy system, with a high degree of detail on hydrogen production technologies and all other parts of its value chain, represented at country level. The learning optimization model explores the path dependency of technology costs linked with investment trajectories and provides optimized investment paths for decarbonization technologies given their potential for cost reductions. Due to the complexity of the problem solved by the learning optimization model, technologies, geography, and policies are represented at an aggregated level. The hydrogen import mode allows representing competition between domestic hydrogen production within Europe and imports from non-European countries.

52. For representing interplays between the different sectors within Europe, the detailed energy system model and the learning optimization model have been combined by a soft link, harnessing the strengths of each model (figure 10). This combination of models allows for a detailed representation of the energy system's evolution and the potential for the different technologies at country level. Moreover, the approach also accounts for endogenous cost reductions through investments and the avoidance of lock-in effects in terms of chosen technologies. As such, the technical boundaries and computational limits, which would characterize each model when taken separately, can be overcome. Reliance on the same databases constitutes the first link between the models. The learning optimization model was then adjusted based on results from the detailed energy system model to ensure coherence and fully appreciate limitations of the learning optimization model relative to the detailed energy system model. In a final step, the optimized investment trajectories and corresponding cost profiles were fed into the detailed energy system model where they are implemented as minimum restrictions for investments and as updated cost trajectories.

53. Additionally, the import model is also aligned with the cost assumptions adopted by the European models and includes a feedback loop for considering learning effects. It provides cost curves to the European models to allow them to optimize between importing certain volumes of hydrogen at certain prices or domestically producing it. The assumptions regarding the production of hydrogen and the development of transport alternatives are based in the most recent literature and in line with the ambitions of the European Hydrogen Strategy.

Figure 10. Modelling framework with soft- linking of a detailed energy system model and learning optimization model



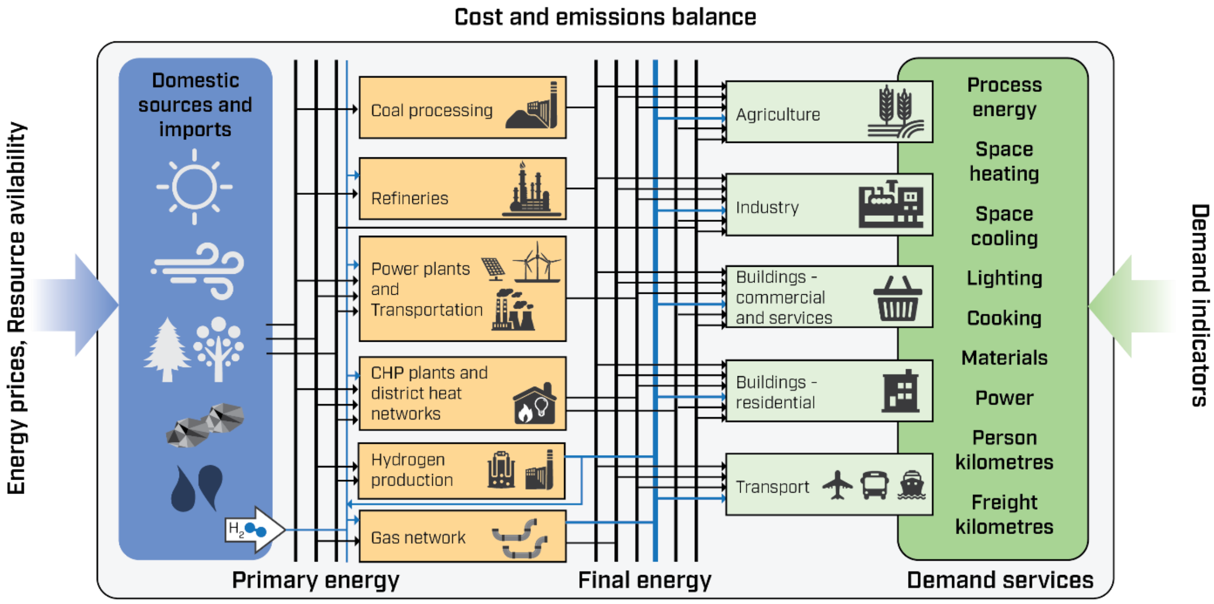
Source : *Hydrogen for Europe* study

Overview of the detailed energy system model – MIRET-EU

54. MIRET-EU is a multiregional and inter-temporal partial equilibrium model of the European energy system developed by IFPEN, based on the TIMES[17] model generator. A complete description of the TIMES model equations appears in the ETSAP[18] documentation. It is a bottom-up techno-economic model that estimates the energy dynamics by minimizing the total discounted cost of the system over the selected multi-period time horizon through powerful linear programming optimizers. The components of the system cost are expressed on an annual basis while the constraints and variables are linked to a period. Special care is taken to precisely track cash flows related to process investments and dismantling for each year of the horizon. The total cost is an aggregation of the total net present value of the stream of annual costs for each of the model's countries.

55. MIRET-EU represents the European energy system divided into 27 countries. It is set up to explore the development of its energy system from 2010 through to 2050 with 10-year steps and is calibrated on the latest data provided by energy statistics such as JRC-IDEES[19] database, POTEnCIA[20] database, EUROSTAT database, and other international databases from IEA, IRENA, World Bank, among others. The model is data driven[21], its parameterisation refers to technology characteristics, resource data, projections of energy service demands, policy measures, etc. This means that the model varies according to the data inputs while providing results such as technology pathways or changes in trade flows for policy recommendations. For each country, the model includes detailed descriptions of numerous technologies, logically interrelated in a Reference Energy System – the chain of processes that transform, transport, distribute and convert energy into services from primary resources and raw materials to the energy services needed by end-use sectors (figure 11).

Figure 11. Simplified overview of the energy system covered in the detailed energy system model



Note: European produced hydrogen is not is not considered as a primary energy (left hand side) but is represented on the figure for illustrative purposes.

Source : Based on Remme and Mäkela, 2001

[17] MIRET has been based on the TIMES model generator, developed by one of the IEA implementing agreements (ETSAP) in 1997 as a successor of the former generators MARKAL and EFOM with new features for understanding and greater flexibility. The manuals and a complete description of the TIMES model appear in ETSAP documentation (https://iea-etsap.org/index.php/documentation)

[18] Energy Technology Systems Analysis Program. Created in 1976, it is one of the longest running Technology collaboration Programme of the International Energy Agency (IEA). https://iea-etsap.org/index.php/documentation

[19] JRC-IDEES (Integrated Database of the European Energy System) has been released in July 2018 and is revised periodically. We then used the latest data released in September 2019.

[20] POTEnCIA (Policy-Oriented Tool for Energy and Climate change Impact Assessment)

[21] Data in this context refers to parameter assumptions, technology characteristics, projections of energy service demands, etc. It does not refer to historical data series

Overview of the learning optimization model - Integrate Europe

56. The impact of learning effects on the cost-effective investment pathway towards a decarbonized energy system that can contribute to the decarbonization of the energy system is analysed by Integrate Europe, an in-house model developed by SINTEF. Technologies such as solar PVs, wind turbines, electrolysers and reformers, see declining investment costs (CAPEX) with increasing investments in Europe and globally. This is commonly known as the learning-by-doing effect, and it is a path dependency that models such as TIMES cannot handle due to the resulting non-linear optimization problem formulation. In Integrate Europe the energy system costs are minimized by considering both investment (CAPEX) and operational costs (OPEX). Optimization of investments is performed in Integrate Europe via dynamic programming (DP), which allows for inclusion of technology investment costs that depend on investment trajectories. Operational expenses are assessed by estimation of diurnal operation for different periods of the year for each alternative system design. This operational module can be run independently from the investment module and is based upon linear programming (LP). A comprehensive analysis of observed learning-by-doing effects for technologies related to electricity and hydrogen production was carried out as a part of the study. The resulting data was implemented into a standalone learning-by-doing module which is used to feed investment cost data into Integrate Europe.

57. Integrate Europe optimizes investments over the planning horizon in four investment periods, each encompassing ten years. The goal of the optimization is to bring available energy to the end user in such quantities and in such form that the demands are covered in the best economic way possible, while complying with set policy targets (for CO_2 emissions, for example). The model performs a system optimization, minimizing the total present value of all costs. To unlock the analytical capability to deal with the learning-by-doing effect and avoid computational hurdles, the energy system is represented at a European level and by aggregation of technologies into main categories. In addition, the main investment options to be analysed are bundled into pre-defined 'investment packages' which compete with each other within the dynamic programming module. The characteristics and investment breakdown within each package were calibrated mainly on the basis of cost-data for included technologies, results from the detailed energy system model and other stand-alone assumptions.

Overview of the import model Hydrogen Pathway Exploration model (HyPE)

58. The HyPE model developed and implemented by Deloitte provides the main energy system and learning optimization models with hydrogen import potentials from neighboring regions to represent competition between domestically produced hydrogen and imports. In line with the EU hydrogen strategy, which focuses on clean hydrogen trade and highlights the potential partnership with Southern and Eastern Neighbourhood countries, only low-carbon and renewable hydrogen imports are considered from North Africa, the Middle East, Ukraine and Russia.

59. The model estimates hydrogen import supply curves, indicating both the potential of hydrogen production per region and the associated costs, following a levelized cost of hydrogen approach (LCOH[22]). The LCOH is calculated for each delivery point in Europe (Cost, Insurance and Freight[23]). The methodology builds on the full delivery value chain from the hydrogen production site to determine LCOH at each entry point in Europe.

60. In the upstream, depending on resource endowments, all hydrogen production technologies and their associated cost evolutions are considered as possible for exports. A country-specific risk consideration was included as a mark-up to the weighted average cost of capital (WACC) of each country based on the Ease of Doing Business scores (WB 2020). In the midstream, the transport modes cover inland transport for the distance from production site to exit point in each country of origin (i.e. by national pipelines, gasified hydrogen trucks and/or ammonia trucks), and international transport for the distance from the exit point, in the producing country, to the entry in Europe (i.e. by cross-border pipeline interconnectors and/or maritime shipping routes). The optimal combination between the transport mode, the distances and the flows are obtained by an optimization approach resulting in least-cost LCOH CIF import curves. Further details on the methodology are provided in annex D.

[22] The levelized cost of hydrogen (LCOH) adopts the life cycle costing methodology where all related costs and produced quantities are included to compute an average ration on the cost per kilogram produced.
[23] CIF includes the cost of transport and logistics from the exit point to the entry point in Europe.

2 Decarbonizing the European energy system

61. CO_2 emissions of the European energy sector amounted to more than 3 billion tons in 2018[24], stemming from a variety of fossil fuel and biomass consumption in sectors like power generation, transport, industry or buildings. Deep decarbonization of the European energy system by 2050 is thus a challenging undertaking. This task requires massive efforts across the entire energy system to reduce energy consumption and decarbonize also the 'hard-to-abate' energy uses. The last two decades have seen the energy system follow a path of falling emissions. Nonetheless, efforts need now to accelerate in order to achieve the objectives set by policy-makers: reducing CO_2 emissions by 55% between 1990 and 2030 in accordance with the EU climate target plan and reaching climate neutrality in 2050.

62. Meeting these targets requires a coordinated strategy based on three main levers: further electrification of end-use, energy efficiency improvements, and the development of alternative energy carriers and fuels, such as hydrogen, biofuels, ammonia or synthetic fuels. Each sector and subsector of the energy system has its own specificities and requires a different combination of those levers and their underlying technologies.

63. The *Hydrogen for Europe* study looks in detail into these challenges and proposes two alternative pathways to climate neutrality in the European energy system. The Technology Diversification pathway establishes a level playing field between all technologies and assesses the implications of a least-cost approach to the energy transition that comprehensively includes all technologies. The Renewable Push pathway reflects a step change of renewable energy deployment, echoing the current policy discussions around renewable energy prioritization in the Green Deal and other directive documents. Both pathways are the result of a modelling approach that takes as given the already binding policies and regulations regarding decarbonization, renewable energy shares or energy efficiency and reflect in particular the following key constraints:

   a. A reduction of 55% of net CO_2 emissions by 2030 and of 100% by 2050, also allowing for negative emissions.[25]

   b. At least 32.5% energy efficiency improvement by 2030.

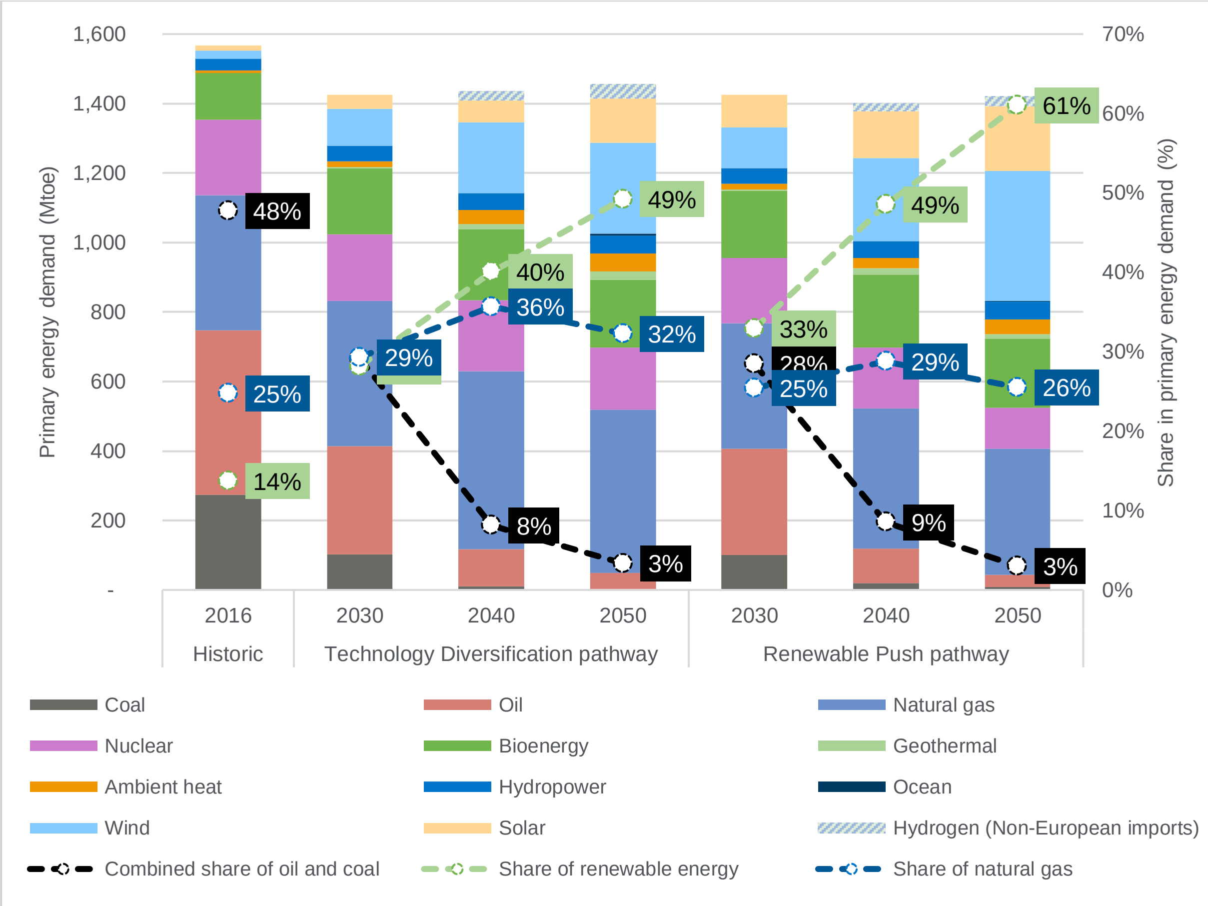
   c. And a renewable energy target for the EU of at least 32% of gross final energy consumption in 2030.

2.1 Evolution of total primary energy demand

64. Primary energy demand in the *Hydrogen for Europe* pathways drops by 7% to 9% between 2016[26] and 2050, or by about 0.2% to 0.3% per year on average, depending on the pathway (figure 12). The reduction of final energy consumption is the main downward force (see section 2.2). The level of primary energy demand is also strongly affected by the switch to alternative energy carriers and fuels like hydrogen and e-fuels. The production of those alternatives relies on energy-intensive processes, with large electricity needs and efficiency losses that partially offset the decrease in final energy consumption.

[24] Source: Eurostat
[25] An interim target has been implemented in the models for 2040 to allow a linearization of the reduction in emissions (figure 16).
[26] Note: through the report, results are compared with 2016 historical values from the JRC database. The latest available database consolidated concerns 2015-2016 data.

Figure 12. Evolution of total primary energy demand in the Technology Diversification and Renewable Push pathways, 2016 to 2050



Definition of primary energy content is based on Eurostat methodology[27].

Source : *Hydrogen for Europe* study

65. The primary energy mix is fundamentally reshaped in the two pathways. It sees a pronounced shift to renewable energy, which is underpinned by the CO_2 emission reduction constraints and the implementation of binding targets on renewable deployment.

   a. In the Technology Diversification pathway, renewable energy deployment is supported by a 32%-share target for 2030 (related to gross final energy consumption), as currently enshrined in the EU framework for Climate and Energy (figure 13). After 2030, the pathway assumes a level playing field between renewable and other low-carbon technologies in their contribution to climate neutrality. The increasing constraints in terms of decarbonization, coupled with other techno-economic drivers[28] lead to a near-doubling of the renewable energy share between 2030 and 2050. By 2050, renewable energy supply represents 60% of gross final energy consumption in this pathway.

   b. The Renewable Push pathway assumes higher renewable energy shares for the years 2030, 2040 and 2050. The starting point is fixed at 40% of gross final energy consumption in 2030, reflecting the current discussions on the increase of the binding target in the revision of the renewable energy directive. Afterwards, a linear progression of renewables is assumed, with binding targets set at 60% and 80% for

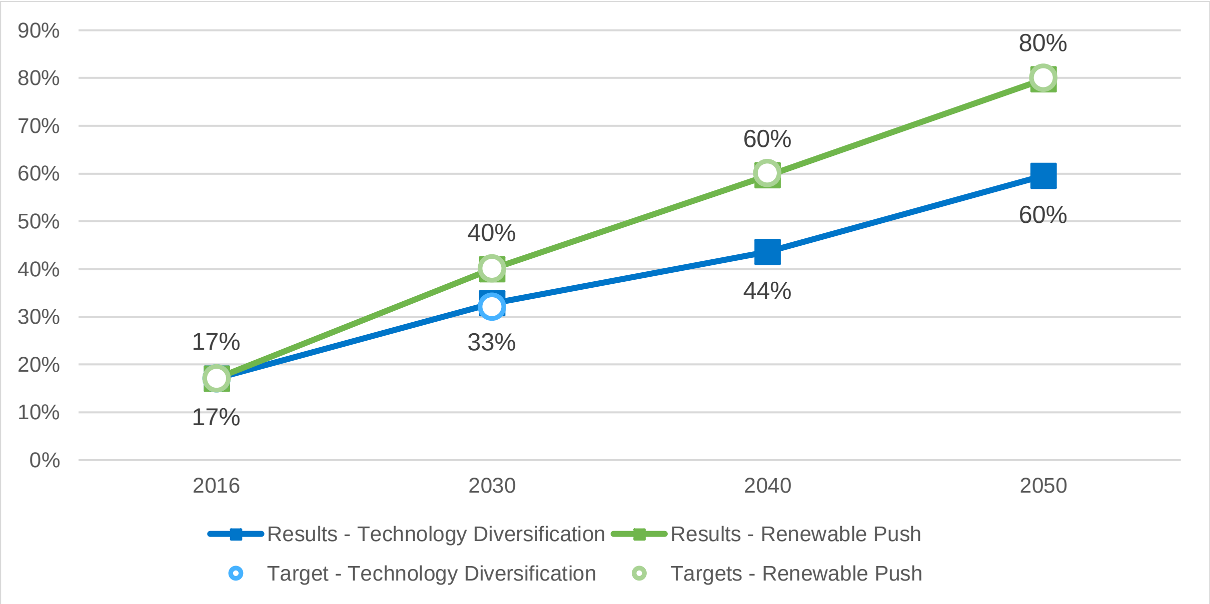
[27] See Eurostat, 2019. Calculation methodologies for the share of renewables in energy consumption. https://ec.europa.eu/eurostat/statistics-explained/pdfscache/43297.pdf
For example, according to the Eurostat methodology, primary energy content of solar photovoltaic, wind, hydropower and ocean is based on the electricity content.
[28] Maximum potential, competition between the different technologies and supply sources.

2040 and 2050. These targets restrict the pathway over the next decades and impact some aspects of the transition to net-zero emissions, as shown in the next sections.

c. At technology level, the renewable energy uptake is sustained by very ambitious investments in wind and solar, with a tenfold increase of supply between 2016 and 2050 (figure 12). Combined, those two variable energy sources supply more than 380 Mtoe in 2050 in the Technology Diversification pathway (27% of the total primary energy demand), and 560 Mtoe in the Renewable Push pathway (39% of the total). Other renewable energies show significant increases, such as bioenergy which remains the second source of renewable energy in Europe with about 200 Mtoe, behind wind and before solar, based on a 50% increase in supply. Bioenergy reaches the maximum potential indicated in the ENSPRESO BaU scenario. A sensitivity analysis on the Technology Diversification pathway was also conducted, considering instead the ENSPRESO Reference Trajectory for bioenergy potential (see

). It shows that a greater potential of bioenergy would enable a more important role of biomass with CCS for hydrogen and power production, and hence, for negative emissions.

Figure 13. Evolution of the share of renewable energy in final gross energy consumption in the Technology Diversification and Renewable Push pathways, 2016 to 2050



Source : *Hydrogen for Europe* study

66. The renewable energy uptake is mirrored by a dwindling role for oil and coal in the energy system. Their combined contribution to primary energy demand drops from 48% in 2016 to 3% in 2050, with a steep decline until 2040. Their relatively high CO_2 intensity makes oil and coal inconsistent with deep decarbonization. Their evolution is also strongly determined by policy. Current measures already include a progressive phase-out of coal in the power sector[29], and ambitious CO_2 emission thresholds in the transport sector. Still, their current

[29] Phase out of coal power production facilities are widely discussed in Europe. Where phase out decisions have been included in the national NECP or law, phase out of the corresponding power plant capacities have been included in the models.
On average, accelerated phase out of coal power plants between 2020 and 2050 concerns 13% of the 2020 capacity. In addition, a significant share of the existing coal power plants will reach the end of their expected lifetime before 2050. In total, there is an average capacity reduction of 93% between 2020 and 2050.
The *Hydrogen for Europe* study also shows very minor investments in coal power production plants with CCUS (up to 3GW installed in 2050). Indeed, while coal power generation in Europe saw a steep decrease in 2019 due to the strong renewables

level in primary energy supply highlights how technically and economically challenging it will be to substitute these fossil fuels in the energy system, and to achieve net-zero emissions by 2050.

67. Although the share of nuclear energy is relatively stable in the Technology Diversification pathway (falling slightly from 14% in 2016 to 12% in 2050), in absolute terms, nuclear energy decreases by about 20%. This decrease is directly reflected in the electricity mix, where the share of nuclear drops by 10 percentage points (from 24% to 11% by 2050). Installed capacities for power generation decrease from 127 GW to 106 GW in 2050. Several countries have announced to refrain from using nuclear (e.g. Germany, Switzerland or Belgium) in the future while others have reinstated their ambitions to construct new nuclear power stations (e.g., Czech Republic, Hungary, Poland, etc.)[30]. There is less room for nuclear in the Renewable Push pathway, with nuclear's share in primary energy supply dropping to 8% and to 6% in the power mix in 2050.

68. Natural gas is the main element of continuity in the primary energy mix. In the Technology Diversification pathway, the share of natural gas in the energy mix increases to reach a high point of 36% by 2040, before falling back slightly to 32% at the end of the outlook period. Natural gas offers greatest benefits when coupled with CCUS. In this pathway, much of natural gas use is thus displaced from final energy consumption to intermediary transformation processes, with significant contributions to hydrogen production and power generation. Note that natural gas' contribution is largely tied to the success of CCUS deployment. Failure to alleviate barriers related to CCUS (especially social acceptance and regulatory hurdles) could therefore markedly deteriorate the long-term prospects of natural gas in the transition.

69. In the Renewable Push pathway, the share of natural gas stays at today's level in the long term. Natural gas remains strikingly resilient and provides important flexibility as a complement to renewables, thus underscoring the strategic value of natural gas in the transition. It is particularly resilient in power generation, with only a marginal difference in 2050 between the two pathways. By the end of the outlook of period, natural gas use for hydrogen production is about 50% lower than in the Technology Diversification pathway (see section 4.1). Nevertheless, in 2050, natural gas remains an important complement to renewable energy for the supply of hydrogen in Europe.

2.2 Evolution of final energy consumption

70. The *Hydrogen for Europe* pathways see energy efficiency play its expected role in the transition to climate neutrality. Final energy consumption is reduced by nearly a quarter in 2050 when compared to 2005, achieving along the way, the binding target of at least 32.5% reduction by 2030 compared to a 'business-as-usual' scenario for the EU member states[31]. It is driven primarily by efficiency efforts in the transport and building sectors and the switch to more efficient end-use technologies (e.g., electric vehicles).

71. Electrification is also confirmed as one of the critical contributors to deep decarbonization. Electricity's share in gross final energy consumption jumps from 26% in 2016 to over 40% in 2050 in the Technology Diversification pathway, representing an almost 50% increase in final use of electricity (figure 14). Step changes are observed in the industry, transport and building sectors, where electricity consumption increases both for appliances and for heating. While this confirms the high expectations put on electrification, it also highlights the complementary

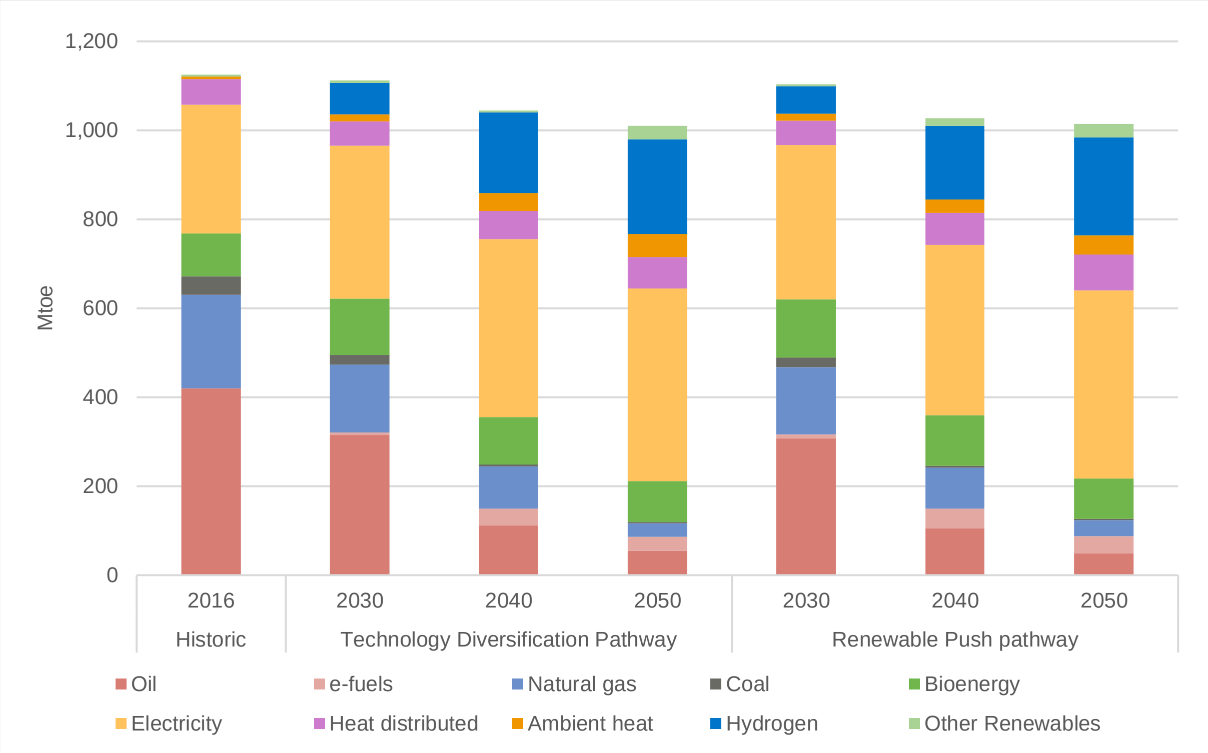
generation and coal-to-gas switching (IEA, 2020), retrofit coal power generation capacities with CCUS appears to be a solution for decarbonization in other parts of the world and cannot be disregarded entirely. The IEA identifies it as an attractive solution for Southeast Asia where 45% of the installed capacity of fossil-fueled power generation was built within the last decade, and 70% within the last 20 years. In the Sustainable Development Scenario of the IEA, around 190 GW of coal power production capacity is retrofitted with CCUS, with the majority occurring in China.

[30] About 10 GW of nuclear power plants are planned or under consideration to be operational by 2030 according to the World Nuclear Association (Nov. 2020 update) including 3 GW in Finland, 2.4 GW in Hungary, 1.4 GW in Romania and 1.2 GW in Czech Republic. France, despite its past announcements, is currently assessing opportunities for new nuclear power plants as an alternative roadmap to a 100% renewable scenario. In the UK, the Nuclear Industry Council recently announced a roadmap to produce one-third of renewable and low-carbon hydrogen from nuclear power by 2050.

[31] The 32.5% target is relative to the Commission's 2007 modelling projections for 2030. It corresponds to a 20% reduction of final energy consumption between 2005 and 2030 according to the amending energy efficiency directive. Note that the target has been set for EU member states only (at the time of the directive) and thus does not include Norway and Switzerland, which are part of the modelling scope.
No other constraint is set for energy efficiency from 2030 onward.

roles played by molecules and other energy carriers to decarbonize end-use. As such, more than half of total gross final energy consumption is supplied by non-electrified technologies in 2050.

Figure 14. Evolution of gross final energy consumption in the Technology Diversification and Renewable Push pathways, 2016 to 2050



Other renewables in final energy consumption correspond to solar and geothermal energy.

Source : *Hydrogen for Europe* study

Box 4. Energy accounting in the Hydrogen for Europe study

To comply with standard energy statistics, the study defines and calculates final energy consumption and gross final energy consumption as follows:

- Final energy consumption includes the final energy consumed by end-use sectors (industry, transport, …) and ambient heat from heat pumps. It excludes international aviation and maritime bunkers.

- Gross final energy consumption includes final energy consumption, international aviation (according to Eurostat methodology[32]), and energy losses and self-consumption in electricity and heat distribution. It still excludes maritime bunkers.

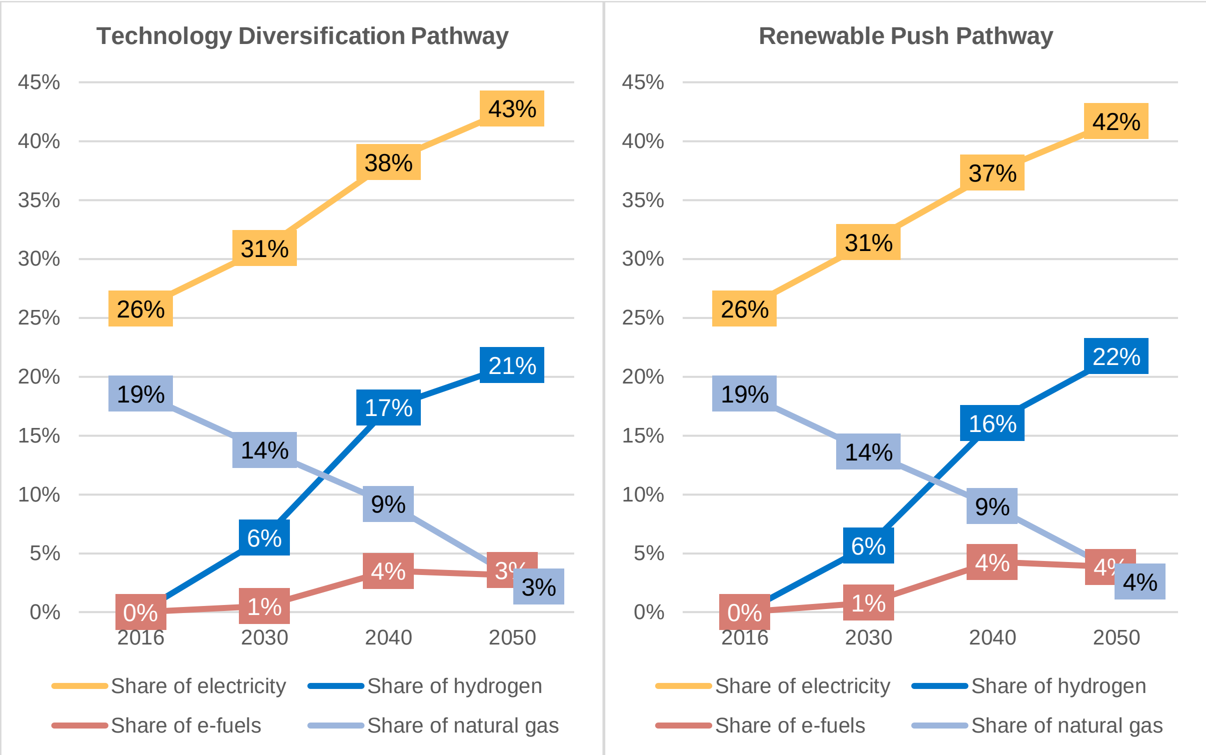
Unless otherwise mentioned, most of the results in this subsection relate to gross final energy consumption.

72. The acceleration of renewable deployment in the Renewable Push pathway does not lead to markedly higher electrification in the end-use sectors (figure 15). Shares in gross final energy consumption are similar to the other pathway, despite the significant increase in energy supply from solar PV and wind. Instead, most of the

[32] http://ec.europa.eu/eurostat/documents/29567/3217334/Aviation+Reference+Manual+%28version+14%29/e2d532c6-a54a-465a-95e0-f62b76e7da4c

additional renewable electricity is used in intermediary consumption for energy transformation, especially for production of hydrogen and e-fuels. This confirms the challenge of fully electrifying the European economy.

Figure 15. Evolution of the shares of hydrogen, electricity, e-fuels and natural gas in gross final energy consumption in the Technology Diversification and Renewable Push pathways, 2016 to 2050



Source : *Hydrogen for Europe* study

73. Hydrogen as an energy carrier sees rapid deployment in the period from 2025 to 2050, topping a share of one fifth of gross final consumption in 2050, or more than 200 Mtoe. Moreover, by 2050, hydrogen is the second largest contributor to final energy consumption. Meanwhile, (hydrogen-based) e-fuels grow to a 3% to 4% share of energy consumption in 2050. This is significant, as the use of e-fuels is primarily geared towards sectors like aviation, where it is difficult to switch away from conventional fuels like kerosene (see box 5 and section 3.2). With e-fuels included, the penetration of hydrogen-based technologies in end-uses reaches around one quarter by the end of the outlook period; with only minor differences between the two pathways.

Box 5. The value of e-fuels in the transition to net-zero emissions

E-fuels are synthetic substitutes to oil-based fuels like diesel, gasoline, or kerosene. They are produced by combining hydrogen with carbon dioxide through processes like methanol synthesis (potentially coupled with methanol to gasoline) or Fischer-Tropsch. Furthermore, co-electrolysis as a novel process involves the primary use of electricity in an electrochemical reaction to co-produce hydrogen and e-fuels. These processes are commonly called "Power-to-Liquid", if the former uses hydrogen from electrolysis. Carbon dioxide used for e-fuel production is to be recovered through carbon captured in the industry, power and transformation (hydrogen and biofuel production) sectors, or through direct air capture (DAC) technologies (see section 2.3).

Synthetic fuels can be considered as carbon neutral under certain conditions: for example, that the electricity and/or hydrogen used is from renewable or low-carbon origin, and that the used carbon dioxide comes from neutral processes like direct air capture or sustainable biomass. Their technical characteristics (e.g., mass and volume to energy ratios) make them promising candidates to decarbonize fuel use in sectors such as maritime and aviation. In aviation in particular, the weight of batteries and the low energy density and storage constraints of hydrogen make them less suited for all flight categories and distances. These constraints would call for a major research effort and the development of new types of aircraft, while the use of e-fuels would not require redesigning aircraft or refuelling airport infrastructures (IEA, 2019).

74. Oil and coal are displaced by electricity, hydrogen, e-fuels and other renewable energy carriers in the end-use sectors and plummet in end-use consumption (around 90% drop between 2016 and 2050). Achieving this decrease is a major challenge for oil, which still represented 37% of gross final energy consumption in 2016. Strong policy and industrial action and innovation would be needed to concretize the reduction in oil use, most notably in the transport sector.

75. As the share of hydrogen in final energy use grows, that of natural gas decreases. The share of natural gas in gross final energy consumption drops from 19% in 2016 to between 3% and 4% in 2050. As discussed in the previous section, these results are the evidence of natural gas transitioning from being a primary fuel to a feedstock for producing hydrogen and electricity. They also underscore the ability of hydrogen to replace natural gas where CO_2 capture is difficult.

76. Among the other energy carriers, the increase in use of ambient heat stands out. By 2050, it reaches between 40 Mtoe to 50 Mtoe for use in heat pumps (figure 14). The development of heat pumps is a key element to the success of decarbonization in heating, as it helps overcoming the limits of energy efficiency improvements and fuel switching. They are best placed in the building sector, where they reach a 15% share in 2050 consistent with the JRC analysis on heat pumps. It is complemented by other solutions, such as continued use of natural gas, bioenergy, geothermal energy but also hydrogen, either pure or blended with natural gas.

77. Finally, bioenergy (solid biomass, biofuels and biogas) follows a bell-shaped trajectory. Its consumption in end-use peaks in the next decade at more than 130 Mtoe (a 33% increase in final consumption compared to 2016), before progressively falling back to recent historic levels. Like for natural gas, this does not imply a lesser potential for bioenergy in primary energy supply. Rather, this marks the progressive uptake of BECCS (bioenergy with CCS) in the production of electricity and hydrogen. In total, primary bioenergy supply still increases by about 50% between 2016 and 2050.

2.3 Pathways to net-zero CO_2 emissions

78. The two *Hydrogen for Europe* pathways follow a progressive trajectory towards deep decarbonization and reach net-zero emissions by 2050 (figure 16). The results suggest that achieving net-zero emissions relies notably on the development of carbon dioxide removal solutions. Those solutions enable negative emissions by permanent capture of CO_2 from the atmosphere and storage in carbon sinks. The *Hydrogen for Europe* pathways rely on the development of two technologies:

    a. BECCS allows for negative emissions by combining combustion of the biomass in energy transformation processes with CCS[33]. The solution is developed in the power sector, in second generation biofuel processes[34], and in the production of renewable hydrogen.

    b. Direct air CO_2 capture, when associated with storage (DACCS)[35], allows direct capturing of CO_2 from the atmosphere for permanent storage. Direct air capture complements BECCS, benefitting from a lesser land footprint, and unlock direct air-to-storage removal solution. DAC technologies take off most strongly in the last decade when decarbonization constraints become more stringent. Success in reaching this potential depends on a combination of innovation and policy support, aimed at tackling the issue raised by the high energy intensity of the process.

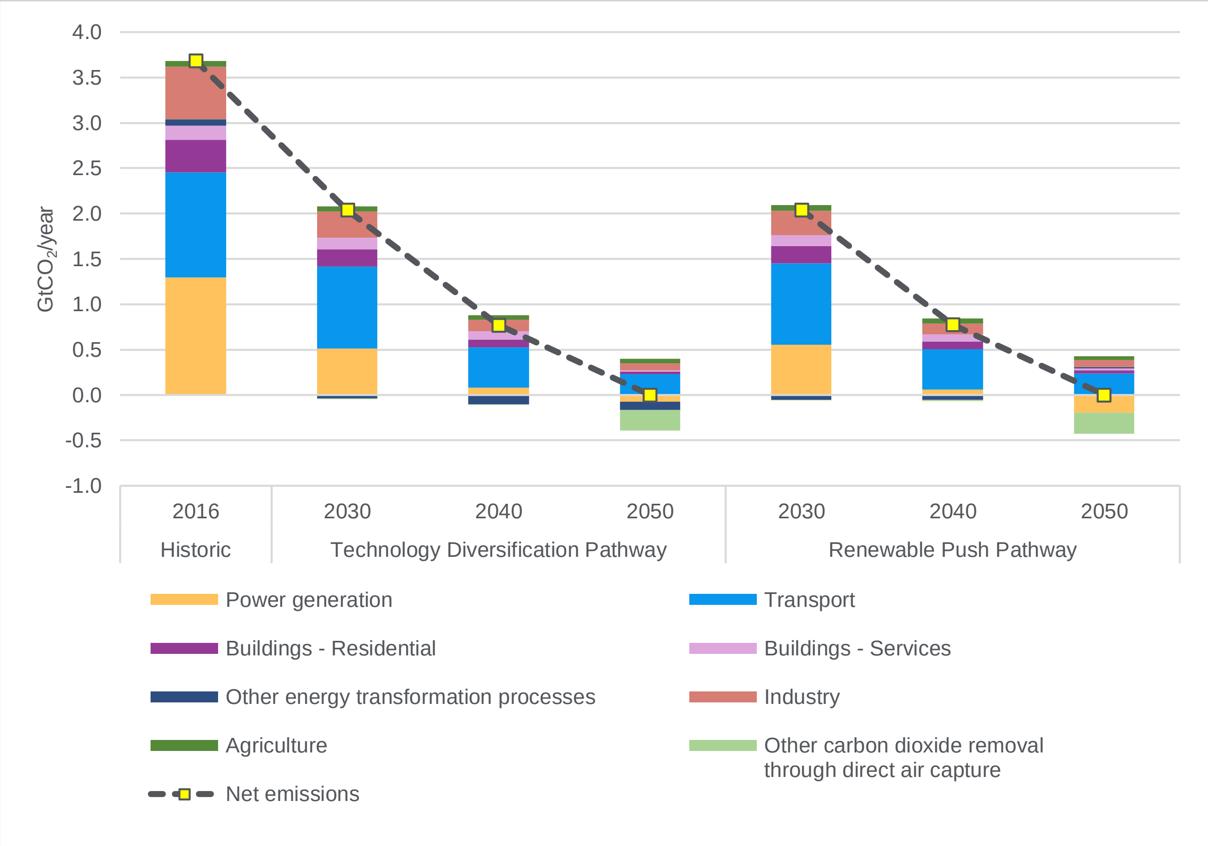
[33] The carbon dioxide captured in biomass could be also be recycled to the atmosphere by traditional use of bioenergy or through blending captured carbon into eFuels.
[34] E.g. Ethanol and diesel/kerosene production technologies from lignocellulosic biomass
[35] Direct air capture can also serve as a supply source for climate-neutral CO_2 (e.g., for the production of e-fuels).

79. In the Technology Diversification pathway, the energy transformation sectors (including power and hydrogen production) achieve net-negative emissions before the end of the outlook period: this means that residual emissions from fossil fuels into the atmosphere are more than offset by negative emissions from BECCS and DACCS. In the power sector, net-negative emissions reach -73 $MtCO_2$ in 2050. Net-negative emissions are also obtained from hydrogen production and biorefining from 2030 (some -40 $MtCO_2$ combined). Emissions for those latter processes drop further to around -95 $MtCO_2$ in 2050. Direct air capture is also used to remove carbon dioxide from the atmosphere, with about 215 $MtCO_2$ of removal for permanent storage or use in e-fuels in 2050.

80. These negative emissions offset the remaining emissions in the hard-to-abate sectors. In particular, the transport and industry sectors remain relatively carbon-intensive throughout the outlook period, despite significant efforts in terms of efficiency and technology switch. BECCS and DACCS thus offset the remaining emissions from oil, coal and unabated natural gas. Although the power, hydrogen and refining sectors are net negative in terms of emission, they also benefit from this offset: there remain other technologies in operation that still emit CO_2 in these sectors and thus need offsetting.

81. It should be noted that the Renewable Push pathway shows different choices in terms of negative emissions. The prominence of hydrogen from electrolysis displaces the use of BECCS to the power sector, which reaches 190 $MtCO_2$ in negative net emissions in 2050. Carbon removal through DACCS is favored in that pathway and reaches 235 $MtCO_2$ of negative emissions by 2050.

Figure 16. Evolution of CO_2 emissions by sector in the Technology Diversification and Renewable Push pathways, 2016 to 2050



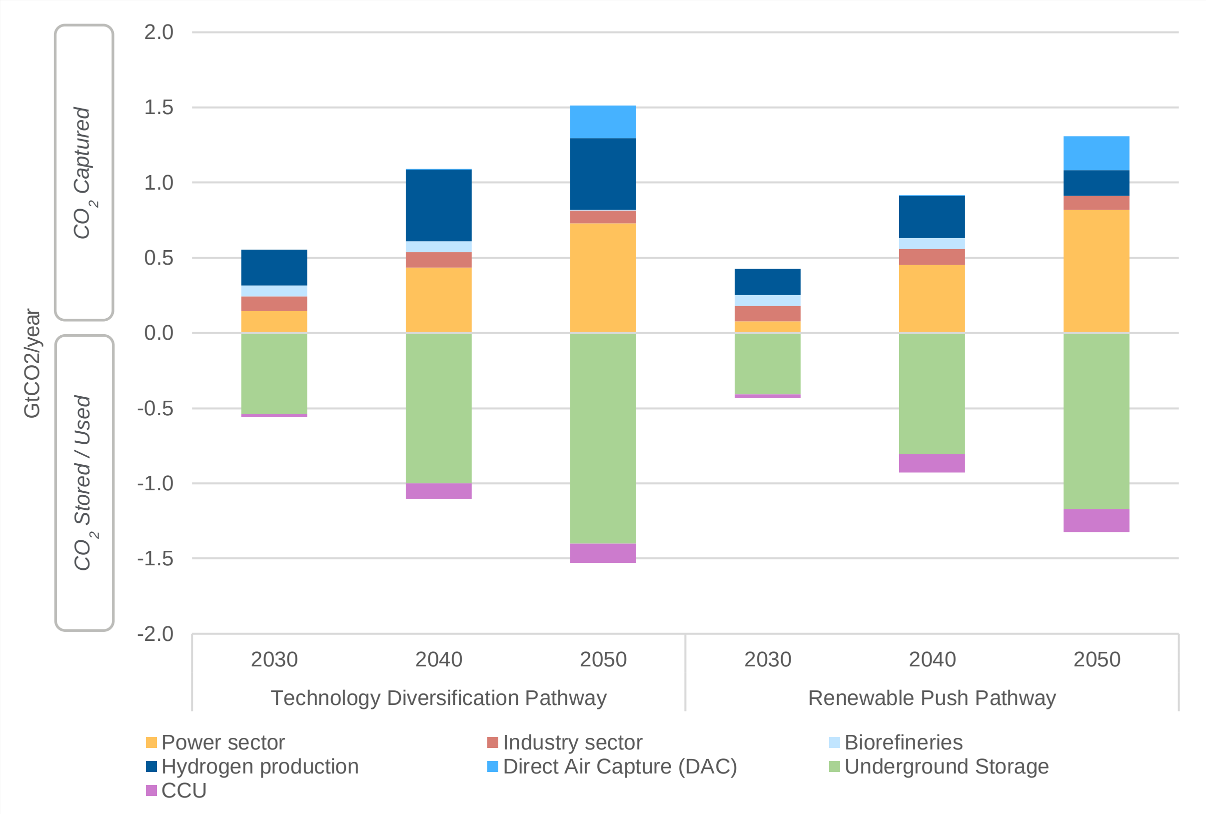
Other energy transformation processes include hydrogen production and refining.

Source : *Hydrogen for Europe* study

82. The success of the pathways to net-zero emissions depends on the overall development of a fully operational CCUS value chain. This value chain goes beyond BECCS and DACCS and also includes fossil fuel use with CCS, the use of CO_2 in energy and industry processes, as well as transport of CO_2 from the capture site to

their place of use or storage. The CCUS value chain, almost non-existent today, represents 1.5 Gt of captured CO_2 in the Technology Diversification pathway by 2050 (figure 17). When compared to 2016, that means that CCS alone, comprising negative emissions, is responsible for about 40% of the reduction in CO_2 emissions. The remainder is achieved through energy efficiency, fuel switching and renewable energy deployment.

Figure 17. Evolution of CO_2 capture (in positive), use and storage (in negative) in the Technology Diversification and Renewable Push pathways, 2016 to 2050



Source : *Hydrogen for Europe* study

83. CO_2 capture is applied to five main sources: hydrogen production, power generation, industry, biorefineries and direct air capture. By 2050, most of the CO_2 is captured in the power and hydrogen production sectors and through direct air capture (figure 17). In both power and hydrogen production, CO_2 is captured from natural gas and biomass with post-combustion CCS, highlighting co-dependencies between the development of natural gas and biomass with CCS in the decarbonization pathways. The more widely CCS is available, the more biomass and natural gas can be used to produce hydrogen and electricity in combination with CCS.

84. Differences in terms of CO_2 capture between the Technology Diversification and Renewable Push pathways are noteworthy. The former favours a more diversified sourcing of CO_2. The latter sees the dominance of CO_2 capture in the power sector (reaching 820 $MtCO_2$ in 2050, or 63%), and lower CO_2 capture from hydrogen production[36]. This effect is due to the increased adoption of electrolysis in hydrogen production in the Renewable Push pathway, which does not require CCS, and to greater use of biomass with CCS in the power sector. In absolute terms, the Renewable Push pathway involves an accelerated and more intense deployment of renewables.

85. About 10% of the captured CO_2 is re-used in 2040 and 2050, after a moderate start in the previous decade. By the end of the outlook period, use of captured CO_2, for e-fuel production, reaches 125 $MtCO_2$ in the Technology Diversification pathway and 150 $MtCO_2$ in the Renewable Push pathway. Non-fossil sources such as biomass and direct air capture provide part of this CO_2, allowing for a carbon neutral process while guaranteeing the

[36] Whose 2050 share in carbon capture drops from 32% to 13% in the two pathways.

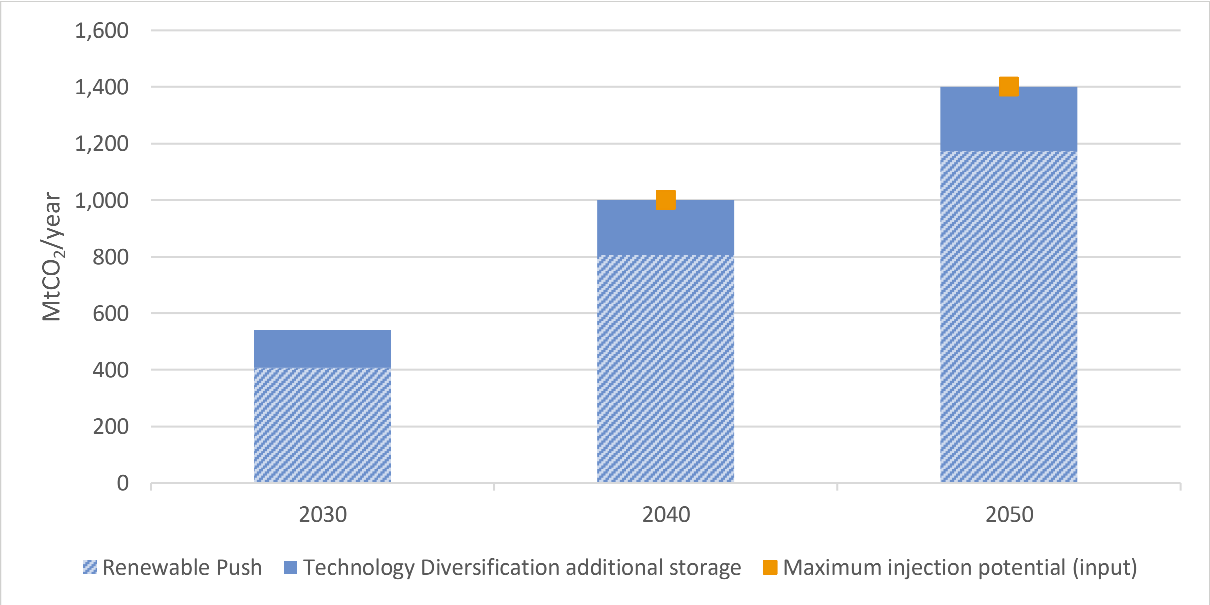
progressive transition towards low-carbon technologies in CO_2-dependent end-uses. Combined with hydrogen and electricity, captured CO_2 from direct air capture can be utilized to produce carbon neutral liquid fuels (e-fuels), with a slightly higher potential in the Renewable Push pathway.

86. The majority of captured CO_2 is stored permanently in deep saline aquifers, depleted oil and gas fields or through enhanced coal bed[37] and enhanced oil recovery[38] processes. Permanent storage allows for a substantial reduction of CO_2 release into the atmosphere from natural gas and other fossil fuel combustion and unlocks the possibility of negative emissions when associated with biomass or direct air capture.

87. The development of CO_2 storage in the Technology Diversification pathway broadly follows a linear trajectory, reflecting continuous ramp up of drilling and increase in annual injection capacities (figure 18). CO_2 injection reaches the maximum limit of 1,000 $MtCO_2$/year in 2040 and 1,400 $MtCO_2$/year in 2050. These injections capacity levels have been derived as a reasonable estimate from a survey of existing literature and expert knowledge (see box 6).

88. With CO_2 injection at its maximum limit in 2040 and 2050, access to CO_2 storage becomes scarce, leading to competition between different CO_2 capture sources. Reaching the injection rate limit constrains any further development of BECCS, DACCS and other low-carbon technologies based on CCS. This particularly affects the potential of BECCS and natural gas for power and hydrogen production, responsible for most of the captured CO_2. A sensitivity analysis relaxing the constraint on CO_2 injection capacities illustrates this dependency (see section 4.1)

Figure 18. Evolution of CO_2 storage injection rate in the Technology Diversification and Renewable Push pathways, 2030 to 2050



Source : *Hydrogen for Europe* study

89. The picture looks different in the Renewable Push pathway. The acceleration of renewable energy deployment, mostly solar and wind, boosts the share of renewable hydrogen and lowers the need for hydrogen production from reformers with CCS. As a result, CO_2 capture and storage are less needed and the estimated limit on CO_2 injection does not constrain CCS' potential. In that pathway, the CO_2 injection limits are not reached in 2040 and 2050. By the end of the outlook period, annual storage stands at 1,170 $MtCO_2$/year (16% below the constraint).

[37] Injection of CO_2 in the coal seam to produce additional coal bed methane.
[38] Injection of gases (including CO_2) in the reservoir for additional extraction of crude oil.

Box 6. Assessing the potential for CO_2 storage

Permanent storage of CO_2 is required for four main reasons: the need to capture and store CO_2 emissions from hard to decarbonize industries, hydrogen and power production from natural gas with CCS, and carbon dioxide removal technologies. The latter includes hydrogen and electricity produced from biomass with subsequent capture and storage of the produced CO_2 and direct air capture. The need for such technologies arises around 2040 and increases towards 2050 when the system must reach the zero-emission criterion.

There is growing momentum for CCS in European countries. Last year the Norwegian parliament approved the financing of the full-scale CCS project Longship. Five cross-border CO_2 projects are currently included in the PCI list and thus eligible for funding under the Connect Europe Facility (CEF) (European Commission 2017). These projects all include or are connected to offshore CO_2 storage in the North Sea. Nevertheless, existing knowledge of the overall potential for annual injection in Europe is still scarce, both from technical and commercial perspectives.

The feasible level of annual CO_2 injection in the study has been estimated based on a survey of available knowledge about the potential for carbon storage in Europe, both in terms of total available geologic potential, which sets the overall frame for accumulated storage of European CO_2,and regarding the progressive increase in annual injection capacity, taking a sensible view on what is feasible in terms of drilling and sequestration in the absence of societal and regulatory barriers.

In terms of total storage capacities in Europe, the United Kingdom[39] and Norway[40] hold the largest CO_2 storage potential by far with an offshore storage capacity of 70 Gt CO_2 each. The Dutch storage potential is assessed at 1.7 Gt (Partenie and de Kler 2018). A scientific study carried out by Ringrose and Meckel (2019) investigated the potential for scaling up CO_2 storage on the Norwegian continental shelf (Halland, Johansen, and Riis 2019). They estimated that offshore wells have an average injection rate capacity of 0.695 ± 0.222 Mt per year. Using historical data for well performance for the Norwegian North Sea, an estimated 2083 wells could be active by 2050 (using 2020 as initiation point for well development) in Norway. This corresponds approximately to an available injection rate of 1.4 Gt CO_2 per year by 2050 for Norway alone.

In light of this information from projects and the literature and given the remaining uncertainty on future potential, a maximum of 1.0 Gt stored annually by 2040 and 1.4 Gt CO_2 by 2050 – across Europe – has been determined as an adequate constraint for the *Hydrogen for Europe* study. A sensitivity analysis on the Technology Diversification pathway was also conducted on the annual CO_2 injection rate (see annex A). It shows that without restriction to the injection capabilities, CO_2 annual storage injection could reach up to 1.8 Gt/year in 2050.

[39] Further information about the UK CO_2 storage potential and projects is available at: https://www.bgs.ac.uk/geology-projects/carbon-capture-and-storage/; http://www.co2stored.co.uk/home/index
[40] Further information about the Norwegian CO_2 storage potential is available at: https://www.npd.no/en/facts/publications/co2-atlases/

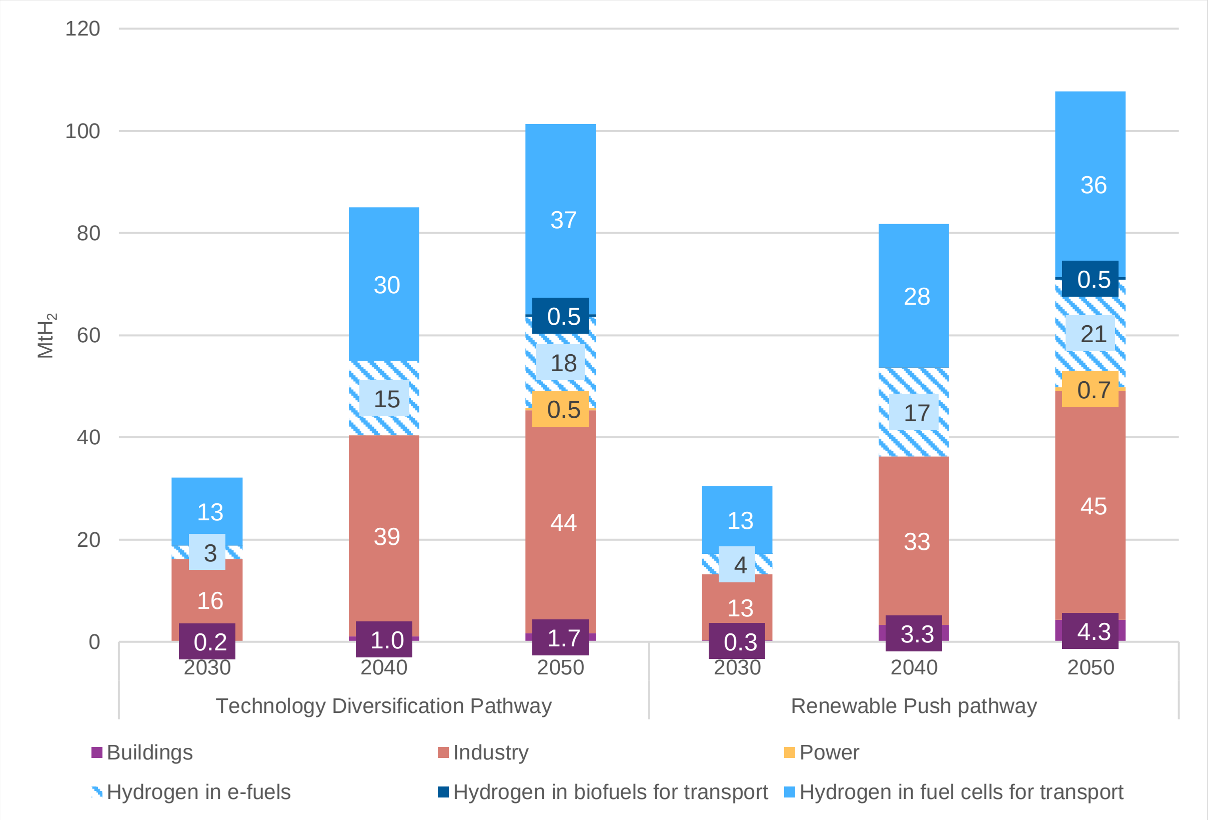
3 The role of hydrogen in the energy transition

90. The two *Hydrogen for Europe* pathways see hydrogen play a major role in the decarbonization of the energy sector with energy-related consumption exceeding 100 million tons (Mt) by 2050 in both pathways (figure 19). The Renewable Push pathway, which shows a stronger penetration of renewable energy, demonstrates hydrogen's complementarity with renewable energies, helping to absorb, store and transport the bulk of the additional energy from renewable sources.

91. In light of the ambitious decarbonisation objectives, European hydrogen demand already exceeds 30 Mt by 2030, which is triple the current policy objective described in the EU hydrogen strategy. This emphasizes the significant potential of hydrogen if all market, regulatory, and societal barriers are addressed, and with an optimal combination of low-carbon and renewable technologies.

92. The biggest ramp-up happens over the 2030s as demand nearly triples to reach between 82 Mt and 85 Mt in 2040. The momentum then slows a bit, with hydrogen demand reaching between 101 Mt and 108 Mt by the end of the outlook period. In low-heating value, this is equivalent to between 3,400 TWh and 3,600 TWh (more than total 2016 electricity production) or around 300 Mtoe (27% of 2016 gross final energy consumption). Hydrogen thus soon becomes one of the main energy carriers of the future European energy system and replaces natural gas as the main gaseous carrier. Although the levels are similar, the growth of hydrogen demand exhibits a slightly different profile in the two pathways, especially in the last decade (101 Mt in the Technology pathway versus 108 Mt in the Renewable Push pathway).

Figure 19. Evolution of hydrogen demand by sector in the Technology Diversification and Renewable Push pathways, 2016 to 2050



In the Hydrogen for Europe *results, hydrogen end-use in transport for fuel cells also includes the potential for hydrogen and hydrogen-embedded energy carriers as shipping fuels.*

Source : *Hydrogen for Europe* study

93. The sectoral breakdown of hydrogen demand confirms the versatility of hydrogen in decarbonizing the energy system. Hydrogen provides an answer to the challenges of deep electrification and the limits of energy efficiency. It proves to be a particularly cost-efficient solution for certain hard-to-abate energy uses in transport and industry.

a. More than half of hydrogen demand (above 50 Mt) comes from the transport sector, either for consumption in fuel cells, as intermediary feedstock for the production of synthetic fuels, or for use in biorefineries (figure 3). By 2050, demand for hydrogen for e-fuels reaches around 20 Mt, with the overall majority being used in the transport sector and especially aviation. Hydrogen, e-fuels and other hydrogen-based solutions provide energy-dense fuels and gases to heavy and long-distance road transport, aviation and shipping, and thus address some of the limitations electric mobility faces in terms of energy density, weight, range and refueling.

b. Industrial hydrogen demand, primarily for energy, reaches some 45 Mt by 2050. Hydrogen is consumed in a diverse set of industry sectors mainly to provide process heat and steam. Its potential is particularly high in the steel sector and in the chemical industry.

c. Hydrogen also contributes to decarbonization in buildings and power generation (with slightly greater use in those sectors in the Renewable Push pathway). Combined, buildings and power generation represent up to 5 Mt of hydrogen demand in 2050 in the Renewable Push pathway. This moderate uptake is notably due to trade-offs between a wide range of available options to decarbonize those sectors such as biogas, direct renewables, heat pumps and continued use of natural gas.

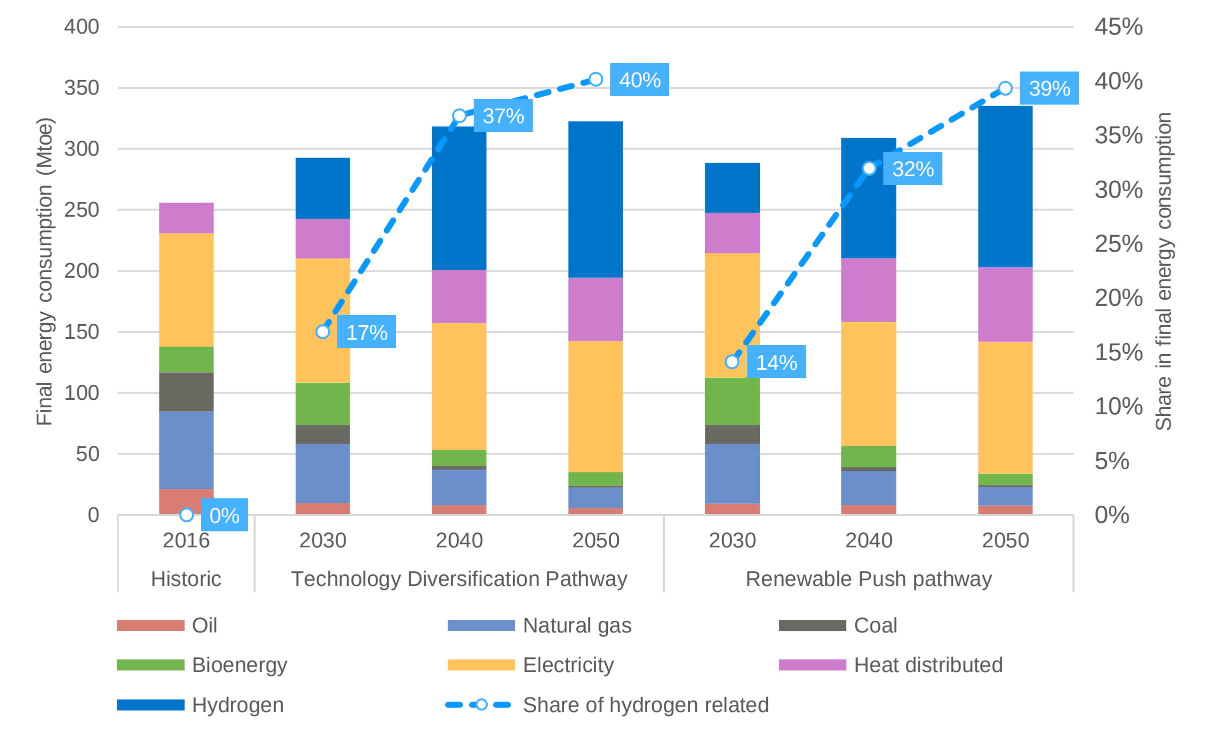
3.1 Hydrogen and decarbonization in industry

94. Energy demand in industry is projected to rise over the next 30 years, underpinned by economic growth and increase in demand from non-energy intensive industries, more than offsetting energy efficiency improvements (figure 20). The decarbonization of the industry's energy consumption relies on the combined use of electricity, hydrogen and distributed heat[41], increased efficiency in production processes, and CCUS, with specific solutions and constraints for each subsector of the industry. Simply speaking, there is no “one size fits all” solution for the entire industry sector.

95. Considering the different industry subsectors[42], the share of electricity in energy consumption remains stable throughout the outlook period, between 30% and 35%, reflecting the challenge of wide-spread electrification of high-temperature heat and steam. Consumption of distributed heat doubles during the period, reaching more than 50 Mtoe by 2050. The most remarkable uptake is for hydrogen, whose energy-related consumption in industry jumps from virtually zero today to about 130 Mtoe in 2050 (about 45 Mt of hydrogen). By the end of the outlook period, hydrogen becomes the primary source of energy for industry, representing up to 40% of total energy demand[43]. Together with distributed heat, hydrogen helps compensate for the decrease in the use of fossil fuels, whose combined share in the final energy consumption drops from 46% in 2016 to 7% in 2050.

[41] Heat produced in a centralized way and distributed to final locations for end-use requirements.
[42] Note that consumption in refineries is attached to the transport sector (section 3.2) and not to the industry sector.
[43] Also including the minor consumption of e-fuels in the sector.

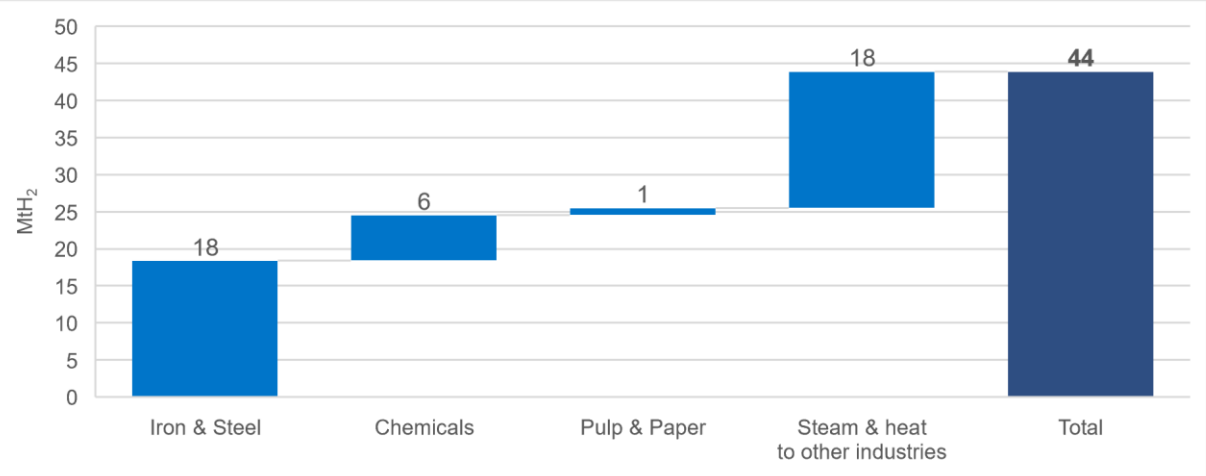
Figure 20. Evolution of final energy consumption in the industry sector in the Technology Diversification and Renewable Push pathways, 2016 to 2050



Source : *Hydrogen for Europe* study

96. CCS also plays an important role in accompanying decarbonization and neutralizing emissions from the residual use of natural gas, oil and coal (e.g., for Corex process[44] and conventional blast furnaces in the steel sector) in industry. In 2050, the combined energy production from these fuels still amounts to some 25 Mtoe, or 7% of total consumption (Technology Diversification pathway). This is due to the complexity of decarbonizing some industrial processes fully. Direct CCS in this sector allows to capture part of the energy-related emissions. In 2050, the level of carbon capture in industry is in the 90-million-ton range, higher than the volume of residual emissions in the sector by that date (less than 80 million tons).

Figure 21. Hydrogen demand in the industry sector in 2050 - Technology Diversification pathway



Consumption of hydrogen in refineries is attached to the transport sector (section 3.2) and not to the industry sector.

[44] Corex is an alternative to blast furnace for steel production based on smelting reduction processes.

Source : *Hydrogen for Europe* study

97. The biggest part of industrial hydrogen consumption is for steel-making, where it reaches 18 Mt in 2050 (figure 21). This represents 40% of total industry consumption (around 15% of total European hydrogen demand by 2050). In this sector, hydrogen is particularly well placed as the main reduction agent to produce steel through an alternative process known as DRI EAF (direct reduction of iron with electric arc furnace). This alternative process currently accounts for a marginal share of iron and steel production and is mostly based on natural gas today: its development as well as increase in the proportion of hydrogen directly fed into the electric-arc furnace as a reductant (up to 100%), would drive the hydrogen-based decarbonization of the sector. There is also the possibility of blending hydrogen in natural gas for all processes which are consuming natural gas.

98. The chemical industry is the second largest outlet for hydrogen as an energy carrier. The sector is characterized by its reliance on high-temperature heat and energy consumption from natural gas, making it prone to a switch to hydrogen. Hydrogen-fueled heaters and boilers have been modeled in the study in order to account for the possibility to produce steam and heat from hydrogen, respectively. As for steel, hydrogen can also be blended with natural gas. The results show hydrogen demand for energy in the chemical industry reach about 6 Mt in 2050 (around 13% of total industrial hydrogen consumption). This energy-related potential of hydrogen should be supplemented by a precise assessment of the future hydrogen demand as a feedstock in chemistry processes, where hydrogen is already being produced on-site using grey production routes[45] (see box 7).

Box 7. Hydrogen as a feedstock in the (chemical) industry

Worldwide, around 70 Mt[46] of hydrogen are used per year as feedstock in industrial processes. Ranking at the topmost industrial applications of hydrogen (in pure and mixed form) are: the production of ammonia for industrial and agricultural use and methanol (38%), oil refining (33%) and metal processing (3%). In Europe, hydrogen demand amounts to 10 Mt[47] with around 4 Mt used for the production of ammonia and methanol, around 4 Mt for oil refining and the remainder used in the steel industry.

The production of hydrogen as feedstock to meet such industrial needs is usually done on-site, mainly from natural gas (steam methane reforming), oil (as a by-product of oil refining) and coal, with associated CO_2 emissions.

This non-energy use represents significant potential for hydrogen in the industry, either produced on-site or procured from a market. Taking this into account in decarbonization pathways is relevant as the 2050 hydrogen feedstock demand is forecasted to increase by 20% in the business as usual scenario, or to double in the most ambitious scenario of the Green Hydrogen for a European Green Deal report[47]. Shifting from unabated reforming to renewable or low-carbon hydrogen for chemical feedstock could then mean that the potential of hydrogen for industry (both as a feedstock and as an energy fuel) in Europe would add to what the *Hydrogen for Europe* study's numbers suggest.

As a caveat, it should be noted that the energy transition could redistribute cards at the global level in many industry sectors, especially in the steel, cement, ammonia and methanol production. The future growth of hydrogen feedstock volume is thus linked to the evolution of demand and production in Europe for products like ammonia or methanol.

99. The cement and paper industries show a minor potential for hydrogen, with a combined consumption of less than 2 Mt in 2050. The decarbonization of these industries is rather driven by use of CCS (and biomass) as well as progress in electrification. The production of steam and process heat for other industries (e.g. manufacturing, food & beverages or textiles) represents another important source of hydrogen use. In 2050, this consumption reaches between 18 Mt and 20 Mt depending on the pathway, or 40% share of total consumption in industry.

[45] The potential related to use of hydrogen in the industry sector covered in the Hydrogen for Europe study corresponds primarily to hydrogen use for production of high temperature heat and as a reduction agent for the iron industry. Other uses as feedstock in the chemical industry, such as existing methanol synthesis, are not included due to model limitations.
[46] IEA 2019. "the Future of Hydrogen"
[47] Wijk, Ad van, and Jorgo Chatzimarkakis. 2020. "Green Hydrogen for a European Green Deal. A 2x40 GW Initiative." Hydrogen Europe. https://www.hydrogen4climateaction.eu/2x40gw-initiative.

3.2 Hydrogen and decarbonization in transport

100. The transport sector is also composed of various sub-sectors whose specificities prevent the adoption of a single solution for decarbonization. Some segments of mobility, such as aviation, maritime and heavy-duty road transport, would be particularly challenging to decarbonize via electrification and efficiency improvements only.

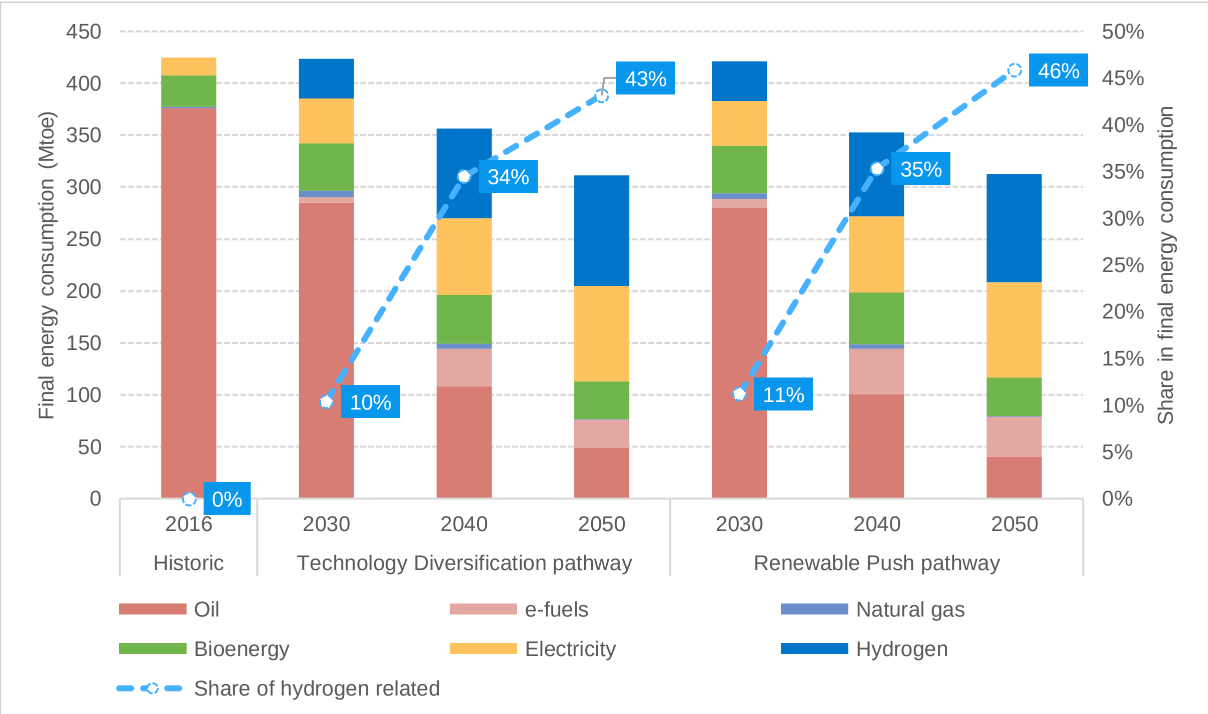
101. This study confirms the major role to be played by hydrogen and embedded hydrogen (such as e-fuels and ammonia) in decarbonizing the sector (figure 22). Like biofuels, hydrogen-based solutions provide energy-dense fuels and gases to heavy and long-distance road transport, aviation and shipping, and thus address some of the limitations electric mobility faces in terms of energy density, weight, range and refueling.

   a. In the results, hydrogen demand for consumption in fuel cells increases steadily between 2030 and 2050. Also including the potential of hydrogen-embedded fuels in the maritime sector, hydrogen becomes by the end of the outlook period the main fuel in the transport sector with a demand exceeding 100 Mtoe, or one-third of total transport sector energy use.

   b. Meanwhile, after a moderate start in 2030, e-fuels for transport are developed at a larger scale over the 2040s and 2050s, with particularly promising prospects in the aviation sector, where the range of viable decarbonized technologies remains limited. Their use reaches almost 40 Mtoe in 2050 in the Renewable Push pathway, which raises the share of hydrogen-based solutions in transport to more than 40% in 2050.

   c. Hydrogen also serves indirectly in biorefining, where it is consumed in the production process for first and second-generation biofuels. It is also blended along with biofuels in conventional fuels like diesel (B7, B10, B30), gasoline (E5, E10 and E85) and jet fuels.

Figure 22. Evolution of gross final energy consumption in the transport sector in the Technology Diversification and Renewable Push pathways, 2016 to 2050



Gross final energy consumption as described in this subsection on transport includes domestic and international aviation and maritime bunkers (following Eurostat / JRC-IDEES nomenclature). Regarding the standard nomenclature, the figures are obtained by summing all road, rail, aviation and maritime.
In the Hydrogen for Europe *results, hydrogen end-use in transport also includes the potential for hydrogen and hydrogen-embedded energy carriers as shipping fuels.*

Source : *Hydrogen for Europe* study

102. Besides hydrogen-based solutions, electrification is also critical for the future of mobility. The final consumption of electricity grows fivefold between 2016 and 2050. Electricity represents 30% of total final consumption in the later years, with most of it in passenger cars, light-duty road vehicles and trains. When considering the development of hydrogen-based FCEV, over half of the road vehicle stock would be propelled by electric engines in 2050, thus unlocking strong efficiency gains in energy use for mobility. Energy efficiency is the third major enabler of the sector's decarbonization. Electrification of the powertrain, automation, technological improvements, and modal shifts are assumed to reduce total energy consumption significantly over the next thirty years. In 2050, final energy consumption for mobility in Europe thus drops to around 310 Mtoe, a 27% drop from 2016 levels.

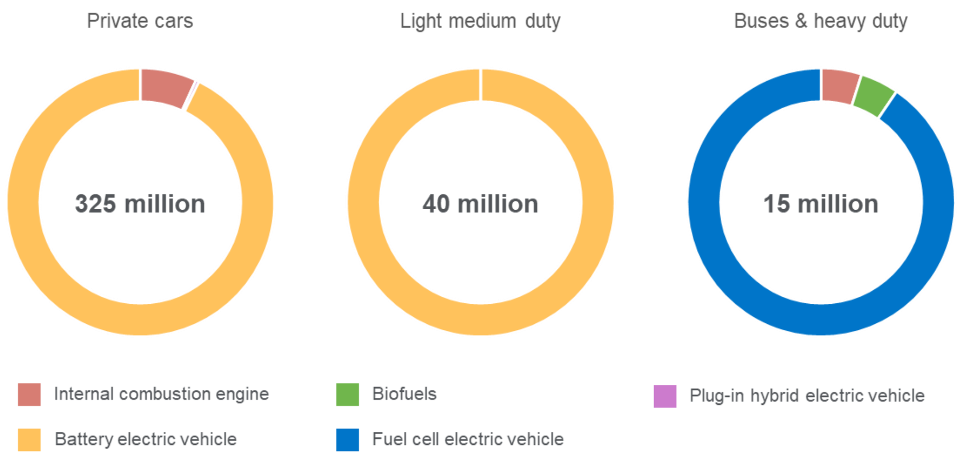
103. Taken together, hydrogen and hydrogen-based solutions, electrification and energy efficiency are sufficient to tackle most of the carbon emissions in the sector. Oil consumption, which represented 88% of total energy demand in 2016, drops by 85% to less than 50 Mtoe by 2050. The rest of consumption comes from biofuels. Biofuel demand for transport represents around 35 Mtoe in 2050, which is stable compared to 2016, but hides a peak at almost 50 Mtoe (+66%) during the transition period, as it helps paving the way to net-zero emissions.

104. In the road sector (figure 23), passenger and light-duty mobility becomes the domain of electricity. By 2050, the share of battery-based and plug-in hybrid electric vehicles climbs to 93% for passenger cars and up to 100% for light-medium duty vehicles, with a combined stock of more than 350 million vehicles.

105. Hydrogen has a key role to play for buses and heavy-duty road freight, benefitting from its higher energy density, lighter fuel cell and storage weight compared to batteries, and shorter refueling times. By 2050, the majority of the truck and bus fleets in circulation are powered by fuel cells. The uptake of hydrogen fuel cells in these sectors is underpinned by the deployment of the necessary refueling infrastructure. Unlike for light vehicles, captive fleets[48] offer the opportunity to mitigate the risk on the commercial viability of such infrastructure. Captive fleet would enable high utilization rates from the start and the progressive developments of hydrogen stations along the main transport routes and hubs. Achieving this potential would also depend on further improvements to of fuel cells and refueling technologies.

106. The remainder of energy consumption in the road sector is coming from a combination of biofuels, e-fuels and oil, mostly in the form of blended final fuels. Bioenergy shows promises for the decarbonization of trucks and buses, where it complements hydrogen fuel-cells, and propels an important share of the total fleet in 2050. Meanwhile, e-fuels see minor development in the road sector, challenged by relatively high costs and low-efficiency in the production process, making it a premium fuel for applications where very few alternatives exist. Together with the low efficiency of internal combustion engines, e-fuels rank low in competitiveness against electric vehicles and other low-carbon solutions.

Figure 23. Composition of road transport fleets in 2050 in the Technology Diversification pathway

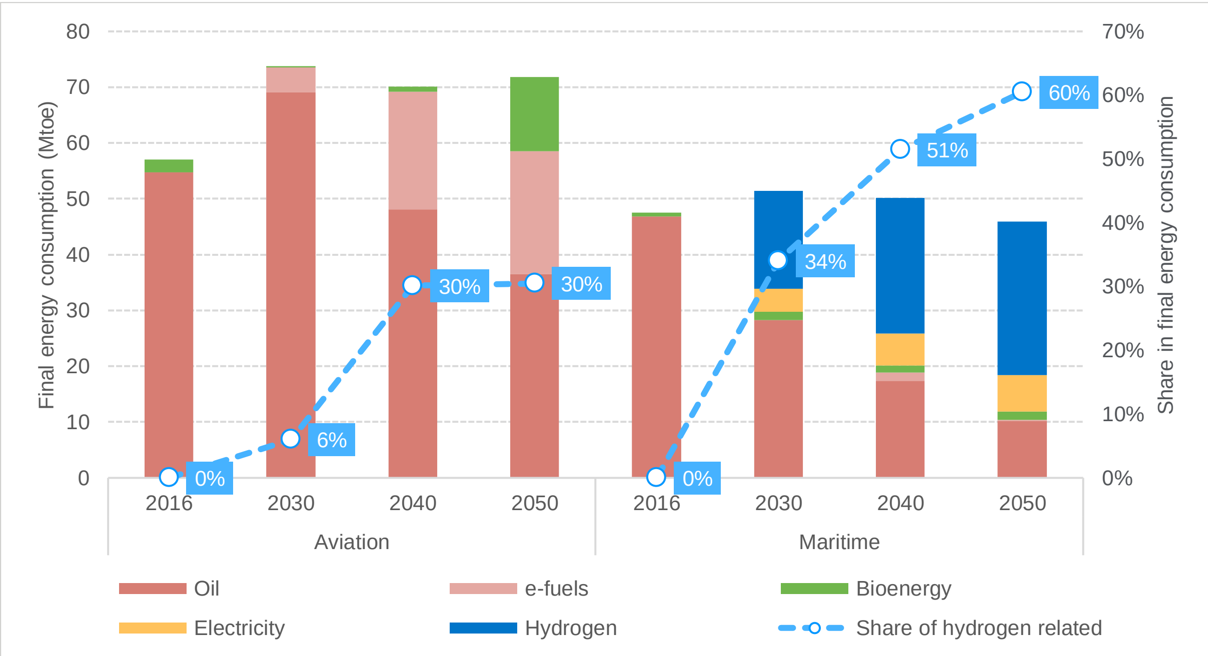


Source : *Hydrogen for Europe* study

[48] Public or private-owned fleets of vehicles whose refueling/charging can be optimized around dedicated infrastructure.

107. In aviation, especially for long-distance flights, the potential of direct hydrogen consumption is limited by the challenge of storing the required large amounts of fuel in the aircraft. E-fuels and biofuels are therefore likely to be the best fit to decarbonize the sector. These fuels minimize the efforts needed to adapt the manufacturing and operation of planes and allow continuous utilization of existing technologies at least cost[49]. By 2050, e-fuel consumption in aviation amounts to 30% of total consumption in the Technology Diversification pathway (over 20 Mtoe) and 45% (over 30 Mtoe) in the Renewable Push pathway. As for the road sector, e-fuels for aviation suffer today from low efficiencies and low competitiveness in the short-to-medium term. Their outlook strongly depends on further innovation and on the ability of the aviation industry to fully internalize the cost of carbon emissions, for example through the extension of the EU-ETS scheme, carbon taxes and other quotas to progressively phase out carbon-intensive fuels. The results show that even in the absence of market or regulatory barriers, e-fuels and biofuels are to be complemented by conventional kerosene, which still represents between 40% and 50% of total consumption in 2050.

Figure 24. Evolution of final energy consumption in aviation and maritime in the Technology Diversification pathway, 2016 to 2050



This figure includes domestic and international aviation and maritime bunkers (following Eurostat / JRC-IDEES nomenclature). In the Hydrogen for Europe *results, hydrogen end-use in transport also includes the potential for hydrogen and hydrogen-embedded energy carriers as shipping fuels.*

Source : *Hydrogen for Europe* study

108. In the maritime sector, hydrogen-based solutions such as gaseous or liquid hydrogen or ammonia could become a significant carbon-abated alternative to oil. In 2050, their share in final energy consumption (also including bunkers) reaches 60%. Electricity consumption in navigation does not exceed 6 Mtoe in the long term, less than 15% of total consumption. The exact breakdown of hydrogen potential between alternate energy/hydrogen carriers remains subject to uncertainties. Hydrogen as a direct fuel (in fuel cells) is promising for short trips (e.g., for barges or ferries). Open-ocean navigation would require fuel with a higher energy density, relying on liquefied hydrogen or ammonia. As for aviation, achieving that development of hydrogen in the maritime sector also depends on the ability of the market to send the right signals to encourage switching to decarbonized solutions.

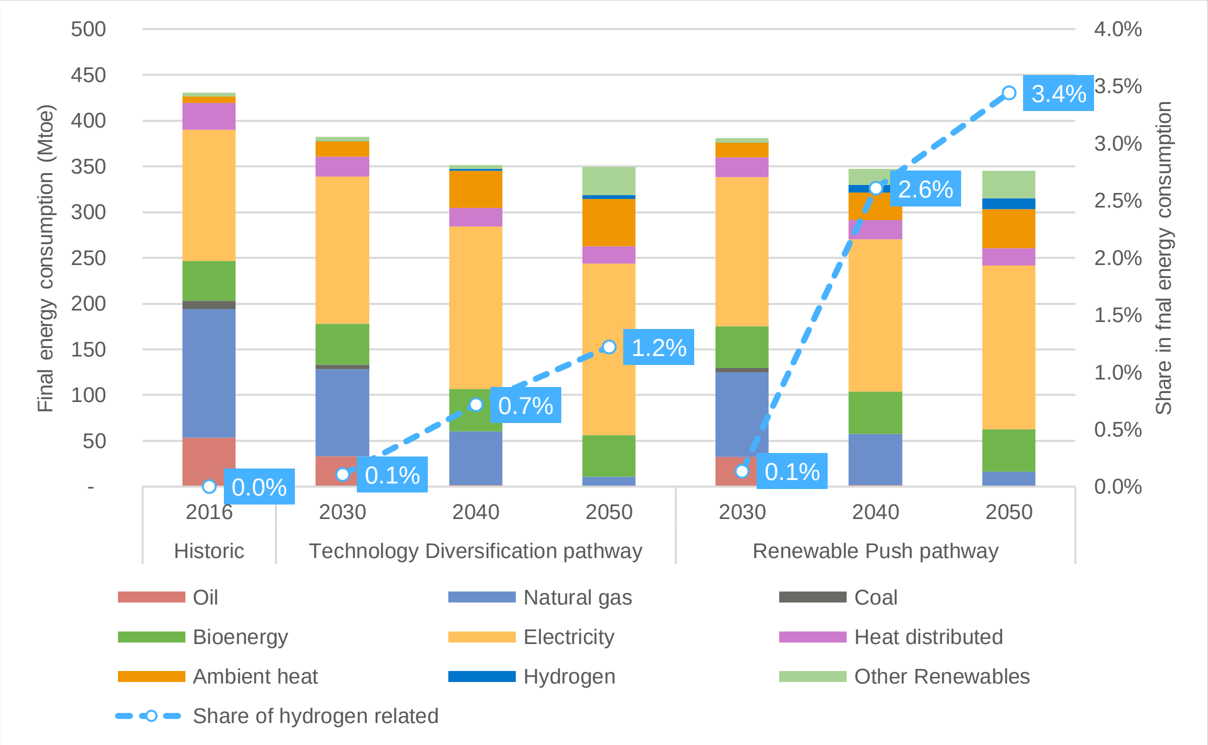
[49] Turbine adaptations and refueling and airport infrastructures

3.3 Hydrogen and decarbonization in buildings

109. The building sector accounts for the largest share of final energy consumption in Europe, with some 40% of final energy in Europe being consumed for heating, cooking, cooling and appliances. While electricity and other renewable energies already account for more than half of this consumption, the sector remains a significant source of CO_2 emissions, emitting more than 500 million tons of CO_2 in 2016, mostly from natural gas and oil consumption for space and water heating. The seasonality of demand for heating raises increasing challenges in terms of investments and energy security.

110. Further decarbonization of buildings entails challenges, but large emissions reductions can be achieved via energy efficiency improvements (figure 25), which allow for a 20% reduction in energy consumption between 2016 and 2050 (29% when compared to 2005). Like transport, the building sector still holds large untapped energy efficiency potentials, with thermal insulation as one of the main solutions to reduce consumption in an aging building stock. The pathways show a renovation potential in line with the EU Renovation Wave Strategy, with up to 3.5% annual renovation rate in some countries.

Figure 25. Evolution of final energy demand in the building sector in the Technology Diversification and Renewable Push pathways, 2016 to 2050



Source : *Hydrogen for Europe* study

111. Electrification of energy use in buildings, in combination with deployment of low-carbon sources in power generation is another major source of emissions reduction. The share of electricity in final energy consumption in buildings increases to more than 50% in 2050. The development of electrification for space and water heating is facilitated by proven technologies and by the deployment of next generation heat pumps. These factors allow for an almost ten-fold increase in the utilization of ambient heat for heat pumps in the Technology Diversification pathway (an additional 45 Mtoe between 2016 and 2050).

112. Other renewables, mostly geothermal and solar thermal, also make inroads to the buildings sector over the outlook period. District heating systems, where they can be switched to low-carbon sources, continue to play a role in supplying energy to buildings.

113. There is clear scope for continued use of gaseous fuels for heating purposes in buildings, albeit in a more diversified manner than today. The pathways see a combination of biogas, natural gas and hydrogen serving energy demand where other technologies reach their technical or economic limits. It therefore requires a local assessment of the available energy sources, energy needs and existing infrastructure, to decide which fuel is best placed to reduce the emissions of the local buildings stock. For example, the share of hydrogen in final consumption is, with up to 3% (or 12 Mtoe), on a par with that of natural gas in the Renewable Push pathway. This energy is either directly consumed in home fuel cells and boilers or blended with natural gas.

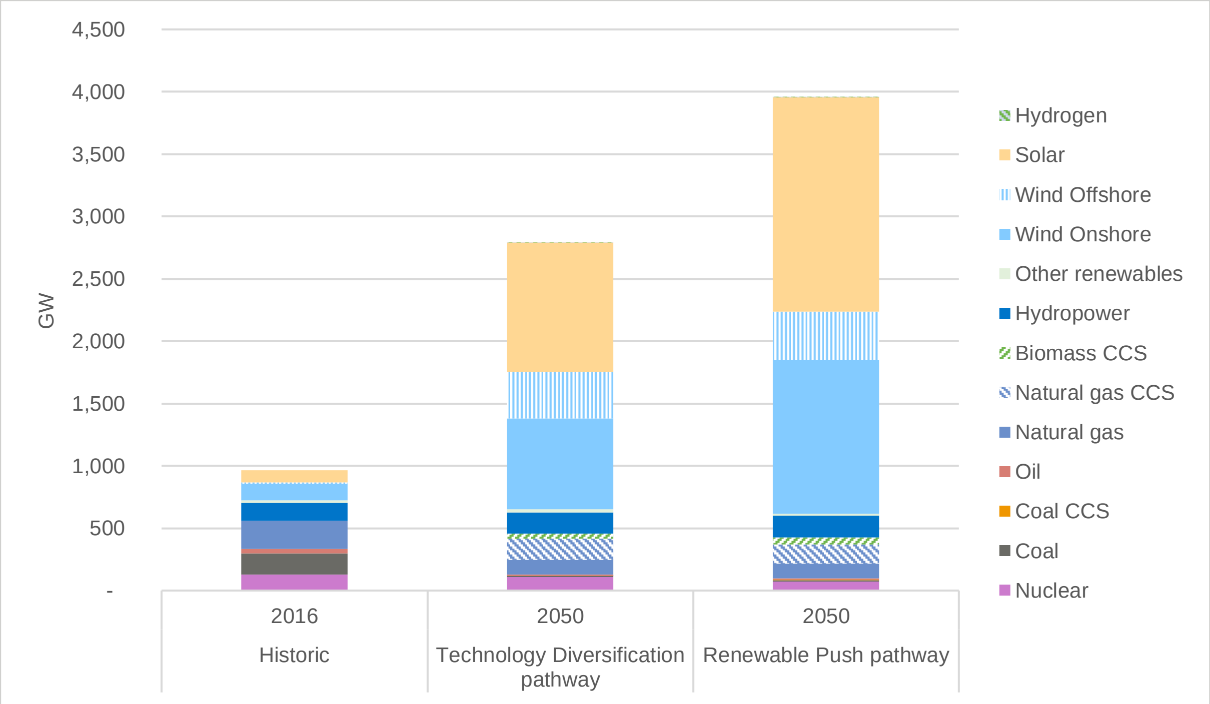
114. Ample availability of renewable electricity, promising technologies for electric heating and the 'sunk' nature of gas distribution infrastructure challenge a strong uptake of gaseous fuels in buildings in our modelling. However, constraints in the supply of renewable electricity and the conversion to heat pumps, efforts to protect the value of existing distribution grids and wider economic considerations, such as the creation of regional hydrogen ecosystems, could locally confer a more important role to hydrogen in buildings.

3.4 Hydrogen and decarbonization of the power sector

115. Electricity is one of the key pillars of the energy transition, complementing hydrogen, energy efficiency and end-use of renewable energy to achieve deep decarbonization of the energy system. In the period to 2050, the share of electricity grows, both in final energy consumption (from 3,370 TWh to almost 5,000 TWh between 2016 and 2050 corresponding to an increase of about 50%) but also in the transformation sector for the production of other energy carriers like hydrogen and e-fuels.

116. The net-zero emissions challenge is remarkable for the power system: total installed generating capacity is projected to reach 2,800 GW in the Technology Diversification pathway (three times as high as 2016's value) and around 4,000 GW in the Renewable Push pathway (four times), mostly due to accelerated installation of renewable electricity production (figure 26). Power generation is boosted from 3,300 TWh in 2016 to 7,500 TWh in 2050 in the Technology Diversification pathway and to 9,300 TWh in the Renewable Push pathway, as a direct effect of the higher share of renewables in that pathway.

Figure 26. Installed capacities for power generation in the Technology Diversification and Renewable Push pathways, 2016 compared to 2050



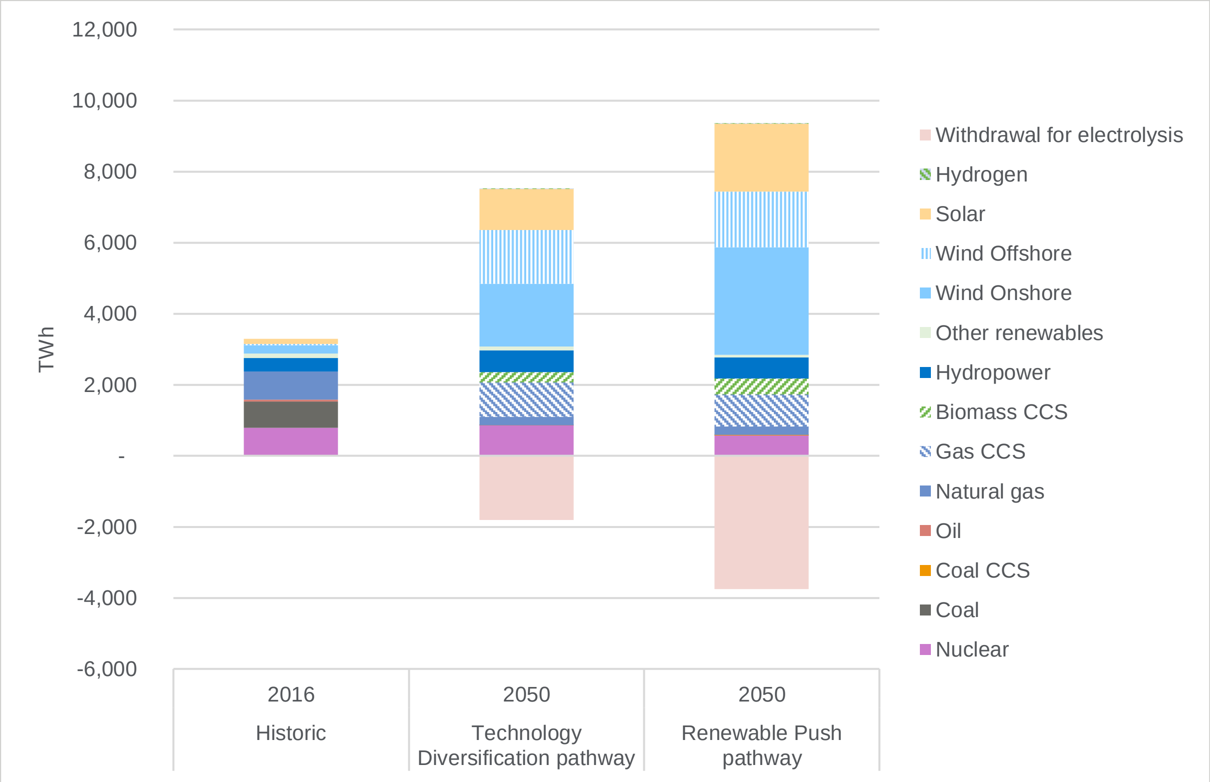
Source : *Hydrogen for Europe* study

117. To achieve the uptake, large amounts of capital spending is needed to finance power plants, reinforce grids and roll out flexible technologies. Variable generation from solar and wind is multiplied by eleven in the Technology Diversification pathway between 2016 and 2050, and by sixteen in the Renewable Push pathway. In the latter pathway, electricity production from solar and wind in 2050 represents 70% of total generation (figure 27).

118. Network operators need to adapt to new challenges in balancing the system and handling more frequent and more pronounced situations of congestions and peak load. Seasonality of demand and meteorological uncertainty calls for new investments in flexible means to ensure the stability and reliability of electricity supply. This involves a combination of network investments (e.g. to transport energy away from renewable sources and to consumption hubs) and flexibility options such as smart grids, electricity storage, flexible generation units (such as gas-fired plants with CCS) and power-to-hydrogen.

119. The *Hydrogen for Europe* study highlights the role of power-to-hydrogen to accommodate the increasing share of variable renewables in the system. Production of hydrogen through electrolysis is the main outlet for the generation of future solar and wind capacities. Electrolysis also makes increasingly important contributions to power system flexibility and to mitigating curtailment and congestion. By 2050, electricity consumption for hydrogen production via electrolysis exceeds 1,800 TWh in the Technology Diversification pathway and 3,700 TWh in the Renewable Push pathway. This corresponds to between 40% and 60% of the variable generation from wind and solar in 2050. Moreover, the results show that most power-to-hydrogen is operated in an "offgrid" set up, with electrolyzers primarily powered by a direct connection to solar and wind farms onshore and offshore (see section 4.1.2). Such offgrid power-to-gas directly evacuates 35% of the generation from solar and wind in 2050 in the Technology Diversification pathway, thus providing flexibility for the integration of variable renewables and reduces investment needs in electricity network infrastructure. The share of offgrid power-to-hydrogen is higher in the Renewable Push Pathway, where the accelerated deployment of renewable energy leads to some 55% of all solar and wind production in 2050 happening off the grid to directly feed electrolyzers.

Figure 27. Power generation and withdrawal for electrolysis in the Technology Diversification and Renewable Push pathways, 2016 compared to 2050



Power generation and electrolysis both ongrid and offgrid (dedicated to hydrogen production)

Source : *Hydrogen for Europe* study

120. Meanwhile, a smaller amount of hydrogen is also consumed for power generation: power generation from hydrogen reaches between 12 TWh and 16 TWh in 2050, using around a million tons of hydrogen. The load factors of hydrogen-fueled power installations (between 5 GW and 7 GW in 2050) tops 25%, positioning hydrogen as a flexible source of mid load and peaking power. It complements other decarbonized solutions in this role such as nuclear or natural gas and biomass power generation with CCS:

a. Natural gas is resilient in the power sector and still represents a 20% share of the ongrid power mix in 2050 (against 24% in 2016). About 80% of the gas-fired fleet are combined-cycle gas turbines equipped with CCS. Low-carbon power generation from natural gas demonstrates highest value in the mid-load segment with an average load factor of around 65%. The remaining turbines (combined-cycle and open cycle turbines without CCS) serve as peaking units with a load factor of around 20% in 2050.

b. Biomass and hydropower are dispatchable renewable energies that contribute substantially to the integration of variable renewables, providing mid-load and peak-load power as well as flexibility. The large majority of biomass power generation is equipped with CCS in 2050, representing 5-7% of the total ongrid power mix and constituting and an important source of negative emissions in the energy system.

c. Nuclear power generation represents 14% of the ongrid mix in the Technology Diversification pathway in 2050 compared to 24% in the past. As a low-carbon source of electricity it contributes to decarbonisation but political headwinds and social acceptance problems put the break on nuclear development in various European countries.

121. Hydrogen has a clear value proposition for the integration of variable renewable energies into the system. Electrolysers absorb a large part of the renewable energy locally, thus limiting the strain on the transmission and distribution infrastructure. The renewable hydrogen can then be stored and transported to the most valuable consumption outlets. As described in the previous sections, these outlets are primarily the hard-to-abate energy uses in industry, transport and buildings. Meanwhile, a smaller amount of hydrogen is reinjected in the power sector as a flexibility option, in complement to other solutions like gas-fired power plants with CCS or power-to-hydrogen. Deployment of hydrogen turbine technologies and backlash on the roll-out of CCS and nuclear could however create a role for hydrogen in power generation that goes beyond balancing (0).

Box 8. The potential of hydrogen for power generation

The rapid growth of variable renewable electricity production causes an increased need for additional electricity production to cover peak demand and seasonal balancing. Hydrogen holds a potential to play a significant role in combination with electricity storage technologies such as batteries and pumped hydro storage. In addition to fuel cells, which have been included in the study, hydrogen fuelled open- and combined cycle gas turbine power plants (OCGTs and CCGTs) are promising technologies. Gas turbines already have a balancing role in the power sector, fuelled by natural gas. Hydrogen-fired gas turbines offer the advantage of creating demand for hydrogen, thus possibly contributing to kick-start the hydrogen economy. They offer the possibility for uptake of hydrogen from all sources, including hydrogen with impurities that is not fuel-cell grade, thus providing system flexibility and the capability of handling large volumes of hydrogen. Further, hydrogen-fired gas turbines can be deployed at locations where transport and storage of CO_2 is challenging and do not require expansion of the plant site. Finally, in many existing combined cycle power plants, the transition to hydrogen firing of gas turbines only requires the replacement of the combustion chamber in some of the most common layouts (can-annular systems). Moderate conversion costs of CCGTs are thus expected for many power plants.

Ongoing developments in all the major CCGT suppliers aim at an ultimate capability of taking 100% hydrogen fuel. A key focus in these developments is to qualify advanced combustors fit for 100% hydrogen, with proper NOx control. Here, the development of lean premixed combustion systems, based on "multi-cluster" or two stage "sequential" combustor technologies, seems to be viable solutions for 100% hydrogen. As long as the market for 100% hydrogen CCGTs is uncertain and the large amounts of hydrogen for qualification testing is not available, the strategy of the CCGT suppliers and plant owners should be to build "hydrogen-ready" gas fired power plants that can already now take 20-50% hydrogen by volume but can be converted if and when 100% hydrogen becomes available. There are now four such projects under development in the US. The first gas turbines based on lean-premixed combustor systems fuelled with 100% hydrogen could be commercially available by 2030. The most advanced project currently undertaken is the conversion of a 440 MW combined-cycle gas turbine to hydrogen at Vattenfall's Magnum gas-fired power plant in the Netherlands.

A recent analysis by the IEA indicates that hydrogen gas turbines are cost competitive against natural gas fuelled gas turbines with integrated CO_2 capture at decreasing load factors. At load factors above approximately 10%, hydrogen and CO_2 emission costs are decisive drivers of which technology is the most cost efficient. This poses a significant challenge for the assessment of the potential for hydrogen in the power sector in an energy system model with the geographical and temporal time coverage required to assess the European energy system until 2050 and should be subject for further studies.

The following example illustrates the order of magnitude for hydrogen in the power sector. If 10% of the electricity produced by gas turbines in 2050 in the Technology Diversification pathway was replaced by hydrogen gas turbines, the demand for hydrogen would correspond to 6 Mt hydrogen per year. This assumes a similar energy efficiency as applied by IEA. The power sector would then comprise 6% of the total hydrogen use in 2050 and would require a combination of additional hydrogen production and reduced hydrogen demand in other sectors.

4 Development of the hydrogen value chain

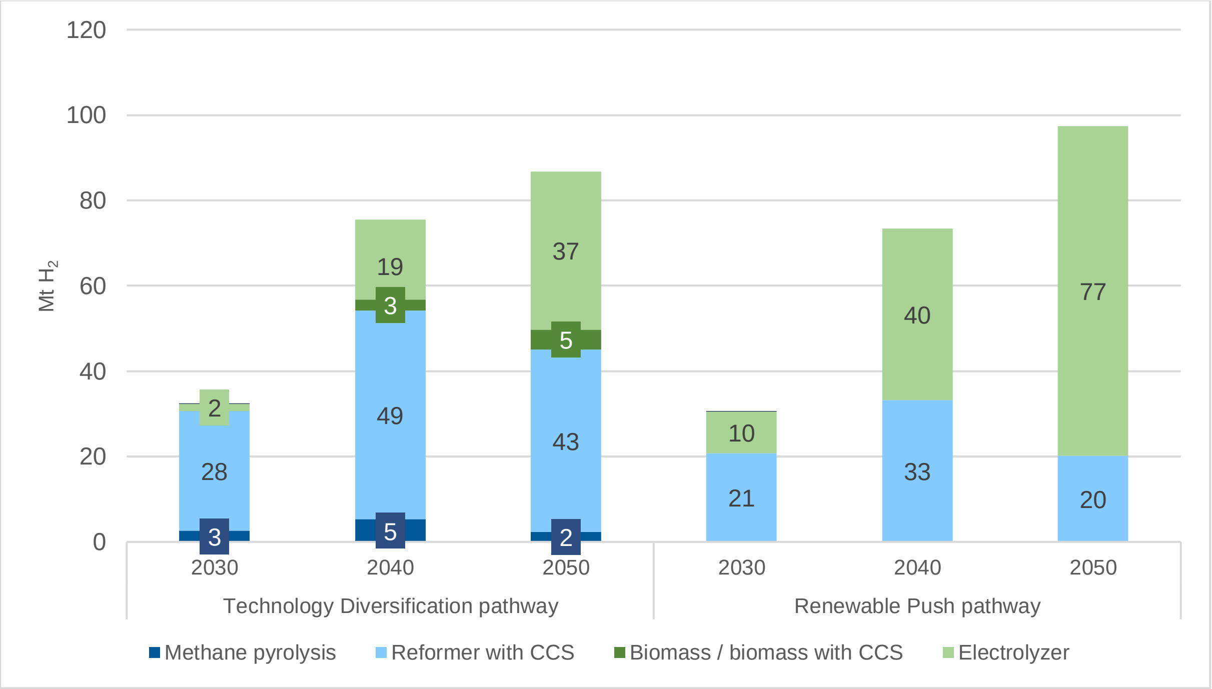
122. The development of the hydrogen value chain relies on the roll-out of production and a dedicated European-scale energy infrastructure that includes transport and distribution of hydrogen, storage and refuelling options. Hydrogen trade between European countries fosters the emerging hydrogen economy, enabling hydrogen flows between producing and consuming areas.

4.1 Production of hydrogen in Europe

123. In light of the targets announced in the European and national hydrogen strategies (e.g. in Germany, France, Spain, or Portugal), hydrogen production in Europe is envisaged to soar in the coming decades. Currently, a hydrogen supply sector is burgeoning in Europe, with many industrial projects already announced for the coming years. In this fast-moving context, the *Hydrogen for Europe* study directly assesses, in its two main pathways, the potential for renewable and low-carbon hydrogen production in Europe. The two pathways shed light on the way European hydrogen could be produced i.e. with which production technologies, at which cost, in what timing.

124. In the two *Hydrogen for Europe* pathways, European hydrogen production skyrockets over the next three decades, relying on a diverse production mix comprising renewable and low-carbon technologies (figure 28). Output increases markedly between 2030 and 2040, going from just over 30 Mt in 2030 to around 75 Mt in 2040, reflecting the accelerating uptake of the hydrogen economy after 2030. This trajectory highlights the importance of keeping the momentum that is currently seen in Europe behind hydrogen production projects. Early investments are needed to increase the volumes of hydrogen production as soon as the next decade and create the necessary scale. A significant share of this hydrogen is produced with low-carbon technologies that rely on natural gas (reformers with CCS or pyrolysis). In the Technology Diversification pathway, low-carbon hydrogen production reaches around 45 Mt in 2050.

Figure 28. Evolution of hydrogen production in Europe in the Technology Diversification and Renewable Push pathways, 2030 to 2050



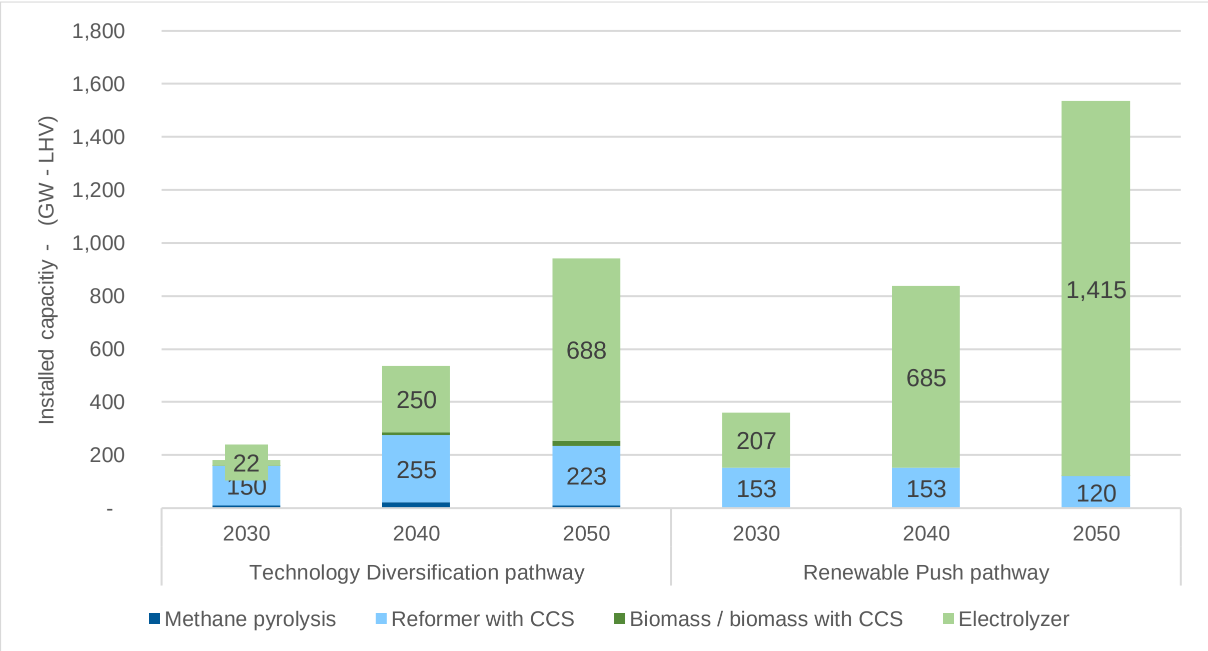
Source : Hydrogen for Europe study

125. Hydrogen is not necessarily produced where it is consumed. Hydrogen trade between European countries is required in order to transport the molecules from their production sites to the end-users. While all European regions show some potential for hydrogen production and consumption, the European hydrogen economy mostly evolves around eight countries (Germany, Norway, Italy, the Netherlands, France, Poland, Spain and the UK).

126. Norway becomes the main producer of hydrogen in Europe. It exports almost all its hydrogen production, thus continuing to play its traditional role of energy exporter to the rest of Europe. In both pathways of the *Hydrogen for Europe* project, Norway mostly produces low-carbon hydrogen via reformers equipped with CCS and exports hydrogen via pipeline to the continent. In the Renewable Push pathway, the increased ambitions in renewables markedly impact the role of low-carbon hydrogen supply from Norway in the European hydrogen economy, reducing the scope for exports significantly. Germany is not only the biggest consumer of hydrogen in the two pathways but also the main off-taker of Norwegian hydrogen exports.

127. The pathways highlight the diversity of hydrogen production technologies and the complementarity between low-carbon and renewable routes. While low-carbon hydrogen plays a critical role in establishing a hydrogen economy between 2020 and 2030, renewable hydrogen develops mainly after 2030 and meets the bulk of the additional demand growth. In the Technology Diversification pathway, the production mix is very balanced in 2050 with low-carbon and renewable sources both providing about half of the European output. In the Renewable Push pathway, underpinned by higher policy targets for renewable energy deployment, renewable hydrogen sees a major upscaling during the late 2030s and becomes the biggest hydrogen production source by 2040.

Figure 29. Evolution of hydrogen production capacity by technology in the Technology Diversification and Renewable Push pathways, 2030 to 2050



Source : Hydrogen for Europe study

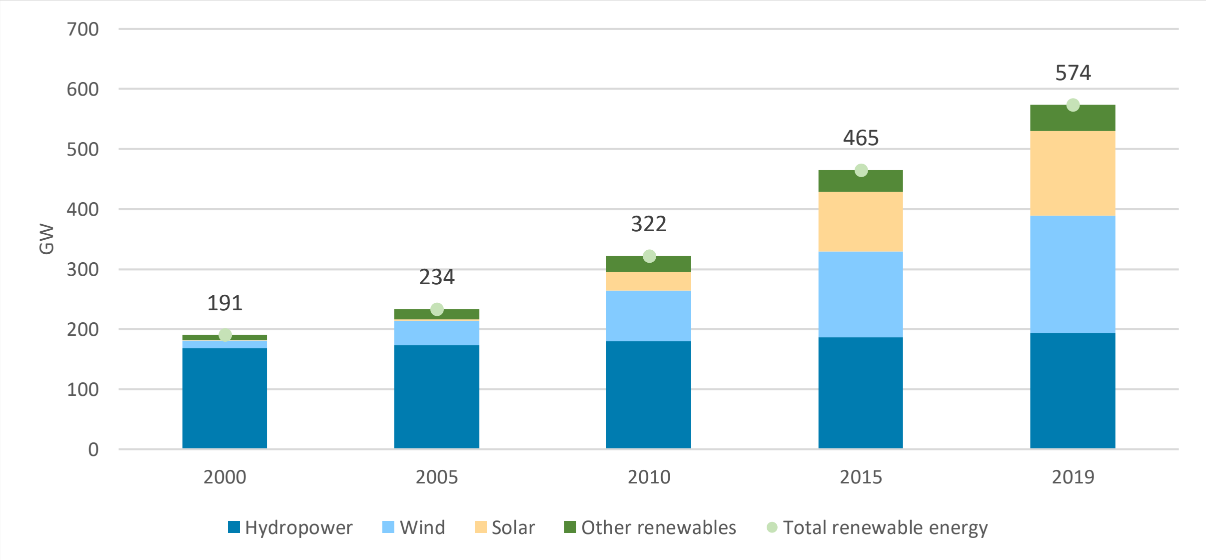
128. The growth in output is accompanied by a rapid ramp-up of hydrogen production capacity in Europe (figure 29). The investment in renewable and low-carbon hydrogen facilities starts between 2020 and 2030, with overall capacity growing to more than 175 GW[50] in 2030. This emphasizes the need for immediate policy and industrial action to support this ramp-up. By 2050, hydrogen production capacity in Europe reaches 945 GW in

[50] Steam methane reformers (without CCS) are also installed before 2025 in the pathways, representing more than 15 GW. They are used to produce some non-decarbonized hydrogen between 2025 and 2030. Starting 2030, no more hydrogen is produced with these reformers. This would indicate that SMR assets would need to be designed from the start as CCS-ready to avoid being stranded at a very early date.

the Technology Diversification pathway, and more than 1,500 GW in the Renewable Push Pathway. Heavy reliance on electrolyzers running on variable renewable electricity leads to lower capacity utilisation in this scenario.

129. The increase in hydrogen production capacity in Europe is an unprecedented industrial effort, even compared to the increase in renewable installed capacity in the power generation sector over the last two decades. Between 2000 and 2019, Europe has seen its total renewable installed capacity growing from 191 GW to 574 GW in the power generation sector (figure 30). As such, there is a clear need for conscious and effective policy support for the establishment of a hydrogen production industry in Europe. The task is all the more formidable as the development of electrolyzers is itself contingent on the installation of almost 2,000 GW of new renewable energy capacities in the period to 2050. Social acceptance of renewable energy installations, as well as the ability of the supply chains of renewable energy components and electrolysers to deliver this ramp up, is an indispensable feature of the pathway towards net-zero emissions.

Figure 30. Evolution of installed renewable energy capacity for electricity production in Europe, 2000 to 2019



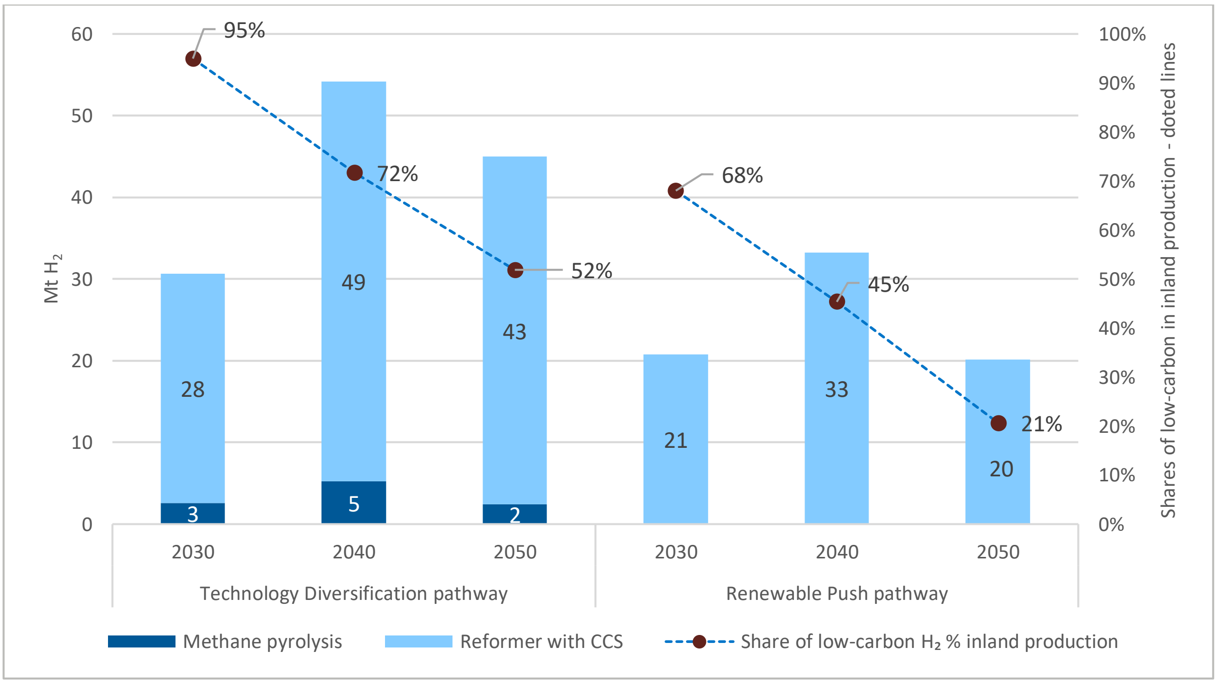
Source : IRENA

4.1.1 Production of low-carbon hydrogen in Europe

130. Low-carbon hydrogen technologies (reformers with CCS or methane pyrolysis) are rolled out rapidly over the 2020s with production reaching 30 Mt by 2030 in the Technology Diversification pathway, corresponding to 95% of total hydrogen production by that year (figure 31). In that same pathway, production peaks in 2040, at around 55 Mt, covering more than two thirds of European production. Production then tapers off to 45 Mt (just over half of total hydrogen production) in the last decade of the outlook period, mostly constrained by the limitations in CO_2 storage injection.

131. Low-carbon hydrogen is also a key feature of the Renewable Push pathway, despite the greater focus on renewable energies. As in the Technology Diversification pathway, low-carbon hydrogen establishes the hydrogen production industry and serves the bulk of demand in the first half of the outlook period, before sufficient renewable energy is available to power electrolyzers. In 2030, low-carbon hydrogen represents two thirds of total production (20 Mt), and then peaks in 2040 at nearly 35 Mt (meeting almost half of the total hydrogen demand). In the last decade, low-carbon hydrogen gradually falls, reaching a share of 20% of the production mix by 2050.

Figure 31. Evolution of low-carbon hydrogen production by technology in the Technology Diversification and Renewable Push pathways, 2030 to 2050



Source : *Hydrogen for Europe* study

132. While reformers with CCS dominate the low-carbon hydrogen production mix from 2030 to 2050, there is a role for pyrolysis in the Technology Diversification pathway. The prospects of pyrolysis depend on several parameters as the technology has still not reached its commercial stage in 2021: the feed-gas cost, the sales price of carbon black (a by-product of the pyrolysis process), the success of the industry to bring down capital cost and the economics of competing sources of hydrogen (see box 9). In the Renewable Push pathway, pyrolysis does not feature, mostly because the push towards renewables lead to significant cost decreases of electrolyzers that end up producing the bulk of hydrogen in 2050 (section 4.1.2). In this pathway, virtually all domestic low-carbon hydrogen is produced via reforming technologies with CCS.

Box 9. The prospects for pyrolysis and the carbon black market

Among the known pyrolysis technologies, the Kværner process, the molten media methane and non-catalytic methane pyrolysis technologies have been included in this study. The Hazer process, a catalytic pyrolysis technology utilizing iron ore, is promising, but currently not included due to lack of adequate data. Except for the Kværner process, a cost reduction of 20% is assumed when going from pilot scale to the first commercially available plants.

In addition to hydrogen, carbon black is a potentially valuable product of the pyrolysis process, even if there are still uncertainties around the quality of the carbon product coming from pyrolysis. The purity and also the form of the carbon black byproduct may impact the market size and earning associated to selling carbon black.

A market for carbon black produced in Europe is set to around 70 Mt/year, with earnings of 100 €/ton if produced for the market. Assuming that the carbon black produced by pyrolysis process is sold on the carbon black market, This market corresponds to admixture to cement (10 Mt/year, up to 4 % of the European cement demand) and usage of carbon black for soil enhancement (60 Mt/year). The earnings are calculated as substitution for cement and fertilizer. the revenue of the transaction is incorporated as a reduced variable cost of 0.3€/kg H2 produced.

The molten media and non-catalytic methane pyrolysis technologies are assumed to reach the commercial stage by 2030. In the Technology Diversification pathway, pyrolysis-based production holds a share of 8% in 2030 and 3% in 2050, while higher shares of renewables are found to reduce the scope for hydrogen production via pyrolysis.

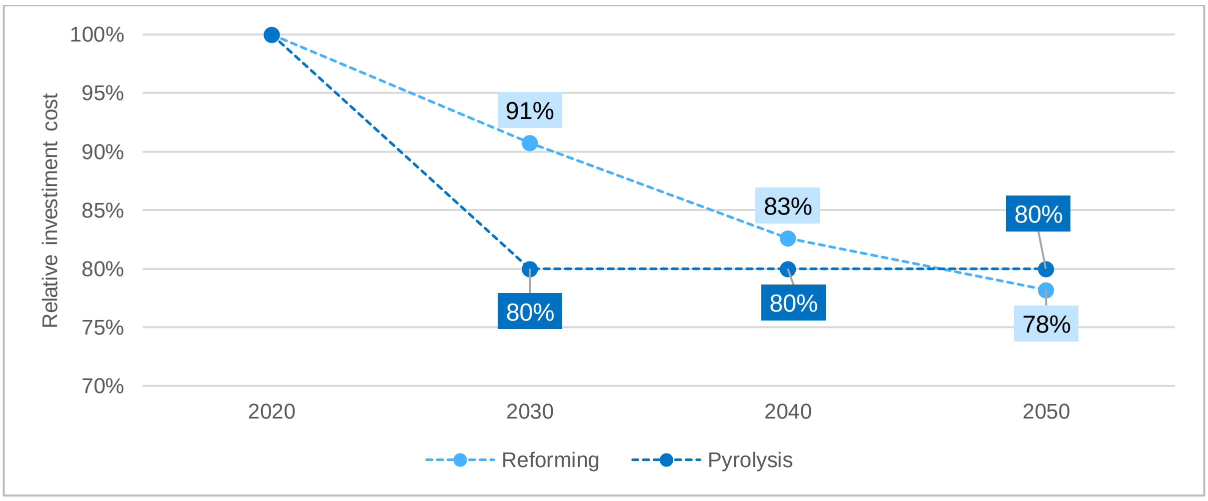
As for all new technologies, the uncertainty whether and when pyrolysis becomes commercially viable is high. Therefore, a sensitivity has been carried out to assess the results of a scenario with a delayed timeline for commercial availability of pyrolysis technology. The sensitivity assumes an alternative cost profile of the pyrolysis technology, reaching commercial stage by 2040 instead of 2030. Specifically, the capital cost of pyrolysis is modified to yield a 5% reduction compared to demonstration stage in 2030 (in contrast to 20% reduction in the main pathways) and a 20% reduction in 2040 (similar as in the main pathways).

The results of the sensitivity show that the *Hydrogen for Europe* pathways are not significantly impacted by a delay in pyrolysis technologies maturity. The delay would only induce a shift in low-carbon hydrogen production with pyrolysis to the next decades, with lower volumes of produced molecules in 2040 and higher volumes in 2050. In 2040, pyrolysis produces around 1 Mt (-17%) less low-carbon hydrogen compared to the Technology Diversification pathway. In 2050, the results show a slightly more important role of pyrolysis, with production of low-carbon hydrogen with pyrolysis standing at 3.1 Mt in the sensitivity case, which is about half a million ton (+29%) above the corresponding output number in the main pathway. These relative variations should be put in perspective with the wider role of pyrolysis in the outlook for low-carbon hydrogen production in Europe: its potential is biggest in countries with low endowment of renewable resources or with difficulties in deploying CCS (due to social acceptance or costly access to CO_2 transport and storage infrastructure).

Natural gas prices also play a role in the development and the profitability of pyrolysis, as methane is the main feedstock used in the process. To test the resilience of pyrolysis' development to varying fossil fuel prices, a sensitivity has been performed. It assumes an environment with lower fossil fuel prices in the future, which are based on the IEA's SDS scenario (see annex A). The results of the sensitivity case confirmed that pyrolysis is highly dependent of natural gas prices. When fuel prices are lower, pyrolysis sees its share in low-carbon hydrogen production rising up to 10% in 2040, standing at nearly 8 Mt i.e. 50% higher than in the Technology Diversification pathway.

133. In the Technology Diversification pathway, reforming sees its costs falling by over a fifth in the period to 2050 under learning effects (figure 32). The cost decreases observed for pyrolysis are in a similar range. Innovation in reforming drives the technological deployment of low-carbon hydrogen (see box 10). Gas-heated reformers combined with autothermal reformers with CCS represent the bulk of low-carbon production. They are complemented by pyrolysis for countries where renewables are scarce and where CCS is politically difficult, with annual production between 2 Mt and 5 Mt in the period between 2030 and 2050 in the Technology Diversification pathway.

Figure 32. Evolution of investment costs for low-carbon hydrogen production technologies in the Technology Diversification pathway, 2020 to 2050



Source : *Hydrogen for Europe* study

Box 10. Innovation in reforming technology with CCS

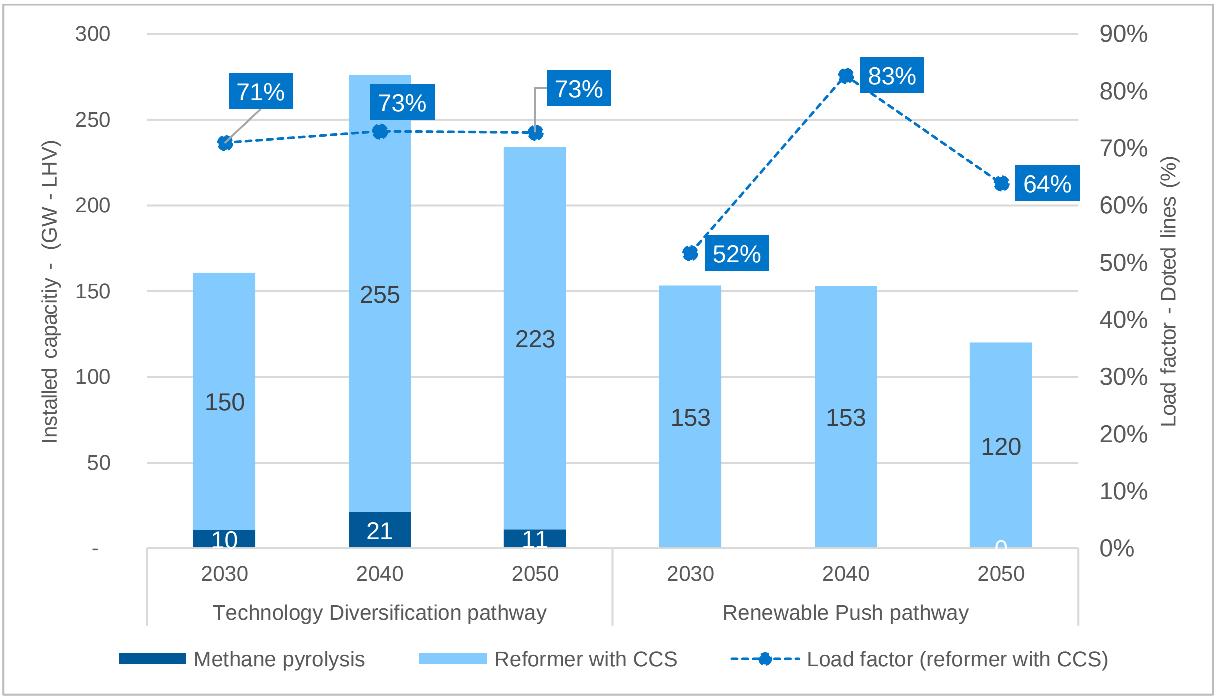
Global hydrogen production currently relies on steam methane reforming (SMR) with heat provided externally of the reactor. CCS for SMR with high CO_2 capture ratios is energy intensive due to the low partial pressure of the CO_2 in the flue gas from heating. As an alternative, autothermal reforming (ATR) keeps CO_2 in a single high-pressure gas stream through the combination of partial oxidation and steam reforming, reducing the energy demand for CO_2 capture. The technology is already applied in methanol and gas-to-liquids processes (oxygen blown) and ammonia processes (air blown). A new reactor technology, gas-heated reforming, combines the concepts of both SMR and ATR for improved utilization of energy, boosting efficiency.

In addition to improvements to the reformer technology, several new approaches for integration of CO_2 capture in the production of hydrogen are under development. These include sorption enhanced reforming or water-gas shift in which CO_2 is adsorbed on the surface of the catalyst and removed in a cyclic approach either through the use of several reactors and switching between the reactors or applying a moving bed for regeneration of the adsorbent. This approach has the advantage of changing the chemical equilibrium through removal of CO_2 from the mixture in the reactor. In addition, the combination of hydrogen and CO_2 purification through a single technology, e.g. vacuum pressure swing adsorption, may result in a reduced energy penalty for CO_2 capture.

In the pathway described by the Hydrogen for Europe study, ATR technologies represent the bulk of low-carbon hydrogen production, thus confirming their technical potential which results in significant cost reductions.

134. In the Technology Diversification pathway, low-carbon hydrogen production capacity (including reformers with CCS and pyrolysis facilities) ramps up substantially in the period to 2040, going from virtually zero today to 160 GW in 2030 and around 275 GW in 2040 (figure 33). As the oldest reformers are gradually pushed out of the market at the end of the outlook period, low-carbon hydrogen production capacities taper off to around 235 GW (around a quarter of the overall hydrogen production capacities in Europe). Reformers run at high load factors throughout the outlook period (e.g. at around 70% by 2050). As such, timely investment in reformers – the bulk is happening between the mid-2020s and mid-2030s – thus allows for high capacity utilization and financial viability before other sources of hydrogen ramp up.

Figure 33. Evolution of low-carbon hydrogen installed capacities by technology in the Technology Diversification and Renewable Push pathways, 2030 to 2050

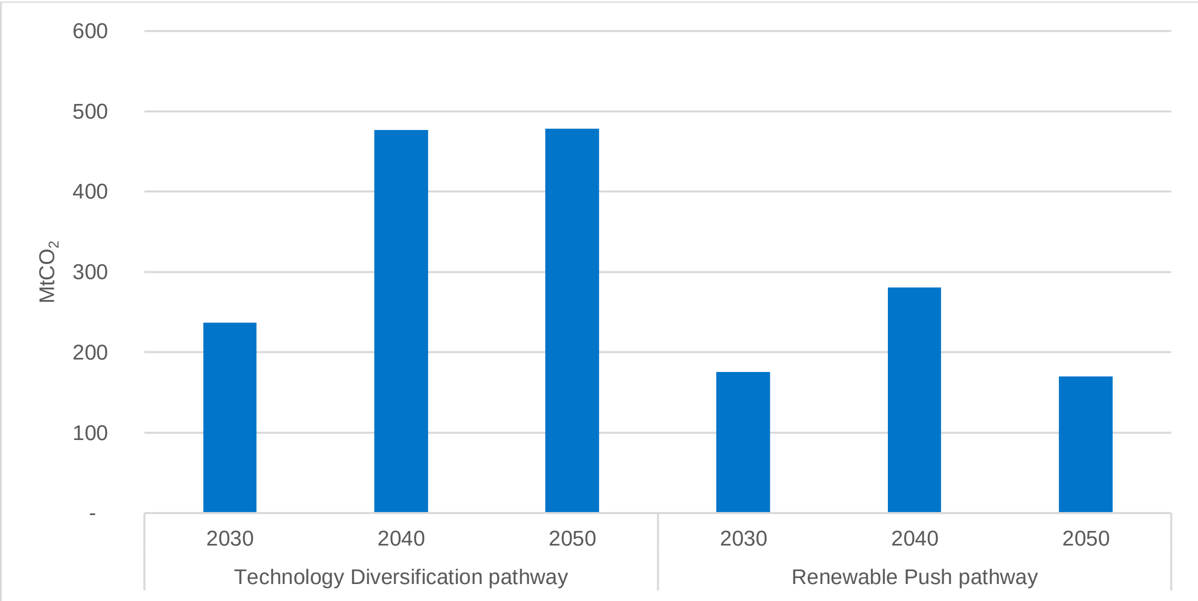


Source : *Hydrogen for Europe* study

135. Despite ample long-term availability of renewable hydrogen in the Renewable Push pathway, substantial capacities of natural gas reformers with CCS are needed to meet rapidly rising hydrogen demand in the first half of the outlook period. However, in this scenario the transition time is shorter, leading to fluctuating utilization rates. In this pathway, low-carbon hydrogen capacity tops 150 GW in 2030 (-6.5% compared to the technology Diversification pathway) but investment dries up in the mid-2030s as low-carbon hydrogen progressively gives way to renewable hydrogen. The window of opportunity for low-carbon hydrogen production technologies is thus shorter when compared with the Technology Diversification pathway.

136. These levels of low-carbon hydrogen production lead to significant volumes of captured CO_2 (figure 34). In the Technology Diversification pathway, CO_2 captured through use of reformers, but also from biomass with CCS (see section 4.1.2) increases from just under 240 Mt of CO_2 in 2030, to nearly 480 Mt in 2040, broadly staying at that level to the end of the outlook period. In the Renewable Push pathway, these levels are markedly lower as electrolysis constitutes the bulk of hydrogen production, but they remain nevertheless significant, with 175 Mt in 2030 (-26%), peaking at over 280 Mt in 2040 (-41%) and then drop to 170 Mt in 2050 (-65%).

Figure 34. Evolution of CO_2 captured from hydrogen production in the Technology Diversification and Renewable Push pathways, 2030 to 2050



This includes both reformers with CCS and biomass with CCS.

Source : *Hydrogen for Europe* study

137. Given the important role of reformers with CCS, the potential of low-carbon hydrogen is highly dependent on the parallel deployment of the CCUS value chain and the ability of carbon storage capacities to grow in lockstep with low-carbon hydrogen production over the next thirty years. Further low-carbon hydrogen development in the Technology Diversification pathway is constrained by the annual CO_2 injection limit of 1.4 Gt in 2050. The success of low-carbon hydrogen is thus closely tied to the development of an adequate CO_2 storage and transport infrastructure.

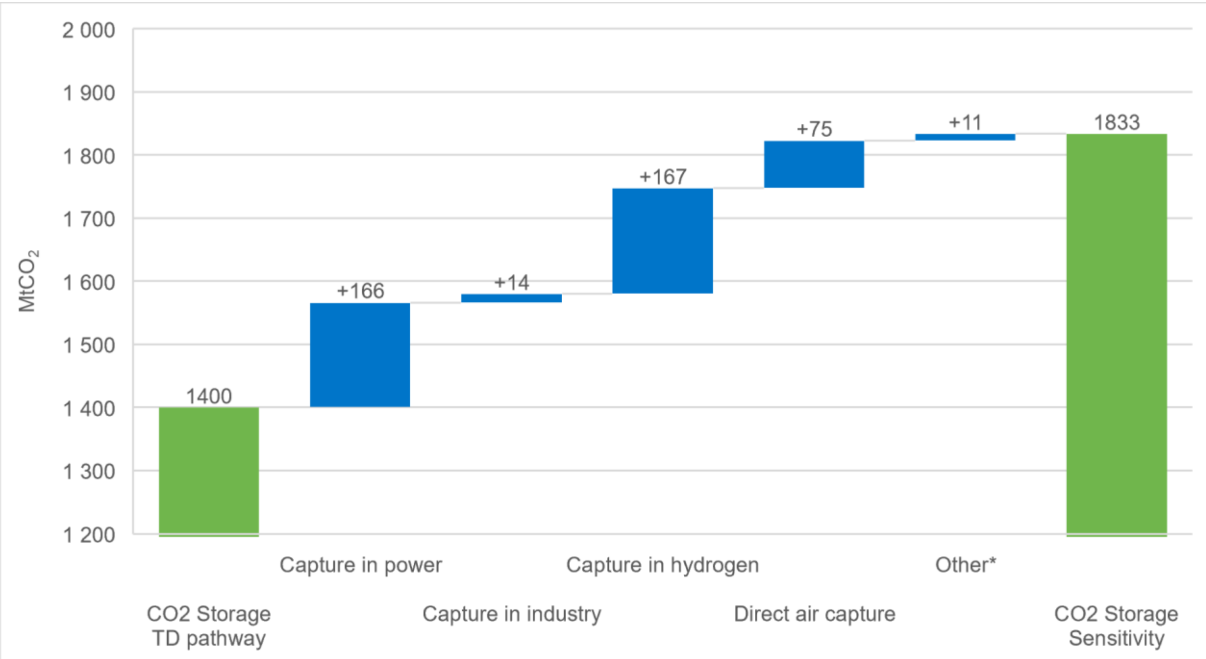
138. The findings show that timing is critical for the uptake of low-carbon hydrogen production technologies in Europe. In both pathways, early investments are required to benefit from a window of opportunity wide open at the beginning of the transition. To take most advantage of this window of opportunity, investors would need to start sanctioning low-carbon hydrogen projects by the mid-2020s, supported by the necessary policy enablers (see section 0).

Sensitivity analysis on the annual maximum CO_2 injection capacity in Europe

139. The results of the Technology Diversification pathway demonstrate that timely availability of sufficient CO_2 storage is indispensable for the deployment of low-carbon technologies with carbon capture. Nevertheless, in the latter half of the outlook period, CO_2 injection into storage formations reach – in the Technology Diversification pathway – what is considered a reasonable estimate of CO_2 injection capacity (1 Gt in 2040 and 1.4 Gt in 2050). It is therefore instructive to study what maximum CO_2 injection capacities would be desirable from a climate mitigation and least-cost perspective.

140. A sensitivity analysis on the Technology Diversification pathway was conducted without restriction on the annual CO_2 injection rate. Without that constraint, CO_2 annual storage injection reaches up to 1.2 Gt/year in 2040 and 1.8 Gt/year in 2050, respectively 20% and 30% higher than the Technology Diversification pathway. Greater storage potential allows for additional carbon capture from several sources (see figure 35): direct air capture (+75 Mt/+35% in 2050), industry (+14 Mt/+16%), power generation (+166 Mt/+23%) through BECCS and natural gas with CCS, and hydrogen production (+167 Mt/+35%).

Figure 35. Changes in 2050 carbon capture and storage from the Technology Diversification pathway to the sensitivity with unconstrained CO_2 injection capacity



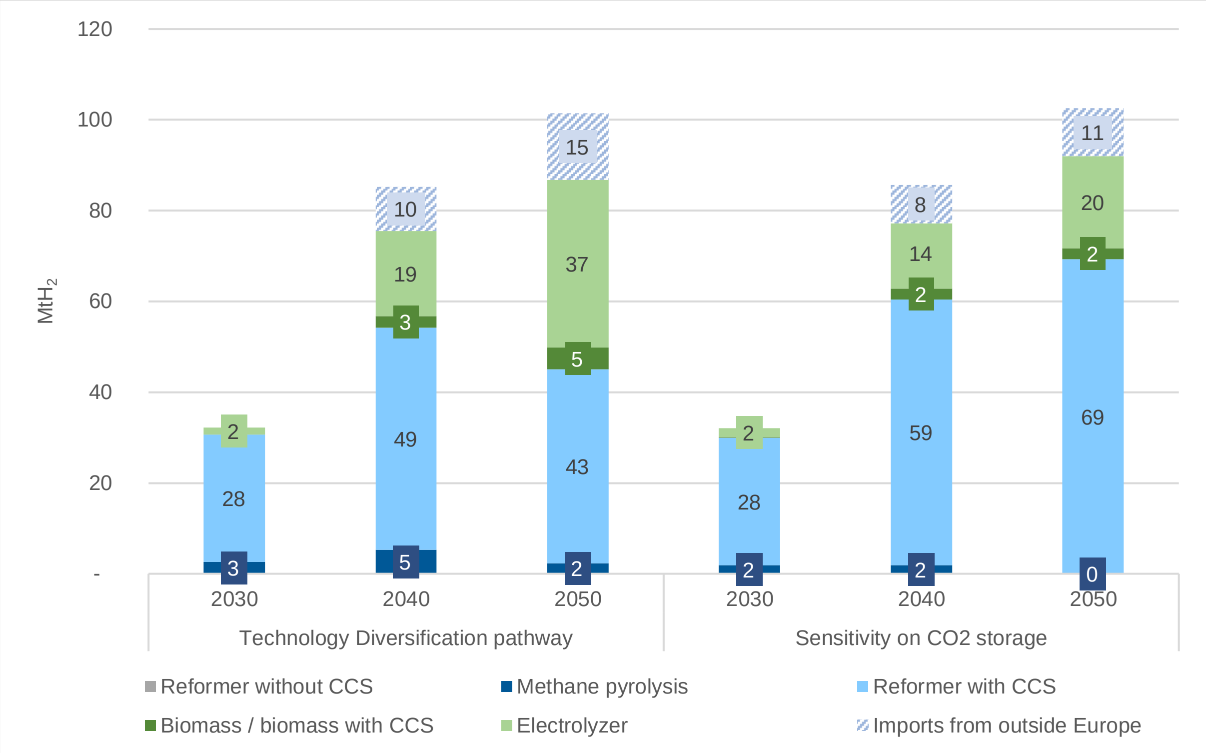
"Other" category includes net changes in carbon use and perimeter effects

Source : *Hydrogen for Europe* study

141. The increase in carbon capture from hydrogen production allows for higher output of hydrogen produced by reformers with CCS (figure 36). In the sensitivity, significant differences appear in the last decade: in 2040, production of hydrogen from reformers with CCS is 20% higher compared to the Technology Diversification pathway (+10 Mt). Hydrogen production from reformers with CCS then grows to 69 Mt (+27 Mt/+63%) in 2050, around 75% of inland hydrogen production.

142. Ample availability of CO_2 storage benefits reforming technologies with CCS. In 2040, renewable hydrogen production is about 5 Mt lower in the sensitivity, offset by output from reformers with CCS. In 2050, renewable hydrogen production represents around 22 Mt and account for about a quarter of European production. Output from pyrolysis is about 1 Mt lower in 2030 and about 4 Mt lower in 2040.

Figure 36. Evolution of renewable and low-carbon hydrogen production in in the Technology Diversification pathway and an unconstrained CO_2 underground storage sensitivity, 2030 to 2050



Source : *Hydrogen for Europe* study

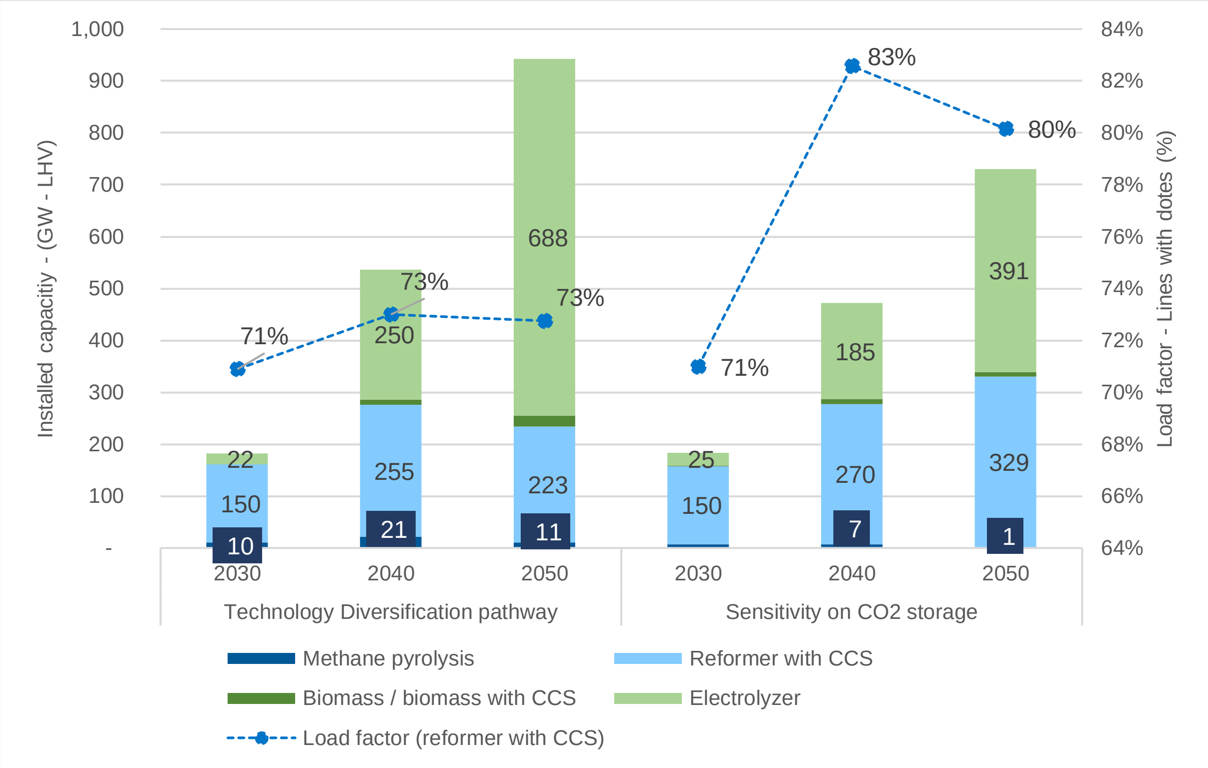
143. Total hydrogen production in Europe is hardly different in the sensitivity compared to the Technology Diversification pathway. In the period to 2050, the difference between the two model runs does not exceed 1 Mt of hydrogen. Nevertheless, greater storage availability is not a zero-sum game between the different sources of domestic hydrogen production but also lead to repercussions on international trade of hydrogen. By 2050, hydrogen imports from outside Europe are nearly 30% lower in this sensitivity.

144. Similar substitution effects can be observed in terms of installed capacity (figure 37). In 2040 and 2050, reforming capacity with CCS is 15 GW and 113 GW higher, respectively. In this sensitivity, additional reformers are installed between 2040 and 2050. This is not the case in the Technology Diversification pathway where reforming capacities with CCS peak around 2040, as access to CO_2 storage gets increasingly scarce. Capacities for electrolysis are lower in this sensitivity: in 2050, the level of electrolyzer capacity stands at around 390 GW, which is some 295 GW less than in the Technology Diversification pathway.

145. The relaxing of the CO_2 storage constraint opens cheaper production routes, leading to a reduction in investments in the hydrogen value chain and a lower total cost for the energy transition. In the sensitivity, cumulative investments until 2050 are €700 billion lower than in the Technology Diversification pathway[51]. This difference is mostly explained by the lower investment needs in renewable electricity in the sensitivity (around €480 billion less) and in electrolyzers (around €245 billion less). These two lower cost items are not offset by the higher investment needs in low-carbon hydrogen production (around €70 billion more).

[51] Also accounting for investment in offgrid renewable capacities. See in section 4.3 for more analysis on investments in the hydrogen value chain for the two main pathways.

Figure 37. Evolution of hydrogen production installed capacity by technology in the Technology Diversification pathway and an unconstrained CO_2 underground storage sensitivity, 2030 to 2050



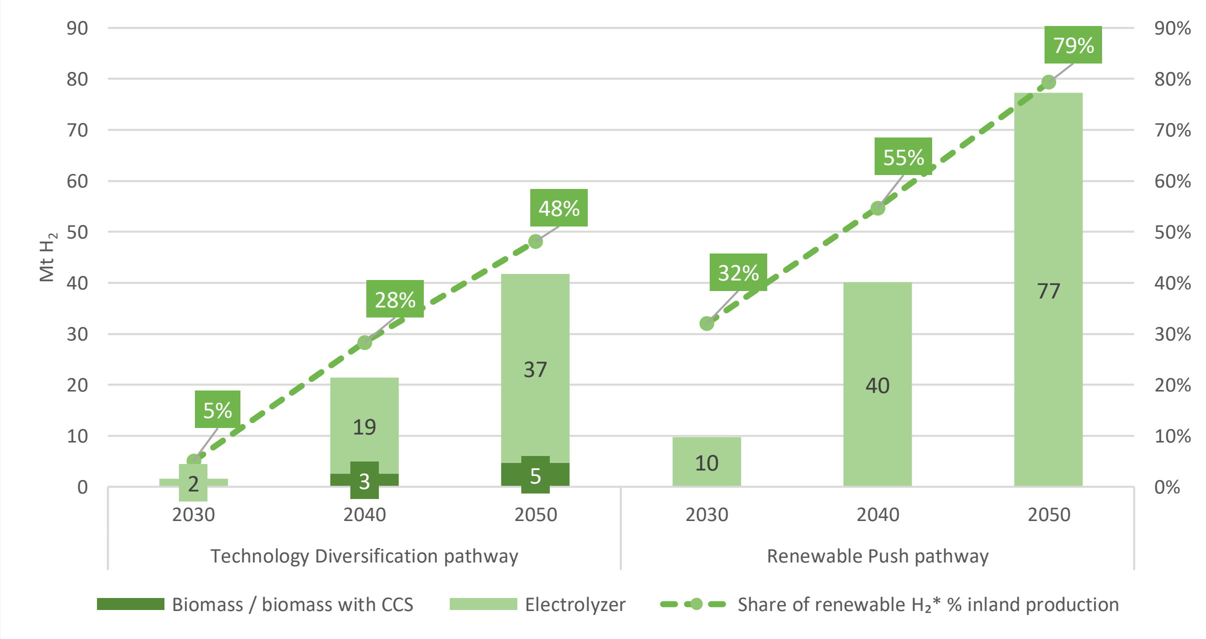
Source : *Hydrogen for Europe* study

4.1.2 Production of renewable hydrogen in Europe

146. Renewable hydrogen has a key role to play in European energy transition, gradually replacing low-carbon hydrogen in the European hydrogen production mix and – in the Renewables Push pathway – becoming the main source of hydrogen supply in Europe by 2050 (figure 38). Renewable hydrogen helps integrating variable renewable electricity sources, such as solar and wind, into the system, transforming their energy and transporting it to the sectors where it is most needed.

147. In the Technology Diversification pathway, renewable hydrogen sees a slow start as it takes time to bring down production costs and as the available renewable electricity is best used to decarbonize electricity end uses in the first half of the outlook period. Its production reaches around 1.5 Mt in 2030 (all from electrolysis), amounting to around 5% of the total share of hydrogen production in Europe. In the meantime, electricity demand reaches around 4,100 TWh. Renewable hydrogen scales up rapidly over the 2030s, supported by massive investments in electrolysers and renewable electricity capacities to reach around 20 Mt (just under 30% of total production) by 2040. Renewable hydrogen gains momentum over the 2040s, topping 40 Mt (just under half of total production) in 2050.

Figure 38. Evolution of the production of renewable hydrogen (including biomass with CCS) in the Technology Diversification and Renewable Push pathways, 2030 to 2050



Source : *Hydrogen for Europe* study

148. This renewable hydrogen is mainly produced from electrolyzers that can either be connected to the electricity grid (ongrid electrolyzers) or coupled with renewable electricity installations in an “offgrid” set-up. Electrolysis thus represents about 90% of total renewable hydrogen production in 2050 in the Technology Diversification pathway. It is complemented by production of hydrogen from biomass coupled with CCS technology, which also allows for negative CO_2 emissions as the CO_2 rejected during the hydrogen production process is captured and stored permanently. In this pathway, production of renewable hydrogen with biomass accounts for 2.5 Mt of hydrogen in 2040 and for some 5 Mt in 2050. A sensitivity analysis on the potential of bioenergy shows that a greater potential may affect the dynamics of hydrogen development and lead to a bigger role for biomass with CCS in hydrogen production, lowering slightly the need for electrolyzers in the long term (box 11).

Box 11. Sensitivity analysis on the availability of bioenergy

A sensitivity analysis has been carried out considering the ENSPRESO Reference Trajectory for bioenergy potential instead of the alternative “Business as Usual” (BaU) trajectory. The Reference trajectory has around 45-50% greater potential of bioenergy in Europe.

The greater potential of bioenergy in Europe leads to a more important role of this energy source in primary energy demand. Bioenergy mostly displaces natural gas in the energy mix; the share of which is lower. The share of renewables in primary energy demand is higher compared to the Technology Diversification pathway.

In the sensitivity, bioenergy plays a greater role in power generation and in hydrogen production, where it is combined with CCS. In 2050, power generation based on BECCS is almost double the amount in the Technology Diversification pathway. Hydrogen production based on BECCS is doubled in 2050 compared to the Technology Diversification pathway. The greater use of BECCS for power generation and hydrogen production displaces DAC technologies, which hardly feature in the sensitivity. More negative emissions enable greater use of oil. In 2050, oil consumption in the transport sector is 20 Mtoe higher. In contrast, greater availability of bioenergy does not lead to higher use in final consumption.

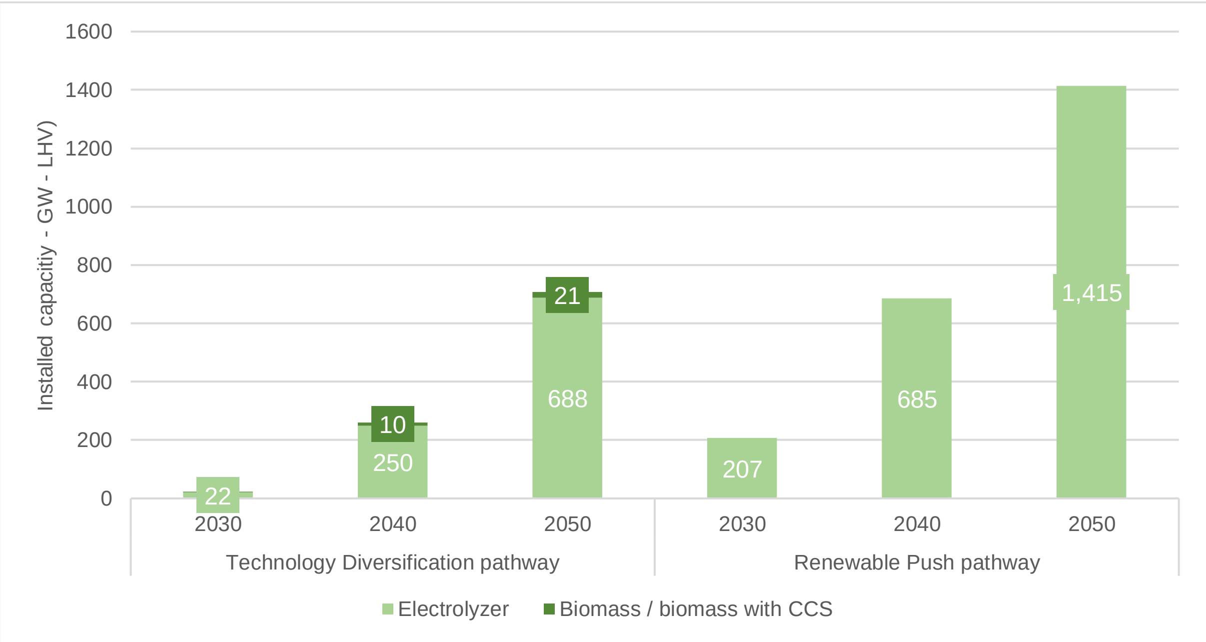
Notable shifts are observed in hydrogen supply and demand. The uptake of hydrogen demand (and thus of the whole hydrogen economy) is slower in the sensitivity, as the use of BECCS allows for more negative emissions and shifts some of the need for hydrogen towards the end of the outlook period. In parallel, the evolution of the hydrogen production mix is significantly reshaped. Production from reformers with CCS increases more progressively throughout the outlook period but ends up slightly higher than its level observed in the Technology Diversification pathway in 2050, while pyrolysis makes only a marginal contribution. Biomass with CCS takes a more important role for hydrogen production. It doubles its long-term contribution to more than 10 Mt. Finally, in 2050, hydrogen production from electrolyzers ends up almost 20% lower and hydrogen imports are some 25% lower.

149. In the Renewable Push pathway the acceleration of renewable energy deployment is primarily achieved by a strong expansion of wind and solar capacities. Most of this additional production is used to produce renewable hydrogen via electrolyzers, helping to mitigate the flexibility and grid reinforcement needs for the power system and distribute the renewable energy to where it is most needed. While there is some renewable hydrogen produced from biomass with CCS in the Technology Diversification pathway, the technology does not appear in in the Renewable push pathway. Finally, in that scenario, the increase of renewable hydrogen production starts sooner and reaches 10 Mt in 2030, in line with the current goal of the EU hydrogen strategy. Production then quadruples in the period to 2040 to reach 40 Mt (a doubling compared to the Technology Diversification pathway), by which point renewable hydrogen takes over and becomes the backbone of hydrogen supply. By 2050, renewable hydrogen represents almost 80% of total hydrogen production with over 75 Mt.

150. These levels of renewable hydrogen production imply major capacity needs in the next decades (figure 39). In the Technology Diversification pathway, electrolysis capacity experiences a major ramp-up, from around 20 GW in 2030 to nearly 690 GW of installed capacity by 2050. To feed these electrolyzers with clean electricity, renewable energy investments need to grow in lockstep, requiring substantial investment in that sector too (see box 12). In the Renewable Push pathway, deployment of capacities in each decade is twice as high as in the Technology Diversification pathway.

151. In the two pathways, most of the electrolyzers run in an offgrid configuration, with a direct connection to new renewable capacities such as solar, onshore and offshore wind. The load factors of offgrid electrolyzers depend on the yield of the renewable energy technology they are connected to, with electrolyzers connected to windmills typically achieving higher load factors than electrolyzers fed by solar plants. Electrolyzers primarily running on electricity procured from the network provide important flexibility to the power system as they help to reduce curtailment during periods of excess renewable electricity generation.

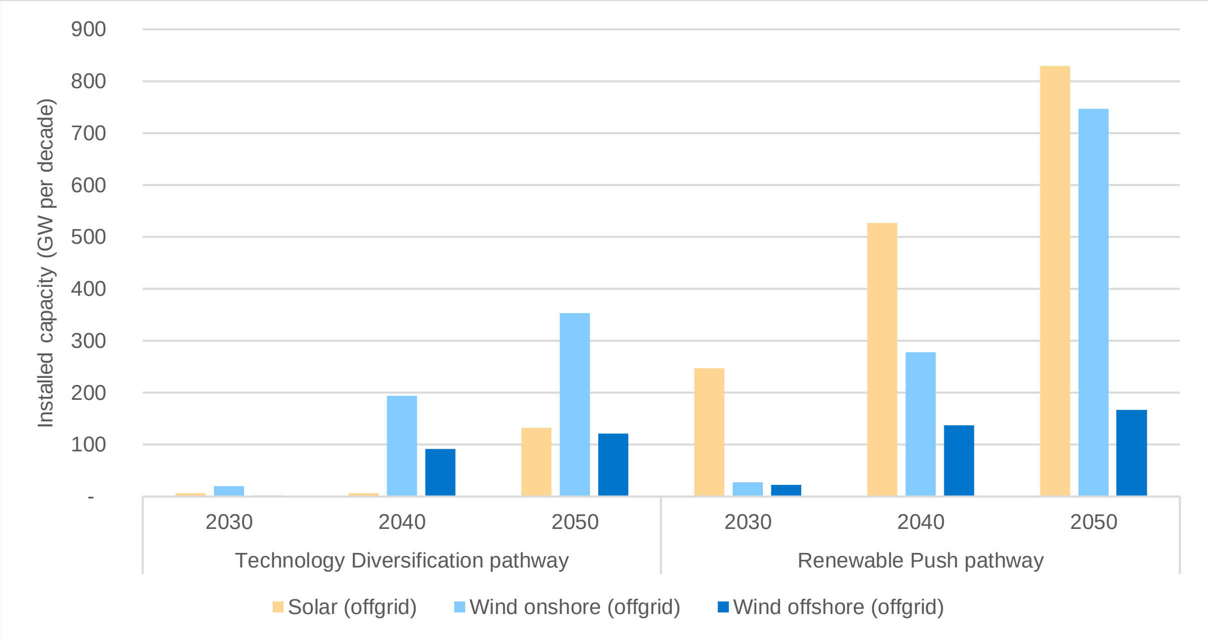
Figure 39. Evolution of renewable hydrogen (electrolyzers and biomass with CCS) installed capacities in the Technology Diversification and Renewable Push pathways, 2030 to 2050



Source : *Hydrogen for Europe* study

152. Electrolyzers running on offgrid electricity rely on a balanced mix of electricity from solar, onshore wind and offshore wind capacities (figure 40). In the Technology Diversification pathway, solar, onshore wind and offshore wind capacities connected directly to electrolyzers represent around 130 GW, 350 GW, and 120 GW respectively in 2050. In the Renewable Push pathway, the acceleration of renewable energy deployment results in offgrid solar capacity that is, by 2050, six times higher than in the Technology Diversification Scenario, benefitting from further cost decreases and untapped deployment potential. Wind onshore doubles and wind offshore is more than 35% higher vis-à-vis the Technology Diversification pathway.

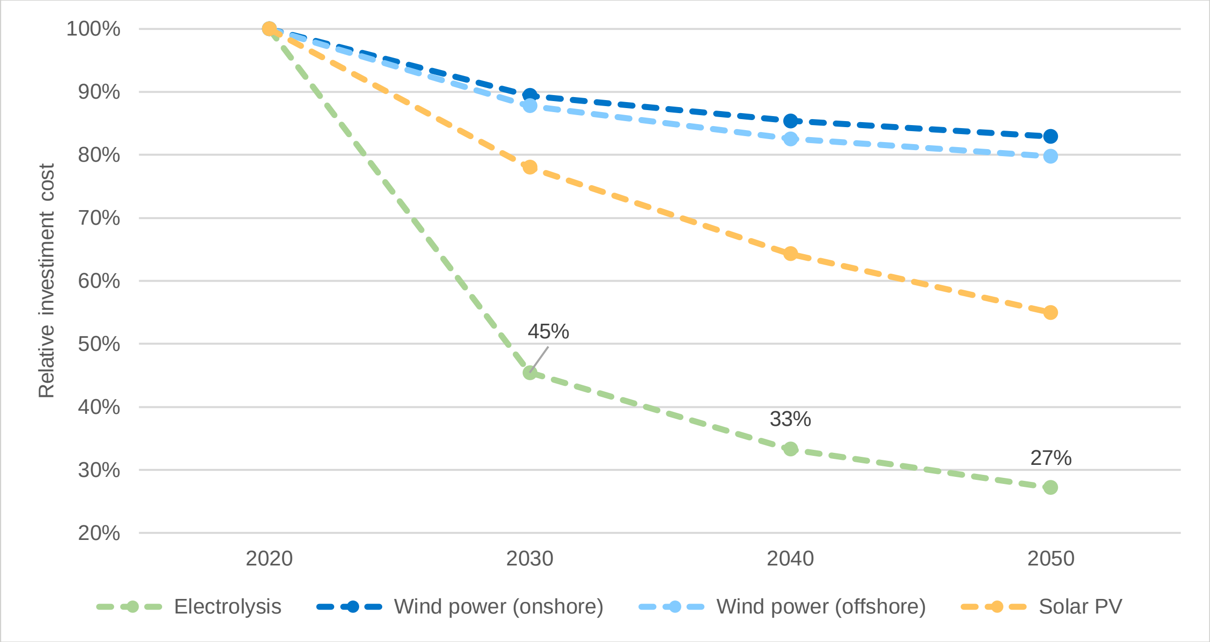
Figure 40. Evolution of installed capacity in offgrid renewables for electrolysis in the Technology Diversification and Renewable Push pathways, 2030 to 2050



Source : *Hydrogen for Europe* study

153. The rise of electrolyzers and renewable hydrogen in the *Hydrogen for Europe* pathways is underpinned by a large potential for cost reduction through learning-by-doing, allowing to improve the competitiveness of these technologies in the period to 2050 (see figure 41). The cost decrease of electrolyzers is particularly remarkable, propelled by global learning (exogenous to the model) and local learning (endogenous to the model). Their installation costs end up more than 70% below today's costs in 2050 in the Technology Diversification pathway. This cost reduction corresponds to a reduction in installed cost and is caused by high learning rates, low investments so far in electrolyzers, and large future investments. Despite significant learning over the past thirty years, renewable energy capacities have untapped potential for further cost reduction light of the reported learning rates in literature (box 12). Solar PV is a case in point: capital costs are almost cut by half over the outlook period in this study.

Figure 41. Evolution of investment costs for renewable hydrogen production with electrolysis and renewables in the Technology Diversification pathway, 2020 to 2050



Source : *Hydrogen for Europe* study

Box 12. The importance of learning effects to spur renewable hydrogen deployment

Electricity generation from solar and wind as well as hydrogen production via electrolyzers are essential for achieving net-zero emissions in the European energy system. Cost reductions due to growing capacity in Europe and elsewhere are still significant as shown in this study. For solar PV systems, the modules have a learning rate of approximately 20% and 13 % for the balance of plant, which, in the scenarios, results in cost reductions in the range of 45%-50% by 2050, compared to current costs. Similarly, wind power has a learning rate of approximately 5%-8%, for off- and onshore wind respectively, which results in a reduction of 17% to 21% by 2050 over the outlook period. The potential for cost reductions for electrolyzers is significant. An estimated learning rate of 18% results in a cost reduction of 73% to 75% over the next three decades due to the large investments both in Europe and outside Europe and the currently low installed capacity.

The demand for hydrogen produced spurs extensive investment in solar and wind power that directly feeds electrolyzers, so called offgrid electricity. Although the electrolyzers connected to these offgrid units operate only when electricity is being produced, they are estimated in this study to be cost efficient within the energy system compared to investing in the distribution grid for electricity and connecting the power units to it.

It must be noted that there is a significant uncertainty in learning-by-doing rates of the selected technologies. The modelling exercise performed in this study is using an approach based on the percentiles of the data to assess the robustness of the results regarding the uncertainty of the underlying CAPEX data. In this context, a sensitivity has been performed to assess the impact of uncertainties in capital investment costs for renewable electricity production and electrolyzers (see annex 6).

In the main pathways (Technology Diversification and Renewable Push), the learning optimization model uses the 50^{th} percentile learning-by-doing rates. The objective of the sensitivity is to use the 25^{th} percentile learning-by-doing in the renewable power generation technologies and electrolyzers in order to investigate the impact of overestimating the learning-by-doing rates for electricity production from wind and solar, as well as for hydrogen production from electrolyzers.

The results of the sensitivity show that the findings in terms of hydrogen supply and demand for the Technology Diversification pathway are hardly affected by this uncertainty. In 2050, the overall volumes of hydrogen production are very similar between the Technology Diversification pathway and the sensitivity (around 1 Mt less in the sensitivity). The amount of renewable hydrogen produced with electrolyzers is slightly lower in the sensitivity case (around 3.5 Mt or 10% less), partially offset by an increase in hydrogen production from reformers with CCS (around 1.5 Mt more). One potential explanation for this counterintuitive result can be found in the restriction on CO_2 storage which therefore requires a significant amount of renewable power (and renewable hydrogen) independently of the costs.

The results in terms of investment are somewhat more telling: in the sensitivity, cumulative investments in the hydrogen supply chain in 2050 are €72 billion lower than in the Technology Diversification pathway (or around 2% less). They are mostly driven by the decreased investments in offgrid renewable electricity (around €40 billion less) due to the operated substitutions. Therefore, one can conclude that the uncertainty in the learning-by-doing rates does not have a significant impact on the overall costs of reaching the target of carbon-neutrality in 2050.

4.2 Imports of hydrogen from outside Europe

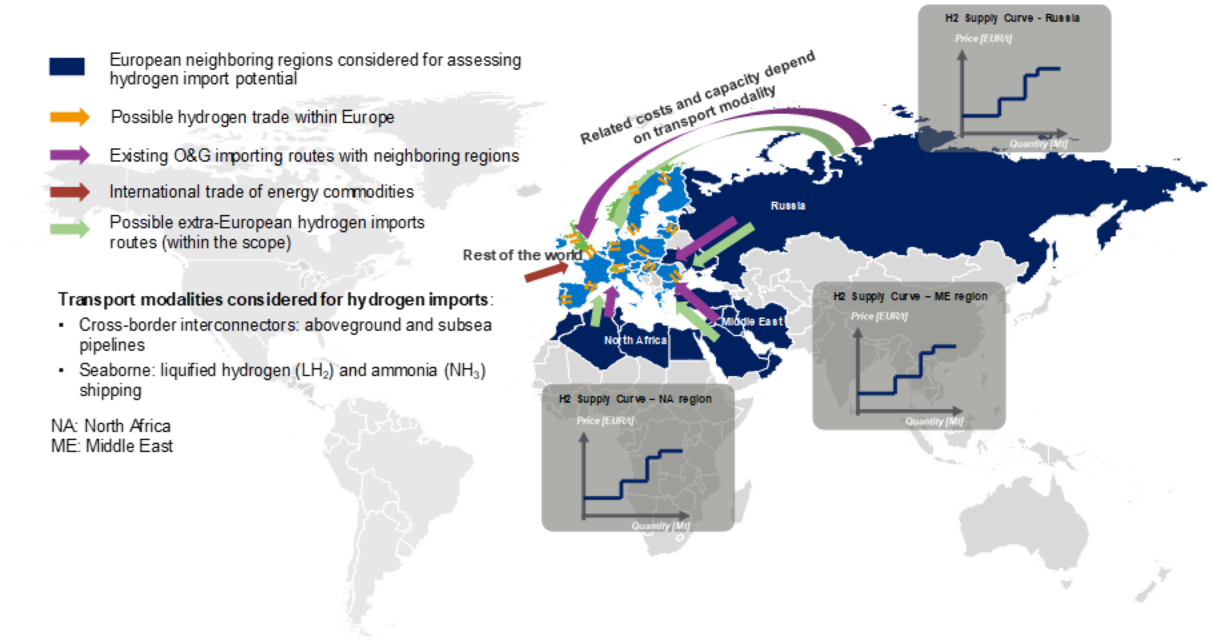
154. The incremental adoption of hydrogen uses, progress on the supply side and the development of trade are not only a European affair. The future development of an international hydrogen market has raised significant interest over the last couple of years. It has become an integral part of the hydrogen roadmaps and strategies recently announced in Europe. Germany has, for instance, issued collaboration agreements with Morocco and Australia. Japan has also paved the ground for hydrogen partnerships, notably with Australia for importing hydrogen. Large investments have been announced in Chile, Saudi Arabia, Morocco and Australia aiming at exporting hydrogen and leveraging their huge potential in renewables or, where available, natural gas.

155. This international dimension is explicitly put forward in the EU hydrogen strategy, where the European Commission explains that “an international hydrogen trade market is likely to develop” and should be aligned with the decarbonization objectives of the European Commission. Due to the geographic proximity and the expected cost-competitiveness, the European policy agenda particularly focuses on cooperation with Eastern European and North African countries as priority partners for hydrogen trade. On that matter, the EU strategy is aligned with the industrial view, estimating that around 40 GW of renewable hydrogen production capacity could be made available[52] for exports from such neighboring countries to Europe, by 2030. These ambitious goals would require significant investments in production and transport capacities[53], together with innovation in policy and cooperation to ensure that the deployment of a steady cross-border hydrogen market with Europe contributes to the reduction of CO_2 emissions in the countries of origin and in Europe.

156. To achieve this goal, the European Hydrogen Strategy mentions the need to reinforce and extend cooperation on hydrogen in existing international frameworks for research and within the financing instruments[54]. The *Hydrogen for Europe* study specifically addresses this issue by studying the role of hydrogen imports in Europe from such priority regions[55] and illustrated in figure 42 (box 13 and annex D provide for further methodological details).

[52] Provided that the investment in production capacity in such extra-European regions strongly accelerates.
[53] While the European Hydrogen Backbone (Guidehouse 2020) focuses on the development of interconnection capacity for hydrogen within European countries, it also elaborates on the interconnection links that are expected come online with non-EU countries by 2050.
[54] Such as the International Partnership for a Hydrogen Economy (IPHE), The Neighbourhood Investment Platform, The Western Balkans Investment Framework, the Africa-Europe Green Energy Initiative and the European Fund for Sustainable Development (EFSD).
[55] Also including some key Middle East countries, and the possibility to include in the international trade flows CO_2 abated low-carbon hydrogen.

Figure 42. Import of energy commodities with a focus on possible extra-European hydrogen trade and transport modalities



Source : Hydrogen for Europe study

Box 13. In a nutshell: modelling the potential for hydrogen imports from outside Europe

In alignment with the EU hydrogen strategy, hydrogen imports from the neighboring regions have been assessed in the *Hydrogen for Europe* project, following two overarching principles: i) CO_2 neutrality of European energy imports, and ii) technology neutrality on the supply side. Therefore, potential renewable and low-carbon hydrogen (from methane with abated CO_2 emissions between 2020 and 2050) imports from North African countries, Middle East and Russia to Europe are assessed.

The Hydrogen Pathway Exploration model (HyPE) follows a value chain approach in which onsite production, transport modes and conversion/reconversion steps are included from the different possible origin sites to the different entry points in Europe (further details of the model are presented in annex D). The approach considers the trade-offs between different transport routes and modes to calculate levelized cost of hydrogen[56] (LCOH) curves following a cost, insurance and freight perspective[57] (CIF) for each importing terminal in Europe.

On the supply side, there is little doubt about the massive potential of renewable resources in the targeted countries. Solar resources are abundant in North Africa and the Middle East and considerable amounts of biomass are available in Russia and Ukraine. Wind resources are also prolific at some sites within these regions. Similarly, current natural gas exporting countries within these regions have important gas reserves and an experienced gas producing industry. However, for the creation of an international trade-market, the two key unknowns are the pace at which the investment in production capacity and transport infrastructure happen, and the amount of energy that can be dedicated to export-oriented hydrogen production after satisfying domestic demand and other energy trade obligations.

Acknowledging these issues and in line with the industrial view provided by the 2x40 GW initiative (van Wijk and Chatzimarkakis 2020), the core assumption adopted in the study is that the interregional cooperation frameworks and financing instruments would allow renewable energy to follow a similar development trend in such countries as in Europe in the early 2000's. Moreover, the required investments to export hydrogen take place whenever it is cost

[56] The levelized cost of hydrogen adopts the life cycle costing methodology. It is defined as the summation of all the discounted fixed and variable costs necessary for the production of hydrogen over the expected lifetime of the installation, divided by the total volume produced during its lifetime.
[57] Cost, insurance and freight, as defined in Incoterms 2010, means that the exporter delivers the product at the port of destination, so the cost at the loading port includes the cost of transport and logistics.

competitive vis-à-vis production in Europe. Therefore, the investment cost in hydrogen production technologies and their learning rates from outside Europe are assumed to be the same as for European countries. To account for cost related to investment risk, the study assumed a risk-related mark-up to the cost of capital for each country in scope[58].

Cautious assumptions are adopted regarding the land available to renewable energy plants for export-oriented hydrogen production. These land use restrictions also aim at integrating the land required for other uses in competition, including the energy production to satisfy the domestic demand (further details are available in annex D). Depending on the load factor of the renewable site considered, a first optimization step is conducted to determine the most suitable electrolyzer capacity with respect to the renewable generator in each site.

For gas exporting countries, the shares of natural gas dedicated to export-oriented hydrogen production is assumed to compete with domestic consumption and current natural gas exports to other markets. Therefore, the study assumes that it should not be higher than the current shares of natural gas currently being exported to Europe. The price of methane to produce low-carbon hydrogen is assumed to be the average breakeven gas prices of the producing country.

In the midstream, transport was divided between an inland national part (from site to the exit point) and an international part (from exit point to an entry point in Europe). For inland transport, road transport by truck or national pipelines are considered, while for international transport cross-border interconnectors or ships (liquefied hydrogen and ammonia) are considered. The optimal transport options are obtained by taking the least-cost combination of technologies available for each part and the type of molecule required with the associated conversion/reconversion steps. The timing at which natural gas cross-border interconnectors are repurposed to hydrogen is in line with the assumptions of the European Hydrogen Backbone (Guidehouse 2020). The cost trajectories associated with the required technology for each step of the value chain and transport are based on a review of recent literature and have been discussed with industrial experts (see further details in annex D).

The locations where renewable hydrogen can be produced are manifold since only offgrid electrolyzers are considered and are assumed to be collocated with the renewable plants[59]. Inland transport cost for renewable hydrogen depend on the distance from the production site to the export terminal. The production of low-carbon hydrogen from methane for exports is assumed to take place at the exporting terminal of the origin country since national pipelines linking natural gas fields and current natural gas export terminals already exist in these countries. Availability of cross-border pipelines for hydrogen depends on the timing of repurposing the gas interconnectors. For maritime transport, different combinations of the shipping routes and transport mode (liquefied hydrogen or ammonia) exist, allowing for new links between export terminals and any suitable entry point in Europe. The optimal inland and international routes are the result of a second optimization step in which total costs to the delivery point in Europe are minimized.

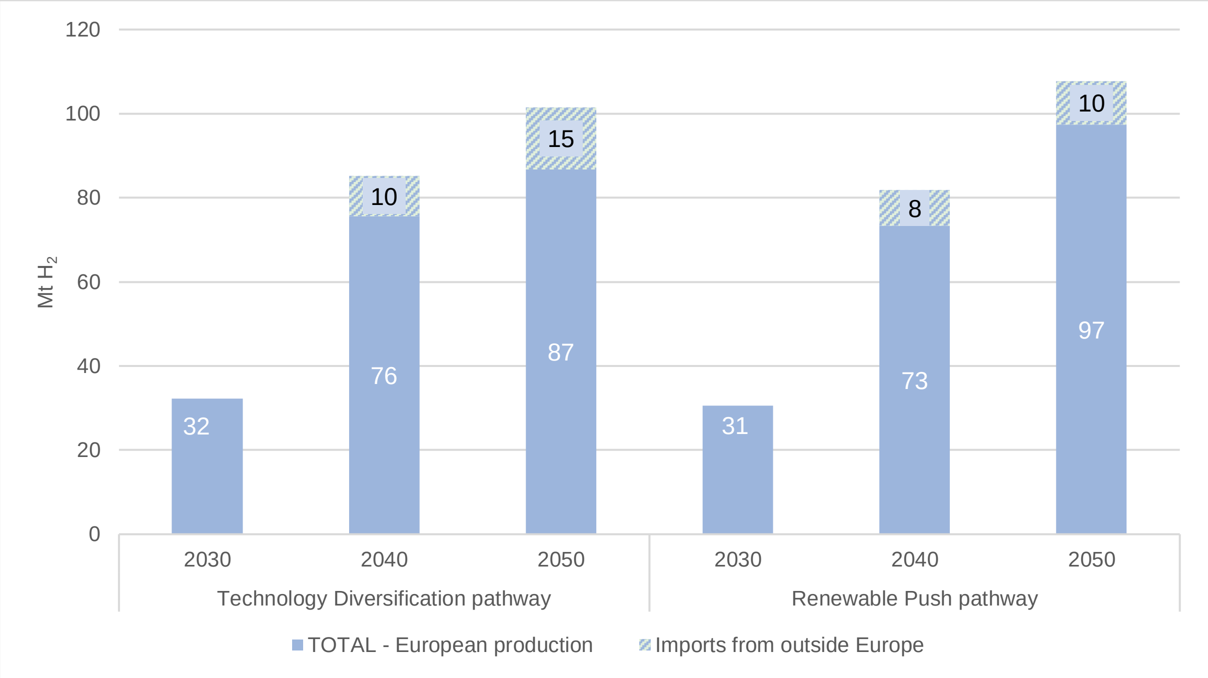
After considering a final reconversion step if hydrogen is transported as liquefied or as ammonia, the model provides cost curves showing the cost and potential of hydrogen imports from outside Europe at each of the entry points in Europe. Such curves allow to represent competition between imports and domestic production in the importing countries within Europe. Importing countries could also become crossing platforms allowing to trade with other European countries provided there is cross-border capacity linking them (as for the European Hydrogen Backbone).

157. In the *Hydrogen for Europe* pathways, hydrogen imports from neighboring regions take off during the 2030s, and keep growing between 2040 and 2050. The repurposing of cross-border gas infrastructure to handle hydrogen is a key enabler for imports, together with the cost decreases observed for renewables and electrolyzers. The findings confirm the importance of hydrogen imports to complete the European production and sustain the ambitious uptake of hydrogen flows throughout the European economy.

[58] The add-up to the weighted average cost of capital to account for risk is calculated based on the relative difference of the Ease-of-doing Business score (World Bank 2020) of each country compared to the average of the EU-27. The Ease of doing business score uses a standard methodology to monitor 41 indicators for 10 Doing Business topics that allow estimating quantitative indicators of regulatory performance. Further information is available in Annex D and at Score-Ranking (doingbusiness.org).
[59] This is required to avoid any unrealistic assumption on the carbon content of the local power production and its evolution, which might not become carbon neutral within the time horizon considered

158.In both pathways, imported volumes of low-carbon and renewable hydrogen from North Africa, Russia, Ukraine and the Middle East are between 8 Mt and 10 Mt in 2040, representing around 10% of the total hydrogen supply in Europe (figure 43 and Figure 44). By 2050, hydrogen imports grow to 10 Mt and 15 Mt in the Renewable Push and Technology Diversification pathways respectively (about 10% and 15% of total supply, respectively), diversifying supply sources and contributing to affordability of hydrogen. Relative to the total assessed potential, the volume of imports remains constrained by the low competitiveness of certain supply sources compared to domestically produced hydrogen. The availability of pipelines for hydrogen imports from 2040 onwards is an important differentiator that allows for cost-competitive supply: the majority of imports from the neighboring regions relies on cross-border pipeline infrastructure.

Figure 43. Evolution of hydrogen imports from extra-European countries in the Technology Diversification and Renewable Push pathways, 2030 to 2050[60]



Source : *Hydrogen for Europe* study

159.Russia, the largest exporter of natural gas today, is also well placed to become a major exporter of hydrogen to Europe. By 2050, in the Technology Diversification pathway, about 55% of Europe's hydrogen imports come from Russia. The country benefits from relatively low-cost natural gas endowments and several major gas pipeline routes into Europe.

160.Algeria, another traditional exporter of natural gas to Europe, also benefits from existing cross-border pipeline infrastructure that can be repurposed for hydrogen transport. Specifically, it is assumed that MEG and Medgas pipelines become hydrogen ready by 2040[61] (Guidehouse, 2020). Natural gas production in Algeria becomes increasingly challenging and feed-gas costs are much higher than in Russia. Benefitting from abundant sunshine and good wind resources, Algeria becomes a diversified hydrogen exporter with about a third of its exports each stemming from solar, wind and natural gas.

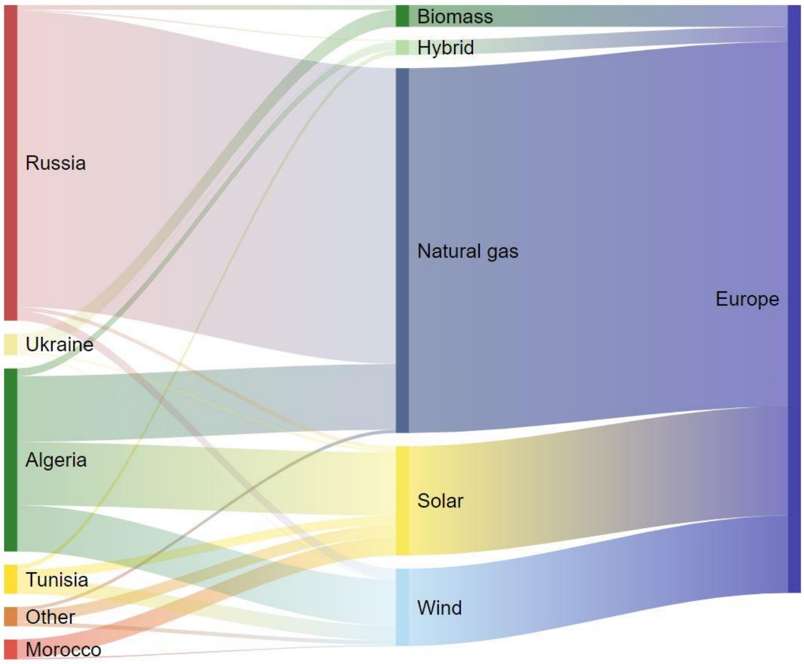
161.Tunisia and Morocco benefit from similarly good renewable energy resources but lack the potent existing pipeline export infrastructure that puts Algeria in the pole position. Tunisia and Morocco also become important exporters of hydrogen to Europe developing renewable hydrogen based on wind and solar. Smaller quantities of hydrogen are also produced in hybrid systems (solar plus wind) allowing to improve the load factor of

[60] In parallel to hydrogen imports, natural gas imports from extra-European countries are also considered. CO_2 trade is only considered within Europe. Imports of eFuels or green Ammonia for direct uses is out of the scope of the project.
[61] According to the European Hydrogen Backbone, the Transmeda MEG, Medgas and TANAP are assumed to become hydrogen ready by 2040. Similarly, for the Kyev - Western Border Pipeline.

electrolyzers of producing sites with less constant wind[62]. Biomass from Ukraine, where resource endowments are good, is also used for the export-oriented production of hydrogen, although to a lesser extent.

162. Hydrogen from reformers with CCS or based on solar in the Middle East benefits from low production cost (due to ample availability of low-cost feed-gas and abundant sunshine). However, the lack of export pipeline infrastructure to Europe and long maritime transport distances put these sources at a disadvantage compared to European production and exporters with easy access of export infrastructure.

Figure 44. Origin of hydrogen imports in 2050 in the Technology Diversification pathway[63]



Source : *Hydrogen for Europe* study

163. These findings show that the competitiveness of hydrogen exports is sensitive to the options available to transport the molecules from the producing country to Europe. For the establishment of a thriving hydrogen export industry it is critical to have the necessary transport infrastructure in place and ensure that technology readiness progresses rapidly. Historical gas exporters to Europe have existing national gas infrastructure and cross-border links to Europe in place that give them a clear transport cost advantage over new entrants without a legacy industry. The example of Algeria shows that this infrastructure does not only benefit low-carbon hydrogen but can also be an enabler for renewable hydrogen production.

164. Looking at the broader picture, the findings show that:

a. Volumes of imported hydrogen in 2050 are slightly higher in the Technology Diversification pathway than in the Renewable Push pathway due to the ambitious renewable energy target applied in the latter (see figure 43). Both pathways see similar prospects for the rise of an international hydrogen trade market and potential exporters.

b. Importing low-carbon hydrogen from natural gas producing countries within the European neighborhood could entail lower cost than producing it in Europe. Major natural gas producers with production geared towards the European market risk stranding part of their resource if they do not prepare for a nascent

[62] With some additional investment costs compared to an equivalent single system of similar size.
[63] The figure shows some small shares from coming from the Eastern countries of the Mediterranean Sea. Such imports are based on the economic considerations within the methodology, which have kept aside geopolitical issues that might change the picture. In any case, other import routes exist with very similar CIF LOCH prices that would take the shares coming from these countries if not available.

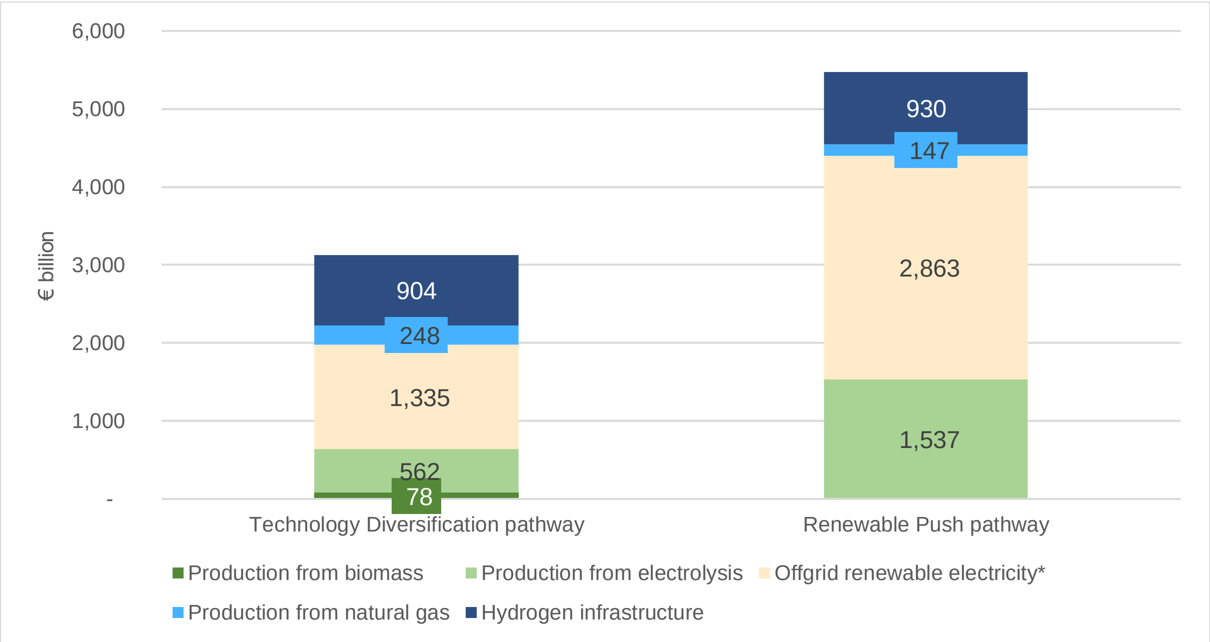
hydrogen trade. Existing gas export infrastructure is a key enabler for a rapid rise in cross-border trade of hydrogen. This provides a comparative advantage to incumbent natural gas exporting countries.

c. In the Technology Diversification pathway about 40% of the imports come from North Africa where solar and wind resources allow electrolyzers to attain very competitive load factors.

4.3 Implications for infrastructure and investments

165. Large-scale investments are needed to establish a hydrogen industry as described in this report. These investments create, over the next thirty years, a hydrogen value chain, including production, end-use technologies, transport and storage infrastructure, that is virtually non-existent today in Europe.

Figure 45. Cumulative investment in the hydrogen value chain to 2054 in the Technology Diversification and Renewable Push pathways



Hydrogen infrastructure includes hydrogen storage, national hydrogen infrastructure, cross-border hydrogen pipeline and retrofitted infrastructure.
Offgrid renewable electricity includes the investment costs in solar, on- and offshore wind capacities directly connected to electrolyzers.

Source : Hydrogen for Europe study

166. Cumulative investments in the hydrogen value chain, including investments in renewables for offgrid electrolysis, amount to several trillion euros over the outlook period[64]. Concretely, they top €3.1 trillion in the Technology Diversification pathway and reach almost €5.5 trillion in the Renewable Push pathway (figure 45). The difference of more than two trillion in capital spending between the two scenarios demonstrates the higher capital intensity of a pathway focusing primarily on renewable assets and electrolyzers. As such, one of the main challenges of the Renewable Push pathway is the ability to mobilize almost twice as much capital over the next thirty years to accomplish the hydrogen uptake.

167. Investments in electrolyzers amount to between €0.6 trillion (Technology Diversification pathway) and €1.5 trillion (Renewable Push pathway) for the period to 2050, accounting for almost 20% of the total cumulative investments in the Technology Diversification pathway. They echo the even more significant need for investments in offgrid renewable capacities that produce the electricity feeding the offgrid electrolyzers. These

[64] The time-steps in the planning period are: 2020 (today's system; no new investments), 2030, 2040 and 2050. Each period represents 10 years, e.g. 2045 – 2054 for 2050. The first day after the planning horizon is thus 2055.

investments amount to €1.3 trillion in the Technology Diversification pathway (around 45% of total investment needs) and €2.9 trillion in the Renewable Push pathway (around 50%). In both pathways, investments in low-carbon hydrogen production technologies are limited. They represent around 8% and 3% respectively of the total cumulative investments in the Technology Diversification and the Renewable Push scenario. However, this perspective excludes the capital spending in the upstream for feed-gas production. The methane used for low-carbon hydrogen production is procured at the market price for natural gas which is sufficient to incentivise the necessary investments in the upstream. Natural gas prices feature in the operational cost component of hydrogen production.

168. Investments in hydrogen infrastructure amount to more than €900 billion of cumulative investments in the two pathways (figure 45). These investments encompass:

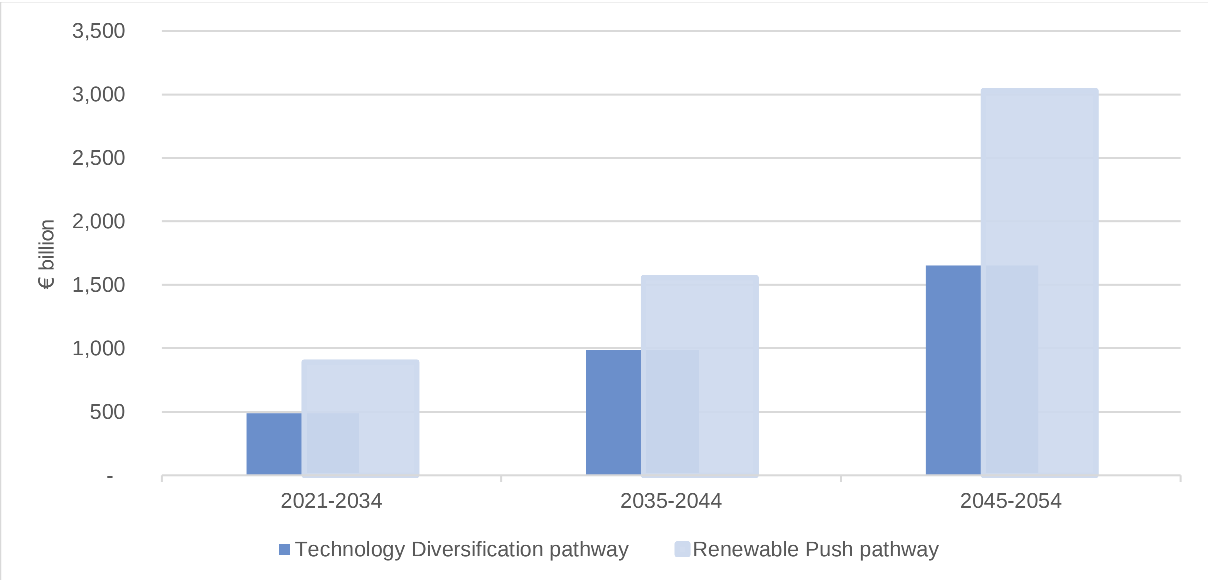
a. Storage assets (accommodating a maximum of around 15 Mt of storage capacity in 2050 in the Renewable Push pathway)

b. Investments in refuelling, distribution and transport infrastructure for hydrogen at national level

c. Cross-border infrastructure: in the Technology Diversification pathway, the results show that some three-quarters of cross-border capacities are repurposed natural gas assets, while a quarter of the cross-border capacity is specially developed for hydrogen transportation purposes. These results underscore the value of repurposing existing natural gas infrastructure, limiting stranded assets and unlocking a low-cost option for hydrogen transportation.

d. The pathways also show some potential for blending hydrogen with natural gas, with blending rates up to 15% in certain periods and in some countries. Blending with natural gas helps, in particular, to reduce emissions in the buildings sector and in industry.

Figure 46. Investments pathways in the hydrogen value chain (including offgrid electricity) in the Technology Diversification and Renewable Push pathways, 2021-2054

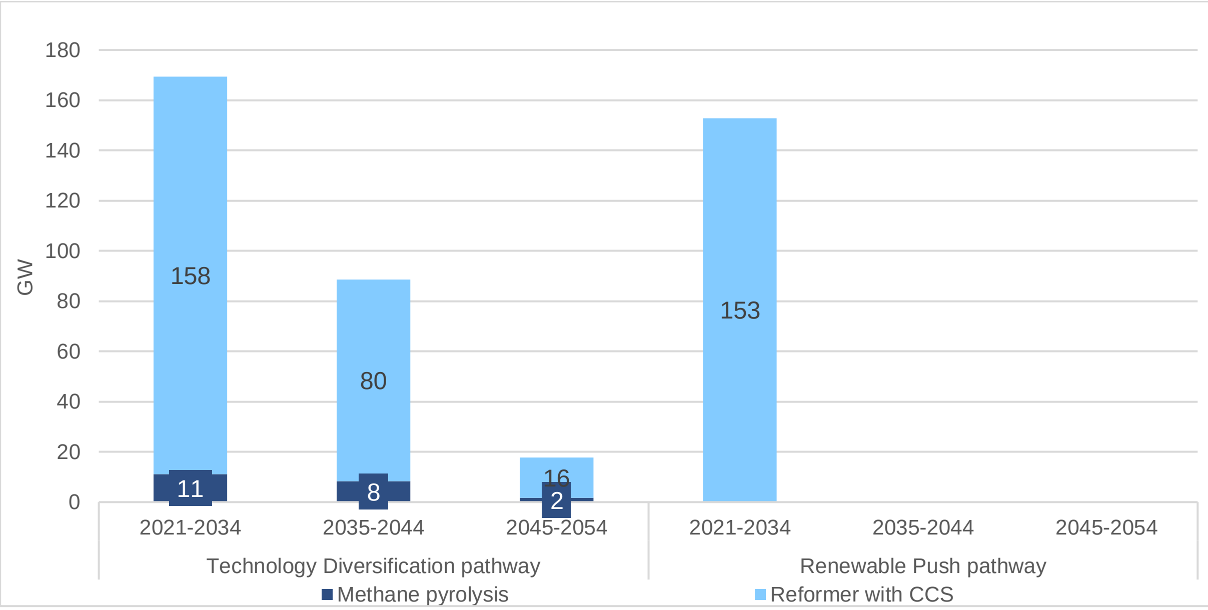


Source : *Hydrogen for Europe* study

169. Timeliness of investments is paramount in the two pathways (figure 46). In the Technology Diversification pathway some €480 billion need to be mobilised between the mid-2020s and the mid-2030s to finance the hydrogen value chain. Between the mid-2030s and the mid-2040s, investment needs rise to almost €1 trillion. They finally climb to €1.65 trillion in the last decade of the outlook, adding up to a cumulative total of around €3.1 trillion.

170.The Renewable Push pathway requires investing more and earlier in the hydrogen value chain. Sound investment schemes and timely access to financing are critical to start rolling out additional renewables early. Some €890 billion need to be mobilised between the mid-2020s and the mid-2030s; almost twice the funding needed in the Technology Diversification pathway. The real investment challenge is certainly in the last ten years of the outlook period when some €3 trillion need to be mobilised for the hydrogen value chain's contribution to achieving net-zero emissions.

Figure 47. Evolution of new installed capacities in low-carbon hydrogen technologies in the Technology Diversification and Renewable Push pathways, 2021 to 2054

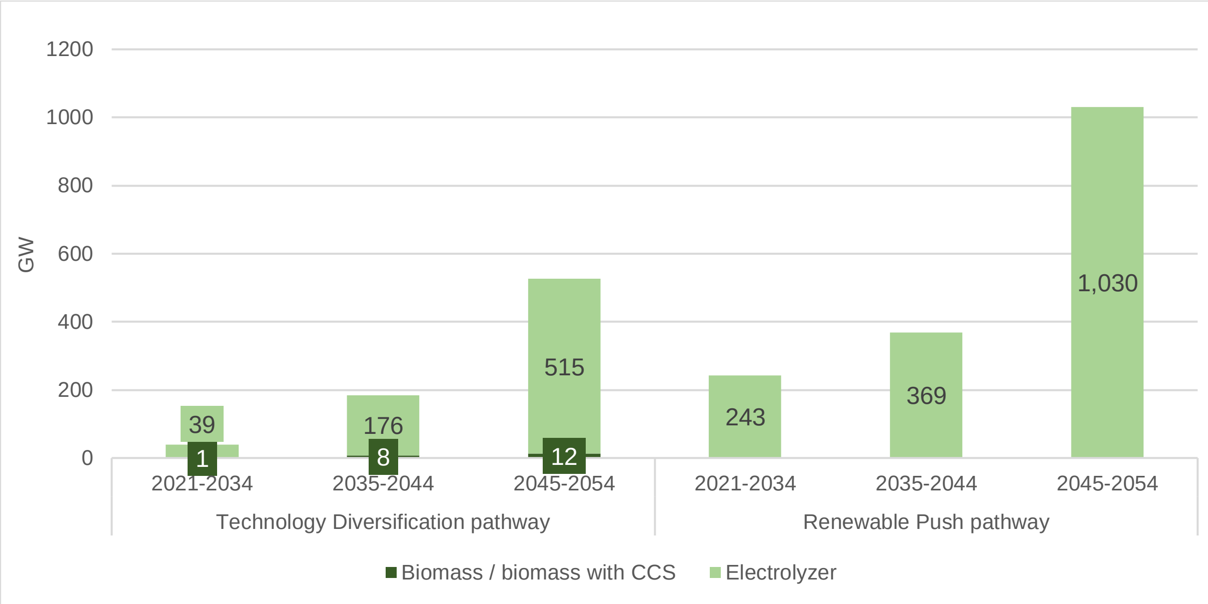


Source : *Hydrogen for Europe* study

171.The investment pathways give indications on how to leverage the full potential of hydrogen in the energy transition while limiting the risk of stranded assets, both in terms of infrastructure (with the repurposing of natural gas infrastructure) and production assets. In particular, the results show that investors targeting low-carbon hydrogen projects, need to sanction such projects from the mid-2020s onwards to take advantage of a temporary but wide-open window of opportunity (figure 47). First movers in low-carbon hydrogen are able to run their installations at sufficiently high utilization rates throughout the outlook period – independent of whether policy-makers give preference to renewable energy sources. In the Renewable Push pathway, new low-carbon hydrogen projects would no longer be financially viable in the second half of the outlook period; as such, no more installations are added from the mid-2030s. Although the window of opportunity also closes for low-carbon hydrogen in the Technology Diversification pathway, it does so much more slowly: new low-carbon hydrogen projects remain viable through 2050 but the scope for new installations narrows.

172.As soon as the window of opportunity for investments in low-carbon hydrogen closes, that of renewable hydrogen opens to support its major role in the second part of the transition. In the Technology Diversification pathway, investments in electrolyzers (and connected renewables) ramp up progressively during the transition (figure 48). Around 430 GW of electrolyzers are installed during the last decade, both ongrid and offgrid. In the Renewable Push Pathway, the ramp-up in investments starts earlier because renewable hydrogen already plays a role in 2030. The deployment pace then accelerates significantly, with more than 1000 GW of new electrolyzers installed during the last decade.

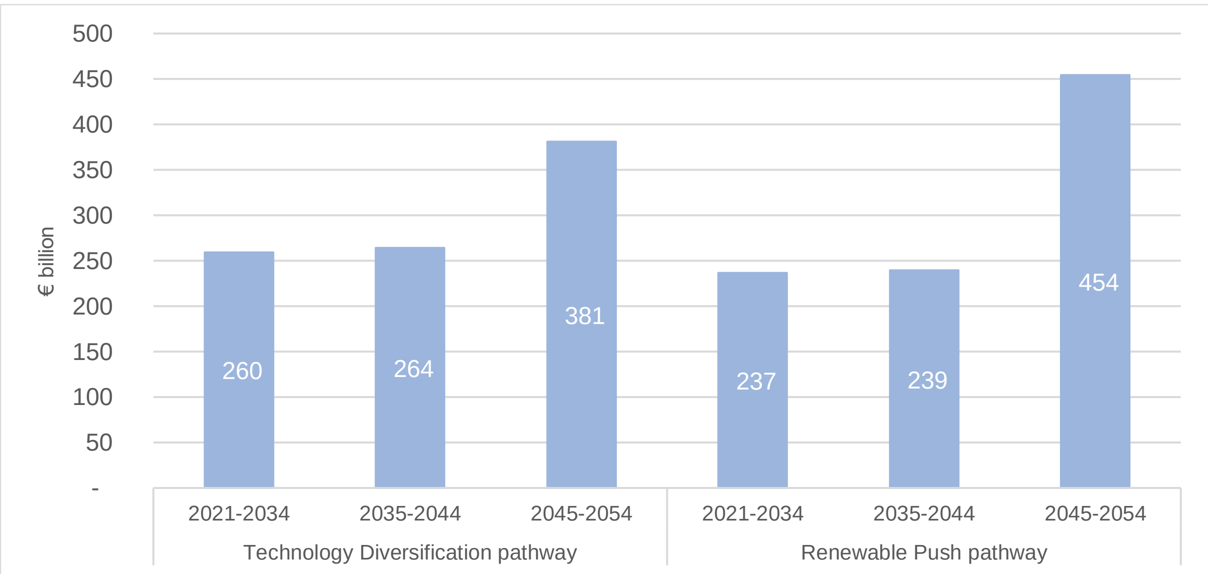
Figure 48. Evolution of new installed capacities in renewable hydrogen production in the Technology Diversification and Renewable Push pathways, 2021 to 2054



Source : *Hydrogen for Europe* study

173. Investments in hydrogen-related infrastructure need to come in a timely manner (figure 49) as the need for transporting and storing hydrogen arrives as soon as the next decade. In the Technology Diversification pathway, through the mid-2020s, almost €260 billion need to be mobilized in hydrogen infrastructure (including hydrogen storage, national hydrogen infrastructure, cross-border hydrogen pipelines and retrofitted natural gas infrastructure). These early investments establish the foundations of the backbone of the European hydrogen infrastructure. After this first period, investments in hydrogen infrastructure follow linear growth with around €265 billion invested between the mid-2030s and the mid-2040s, reflecting the ramp up of hydrogen production and demand during the period. Towards the end of the outlook period, investments in hydrogen infrastructure accelerate, representing more than €380 billion. They reflect the need for additional infrastructure to transport and store the bulk of the hydrogen that are produced until 2050. The results are very similar in the Renewable Push pathway, with the same investment trends and almost the same magnitude of needed investments.

Figure 49. Investment pathways in hydrogen infrastructure in the Technology Diversification and Renewable Push pathways, 2021 to 2054



Source : *Hydrogen for Europe* study

Box 14. High-level insights on energy system economics

The Technology Diversification and Renewable Push pathways both confirm the essential role of hydrogen to achieve net-zero emissions by 2050. Although the results show variations between the two pathways, they both harness low-carbon and renewable hydrogen for decarbonization and renewable energy integration. They highlight the value of combining all available decarbonization options, factors and technologies: renewable energies, electrification, CCUS, energy efficiency, and the switch to decarbonized molecules and fuels, with differentiated approaches for each sector of the energy system.

Policy-makers need to balance many considerations – economic, social, environmental, geopolitical, to name but a few – when they design energy policy. The comparison between the two *Hydrogen for Europe* pathways helps to understand the implications on energy system economics when contrasting two paradigms: an 'agnostic' approach with a level playing field between technologies and a technology-specific approach in which renewable energies are politically favoured.

From the perspective of energy system economics, the Technology Diversification pathway offers to European society several advantages that policy-makers should trade-off against other criteria:

- It allows for a wider set of technology options to be included, thus de-risking the decisions related to energy transition. It mitigates the challenges related to ramping up primarily the renewable and electrolysis value chain. The diversity of hydrogen sources and assets also offers an option value for a mid-point reassessment of feasible alternatives going forward.

- It helps lower the strain on financing: €2 trillion less need to be mobilized for the hydrogen value chain.

- It allows for a more competitive and efficient energy system. The positive learning effects brought by earlier investments in renewables and electrolysis do not compensate for the higher costs in terms of distortion of technology competition. Meanwhile, the Technology Diversification pathway allows for cheaper and more efficient energy sources to be considered and reduces the risk of stranded assets.

- It achieves the net-zero emissions goal at a lower cost: total energy system cost over the next 30 years are more than €1 trillion (or more than €70 billion per year[65]) lower in the Technology Diversification pathway.

[65] Comparison between the resulting system costs of the two pathways (outcomes of the model's optimization). The Technology Diversification pathway requires €90.31 trillion in total energy system cost (both OPEX and CAPEX) until 2050. The Renewable Push pathway requires €91.4 trillion.

5 Establishing the European hydrogen economy

174. The two *Hydrogen for Europe* pathways show the timing of investments and technology developments required to ensure a feasible and cost-effective transition to net-zero emissions by 2050. The pathways build on a wide range of economic and technological opportunities and establish true energy system integration. As the outcome of a modelling exercise of the energy transition, they are not a forecast and depend on the chosen assumptions and paradigms. The expectations on how these assumptions and paradigms could evolve in the future naturally differ from stakeholder to stakeholder. In some cases, these differences highlight potential discrepancies between the current energy transition landscape and what is needed to achieve ambitious climate objectives. They also underscore the necessary actions and what it would take, in terms of policy framework, value chain adaptation and investment, to foster a pathway that is optimal from an energy system perspective.

175. The least-cost 'Technology Diversification' pathway is itself the stylized outcome of an economic optimization of the energy transition that assumes policy-makers and industrial leaders manage to overcome all barriers and uncertainties along the road to net-zero emissions. It supposes that governments, industry and all other relevant stakeholders – across Europe – adapt their frameworks and strategies to reduce CO_2 emissions at the least possible cost. As such, they can combine all opportunities and technologies and anticipate learning-by-doing and stranded asset risks. Along this pathway, investments break even and market distortions and externalities are neutralized. The reliability, transparency and effectiveness of the policy framework is therefore a given for the pathways described in this study. Technology neutrality, the assumption of a comprehensive approach to decarbonization that includes the potential of a much wider range of technologies is an additional feature of the Technology Diversification pathway.

176. The results stress the important role of regulation and policies to allow for an optimal contribution of hydrogen to the energy transition. As part of the actions related to the Paris Agreement and the European Green Deal, policies and regulations are currently being reshaped to concretize the net-zero emissions objective. In this context, European policy-makers have opened the way for hydrogen with several important policy packages strategies already published. Nevertheless, many of the enablers identified in the *Hydrogen for Europe* pathways are yet to be developed. The current regulatory and policy framework still lack the tools and measures needed to stimulate hydrogen's upscaling, and more generally to allow decarbonized options to compete on a level playing field with existing CO_2-emitting solutions and to break even in the long term.

177. The policy calendar identifies the necessary building blocks that will be published in the awaited 'Fit for 55' policy packages and that would underpin energy system integration and help deliver the Green Deal and the hydrogen strategy. It is however still unclear how they will relate to each other, and whether they will be sufficient to lead to net-zero emissions. In addition, many barriers and uncertainties, such as the lack of clear valorization of CO_2 content or lack of incentivizes to invest in the appropriate decarbonization technologies, are still preventing the optimal development of some technologies, and doubts remain on whether policy-makers plan to address these barriers or which paradigm they would adopt. As an example, policy announcements and publications of last year put clear emphasis on certain technologies like renewable hydrogen, at the risk of creating a two-speed system and limiting the choice of available solutions. In light of the *Hydrogen for Europe* study's results, the already announced ambitions and strategies in terms of hydrogen could themselves prove difficult to achieve without significant and timely acceleration of policy support.

178. The momentum built over the last few years therefore needs to be followed by concrete actions to implement the building blocks of the European energy transition and of the hydrogen policy framework. The announced 'Fit for 55' policy package brings an opportunity to fundamentally reshape European energy policy. It is also the occasion to foster an optimal pathway to hydrogen deployment and decarbonization that complements the least-cost principle with other key policy considerations like energy security and social acceptance.

179. The results of the *Hydrogen for Europe* study and their underlying assumptions can help inform the design of these next policy packages and measures. The results can be used to better understand the gap between the current framework and the enablers of an optimal pathway. In order to help achieving the overarching policy objective of net-zero emissions by 2050, five main guidelines are proposed:

(1) Include externalities of CO_2 emissions in the economics of the energy system, in order to incentivize CO_2 abatement technologies and uses.

(2) Design accounting rules for CO_2 content of energy use in a fair and inclusive manner, harnessing the benefits of all renewable and low-carbon technologies.

(3) Foster innovation and R&D to bring clean technologies, such as hydrogen, to commercial viability.

(4) Enable low-cost financing and bankability of investments in low-carbon and renewable solutions, addressing in particular the funding of the hydrogen value chain.

(5) Connect the dots: ensure effective energy system integration and coordination between demand and supply growth to create a functioning hydrogen economy (including market integration and competition).

(1) Internalizing CO_2 emissions and incentivize CO_2 abatement technologies and uses

180. The *Hydrogen for Europe* pathways optimize the investments and operations in renewable and low-carbon technologies in order to comply with the net-zero emissions objective. In the modelling, the market sends the right price signals to encourage switching to these alternative technologies and guarantees the profitability of related investments. The model does so by imposing a shadow price for CO_2 emissions, that increases the cost of emitting technologies and allows low-carbon energy to become competitive. Under these conditions, the energy system can transform itself optimally by internalizing the cost of CO_2 emissions and making abatement options profitable.

181. There are multiple market and regulatory barriers that prevent renewable and low-carbon technologies from competing on a level playing field with today's emitting technologies. An important barrier is the limitation of CO_2 pricing mechanisms, such as the EU-ETS and national carbon taxes. The price of CO_2 in markets that are covered by these schemes is today too low to allow for a rapid development of CO_2 abatement options, such as renewable hydrogen or CCS. Numerous studies have shown that the CO_2 price would need to follow a steep and regular increase over the next thirty years to unlock more costly abatement options as the net-zero deadline gets closer. CO_2 pricing also suffers from fragmented, limited and non-coordinated applications, depending on countries and sectors. The international aviation and the maritime sectors are not covered by the EU-ETS, while many industrial sectors are at risk of carbon leakage due to their exposure to the global market.

182. The reform of the EU-ETS, and the current reflections around a carbon border adjustment mechanism (both due before December 2022) are obvious opportunities to address obstacles to coordinated and efficient CO_2 pricing and reflect the reinforced objectives of climate neutrality.

   a. The reform of the EU-ETS is an opportunity to include new energy carriers and sectors in the ETS, positioning the scheme as a comprehensive system for CO_2 pricing in Europe. The reform should also increase the pace of reduction of emissions, encouraging a more rapid switch to low-carbon and renewable solutions.

   b. Carbon leakage risks may be addressed by the establishment of a carbon border adjustment mechanism that would ensure that prices of products imported into Europe reflect their CO_2 content and would support the competitiveness of European industries that fall under European CO_2 pricing schemes.

183. These measures, even if well-designed, may not be sufficient to encourage the uptake of abatement technologies. There might be a need to complement them with other options and regulatory tools, in a wider policy framework, to address other regulatory and economic barriers to low-carbon and renewable hydrogen.

   a. Direct support might help renewable and low-carbon hydrogen gain a critical foothold in the energy system from which to expand on their own merits, responding to CO_2 pricing. Classic tools, such as technology-specific feed-in tariffs and premiums, but also innovative schemes like carbon contract for differences could be well suited. In the EU, the upcoming revision of the Environmental and Energy Aid Guidelines (EEAG) is an occasion to clarify and tailor the framework to climate neutrality, by recognizing the potential and the specific needs of all technologies, and by addressing the current guidelines' limitations. Criteria and objectives could be redefined with environmental performance and carbon neutrality as the central element. A specific chapter could be created for hydrogen, tackling aid for investment and operation but also addressing the issues related to transport and storage. The treatment of CO_2 transport could also be clarified as it currently constitutes a barrier to companies' current CCUS projects and long-term visions.

b. Mandates and binding targets are other possible options to support renewable and low-carbon technologies. The upcoming revision of the EU renewable energy directive is expected to increase the EU target on the share of renewables in gross final consumption. This revision could be an opportunity to prepare a coordinated roll-out of sectoral decarbonization roadmaps on the demand side, especially in hard-to-abate sectors such as transport or industry. A level playing field between a large suite of decarbonisation technologies, e.g. via targets based on CO_2 content, would help achieving the transition in a cost-effective manner. Existing mandate schemes e.g. in the transport sector could be revised and complemented with mandates in other sectors or applications.

c. There are other schemes that could bolster the competitiveness of low-carbon and renewable hydrogen. Those include the Energy taxation directive (to harmonize taxation according to environmental principles and CO_2 content and remove current incentives for emitting technologies), the ReFuelEU Aviation and FuelEUMaritime schemes to address the specificities of decarbonization for aviation and maritime, or the revision of the EU-directive on the deployment of alternative fuels infrastructure (AFID).

(2) Accounting for CO_2 content of energy use

184. The Technology Diversification pathway optimizes the deployment of CO_2 abatement options to achieve net-zero emissions at the least cost for European society. All technologies, fuels, energy carriers and other abatement options (e.g., energy efficiency) are thus assessed regarding the CO_2 emissions they either emit, neutralize or permanently remove from the atmosphere. Under this paradigm, investors are able to target the appropriate technologies and to roll out necessary investments in a coordinated and timely manner with respect to the decarbonization targets. In the hydrogen value chain, investments focus on low-carbon hydrogen production technologies and infrastructure in the first decades in order to kick-start the hydrogen economy, while investments in electrolyzers (and connected renewables) ramp up progressively to accommodate for the major role of renewable hydrogen in the second half of the transition.

185. Reflecting this and embedding CO_2 content with markets and regulations would contribute to lowering the cost of the transition. This is an important step in establishing a level playing field between technologies. It enables efficient identification and treatment of abated solutions and provides a transparent tracing mechanism of technologies and energy carriers.

186. EU policy-makers have opportunities coming up to progress on CO_2 accounting and on the treatment of energy based on CO_2 content:

a. The upcoming revision of the Renewable Energy Directive (RED) could update the framework for the use of guarantees of origin (GO), which are used to inform the final consumer on the GHG content of the energy they purchase. The implementation of an EU-wide GO scheme, encompassing all low-carbon and renewable technologies (including hydrogen), would foster the development of markets for hydrogen and alternative energy carriers and fuels and enable their integration within a single framework. Such a scheme would also facilitate both compliance monitoring and the application of standards and mandates in end-use sectors.

b. Another opportunity comes with the finalization of the EU taxonomy in 2021. The final version of the taxonomy should classify technologies according to their carbon content in alignment with the other methodologies, such as defined in the upcoming revision of the renewable energy directive. The qualification of renewable and low-carbon technologies to the environmentally sustainable category could be based on a common CO_2 threshold that would decrease progressively over time. The threshold could be fixed so that low-carbon technologies, including low-carbon hydrogen, can contribute to achieving emission reductions.

(3) Fostering innovation and R&D and bringing new technologies to commercial viability

187. Most clean technologies that are critical for achieving net-zero emissions are still at an early stage of technology readiness. Bringing them to commercial viability entails considerable research and innovation uncertainties. More advanced technologies like solar PV or wind still show great potential for further innovation and cost decrease (respectively, their investment cost could drop another 40% and 20% during the next thirty years). Knowing that, policy-makers need to ensure the right conditions for innovation to take place and give these new technologies a hand so they can enter the market while keeping the virtuous learning-by-doing process for mature technologies going.

188. Two existing programs appear particularly well-suited for hydrogen technologies:

   a. The €95 billion Horizon Europe program could reinforce its hydrogen research program, underpinned notably by the capacities of the FCH-JU. The funds dedicated to hydrogen should reflect the volume and variety of investments and innovations needed to bring hydrogen to commercial viability. Risks for first movers and early industrial-size projects need to be addressed for renewable hydrogen, pyrolysis, reformers and CCS, as well as on the demand side.

   b. The ETS-financed Innovation Fund, currently estimated at €10 billion for the period 2020-2030, could be expanded to target more largely low-carbon and renewable hydrogen and CCUS-related projects, complementing Horizon Europe. Under current rules, those projects would be able to receive grants up to 60% of additional capital expenditure and operational expenditure for large projects, and 60% of capital expenditure for small projects, and the rest is eligible for direct support from a member state.

189. National support schemes and State aid can be used to support the uptake of less mature technologies and to encourage learning-by-doing and cost decrease. The *Hydrogen for Europe* study shows that cost decrease for currently non-mature technologies is an essential enabler of the energy transition (e.g., costs of electrolyzer dropping more than 70% from today to 2050 in the Technology Diversification pathway, spurred by significant potential for learning by doing, while low-carbon technologies such as reformers with CCS and pyrolysis observe cost reduction of more than 20%). If well-designed, the national support schemes could allow innovative renewable and low-carbon technologies, like hydrogen, to compete with more mature technologies such as renewable electricity. New support schemes could incorporate a dual objective, not so different from the current distinction made in the EEAG between renewable energy technologies based on their maturity. It is important that the schemes support the competitiveness of renewable and low-carbon solutions vis-à-vis CO_2-emitting ones and provide the conditions for continuous innovation.

190. Finally, the IPCEI (important project of common European interest) option should be considered by policy-makers to accelerate the roll-out of large-scale value chains and infrastructure. The multi-billion hydrogen programs implemented under IPCEI status would benefit from public funding while being compliant with the EU State aid rules and other financing vehicles such as the Connecting Europe Facility, also allowing for coverage of operational expenses. They could represent a significant step forward for the establishment of a full-fledged hydrogen value chain, encompassing all sectors and technologies and multiple European countries. The IPCEI Hydrogen launched by the German federal ministry for economic affairs and energy, in association with 22 other EU member states and Norway, is perhaps a pointer in the right direction. Beyond that project, the European Commission could clarify the eligibility rules and could be more explicit on the role of IPCEI to foster the European Green Deal and the EU hydrogen strategy.

(4) Enabling financing of investments

191. The pathways show that the transition of the European energy system requires €3 to 5.5 trillion in investments in renewable and low-carbon hydrogen production and the related value chains. Further investments would then be needed on the demand side (e.g., investments in an adapted transport fleet, retrofitting of industrial processes, switch in heating appliances, energy efficiency…) and for other energy-carriers and technologies contributing to reaching net-zero emissions.

192. Optimal timing of these investments implies that they are realized in lock-step with the progressive decarbonization and deployment of hydrogen in the energy system, for the least possible financing cost. These

investments would need to start soon. Some € 400 to €800 billion need to be mobilized until the mid-2030 (€40-80 billion per year on average). The future policy framework and technological environment of the transition to climate neutrality is still uncertain, increasing the risk for certain clean energy investments.

193. Policy-makers have a role to play in mitigating these financing risks and opening the door to low-cost financing. Acceleration of the development of the future policy and regulatory frameworks for hydrogen and energy system integration should help providing more clarity for investors. Governments and legislators need to ensure that the framework is perceived as reliable and transparent by investors. The upcoming 'Fit for 55' legislative package, including the EU taxonomy, the revision of the renewable energy directive and the revised regulatory framework for competitive decarbonized gas markets (i.e. the hydrogen and low-carbon gas markets package) expected at the end of the year, are therefore crucial in alleviating uncertainty.

194. Public financial institutions could help providing access to low-cost financing, complementing equity, to lower the cost of capital. Many public schemes and regulatory tools are, or could be, available to finance the European Green Deal and support innovation and competitiveness for low-carbon and renewable technologies. The following funds and facilities could be coordinated and enhanced to target more explicitly hydrogen financing:

a. The European and national Covid-19 recovery plans could explicitly target hydrogen development. 30% of the EU recovery fund (representing€ 547 billion through the NextGenerationEU vehicle and the Multiannual financial framework) is announced to be dedicated to fighting climate change. This could represent a major funding avenue for the hydrogen value chain, by reinforcing the capabilities of facilities such as InvestEU and Horizon Europe.

b. The €40 billion Just Transition fund, that is also supported by the EU Recovery Plan, is aimed at supporting territories facing socio-economic changes related to the transition towards climate neutrality. Policy-makers could allow for part of this fund to be allocated to efforts towards the hydrogen economy and the establishment of low-carbon technologies in the more carbon-intensive economies. The Just Transition Mechanism's criteria could also be amended to allow more targeted loans from the European Investment Bank.

c. The €14 billion Modernization fund, funded by 2% of the auction of EU-ETS allowances, could complement the Just Transition fund to target investments in the hydrogen value chain in the most carbon-intensive regions. The upcoming revision of the EU-ETS could relax the conditions for investment eligibility and explicitly target hydrogen-related technologies.

d. If the European parliament and member states vote to follow the European Commission's proposal for revision of the TEN-E regulation, then that would open Project of Common Interest status to hydrogen infrastructure projects. These "hydrogen PCIs" would be eligible to regulatory and permitting advantages and to Connecting Europe Facility (CEF) grants. These grants could accelerate the deployment of a European hydrogen backbone, based on a combined use of retrofitted gas infrastructure and new dedicated hydrogen pipelines. The CEF Energy funding program, that provided up to €4.7 billion in grants in the last decade, could be expanded and realigned with future priorities, targeting in particular hydrogen. The same applies for the CEF Transport budget, which should target alternative fuel infrastructure and vehicles.

e. Finally, the European Investment Bank (EIB) and other public financing institutions could play an important supporting role for hydrogen projects. Their criteria for loans, investment and assistance should reflect the EU taxonomy and encompass all promising renewable and low-carbon technologies. EIB financing for renewable and low-carbon hydrogen projects would be an important signal to other financial intermediaries that the projects have political support and mitigated risk.

(5) Ensure system integration and create a hydrogen market

195. The successful creation of a hydrogen economy depends on a synchronized momentum in supply, demand and transport of hydrogen. The results show that a 30-million-ton hydrogen economy by 2030 helps achieving early CO_2 emission reductions – a key step in getting to net-zero emissions in the long term. By that time, a functioning market and regulatory framework, which would enable trade of hydrogen within Europe and the

efficient development and use of infrastructure needs to be in place. This is certainly a major challenge but policy-makers benefit from past experience in designing the successful frameworks for European electricity and gas market integration and liberalization.

196. The first opportunity for policy-makers comes with the upcoming framework for competitive decarbonized gas markets that will be revised within the hydrogen and low-carbon gas package, due by the end of the year as part of the ‘Fit for 55’ package. Revision of the third energy package for gas and its extension to low-carbon and renewable gases like hydrogen is an important step. The revised framework is expected to lay the grounds of the future internal market for hydrogen.

a. Progressively establish an organized and liquid market for hydrogen: the hydrogen market could be integrated within the existing gas market, and, in the longer term, be based on European hubs with a hydrogen price index in Euro that would ascertain Europe’s leading position on hydrogen. Coherence with the revision of the renewable energy directive and with the EU taxonomy to set the rules of future trade of hydrogen, based on carbon content and an all-encompassing guarantee of origin scheme, is important. In the long term, this could be the foundation of a truly European hydrogen market. The market should also adapted to hydrogen imports from outside Europe, thanks to common standards and carbon certification methods.

b. Introduce a phased reform of gas infrastructure regulation, accommodating a full-fledged regulatory framework for hydrogen infrastructure: it should settle the uncertainties regarding anti-trust regulation, unbundling, third-party access, harmonization of network codes and standards and safety rules. At the center of current expectations, the package ideally also clarifies the rules regarding blending and retrofitting of gas infrastructure, recovery of natural gas infrastructure sunk costs, CCUS infrastructure and the role for existing gas infrastructure operators in hydrogen infrastructure.

197. Taking a holistic perspective on the energy transition, the future hydrogen policy framework could be embedded in the European Commission’s efforts towards energy system integration. The legislative package of June 2021, which is supposed to enshrine the objectives of the European Green Deal and energy system integration strategy in law, thus also needs to ensure that the hydrogen investments and policy actions are coordinated with the rest of the energy system. This entails doubling down on an integrated system development plan for hydrogen, gas and electricity, further harmonization of regulations and markets of electricity and gas, and clear regulatory definition of the interface between the sectors (power to gas, power to liquid, etc.). The transport policy package also needs to be revised accordingly, notably regarding the reform of TEN-T regulation and of the alternative fuel directive. Under these conditions, policy and regulation could overcome the bulk of the current uncertainties that hinder the optimal development of the hydrogen value chain, unlocking hydrogen’s contribution to the energy transition.

Annexes

6 Annex A: Sensitivity analyses

198. The Hydrogen for Europe study is based on two main scenarios representing two pathways in which the European energy sector reaches carbon-neutrality in 2050. The pathways depict different European policy frameworks but share the same decarbonization goals and apply the same modelling and assumption framework. To assess the robustness of the most dimensioning technical and economic assumptions of the two main pathways, sensitivities on the quantitative parameters representing these assumptions have been carried out.

199. Five sensitivity parameters have been considered and compared to the Technology Diversification pathway:

a. Restrictions have been set in the Technology Diversification pathway for annual injection rate of CO_2 to permanent storage: 1.0 Gt from 2020 to 2040, 1.2 Gt for 2045 and 1.4 Gt for 2050. Considering a pathway with an unconstrained development of such storage offers value to appraise the importance of CO_2 storage limitations on the role of low-carbon hydrogen. It also helps to understand what the maximum potential of low-carbon technologies could be an unconstrained set up. Therefore, a sensitivity analysis on the Technology Diversification pathway has been realized. It assumes no restriction on the annual CO_2 injection rate.

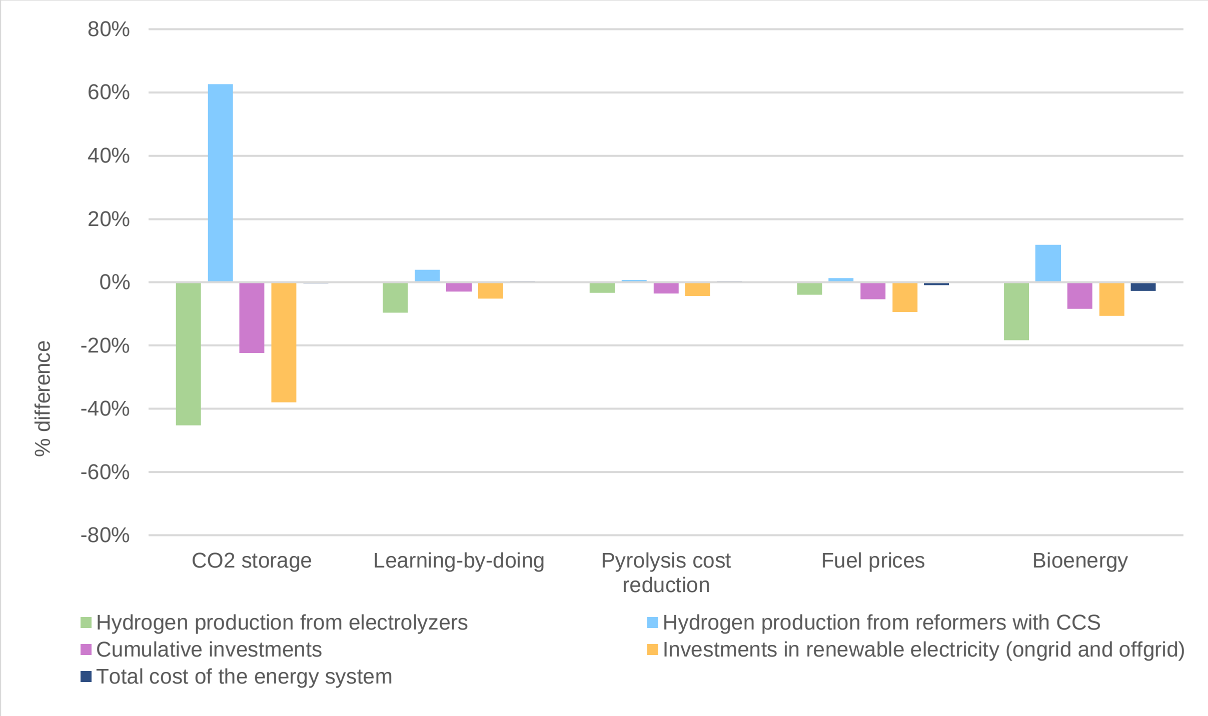
b. The learning model relies on learning rates extracted from literature, and by selecting the median (50^{th} percentile) rate from the collected dataset. A sensitivity has been carried out for variable renewable electricity production units and electrolyzers to assess the impact of uncertainty on their learning rates and on their capital cost reduction potential, using the 25^{th} percentile rates.

c. The molten media and non-catalytic methane pyrolysis technologies are assumed to reach the commercial viability by 2030 in both *Hydrogen for Europe* pathways. These technologies are currently at relatively low technology readiness levels. A sensitivity has been carried out to assess the impact of a delayed timeline for commercial availability of pyrolysis technology. The sensitivity assumes an alternative cost profile of the pyrolysis technology, reaching commercial stage by 2040 instead of 2030.

d. Fossil fuel prices, and especially natural gas prices play a role in the development and the profitability of low-carbon hydrogen (reformers and pyrolysis), as methane is the main fuel or feedstock used in the production process. To test the resilience of low-carbon hydrogen' development to varying fossil fuel prices, a sensitivity has been performed. It assumes an environment with lower fossil fuel prices in the future.

e. Finally, bioenergy potential represents one of the main drivers of the European energy system in the *Hydrogen for Europe* study, as it is consumed in many sectors but is also used to produce power and hydrogen. The Technology Diversification pathway considers the latest data published by the JRC regarding bioenergy potential in Europe, but other scenarios from the JRC consider a greater potential of bioenergy in Europe towards 2050. Therefore, a sensitivity has been carried out to consider a higher potential of bioenergy in Europe, based on the ENSPRESO Reference Trajectory which assumes wider utilization of forest resources and related market developments.

Figure 50. Sensitivity analysis on key indicators in 2050 – comparison with the Technology Diversification pathway



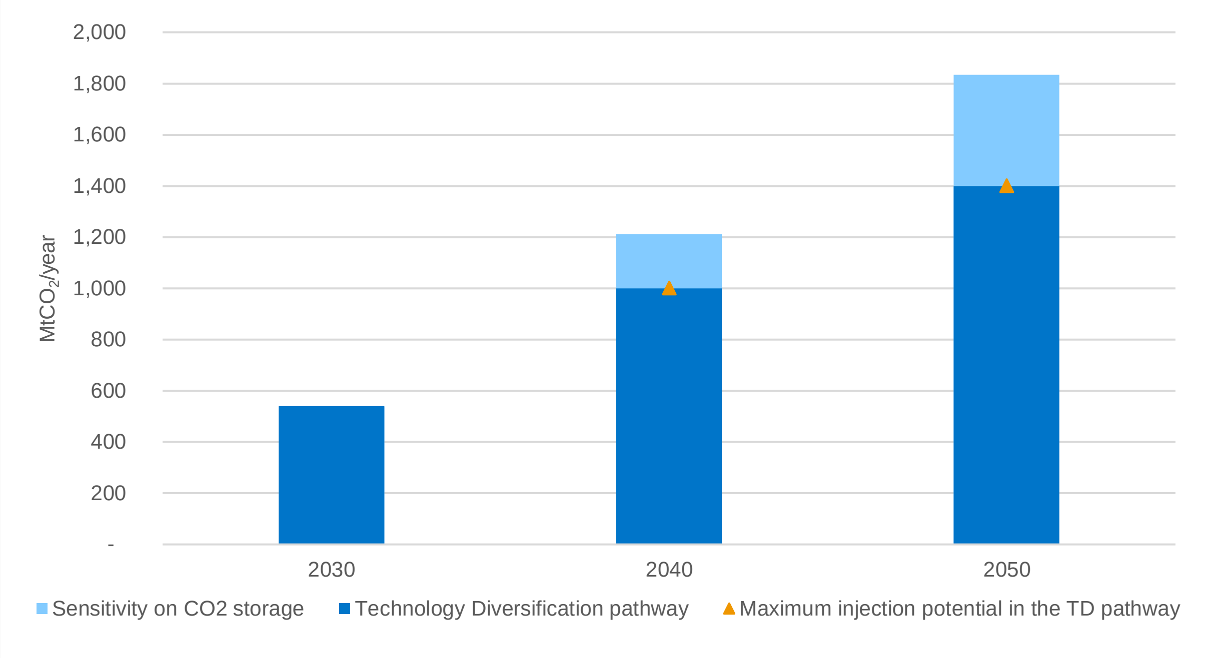
Source : *Hydrogen for Europe* study

200. The results of the sensitivities show the overall effects of the five sensitivities on key performance indicators (figure 50). It becomes clear that among the five key parameters that have been tested, the constraint on the annual CO_2 injection rate is the most dimensioning, followed by bioenergy. As such, it emphasizes the key role of CCS technologies and their underlying value chain in the transition towards carbon-neutrality.

6.1 Unconstrained injection of CO_2 into permanent storage sites

201. Permanent storage of CO_2 is a cost-efficient option for decarbonization. The two main pathways include restrictions for annual CO_2 injection to permanent storage, based on the research consortium's assessment of adequate injection rate evolution during the next thirty years. The CO_2 injection limits are reached in the Technology Diversification pathway in 2040 and 2050, preventing any further development of BECCS, DACCS and other low-carbon technologies based on CCS. An unconstrained access to storage within an energy system optimization could thus result in higher injection rates for storage of CO_2 for those years, leading to a greater potential for direct air capture and technologies based on CCS. To test this conjecture, a sensitivity has been performed to provide more insights on the potential role of CCS in the energy transition when injection into permanent storage is not limited (figure 51). All other assumptions are equal to those of the Technology Diversification pathway. The results shed light on the upper bound potential for carbon dioxide capture and removal technologies in Europe.

Figure 51. Evolution of CO_2 storage injection rate in the Technology Diversification pathway and a sensitivity with unconstrained CO_2 injection rates, 2030 to 2050



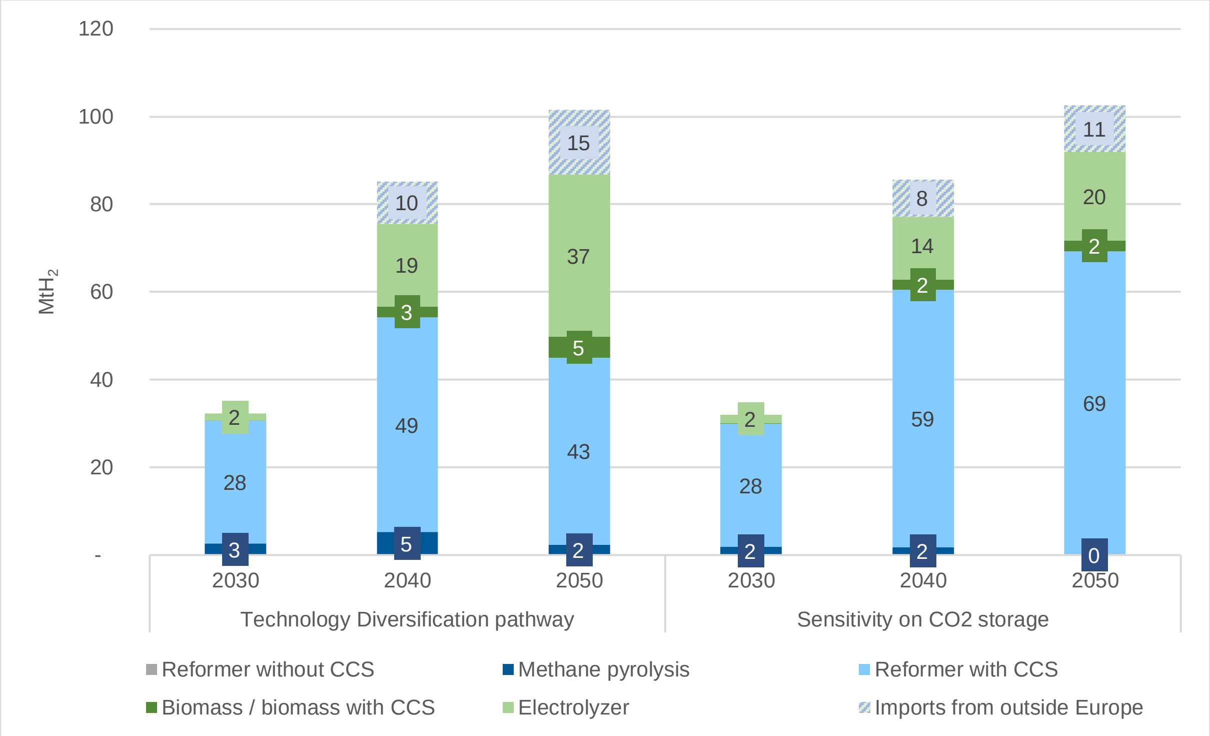
Source : *Hydrogen for Europe* study

202. The results of this sensitivity analysis diverge from the Technology Diversification pathway, especially in terms of hydrogen production volumes and needed installed capacities (figure 52). In the sensitivity, the production of low-carbon and renewable hydrogen are almost unchanged in 2030 compared to the Technology Diversification pathway, as access to CO_2 storage is not yet a scarce resource. Marked differences appear in the latter half of the outlook period: in 2040, production of low-carbon hydrogen is some 20% higher in the sensitivity compared to the Technology Diversification pathway while renewable hydrogen production drops by 20%. Imports are also lower in this sensitivity.

203. Low-carbon hydrogen production is then boosted to almost 70 Mt in 2050, around 75% of inland hydrogen production, displacing renewable hydrogen production and imports. In parallel, CO_2 injection rate reaches more than 1,800 Mt which is some 400 Mt higher than the limitation implemented in the Technology Diversification pathway (figure 51). This confirms CO_2 storage as a major driver of low-carbon hydrogen potential. Overall, the total volumes of hydrogen production in Europe are similar between the Technology Diversification pathway and the sensitivity.

204. Looking in more detail at low-carbon hydrogen, the availability of CO_2 storage leads to a substitution from pyrolysis to reformers with CCS. Pyrolysis production peaks around 2030 and does not see any investment after 2035. In 2040, production is two thirds lower than in the Technology Diversification pathway.

Figure 52. Evolution of hydrogen supply in the Technology Diversification pathway and a sensitivity with unconstrained CO_2 injection rates, 2030 to 2050



Source : *Hydrogen for Europe* study

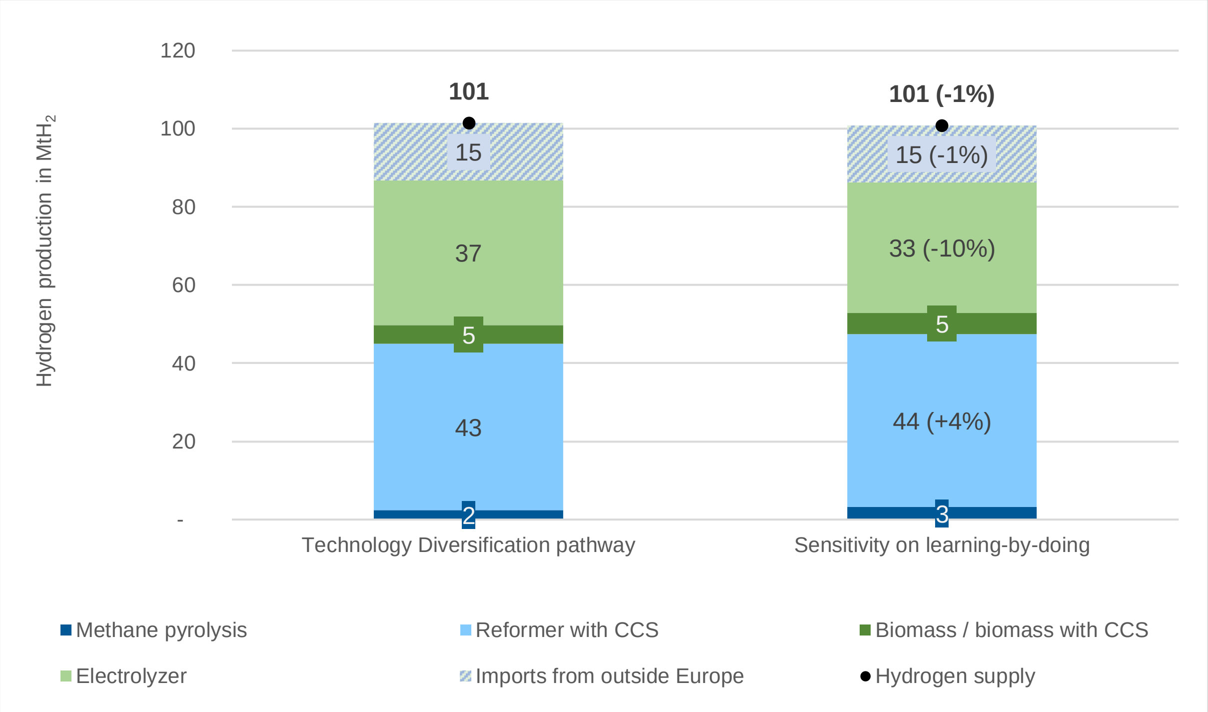
205. The evolution of hydrogen production, especially the shift towards reformers with CCS in the sensitivity is partly reflected in cumulative investments in the hydrogen value chain. In the sensitivity, cumulative investments in 2050 are €2.5 trillion, which is almost €700 billion lower than in the Technology Diversification pathway. This difference is mostly explained by the decreased investment needs in offgrid renewable electricity (-€477 billion) and in electrolyzers (-€245 billion).

206. The Technology Diversification pathway is identified as a low-cost option to get to net-zero emissions in 2050 by the *Hydrogen for Europe* study. However, the total cost of the energy transition toward carbon-neutrality is still €230 billion lower in the sensitivity than in Technology Diversification pathway, representing around €15 billion of savings per year. This underscores the value for European society of developing an adequate CCS value chain.

6.2 Higher capital costs for renewable electricity generation and electrolyzers

207. The reduction in capital costs for hydrogen and electricity production units are outcomes of the learning-by-doing potential of those technologies, as assessed in the learning optimization model. This model relies on learning rates extracted from literature, and by selecting the median (50th percentile) rate from the collected dataset. A sensitivity has been carried out for variable renewable electricity production units and electrolyzers to assess the impact of uncertainty on learning rates on the learning-by-doing effects. The sensitivity consists of taking the 25th percentile rate instead of the median as in the Technology Diversification pathway, all other things being equal. Hence, the potential for cost reductions for on- and offshore wind as well as solar power production and hydrogen produced via electrolyzers is lower in this sensitivity.

Figure 53. Hydrogen supply by technology in 2050 in the Technology Diversification pathway and a sensitivity with higher capital costs for variable renewable electricity and electrolysis



Source : *Hydrogen for Europe* study

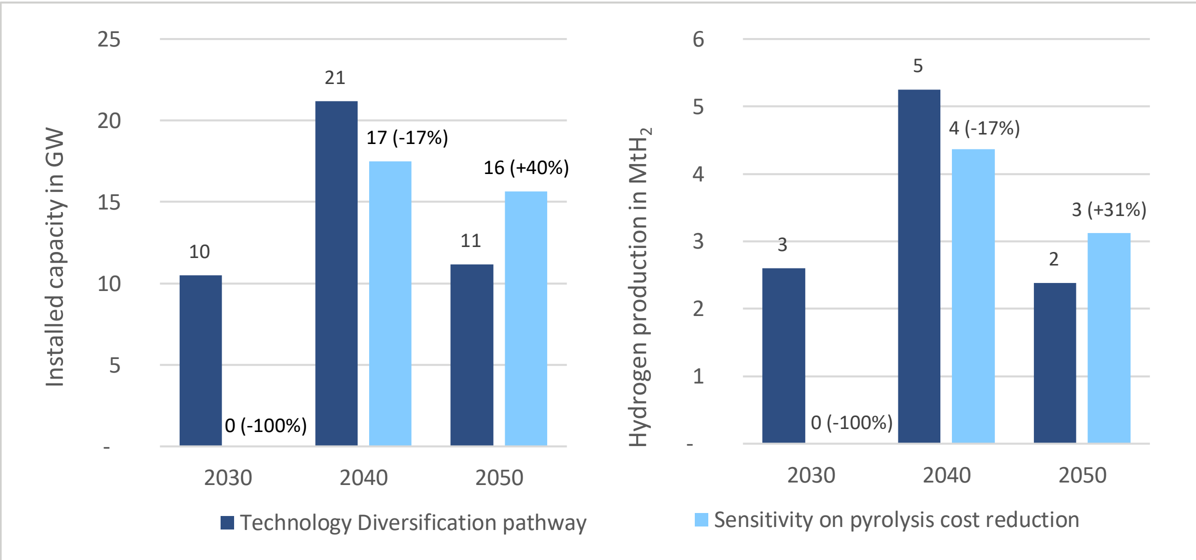
208. The findings in terms of hydrogen supply and demand for the Technology Diversification pathway are not significantly impacted by the uncertainty on the learning rates (figure 53). In 2050, the overall volumes of hydrogen production are similar between the Technology Diversification pathway and the sensitivity (around 1 Mt less in the sensitivity). The volumes of renewable hydrogen produced with electrolyzers are slightly lower in the sensitivity case (around 3.5 Mt less, -10%), partially compensated by the increase of low-carbon hydrogen production from reformers (around 1.5 Mt more). The overall investments in the hydrogen value chain until 2050 are, with €72 billion less than in the Technology Diversification pathway, marginally lower in this sensitivity.

6.3 Modified cost reduction profile of molten media and non-catalytic methane pyrolysis technologies

209. The molten media and non-catalytic methane pyrolysis technologies are assumed to reach commercial viability by 2030 in both *Hydrogen for Europe* pathways. These technologies are currently at low technology readiness levels. Hence, there remains some uncertainty on whether commercial viability can indeed be reached by 2030 or at a later date. A sensitivity has been designed to assess the impact of a delay in commercial viability of pyrolysis technologies until 2040.

210. The sensitivity assumes a shift in capital cost of the two pyrolysis technologies in the Technology Diversification pathway. The study considers that the capital costs of available pyrolysis technologies have a reduction potential of 20% compared to 2020 levels. In the main pathways the cost reduction occurs after 2030. In the sensitivity this reduction is delayed until 2040.

Figure 54. Methane pyrolysis installed capacity (left) and hydrogen production from pyrolysis technologies (right) in the Technology Diversification pathway and a sensitivity with delayed commercial viability of pyrolysis, 2030 to 2050.



Source : *Hydrogen for Europe* study

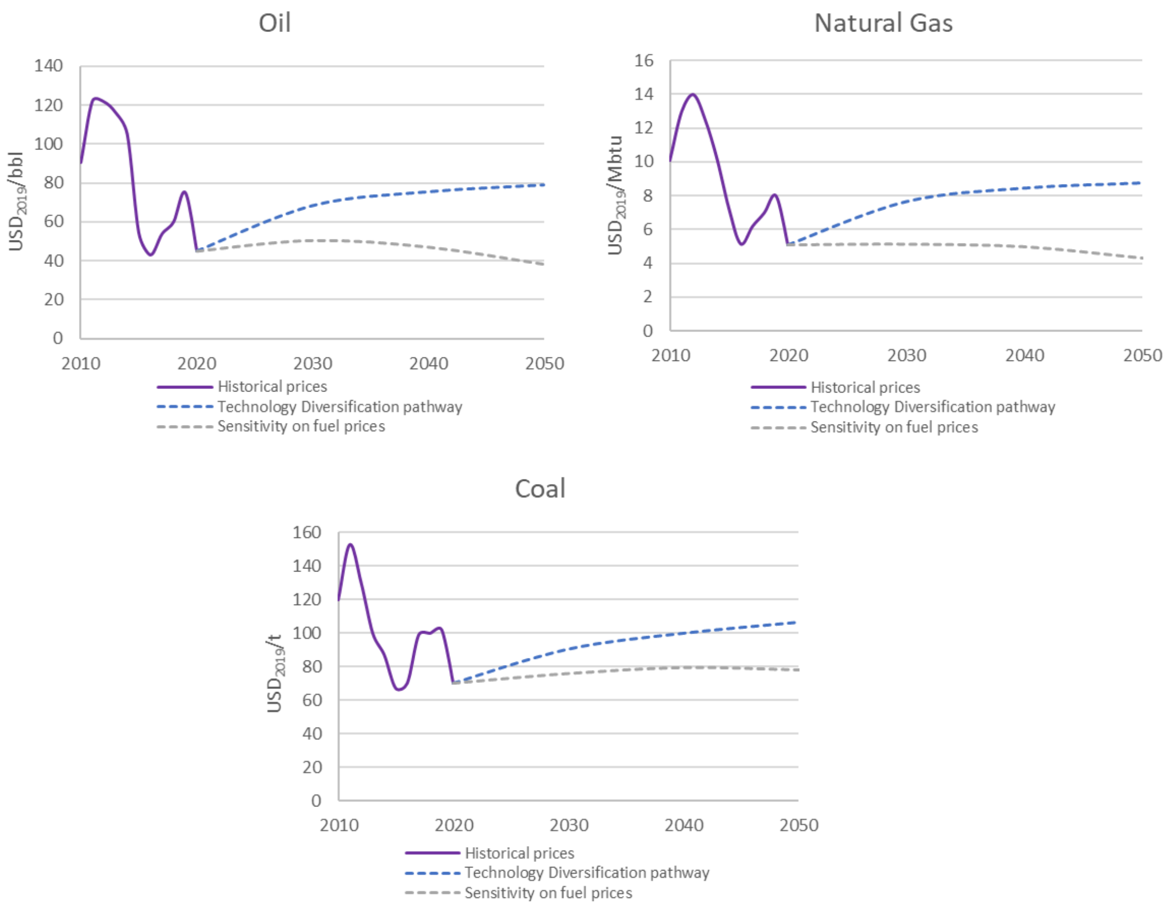
211. In the sensitivity, commercial viability is delayed leading to no installation or hydrogen production before the mid-2030s. Installed capacity of pyrolysis and production from pyrolysis peak during the 2040s (figure 54), but their levels at that date are 17% below the levels reached in the Technology Diversification pathway. In the last decade, 5 GW more capacity is available in the sensitivity, due to the delay in initial investment and about 1 Mt of hydrogen more is produced. Overall, the conclusions highlighted by the two *Hydrogen for Europe* pathways in terms of the role of pyrolysis in the hydrogen supply economy are robust. In the sensitivity, hydrogen production from pyrolysis still represents around 3% of the total European supply in 2050. Cumulative investments are 3% lower (around €90 billion) in this sensitivity and the total cost of the energy system remains unchanged. These relative variations are to be put in perspective with the wider role of pyrolysis in the outlook for low-carbon hydrogen production in Europe: its potential lies in certain economies, especially where there are restrictions to geological storage of CO_2[66] or limited renewable energy potential but also in certain non-European countries that supply hydrogen into Europe.

[66] Directive 2009/31/EC on the Geological Storage of Carbon dioxide - COM(2017) 37 "A few Member States do not allow geological storage of CO_2 (Austria, Croatia, Estonia, Ireland, Latvia, Slovenia) or restrict it offshore (the Netherlands, UK, Sweden), in time (Czech Republic), in quantity (Germany) or for demonstration purposes only (Poland)"

6.4 Lower fossil fuel prices

212. The fossil fuel prices considered in the *Hydrogen for Europe* pathways are based on the EU Reference scenario 2016. The Covid-19 effect is considered through a modification of 2020 prices. The resulting price trajectories are relatively similar to the fossil fuel prices of the IEA World Energy Outlook's Stated Energy Policies Scenario (STEPS). European prices of natural gas, oil and coal are subject to supply and demand evolution on global markets for these commodities.

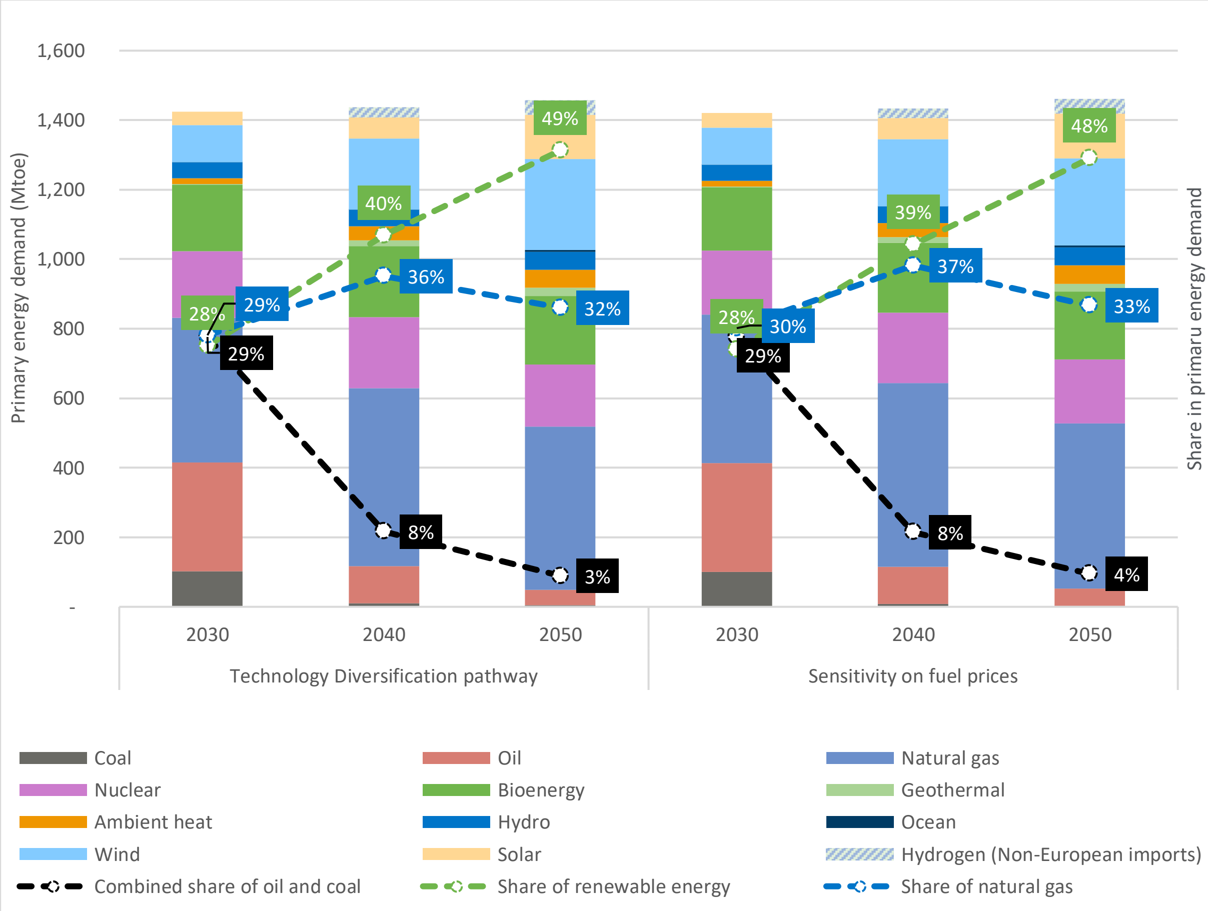
Figure 55. Evolution of commodity prices in the Technology Diversification pathway and in a sensitivity with lower fuel prices, 2010 to 2050



Source : *Hydrogen for Europe* study

213. To test the impact of the chosen fuel price assumptions on the findings of the study, a sensitivity has been performed. The objective of the sensitivity is to consider a future with lower fossil fuel prices, for instance due to lower global demand for these commodities. As such, the price trajectories of the sensitivity are based on the IEA World Energy Outlook's Sustainable Development Scenario (SDS), which is consistent with global action to achieve the long-term goals of the Paris Agreement (figure 55). In this scenario, fossil fuel demand and prices are lower than in the STEPS scenario. Specifically, the relationship between the prices of the STEPS and SDS was calculated and then applied to the adapted prices of the EU Reference scenario (since the IEA provides price trajectories only until 2040, this methodology allows to extrapolate to 2050).

Figure 56. Evolution of primary energy demand in the Technology Diversification pathway and a sensitivity with lower fossil fuel prices, 2030 to 2050

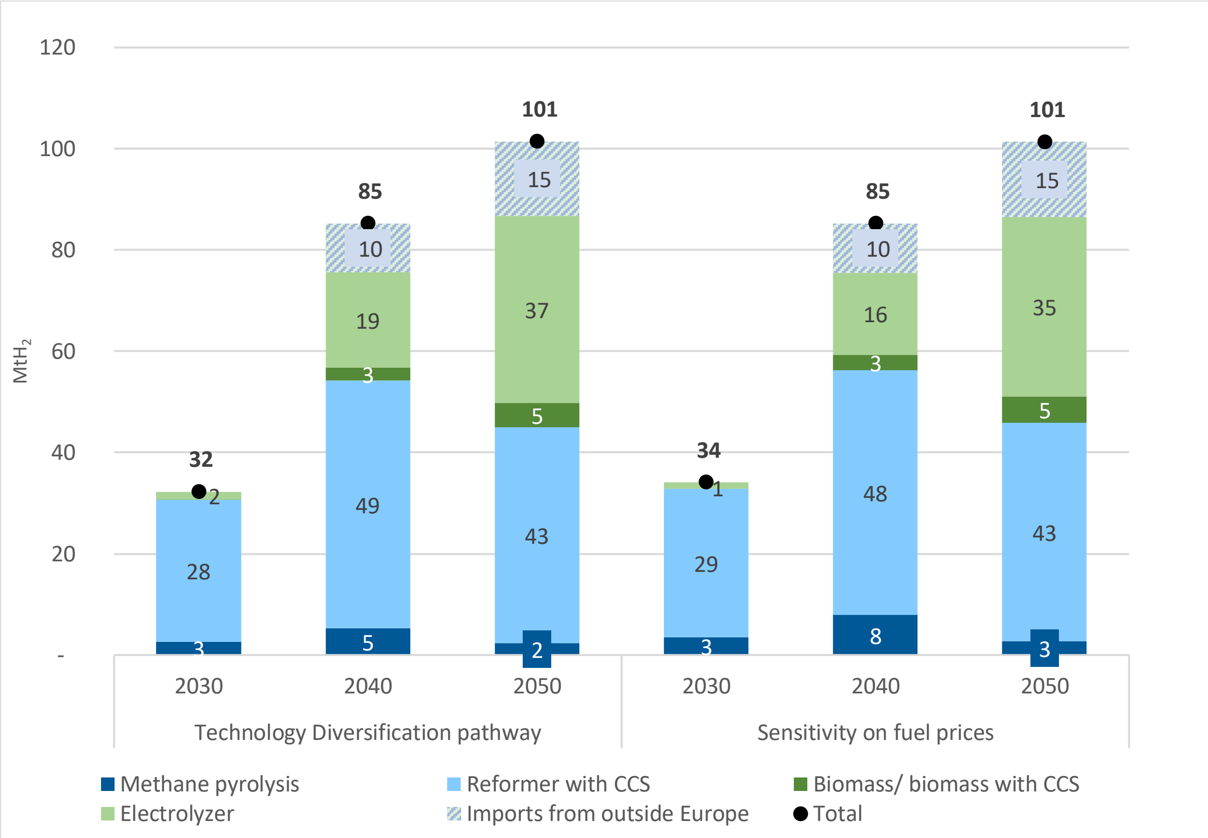


Source : *Hydrogen for Europe* study

214.In this sensitivity, the shares of fossil fuels in primary energy consumption are marginally higher than in the Technology Diversification pathway, while the share of renewables is slightly lower (figure 56). Overall, primary energy demand is thus not markedly impacted by the lower fossil fuel prices as the use of fossil fuels is effectively constrained by the net-zero emissions objective and the limited availability of CO_2 injection capacity.

215.Natural gas is the primary input for hydrogen production form reformers and pyrolysis plants. The price of natural gas is thus a critical driver of the competitiveness of these technologies vis-à-vis other decarbonisation options. Lower natural gas prices thus improve the economics of low-carbon hydrogen. This is particularly the case for pyrolysis, which sees nearly twice as much production in 2040 in the sensitivity as compared to the Technology Diversification pathway (figure 57). Hydrogen production from reformers with CCS, as well as imports of hydrogen from outside Europe are relatively unaffected by the lower natural gas prices. The main substitution effects are thus between pyrolysis and renewable hydrogen, which sees slightly lower output in the sensitivity.

Figure 57. Evolution of hydrogen production by technology in the Technology Diversification pathway and a sensitivity with lower fossil fuel prices, 2030 to 2050



Source : *Hydrogen for Europe* study

216. In the sensitivity case, renewable hydrogen is relatively less competitive than in the Technology Diversification pathway. This results in lower levels of investments on offgrid renewable electricity (-€160 billion) and electrolyzers (-€150 billion) in the sensitivity case and higher investments on hydrogen production based on natural gas (+€20 billion). Therefore, the cumulative investments are 22% lower in this sensitivity scenario. Finally, the overall cost of the system the sensitivity case is €763 billion less than in the Technology Diversification pathway (-0.8%).

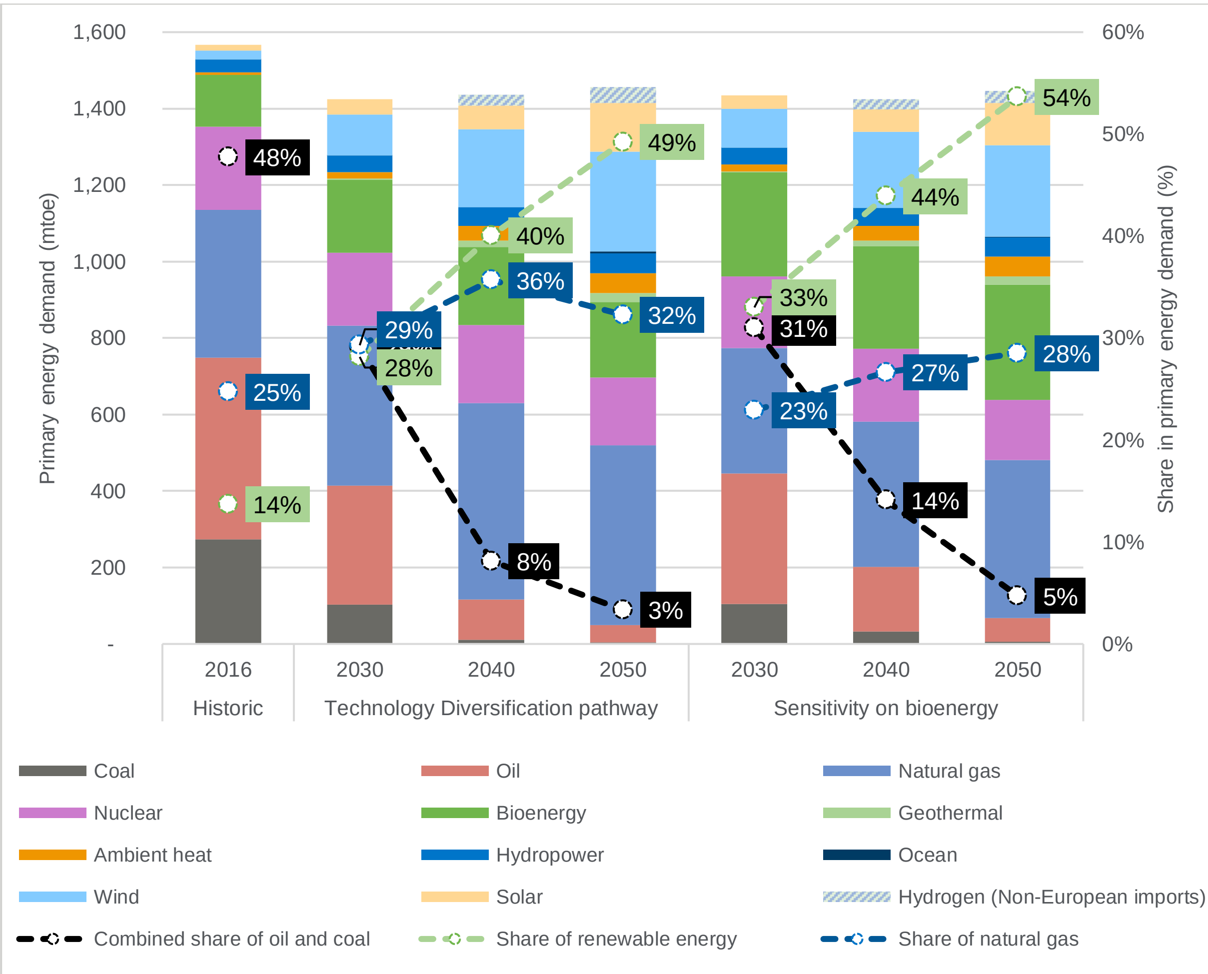
6.5 Higher potential of bioenergy

217. The Technology Diversification pathway uses the alternative "Business as Usual" trajectory from ENSPRESO for bioenergy potential in Europe. This trajectory represents the latest released trajectory for bioenergy published in the JRC database. To understand how this bioenergy potential could constrain the use of bioenergy and impact the results of the Technology Diversification pathway, a sensitivity on bioenergy availability has been carried out.

218. The sensitivity analysis considers the ENSPRESO Reference trajectory for bioenergy potential. Compared to the ENSPRESO's alternative "Business as Usual" trajectory, the Reference trajectory has around 45-50% greater potential of bioenergy in Europe over the period to 2050, due to wider utilization of forest resources and related market developments.

219. The higher potential of bioenergy in Europe leads to a more important role of this energy source in primary energy demand. In 2030 and 2050, bioenergy represents respectively 19% (+40% increase in supply compared to the Technology Diversification pathway) and 21% (+50%) of total primary energy demand in Europe in the sensitivity. Bioenergy displaces natural gas but also solar PV, wind and nuclear in the energy mix; the shares of which are lower in the sensitivity. The share of renewables in primary energy demand is higher in the sensitivity compared to the Technology Diversification pathway. It ends up five percentage points higher in 2050.

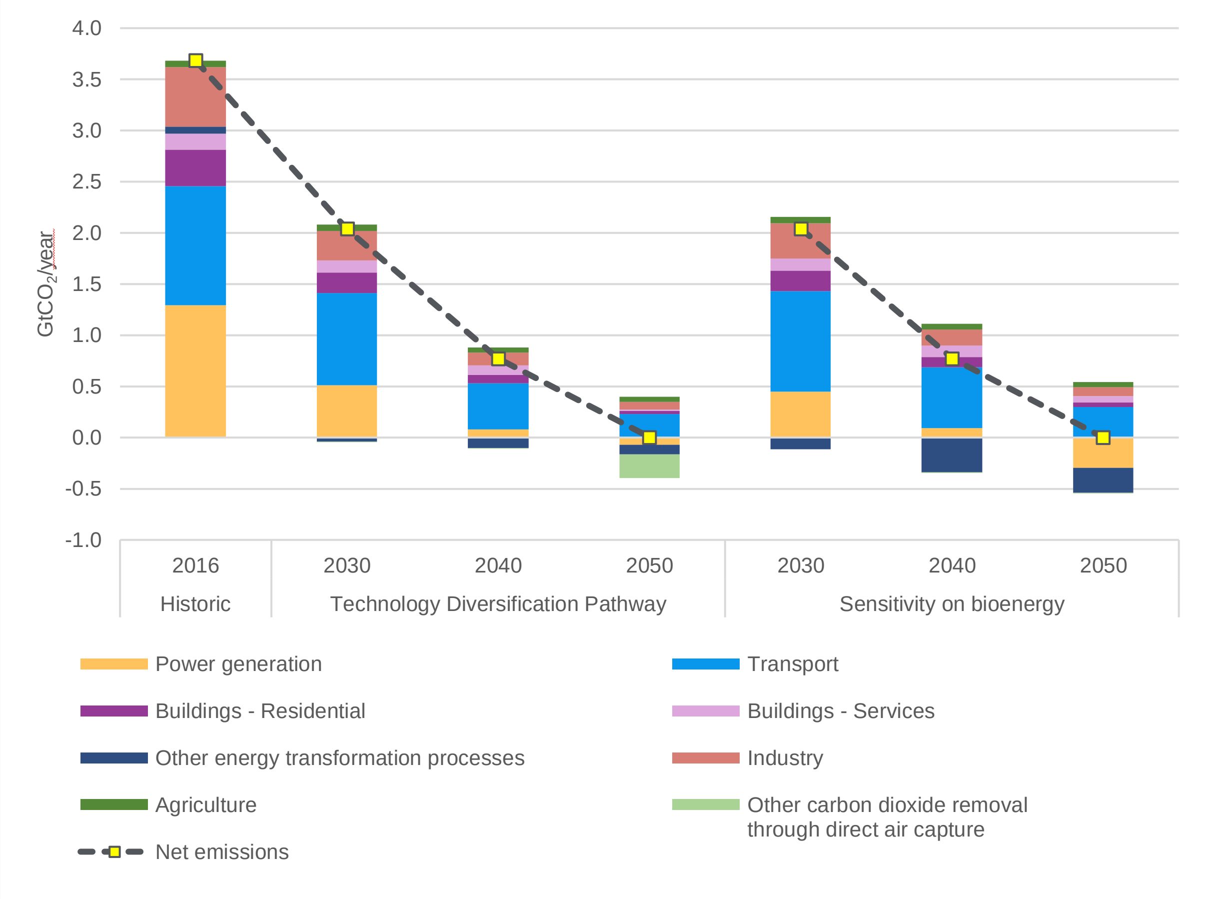
Figure 58. Evolution of total primary energy demand in the Technology Diversification pathway and the sensitivity on bioenergy potential, 2016 to 2050



Source : *Hydrogen for Europe* study

220. In the sensitivity, bioenergy plays a greater role in power generation and in hydrogen production, where it is combined with CCS (BECCS). In 2050, power generation based on biomass with CCS is almost two times higher in the sensitivity compared to the Technology Diversification pathway, reaching more than 570 TWh. Hydrogen production based on biomass with CCS is doubled in 2050 in the sensitivity compared to the Technology Diversification pathway, exceeding 10 Mt. The greater use of BECCS for power generation and hydrogen production displaces DAC technologies, which hardly feature in the sensitivity (figure 59). This is an important difference to the Technology Diversification pathway. More negative emissions also enable greater use of oil in the sensitivity. In 2050, oil consumption in the transport sector is 20 Mtoe higher in the sensitivity. In contrast, the higher potential of bioenergy does not lead to a significantly higher use of bioenergy in final consumption.

Figure 59. Evolution of CO_2 emissions by sector in the Technology Diversification pathway and the sensitivity on bioenergy potential, 2016 to 2050



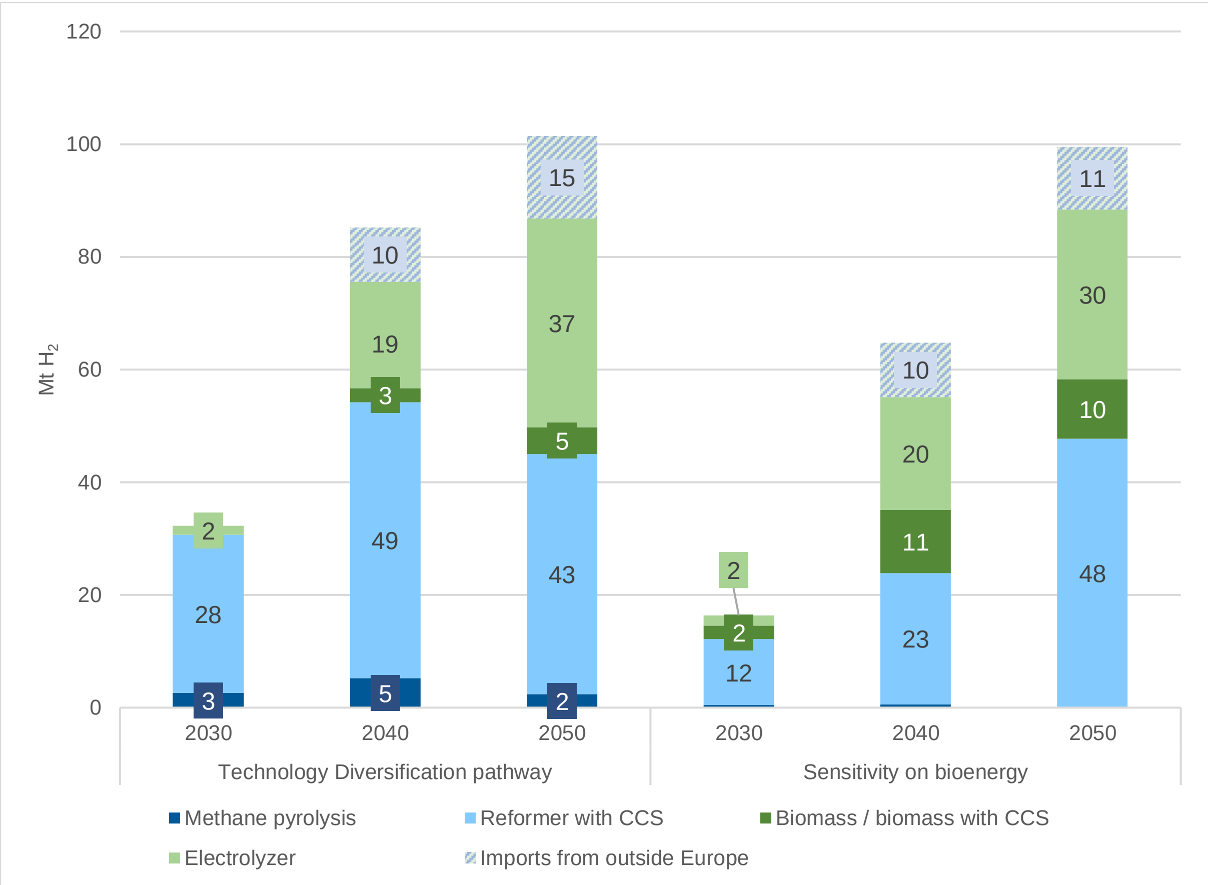
Source : *Hydrogen for Europe* study

221. Higher potential of bioenergy does not significantly impact the level of hydrogen demand in the long term. By 2050, hydrogen demand in the sensitivity stands at around 100 Mt, similar to the level reached in the Technology Diversification pathway. However, some notable shifts are observed the evolution of hydrogen demand over the outlook period. The uptake of hydrogen demand (and thus of the whole hydrogen economy) happens later in the sensitivity, mostly because the use of bioenergy with CCS allows for more negative emissions and shift some of the need of hydrogen to the end of the period. In the sensitivity, hydrogen demand is half its 2030 level observed in the Technology Diversification pathway (around 15 Mt compared to 30 Mt), but gradually catches up from 2030 to 2040 (-24%) and 2050 (-2%).

222. The evolution of the hydrogen production mix is significantly reshaped in the sensitivity (figure 60) in 2030 and 2040. In 2030, low-carbon hydrogen production is markedly lower than in the Technology Diversification pathway at 12 Mt. Production from electrolyzers is unaffected, standing at a similar level as biomass with CCS.

By 2040, production from reformers with CCS is still lower than in the Technology Diversification pathway but shows an almost 100% increase compared to 2030, while pyrolysis makes a minor contribution. Biomass with CCS takes a much more important role by then, producing more than 11 Mt of hydrogen by 2040 in the sensitivity. The picture is more stable in 2050, both in terms of overall production level and mix composition. As a notable change, hydrogen production based on reformers with CCS exceeds the output levels observed in the Technology Diversification pathway by 10%, and shows a significant increase compared with 2040. In the sensitivity, production from reformers with CCS thus increases progressively throughout the outlook period. This is due to a different balance in carbon capture and storage. Greater potential of biomass and resort to BECCS lead to lesser needs for DACCS and allow for additional carbon capture from other sources, including hydrogen production from reformers with CCS. Hydrogen production from electrolyzers ends up 20% lower and hydrogen imports are some 25% lower. Biomass with CCS confirms its bigger role in the hydrogen production outlook, doubling its long-term contribution to more than 10 Mt.

Figure 60. Evolution of hydrogen production by technology in the Technology Diversification pathway and the sensitivity on bioenergy potential, 2030 to 2050



Source : *Hydrogen for Europe* study

223. These changes lead to slightly different numbers regarding cumulative investment in the hydrogen value chain. Total cumulative investments in the hydrogen value chain are lower in the sensitivity. They stand at around €2.9 trillion, which is around €0.2 trillion less than cumulative investments in the Technology Diversification pathway, with marked decreases in investments in all categories except biomass. The overall energy system cost, discounted over the outlook period, is about €2.5 trillion (-2.5%) lower in the sensitivity than in the Technology Diversification pathway.

7 Annex B: Technical overview of the modelling framework

7.1 The modelling framework

7.1.1 Modelling setup

224. The Hydrogen for Europe project is based on a quantitative modelling-based analysis that entails the representation of the European energy system and its transition until 2050 under the EU decarbonization targets. The modelling architecture relies on a detailed European energy system model (MIRET-EU) and an optimized learning model (Integrate Europe), two state-of-the-art partial-equilibrium models enhanced specifically to tackle the objectives of this study:

- At a first level, a detailed view considering country specificities in Europe is provided by the MIRET-EU model, developed by research center IFPEN. It is a version of the well-known TIMES/MARKAL family used by the International Energy Agency (IEA) within the ETSAP program. It is a bottom-up prospective model providing a country level representation of the entire European energy system. This version of TIMES pays particular attention to the integration of renewables in the energy and transport sectors, including aspects related to infrastructure, life cycle assessment and availability of strategic materials, under ambitious climate constraints and evolving energy demand[67].

- At a second level, the Integrate Europe model from research center SINTEF focuses on accurately representing the temporal dynamics of the energy system to optimize the investment decisions. It is a tool that combines different optimization techniques (i.e. dynamic programming for investment decisions coupled with linear programming for operations) to capture path dependencies and cumulative effects such as endogenous learning and associated cost decreases. It is used to calculate optimal investment pathways which minimize total system costs, taking into account the influence that learning effects from early investments can have on the decrease of future costs for various technologies.

225. The modelling framework implies soft- linking the two models to represent in detail the European energy system and its evolution until 2050. They are calibrated to optimize system operations and capacity expansion decisions under a total system cost minimization, here enabling to assess the cost-optimal pathways towards the EU decarbonization objectives in 2030 and 2050. Their technical capabilities and complementarity are leveraged to provide detailed insights on the spatial and temporal dimensions, with a large set of technologies considered, and on the impacts future technology learning can have on the optimal decarbonization pathway. This enables to investigate the importance of path dependencies, the associated costs, energy system response and modified risk picture of policies that restricts the optimal transition path, the value of existing infrastructure among other complex questions related to market signals, their timing and their overall efficiency.

7.1.2 Modelling scope

226. As introduced in the previous subsection, the modelling framework combines a detailed and exhaustive representation of technologies, sectors and countries in the detailed energy system model (MIRET-EU model) with an aggregated modelling taking place in the learning optimization model (Integrate Europe model) to study learning-by-doing path dependencies, and feed the results back to MIRET-EU.

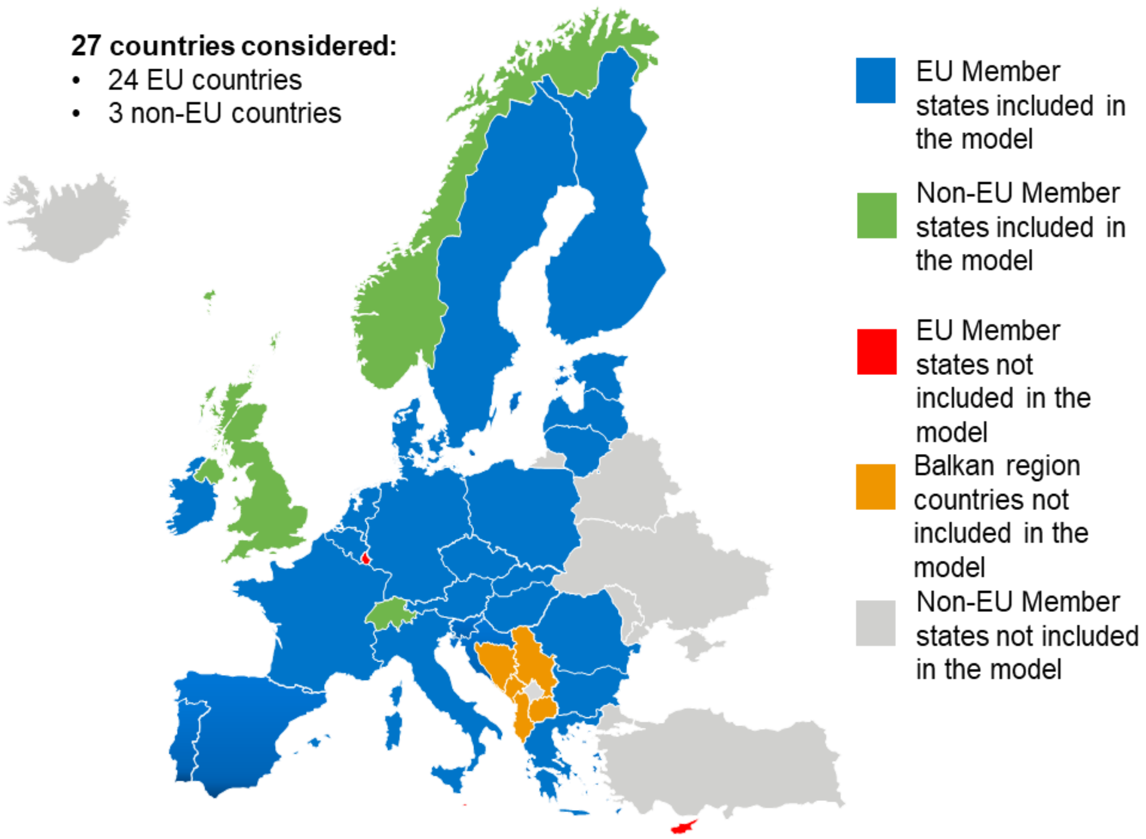
227. At country level, the modelling framework covers 27 European countries (see figure 61) through the MIRET-EU model, which is under development and in continuous improvement at IFPEN[68]. Its perimeter does not coincide with the borders of the European Union: the model notably includes Norway, the United Kingdom and Switzerland. Norway and the United Kingdom are particularly relevant to the study due to their central role in

[67] These are, among others, the capabilities of the MIRET model tested on previous projects by IFPEN. However, a life cycle assessment and the assessment of demand of strategic materials are out of the scope the study.

[68] MIRET has been based on the TIMES model generator, developed by one of the IEA implementing agreements (ETSAP) in 1997 as a successor of the former generators MARKAL and EFOM with new features for understanding and greater flexibility. The manuals and a complete description of the TIMES model appear in ETSAP documentation (https://iea-etsap.org/index.php/documentation)

the European gas economy. Both are European gas producers, and both have already carried out extensive research and demonstration projects on hydrogen and CCS[69]. The model linking is done in such a way that all quantitative results are available for each of the 27 countries in the MIRET-EU scope. This enables a complete overview of the European strategy for decarbonization and hydrogen deployment and the drivers for country-related specificities.

Figure 61. Geographic coverage of the *Hydrogen for Europe* project



228. At the technical level, MIRET-EU provides a disaggregated representation of the energy system. It takes into account all the steps from primary resources to the transformation, distribution and conversion of energy to final energy consumption, providing a highly detailed representation of technologies and energy carriers at the supply (import, processing and transformation into secondary energy carriers), transportation and storage, and demand (residential, commercial, agricultural, transport and industrial sectors) sides. Those technologies and energy needs are condensed into an aggregated energy system in the Integrate Europe model, comprising a list of discrete '*investment packages'* which serve for the capacity expansion least-cost optimization.

229. A simplified overview of the main categories of technologies and end-uses represented in the models is provided in table 4. The listed elements are disaggregated into more exhaustive components within the models, according to the level of detail suitable within MIRET-EU and Integrate Europe. The articulation between the two models in the Hydrogen for Europe study allows to benefit from all results at the most disaggregated scale possible.

230. As seen in table 4, import of hydrogen is included into the modelling framework on the same terms as fossil fuels and biomass. However, unlike for the latter energy commodities, hydrogen prices from abroad have been estimated following a merit order logic based on the LCOH metric to build import supply curves. The estimates

[69] On the other hand, Luxemburg, Malta and Cyprus are excluded due to their small size and marginal status within the internal European energy system

include production cost and transport cost from non-European production sites to entry points in Europe. The methodology follows the principles of CO_2 neutrality of EU energy imports and technology neutrality on the supply side. The hydrogen import option thus comprises clean hydrogen imported from North African countries, Middle East and Russia, where the hydrogen is produced both from dedicated off grid renewable energy and from methane with abated CO_2 emissions.

Table 4. Aggregated overview of the technological scope[70]

Primary energy supply	Energy transformation	Final energy supply	End-use sector
Lignite (resources and import) Oil (resources and import) Coal (resources and imports) Natural gas (resources and imports) Bioenergy Solar energy Wind power	Electricity production CHP sector Electrolysis Biomass gasification Methane pyrolysis Methane reforming Liquefaction Coal processing Refineries Gas network …	Electricity Hydrogen Coal Natural gas Oil Bioenergy Other final RES	Residential Commercial Industry Transport (road, rail, aviation, maritime[71]) Agriculture

+ Representation of CCUS routes (direct air capture or carbon capture, CO_2 use and storage)
+ Representation of electricity, natural gas and hydrogen storage

7.2 Focus on the models

7.2.1 The MIRET-EU model

231. MIRET-EU is a multiregional and inter-temporal partial equilibrium model of the European energy system developed by IFPEN, based on the TIMES[72] model generator. A complete description of the TIMES model equations appears in the ETSAP[73] documentation. It is a bottom-up techno-economic model that estimates the energy dynamics by minimizing the total discounted cost of the system over the selected multi-period time horizon through powerful linear programming optimizers. The components of the system cost are expressed on an annual basis while the constraints and variables are linked to a period. Special care is taken to precisely track cash flows related to process investments and dismantling for each year of the horizon. The total cost is an aggregation of the total net present value of the stream of annual costs for each of the model's countries. It constitutes the objective function (Eq. 1) to be minimized by the model in its equilibrium computation. A detailed description of the objective function equations is provided in Part II of the TIMES documentation (Loulou et al., 2016). We limit our description to giving general indications on the annual cost elements contained in the objective function:

- Investment costs incurred for processes;
- Fixed and variable annual costs,
- Costs incurred for exogenous imports and revenues from exogenous exports;
- Delivery costs for required commodities consumed by processes;

[70] This overview presents a simplified representation of the energy sector as modelled in the Hydrogen for Europe study. The detailed energy system representations of MIRET-EU and Integrate Europe are provided in sections 9.1 and 9.2.
[71] Only within Europe.
[72] MIRET has been based on the TIMES model generator, developed by one of the IEA implementing agreements (ETSAP) in 1997 as the successor of the former generators MARKAL and EFOM with new features for understanding and greater flexibility. The manuals and a complete description of the TIMES model appear in ETSAP documentation (https://iea-etsap.org/index.php/documentation)
[73] Energy Technology Systems Analysis Program. Created in 1976, it is one of the longest running Technology collaboration Programme of the International Energy Agency (IEA). https://iea-etsap.org/index.php/documentation

- Taxes and subsidies associated with commodity flows and process activities or investments;

$$NPV = \sum_{r=1}^{R} \sum_{y \in YEARS} (1 + d_{r,y})^{REFYR-y} * ANNCOST(r,y) \qquad \text{(Eq. 1)}$$

NPV is the net present value of the total cost for all regions (the objective function);

ANNCOST(r,y) is the total annual cost in region *r* and year *y* (more details in section 6.2 of PART II (Loulou et al., 2016)

$d_{r,y}$ is the general discount rate;

REFYR is the reference year for discounting;

YEARS is the set of years for which there are costs, including all years in the horizon, plus past years (before the initial period) if costs have been defined for past investments, plus a number of years after end of horizon (EOH) where some investment and dismantling costs are still being incurred, as well as Salvage Value; and

R is the set of regions/countries in the area of study.

232. MIRET-EU represents the European energy system divided into 27 countries. It is set up to explore the development of its energy system from 2010 through to 2050 with 10-year steps and is calibrated on the latest data provided by energy statistics such as the JRC-IDEES[74] database, POTEnCIA[75] database, EUROSTAT database, and other international database from IEA, IRENA, World Bank, among others. In MIRET-EU, we consider four seasons (spring, summer, autumn, winter) disaggregated into day, night and peak resolution as is also the case in our world multiregional model TIAM-IFPEN. Every year is therefore divided in twelve time-slices that represent an average of day, night and peak demand for each season of the year (e.g. summer day, summer night and summer peak, etc.).

233. The MIRET-EU model is data driven[76], its parameterisation refers to technology characteristics, resource data, projections of energy service demands, policy measures, etc. (Loulou et al., 2016). This means that the model varies according to the data inputs while providing results such as technology pathways or changes in trade flows for policy recommendations. For each country, the model includes detailed descriptions of numerous technologies, logically interrelated in a Reference Energy System – the chain of processes that transform, transport, distribute and convert energy into services from primary resources and raw materials to the energy services needed by end-use sectors (see Section 0).

234. A few models have already been developed at European scale using the TIMES model over the last 15 years. The Pan-European TIMES (PET) model has been developed by the Kanlo team following a series of European Commission (EC) funded projects (NEEDS[77], RES2020[78], REACCESS[79], REALISEGRID[80], COMET[81], Irish-TIMES[82]) between 2004 and 2010. It represents the energy system of 36 European regions. The JRC-EU-TIMES model is one of the models currently pursued and developed in the Joint Research Centre (JRC) of the European Commission under the auspices of the JRC Modelling Taskforce. The JRC-EU-TIMES model was developed as an evolution of the Pan European TIMES (PET) model of the RES2020 project, followed up within

[74] JRC-IDEES (Integrated Database of the European Energy System) has been released in July 2018 and is revised periodically. We then used the latest data released in September 2019.
[75] POTEnCIA (Policy-Oriented Tool for Energy and Climate change Impact Assessment)
[76] Data in this context refers to parameter assumptions, technology characteristics, projections of energy service demands, etc. It does not refer to historical data series
[77] http://www.needs-project.org/
[78] http://www.cres.gr/res2020
[79] http://reaccess.epu.ntua.gr/
[80] http://realisegrid.rse-web.it/
[81] The final aim of the modelling tasks in the research project COMET is the evaluation of different possible developments of CCS using a hard-link approach of TIMES-Morocco, TIMES-Portugal, TIMES-Spain, and TIMES-CCS. http://rdgroups.ciemat.es/documents/10907/86733/Comet_12Dec.pdf/b29424d6-1287-4644-9192-c2994daef02e
[82] https://www.epa.ie/pubs/reports/research/climate/Irish%20TIMES%20Energy%20Systems%20Model.PDF

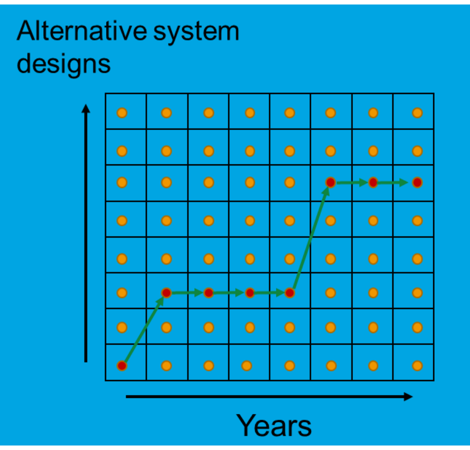
the REALISEGRID and REACCESS European research projects. In fact, the detailed residential, services and hydrogen modules of the JRC-EU-TIMES have been incorporated to the MIRET-EU. Therefore, the modelling framework of MIRET-EU follows the same framework developed successively in the PET36, the JRC-EU-TIMES, MIRET-FR[83] and TIAM-IFPEN[84] models with additional expertise from IFP Energies Nouvelles in specific sectors such as transport, refineries and bioenergy conversion technologies, hydrogen infrastructure, power sector and industry.

7.2.2 The Integrate Europe model

235. Integrate Europe is an in-house model developed by SINTEF for planning complex energy systems[85]. The model can optimize the investments in infrastructure for most relevant energy carriers, including electricity, heating, cooling, natural gas, hydrogen, waste, and biomass, including conversions between these. The main energy component types are sources, conversion, storage, transport/distribution, end-use and markets. For the Hydrogen for Europe study, we have developed a new set of components, which also include end-use technologies for the mapping between energy carriers and the need for various energy services by specific technologies.

236. The main task of the model is to optimize investments over a planning horizon of several decades to bring available energy to the end user in such quantities and in such form that the end user demands are covered in the best economic way possible, that conforms with enacted regulation e.g. the CO_2 emission reduction targets. The model performs a system optimization, minimizing the total present value of all costs. The energy system costs are minimized by considering both investment (CAPEX) and operational costs (OPEX). The latter is assessed by optimization of diurnal operations for different seasons of the year for each alternative system design. This operational optimization run prior to investment optimization and is based upon linear programming (LP). Optimization of investments is performed via dynamic programming (DP).

Dynamic programming is used to calculate the optimal expansion plan for energy infrastructure in Integrate Europe. Each point on the vertical axis corresponds to one possible state of the energy system, and the green lines denote the optimal transition between such states as a function of time for a given path from e.g. 2020-2050.



237. Integrate Europe is used specifically in the Hydrogen for Europe study to analyse the impacts of technology learning on the cost-effective transition to an emission-free European energy system. Examples of central technologies are hydrogen production technologies such as electrolyzers, biomass- or natural gas-based reforming with integrated CO_2 capture, and methane pyrolysis. To unlock this analytical capability and avoid computational hurdles, the energy system is represented at a European level and by aggregation of technologies into main categories. In addition, the main investment options to be analysed are bundled into pre-defined *'investment packages'* which compete with each other within the dynamic programming module. The characteristics and investment breakdown within each package are calibrated mainly on the basis of cost-data for included technologies, results from MIRET-EU's simulations and other stand-alone assumptions. The included quantities in the packages were also tuned by running the model many times.

[83] MIRET-FR is the version developed and maintained for France by IFPEN since 2008.

[84] TiAM-IFPEN (TIMES Integrated Assessment Model) is the world version currently developed by IFPEN since 2018.

[85] "Linear models for optimization of interconnected gas and electricity networks", Bakken and Mindeberg, 2009. "Integrate Europe: Investment planning in energy supply systems with multiple energy carriers", Bakken, Skjelbred and Wolfgang, 2007.
" Linear Models for Optimization of Infrastructure for CO_2 Capture and Storage" Bakken and von Streng Velken, 2008.

7.2.3 The Hydrogen Pathways Exploration model (HyPE)

238. The HyPE model provides the main energy system and learning models with hydrogen export potentials from neighboring regions to represent competition between domestically produced hydrogen and imports. In line with the European hydrogen strategy, only low-carbon and renewable hydrogen imports are considered, with a focus on North Africa, the Middle East and Russia.

239. The model estimates hydrogen import supply curves, indicating both the potential of hydrogen production per region and the associated costs, following a levelized cost of hydrogen approach (LCOH[86]). The LCOH is calculated for each delivery point in Europe (Cost, Insurance and Freight[87]). The methodology builds on the full delivery value chain from the hydrogen production site to determine LCOH at each entry point in Europe.

240. In the upstream, depending on resource endowments, all hydrogen production technologies and their associated cost evolutions are considered as possible for exports. A country-specific risk consideration was included as a mark up to the weighted average cost of capital (WACC) of each country based on the Ease of Doing Business scores (WB 2020). In the midstream, the transport modes cover inland transport for the distance from production site to exit point in each country of origin (i.e. by national pipelines, gasified hydrogen trucks and/or ammonia trucks), and international transport for the distance from the exit point, in the producing country, to the entry in Europe (i.e. by cross-border pipeline interconnectors and/or maritime shipping routes). The optimal combination between the transport mode, the distances and the flows are obtained by an optimization approach resulting in least-cost LCOH CIF import curves.

7.3 Strengths, weaknesses and opportunities of the models related to the goals of the study

7.3.1 Capabilities and limits of the MIRET-EU model

241. MIRET-EU is an economic model with a rich technology representation for estimating capacity investment pathways over the long term. It combines two different, but complementary, systematic approaches to energy system modeling: a technical engineering approach and an economic approach. TIMES[88] uses linear-programming to produce a least-cost energy system, optimized across regions and sectors according to a number of user constraints, over medium to long-term time horizons. This unique objective function guarantees the internal consistency of the resulting scenario, as the decision criteria are the same for all processes and flows. These types of models are effective for assessing long-term investment decisions in complex systems where future technologies are different from current technologies. The TIMES model assumes perfect foresight over the entire horizon, i.e. all investment decisions are made in each period with full knowledge of future events. This technology-detailed model provides insights to decision-makers regarding energy systems in order to determine which technologies are competitive, marginal or uncompetitive in each market according to dynamic economic cost-benefit analyses. In short, MIRET-EU is used for "the exploration of possible energy futures based on contrasted scenarios" (Loulou et al., 2016). The time horizon of MIRET-EU is 2010-2050 and the base year 2010 is calibrated to energy statistics such as JRC-IDEES, POTEnCIA[89], EUROSTAT, and other international database from IEA, IRENA, World Bank, among others.

[86] The levelized cost of hydrogen (LCOH) adopts the life cycle costing methodology where all related costs and produced quantities are included to compute an average ratio of cost per kilogram produced.
[87] The cost, insurance and freight view (CIF) includes the cost of transport and logistics from the exit point to the entry point in Europe.
[88] MIRET has been based on the TIMES model generator, developed by one of the IEA implementing agreements (ETSAP) in 1997 as a the successor of the former generators MARKAL and EFOM with new features for understanding and greater flexibility. The manuals and a complete description of the TIMES model appear in ETSAP documentation (https://iea-etsap.org/index.php/documentation)
[89] POTEnCIA (Policy-Oriented Tool for Energy and Climate change Impact Assessment)

242. As a partial equilibrium model, MIRET-EU does not model economic interactions outside the European energy sector. As stated by Gielen and Taylor (2007), this type of model, based on TIMES generator, has the following advantages:

- The model is based on a single objective cost criterion.
- A detailed technology-rich modeling paradigm from primary resources to end-uses
- Stock turnover is considered explicitly.
- Provide options to decision makers regarding energy systems over medium to long-term time horizons
    - Economically affordable
    - Technically feasible
    - Environmentally sustainable
- The model is well suited to the development of Energy Roadmaps by making explicit the representation of technologies and fuels in all sectors in order to anticipate achievable futures based on actual knowledge. This is relevant for investment decisions in complex systems with differences between existing and future technologies.
- The model optimizes operation and investment decisions based on the characteristics of alternative generation technologies, energy supply economics, and environmental criteria. TIMES is thus a vertically integrated model of the entire extended energy system.
- The scope of the model extends beyond purely energy-oriented issues, to include the representation of environmental emissions, and materials, related to the energy system. In addition, the model is suitable for the analysis of energy-environmental policies, which may be accurately represented by making explicit the representation of technologies and fuels in all sectors.
- The great flexibility of TIMES, especially at the technological level, allows the representation of almost all policies, whether at the national, sectoral, or subsectoral level.
- The model is driven by explicit exogenous final energy services demand and fuel prices.

243. On the other hand, it could be pinpointed some limitations inherent to this type of model:

- MIRET-EU is data consuming; therefore, data availability could limit the scope and depth of possible analyses.
- Moreover, there is no explicit representation of macro-economic factors which means no feed-back loops between the effects of energy system changes and the economy[90].
- As all models are simplified representations of reality and its complex dynamics, they inherently have limitations as to the detail and scope of their mathematical representation. These simplifications, e.g. time and spatial resolution, sector or technology representation and system boundaries, which are mostly due to the data availability, may represent significant modeling limitations.
- Long computational times could be observed due to a very detailed representation of complex energy system.
- The model is sensitive to the data assumptions for emerging technologies which are by definition more uncertain, and decision makers in practice do not always balance efforts across regions and sectors.
- Decision making that conditions investment in new technologies is often not rational[91], however representing non-rational decisions could be done via exogenous constraints. This does not allow capturing in detail all the aspects related to consumer behaviour, which play a fundamental role in decision-making processes. As highlighted by Gielen & Taylor (2007), even if decision making is rational, it is often not based on least-cost criteria. Policy rationality may stress effectiveness, equity issues, timing, risk and other factors that are not accounted for in this framework.
- The optimistic view of the future due to the perfect foresight approach which does not account for real-world uncertainty. However, it is possible to implement via the model to have foresight over a limited part of the horizon, such as one or a few periods or to temper it by using higher discount rates. By so doing, a modeler may attempt to simulate "real-world" decision making conditions, rather than socially optimal ones (Loulou et al., 2016)

[90] However, they could be considered exogenously through the price elasticities of service demands.
[91] In a strict economic sense.

- In this study, there is no disaggregation by plant size unlike in the MIRET FR model (France) due to a lack of data and the consequences of so doing on computational time. This implies, as a simplification, that all installations in industry and CHP are considered as falling within the scope of the EU ETS Directive.
- Reconciliation of the very short-term physical dynamics (e.g. integrating system adequacy, transient stability analysis in the power sector) into long-term prospective models such as MIRET-EU.

7.3.2 Capabilities and limits of the Integrate Europe model

244. The Integrate Europe model brings to the modelling framework its capability to account for learning-by-doing effects and the impacts on the overall cost-efficiency in the energy transition. A model based on linear programming would not be able to account for technology cost reductions due to past investments: instead, it would depend upon a forecast for the future cost reductions for a technology given exogenously to the model. Hence, it would tend to be locked into pathways based on existing technologies and postpone investments in promising technologies until they become more competitive in the future, even though the early investments in such technologies are an essential factor for driving down the costs in practice. By using Integrate Europe cost reductions through learning are included in the investment optimization, and hence consistent for each investment pathway considered.

245. An additional advantage of Integrate Europe is how it shows the solution space after ended calculations. The model reports the results for several (typically up to 20) of the allowed pathways, including the optimal solution. This allows for assessing the sensitivity of the optimal solution, and for estimating the additional costs of choosing a non-optimal investments pathway. Integrate Europe is an in-house software making it possible to adapt it according to needs and enable a transparent and open model specification.

246. One of the main challenges behind quantitative modelling is the level of complexity in relation with input needs and the computational time required. The main limitations for the Integrate Europe itself within this study are:

- Aggregated representation regarding geographical and element resolutions. Element resolution here refers to the number of technologies, sectors, and energy carriers included in the model. Integrate Europe indeed considers Europe as an aggregated region without geographical resolution at the country level. This implies the need for a special treatment of transport capacities and regional differences within Europe. It is also necessary to perform a second aggregation with respect to the representation of technologies compared to MIRET-EU which has a very detailed technology database.
- Limitation in the number of different investment packages that can be specified for dynamic programming optimization, and thus a need for bundling several technologies and corresponding capacities, specified *ex ante*. While the packages are set up to focus on the issues that are most important to the project, the bundling means that some dynamic effects cannot be represented. Notably, the competition between the technologies within a package are omitted in the investment algorithm itself, but it is dealt with in designing the packages.
- Learning-by-doing is included only for the supply-side of the energy system. Furthermore, the computational complexity only allows to study endogenous learning effects for a limited set of the most relevant technologies. For this reason, some technologies with relatively less learning potential, and end-use technologies are treated differently using a linear programming levelized cost approach.

7.4 The model linking strategy

247. The modelling framework capitalizes on the strengths and synergies between MIRET-EU and Integrate Europe. On the one hand, MIRET-EU provides a robust and proven methodology based on linear programming for the representation of the energy system, with a very high level of detail on hydrogen technologies and all other parts of the value chain. This enables to model the European energy system in all its complexity at country level. On the other hand, Integrate Europe is used to explore more finely the dynamics of the transition, using dynamic programming to analyze endogenous technology learning of different decarbonisation strategies. Together, they enable to represent finely the energy system's evolution and the potential for the different technologies at country level, account for endogenous investment and cost reduction and avoid lock-in effects

in terms of chosen technologies. Their combination allows to overcome the technical boundaries and computational limits which would characterize each model when taken separately.

248. One particular issue that the modelling framework addresses regards the dynamics and non-convex optimization in Integrate Europe, and the degree of simplification in detail and scope required to reduce computational time and allow for a tractable problem. The model combination here considered, also called *soft-linking*, consists of an iterative process between MIRET-EU, Integrate Europe and HyPE. Initially, the models are aligned by comparing the results of the detailed analysis in MIRET-EU at sector and country level with the results from Integrate Europe. The Integrate Europe model is subsequently adapted to ensure the coherence of its aggregated representation of the energy system. When alignment is reached, the dynamic analysis is performed by Integrate Europe and the resulting investment and cost trajectories for the supply side are sent to HyPE for estimating the potential hydrogen imports, and to MIRET-EU for the disaggregated optimization.

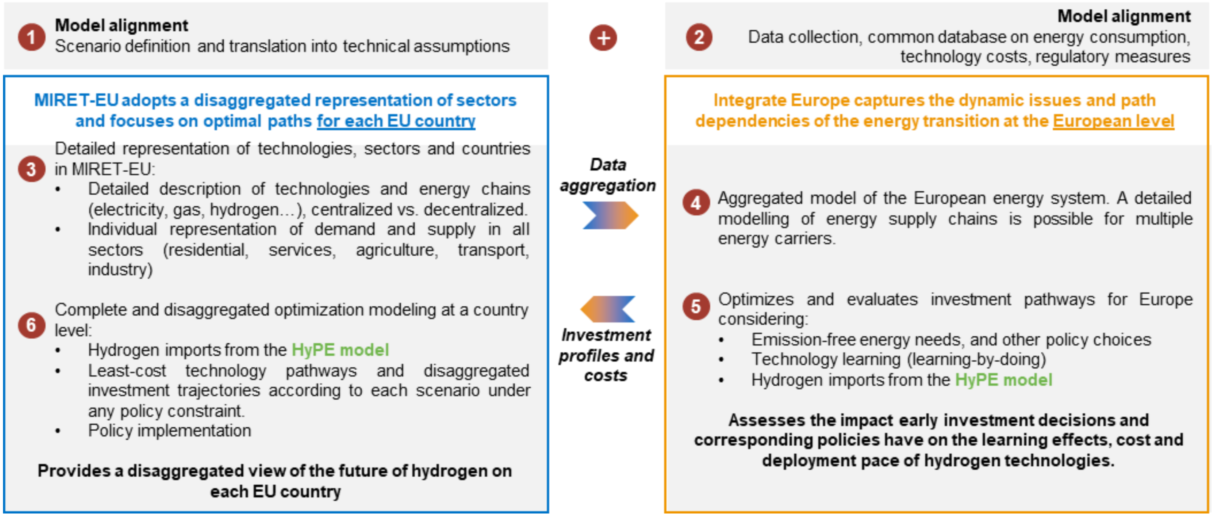
249. The modelling workflow and linking between the HyPE, MIRET-EU and Integrate Europe models can be summarized as follows:

- The first link between the models is done by representing the same technologies and end-uses in Integrate Europe and MIRET-EU, collecting a comprehensive and common data set and enabling a detailed representation of technologies, end-uses and countries in the models (figure 62, steps 1 to 3).
- The Integrate Europe model focuses on a detailed representation of the dynamics of the system including non-convexities. For that reason and to avoid computational hurdles, the modelling strategy then consists in a technology-wise and geographically wise data aggregation step (step 4)[92]. The aggregation is performed such that the geographical resolution consists of a single node, while the technologies are aggregated into the most relevant technologies for each production and conversion category on the supply side. The *investment packages* consist of aggregated sets of available investment options to be represented and studied in the Integrate Europe model in terms of endogenous cost reduction.
- The Integrate Europe model is then run to obtain optimal investment capacities and cost evolutions including detailed learning effects[93] (step 5). Cost evolutions are sent to HyPE for estimating the cost curves of hydrogen imports.
- For the technologies included in the investment packages, optimized capacities are sent back as EU-level aggregated constraints to MIRET-EU, which disaggregates them again (by country and technology) and takes them into account for the optimization of the European energy system up to 2050 (step 6). The corresponding Integrate Europe cost evolutions, and cost curves of hydrogen imports are also applied in the optimization of MIRET-EU.

250. In the end, this modelling strategy allows to consider the country, sector and end-use allocation of energy production, consumption storage and flows, the resulting CO_2 emissions and their trajectories towards 2050.

[92] See section 9.2 for a full description of the aggregation strategy.
[93] These results reflect an optimal decision rule on the sense of Bellman's principle of optimality: where a dynamic process defined by an additive performance criterion can be reduced to local evaluations of sequential stages for evolving subprocesses, the optimal decision rule (strategy) is defined as the sequence of decisions that are optimal with respect to its own subprocess's initial conditions and the corresponding number of stages.

Figure 62. Modelling framework of the Hydrogen for Europe study



Source : Hydrogen Europe study

251. This linking procedure allows to enhance each individual model's scope and to foster synergies between them. Each scenario and set of sensitivities considered is simulated following this workflow. It enables to compare and quantitatively assess the effects of the underlying assumptions relative to each of them.

8 Annex C: main assumptions and scenarios

252. Scenarios and assumptions are needed together with the modelling framework to complete the study framework. The scenarios are set up such as to provide meaningful insights to the research questions. Hence, they must be carefully chosen to span different transition pathways to provide a suitable basis for the analysis. The baseline assumptions are pre-defined and not calculated as a part of the simulations. These are thus an important part of the context of the study. Sensitivity analyses are carried out to complement the main results and provide information on their robustness.

8.1 Baseline assumptions

253. Baseline assumptions are implemented for macroeconomic parameters, commodity prices and energy demand projections. To this end:

- Main macroeconomic drivers (population growth and GDP) have been collected from the JRC assumptions under the EU Reference 2016 scenario.
- Oil, natural gas and coal prices are based upon the trajectories of the EU Reference scenario 2016 as considered by the JRC in their energy models. However, an update was made based on 2020 prices to take into account the COVID-19 effect[94]. The research centers have compared this EU reference 2016 scenario of the JRC to the different IEA scenarios' baseline assumptions: the retained trajectory is between the Sustainable Development (SDS) and Stated Policies (SPS) scenarios of the IEA World Energy Outlook, 2019 (WEO, 2019).
- The Energy demand projections have been extracted from the JRC-EU-TIMES in order to consider an identical and unique public European database within the consortium. The sectorial (industry, residential and services, and transports) demand assumptions are based on data from JRC-POTEnCIA central scenario (2019). The demand of the energy intensive industrial sectors is defined in the model through production amount while the non-energy intensive sectors have their demand represented in energy terms. Residential and services sectors have their demands characterized in energy terms by use, i.e., space heating, cooling, water heating and cooking/catering. The transport sector has its demands represented by passengers and freight activities (road transports, rail/metro/tram, and aviation). It is worth mentioning that these data still do not take into account the global situation currently experienced with Covid-19, which will possibly result in the reduction of the European industrial production and a drop in its energy demand, as well as will bring changes in the energy demand of the residential and service sectors, and in the transport activity.

The table 5 and table 6 together with figure 63 presents details of the baseline assumptions.

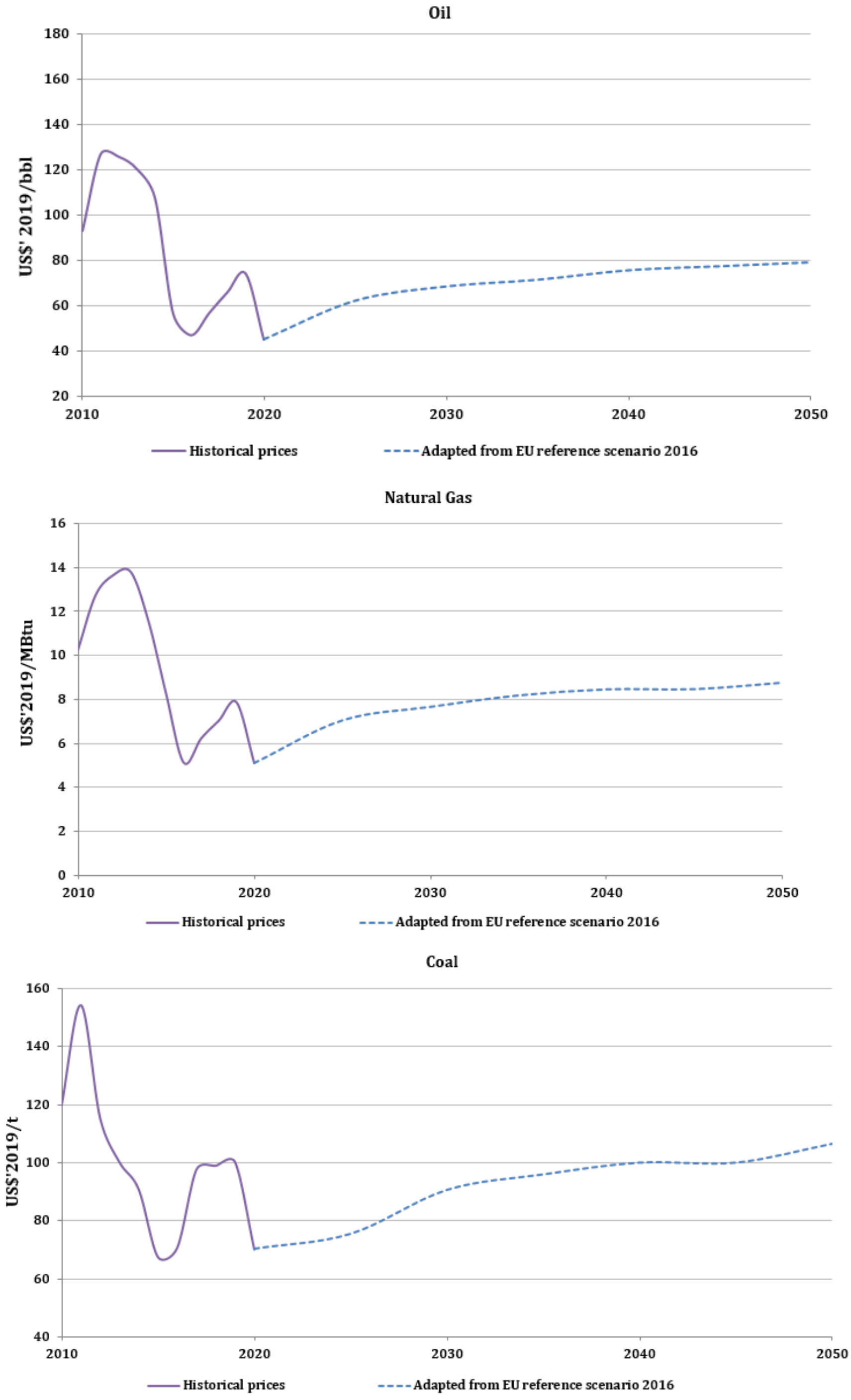
Table 5. Macroeconomic data and energy commodity prices evolution

	Scenario	Period					
		2020-2025	2025-2030	2030-2035	2035-2040	2040-2045	2045-2050
Population average annual growth rate	EU Reference 2016	0,10%	0,10%	0,10%	0,10%	0,10%	0,10%
GDP average annual growth	JRC POTEnCIA 2019	1,43%	1,28%	1,26%	1,34%	1,48%	1,54%
Fuel prices average annual	Crude Oil	6,64%	1,95%	0,85%	1,15%	0,46%	0,45%
	Coal	1,42%	3,72%	1,15%	0,83%	0,00%	1,27%
	Natural Gas	6,66%	1,69%	1,32%	0,67%	0,02%	0,69%

Source: JRC-EU-TIMES, JRC POTEnCIA 2019, Authors

[94] This is only a datapoint estimation from Reuters (2020); Argus (2020)

Figure 63. Evolution of oil, coal and natural gas prices



Source: Adapted from JRC POTEnCIA 2019 (EU Reference 2016)

Table 6. Demand projections

Sectors		2020	2025	2030	2035	2040	2045	2050
Industry								
Energy intensive sectors production (Mton)	**Iron and Steel**	180.0	181.1	180.4	179.3	178.7	178.1	177.5
	Cement	186.5	190.4	194.1	197.4	200.7	204.1	201.0
	Pulp and paper	112.5	119.5	123.7	125.6	126.6	128.3	130.8
	Ammonia	16.0	16.3	16.5	16.7	16.8	16.9	17.1
	Chlorine	10.3	10.5	10.6	10.6	10.7	10.8	10.9
	Pulp & paper	112.5	119.5	123.7	125.6	126.6	128.3	130.8
	Lime	28.2	29.7	31.1	32.3	33.5	34.5	35.4
	Glass	37.2	37.7	37.7	37.7	37.6	36.8	35.2
	Copper	0.25	0.24	0.26	0.26	0.26	0.26	0.27
	Aluminium	7.5	7.6	7.8	7.9	7.9	7.9	7.9
Non-energy intensive sectors energy demand (PJ)	**Other Non-Ferrous Metals**	354.3	357.9	367.6	370.8	375.0	378.7	382.0
	Other Non-metallic mineral products	622.6	658.6	693.7	723.0	753.6	779.6	803.1
	Other Chemicals	2 110.6	2 236.8	2 363.9	2 496.4	2 639.8	2 777.1	2 915.3
	Other industrial sectors	3 900.0	4 102.2	4 314.6	4 545.4	4 793.3	5 044.1	5 308.1
Agriculture								
Energy service demand (PJ)	**Energy demand**	1 164.5	1 170.8	1 174.8	1 179.1	1 183.4	1 185.8	1 188.1
Residential and Services								
Number of households (000units)	**Number of households**	184 554	188 401	192 329	196 338	200 431	204 609	208 875
Services surface evolution (Mm2)	**Services surface**	6 638.6	6 788.4	6 941.5	7 098.2	7 258.3	7 422.1	7 589.6
Electric appliances (Million Appliances)	**Residential electric appliances**	4 995.1	5 102.9	5 212.8	5 312.9	5419.1	5524.3	5633.9
	Services electric appliances	150 321	158 730	167 553	174 018	180839	187598	194540
Transport								
Passenger transport activity (1000 mio pkm)	**Road transport**	7 012.9	7 280.9	7 565.7	7 800.5	8 013.0	8 212.6	8 383.0
	Rail, metro and tram	626.2	682.9	733.5	782.5	834.2	882.0	929.7
	Aviation	1 786.0	1 982.7	2 184.5	2 380.8	2 598.4	2 781.4	2 961.0
Freight transport activity (1000 mio tkm)	**Road transport**	3 285.2	3 502.9	3 710.5	3 865.8	4 009.1	4 125.5	4 219.6
	Rail transport	515.6	566.8	614.6	653.2	696.2	727.6	755.8
	Aviation	45.5	50.2	54.9	59.5	64.9	69.7	74.3

Source: JRC-EU-TIMES

8.2 Technology-related assumptions

254. The models are built upon a comprehensive dataset containing both economic and technical performance data for all technologies as well as limitations related to certain energy carriers such as biomass, or to technologies such as available area for solar and wind power. The dataset is built from renowned databases and data sources such as the JRC European Commission, the International Energy Agency (IEA), IRENA, BP and the World Energy Council.

255. The inventories of the existing and future technologies are based on JRC data catalogue (IDEES 2018, POTEnCIA 2019, JRC-EU-TIMES (2012, 2019), ENSPRESO 2019, BREFs reports…), IEA data catalogue (IEA 2019b, IEA MoMo model, ETP 2017,...), IRENA (2018), de Vita et al. (2018), ENTRANZE database, KanoRs database (Pan-European TIMES PET36), IFPEN data catalogue (CEDIGAZ, and RafGen model), ETSAP community database and specialized literature.

256. The reference scenario presented by the ENSPRESO database is applied as a restriction of the potential for solar and wind. For biomass, the coherent business as usual reference scenario of ENSPRESO is framing the availability.

257. All assumptions related to regional fossil fuel reserves and trade capacities are implemented along with the regional renewable energy potentials (World Energy Council, BP Statistics, IRENA, ENSPRESO 2019, US Geological Survey, TYNDP (ENTSOG 2020, ENTSOE 2016) and specialized literature). For the power generation sector, the general sources of data are the National Renewable Energy Laboratory (NREL), PLATTS database, IRENA, IEA's World Energy Outlook and specialized literature.

258. The hydrogen production technologies data have been consolidated within the hydrogen for Europe study in collaboration with project stakeholders. The main sources are the H21 North of England report (2018), Blanco et al. (2018a), Blanco et al. (2018b), Sgobbi et al. (2016), Bolat et al. (2014a), Bolat et al. (2014b), Schmidt et al. (2017), NREL Technical report (2009), Parkinson et al. (2018) and Keini et al. (2018). The applied dataset is summarized in table 21 and table 22.

259. The table below summarizes the data types considered and their sources.

Table 7. Data sources – Energy system

Data	Sources
Inventories of existing and future technologies	JRC data catalogue (IDEES 2018, POTEnCIA 2019, JRC-EU-TIMES (2012, 2019), ENSPRESO 2019, BREFs reports,…), IEA data catalogue (IEA 2019b, IEA MoMo model, ETP 2017,..), IRENA (2018), de Vita et al. (2018), ENTRANZE database, KanoRs database (Pan-European TIMES PET36), IFPEN data catalogue (CEDIGAZ and RafGen model), ETSAP community database and specialized literature
Fossil fuel reserves and trade capacities	World Energy Council, BP Statistics, US Geological Survey, TYNDP (ENTSOG 2020, ENTSOE 2016) and specialized literature
Power generation	National Renewable Energy Laboratory (NREL), PLATTS database, IRENA, IEA's World Energy Outlook and specialized literature, POTEnCIA 2019, de Vita et al. (2018), ENSPRESO 2019, IRENA
Hydrogen production technologies	H21 North of England report (2018), Blanco et al. (2018a), Blanco et al. (2018b), Sgobbi et al. (2016), Bolat et al. (2014a), Bolat et al. (2014b), Schmidt et al. (2017), NREL Technical report (2009), Parkinson et al. (2018), Keini et al. (2018).

260. In addition to the more general technical assumptions outlined above, three special technically related constraints have been implemented. These are related to amount of variable renewable energy in the power sector, to the deployment of CO_2 storage and to deployment rate of heat pumps in the residential sector.

- To ensure the reliability of the power grid in each country considered in the study, a restriction of minimum 20% back-up capacity from reliable sources for the electricity production within each country is applied.
- The available injection rates for CO_2 to permanent storage, measured in tonnes per year, has been restricted to 1.0 Gt per year from 2020 to 2040, 1.2 Gt per year in 2045 and 1.4 Gt per year in 2050. The restriction is set based upon the assessment of Ringrose and Meckel (2019), and is included in the aspiration to establish a technology neutral framework for the energy system analysis.
- The potential of heat pumps has been implemented following the latest assumptions from the JRC heat pump analysis. Their techno-economic characteristics have been provided by the JRC database for residential and commercial services

8.3 Policy assumptions

261. The scenarios depicted in the study are not an attempt to forecast the actual development of the European energy system. The modelling framework is nevertheless aligned with the agenda of the European Green Deal and EU pillars and targets, incorporating the main targets for CO_2 emission reductions, share of renewable energy deployment, energy efficiency, and national decisions on the phasing out of coal and nuclear plants for power generation, among others. The following sections outlines the policies implemented in the MIRET-EU and Integrate Europe models.

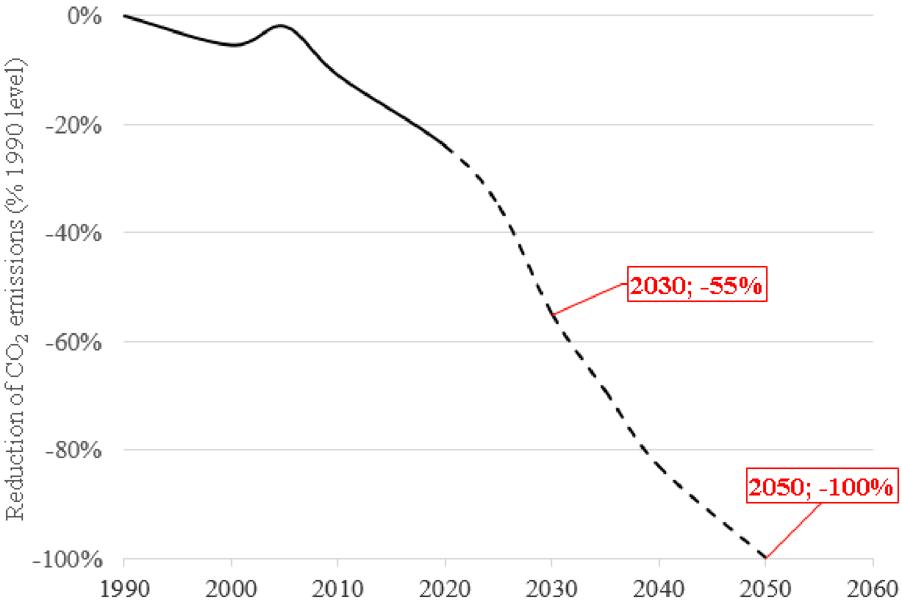
8.3.1 Policy assumptions implemented in MIRET-EU

Overall EU CO_2 emission targets

262. Under the EU's commitment to be climate-neutral by 2050, we model a 100% CO_2 emission reduction (compared to 1990 level) by 2050 at the European level, i.e. a collective constraint[95]. The intermediate emission targets (2020 and 2030) have also been implemented as they have been set as minimum binding legislation to achieve the transformation towards a low-carbon energy system. The 2020 package has set a minimum of 20% cut in emissions (from 1990 levels) by 2020. In 2020, to align with the goals of the European Green Deal, the Commission has raised the EU target to a 55% reduction in 2030. The EU is already on track to meet its emission reduction target for 2020 as, according to latest figures, the emissions were reduced by 23% between 1990 and 2018[96]. Our emission cap constraint assumes a minimum reduction of 24% by 2020 (in line with the latest figures), and 55% by 2030 (in line with the foreseen European Green Deal target) and of 100% by 2050 (figure 64).

[95] The target should be achieved collectively across the EU.
[96] https://ec.europa.eu/clima/policies/strategies/progress_en

Figure 64. CO_2 emission trajectory through to 2050



Source: Consortium Carbon neutrality scenario

The sectors covered by the EU ETS

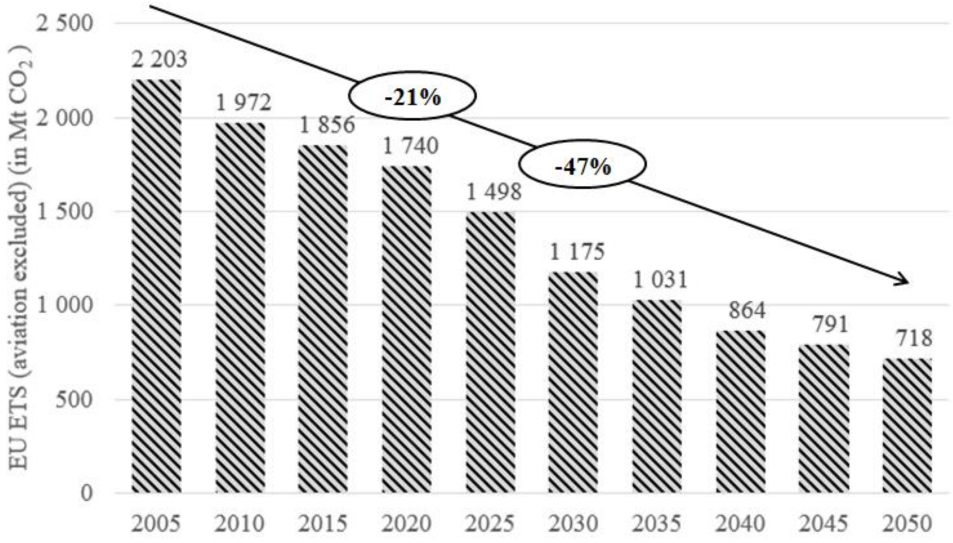
263. The EU emissions trading system (EU ETS) is a cornerstone of the EU's climate change policy and its key tool for reducing greenhouse gas emissions in a cost-effective way. The system covers the following sectors and gases, focusing on emissions that can be measured, reported and verified with a high level of accuracy:

- Power and heat generation
- Energy-intensive industrial sectors including petroleum refineries, steel, aluminium, metals, cement, lime, glass, ceramics, pulp and paper, cardboard, acids and bulk organic chemicals
- Commercial aviation

264. However, only plants above a certain size are included in some sectors and smaller facilities could be excluded if a fiscal or other kind of measures that will cut their emissions by an equivalent amount has been put in place by Member States. Moreover, only flights between airports located in the European Economic Area (EEA) should be considered in the EU ETS until 31 December 2023.

265. Under the Directive 2009/29/EC of the European Parliament and of the Council amending Directive 2003/87/EC, and the Directive (EU) 2018/410 of the European Parliament and of the Council of 14 March 2018 amending Directive 2003/87/EC, emissions from the EU ETS sectors should be reduced by 21% in 2020 compared with the 2005 levels (including aviation), while it should achieve 43% reduction in 2030. In the MIRET-EU model, the EU ETS is only encompassing the emissions from power and heat generation and the industries, while the aviation has been excluded. This assumption has been considered in order to implement the data assumptions of the EU ETS emission limits from the JRC-EU-TIMES. Indeed, the Joint Research center of the European Commission has worked on EU ETS emission reduction trajectory beyond 2030, i.e. until 2050 (figure 65).

Figure 65. Evolution of the CO_2 emissions covered by the EU ETS (aviation excluded) until 2050

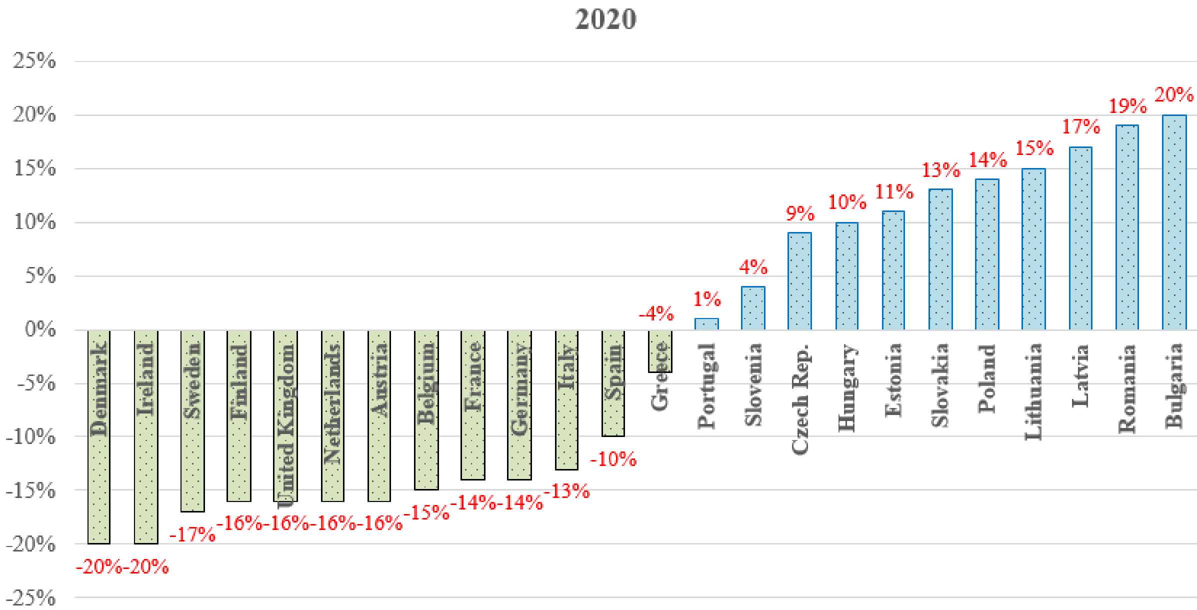


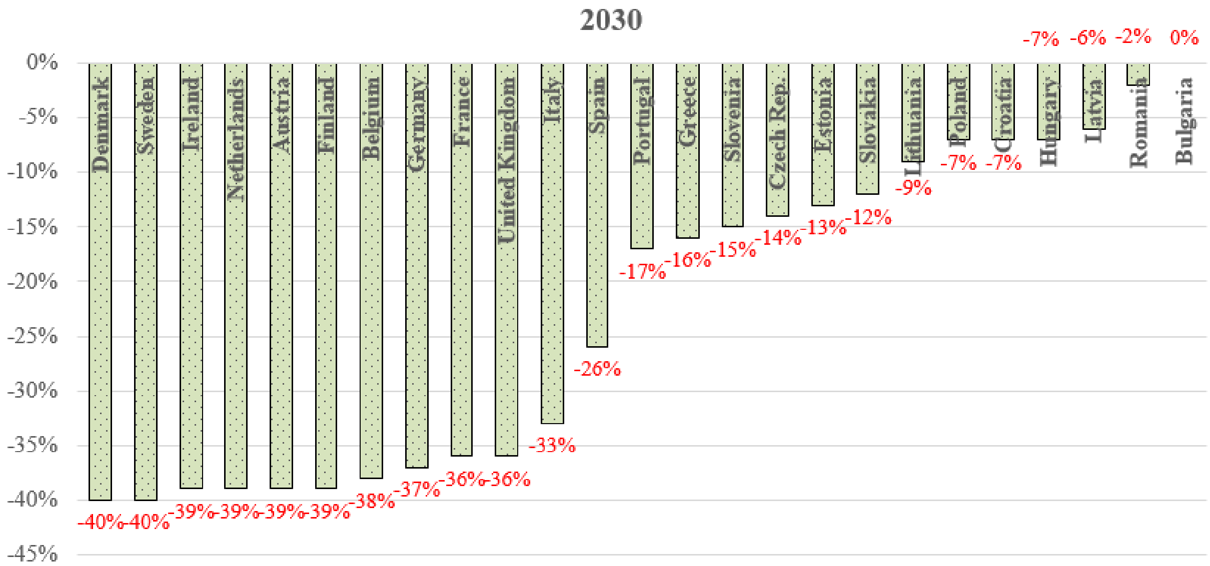
Source : JRC-EU-TIMES

Non-EU ETS sectors

266. The Effort Sharing Regulation (ESR) defines legally binding national GHG emission targets in 2020 and in 2030 compared with 2005 for sectors not covered by the EU ETS excluding LULUCF, such as transport, buildings, agriculture. The national targets for 2020 are ranging between -20% (for the richest Member States) and +20% (for the less wealthy countries) compared with 2005 levels to collectively achieve a reduction of 10% in total EU emissions (Decision No 406/2009/EC). While for 2030 they will range between 0% and -40% compared with 2005 levels in order to achieve collectively 30% reduction of the total EU emissions of the non-EU ETS sectors (Regulation (EU) 2018/842) (see figure 66).

Figure 66. Evolution of non EU ETS emissions (aviation excluded) targets for 2020 and 2030





Source: Decision No 406/2009/EC; Regulation (EU) 2018/842

Cross sectoral energy efficiency targets

267.Energy efficiency measures and targets are a second strand of comprehensive measures in the policy-making of the European Commission. The 2012 Energy Efficiency Directive (2012/27/EU)[97] aims to achieve an energy efficiency of 20% in 2020 for the European Union. In addition, a new target has been set in the new amending Directive on Energy Efficiency (2018/2002)[98] in order to achieve at least 32.5% energy efficiency by 2030. The latter objective thus corresponds to a primary energy consumption not exceeding 1 128 Mtoe (million ton of oil equivalent), or no more than 846 Mtoe of final energy consumption for the European Union in 2030[99].

Energy efficiency targeting the transport sector

268.Regulation (EC) 443/2009 set mandatory emission reduction targets for new cars. The first target fully applied from 2015 onward and a new target phased-in in 2020 and will be fully applied from 2021 onwards. Following a phase in from 2012 onward, a target of 130 grams of CO_2 per kilometer applied to the EU fleet-wide average emission of new passenger cars between 2015 and 2019 is in place.

269.A new target was enacted in 2020, and stipulates that from 2021 onwards the EU fleet-wide average emission target for new cars will be 95 gCO_2/km.

270.On 17 April 2019, the European Parliament and the Council adopted Regulation (EU) 2019/631 setting CO_2 emission performance standards for new passenger cars and for new vans in the EU. This Regulation started applying on 1 January 2020, replacing and repealing Regulations (EC) 443/2009 (cars) and (EU) 510/2011 (vans). The new Regulation maintains the targets for 2020, which were set out in the former Regulations. It adds new targets that apply from 2025 and 2030.

271.Regulation (EU) 2019/631 sets new EU fleet-wide CO_2 emission targets for the years 2025 and 2030, both for newly registered passenger cars and for newly registered vans.

272.These targets are defined as a percentage reduction from the 2021 starting points:

[97] https://ec.europa.eu/energy/topics/energy-efficiency/targets-directive-and-rules/energy-efficiency-directive_en
[98]https://ec.europa.eu/energy/topics/energy-efficiency/targets-directive-and-rules/energy-efficiency-directive_en#content-heading-0
[99] Without the withdrawal of the UK these figures correspond to 1273 Mtoe (million tonnes of oil equivalent) of primary energy and/or no more than 956 Mtoe of final energy.

- 15% reduction from 2025 (which is equivalent to 80.75 grams of CO_2 per kilometer applied for the EU fleet-wide average emission of new passenger cars between 2025 and 2029)
- 37.5% reduction from 2030 (around 60 grams of CO_2 per kilometer applied for the EU fleet-wide average emission of new passenger cars from 2030)

Targets on final energy consumption: the Renewable Energy Directives (RED I and RED II) and the NECPs

273. The European Union Directive 2009/28/EC establishes binding renewable energy targets for each member state for 2020 to collectively achieve at least the share of renewables of 20% in their gross final energy consumption by 2020. EU member states have also adopted binding national targets (Annex I of the 2009/28/EC Directive) for raising the share of renewables in their energy consumption by 2020.

274. The revised renewable energy directive 2018/2001/EU has established a new binding renewable energy target for the EU for 2030 of at least 32% of gross final energy consumption in 2018 with a clause for a possible upwards revision by 2023100. Under the new Governance regulation (EU/2018/1999), EU member states have submitted their draft NECPs national contributions that are sufficient for the collective achievement of the Union's 2030 target. However, in the COM (2019) 285, the European Commission has assessed the current draft plans, and find that the share of renewable in the gross final energy consumption would achieve between 30.4% and 31.9% in 2030 instead of at least 32% as required. Therefore, they provided recommendations to several member states to reconsider their level of ambition to satisfy the EU target collectively. The table below resumes the final integrated national energy and climate plans for the period from 2021 to 2030 as submitted by Member States in the end as of 24th June 2020 (see table 8).

Table 8. National overall targets for the minimum share of energy from renewable sources in gross final consumption of energy in 2020

Target	Countries	2020	NECP 2030
Share of energy from renewable sources in gross final consumption of energy	Belgium	13 %	10.5%[101] / 17.5%[25]
	Bulgaria	16 %	27 %
	Czech Republic	13 %	22 %
	Denmark	30 %	55 %
	Germany	18 %	30 %
	Croatia	28.6 %	36.4 %
	Estonia	25 %	42 %
	Ireland	16 %	32 %
	Greece	18 %	31 %
	Spain	20 %	42 %
	France	23 %	33 %
	Italy	17 %	30 %
	Latvia	40 %	50 %
	Lithuania	23 %	45 %
	Hungary	13 %	21 %
	Netherlands	14 %	27 %
	Austria	34 %	45%[28] / 50%[29]

[100] The original target of 27% has been revised upwards.
[101] With existing measures (WEM)

	Poland	15 %	21% / 23%[102]
	Portugal	31 %	47 %
	Romania	24 %	30.7 %
	Slovenia	25 %	27 %
	Slovak Republic	14 %	19.2 %
	Finland	38 %	51 %[103] / 54%[104]
	Sweden	58.2 %	66.5 %
	United Kingdom	15 %	
	EU28	20 %	32 %

Source : Final NECPs[105]

275. The RED set targets for renewable energy consumption, including sub-targets of energy used in transport to be produced with renewable sources. All EU countries must also ensure that at least 10% of their transport fuels (road and rail) come from renewable sources by 2020 according to the renewable energy directive (2009/28/EC) RED I. It has been established at 14% by 2030 in the RED II (2018/2001/EU) and would be assumed until 2050.

276. The maximum contribution of biofuels produced from food and feed crops (1st generation biofuel) should be under the cap of 7% for road and rail transport in each member state from 2020 onwards.

277. Additionally, the contribution of advanced biofuels and biogas (2nd generation biofuels) should be at least 0.2 % in 2022, at least 1 % in 2025 and at least 3.5 % in 2030 of the final consumption of energy in the transport sector.

8.3.2 Policy assumptions implemented in Integrate Europe

278. An overview of the policy targets as applied on an EU-level in Integrate Europe is found in table 9.

Table 9. GHG reduction and renewable share policy constraints that are implemented in the Integrate Europe model

Target	Year	Technology Diversification pathway	Renewable Push pathway
CO_2 reduction with respect to 1990 levels	2030	- 55%	- 55%
	2050	Net-zero emissions	Net-zero emissions
Energy efficiency target with respect to business as usual	2030	32.5%	32.5%
Share of renewable energy supply in gross final energy consumption	2030	32%	40%
	2040		60%
	2050		80%

Source : Hydrogen for Europe study

[102] The 23% objective would be achievable if Poland is granted additional EU funds, including those allocated for equitable transformation
[103] Minimum level
[104] With additional measures (WAM)
[105] https://ec.europa.eu/energy/topics/energy-strategy/national-energy-climate-plans_en

279. Phase out targets for coal is based on IDEES and the JRC database, which on an aggregated level is consistent with the Beyond coal database. For nuclear power, Integrate Europe take optimized values (capacity, annual energy) from MIRET-EU.

8.4 Scenarios and sensitivities

280. The *Hydrogen for Europe* study describes two scenarios denoted as the "Technology Diversification" and "Renewable Push" pathways. The first pathway is designed to provide insights into the most cost-efficient path for transformation of the European energy system. The second pathway, in contrast, examines the possible impact that an increased push for deployment of renewable energy could have on the hydrogen market size and development. The two scenarios thus depict different policy frameworks but share the same decarbonization goals and apply the same modelling and assumption framework.

The Technology Diversification pathway

281. The Technology Diversification pathway assumes a perfect market where the European energy technology transition is underpinned by the Climate law in combination with already approved national targets as well as the overarching objective for renewable energy share and energy efficiency[106]. The markets are characterised by perfect foresight, meaning that investment decisions are made in each period with full knowledge of future developments. Further, deployment of technologies needed for decarbonization of the energy system occurs at the time of demand without any delays. This scenario provides the least-cost transition pathway given the current policies and is the benchmarking scenario for the sensitivities.

The Renewable Push pathway

282. Using the same starting point with respect to currently implemented policies, policy announcements and overarching objectives, the renewable push scenario is set up to assess the consequences of a more favourable framework for investments in wind and solar energy. This is implemented in the form of a series of targets on the share of renewables in the gross final energy consumption, which is more ambitious for 2030 compared to today's policy and includes binding targets for 2040 and 2050. The target for 2030 is increased from 32%, which is the current set policy target, to 40%. Additional targets are set for 2040 and 2050 at 60% and 80% respectively. The scenario also analyses the energy system under perfect foresight.

Sensitivity analyses and selected sensitivity parameters

283. Sensitivity analyses have been carried out in the study to assess the robustness of the energy transition pathway resulting from the Technology Diversification scenario. The selection of sensitivity parameters has been made based on an objective to understand the consequences for the overall transition pathway caused by modification of a single, central parameter. In total four sensitivity parameters have been considered:

- Unconstrained injection of CO_2 into permanent storage sites
- Less learning-by-doing related cost reductions for solar and wind power production and electrolysers
- Delayed availability of commercial molten media and non-catalytic methane pyrolysis plants for hydrogen production
- Lower fossil fuel prices
- Higher potential of bioenergy

[106] The energy market represented within the models assumes all the conditions of a perfect market (perfect competition, perfect information, no barriers to entry or exit, no transaction costs, among others). In addition, this scenario supposes the absence of market distortions or biased incentives towards certain technologies, thus, a technology-neutral framework. The setting is said to have full awareness of the "path dependencies" to the extent that learning by doing, and to a certain extent, economies of scale and network economies are accounted for.

9 Annex D : Model documentation

9.1 Description of the MIRET-EU model

284.MIRET-EU is a multiregional and inter-temporal partial equilibrium model of the European energy system developed by IFPEN, based on the TIMES[107] model generator. A complete description of the TIMES model equations appears in the ETSAP[108] documentation. It is a bottom-up techno-economic model that estimates the energy dynamics by minimizing the total discounted cost of the system over the selected multi-period time horizon through powerful linear programming optimizers. The components of the system cost are expressed on an annual basis while the constraints and investment variables are linked to a period. Special care is taken to precisely track cash flows related to process investments and dismantling for each year of the horizon. The total cost is an aggregation of the total net present value of the stream of annual costs for each of the countries modelled. It constitutes the objective function (Eq. 1) to be minimized by the model in its equilibrium computation. A detailed description of the objective function equation is provided in Part II of the TIMES documentation (Loulou et al., 2016). We limit our description to giving general indications on the annual cost elements contained in the objective function:

- Investment costs incurred for processes;
- Fixed and variable annual costs,
- Costs incurred for exogenous imports and revenues from exogenous exports;
- Delivery costs for required commodities consumed by processes;
- Taxes and subsidies associated with commodity flows and process activities or investments;

$$NPV = \sum_{r=1}^{R} \sum_{y \in YEARS} (1 + d_{r,y})^{REFYR-y} * ANNCOST(r,y) \qquad \text{(Eq. 1)}$$

NPV is the net present value of the total cost for all regions (the objective function);

ANNCOST(r,y) is the total annual cost in region *r* and year *y* (more details in section 6.2 of PART II (Loulou et al., 2016)

$\boldsymbol{d_{r,y}}$ is the general discount rate;

REFYR is the reference year for discounting;

YEARS is the set of years for which there are costs, including all years in the horizon, plus past years (before the initial period) if costs have been defined for past investments, plus a number of years after end of horizon (EOH) where some investment and dismantling costs are still being incurred, as well as Salvage Value; and

R is the set of regions/countries in the area of study.

285.The detailed energy system model (MIRET-EU) represents the European energy system divided into 27 European countries, including 24 EU member states and 3 Non-EU member states (see figure 61, page 104). Each country has its own energy system with its main demand sectors. Moreover, each country can trade petroleum products, electricity, natural gas, hydrogen and CO_2 captured. Thus, the model fully describes within each country all existing and future technologies, from supply (primary resources), through the different conversion steps, up to end-use demands. It is set up to explore the development of its energy system from 2010 through to 2050 with 10-year steps and is calibrated on the latest data provided by energy statistics

[107] MIRET has been based on the TIMES model generator, developed by one of the IEA implementing agreements (ETSAP) in 1997 as a successor of the former generators MARKAL and EFOM with new features for understanding and greater flexibility. The manuals and a complete description of the TIMES model appear in ETSAP documentation (https://iea-etsap.org/index.php/documentation)

[108] Energy Technology Systems Analysis Program. Created in 1976, it is one of the longest running Technology collaboration Programme of the International Energy Agency (IEA). https://iea-etsap.org/index.php/documentation

databases such as the JRC-IDEES109 POTEnCIA[110], EUROSTAT, and other international databases from IEA, IRENA and World Bank, among others.

286. MIRET-EU considers four seasons (spring, summer, autumn, winter) which are disaggregated into day, night and peak resolution[111]. Every year is therefore divided in twelve time-slices that represent an average of day, night and peak demand for each season of the year (e.g. summer day, summer night and summer peak, etc.).

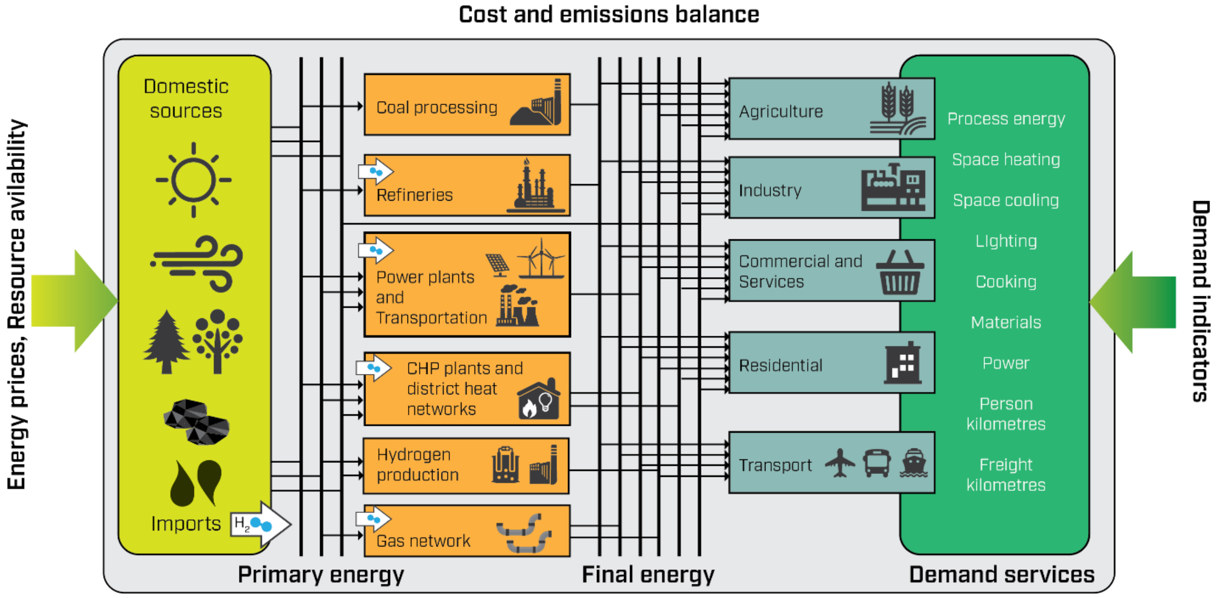
287. The MIRET-EU model is data driven[112], its parameterisation refers to technology characteristics, resource data, projections of demand for energy services, policy measures, among other. This means that the model varies according to the data inputs while providing results such as technology pathways or changes in trade flows for policy recommendations. For each country, the model includes detailed descriptions of numerous technologies, logically interrelated in a Reference Energy System – the chain of processes that transform, transport, distribute and convert energy into services from primary resources and raw materials to the energy services needed by end-use sectors.

288. A few models have already been developed at European scale using the TIMES model over the last 15 years. The Pan-European TIMES (PET) model has been developed by the Kanlo team following a series of European Commission (EC) funded projects (NEEDS[113], RES2020[114], REACCESS[115], REALISEGRID[116], COMET[117], Irish-TIMES[118]) between 2004 and 2010. It represents the energy system of 36 European regions. The JRC-EU-TIMES model is one of the models currently pursued and developed in the Joint Research Centre (JRC) of the European Commission under the auspices of the JRC Modelling Taskforce. The JRC-EU-TIMES model was developed as an evolution of the Pan European TIMES (PET) model of the RES2020 project, followed up within the REALISEGRID and REACCESS European research projects. The detailed residential, services and hydrogen modules and database of the JRC-EU-TIMES have been incorporated with additional modifications to MIRET-EU. Therefore, the modelling framework of MIRET-EU follows the same framework developed successively in the PET36, the JRC-EU-TIMES, MIRET-FR[119] and TIAM-IFPEN[120] models with additional expertise from IFP Energies Nouvelles in specific sectors such as transport, refineries and bioenergy conversion technologies, hydrogen infrastructure, power sector and industry.

289. MIRET-EU encompasses all stages from primary resources through the chain of processes that transform, transport, distribute and convert energy into the supply of energy services demanded by energy consumers. On the energy supply side, it comprises fuel production, primary and secondary energy sources, and imports and exports. Through various energy carriers, energy is supplied to the demand side, which is structured into residential, commercial, agricultural, transport and industrial sectors (see figure 67).

[109] JRC-IDEES (Integrated Database of the European Energy System) has been released in July 2018 and is revised periodically. We then used the latest data released in September 2019.
[110] POTEnCIA (Policy-Oriented Tool for Energy and Climate change Impact Assessment)
[111] It follows the same time slice disaggregation as in the world multiregional model TIAM-IFPEN.
[112] Data in this context refers to parameter assumptions, technology characteristics, projections of energy service demands, etc. It does not refer to historical data series
[113] http://www.needs-project.org/
[114] http://www.cres.gr/res2020
[115] http://reaccess.epu.ntua.gr/
[116] http://realisegrid.rse-web.it/
[117] The final aim of the modelling tasks in the COMET research project is the evaluation of different possible developments of CCS using a hard-link approach of TIMES-Morocco, TIMES-Portugal, TIMES-Spain, and TIMES-CCS. http://rdgroups.ciemat.es/documents/10907/86733/Comet_12Dec.pdf/b29424d6-1287-4644-9192-c2994daef02e
[118] https://www.epa.ie/pubs/reports/research/climate/Irish%20TIMES%20Energy%20Systems%20Model.PDF
[119] MIRET-FR is the version developed for France by IFPEN since 12 years
[120] TiAM-IFPEN (TIMES Integrated Assessment Model) is the world version currently developed by IFPEN since 3 years.

Figure 67. Partial view of the Reference Energy System with its interdependencies in MIRET-EU model



Source : Remme and Mäkela, 2001

290. The reference energy economy is thus composed (from left to right) of:

- **A primary energy supply block**, which includes:
  - Imported primary energy sources (uranium, crude oil, coal, natural gas);
  - Biomass which has been disaggregated into four types of commodity groups in order to better take into account the competition between their consumption in biofuels production (1st and 2nd generation), hydrogen production, power sector, industry, residential and commercial. These groups are derived from the JRC database ENSPRESO (Energy System Potentials for Renewable Energy Sources) related to bioenergy potentials for EU and neighbouring countries (Ruiz et al., 2019). Agriculture, forestry and waste are the main sectors providing biogenic resources for energy production following the ENSPRESO database. The biomass resources have been disaggregated into sugar beet, starch, rape-seed and lignocellulosic potentials, municipal waste and industrial waste-sludge potentials, and also biogas potentials provided by dry and wet manure coming from cattle. In addition to the resource potentials, the related supply costs have also been provided in ENSPRESO in order to determine the systemic impact of biomass, together with other system-related variables, such as carbon price (Ruiz et al., 2019);
  - Imported raw materials for industry sectors.

- **An energy technology block**, whose technologies transform primary energy into energy vectors and energy services. It includes:
  - The electricity generation (all power plants from fossil-based to renewable energy sources, CHP);
  - Oil refining and biofuel units are modelled based on IFPEN's approach and recognized expertise in the field of refineries and biofuels. The production chain is divided into feedstock pre-processing, production processes, and blending (Blending of diesel B7, B10), gasoline SP95 grades E5, E10 and E85, and jet fuels):
    - First generation biofuel production is subdivided into four sources: ethanol production from sugar beet and starch feedstock's, the trans-esterification and hydro-treatment of crushed oilseeds into FAME (Fatty Acid Methyl Esters) and HVO (Hydro treated Vegetable Oils), respectively;
    - Second generation production is subdivided into two sources: ethanol and synthetic FT-Diesel from lignocellulosic feedstock's.

  - The end-use technologies related to agriculture, industry, transport, residential and services (see below for more sectorial details).

- **<u>A final energy / energy services demand block</u>** such as industrial demands, space and water heating demands, mobility demands in the transport sector, trades (oil products, electricity, hydrogen, CO_2 captured), etc.
- **<u>A policy block</u>** which includes measures and constraints of several types affecting all sectors. Some are of microscopic nature, such as quality norms for refinery products, the number of functioning hours of fuel turbines, power plants, etc. Some are macroscopic in nature, e.g. global emission constraints or sectoral restrictions.

9.1.1 Strengths and weaknesses of MIRET-EU related to the goals of the study

291. MIRET-EU is an economic model with a rich technology representation for estimating capacity investment pathways over the long term. It combines two different, but complementary, systematic approaches to energy system modelling: a technical engineering approach and an economic approach. TIMES uses linear-programming to produce a least-cost energy system, optimized across regions and sectors according to a number of user constraints, over medium to long-term time horizons. This unique objective function guarantees the internal consistency of the resulting scenario, as the decision criteria are the same for all processes and flows. These types of models are effective for assessing long-term investment decisions in complex systems where future technologies are different from current technologies.

292. The TIMES model assumes perfect foresight over the entire horizon, i.e. all investment decisions are made in each period with full knowledge of future events. This technology-detailed model provides insights to decision-makers regarding energy systems in order to determine which technologies are competitive, marginal or uncompetitive in each market according to dynamic economic cost-benefit analyses. In short, MIRET is used for the exploration of possible energy futures based on contrasted scenarios.

293. As a partial equilibrium model, MIRET-EU does not model economic interactions outside the European energy sector. As stated by Gielen and Taylor (2007), this type of model, based on the TIMES generator, has the following advantages:

- The model is based on a single objective cost criterion.
- A detailed technology-rich modelling paradigm from primary resources to end-uses.
- Stock turnover is considered explicitly.
- Provide options to decision makers regarding energy systems over medium to long-term time horizons
  - Economically affordable
  - Technically feasible
  - Environmentally sustainable
- The model is well suited to the development of Energy Roadmaps by making explicit the representation of technologies and fuels in all sectors in order to anticipate achievable futures based on actual knowledge. This is relevant for investment decisions in complex systems with differences between existing and future technologies.
- The model optimizes operation and investment decisions based on the characteristics of alternative generation technologies, energy supply economics, and environmental criteria. TIMES is thus a vertically integrated model of the entire extended energy system.
- The scope of the model extends beyond purely energy-oriented issues, to include the representation of environmental emissions, and materials, related to the energy system. In addition, the model is suitable for the analysis of energy-environmental policies, which may be accurately represented by making explicit the representation of technologies and fuels in all sectors.
- The great flexibility of TIMES, especially at the technological level, allows the representation of almost all policies, whether at the national, sectorial, or sub-sectorial level.
- The model is driven by explicit exogenous final energy services demand and fuel prices.

294. On the other hand, it could be pinpointed some limitations inherent to this type of model:

- MIRET-EU is data consuming; therefore, data availability could limit the scope and depth of possible analyses.

- Moreover, there is no explicit representation of macro-economic factors which means there are no feed-back loops between the effects of energy system changes and the economy[121].
- As all models are simplified representations of reality and its complex dynamics, they inherently have limitations as to the detail and scope of their mathematical representation. These simplifications, e.g. time and spatial resolution, sector or technology representation and system boundaries, which are mostly due to the data availability, may represent significant modelling limitations.
- Long computational times could be observed due to a very detailed representation of complex energy system.
- The model is sensitive to the data assumptions for emerging technologies, which are by definition more uncertain and decision makers in practice do not always balance efforts across regions and sectors.
- Decision making that conditions investment in new technologies is often not rational, however representing non-rational decisions could be done via exogenous constraints. This does not allow capturing in detail all the aspects related to consumer behaviour, which play a fundamental role in decision-making processes. As highlighted by Gielen and Taylor (2007), even if decision making is rational, it is often not based on least-cost criteria. Policy rationality may stress effectiveness, equity issues, timing, risk and other factors that are not accounted for in this framework.
- The optimistic view of the future due to the perfect foresight approach which does not account for real-world uncertainty. However, it is possible to implement via the model to have foresight over a limited part of the horizon, such as one or a few periods or to temper it by using higher discount rates. By so doing, a modeler may attempt to simulate "real-world" decision making conditions, rather than socially optimal ones (Loulou et al., 2016)
- In this study, there is no disaggregation by plant size unlike in the MIRET FR (France) due to a lack of data and the consequences of so doing on computational time. This implies, as a simplification, that all installations in industry and CHP are considered as falling within the scope of the EU ETS Directive.
- Limited consideration of the very short-term physical dynamics (e.g. integrating system adequacy, transient stability analysis in the power sector) into long-term prospective models such as MIRET-EU.

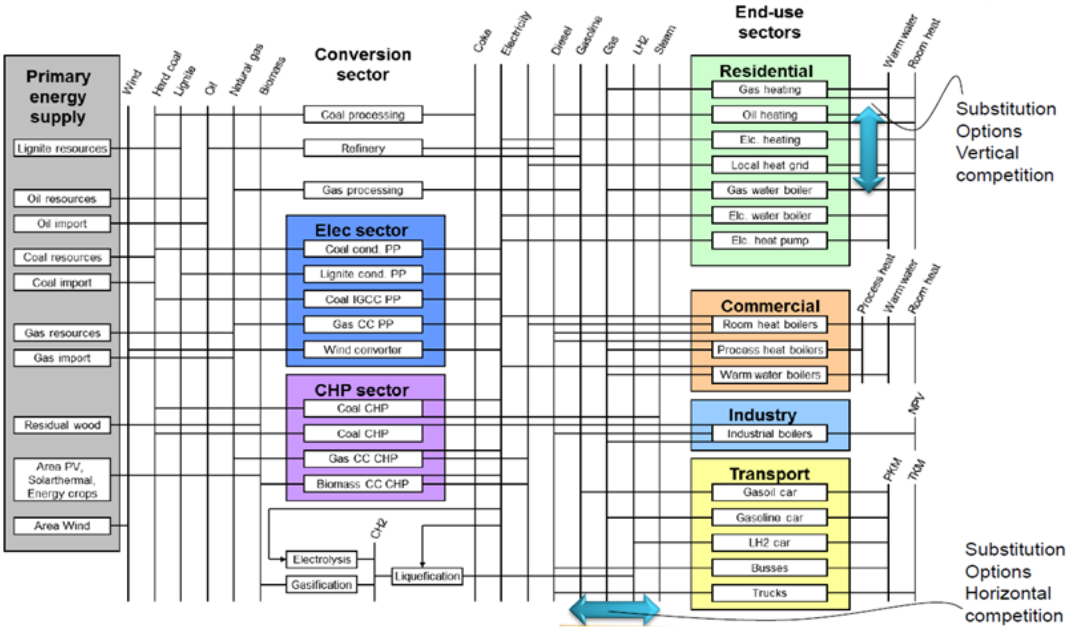
[121] However, they could be considered exogenously through the price elasticities of service demands.

9.1.2 Sectoral representation

295.MIRET-EU provides a disaggregated representation of energy demand. In this section, the different energy end-use sectors are described in detail for a better comprehension of the sectorial assumptions/modelling.

296.MIRET-EU carries out its optimization horizontally across all sectors and vertically across all technologies delivering the same commodity, regions and time periods for which the limit is imposed. Figure 68 shows how substitutions are considered in the model within the different sectors.

Figure 68. Substitution options in MIRET-EU



Source : Gargiulo M., 2018

297.As above-mentioned, MIRET-EU's reference energy system encompasses all the steps from primary resources through the chain of processes that transform, transport, distribute and convert energy into the supply of energy services demanded by energy consumers. The details of each sector represented in the model are presented below. Throughout each description, modelling competencies are identified and limits, which are generally due to the lack of available database, are pointed out.

298.The model considers the existing technologies which are related to what is already installed in all considered countries in an historical year (e.g. the year 2010), and the new technologies which are to be available in the future (e.g. from 2011 onwards).

Power sector

299.The power sector could be subdivided in five parts as depicted in figure 69: Primary resources, power plants, power grid, demand (end-uses) and emissions. The primary resources part is disaggregated into import and mining processes in order to also take into account domestic extraction of resources in each country. These primary resources are converted into other energy carriers (electricity, heat, refinery products) via heat and power plants, cogeneration heat plants (CHP) or refinery plants.

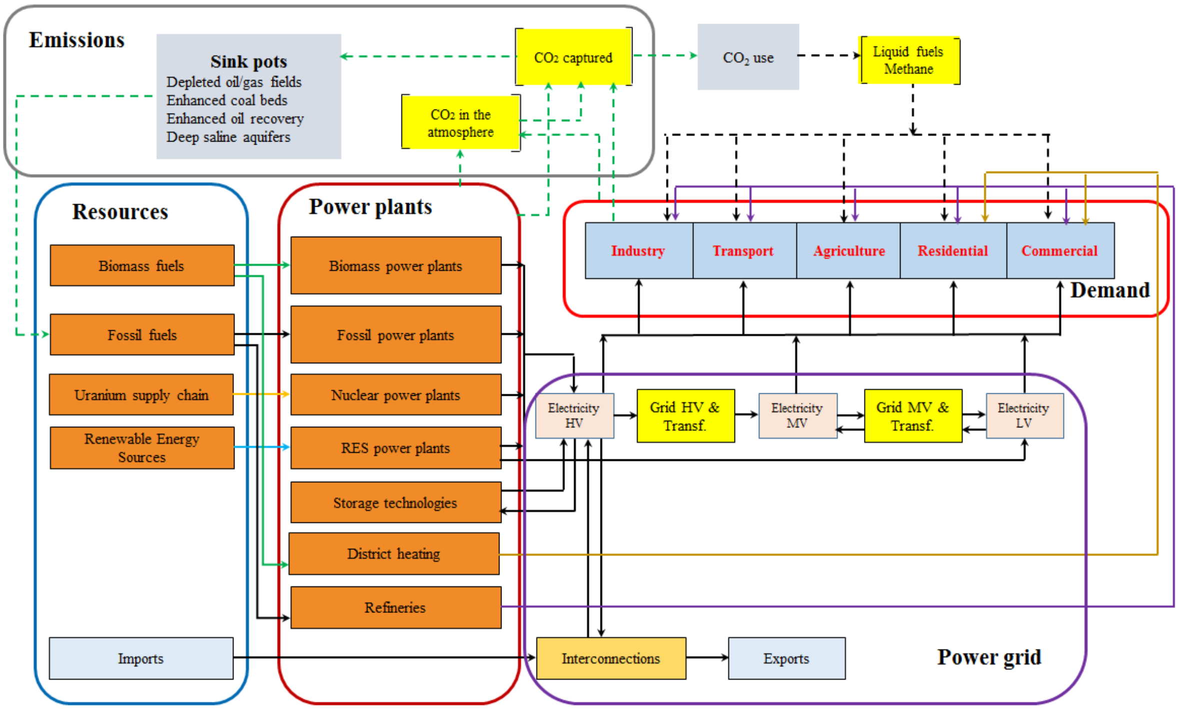
300.The power grid is explicitly represented in MIRET-EU in a simple manner in order to take into account the different voltage levels. All these energy carriers are consumed in the end-uses/processes in agriculture (machine drives, heat uses…), industry (iron & steel, cement, pulp & paper,…), transport (cars, bus,…), residential and services (space heating, cooling, cooking, lighting,…) sectors. Balancing the demand in all later sectors (mobility, tons of cement, space heating) could imply CO_2 emissions as in energy conversion technologies.

301. The CO_2 emissions could come from all demand and supply sectors (each energy carrier has an associated emission factor), and could be released to the atmosphere or captured via carbon capture and storage (CCS). CCS is considered in some industrial processes (ammonia, iron & steel, cement…), in power generation and supply sectors (hydrogen and biofuel production).

302. The model includes CO_2 from carbon capture or from the atmosphere directly by using direct air capture (DAC). The captured emissions can be from fossil or biogenic sources. Afterwards, they are either stored permanently in sinks, traded or reused (CCUS routes) to produce synthetic fuels (PtL), or methane (PtM) which could be incorporated in the natural gas grid.

303. The techno-economic details of electricity generating technologies rely on updated power generation technology assumptions (Efficiency, capital costs, fixed and variable O&M costs) from the JRC database released in October 2019 by the Joint Research Centre (JRC) of the European Commission, as well as from the IEA database. An evolution of these technology characteristics is provided up to 2050. Several country-specific assumptions are introduced in the model such as short and/or medium-term expected phase out and roll out of technologies, etc.

Figure 69. Power sector representation in MIRET-EU

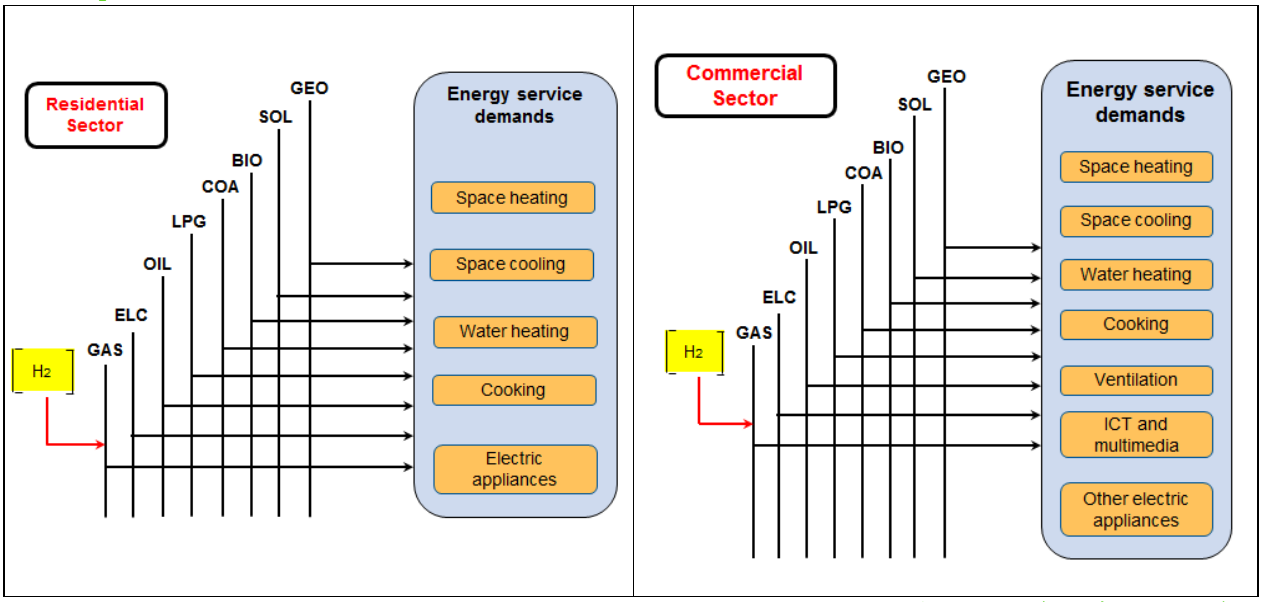


Source : Hydrogen for Europe study

Residential, Commercial and Agriculture sectors

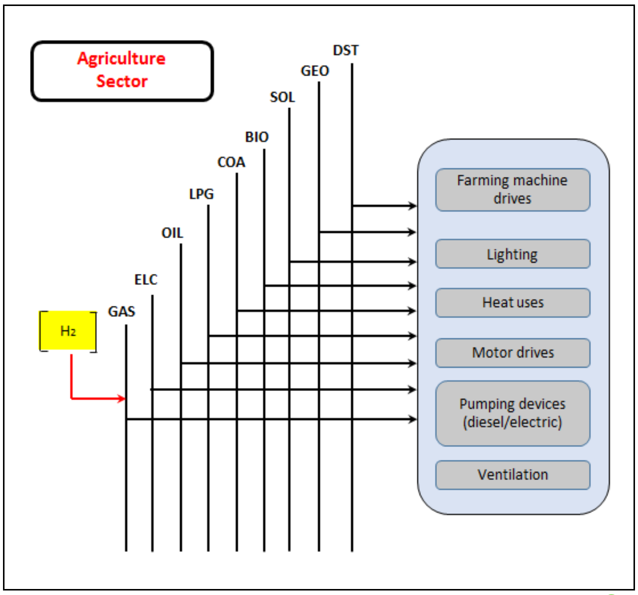
304. The needed data of the residential, services and agriculture sectors have been taken from the JRC-EU-TIMES database with a very disaggregated representation. MIRET-EU considers space heating, space cooling, water heating, cooking, ventilation, ICT and multimedia, and other electric appliances as end-uses in the residential and commercial sectors (see figure 70), while a single energy service demand satisfied by a single technology that consumes a mixture of fuels via different end-uses is considered for the agriculture sector (see figure 71).

Figure 70. Residential and commercial sector in MIRET-EU



Source : Hydrogen for Europe study

Figure 71. Agriculture sector in MIRET-EU



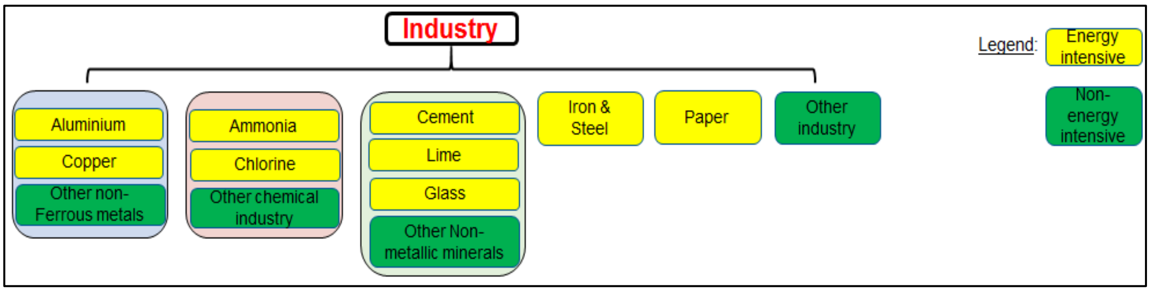
Source : Hydrogen for Europe study

305. The JRC-IDEES (Integrated Database of the European Energy System), released in July 2018, provides very detailed information on the energy system and its underlying drivers for all EU Member States in annual time steps starting from the year 2000 up to 2015 consistent with Eurostat statistics in the last 2018-version. The model calibration has been continued to 2020 when other existing data between 2015-2020 are available. JRC-IDEES has been very useful in order to calibrate the historical evolution of the energy sector in MIRET-EU. The details of the end-use technologies (boilers, heat-pumps, CHP, district heating, water heaters, among others) for residential and services are based on a wide literature review, including in particular, the technology pathways described by the EU-funded project Advanced System Studies for Energy Transition (de Vita et al., 2018), the ENTRANZE database, the Eco-design requirement reports[122] of the European Commission, PRIMES data, VHK reports, among others. It also provided a disaggregation of the different end-uses to consider in the agriculture sector with their fuel efficiency.

Industry sector

306. The modelling framework of the industry is subdivided into two categories according to previous work and studies: manufacturing process of the energy intensive industries where described by their associated energy consumption ratios for each product. Choices are possible between several alternative process solutions (Djemaa A., 2009; ETSAP[123]), while the non-energy intensive industries (or diffuse industry) are modelled by energy end-uses (mechanical processes, heat treatment, evaporation and concentration, drying, etc) due to the unsuitability of the product/process approach (Seck et al., 2013) (figure 72). The BREFs[124], which are the most complete series of reference documents covering industrial activities, provide descriptions of a range of industrial processes and, for example, their respective operating conditions and emission rates. It should be noted that CCS is considered in some energy intensive industries such as cement, glass, pulp & paper, ammonia, iron & steel, etc. The calibration of MIRET-EU relies on the JRC-IDEES, EUROSTAT, IEA database and on the framework of the JRC-EU-TIMES and TIAM-IFPEN.

Figure 72. Industry disaggregation in MIRET-EU



Source : Hydrogen for Europe study

Transport sector

307. The transport sector in MIRET-EU is based on IFPEN previous transport structure of MIRET-FR and TIAM models for critical raw material analyses in this sector up to 2050 (Hache et al., 2019). It is subdivided into four modes: road, rail, navigation and aviation (figure 73).

308. The road transport has been divided into passenger light-duty vehicles (PLDV) (small, medium and large), buses, commercial vehicles (CV) (light, heavy and medium trucks) and 2/3-wheelers. The presentation of technologies relies on a specific understanding of the transport sector within each segment (PLDV, CV, bus, minibus and 2/3-wheelers). The existing and future vehicles have been implemented with their techno-economical parameters. For all technologies across the entire study period 2010-2050, taking into account fuel efficiency, average annual vehicle mileage, lifespan, cost (purchase cost, O&M fixed and variable costs), etc.

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122 Further information available at: https://ec.europa.eu/info/energy-climate-change-environment/standards-tools-and-labels/products-labelling-rules-and-requirements/energy-label-and-ecodesign/energy-efficient-products_en
123 https://iea-etsap.org/index.php/energy-technology-data/energy-demand-technologies-data
124 https://eippcb.jrc.ec.europa.eu/reference/

All these attributes have been derived from the IEA Mobility Model (IEA MoMo) (Fulton et al., 2009) data on transport and the JRC database.

309. For rail, MIRET-EU considered the non-urban rail, urban rail and freight rail while for the aviation and navigation, they have been disaggregated into freight and passengers, inland and bunkers. Contrary to MIRET-FR where all existing and future different aircrafts have been considered in order to allow alternative technologies, it has been assumed to consider single generic technologies at the European level with an average efficiency to satisfy the aviation activity, likewise for navigation. In addition, ammonia for navigation and pure hydrogen for aviation are not considered in the model for the moment.

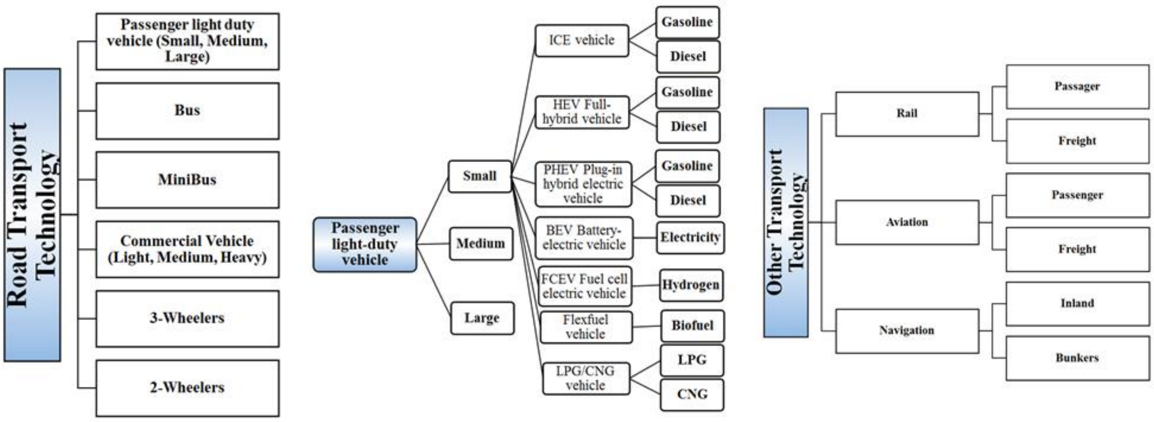
310. The potential role of ammonia in the energy system has been the subject of many discussions, particularly as a marine fuel. However, as ammonia has been represented as an industrial sector and not as a feedstock, it has been proposed a simplified approach which add hydrogen in the fuel mix of a generic ship on an equivalent basis[125]. Thus, the hydrogen demand gives some indications of the potential demand of ammonia as a shipping fuel until 2050. Transport fuels considered in the model are hydrogen, synthetic fuels (XtL), eFuels (PtL), natural gas, Liquefied petroleum gas (LPG), Blending of gasoline, diesel and jet fuels.

311. Modelling of biofuels is based on IFPEN's approach and recognized expertise in the field of refineries and biofuels. The production chain is divided into:

- Feedstock pre-processing (where vegetable oil, starch grain, sugar beet and lignocellulosic are pre-processed),
- Production processes which are grouped into first and second generation biofuel processes,
    - First generation biofuel production is subdivided into four sources: ethanol production from sugar beet and starch feedstock's, the trans-esterification and hydro-treatment of crushed oilseeds into FAME (Fatty Acid Methyl Esters) and HVO (Hydro treated Vegetable Oils), respectively
    - Second generation production is subdivided into two sources: ethanol and synthetic FT-Diesel from lignocellulosic feedstock's.
- And blending (Blending of diesel B7, B10, gasoline SP95 grades E5, E10 and E85, and jet fuels) which is done endogenously in the model:
    - Gasoline SP95 fuels where bioethanol (1st and 2nd generation) could be incorporated to gasoline in a proportion up to 5%.
    - Gasoline SP95-E10 fuels where bioethanol (1st and 2nd generation) could be incorporated to gasoline in a proportion up to 10%
    - Gasoline SP95-E85 fuels where bioethanol (1st and 2nd generation) could be incorporated to gasoline in a proportion up to 85%.
    - Jet fuels for aviation where hydro treated vegetable oils (HVO) and biodiesel from lignocellulosic biomass (2nd generation) could be incorporated in kerosene in a proportion up to 95%
    - Diesel fuels where hydro treated vegetable oils (HVO), transesterification of vegetable oils (FAME), biodiesel from lignocellulosic biomass (2nd generation) could be incorporated in diesel in a proportion up to 95%

[125] The *Hydrogen for Europe* study has adopted a simplified approach to give a broad indication of the potential demand hydrogen for the maritime sector until 2050. In this simplified approach, hydrogen has been added in the fuel mix of a generic ship as an equivalent basis. This is due to challenging model development tasks (lack of data on existing and future ships with their techno-economic assumptions (evolution till 2050), their fuel efficiency per type, lifetime, stocks of existing ships of the different considered category of ships) but also to limitations in the representation of ammonia as a feedstock in the model.
Ammonia, that is produced from hydrogen through the Haber-Bosch process, is a promising solution as a shipping fuel but also for transporting and importing hydrogen into Europe, thanks to already existing ammonia production and transportation infrastructure. Moreover, production of ammonia from hydrogen is a low hanging fruit for decarbonizing existing ammonia demand for industrial and agricultural uses.

Figure 73. Transport representation in MIRET-EU



Source : Hydrogen for Europe study

9.1.3 Representation of the hydrogen supply chain

312.Regarding the hydrogen supply chain structure (see figure 74), the production options are disaggregated under centralized vs. decentralized and by size (large, medium and/or small).

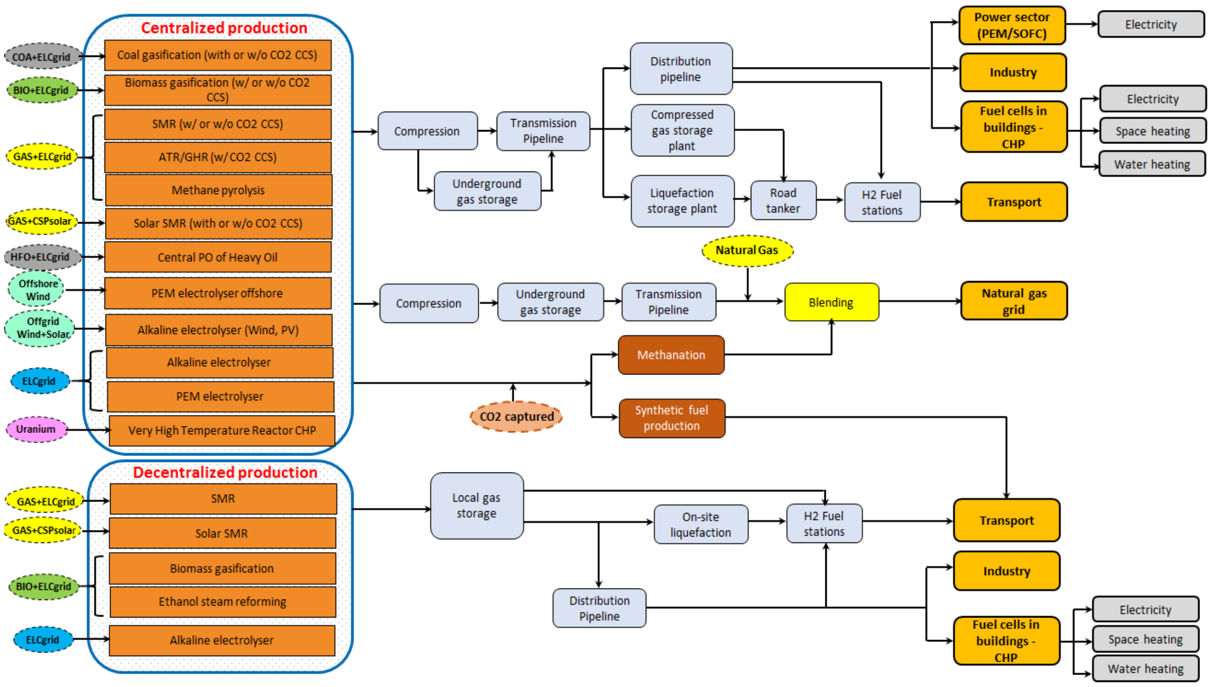
313.In the decentralized option, hydrogen is produced close to where it is consumed, whereas in the centralized option, large scale hydrogen facilities are considered producing hydrogen that needs to be delivered to end-users via an extensive transport and distribution infrastructure. Most of the hydrogen techno-economic assumptions considered in the model have been provided by the JRC to IFP Energies Nouvelles on June 2019. They are based on the JRC hydrogen structure in TIMES input data available for the development of the hydrogen sector in MIRET. The main references for the data are Blanco et al. 2018a, 2018b; Sgobbi et al., 2016; Bolat and Thiel, 2014a, 2014b; Simoes et al., 2013; Krewitt and Schmid, 2005.

314.In total, more than 30 hydrogen production options are considered by process type (with and w/o CCS), by size, by system design (centralized vs decentralized):

- Hydrogen from water
  - Electrolysis
- Hydrogen from fossil fuels
  - Natural gas steam reforming with/without Carbon Capture and Sequestration (CCS)
  - Auto-thermal reformer (ATR)/ Gas-heated reformer (GHR) with CCS
  - Methane pyrolysis
  - Partial oxidation of heavy oil
  - Coal Gasification with/without CCS
- Hydrogen from biomass
  - Biomass Gasification with/without CCS
  - Ethanol steam reforming

315. A data request regarding the techno-economic assumptions on hydrogen production technologies considered in the MIRET-EU model has been extensively discussed with technical experts in order to cross validate and complete the list. The implementations were made based on the data provided.

Figure 74. Hydrogen supply chain in MIRET-EU



Source : Adapted from the JRC hydrogen module for the Hydrogen for Europe study

316. Thus, different input energy sources for hydrogen (e.g. electricity from grid, PV, wind, etc.) have been considered in the model. The JRC representation of the hydrogen supply chain has been improved by adding new hydrogen production options such as offgrid wind and PV with electrolyzers, methane pyrolysis, autothermal reformer (ATR)/Gas-heated reformer (GHR).

317. Hydrogen delivery begins with hydrogen conditioning and is completed with supplying hydrogen to end users. Hydrogen delivery is modelled by creating aggregated processes coupling several hydrogen delivery sub processes. Consequently, an aggregated delivery process is formed by summing all processes of a probable hydrogen value chain, from conditioning to immediately before end-use application (Simoes et al., 2013). Total costs for each of the delivery path result from the cost aggregation of the individual steps. Depending on the selected pathway of hydrogen delivery, sub processes include hydrogen storage options (e.g. underground salt caverns, liquid storage bulk, gas storage bulk and local gas storage bulk), liquefaction, compression, distribution pipeline, road transportation and refueling stations, liquid to liquid, liquid to gas, and gas to gas with small capacity (300 kg/day) and large capacity (1200 kg/day).

318. Regarding end-use applications of hydrogen:

- Hydrogen gas, as a transport commodity can be consumed in buses, cars and commercial vehicles, and marine bunkers[126].
- In the residential and commercial sectors (space heating, water heating and electricity via fuel cells-CHP), and for industrial processes, hydrogen gas and hydrogen-natural gas blending are also possible. For the blending with natural gas, within the current natural gas infrastructure, a maximum of 5% until 2025, 10% from 2025 and 15% from 2030 onwards has been assumed in MIRET-EU in order to be in line with the

[126] The hydrogen use in trains and aviation is not yet included so far in the model, however the use in trains could be implemented in the future according to existing and available data as plans involving hydrogen trains already exist in a number of countries (two hydrogen trains in Germany) (IEA, 2019)

hypothesis considered in the global TIAM IFPEN model, IEA-ETSAP TIAM version, or other European TIMES version[127].

- In the power sector, PEM fuel cell technology is represented in the model in order to take into account the penetration of hydrogen in power generation.
- Hydrogen can also be consumed in biorefineries and within CCUS routes for Power-to-Liquid (PtL), and Power-to-Methane (PtM).

9.1.4 Pipelines and trade representation in the MIRET-EU model

Natural gas and LNG

319. The trade of natural gas between European countries and other regions is modelled via a trade matrix that defines the existing and planned capacities until 2025 with the possibility of investing in additional capacity from 2025 onwards if needs be.

320. The ENTSOG128 Ten-Year Network Development Plan (TYNDP) provides an overview of the European gas infrastructure and its future development. It thus allows depicting the maximum existing and planned capacities in order to have bilateral or unilateral exchanges between European countries until 2025 (see figure 75). Hereafter, an example of a matrix table which is used to declare the traded energy commodities (in this example, natural gas) and the links between countries (1=active links). The countries at the left-most column represent the exporters and the ones at the top-most line are the importers. Two types of trade are considered in the model: either bilateral links between countries (e.g. trade between Germany (importer/exporter) and Austria (importer/exporter) or unilateral links between countries (e.g. trade between Netherlands (importer) and Norway (exporter)).

Figure 75. Endogenous trade matrix of natural gas within European countries

Natural gas	Austria	Belgium	Bulgaria	Czech Rep.	Denmark	Estonia	Finland	France	Germany	Greece	Hungary	Ireland	Italy	Latvia	Lithuania	Netherlands	Poland	Portugal	Romania	Slovakia	Slovenia	Spain	Sweden	United Kingdom	Norway	Switzerland
Austria									1		1		1							1	1					
Belgium								1	1							1								1		
Bulgaria										1																
Czech Rep.									1											1						
Denmark									1							1							1			
Estonia																										
Finland																										
France		1																				1				1
Germany	1	1		1	1			1								1	1									1
Greece																										
Hungary																			1							
Ireland																								1		
Italy	1																			1	1					1
Latvia						1									1											
Lithuania														1												
Netherlands		1							1															1		
Poland																										
Portugal																						1				
Romania			1																							
Slovakia	1			1																						
Slovenia											1		1													
Spain								1										1								
Sweden																										
United Kingdom		1										1				1										
Norway		1						1	1							1								1		
Switzerland								1					1													

Source : Hydrogen for Europe study

321. In addition to natural gas trade within European countries, natural gas trade from Russia and North Africa are also considered for Germany, Finland, Estonia, Lithuania, Hungary, Poland, Romania, Slovakia, Spain and Italy (table 10).

[127] According to the IEA (2019), it is 10% blending max with 8% allowable under certain circumstances in Germany, while it is around 6% in France, 5% in Spain, 4% in Austria, and under 2% in other European countries. The Ameland project in the Netherlands did not find any problem for household devices to blend hydrogen up to 30%.
Hydrogen and natural gas separation is not taken into account in the model.
[128] European Network of Transmission System Operators for Gas

Table 10. Trade of natural gas from outside European countries

Natural gas Country origin	Natural gas Country destination
Russia	Germany
	Estonia
	Lithuania
	Hungary
	Poland
	Romania
	Slovak Republic
	Finland
	EU28
North Africa	Spain
	Italy

Source : Hydrogen for Europe study

Table 11. LNG import terminals considered in the model

LNG Terminals
Belgium
Croatia
Estonia
Finland
France
Germany
Greece
Ireland
Italy
Latvia
Lithuania
Netherlands
Norway
Poland
Portugal
Spain
Sweden
United Kingdom

Source : Hydrogen for Europe study

322. Belgium, Croatia, Estonia, Finland, France, Germany, Greece, Ireland, Italy, Latvia, Lithuania, Netherlands, Norway, Poland, Portugal, Spain and the UK have also the possibility to import LNG from outside Europe (table 11). The GIE[129] LNG Map and the CEDIGAZ[130] database provides comprehensive information on existing and under construction LNG Terminals in Europe. The project tables in the Annex A of the ENTSOG TYNDP 2020 provides the planned or under study LNG terminals for the coming years with a detailed overview of their status .For the H2 4EU study, only confirmed projects (FID)[131] and those with advanced maturity status have been considered.

Electricity

323. Electricity trade is represented like natural gas via a matrix table where the endogenous exchanges are represented. The ENTSO-E[132] Ten-Year Network Development Plan (TYNDP) also provides an overview of the maximum existing and planned capacities until 2030. The model also considers a maximum level of imports and exports of electricity from outside Europe.

[129] Gas Infrastructure Europe
[130] CEDIGAZ is an international not for profit association dedicated to natural gas information, created in 1961 by a group of international gas companies and IFP Energies Nouvelles
[131] Final Investment Decision
[132] European Network of Transmission System Operators for Electricity

Hydrogen

324. Regarding hydrogen transport, if a reduced demand for gas is observed, capacity could become available and could be used to transport hydrogen by repurposing segments of the natural gas pipelines to hydrogen, or by investing in new hydrogen pipelines (Guidehouse, 2020a). Therefore, two types of pipelines for hydrogen trade have been modelled in MIRET-EU:

- Retrofitted natural gas pipelines to hydrogen
- New dedicated hydrogen pipelines

325. Therefore, the model optimizes between retrofitting existing natural gas infrastructure for hydrogen carrying capability on one hand, and alternatively, or additionally, investing in new dedicated hydrogen infrastructure in the other hand (EC ASSET, 2020). Thus, the retrofitted gas pipelines to hydrogen has been assumed to have the matrix between the countries than the existing gas pipelines. The possibility of investing in additional hydrogen transport in the future is also considered within the existing gas matrix (H21NoE, 2018; Schoots et al., 2011). An estimate of the investment and operating costs have been provided in the 2020 European Hydrogen Backbone report of Guidehouse (2020) for new and refurbished pipelines dedicated to hydrogen (table 12).

Table 12. Cost input ranges used for estimating total investment, operating, and maintenance costs for hydrogen infrastructure. Values are for 48-inch pipelines (one of the widest pipeline types in the intra-EU gas network).

		Low	Medium	High
Pipeline CAPEX new	M€/km	2.5	2.75	3.36
Pipeline CAPEX retrofit	M€/km	0.25	0.5	0.64
Compressor station CAPEX	M€/MWe	2.2	3.4	6.7
Operating & maintenance costs	€/year as a % of CAPEX		0.8-1.7%	

Source : Guidehouse, 2020b

326. As regards extra-European trade of hydrogen, their inclusion in the model focuses on potential hydrogen imports from North Africa, Russia and Middle East. The transport modalities considered are maritime transport (LH2 and ammonia) and by cross-border interconnectors (subsea and aboveground). Hydrogen supply curves (based on LCOH trajectories) from extra-European countries is provided by a specific study carried out by in a separate working package. The latter is included in the model as an alternative for hydrogen supply, competing with domestic production within Europe. The maximum import volumes are based on the maximum possible trade flows between the country of origin and the entry point within Europe, with references to transport costs and constraints on planned infrastructure. All data regarding hydrogen transport (transport costs, hydrogen production cost in the foreign regions considered, maximum capacity available today and its evolution through to 2050) are described in section 9.4 of annex D.

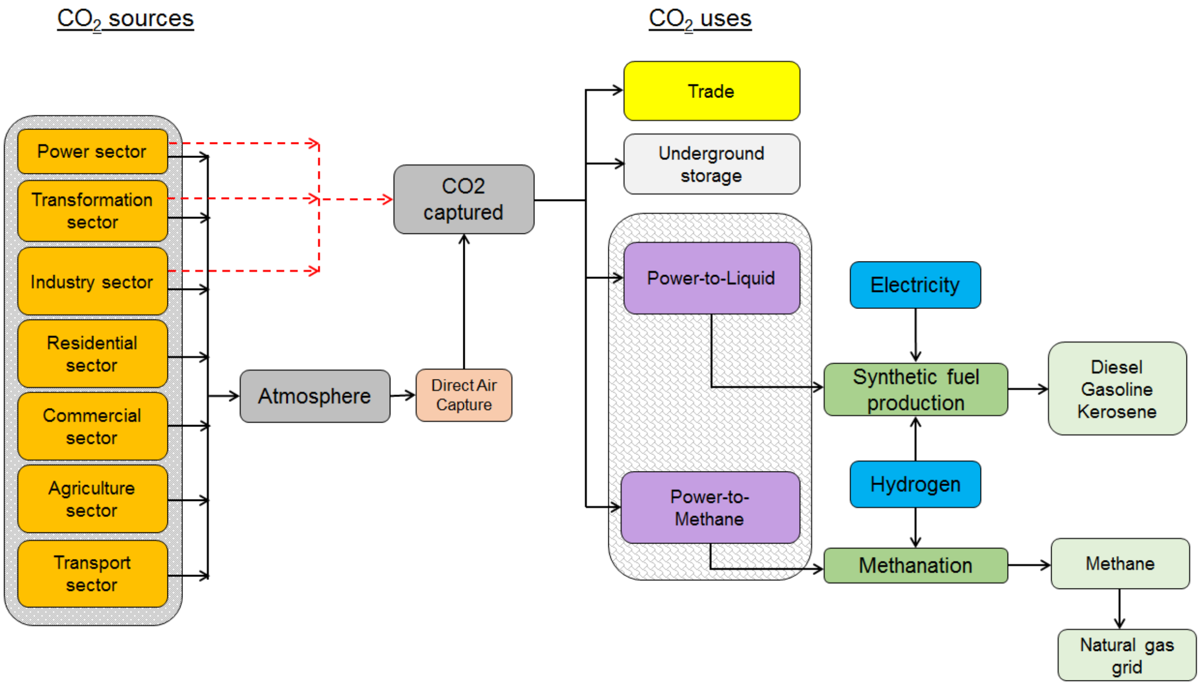
9.1.5 CO_2 flows and CCUS routes in the MIRET-EU model

327. In figure 76, the model recovers CO_2 from carbon captured in industry, electricity and, hydrogen and biofuel production sectors, or from the atmosphere directly by using DAC (Direct Air Capture). The captured emissions can be from fossil or biogenic sources. Afterwards, they are either stored permanently in sinks (depleted oil/gas fields, enhanced coal beds, enhanced oil recovery, deep saline aquifers), traded or reused to produce synthetic fuels (PtL), or methane (PtM[133]). The main sources of data are Blanco et al. (2018a, 2018b) and Meylan et al. (2015). Regarding CO_2 transport considered in the model (Morbee et al., 2010, 2012; Morbee, 2014; Simoes et al., 2013), the pipeline trade among European countries is modeled via a trade matrix that defines the links

[133] Power-to-Methane

between regions. CO_2 transport by tanker could also be implemented provided cost data is available (e.g. France-Norway planned CO_2 trade by tanker).

Figure 76. CCUS routes in the MIRET-EU[134]



Source : Hydrogen for Europe study

9.1.6 Energy policy assumptions in MIRET-EU

328. In MIRET-EU, the policy assumptions presented in Annex C, section 8.3, both at the country and EU-level were explicitly represented through constraints in the model. They include sectors covered by the overall EU emissions targets for 2030 and 2050, the targets for the sectors covered by the EU ETS and that of non-EU ETS sectors, the Energy Efficiency Directive with particular attention to the transport sector, the Renewable Energy Directives and the NECPs.

9.2 Description of Integrate Europe model

9.2.1 Brief overview of modelling framework

329. Integrate Europe is a cost-minimization model for energy-systems. Energy can be extracted from European sources and imports, converted to other energy types, stored (at least for some carriers), and consumed to meet specified energy needs or exported. Hence, there is competition between the different energy carriers and technologies all over their value chain. The full optimization is divided into two parts, which is elaborated in the following section:

- System operations
- Investment planning

330. Central inputs to the system operational part are:

[134] Transformation sector encompasses biofuel and hydrogen production.

- Energy needs, and end-use technologies
- Existing energy supply system (i.e. capacities, efficiencies, and retirement year)
- Cost and available quantities for European energy resources
- Forecasts for prices for import and export
- Policy constraints, notably on CO_2 emissions and RES shares
- A discrete set of investment options

331. The system operations part of the model is solved for each of the possible set-ups of the energy system, and for different years up till 2055[135]. In each of those optimizations the model takes the capacities of various technologies as an input (parameters), and then it minimizes the operation cost of that system for each relevant year using the linear formulation (LP). The time-resolution for the system operations is one hour, and typically one representative day of each season plus a peak load are simulated. From this, an annual operation cost of the system is calculated. The optimization is repeated until all relevant energy system designs have been evaluated for all the years. The set of energy system designs to be considered is implicitly defined as the set of all possible combinations of elements in the specified set of investment options, except those who are explicitly not permitted to reduce computational time. The final output from the system operations part is a matrix of annual operational costs for each combination of {energy system design, year}.

332. The investment planning part has two main input categories:

- The matrix of operational costs for different years and energy system designs, which was calculated by the system operations part of the model.
- Specific information for investments: investment costs, economic life, discount rate, and fixed operational cost.

333. Based on this, the model calculates the least-cost investment plan for the planning period. It minimizes the net present value of total costs (CAPEX + OPEX) using a dynamic programming algorithm (DP). The time-resolution for the investment planning is typically 5 years. The outcome from the investment planning is the cost-optimal investment plan (i.e. which investments and when to invest), plus any number of alternative investment plans and their corresponding costs (2nd best alternative, 3rd best alternative, among other). The operation of the system (all variables) for each year and investment plan is also a part of the output, and corresponding objective function.

9.2.2 Specifying Europe's energy system in Integrate Europe

334. Quantification of the European energy system model into Integrate Europe was based mostly on the JRC database, e.g. the same basis as the MIRET-EU model.

335. The main difference between Integrate Europe and most other energy system models used on the European scale is on how it handles the optimization of investments. Learning effects entail challenging mathematical formulations, thus the Integrate Europe model have been set up in a way that non-linearities due to path dependencies are captured and solved in a reasonable computational time.

336. Learning effects introduce the following non-linearity: Total investment costs in a period (Euro) is equal to the investment amount (MW) multiplied by unit investment costs (Euro/MW), where unit investment costs (Euro/MW) are affected by the aggregated investments (MW) of previous periods. Hence, there is a multiplication between two variables: a) investment in the previous period, indirectly through the unit investment cost term, and b) investments today.

- Non-linear problems cannot be solved in ordinary LP formulations. However, it can be solved by dynamic programming (DP), which is the algorithm used by Integrate Europe, or e.g. by a mixed integer programming (MIP) formulation. The challenge by the discrete DP / MIP formulations are however that the size of the problem in principle doubles for each new investment option that needs to be considered. This explains

[135] The time-steps in the planning period are: 2020 (today's system; no new investments), 2030, 2040 and 2050. Each period represents 10 years, e.g. 2045 – 2054 for 2050. The first day after the planning horizon is thus 2055.

why the representation of the European energy system in Integrate Europe needs to be aggregated and simplified considerably compared to the degree of detail included in MIRET-EU: Integrate Europe is represented by a single geographical node.

- Technology representation is more aggregated in Integrate Europe. However, inputs to the two models are based on the on the same JRC database.
- Investments options are a set of "investment packages" for several technologies, each with a specific capacity, instead of being continuous (or almost continuous) variables for each technology. The investment packages are in principle predefined for the investment optimization. In practice, many different package designs are tested to get the best possible outcome.

337.For the mapping from many investment options in the JRC database to fewer investment options in Integrate Europe, an initial screening was carried out by the calculation of levelized cost for 2019 and 2050. The cost estimate for 2050 accounted for technology learning. As an example, the investment option "Solar power" in Integrate Europe, the corresponding JRC category "Utility c-Si, tracking" was applied because levelized costs for that technology is lower than for alternative solar power technologies in the JRC database. Limitations in the technical potential for certain technologies were are also accounted for.

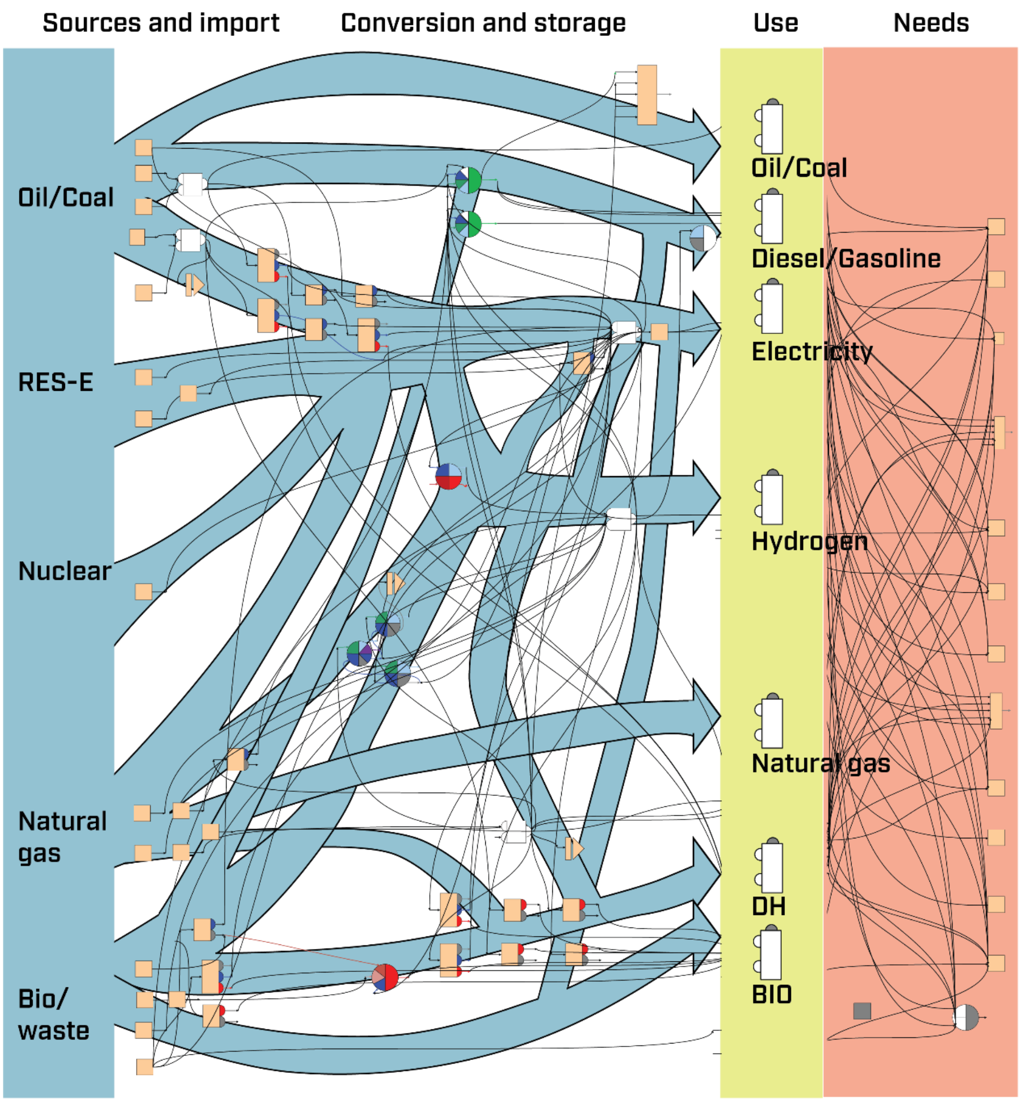
338.Figure 77 illustrates the implemented model of the European energy system that was built in Integrate Europe.

339.At the far left in figure 77 there the European energy sources (e.g. wind-power production or natural gas extraction), and import/export of energy products between Europe and non-European countries (plus Russia). The consumed energy products are shown in the yellow column, whereas the energy need forecasts are represented in the orange column. The thick M lines show how energy flow from energy sources to energy consumption. They cross each other due to conversion between energy carriers.

340.Hydrogen is used as an example of the illustration. Hydrogen can be produced through different options. First, renewable sources shown at the left (RES-E) can be used to produce electricity. This can be converted into hydrogen, as seen by the "link" going from electricity to hydrogen, and the model's symbol for electrolysers are shown there. Even though there is only one symbol representing electrolysers, there can be many different units in the dataset having their own specific parameters. There is also a link from natural gas to hydrogen (and symbols for reforming and pyrolysis, including carbon black market), and from biomass (with the gasification symbol). Hydrogen can be consumed as an energy carrier or converted into electricity, heat production for district heating, or eFuel, as shown by corresponding links. In the optimization model there is also consumption of ammonia produced via hydrogen, and a gas mix with a share of hydrogen in the blend. The end-use of hydrogen can be used to satisfy energy needs with specific end-use technologies. For example, hydrogen can be used as an energy carrier for heavy land-based transport, industry heat, and as a feedstock in iron and steel production – of which all have exogenous forecasts of future demand. However, energy carriers / solutions compete to satisfy those needs in the model. In the optimization model, it is also possible to import low carbon hydrogen (RES-E/electrolysers, and natural gas reforming / CCS).

341.In the model there is also the possibility to capture, use and/or store CO_2. A carbon black market is also included to account for the value of that by-product from the production process of pyrolysis. CO_2 emissions are calculated for extraction, conversion, and consumption of fossil fuels. Biofuels are considered climate neutral, or even providing negative emissions for bio/CCS technologies. Upstream emissions are not calculated for imported energy commodities.

Figure 77. Illustration of the implemented model of the European energy system in Integrate Europe[136]



Source : Hydrogen for Europe study

9.2.3 Integrate Europe's Investment packages

342. As a part of the input to the model, a set of investment packages is specified. Each investment package includes a set of technologies that are represented in Integrate Europe, which share some main characteristics, and a corresponding invested amount for each of them. If the model chooses to invest in one such package, all the included technologies and corresponding capacities are included into the energy system. The amount included for each specific technology in an investment package is in principle pre-defined input to the optimization algorithm.

343. Initially the amount for each technology, e.g. for the different types of renewable electricity in the renewable electricity package, was based on a levelized costs estimate for 2019 and for 2050, and on basis of results from other studies[137]. Gradually, the package specification was further tuned to be coherent with outcomes form MIRET-EU modelling pre-runs. Further details on the model linking strategy are provided in section 7.4.

[136] The illustration is a simplification; not all included energy flows, conversion options, energy carriers or included components in the model are shown.
[137] Notably 2050 values in the Beyond 2°C Scenario in IEA's Energy Technology Perspectives 2017 (ETP 2017).

344. When defining several investment packages, the total number of possible investment pathways grows very fast with the number of packages. The total number of combinations to be considered for one single year is:

$$\#Combinations = (\#A+1)^{\#B},$$

345. Where #B is the number of investment packages, and #A is the number of ambition levels within each investment package. A simple example would be to consider a set of renewable electricity and a set of hydrogen technologies (#B = 2), where each set contains three packages that represent different capacity levels one may invest in (#A = 3). The total number of possible combinations would then be 16.

346. For this reason, the consortium has been working on identifying the right number of investment packages that is required and feasible to be used in the study. Several strategies for designing investment packages were analyzed using the evaluation criteria listed in table 13.

Table 13. Evaluation criteria for the investment package strategies

Priority order	Criteria, and short description
1	Accuracy Ideally, without considering other constraints, it would be beneficial to represent investments as similar as possible to the specifications used in MIRET-EU model. It should enable to represent the most important aspects to be analysed in the study, including: • Hydrogen-based solutions vs. all-electric solutions. • Hydrogen produced from renewable electricity vs. natural gas. • Biofuel/CCS, and hence negative emissions. Negative emissions are needed to compensate for any remaining emissions in 2050, e.g. from natural gas reforming with CCS. • Carbon capture for natural gas reforming, power generation, and other technologies. • Costs of batteries and grid in an all-electric scenario vs. costs of alternative flexibility/storage, e.g. hydrogen storage with corresponding energy conversion from hydrogen to other energy carriers.
2	Computational time In principle, computational time is doubled for each new investment package considered in Integrate Europe. In practice, it is less because of several speed-up strategies implemented. Still, computational time is a main criterion to be considered for dealing with investments. Furthermore, the focus of the project is mainly on the supply-side, so most of the (limited) computational resources should be allocated to that part.
3	Transparency and simplicity Transparency and simplicity in the overall approach is important for both communicating results, and for avoiding different kinds of errors and logical flaws.
4	Manageable graphical representation In Integrate Europe, all modelled components (existing and investment options) are shown individually in the graphical user interface. Hence, there is also a need for keeping a manageable overview on the graphical representation.

347. In addition, the modeling setup aims at analyzing the transition towards a net zero emission energy system in Europe by 2050. Hence, the model focuses on technologies allowing that transformation. It does not consider any new investments in the energy supply chain for coal- and oil-based technologies. For the use of natural gas, we only include investments in new gas-power plants with CCS and investments in hydrogen and ammonia production based on natural gas and CCS.

348. Based on these criteria, the investment packages in table 14 were selected. For each type, there are several ambition levels considered (maximum of four). An example of an investment package is shown in table 15. Even though the quantities formally are predefined for the optimization model, they are not predefined when considering the whole process. When analyzing a specific scenario, typically 8 different set-ups for the investment packages were tested. On basis on the objective function (optimal costs) for those 8 cases, and also considering the operation of the system, eight new cases with respect to investment package setups were specified and tested. That process was repeated typically 6-7 times until no further improvement were observed. Hence, through this iterative procedure, investment packages were tuned to produce as low total cost as possible. There is however no guarantee that the final setup leads to a global optimal being calculated by the model, which would be the case in linear models. Integrate Europe is used because of the need for a non-linear model to handle learning effects, which also may produce a non-convex solution space.

Table 14. Investment packages

Description	Further specification
Renewable electricity (IP#1)	Power generation from solar PVs, on- and offshore wind and corresponding electrical storage. Costs for transmission grid is also included.
Hydrogen produced from natural gas (IP#2)	Hydrogen production from natural gas: reformation with integrated capture of CO_2 and pyrolysis including sale of black carbon. Hydrogen storage costs are also included.
Electrolyser hydrogen production (IP#3)	Hydrogen production through electrolysers. Includes hydrogen storage costs and compensation for the avoided costs in power system (e.g. grid, storage) due to local utilization of renewable electricity.
Hydrogen conversion (IP#4)	Conversion of hydrogen to electricity and/or heat.
Biomass hydrogen, power and heat (IP#5)	Conversion of biomass to hydrogen, power, heat and biofuel. CO_2 capture is included hydrogen- and power production.
Natural gas power and CHP (IP#6)	Natural gas-fueled power generation, heat production for district heating, and CHP with integrated capture of CO_2.

Table 15. Example: Investment packages for RES-E (values in GW)

	Packages					JRC name
	1	2	3	4	Sum	
Wind onshore	135	371	248	48	803	Wind onshore CF25+
Wind offshore	140	143	68	13	364	Wind offshore both Monopile and Jacket
Solar PV	150	330	575	112	1167	Utility c-Si, tracking
Sum	425	844	891	174	2334	

9.2.4 Exceptions in investment optimization modelling and capacity evolutions

349. For some investments, policies are at least as important as profitability for installing new capacities. For other investments, the geographical location of specific resource is important for their competitiveness. Hence, to get the two models fairly aligned in terms of their outputs, the capacities for some technologies were extracted from pre-runs with the MIRET model and taken into Integrate Europe exogenously. This was done for the following technologies: nuclear power, hydropower, gas power with CCS, and methane pyrolysis. For gas power and methane pyrolysis a minimum constraint on the annual operation time was also included.

350. For CO_2-storage and corresponding transport cost to the storage, the learning-by-doing study has revealed that the major cost-reduction can be achieved through economy of scale effect rather than further learning after having large infrastructure in place. Integrate Europe includes a cost markup (in €/ton of CO_2) – instead of explicitly handling capacities – and the cost takes large-scale infrastructure as a premise.

351. End-use technologies are the options to use a specific energy carrier to provide a specific need. An example is electric vehicles (an end-use technology), which consume electricity (an energy carrier) to provide light transport (the energy need). We include investments in new end-use technologies by allowing the model to optimize the extra capacity at a given annual cost per capacity unit. That capacity comes on top of non-retired capacity existing in year 2020, if any. Those investment decisions are included as a part of the linear operational optimization, and not in separate investment packages (cf. main approach for investments in the supply-side of the energy system). The advantage of this approach is that the model is able to include investments on the demand side, and thus also analyze transformation of this end of the energy system towards 2050, even if the number of investment packages we can handle is limited. The disadvantages / limitations with it are: 1) There might be too high flexibility in the capacity optimization since end-use technologies can be optimized within each decade, and 2) No learning effects are included for end-use technologies since they are treated apart.

352. To handle end of period conditions, some early investments which economic life ends before the planning horizon has been extended for a few extra years, whereas investment costs has been increased correspondingly by the discounted annualized cost of the investments for those extra years. This adjustment is accounted for by the technology learning model.

9.2.5 Accounting for technology learning in investment costs

353. Technology learning and corresponding impacts on investment costs is described in a separate chapter. The main elements that goes into the final quantification of investment cost for Integrate Europe investment packages are:

a. *Global investments*, which is an external projection on how the capacities of various technologies will develop in the "rest of the world" over time (i.e. the world outside of Europe). Global investments are exogeneous in Integrate Europe.

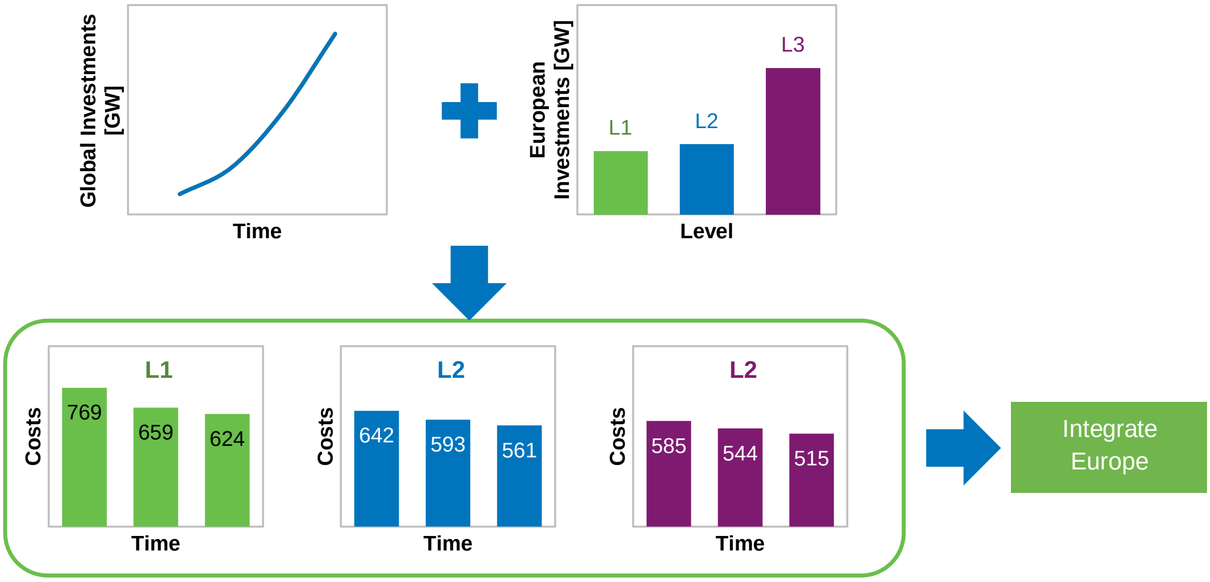
b. The *learning curves*, which describes the estimated cost development as a function of total investment (exogenous for the "rest of the world" plus endogenous for Europe through Integrate Europe), for each considered technology.

c. And different (pre-determined) levels of ambitions regarding the European investments in the specified package / set of technologies. Each level corresponds to a certain level of capacity investments.

354. In Integrate Europe, the global learning is included by an exogenous reduction in the cost of investment packages. The endogenous learning part is included by having a lower unit cost (Euro/GW) for ambitious level no. 2 compared to no 1, and so on. However, package no. 2 cannot be taken before investing in package no. 1. Those cost parameters are calculated as an input to Integrate Europe through an Excel-based tool. Since Integrate Europe takes both endogenous and exogenous learning into account, future technology costs are outputs from the model. Future investment costs are forwarded from Integrate Europe to the MIRET-EU model.

355. Figure 78 illustrates how cost-reduction through learning is implemented in Integrate Europe. The example consists on a single investment package with three pre-determined levels of ambition (L1, L2, and L3) in terms of capacity (i.e. GW invested) which the Integrate Europe investment algorithm can decide to install. Because of global investments and the learning curve, the cost for each investment package (L1 – L3) considered in Integrate Europe goes down over time, as shown at the top right of the figure. In addition, the cost of investment package L2 is reduced due to European investment levels in the investment package L1, which is shown by the lower height of the green bars compared to the yellow ones. This information then goes into Integrate Europe. The L2 investment is only allowed if the L1 investment has already been taken, whereas the L3 investment are allowed only after the L2 investment has been taken. Integrate Europe calculate optimal capacity development over time, and thus also implicitly how investment costs develop.

Figure 78. Schematic illustration of how endogenous[138] and exogenous learning-by-doing effects are implemented in Integrate Europe



Source : Hydrogen for Europe study

356.The levels of ambition regarding investments in each investment package are pre-determined based on the results of another model run, standalone assumptions and/or cost-related data. In particular, as each investment package includes more than one technology, the installed capacity (GW) of a given technology within this package is specified prior to the Integrate Europe optimizations.

9.2.6 Implementing energy policies

357.Energy policies that have significant impact on a European level are implemented in the aggregated model in Integrate Europe[139] (see section 8.3 for further details). These policies are identified as:

- The 2030 and 2050 greenhouse gas emission reduction targets at the EU level,
- The 2030 renewable energy and the energy efficiency targets at the EU level,
- The phase-out timelines for coal and nuclear power plants set at country level,
- And the constraints in the amount of biofuel and hydrogen to be imported to Europe.

358.Among these, only the phase-out targets are not by nature given on an aggregated level. The aggregation approach consists in summating the capacities in the individual countries and remove electricity and heat production capacities for coal at the year's corresponding to phase-out agendas. For nuclear capacity, outputs from the MIRET-EU model are an exogenous input to Integrate Europe.

9.3 Learning-by-doing module

359.*Learning-by-doing* refers to the cost reduction that occurs due to an increased technology deployment. In the simplest models, no assumption is made as to *why* or *how* this learning occurs; it is simply an empirical fact

[138] A hybrid approach is used in the model combining both endogenous and exogenous cost reductions in order to consider potential international learning rates.
[139] Integrate Europe uses enacted policies until 2050.

that technology costs decrease as deployment increases, and this is a relationship that can be quantified by curve fitting historical data and then extrapolating from there. This was the original approach taken by Wright (1936) to model the cost developments of airframe manufacturing, and this model class has since been found to accurately predict the cost of commercialized technologies in general. By now, many variants of such models have been developed, and differences include whether *learning-by-research* is included as a separate contribution. In our study, we focus on the simplest learning models: single-factor learning curves. This is the most widely employed endogenous learning model in the literature, resulting in more available estimates of relevant model parameters.

360. The single-factor learning curve assumes that the cost per unit C as a function of the total installed capacity x follows a power law $C/C_0 = (x/x_0)^b$, where C_0 and x_0 are corresponding values at some earlier time, and b is an empirical parameter determined by fitting historical data.[140] Where historical data does not exist, e.g., for emergent technologies such as CCS, b may be estimated from similar technologies. Typically, instead of reporting the b directly, one reports the *learning rate* LR = $1 - 2^b$. This number has an intuitive interpretation: if the learning rate LR is 20%, the cost C decreases by 20% every time the capacity x doubles.

361. In our treatment, three generalisations of the single-factor learning curve have been employed. First, we split the capacity x into two contributions x_{EU} inside Europe and x_{RW} for the rest of the world, where the former is treated endogenously (model output) and the latter exogenously (model input). This was deemed necessary because we only optimise the European energy system in this project, which means that this is the only region we can treat fully endogenously. Second, we employed a *composite learning curve* for some technologies like natural gas plants with carbon capture. In this case, we split the plant cost into two, $C_{NG+CC}(x_{NG+CC}) = C_{NG}(x_{NG}) + C_{CC}(x_{CC})$, where the natural gas plant (NG) and carbon capture (CC) submodels have different learning rates and existing capacities. This is necessary when a technology is constructed from two subtechnologies with very different learning rates and existing capacities. Third, for technologies with zero or near-zero existing capacities (like CC), we assume learning starts when some critical capacity x_{min} is reached; until that point, a constant cost $C = C(x_{min})$ is assumed. This assumption has an empirical foundation: until a technology has been commercialised, its cost evolution is often unpredictable and can even increase, so the learning curve above is inaccurate. Moreover, it is mathematically required to impose some sort of low-capacity correction to the standard learning curve model to avoid a singularity where $x \to 0$. Step two and three above were based on a similar approach suggested by Rubin et al. (2007).

362. After adjusting the model as described above, the model was discretised to enable integration into Integrate Europe. First, for each investment period (2016-2025, 2026-2035, etc.), we determined the capacity change Δx_{RW} in the rest of the world from global projections (IEA Energy Technology Perspective 2017 and 2020). Second, each investment package ("Electrolyser 1", "Electrolyser 2", "Reformer 1", etc.) is *defined* by its European capacity change Δx_{EU}. This means that investing in a given package, in a given period, produces a net capacity change $\Delta x = \Delta x_{EU} + \Delta x_{RW}$. The average cost of capacity expansion may then be calculated by integrating $C(x)$ over this interval Δx. Repeating this calculation for each investment period and investment package, we populate a table of capacity expansion costs for each technology. This table is used to calculate investment cost during Integrate Europe optimisation.

9.4 The hydrogen import model - Hydrogen Pathway Exploration model (HyPE)

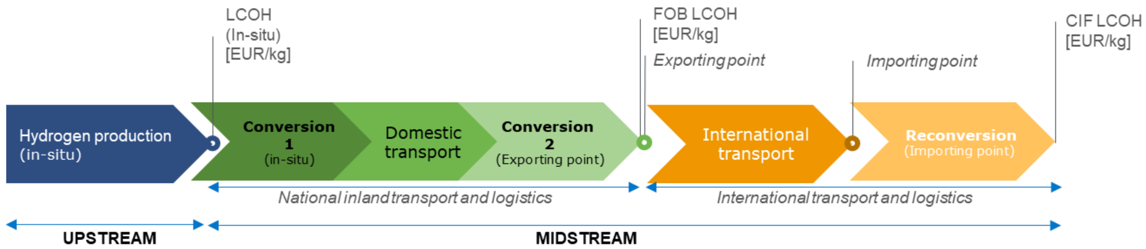
9.4.1 Principles and methodology

363. Hydrogen Pathway Exploration model (HyPE), as illustrated in figure 80, aims at providing to the main models a way to introduce potential hydrogen imports from neighboring regions (namely North-Africa, Middle East and Russia). The results consist in supply curves, indicating both the potential of hydrogen production per region

[140] It is possible to fit a learning curve $C(x)$ to other progress metrics x than the total installed capacity. For example, Wright's original model let x be the number of airplanes produced, which is useful for the manufacturing sector. Aside from the total installed capacity which we discuss here, the *total production* can also be a useful metric for learning curves in energy system models.

and the associated costs following a levelized cost of hydrogen approach (LCOH[141]) with a cost, insurance and freight view (CIF[142]). The methodology builds on the full delivery value chain to determine LCOH at each European importing point, as illustrated in figure 79.

Figure 79. Hydrogen import value chain[143]



Source : Hydrogen for Europe study

364. The two overarching principles of the HyPE model are:

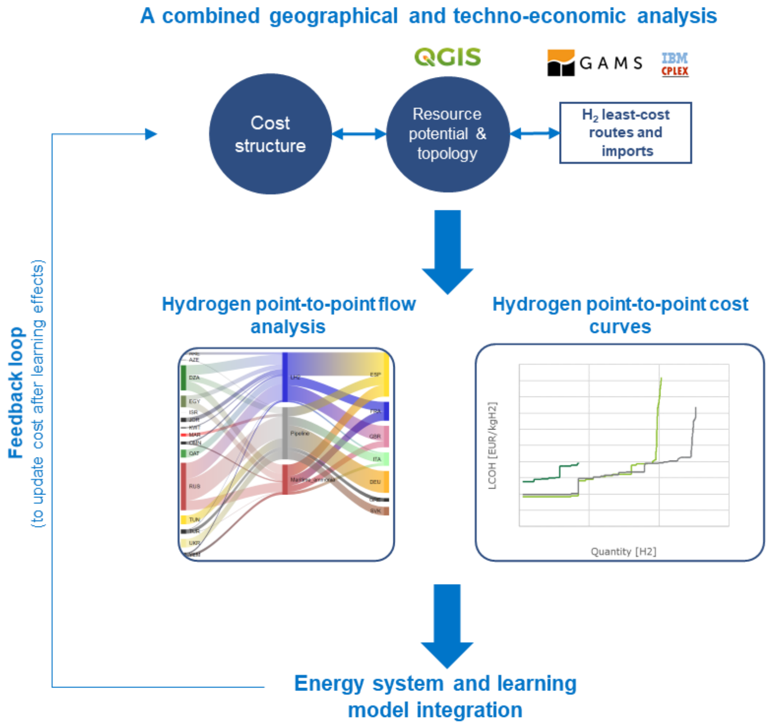
365. **CO_2 neutrality of European energy imports**: *"decarbonization of energy imports can be achieved via decarbonizing imported natural gas (either pre-combustion or post-combustion), or by importing any other renewable or decarbonized gases (e.g. H_2/LH2, P2G, Biomethane, etc.)".*

366. **Technology neutrality of hydrogen production**: "*Natural gas converted to hydrogen at import point/city gate (main study) or direct hydrogen imports*" (ENTSO-E and ENTSO-G 2020).

367. The approach builds on an optimization model choosing the most cost-efficient way to supply hydrogen to Europe, considering different upstream options (renewable energy, natural gas), transport modalities (trucks, pipeline and bunkers) and energy vectors (ammonia, liquified hydrogen, gasified hydrogen). The resulting cost structure is therefore driven by production costs, but also includes transport cost, conversion and reconversion costs depending on the transport technology and route. The cost-minimization is performed in a country-neutral and technology neutral way.

[141] The levelized cost of hydrogen adopts the life cycle costing methodology. It is defined as the summation of all the discounted fixed and variable costs necessary for the production of hydrogen over the expected lifetime of the installation, divided by the total volume produced during its lifetime
[142] Cost, insurance and freight, as defined in Incoterms, means that the exporter delivers the product at the port of destination, so the cost at the loading port includes the cost of transport and logistics
[143] * FOB: Freight on board. **CIF: Cost, insurance and freight

Figure 80. Architecture of the HyPE model



Source : Hydrogen for Europe study

9.4.2 Upstream: Hydrogen production

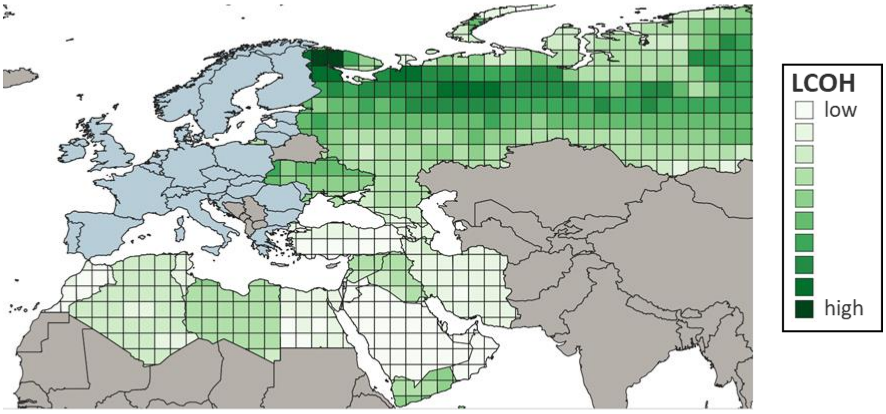
Renewable hydrogen from variable renewable energies

368. The production of renewable hydrogen from variable renewable energies highly depends on local factors such as the natural resources of wind and solar radiation as well as on the availability of suitable land. The methodology for the estimation of feasible solar and wind resources for the production of renewable hydrogen is based on (Ruiz et al., 2019) and (Milbrandt and Mann, 2007).

369. To capture the availability of local solar and local wind resources a 2.5 decimal degree grid has been projected on the considered export regions (see figure 81). For each grid cell both an annual wind speed time series and an annual solar radiation time series were determined at its centroid location based on 2016 data from the NASA MERRA-2 dataset[144]. From these raw data, hourly energy yields were derived. For onshore wind turbines a hub height of 130m and a corresponding power curve were considered to obtain the hourly wind yield at every cell. For solar PV plants a fixed/non-tracked system was assumed and an optimized tilted angle according to the centroids latitude of the cell was determined. The study considers the installation of dedicated hybrid systems that are off-grid and hence, that are not connected to the local electricity grid. The hybrid system can possibly consists of three elements namely an electrolyser system, a wind plant and a solar plant, that are sized optimally based on both techno-economic at global level such as component costs and locational specific factors such as financing costs and natural resources. Consequently, depending on its location, the optimal configuration can either consist of only one power production source (solar PV or onshore wind) plus an electrolyser system or of a combination of both power sources plus an electrolyser system. For the optimally determined system configuration at every cell centroid, the corresponding levelized costs of renewable hydrogen were then derived for every year.

[144] Extracted from renewable ninja https://www.renewables.ninja/ (Pfenninger and Staffell, 2016) and (Staffell and Pfenninger, 2016)

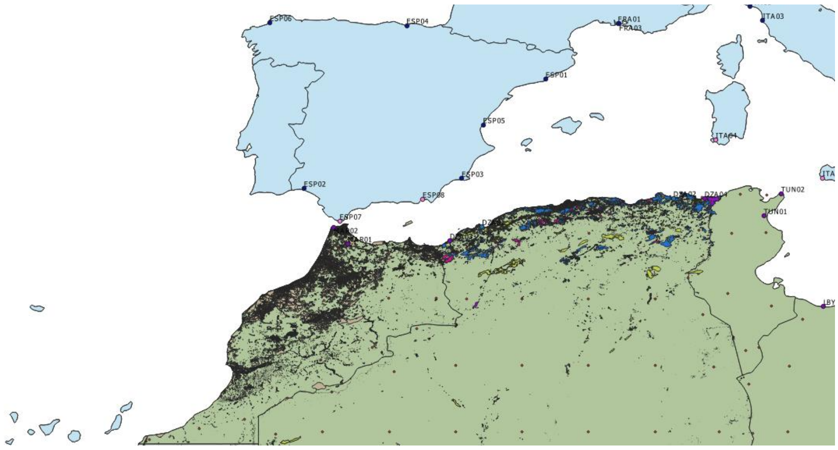
Figure 81. Illustrative map of levelized costs of renewable hydrogen



Source : Hydrogen for Europe study

370. The maximum exploitable renewable potential builds the basis for the determination of the potential renewable hydrogen production volumes. Land-use data[145] of every cell were analyzed to obtain the available space for the installation of renewable energies and hence, to determine the potential production of hydrogen. Surfaces assigned to the categories of residential and industrial areas as well as national parks and water bodies were considered to be non-usable for renewable energies and hence, they were excluded (see figure 82). For the remaining areas, it is considered that only 3% of the surfaces are eligible for the deployment of solar PV. A power density, that describes the maximal installable capacity per square kilometer, of 170 MWp/km^2 was assumed. For onshore wind, all available space was assumed to be eligible for the deployment of onshore wind. A power density of 5 MW/km^2 was applied for this technology (Ruiz et al., 2019). To limit domestic transport costs and energy losses, only cells within a maximum distance of 1000km to an international exit point (terminal or pipeline) were taken into account in the analysis as potential exporting locations.

Figure 82. Determination of the maximum available space for the installation of renewable energies using land-use data



Source : Hydrogen for Europe study

371. The maximum exploitable national renewable energy trajectory until 2050 follows a similar installation pace of solar and wind than that observed in Europe between 2000 to 2018 (IRENA, 2020a and IRENA, 2020b). It is noted that this deployment pace is said to be conservative in absolute terms as the economics of wind and solar have improved since early 2000s, and faster renewable deployment can be expected in the coming decades in theory. Furthermore, to also consider decarbonization efforts of the potential exporting countries,

[145] https://www.geofabrik.de/

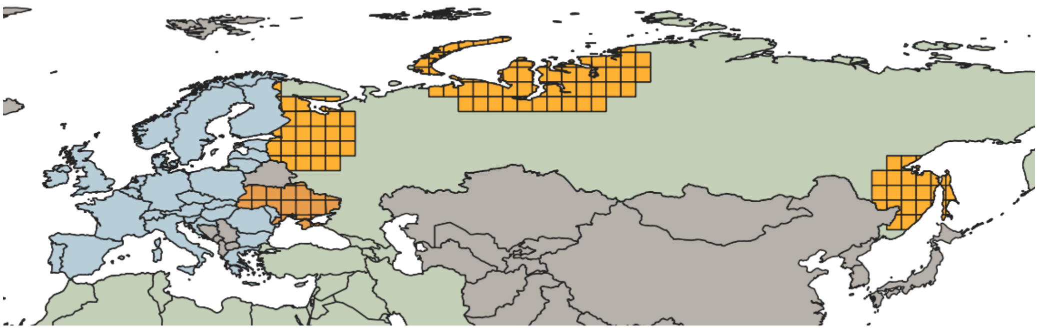
only 50% of the maximum potential installed capacity was allowed to be dedicated for exports to Europe. The obtained renewable potentials were verified against the international potential estimated by NREL (2019).

Hydrogen from biomass

372. The potential renewable hydrogen production from biomass highly depends on the availability of natural feedstock resources. Only Russia and the Ukraine have substantial biomass potential in the considered geographical scope of exporting countries. Therefore, only these two countries were taken into account in this study for the production hydrogen from biomass.

373. Another important aspect for hydrogen from biomass is the ability to transport the feedstock to the production facility which is considered to be centralized and located in the proximity of an exporting point. Therefore, similar to the production of hydrogen from wind and solar, a 2.5 decimal degree grid was projected on the territory of Russia and Ukraine to capture the impact of transportation costs and availability on the production potential of hydrogen from biomass.

Figure 83. Considered regions for supply of biomass feedstock



Source : Hydrogen for Europe study

374. The total biomass feedstock availability is considered to be uniformly distributed over the individual cells in the countries. Furthermore, only forest residues are considered as feedstock for the production of hydrogen as it is the only easily transportable biomass with an economically viable energy density. Considering its volume and energy density, the maximum freight range admissible for biomass that is considered in this study is 700 km (see figure 83). The resulting volumes of biomass that are available for the hydrogen production in the resulting regions are given in table 16. The maximum distances of 700 km allow to compare the transportation of biomass with the transportation of coal so that associated freight cost is assumed to be around 0.425 EUR/kgH2/1000km (Argus, 2017). Moreover, similar to the methodology applied for variable renewable energies, only 50% of the overall available biomass feedstock is assumed to be available for the production of hydrogen for exports to account for potential domestic demand.

Table 16. Considered regional biomass feedstock[146]

Area	Available biomass feedstock (TWh)
Russia - Ural Federal District	4.3
Russia - Far Eastern federal District	0.7
Russia - Northwestern federal District	9.7
Ukraine	29.9

Source : Own calculations based on (Namsaraev, 2018)

[146] Derived from (Namsaraev, 2018)

375. The production of hydrogen from biomass is assumed to take place in centralized gasification plants. The resulting levelized costs of hydrogen consists accordingly of the costs related to the production facility, the transportation of biomass as well as the costs for the feedstock. The costs for the feedstock is considered to be 6.5 USD/GJ (IRENA, 2017). Moreover, the facilities are assumed to operate at a load factor of 85% throughout their technical lifetime.

Low carbon hydrogen from methane

376. Only imports of low carbon hydrogen from methane produced in current gas exporting countries to the EU within the region under the scope were assessed (i.e. Algeria, Azerbaijan, Qatar, Russia, Egypt and Saudi Arabia). Given that natural gas infrastructure is well developed in the countries considered, production facilities are assumed to be installed near the location of the exit point (pipeline and/or terminal) to avoid additional inland transport costs.

377. Two set of technologies to produce low-carbon hydrogen where assessed:

- **Reformers with CCS**: Steam methane reforming (SMR CCS), Autothermal reforming (ATR CCS) and Gas heated reforming (GHR CCS), all with carbon capture and storage (CCS) were considered. Full cost was considered assuming rock formations were available within a reasonable area around the production sites (IPCC 2005, 21) to estimate an average cost related to CO_2 transport and storage[147].

- **Methane pyrolysis** (carbon black co-product revenues included): Same than for the European hydrogen production alternatives, methane pyrolysis was assumed to be commercially available from 2030 onwards. Due to strategic considerations of the Russian national gas producing company, methane pyrolysis is the only technology being currently considered for Russia.

378. Following the approximation made by the IEA in future clean gases demands (IEA 2019b), 15% of the current natural gas exports were considered as the maximum dedicated feedstock potential to export hydrogen to Europe in each country. Additionally, Azerbaijan (AZE) is expected to produce around 50 bcm of natural gas in 2025 at the completion of the SCP/TANAP/TAP project, thus we expect around 20% this production could be used to produce low carbon hydrogen to the EU market by 2025. No further projections regarding the evolution of the exporting shares given future infrastructure developments were considered.

379. Local cost of methane was assumed to be the average breakeven price in each exporting country. Breakeven gas prices were estimated by calculating the percentage difference with respect to country average breakeven oil prices from the International Monetary Fund, and applying it to gas producing countries assuming an average of 2.4 USD/MMBtu as the basis[148]. The obtained range of breakeven gas prices were verified by benchmarking them against typical average wellhead cost of basins of similar type for each region (i.e. onshore, deep, shallow, ultra deep). They don't include any national tax scheme.

380. Price of carbon black (by-product of methane pyrolysis) was assumed constant at 100 EUR/ton, and compensation for unabated emissions for both reformers with CCS[149] and methane pyrolysis[150] were accounted for by assuming a CO_2 cost of 30 EUR/ton (due to lower than 100% CO_2 capture rates or gas-fired reactors).

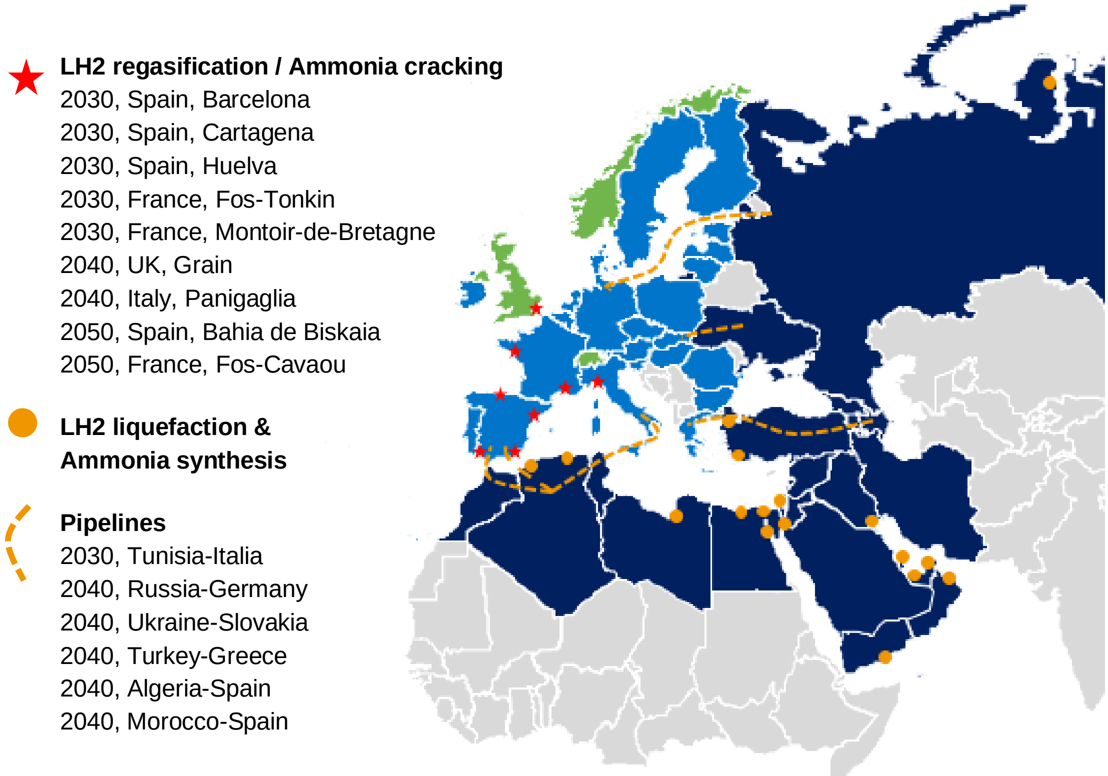
9.4.3 Midstream: Hydrogen transport

381. The competitivity of hydrogen imports is highly determined by the transport infrastructure available. Depending on the distance between production and delivery points, several transportation paths are currently envisaged

[147] At the same time, it was assumed that CO_2 stored volumes at those sites was at least 10 Mt per year which would lead to transport and storage cost of around 11.4 €/ton (after considering economies of scale) based on the H21 North of England report (Sadler et al. 2018, 21).
[148] This value corresponds to the average US dry gas wellheads breakeven values reported by BNEF (BloombergNEF 2019). For Algeria, with a declining export trend (Aissaoui 2016), the breakeven cost assumed was that of a dry gas Africa shore well. Tests have been conducted to provide robustness to this assumption and we have obtained that LOCH are within the +/-10% range for all countries with average breakeven prices changing in the 2 to 2.9 $/MMBTU window.
[149] Capture rates assumed in the 95% range.
[150] Assuming a gas-fired process.

and integrated into the modeling framework in accordance with the overall technology-neutral approach. We considered for national inland transport hydrogen trucks, either with compressed hydrogen or ammonia trucks. For international transport, pipelines, ammonia shipping and liquified hydrogen (LH_2) have been considered.

Figure 84. Assumptions on the likely development of hydrogen import/export infrastructure



Note: Existing gas basins are also entry point for hydrogen shipping

Source : Hydrogen for Europe study, based on data from the European Hydrogen Backbone and own assumptions

382. Liquified hydrogen terminals have been added to the model as possible entry points in Europe for hydrogen. An analysis of the infrastructure utilization rate shows that European LNG terminals are currently under-used (IGU 2020). With the expected ramp-up of NordStream 2 in the coming years[151], ample pipeline connections with Russia should materialize. As the natural gas consumption in Europe drops, EU LNG terminals are assumed to see their utilization rates dropping in the coming years. We therefore make the hypothesis that the refurbishment of LNG terminals to handle liquified hydrogen (LH_2) is an option from 2030 onwards. The older terminals in countries with the lowest utilization rates lowest have been assumed to be the first to be refurbished. The availability timeline is then made by a combination of the commissioning date and the forecasted utilization rate of the terminals (see table 17). Refurbishment of existing terminals is preferred to build brand-new ones as it allows to save around 25% of investment costs from the reuse (avoiding cost of jetties, waterways, utilities, etc.) (Oxford Energy, 2014). In terms of volumetric capacity, liquified hydrogen terminals are supposed to handle each year the same volume of liquid gas than the previous LNG terminals did. On an energetic point-of-view, it means only 40% of the energy capacity of the LNG terminal is available when refurbished to hydrogen.

[151] By the time of writing the project has been almost completed but is the subject of multiple geopolitical controversies between Russia and the EU.

Table 17. Considered liquified hydrogen/ammonia terminals

Country	Terminal	Capacity (TWh)	Start year	Assumed refurbishment year	Terminal age (in 2020)
Spain	Barcelona	180	1969	2030	51
Italy	Panigaglia	37	1971	2045	59
France	Fos Tonkin	31	1972	2030	48
France	Montoir-de-Bretagne	105	1980	2030	40
Spain	Huelva	124	1988	2030	32
Spain	Cartagena	124	1989	2030	31
Spain	Bahia de Biskaia	120	2003	2050	37
UK	Grain	214	2005	2040	15
France	Fos Cavaou	86	2010	2050	30

Source : Hydrogen for Europe study based on data from GIE

383. Capacity of liquified ammonia terminals might as well be expanded, justifying the choice to consider this carrier as a feasible hydrogen importing option in Europe. Ammonia (NH_3) is seen as an effective hydrogen carrier for long distance shipping. It presents the advantage to be liquid at higher temperature than LNG or liquified hydrogen, and its higher energy density allows it to compete in terms of costs against liquified hydrogen. From a volumetric point-of-view, ammonia presents an energy density 1.7 times higher than liquified hydrogen. This means that for the volume transported per year, ammonia regasification plants treat 70% more energy than a liquified hydrogen plant with equivalent capacity. Based on these elements, a timeline has been created to model the evolution of energy-related ammonia importing terminals in Europe. Similar than for shipping liquified hydrogen, ammonia is assumed to be reconverted to hydrogen at the importing port. Thus, a final step of catalytic cracking of ammonia is considered in the LCOH estimate for this route. The international trade of ammonia is well established but despite promising prospects for ammonia as a shipping fuel, such an use is not expected before 2035 (DNV-GL, 2020). Therefore, considering ships fueled and transporting ammonia (decarbonized) is essential to be consistent with the hypothesis of CO_2 neutrality of EU energy imports.

384. Regarding the cross-border interconnectors, the assumptions are based on the European Hydrogen Backbone study (Guidehouse 2020). This is, we assume that a dedicated hydrogen network in the EU is progressively built by repurposing some natural gas pipelines and building new ones. Deployment of such network would start from key industrial clusters in 2030, expand to EU interconnectors by 2035 and reach some non-EU interconnectors by 2040[152]. For calculating a LCOH component of hydrogen transmission by pipeline, assumptions on which and by when each interconnector is available, its route, length and capacity are key. The retrofitted pipeline capacity assessed in the European Hydrogen Backbone Study and its timeline has been considered as inputs to the model (see table 18). More specifically six pipelines have been considered for hydrogen imports, allowing both low-carbon and renewable hydrogen to be imported into Europe. Repurposed pipelines are supposed to handle each year almost the same energy capacity than the previous gas pipeline did[153]. Only one injection point has been considered for each country. It is supposed to be located according to the gas network topology and existing compression stations[154].

[152] Discussions with SNAM, the Italian gas operator, led us to consider a retrofit of half the Trans-Mediterranean Pipeline capacity in 2030.
[153] Assuming low-calorific natural gas with approximately 37.7 MJ/Nm^3 (HHV) and a Wobbe number between 41 and 47 MJ/Nm (Dries Haeseldonckx and D'haeseleer 2007). Assuming low-calorific natural gas with approximately 37.7 MJ/Nm^3 (HHV) and a Wobbe number between 41 and 47 MJ/Nm (Dries Haeseldonckx and D'haeseleer 2007).
[154] For Azerbaijan, Russia and Algeria, additional injection points have been added where pipeline start.

385. The cost assumptions for the midstream are presented in table 19 and table 20Source : .

Table 18. Considered retrofitted pipelines

Entry point (ENTSOG)	Type	Code Country (entry point)	Code Country (exit point)	Start year	Infrastructure name	Max volume (MTPA H2)	Length (km)
207	Pipeline	ESP	MAR	2040	MEG	4.8	45
207	Pipeline	ESP	DZA	2040	MEG	4.8	1082
208	Pipeline	ESP	DZA	2040	Medgas	3.1	210
208	Pipeline	ESP	DZA	2040	Medgas	3.1	757
209	Pipeline	ITA	TUN	2030	Transmed	6.2	155
209	Pipeline	ITA	DZA	2030	Transmed	6.2	1075
222	Pipeline	GRE	TUR	2040	TANAP	3.1	110
222	Pipeline	GRE	AZE	2040	TANAP	3.1	2496
218	Pipeline	SVK	UKR	2040	Kyev - Western Border Pipeline	9.9	650
224	Pipeline	DEU	RUS	2040	Nord-Stream	18.7	1225

Source : Guidehouse, 2020

Table 19. Cost assumptions for hydrogen transport with vessels

	Production	Conversion 1 (production point)	Domestic transport	Conversion 2 (exporting point)		International transport		Reconversion (Importing point)
A. (from 2020)		**Compression**	**Gasified trucks**	**Liquefaction**		**Liquified hydrogen shipping**		**Hydrogen regasification**
LCOH Contribution (EUR17/Kg)		A function of distance: LCOH = 2.65 D + 0.27 D: Distance (1000 Km) ; Max. range: 300 Km		2.03		A function of distance: LCOH = 0.10 D + 0.84		1.30
B. (from 2030)	**From all Sources available in the cell** Depends on the technology and resources available	**Compression**	**Gasified trucks**	**Ammonia synthesis & liquefaction**	New dedicated exporting terminals including storage	**Liquified Ammonia shipping**	Refurbished dedicated importing terminals	**Ammonia catalytic cracking**
LCOH Contribution (EUR17/Kg)		A function of distance: LCOH = 2.65 D + 0.27 D: Distance (1000 Km) ; Max. range: 300 Km		1.53		A function of distance: LCOH = 0.09 D + 0.17		1.80
C. (from 2030)		**Ammonia synthesis**	**Liquid Ammonia trucks**	**N/A**		**Liquified Ammonia shipping**		**Ammonia catalytic cracking**
LCOH Contribution (EUR17/Kg)		1.53	A function of distance: LCOH = 0.66 D + 0.04 D: Distance (1000 Km) Max. range: 1000 Km	-		A function of distance: LCOH = 0.09 D + 0.17		1.80

Source : Own calculations based on data from IEA (2019a), DOE (2019), Fúnez Guerra et al (2020), Ikäheimo et al. (2018) and Davenne et al. (2020)

Table 20. Cost assumptions for hydrogen transport by pipeline

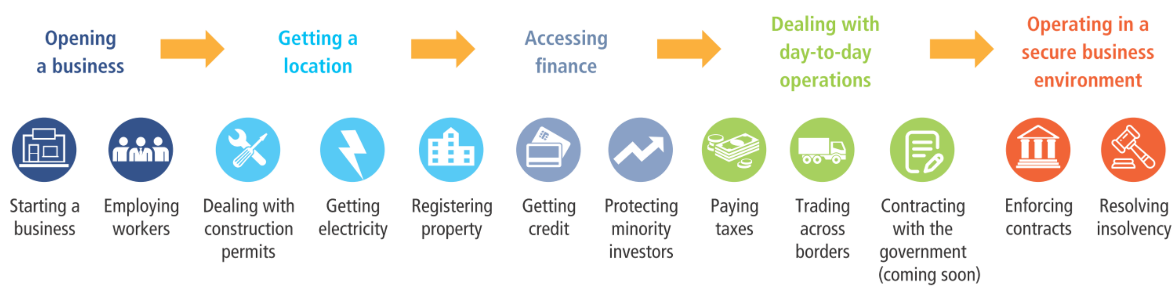
<table>
<tr><th></th><th>Production</th><th>Conversion 1 (production point)</th><th>Domestic transport</th><th>Conversion 2 (exporting point)</th><th></th><th>International transport</th></tr>
<tr><td rowspan="2">D. (from 2040)
LCOH Contribution (EUR17/Kg)</td><td rowspan="8">From all Sources available in the cell
Depends on the technology and resources available</td><td>Compression</td><td>Gasified trucks</td><td>Compression</td><td rowspan="8">Injection point</td><td rowspan="8">Hydrogen pipelines
A function of distance:
LCOH = 0.55 D + 0.06
D: Distance (1000 Km)</td></tr>
<tr><td colspan="3">A function of distance:
LCOH = 2.61 D + 0.25
D: Distance (1000 Km) ; Max. range: 300 Km</td></tr>
<tr><td rowspan="2">E.
(from 2040)
LCOH Contribution (EUR17/Kg)</td><td>Ammonia synthesis</td><td>Liquid Ammonia trucks</td><td>Ammonia catalytic cracking</td></tr>
<tr><td>1.53</td><td>A function of distance:
LCOH = 0.65 D + 0.04
D: Distance (1000 Km) ; Max. range: 1000 Km</td><td>1.80</td></tr>
<tr><td rowspan="2">F. (from 2050)
LCOH Contribution (EUR17/Kg)</td><td>Compression</td><td>Gasified trucks</td><td>Compression</td></tr>
<tr><td colspan="3">A function of distance:
LCOH = 2.52 D + 0.23
D: Distance (1000 Km) ; Max. range: 300 Km</td></tr>
<tr><td rowspan="2">G.
(from 2050)
LCOH</td><td>Ammonia synthesis</td><td>Liquid Ammonia trucks</td><td>Ammonia catalytic cracking</td></tr>
<tr><td>1.53</td><td>A function of distance:
LCOH = 0.64 D + 0.04
D: Distance (1000 Km) ; Max. range: 1000 Km</td><td>1.80</td></tr>
</table>

Source : Own calculations based on data from IEA (2019a), DOE (2019), Fúnez Guerra et al (2020), Ikäheimo et al. (2018) and Davenne et al. (2020)

9.4.4 Country specific WACC

386. As any investment, the deployment of hydrogen facilities has inherent risk that directly translate into cost of capital. Additionally, undertaking such investments in countries with somehow challenging local regulation needs to be factored in into the LCOH calculation (see figure 85). We therefore consider country specific risk premiums, estimated by the relative ratio of the Ease of Doing Business scores (WB 2020) of each country against the EU average. Future values were linearly extrapolated according to the historic trend and corrected by a deflator. This methodology allows to approximate a country dependent risk adjusted weighted average cost of capital (WACC) for the LCOH calculation.

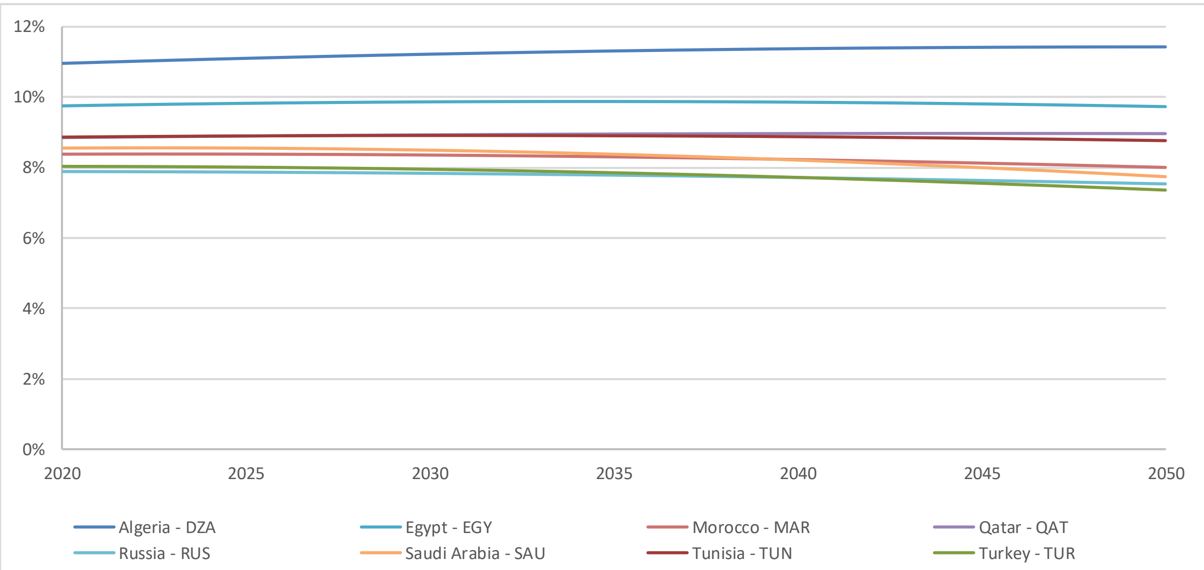
Figure 85. Ease of doing business score perimeter



Source : World Bank, 2020

387. Compared to the average EU-27 WACC of 8%, we consider a range going from 6% in 2018, in economically stable countries such as United Arab Emirates, to more than 15% in countries such as Yemen or Libya, that face long-lasting instability (see figure 86). As an indicative figure, when varying country-specific WACC by +/-20% it results on a difference on LCOH of within the 5% range for low-carbon hydrogen technologies[155].

Figure 86. Country specific WACC by adapting the EU28 average with country risk premiums



Source : Own calculations based on data from the World Bank

[155] Technologies with higher shares of CAPEX on their LCOH would be more sensitive to variations of the WACC.

10 Annex E: Data documentation

388. The data collection phase and the active involvement of the funding partners to review and complete the database have allowed the consortium to come up with sound and up to date cost figures of hydrogen production technologies. They are provided in table 21 and table 22. Both models have applied these inputs in the simulations.

389. For assumptions related to other technologies, see Section 8.2.

Table 21. Hydrogen production technologies – Cost data. All cost data is provided in the lower heating value (LHV)

Technology	Investment costs [€/kW H_2]			Fixed O&M [€/kW H_2]			Variable O&M [€/GJ]			Source
	2020	2030	2050	2020	2030	2050	2020	2030	2050	
Coal gasification, large size, centralized	2363	2363	2363	118	118	118	0.16	0.12	0.12	6, 9, 10
Coal gasification, medium size, centralized	2929	2929	2929	147	147	147	0.22	0.22	0.22	6, 9, 10
Coal gasification + CO_2 capture, large size, centralized	2460	2460	2460	123	123	123	0.26	0.26	0.26	6, 9, 10
Coal gasification + CO_2 capture, medium size, centralized	3376	3376	3376	169	169	169	0.26	0.26	0.26	6, 9, 10
Biomass gasification, small size, decentralized	3099	3099	3099	81.9	81.9	81.9	1.3	1.3	1.3	6, 8, 9, 10
Biomass gasification, medium size, centralized	2959	2929	2929	146	146	146	0.45	0.45	0.45	6, 8, 9, 10
Biomass gasification + CO_2 capture, medium size, centralized	3376	3376	3376	169	169	169	0.46	0.46	0.46	6, 8, 9
SMR, large size, centralized	805	805	805	37.8	37.8	37.8	0.08	0.05	0.05	1, 9
SMR, medium size, decentralized	1945	1509	1509	52.7	29.9	29.9	0.04	0.04	0.04	6, 8, 10
SMR + CO_2 capture, large size, centralized	1487	1204	1133	44.6	36.1	34.0	0.53	0.07	0.07	1, 9
ATR + CO_2 capture, large size, centralized	800	700	700	24.0	21.0	21.0	0.53[156]	0.07[156]	0.07[156]	8, 9
GHR + ATR + CO_2 capture, large size, centralized	830	750	750	24.9	22.5	22.5	0.53[156]	0.07[156]	0.07[156]	8, 9
Ethanol steam reforming, decentralized	2700	2700	2700	0	0	0	19.65	19.65	19.65	6
PEM electrolyzer	1750	-[157]	-[157]	52.5	45	-[157]	0.15[158]	0.06[158]	0.06[158]	2, 3, 7, 9, 10
Alkaline electrolyzer, large size, centralized	1250	-[157]	-[157]	18.8	15	-[157]	0.15	0.06	0.06	2, 3, 7, 9, 10
Alkaline electrolyzer, wind off grid, centralized	2408	-[157]	-[157]	55.3	49.1	-[157]	0.15	0.06	0.06	2, 3, 7, 9, 10

[156] The variable O&M costs for *GHR + ATR* and *ATR* are based on the reported values for *SMR + CO_2 capture* as they are mostly related to process water, cooling water, and catalyst replacement.
[157] Future costs in water electrolysis are highly uncertain and are be calculated through learning by doing in the model Integrate Europe.
[158] The variable O&M costs for *PEM electrolyzer* are based on *Alkaline electrolyzer, large size* as they are mostly related to process and cooling water.

Alkaline electrolyzer, PV off grid, centralized	1878	-[157]	-[157]	34.3	24.7	-[157]	0.15	0.06	0.06	2, 3, 7, 9, 10
PEM electrolyzer, offshore, centralized	4535	-[157]	-[157]	106.4	87.7	-[157]	0.96	0.17	0.17	2, 3, 7, 9, 10
Alkaline electrolyzer, small size, decentralized	1250	-[157]	-[157]	18.8	15.0	-[157]	0.96	0.17	0.17	2, 3, 7, 9, 10
Very High Temperature Reactor CHP, centralized	-	4687	3937		304.7	255.9	-	2.60	2.60	6, 10
Methane pyrolysis (Kvaerner process), centralized	1993	1993	1993	89.8	89.8	89.8	0.70	0.70	0.70	6
Molten media methane pyrolysis, large size	778	778	778	64.9	64.9	64.9	-	-	-	11
Non-catalytic methane pyrolysis, small size	1751	1751	1751	225	225	225	-	-	-	12

Source :

1. IEA 2019: The Future of Hydrogen
2. Blanco H., Nijs W., Ruf J., Faaij A., 2018a, Potential for hydrogen and Power-to-Liquid in a low-carbon EU energy system using cost optimization, Applied Energy 232, pp. 617-639
3. Blanco H., Nijs W., Ruf J., Faaij A., 2018b, Potential of Power-to-Methane in the EU energy transition to a low carbon system using cost optimization, Applied Energy 232, pp. 323-340
4. Sgobbi A., Nijs W., De Miglio R., Chiodi A., Gargiulo M., Thiel C., 2016, How far away is hydrogen? Its role in the medium and long-term decarbonisation of the European energy system, International Journal Hydrogen Energy 41, pp. 19-35
5. Bolat P., Thiel C., 2014a, Hydrogen supply chain architecture for bottom-up energy systems models. Part 1: developing pathways, International Journal Hydrogen Energy 39, pp. 8881-8897
6. Bolat P., Thiel C., 2014b, Hydrogen supply chain architecture for bottom-up energy systems models. Part 2: techno-economic inputs for hydrogen production pathways, International Journal Hydrogen Energy 39, pp. 8898-8925
7. Schmidt O., Gambhir A., Staffel, I., Hawkes, A., Nelson, J., Few, S., 2017 Future cost and performance of water electrolysis … , International Journal of Hydrogen Energy 42, pp. 30470-30492
8. Information provided by partners
9. H21 North of England Report (2018)
10. NREL Technical Report NREL/TP-560-46267 September 2009 and NREL Technical Report NREL/TP-6A10-60528
11. Parkinson, B.; Tabatabaei, M.; Upham, D. C.; Ballinger, B.; Greig, C.; Smart, S.; McFarland, E., 2018, Hydrogen production using methane: Techno-economics of decarbonizing fuels and chemicals, International Journal of Hydrogen Energy 43, pp. 2540-2555
12. Keipi, T.; Tolvanen, H.; Konttinen, J., 2018, Economic analysis of hydrogen production by methane thermal decomposition: Comparison to competing technologies, Energy Conversion and Management 159, pp. 264-273

10.1 Technical assumptions

390. Technological data regarding hydrogen production technologies used in the model are described and detailed in the table below.

Table 22. Hydrogen production technologies – Technological Data

Technology	Size [MW]	Fuel Efficiency [PJ/PJ$_{H2}$] (LHV)				Life			Source
		Fuel	2020	2030	2050	2020	2030	2050	
Coal gasification, large size, centralized	1667	Coal	1.67	1.67	1.67	25	25	25	6, 9, 10
Coal gasification, medium size, centralized	434	Coal	1.67	1.67	1.67	25	25	25	6, 9, 10
Coal gasification + CO_2 capture, large size, centralized	1667	Coal	1.72	1.72	1.72	25	25	25	6, 9, 10
Coal gasification + CO_2 capture, medium size, centralized	442	Coal	1.72	1.72	1.72	25	25	25	6, 9, 10
Biomass gasification, small size, decentralized	0.7	Biomass	2.10	2.10	2.10	25	25	25	6, 8, 9, 10
		Grid electricity	0.03	0.03	0.03				
Biomass gasification, medium size, centralized	33	Biomass	2.10	2.10	2.10	25	25	25	6, 8, 9, 10
		Grid electricity	0.03	0.03	0.03				
Biomass gasification + CO_2 capture, medium size, centralized	33	Biomass	2.10	2.10	2.10	25	25	25	6, 8, 9
		Grid electricity	0.03	0.03	0.03				
SMR, large size, centralized	1530	Natural gas	1.32	1.32	1.32	25	25	25	1, 9
		Grid electricity	-0.02	-0.02	-0.02				
SMR, medium size, decentralized	2	Natural gas	1.36	1.27	1.27	25	25	25	6, 8, 10
		Grid electricity	0.25	0.07	0.07				
SMR + CO_2 capture, large size, centralized	1502	Natural gas	1.385	1.385	1.385	25	25	25	1, 8, 9
		Grid electricity	0.015	0.015	0.015				
ATR + CO_2 capture, large size, centralized	1260	Natural gas	1.36	1.36	1.36	25	25	25	8, 9
		Grid electricity	0.04	0.04	0.04				
GHR + ATR + CO_2 capture, large size, centralized	1260	Natural gas	1.28	1.20	1.20	25	25	25	8, 9
		Grid electricity	0.06	0.05	0.05				
Ethanol steam reforming, decentralized	0.01	Ethanol	1.47	1.47	1.47	10	10	10	6
		Grid electricity	0.08	0.08	0.08				
PEM electrolyzer	NA[159]	Grid electricity	1.60	1.55		6[160]	7	9	2, 3, 7, 9, 10
Alkaline electrolyzer, large size, centralized	72	Grid electricity	1.55	1.45		20	20	20	2, 3, 7, 9, 10

[159] No reference size for costs provided. However, it is expected that the sizes are in the range between *Alkaline electrolyzer large size* and *Alkaline electrolyzer small size*, that is between 0.6 MW and 72 MW.
[160] The lifetime in *PEM electrolyser* are increasing due to R&D. Direct application in offshore parks has a higher lifetime due to the lower capacity factor and may be limited by the lifetime of the offshore wind turbines.

Alkaline electrolyzer, wind off grid, centralized	NA[159]	Wind off grid	1.55	1.45		30	30	30	2, 3, 7, 9, 10
Alkaline electrolyzer, PV off grid, centralized	NA[159]	PV off grid	1.55	1.45		30	30	30	2, 3, 7, 9, 10
PEM electrolyzer, offshore, centralized	NA[159]	Wind offshore	1.5			20	20	20	2, 3, 7, 9, 10
Alkaline electrolyzer, small size, decentralized	0,6	Grid electricity	1.55	1.45		20	20	20	2, 3, 7, 9, 10
Very High Temperature Reactor CHP, centralized	600	Uranium		1.5			60	60	6, 10
Kvaerner process, centralized	19	Natural gas	1.75	1.75	1.75	25	25	25	6
		Grid electricity	0.35	0.35	0.35				
Molten media methane pyrolysis, large size	420	Natural gas	2.05	2.05	2.05	20	20	20	11
Non-catalytic methane pyrolysis, small size	2.8	Natural gas	2.50	2.50	2.50	20	20	20	12

Source :

1. IEA 2019: The Future of Hydrogen
2. Blanco H., Nijs W., Ruf J., Faaij A., 2018a, Potential for hydrogen and Power-to-Liquid in a low-carbon EU energy system using cost optimization, Applied Energy 232, pp. 617-639
3. Blanco H., Nijs W., Ruf J., Faaij A., 2018b, Potential of Power-to-Methane in the EU energy transition to a low carbon system using cost optimization, Applied Energy 232, pp. 323-340
4. Sgobbi A., Nijs W., De Miglio R., Chiodi A., Gargiulo M., Thiel C., 2016, How far away is hydrogen? Its role in the medium and long-term decarbonisation of the European energy system, International Journal Hydrogen Energy 41, pp. 19-35
5. Bolat P., Thiel C., 2014a, Hydrogen supply chain architecture for bottom-up energy systems models. Part 1: developing pathways, International Journal Hydrogen Energy 39, pp. 8881-8897
6. Bolat P., Thiel C., 2014b, Hydrogen supply chain architecture for bottom-up energy systems models. Part 2: techno-economic inputs for hydrogen production pathways, International Journal Hydrogen Energy 39, pp. 8898-8925
7. Schmidt O., Gambhir A., Staffel, I., Hawkes, A., Nelson, J., Few, S., 2017 Future cost and performance of water electrolysis … , International Journal of Hydrogen Energy 42, pp. 30470-30492
8. Information provided by partners
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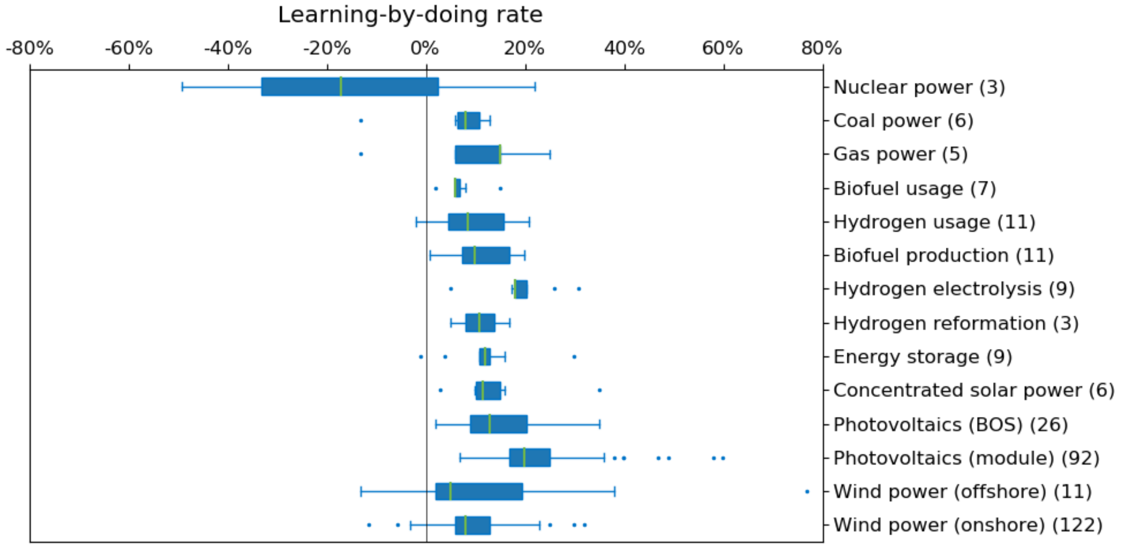
10. NREL Technical Report NREL/TP-560-46267 September 2009 and NREL Technical Report NREL/TP-6A10-60528
11. Parkinson, B.; Tabatabaei, M.; Upham, D. C.; Ballinger, B.; Greig, C.; Smart, S.; McFarland, E., 2018, Hydrogen production using methane: Techno-economics of decarbonizing fuels and chemicals, International Journal of Hydrogen Energy 43, pp. 2540-2555
12. Keipi, T.; Tolvanen, H.; Konttinen, J., 2018, Economic analysis of hydrogen production by methane thermal decomposition: Comparison to competing technologies, Energy Conversion and Management 159, pp. 264-273

10.2 Learning-by-doing literature review

391. To model learning-by-doing effects in Integrate Europe (see section 9.3), we required estimates for the learning rates of relevant energy production and conversion technologies. We have therefore performed an extensive literature review in this project, where we compiled data from hundreds of journal articles. Notably, our review used existing literature surveys by Rubin (2015) and Samadi (2018) as a starting point, so for the technologies that are listed in those sources we have a large overlap in data sources. The results of the literature review are shown in figure 87.

Figure 87. Box plot illustrating the statistical distribution of estimated learning rates for each technology[161]



392. Unfortunately, one of the main conclusions is that there is a large spread in the learning rates reported for each technology. This is perhaps most clear for wind power, where estimates range from roughly -15 % to +80 %, which translates to nearly two orders of magnitude of uncertainty in the cost estimates for 2050 based on current capacity projections.

393. For the main scenarios, we consistently use the median (50th percentile) value for the learning rate. This was chosen instead of the common mean since the median is well-known to be more robust to the presence of outliers. While it would be computationally infeasible to perform a full sensitivity analysis, where every single learning rate in the energy system model is perturbed independently while the other learning rates are kept at the median, the main conclusions of the project can be investigated using a simplified sensitivity analysis. Briefly, one of the core questions this research project aims to answer, is in which technology sectors we expect hydrogen vs. electrification to be most cost-effective during the 2020-2050 transition to clean energy sources. The worst-case scenario would then be if we systematically underestimated all learning rates related to electrification (e.g. wind power and solar power) and overestimated all learning rates related to hydrogen (e.g. reforming), or vice versa. To include this consideration in our numerical experimental design, we therefore performed one extra simulation of the final energy system model, a "hydrogen-optimistic" version that uses the lower quartile (25th percentile) for electrification technologies while keeping the other learning rates constant. This uncertainty has been conducted via a sensitivity over the Technology Diversification scenario (see annex A).

[161] The most important parts are the green lines (median, 50th percentile) and blue box (inter-quartile range, 25th to 75th percentile). As is standard for box plots, the whiskers show the remaining distribution of normal data points, and the points show the distribution of outliers. Numbers in parentheses after labels refer to the number of data points found in the literature for that technology.

394. Based on the data above, we determined the learning rates for various Integrate Europe module components (table 23). We note that we completely neglect such learning effects for trade and markets (T), energy needs (N), end use (U), and storage modules (B), while we included it for certain energy sources (S) and conversion modules (C). For the latter two categories, learning has not been implemented for all technologies, as evidenced by some rows having zero (—) and others having finite (%) learning rate. All technologies without listed learning rates above use exogenous cost reductions in line with the assumptions in the MIRET-EU model.

395. Where data is unavailable, we have tried to find appropriate surrogates. Notably, we use power plant learning rates for boilers, combustion, and CHP plants; natural gas data for H_2 power plants; the same data for biomass gasification and other bio refineries; and common data for all non-natural-gas fossil fuel plants. There were several reasons for the remaining learning rates being neglected. For many fossil technologies, the combination of high existing capacities and unlikely large future investments conspire to make the expected learning effects negligible, as the capacity of these technologies is not expected to nearly double in the future. For some technologies like electric boilers and methane pyrolysis, the learning rate itself is considered to be negligible[162]. For nuclear energy and heat pumps, we did not find data of sufficient quality to model the learning effects.[163]

Table 23. Learning rates used for energy system elements in the Integrate Europe case simulations.

Integrated Europe resource		Learning rate		
		25th percentile	50th percentile	75th percentile
European resources				
S1	Lignite	—	—	—
S2	Coal	—	—	—
S3	Oil	—	—	—
S4	Biomass/waste	—	—	—
S5	Nuclear power	—	—	—
S6a	Wind power / Onshore	6%	8%	13%
S6b	Wind power / Offshore	2%	5%	20%
S7a	Solar power / PV module	17%	20%	25%
S7b	Solar power / PV BOS	9%	13%	21%
S8	Hydropower and other RES-E	—	—	—
S9	Ambient heat	—	—	—
S10	Waste heat	—	—	—
S11	Natural gas	—	—	—
Conversion				
C1	Lignite power	—	—	—
C2	Lignite CHP	—	—	—
C3	Coal power	—	—	—
C4	Coal CHP	—	—	—
C5	Oil power	—	—	—
C6	Oil CHP	—	—	—
C7	Oil combustion	—	—	—
C8	Bio power	6%	6%	7%
C9	Bio CHP	6%	6%	7%

[162] For pyrolysis, the reactor layout and process (Hazer process) are not expected to show major learning effects, as the petrochemical industry has long experience with fluidized-bed reactors. According to a memo written by Prof. Klein (TU Munich), key learning will only affect the prices of the first-of-a-kind unit and is best treated exogenously. Molten media pyrolysis is currently at a low TRL, making it next to impossible to predict future learning rates.

[163] For nuclear energy, the only reported learning rates in the literature appear to be based on half-century old data and appear to be strongly affected by the regulation of nuclear energy in that specific time period. Notably, these data sources do not even agree on the sign of the learning rate. It was therefore considered more accurate to simply neglect learning altogether. This is not considered important for our final results, as nuclear energy usage is expected to be dominated by policy and not costs.

C10	Biomass gasification	—	—	—
C11	Bio combustion	6%	6%	7%
C12	Electrolyzer	18%	18%	21%
C13	Electric boiler	—	—	—
C14	Heat pump	—	—	—
C15	Reformer	8%	11%	14%
C16	Natural gas combustion	6%	15%	15%
C17	Gas power[164]	6%	15%	15%
C18	Gas CHP	6%	15%	15%
C19	H2 combustion	6%	15%	15%
C20	H2 power	6%	15%	15%
C21	H2 CHP	6%	15%	15%
C22	Oil refinery	—	—	—
C23	Bio refinery	8%	10%	17%
C24	Pyrolysis	—	—	—

[164] For natural gas power and CHP plants, all existing capacity (2020) is without CCS, while new capacity from later investment packages is assumed to include CCS. The learning rates listed here are only for the natural gas module itself, as the natural gas plants with CCS are handled via a *composite learning curve* as explained in section 9.3.

11 Annex F: References

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