Strengthening Europe's Energy Infrastructure

European Round Table for Industry

BCG

The power is on but what about the flow?

In the drive towards a sustainable future, ensuring affordable access to renewable energy for every EU citizen and business hinges on bolstering our energy infrastructure. This publication provides real-world insights and practical recommendations for how to reinforce the infrastructure that can deliver competitively priced renewable energy across the European Union.

Europe's potential for renewable energy is vast, but tapping into it requires a resilient and interconnected infrastructure. This document navigates through policies and technologies and aims to demystify the path towards a Europe where clean energy is accessible to all, rather than a luxury for a selected few.

The focus is on practical solutions, breaking down complex issues surrounding energy transition. By understanding and implementing a robust energy infrastructure, we can democratise the benefits of affordable renewable energy, empowering industry and innovation in the process. This publication encourages collective action, illustrating how a strengthened energy backbone can pave the way for a future where every EU citizen and business enjoys the advantages of competitively priced renewable energy. Together, let's make sustainable energy a reality for everyone in Europe.

The report was developed with the support of Boston Consulting Group (BCG). The authors wish to thank Matthias Tauber, Marco Tonegutti, Marcus van der Vegte, Antonia Wissert, Franziska Eberl, Lars Holm and Erik Rakhou.

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Executive summary

Europe's ambition for a greener future calls for a **decisive evolution of its energy infrastructure**. This is not a mere upgrade but a **fundamental transformation** to meet our climate goals and remain globally competitive. To achieve this, we need a massive investment: €0.8 trillion by 2030, scaling to €2.5 trillion by 2050.

Beyond current capacity, **we need both national and cross-border infrastructure** for power grids, hydrogen, and CO_2. **This infrastructure will play a crucial role in managing volatile renewable energy sources, a function currently handled by fossil fuels.**

Bridging the investment gap requires a collaborative effort between private and public capital. We need a stronger Single Market with a supportive regulatory framework to entice private capital investments. This includes de-risking anticipatory grid investments, unlocking flexibility such as storage and demand response, streamlined permitting processes and a priority-based approach for electric grid development, as well as attention to new gases including a role for low carbon hydrogen.

Complex regulations hinder private capital access. We need a leaner regulatory framework and a clear business case for private investors. Implementing 'Fit for 55' and a pan-European infrastructure plan will accelerate progress.

The Single Market is to be revived – EU policymakers and industry leaders must lock arms in efforts to:

- fast-track energy infrastructure development and mobilise the investments required for boosting EU competitiveness as described in chapters 1–3;
- foster a regulatory environment that supports our European Green Deal ambitions as well as global competitiveness of European companies. For more details please see chapter 4.

1. Decarbonisation drives demand for low-carbon and renewable energy sources

The starting point for this publication is clear: We need to quickly move to a net-zero carbon industry because, 'Human activities, principally through emissions of greenhouse gases, have unequivocally caused global warming' and 'any further delay in concerted anticipatory global action on adaptation and mitigation will miss a brief and rapidly closing window of opportunity to secure a liveable and sustainable future for all.'[1]

This chapter highlights the strong commitments of EU industry to a low-carbon future, the significant changes in the EU's energy mix, and the resulting required adaption of the power grid.

1.1. EU industry is committed to achieving climate targets

EU industry leaders have committed to becoming net-zero emissions businesses by 2050 and want to see the region succeed in competitively decarbonising its economy, in line with the EU Green Deal. This commitment is visible in the decarbonisation initiatives which are already being undertaken.[1] It is also reflected in the ERT Vision Paper from October 2023,[2] which spells out the need to strengthen the energy infrastructure.

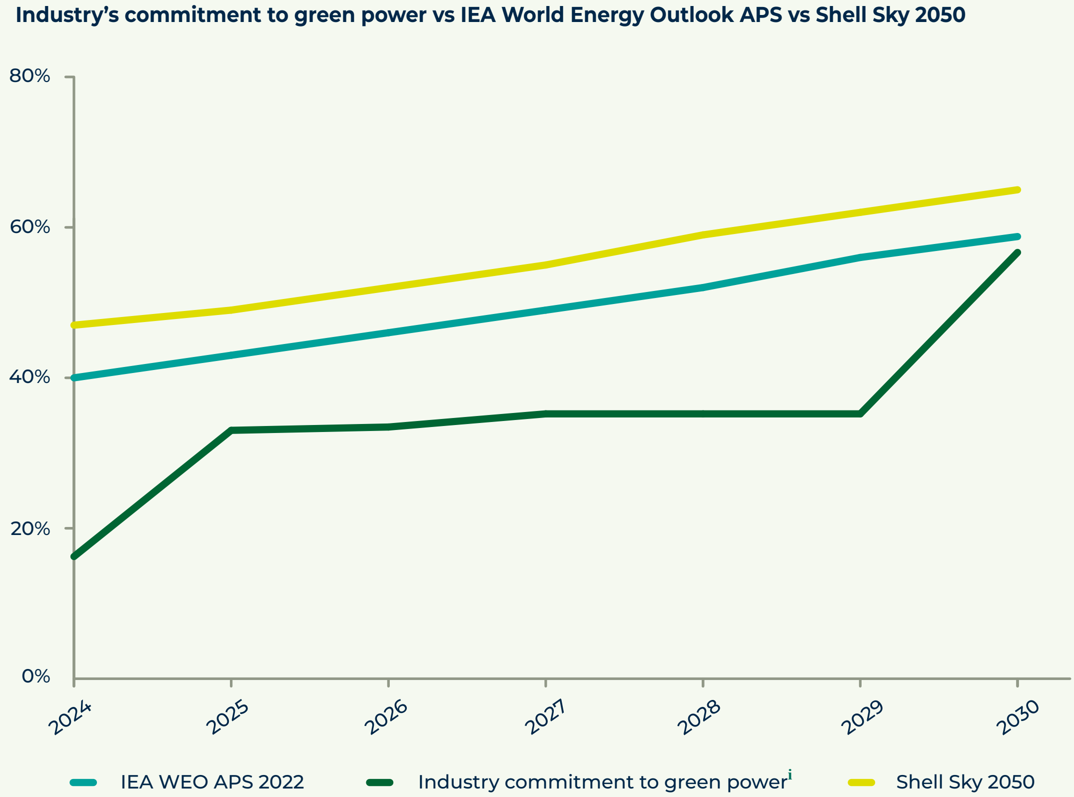
This commitment is also reflected in the public announcements made by the 50+ companies led by ERT members (ERT member companies). Most announcements are about low-carbon power consumption, as clear standards for low-carbon hydrocarbon production and consumption tracking are still pending. Figure 1 shows the number of ERT member companies that have made full or partial low-carbon power commitments. If the build-out of renewables and corresponding infrastructure is delayed, then it will be challenging for individual companies to deliver on their targets.

Martin Lundstedt
President and CEO, AB Volvo

'Our ambition is to be net-zero in our value chain by 2040; this will enable our customers to have net-zero fleets by 2050.'

1 Please consult website: https://industry4climate.eu/ for more information. This website contains several lighthouse projects of the European industry.

2030 commitment of ERT Members consistent with EU pledges



ERT Member's commitment to green power reaches 57% by 2023

Industry commitments are aligned with net-zero Outlooks by 2030. To live up to the commitments significant build out of generation and grids is needed.

Figure 1: 2030 industry commitments to renewable power in line with the EU pledges

i. For this analysis it was assumed that the energy/power consumption of all surveyed ERT Members is at the same level

Source: European Commission, public commitments made by the listed 57 ERT Members

EXPERT CORNER 1

Decarbonisation in the Normandy industrial basin

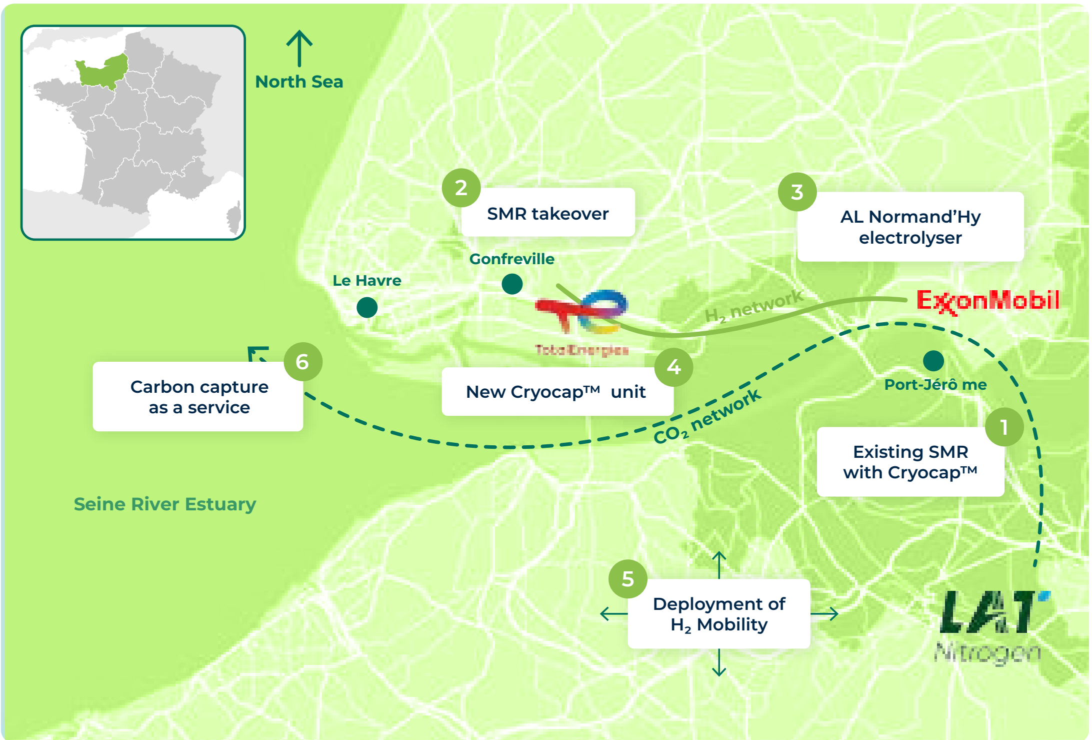
The Normandy industrial basin is ranked in the top three highest industrial CO_2 emitters in France, with more than 8 million tonnes of emissions per year. It is also the location where hydrogen consumption is the most important with over 200,000 tonnes consumed per year. Air Liquide, as a key hydrogen producer in this industrial basin, and thus being an important CO_2 emitter, is determined to dedicate resources in the Normandy industrial basin to reducing its carbon footprint and helping other industries to decarbonise their operations.

Air Liquide's decarbonisation roadmap for the Normandy industrial basin encompasses a combination of projects, including utilising proprietary technologies for producing renewable and low-carbon hydrogen from electrolysis; carbon capture units (Cryocap™) added on to traditional hydrogen production facilities (steam methane reforming); development alongside TotalEnergies, ExxonMobil, LAT Nitrogen, and Yara of a CO_2 hub of infrastructure for collecting and exporting liquid CO_2 to a North Sea sink; and developing hydrogen-clean mobility for heavy-duty applications.

To successfully implement such an ambitious roadmap, each individual step must be justified economically. Technologies are available and infrastructure often already in place. The region has a solid electrical grid with high (225 kV) and very high (400 kV) voltage lines crossing the industrial area. Air Liquide owns and operates a local H_2 pipeline linking Port-Jérôme to Le Havre harbour (H_2 network on the graph above), and TotalEnergies is willing to convert an existing idle crude oil pipeline linking Rouen industrial area to Le Havre harbor (CO_2 network on the graph on the next page) for gaseous CO_2 transportation. The main drivers are compliance with EU regulations and Member State tax legislation, which are incentivising industries to invest. For example, the transport sector must comply with the EU ETS (Emissions Trading System) and the European Renewable Energy Directive (RED), creating strong incentives for transforming existing hydrogen production and reducing CO_2 emissions. For CCS (carbon capture and storage) projects, beyond the necessary regulatory and incentivising framework, the main hurdle to developing profitable projects and making final investment decisions is access to CO_2 sinks (offshore in the North Sea or onshore) at competitive and acceptable legal terms and conditions.

Air Liquide Normandy Basin Decarbonisation Roadmap

Air Liquide



First Worldwide Low-Carbon H_2 Network

1. Existing **SMR+CCU**
2. **SMR takeover** connected to the **H_2 network**
3. Investment in **AL Normand'Hy** H_2 electrolyser
4. **Carbon capture** joint commitment
5. Leverage of industrial infrastructure to deploy **H_2 mobility**
6. **Carbon capture** as a **service** with other industrials in the basin

Figure 2: Air Liquide Normandy Basin Decarbonisation Roadmap

CC: carbon capture

CCU: carbon capture and usage

i. This document is internal

Data provided by Air Liquide

1.2. Industry energy demand shifts towards low-carbon energy

1.2.1. Decarbonisation efforts vary across sectors

Emission reduction targets on the path to net-zero emissions will drive a massive shift to renewable and low-carbon energy sources. Those sources are expected to make up 40% of the EU's final energy supply by 2030 and 70% of total energy supply by 2050.[3]

The pathway to industry decarbonisation is very similar to that of the EU overall. However, as one can see in Figure 3, the annual decarbonisation of industry is 3% lower than other sectors in the 2030s. The speed of decarbonisation in industry is slower than in other sectors because most hard-to-abate processes that emit carbon are industrial processes, as one can see in Figure 4. This is a challenge for industry, as the investment needed to abate these emissions is very high.

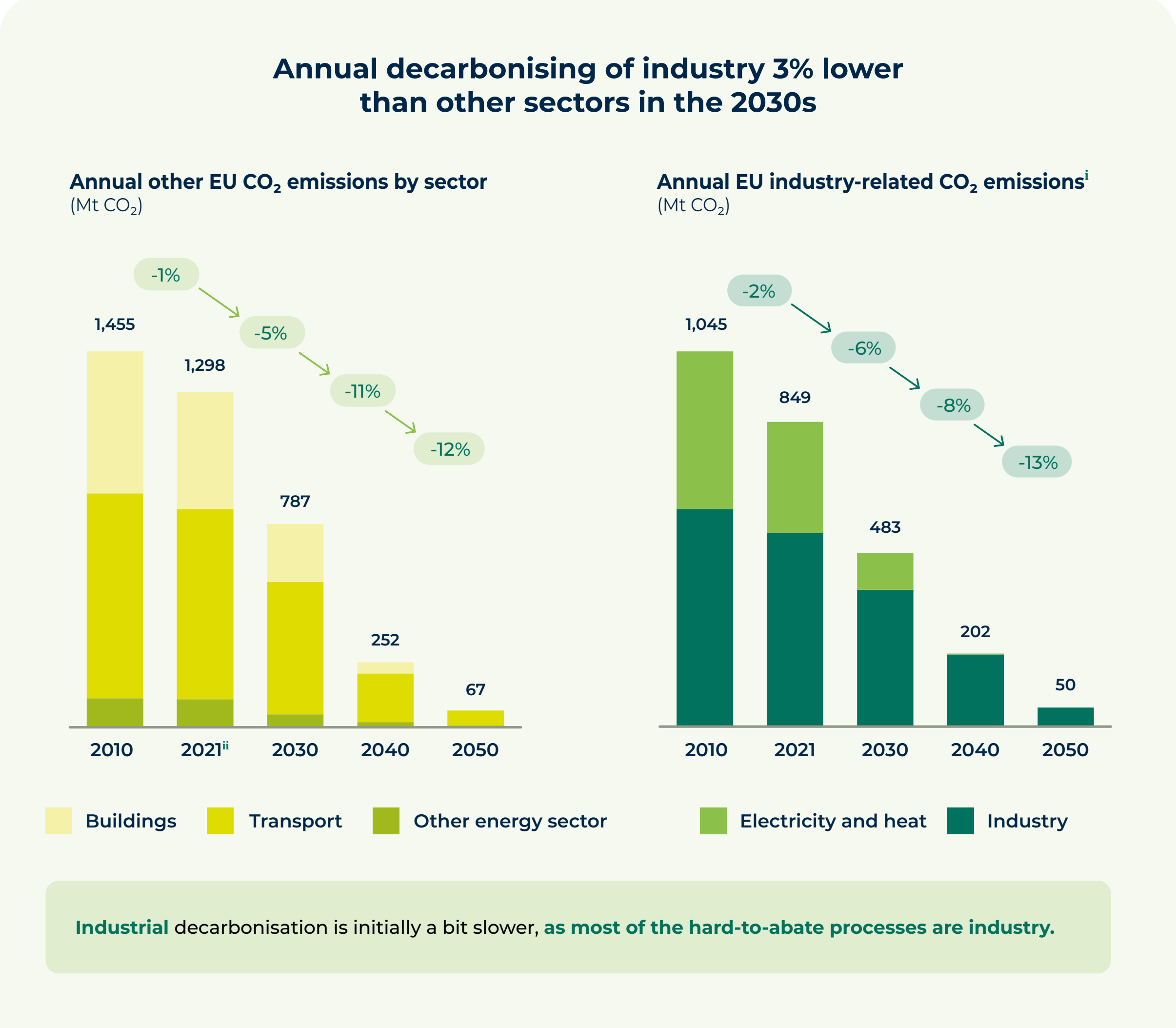


Figure 3: CO_2 emissions by sector (Mt CO_2)

i. Scope 1 + 2 emissions, assuming that power blend in industry is the same as overall power blend in EU
ii. 2021 selected instead of 2020 to minimise COVID-19 impact
Source: IEA World Energy Outlook, announced pledges; BCG analysis

The decarbonisation trajectory of the industry is likely to vary by the differing industrial processes. Hard-to-abate processes will need to shift to renewables or low-carbon fuels and carbon capture technologies.

Hard-to-abate sectors have a low share of renewable energy

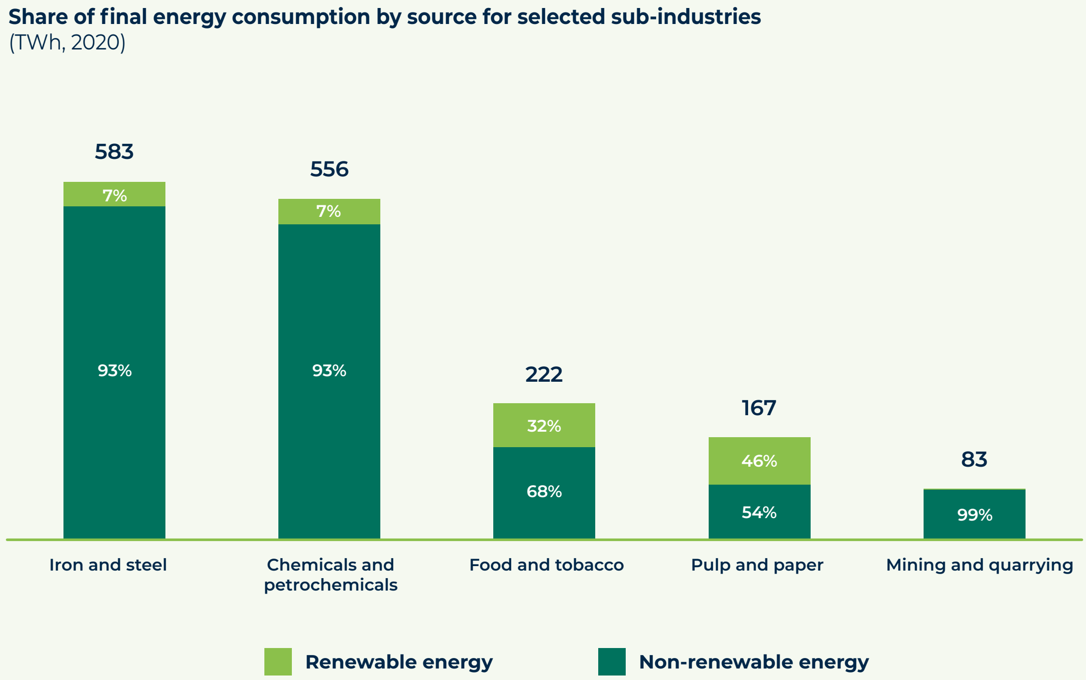


Figure 4: Hard-to-abate sectors have a low share of renewable energy

Source: IEA, REN21, BCG analysis

1.2.2. Industry employs levers to reduce carbon emissions

The five levers for the decarbonisation of industry are:

1. Increasing energy efficiency and the reduction of energy intensity, leading to lower energy consumption
2. Electrifying industrial end uses where possible (see more information below)
3. Decarbonising power supply with renewable energy sources
4. Reducing carbon intensity of hard-to-abate processes through renewable and low-carbon fuels
5. Carbon capture and storage

Leonhard Birnbaum
CEO, E.ON

'Achieving climate targets requires green electricity, green molecules and energy efficiency gains. But it is all worthless without appropriate infrastructure.'

Digitisation is also a key enabler to make the energy system more efficient, reliable and sustainable, which is incorporated in all these levers.

Figure 5 provides the relative publications of these levers to overall decarbonisation targets. The levers complement each other and are different from industry to industry.

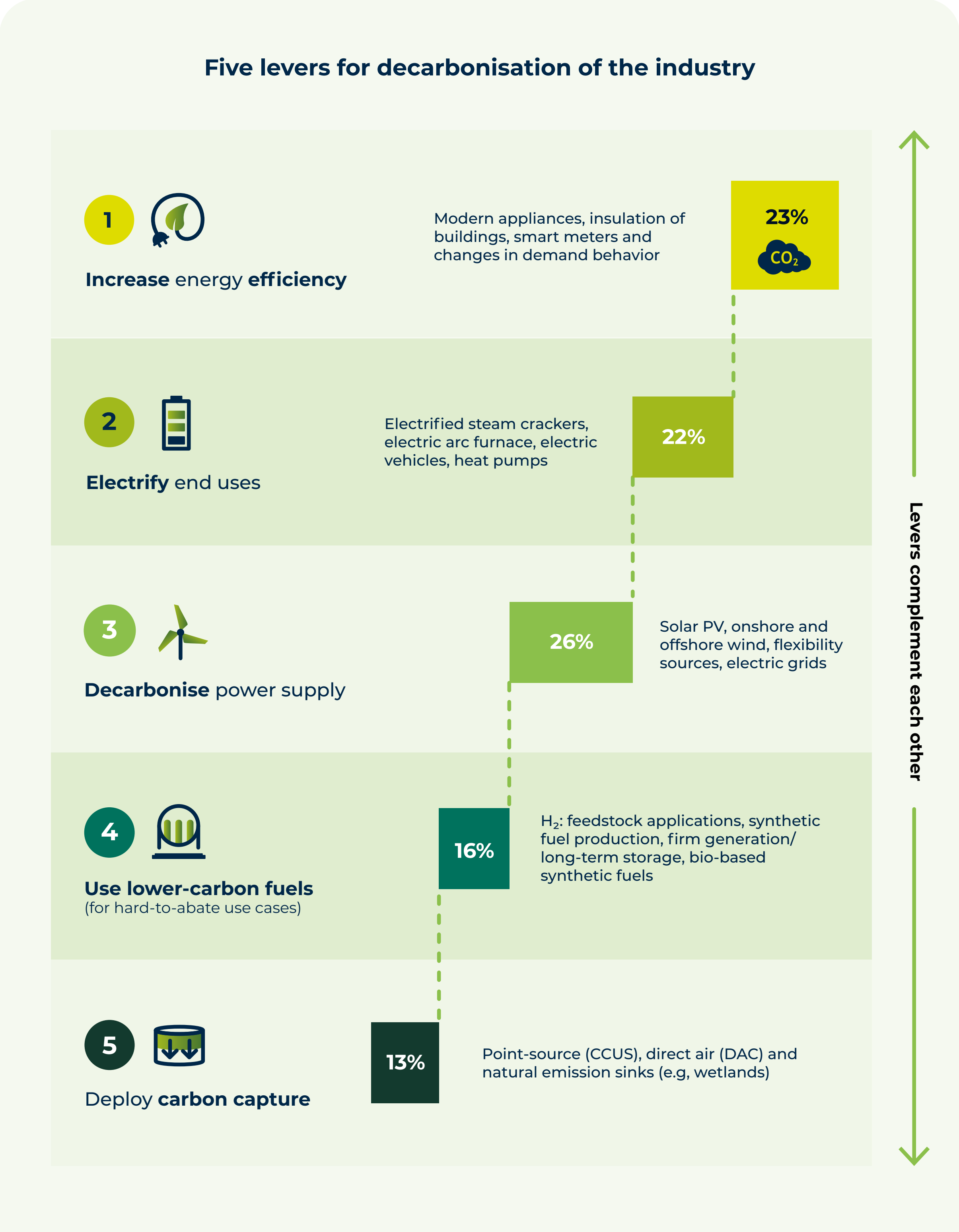


Figure 5: Five levers for decarbonisation of the industry

Source: BCG CEI analysis

Electrifying end use can happen through direct and indirect electrification. Direct electrification describes the process of replacing a source of energy or power with fossil-free electricity. Indirect electrification, on the other hand, refers to using electricity as an input to industrial processes. According to a Eurelectric study, direct electrification in industry may range between 25% in heavy industry, 40% in medium and 74% in light.[4] Including indirect electrification (including power-to-gas), the range varies between 56% and 76%.[4]

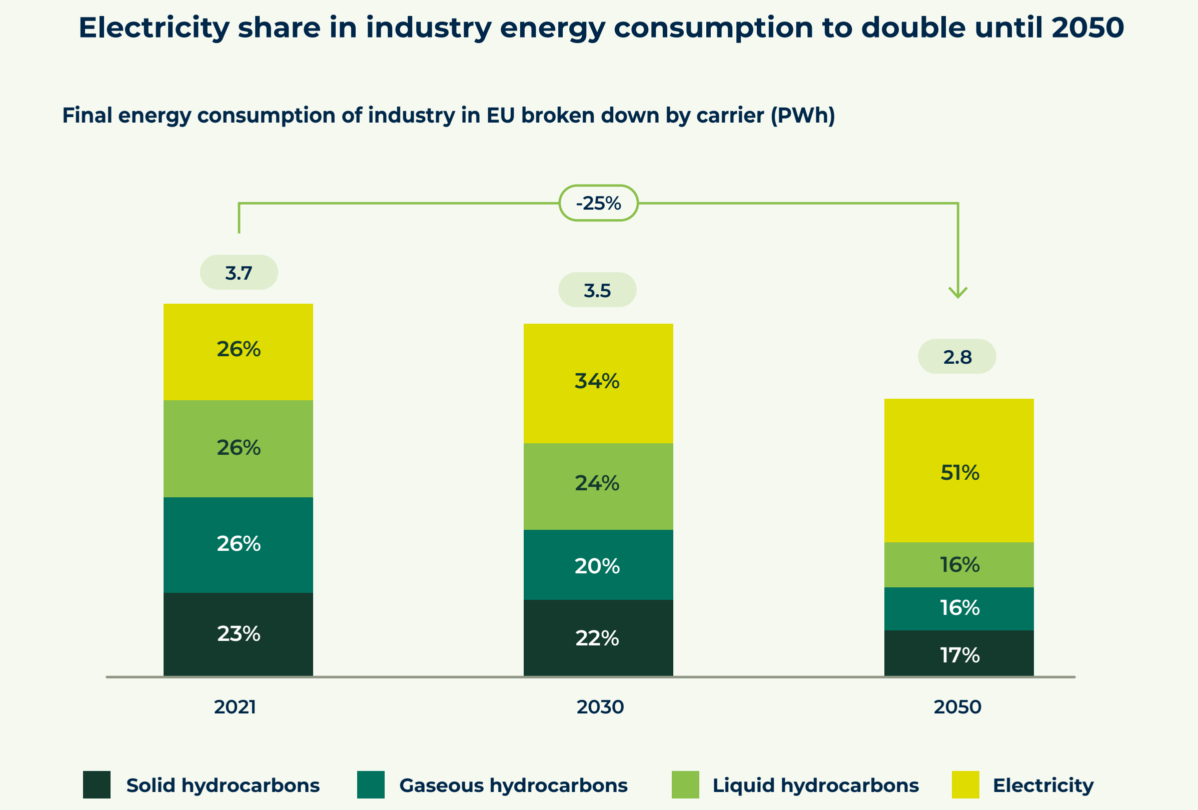


Figure 6: Electricity share in industry energy consumption to double by 2050

Source: IEA World Energy Outlook 2022, announced
Pledges: BCG analysis

We expect many processes in industry to be electrified in the coming years. Today, procured power represents 26% of industry's energy consumption (0.962 PWh [petawatt hours] in 2021). This share is expected to double until 2050; however, given lower energy intensity the absolute power procurement is expected to be 1.43 PWh, all of which is produced carbon-free (BCG analysis based on IEA APS data).

1.2.3. Energy mix will undergo significant changes

Figure 7 highlights the three fundamental changes anticipated by 2050 in the EU's final energy mix:

- **Reduced energy intensity will save 10 PWh of annual final energy consumption by 2050.** This target is critical for the size of the infrastructure that we need to plan for and for maintaining the competitiveness of EU industry.

- **The share of renewable energy will increase 3.5 times,** from 22% to 77%, making it the biggest contributor to reducing carbon emissions.

- **End-user power consumption will grow by 50%,** with 65% of this coming from variable renewable energy (VRE) sources. This has a significant impact on the layout of the power grid. Some studies (see Figure 10) assume even stronger growth of power demand at the end user. Power generation in Europe increases by a factor of 2.4 in the IEA (International Energy Agency) scenario until 2050,[5] which is not reflected in the final energy numbers, as energy is being converted in P2X processes to hydrogen and other derivatives, as shown in Figure 8 and Figure 9.

Final energy split 55/45 between other carriers and electricity; decrease of total energy consumption

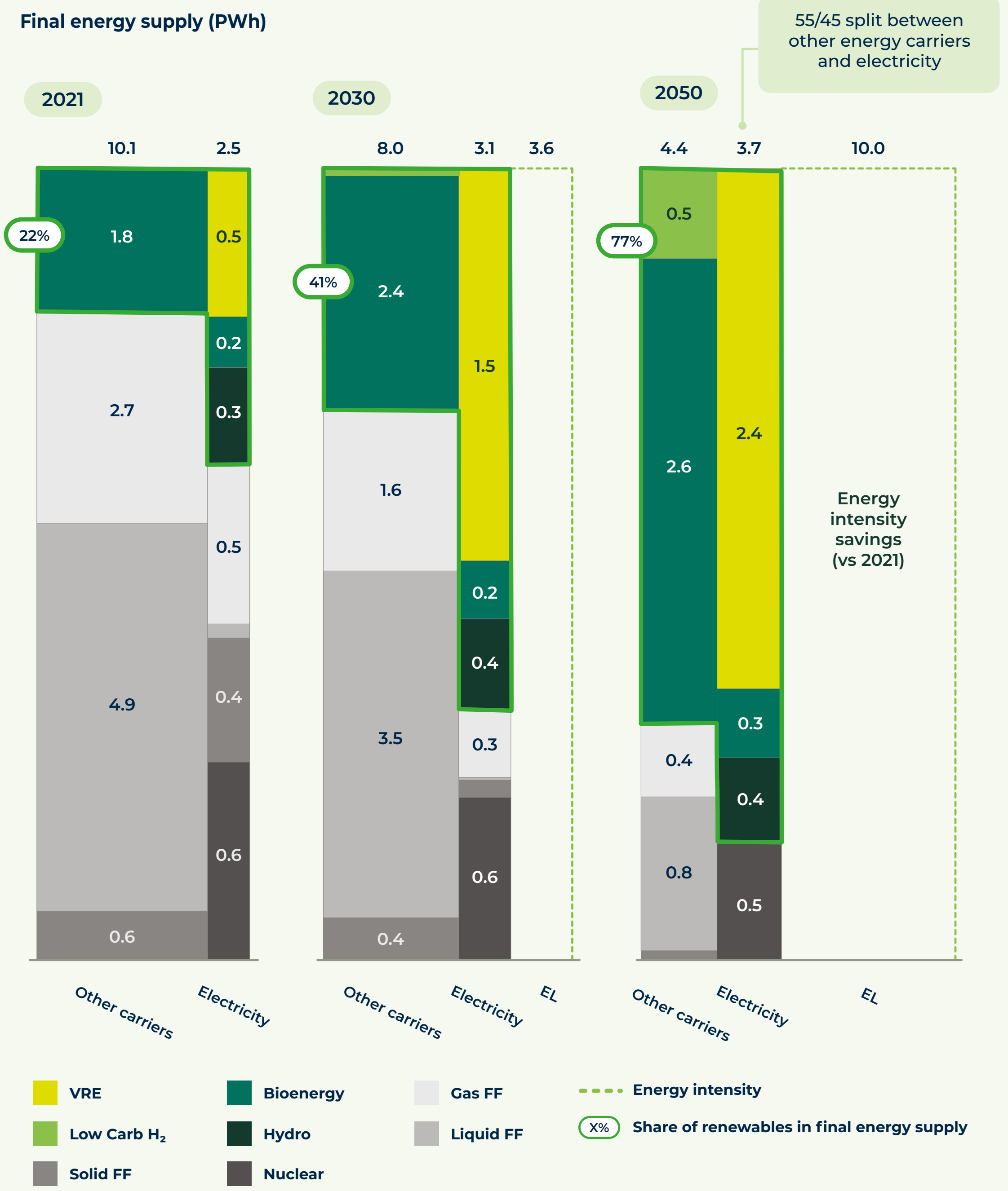


Figure 7 : Mix of final energy consumption changing over time (PWh)

VRE – variable renewable energy
FF – fossil fuels
H_2 – hydrogen
Source: IEA Announced Pledges Scenario, BCG analysis

It is important to note that the transition towards the 2050 energy mix is likely to be non-linear. In a technology-open energy system, some carriers will develop faster than others. The uncertainty is highest when we are looking at emerging industries. The fundamental change in energy mix can be seen in the following charts.

Energy flow in Europe 2021[i]

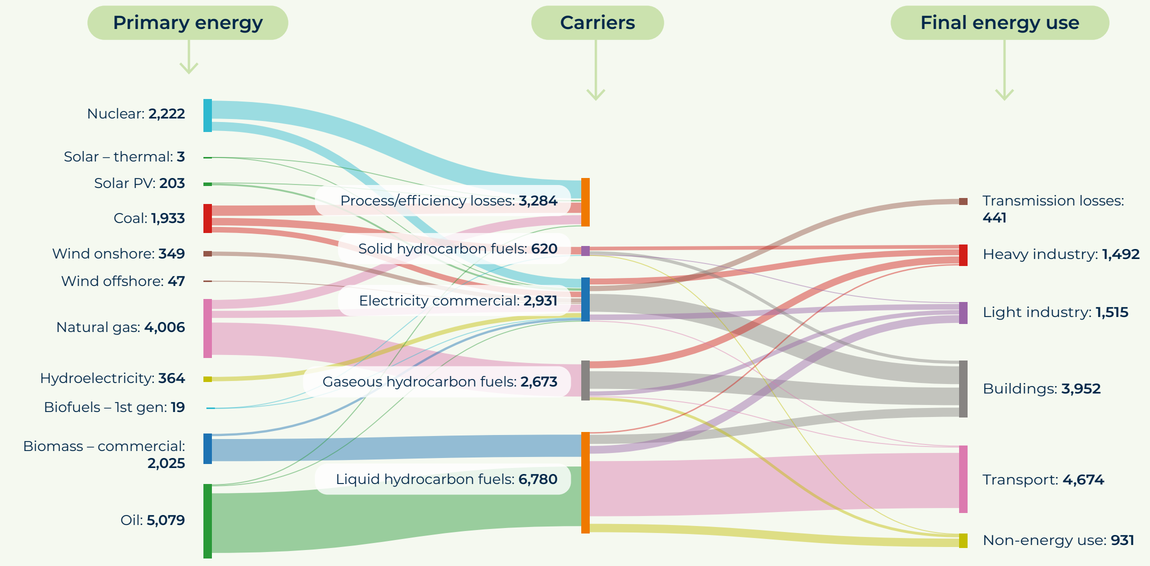


Figure 8: Energy flow in EU-27 by 2021 in TWh/a

i. TWh/a

Source: IEA APS, Shell Sky 2050, BCG analysis

Energy flow in Europe 2050[i]

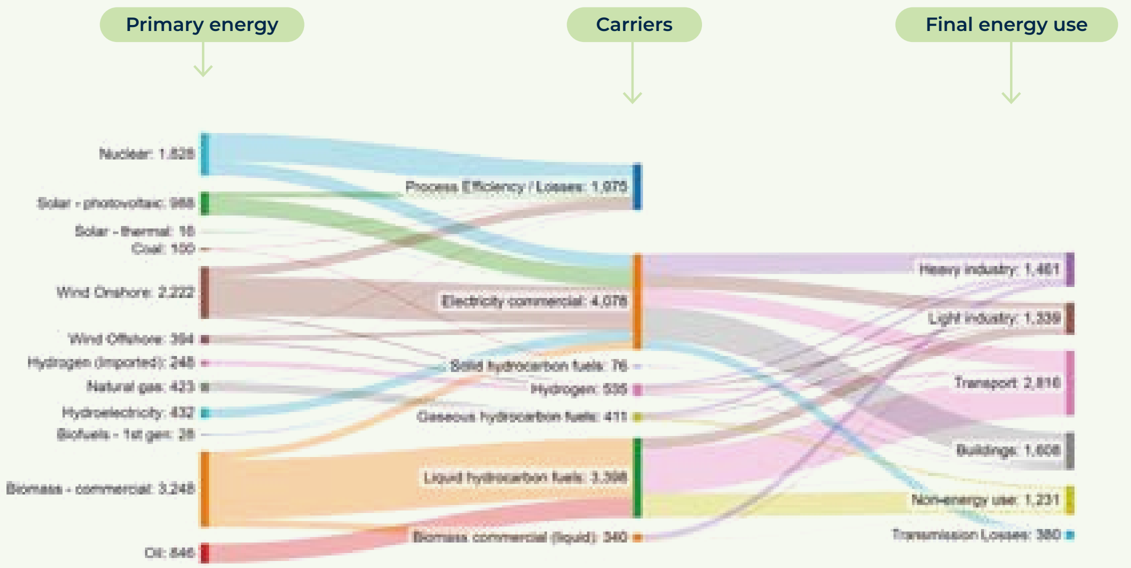


Figure 9: Energy flow in EU-27 by 2050 in TWh/a

i. TWh/a

Source: BCG Analysis using IEA APS and Shell Sky 2050 as starting point.

1.2.4. The role of gas

Claudio Descalzi
CEO, Eni

'A diversified energy portfolio is crucial for a sustainable future: Renewables are essential components of this way. However, it is equally important to recognise that demand is still dependent on fossil fuels. Neglecting this fact can lead to underinvestment and potential supply shortages which can result in higher energy prices and disruptions. A balanced approach that considers both the transition to renewables and the decarbonisation of hydrocarbon products that meet existing demand, is necessary to ensure a reliable and affordable energy supply.'

By 2050, electricity will become the dominant energy carrier, with natural gas (fossil methane) losing relative importance in volume and keeping in the interim its role as a flexibility fuel. The transition of natural gas in Europe is non-linear and two-sided – a good example is what we see in Germany, with multiple FSRUs (floating storage regasification units, flexible liquefied natural gas [LNG] importing terminals) being installed and in parallel a deadline of 2043 for expiring of those FSRUs. Globally, we see natural gas largely replaced in 2050 by storage, biomethane and hydrogen in the electricity production and keeping some role in the global European energy mix. It could play a continued role as energy transition bridge fuel including as a feedstock for low carbon hydrogen as implicitly recognised by G20 'High-Level Voluntary principles on Hydrogen' – For any role of gas as a flexible transition fuel in Europe, the key will be to address methane emissions and ensure the presence of an CCUS ecosystem.

1.3. Consistent trends evident among major studies

The EU's future energy mix is forecasted by multiple professional organisations. The next visualisation shows how the base scenario of this publication (International Energy Agency's Announced Pledges Scenario) compares to the Shell Sky 2050 Scenario and the scenarios assumed by ENTSO-E and ENTSO-G in their Ten Year Network Development Plan.[6][7]

Since differences in assumptions and methodologies lead to different outlooks, the differences can be significant on a carrier level, especially when looking at small volumes in the future.

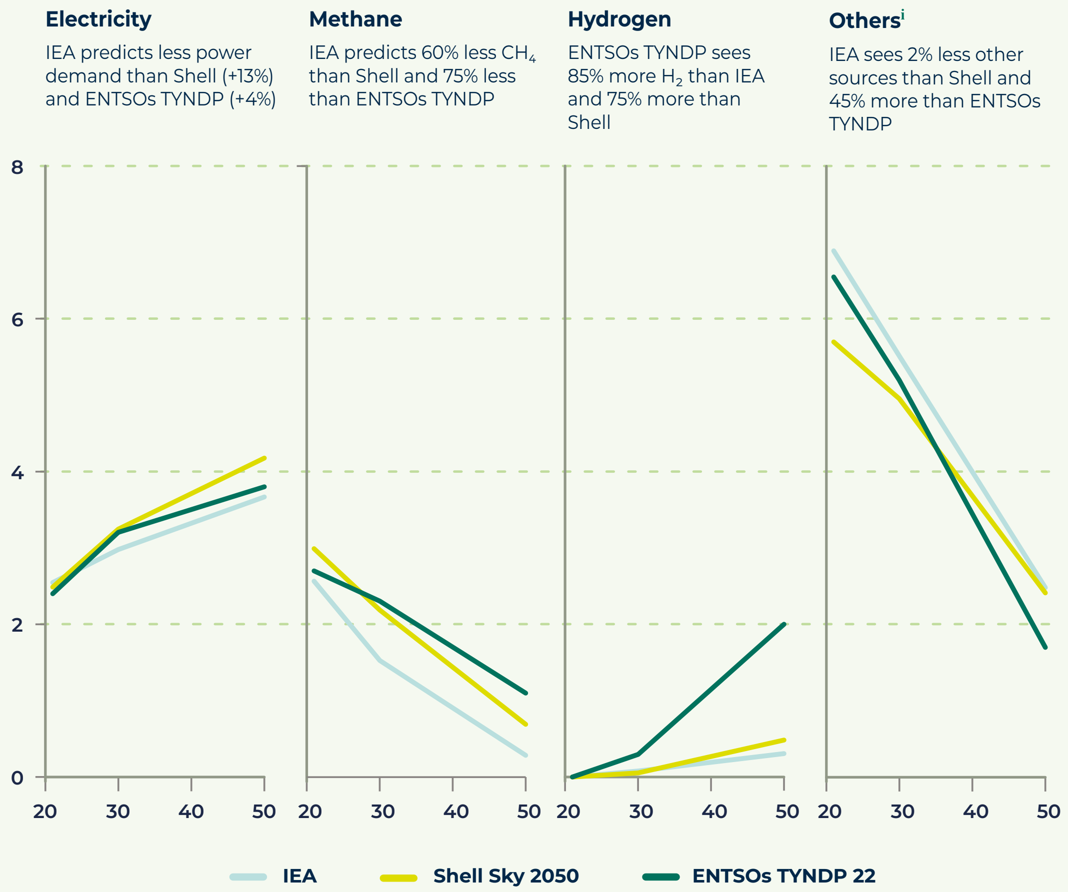
However, the general trend by carrier is the same, with the IEA being most ambitious in its estimation of the effects of a phaseout of gas and overall final energy reduction. Independent of the source, the mix and volume of final energy will change by 2030 and even more so by 2050. The differences include:

- Shell and ENTSO-E see a faster electrification than the IEA. This would require even more investment in the expansion and modernisation of the power grid.
- At the same time, Shell and ENTSO-G see a slower phasedown of gaseous energy carriers. This would lead to a higher utilisation of the gas grid and potentially additional investment needs.
- With regards to hydrogen, ENTSO-E & ENTSO-G are most ambitious, while Shell and the IEA predict a slower take-up of hydrogen.
- For the carriers not considered in this publication, liquid fuels, solid fuels and heat, we also see both upwards and downwards diverging views to the IEA.

The main driver for these ranges comes from a different assumption of the ability of the EU to reduce energy intensity. Delays in improving energy efficiency lead to a higher energy demand (Shell +13% and ENTSO +26% in 2050).

Same trend in all sources, with IEA most ambitious in phaseout of gas and overall final energy reduction

Final energy demand in PWh by carrier and scenario



Total final energy demand

- **IEA Scenario** predicts highest energy intensity reduction leading to 6.8 PWh FE in 2050
- **According to Shell Sky 2050, we will see +13% higher final energy demand** (7.7 PWh)
- **ENTSOs TYNDP sees +26% higher final energy demand** (8.6 PWh)

Figure 10: Same trend in all sources, with IEA most ambitious in phaseout of gas and overall final energy reduction

i. 'Others' include heat, solids and liquids.

Source: IEA World Energy Outlook, announced pledges; BCG analysis

A higher energy demand requires more investment in energy infrastructure. Higher costs for infrastructure and the additional volume of zero-carbon energy carriers will negatively impact the economical position of EU industry. This analysis highlights that a fast transition and investment into energy efficiency are important both from an environmental and a financial perspective. It also underscores the fact that in case of delays the projected infrastructure costs in this publication are at the lower end of the spectrum.

2. The energy transition requires an unprecedented change of energy infrastructure

Energy infrastructure (in the context of this submission) enables transportation and storage of energy[2] to areas of demand for the energy mix and volume at a given point in time. This chapter covers four energy carriers and the disposal of CO_2.

The quick transformation of energy infrastructure is crucial to achieve the EU's ambitious climate goals. In comparison to previous energy transitions, the transition towards renewables needs to be roughly three times faster, as shown in Figure 11.

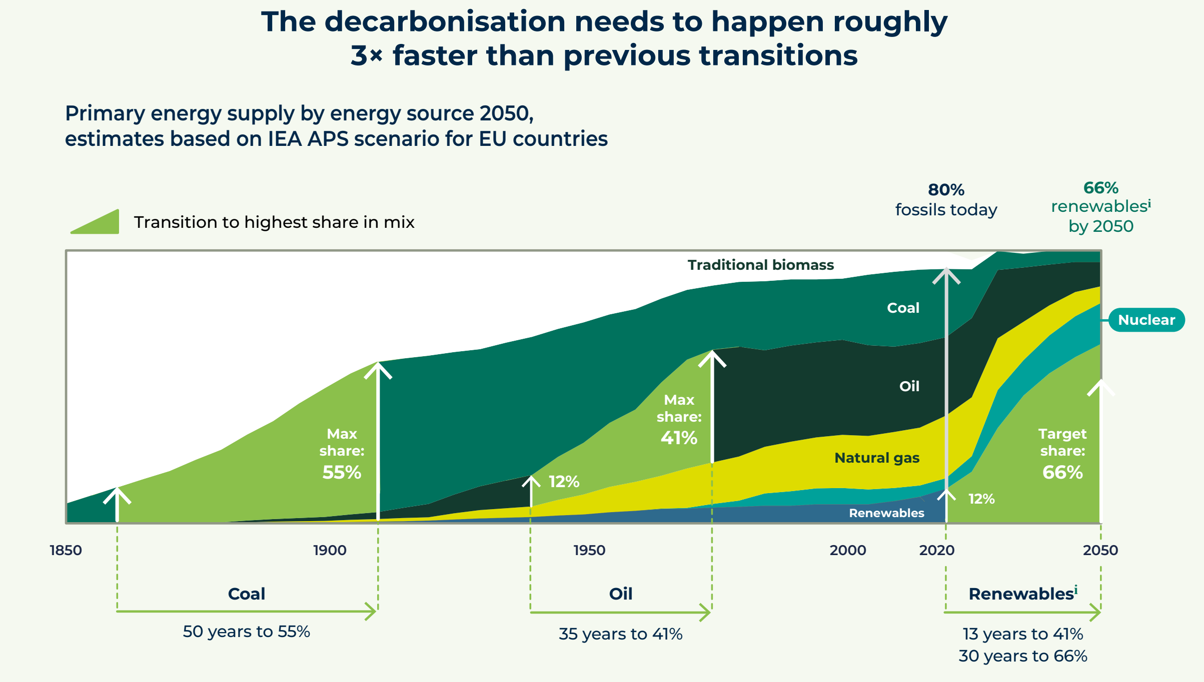


Figure 11: Change needs to be three times faster

i. Renewables include biofuels, solar, wind, hydro and other renewables

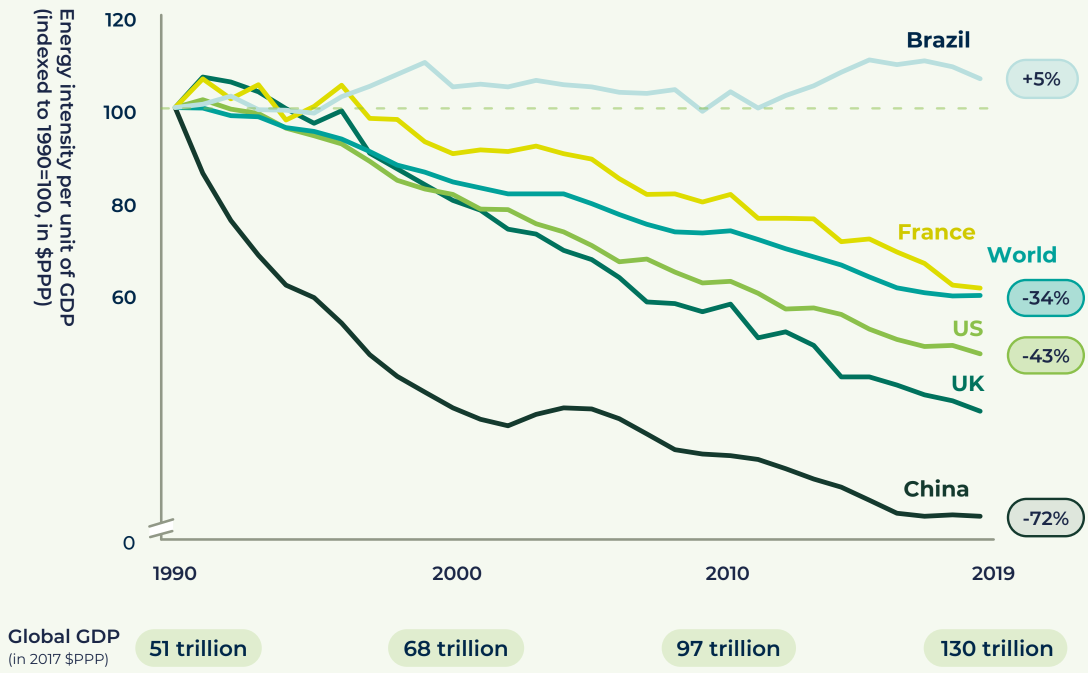
Source: Our World in Data, Vaclav Smil (2017) and BP Statistical Review of World Energy, IEA APS Scenario

These changes need to take place quickly. All modelled pathways that limit warming to 2°C (>67%) or lower by 2100 involve immediate and deep GHG (greenhouse gas) emissions reductions in all sectors.[8]

Before elaborating on the energy carriers and the mix, it is important to understand how much final energy will be needed going forward. This is key to planning the dimensions of future energy infrastructure. Energy demand in the past has been closely correlated with economic growth (GDP). However, in the last few years we have seen some economies that are able to decouple economic growth from energy consumption.

2 In the context of this publication, this infrastructure for transportation and storage of energy can also be infrastructure used in a landing port in the EU for imported gas or oil.

Energy consumption is already decoupling from GDP growth, but continued effort is essential



Global GDP has almost tripled since 1990, while the energy intensity of GDP has decreased by 34%

Three changes have driven decoupling:

- A shift in economic activity from industry to services; for example, in the US, industry's share of GDP decreased from 23% in 2000 to 18% in 2020
- Technological progress in areas such as energy efficiency and electrification
- Policy alterations such as fuel efficiency standards

There is tremendous potential for more efficiency; for example, in the US in 2021, only one-third of primary energy was used, while two-thirds was lost to inefficiencies and energy conversion.

Figure 12: Decoupling of GDP and energy consumption 1990–2019

Note: PPP = purchasing power parity

Source: Lawrence Livermore National Laboratory, IEA SDG7 Database 2022, World Bank, BCG CEI analysis

As encouraging as this past improvement has been, much more progress needs to be made. The Intergovernmental Panel on Climate Change (IPCC) states the following:

'Emissions reductions in CO_2 fossil fuel industry (FFI), due to improvements in energy intensity of GDP and carbon intensity of energy, have been less than emissions increase from rising global activity levels in industry, energy supply, transport, agriculture, and buildings.'[1] This highlights that progress has been made, but it is not sufficient yet.

Both the IEA APS and Shell Sky 2050 scenarios assume a continuous decline in energy intensity by about 50% until 2050. Different scenarios provide different outcomes for declining energy intensity. One reason for this may be a difference in hypotheses around the electrification of road transport (light and heavy), where more electrification implies higher efficiency versus any form of combustion engine.

Declining energy intensity in EU-27

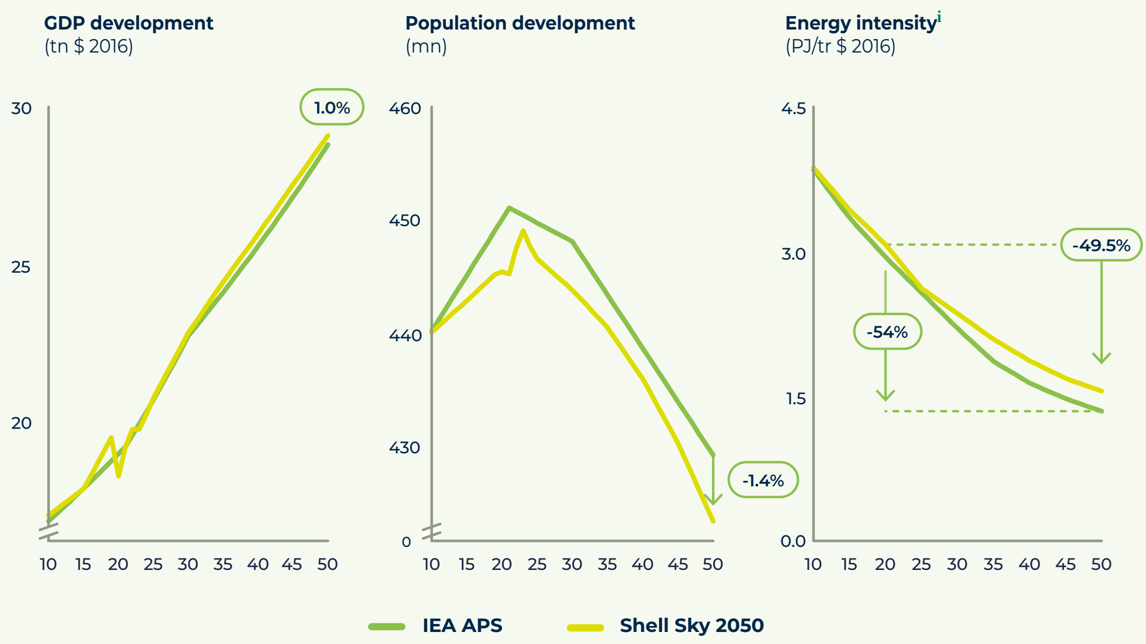


Figure 13: Declining energy intensity in EU-27

i. Primary energy / GDP

Declines in energy intensity may be due to (i) more efficient processes, (ii) less need for energy intensive products, and (iii) the relocation of manufacturing to locations outside of Europe.[9] At ERT we believe that relocation of industry (demand destruction) needs to be avoided from the angle of EU competitiveness and resilience as well as from the angle of reducing global emissions.

In chapter 2, we will cover the physical characteristics of infrastructure before we move to the costs in chapter 3.

2.1. Power infrastructure

2.1.1. Situation today

Electrons are difficult to store. Consequently, power grids need to be balanced at all times. Generation needs to match consumtion in real time.

Electricity infrastructure consists of transmission and distribution grids as well as energy storage systems. For the purposes of this publication, we are including storage, while we acknowledge that power storage is not a network but a market activity today. EU regulations prohibit grid operators from operating storage assets. Storage and more broadly the emerging business models around balancing in the grid require specific attention from policymakers. Currently, 75% of generation sources are connected to the transmission network – although this varies substantially from country to country due to the generation mix and dominant concentrated generation sources, e.g., coal, gas or nuclear power plants.

Electricity transmission infrastructure in the EU currently consists of 390,000 km of high-voltage transmission lines. These lines are, on average, 30 years old. Distribution grids consist of over 9 million km of circuits; out of these, 40–55% of distribution assets will be more than 40 years old by 2030.[10] Grids are natural monopolists and are therefore heavily regulated.

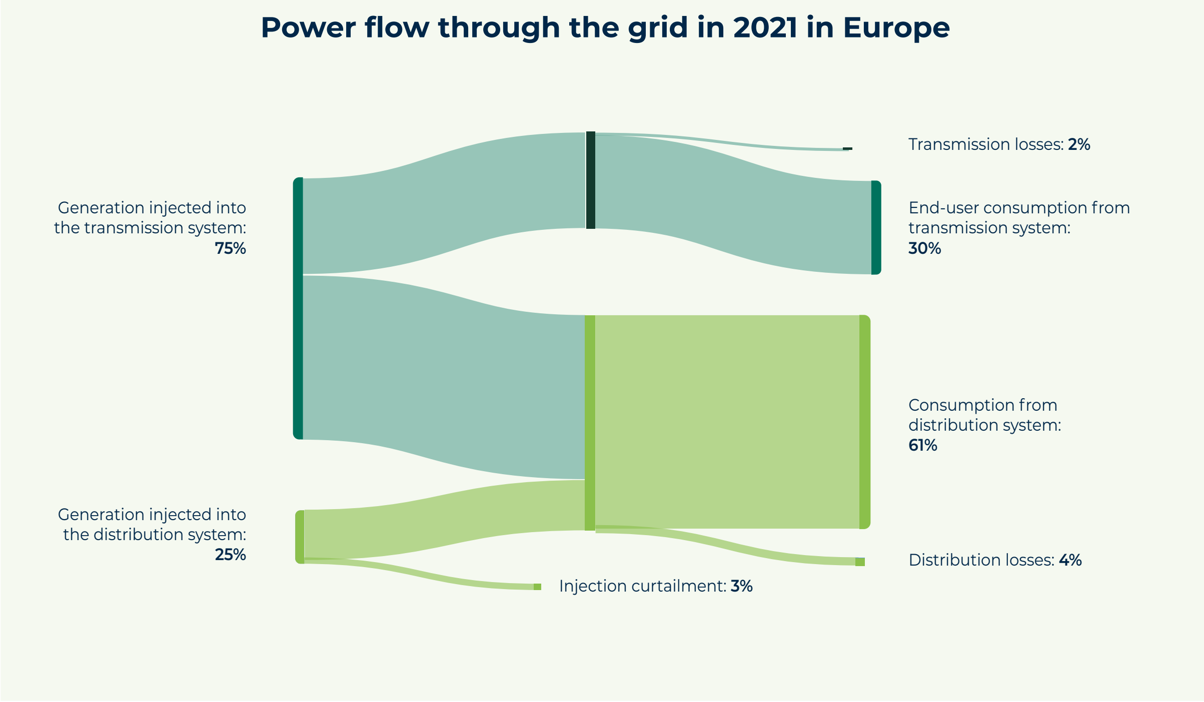


Figure 14: Power flow through the grid in 2021

In order to meet decarbonisation targets, the EU must change its approach to the planning and permitting of generation and transmission. Owners and operators of electricity grid infrastructure need a clear long-term perspective and must be able to translate this into an order book for the supply chain. The permitting provisions in the Renewable Energy Directive III are an important step at EU level to accelerate planning and permitting and should therefore be implemented by member states. According to data from BloombergNEF, more than 150 GW (gigawatts) of wind and solar projects are stuck in grid connection queues in the UK, Spain and Italy.[11]

E.ON estimates to have to deliver one connection every seven seconds to the distribution grids in the six countries it covers (including Germany), by 2030 (see E.ON Expert Corner). The power grid for providing electricity to electric vehicles, including passenger cars, buses, and trucks for the transport of people and goods, needs to develop from zero to megawatt scale by 2030 to comply with carbon emission reduction legislation (see Volvo Expert Corner).

EXPERT CORNER 2

ArcelorMittal

Speed of energy transition: Electricity price development example

Electricity price development is – if policy is not stepping up – hindering investments and decarbonisation of steel industry in Europe: The Arcelor Case

Electricity price development procurement has known unprecedented times in the last three years, which reached record levels around Europe and unlikely to go back to their pre-war levels in the foreseeable future. These increases were not homogenous in all EU countries, due to the different generation mixes and the varying reliance on gas as an electricity source. The spread between the highest priced country vs the lowest Member State price level was particularly stark during August 2022, as shown in Figure 15.[12]

As the Commission's JRC[12] report also underlines, the price of power in the current market structure will continue to be set by high gas and carbon prices at least in the short term, even if these represent just a small part of the portfolio of power production.

This is also applicable to RES PPAs, where the price for consumers is driven by the market prices, which means it will be impossible to source at a cost plus basis. Also, because there is a shortage of RES PPAs and they often do not match the continuous production profile of many industries like steel. They are not the silver bullet to get internationally competitive prices for the moment. For that, other solutions must be found.

Conclusion: Time for action?

The EU Commission's Market Design reform proposal is unfortunately addressing neither investment uncertainty nor difficulties of accessing affordable renewable energy by consumers. Many industrials take the position in dialogue to 'improve the market design to improve affordability and to ensure affordability for EIIs'. This is starting to be recognised as we have seen in the recent IEA/EU ECB/EIB dialogue, 'European industry also finds itself at a competitive disadvantage regarding the price of energy. Compared with other regions, these prices are relatively high, and ambitious industrial programmes are being introduced in countries such as the United States, China, India, Japan and Korea to build up domestic supply chains, resource security and manufacturing capacity. Accelerating energy transition investment will help Europe limit dependence on major fossil-fuel producers and often volatile fuel markets'.[2] Like for these other countries, it is key that also in Europe energy-intensive industries and consumers will be able to source electricity linked to its actual cost of production. This is essential to achieving the internationally competitive prices that energy-intensive industries like steel require to invest in Europe.

Correlation between wholesale electricity market prices and PPA prices

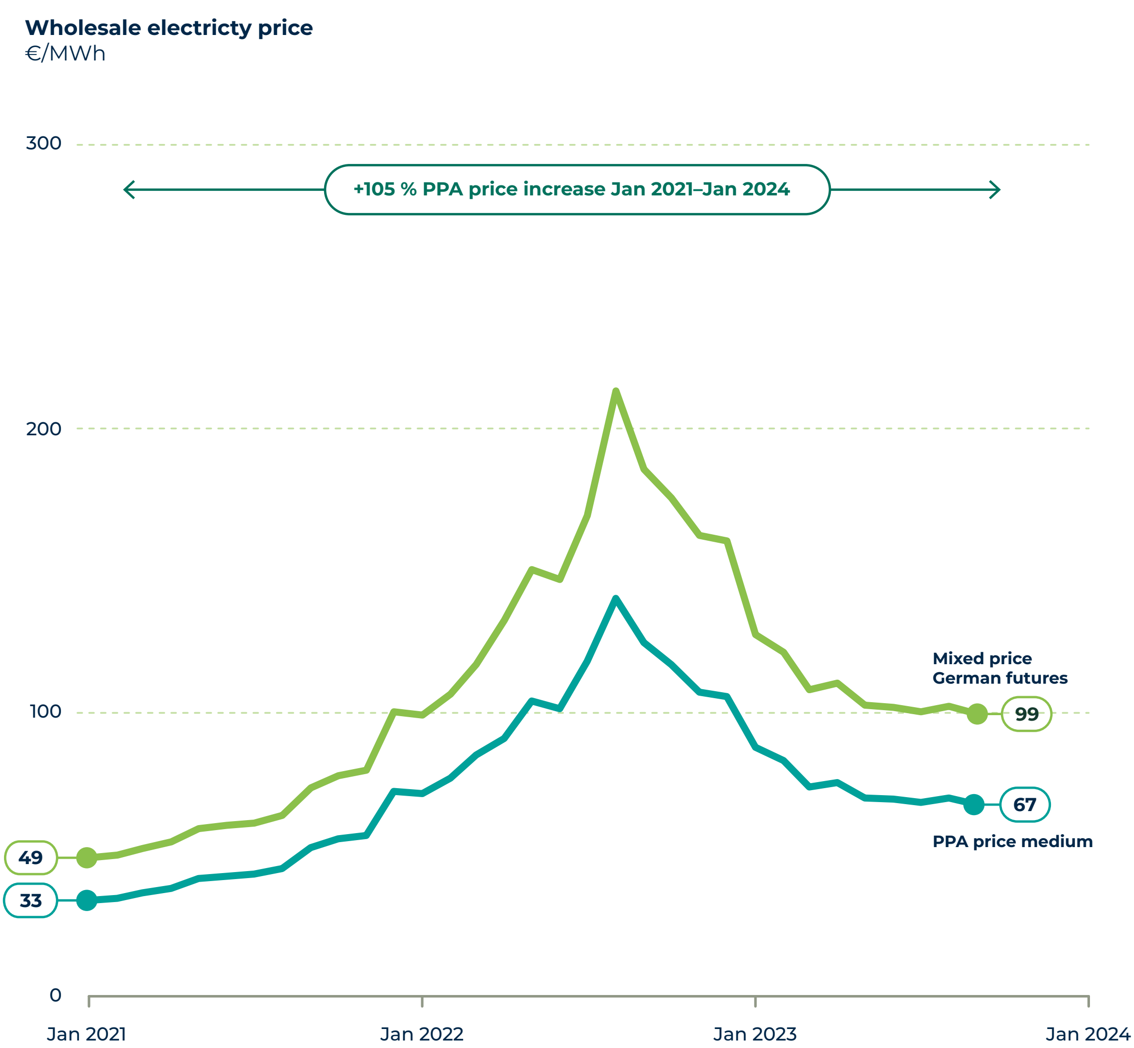


Figure 15: Correlation between wholesale electricity market prices and PPA prices

Source: Encavis PPA Tracker

2.1.2. Developments

2.1.2.1. Generation

Generation from variable renewable energy (VRE) sources requires firm and flexible capacity to ensure security and quality of supply while avoiding potential curtailment (costly forced stopping of generation). Flexibility can be provided by a range of solutions, such as demand response and storage.

VRE needs to be combined with other sources of generation and with increasing demand-side flexibility to ensure a balance of demand and supply, as well as reliability of supply. According to the European Commission, flexibility requirements will grow seven times by 2050 and will become 30% of the EU power demand.[13] Flexibility can be provided by a range of solutions, such as gas-fired power plants, interconnectors, battery storage, electrolysers, hydro, and demand-side response.

2.1.2.2. Transmission systems

Integration of existing and future renewable energy sources (RES) is currently one of the main drivers for investment in transmission grids. Most new power sources (~70%) will inject their power on a distribution level. Only a few large onshore and offshore wind farms and large photovoltaic (PV) facilities will inject directly into the transmission system. In the new world of distributed power generation, consumers are typically geographically further away, so the grid assumes the role of balancing as it connects different weather and time zones. As a result of the need to transport electricity over long distances, investment in high-voltage 'electricity highways' is the largest contributor to new transmission lines being built. Additionally, investments are aimed at improving infrastructure management and utilisation.

To facilitate cooperation across borders and provide flexibility to the system, interconnection points need to be built, both on-and offshore. Investments are also required in grid resilience, in the face of increased electricity consumption, to ensure quality of supply.

The main goals of the EU's current transmission grid developments are as follows:

- Provide the interconnection for new large offshore wind farms and a few large onshore wind and PV installations
- Increase transport capacity between market zones to reduce congestion
- Increase the resilience of the grid
- Develop cross-border connections
- Improve visibility of flexibility needs by system operators

Transmission systems with interconnectors will play an increasing role in balancing the power system, as this allows the power flow to be adapted to the current weather situation (the availability of wind and sun).

Investments include new transmission technologies such as high-voltage direct current (HVDC) lines, which are more efficient for long-distance transmission compared to traditional alternating current (AC) lines. They are also more flexible and are often used to connect offshore wind farms and interconnectors.

Cross-border interconnectors

Electric cross-border interconnections are a key tool to ensure the integration of the EU's internal energy market. On the path towards climate neutrality, increasing investment in onshore and offshore generation facilities and the extended electrification of transport, heating and cooling, and industry requires reinforcing all power grids. Therefore, investment in cross border interconnections is key.

In this sense and in line with the EU energy security and energy efficiency-first principle, the 15% interconnection level mentioned in Article 4.d.1 of Regulation (EU) 2018/1999 on the Governance of the Energy Union and Climate Action must be considered in the context of EU price convergence and the realities of expanded investment in renewable energy, linked to peak demand.

When assessing interconnection reinforcements, the cost-benefit analysis must consider the relocation of electricity demand from EU regions with a structural lack of renewable generation to 'peripherial' renewable energy hubs (i.e., promotion of on-site or national renewable self-consumption). The cost incurred to export significant surpluses of renewable energy from those hubs is not only investment in the interconnection but also indirect grid and system costs which would no longer be designed to balance domestic supply and demand of energy.

2.1.2.3. Distribution systems

Distribution systems are key enablers for decarbonisation, supporting the increased electrification of industry and residential consumers (notably in heating and cooling and transport) and facilitating demand-side response. In the future, we will increasingly see that power is injected and aggregated at the distribution system level and then is consumed locally or is pushed from the distribution level into the transmission system. It is projected that by 2030, 70% of new RES will be connected to distribution grids.[10] Figure 16 illustrates the predicted power flow by 2050.

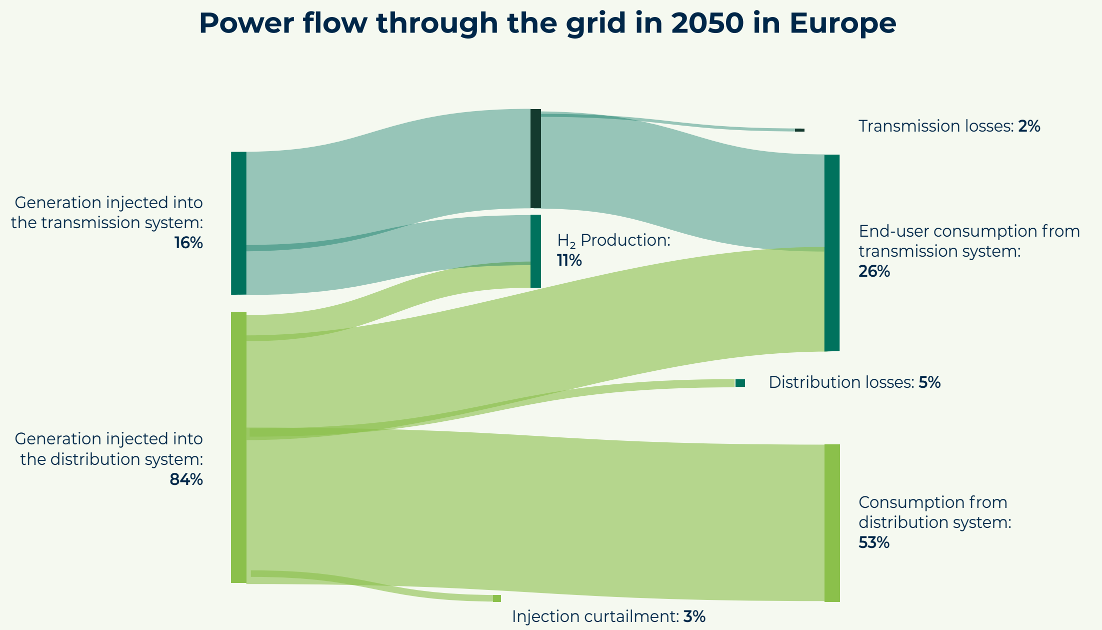


Figure 16: Power flow through the grid in 2050 in Europe

Most current investments in distribution grids are to facilitate the following:

- Incorporation of new distributed resources (estimated 70% of new renewables)
- Modernisation and deployment of smart meters, to enable real-time monitoring of the low-voltage grid and better manage flexibility and integrate distributed resources, smart recharge and new electric heat pumps
- Improvement of stability and removal of grid imbalances
- Ensured security of supply in cases of extreme weather conditions or natural disasters
- Improved data management to increase the observability of grid patterns and cybersecurity
- Improved integration of RES sources, especially behind the meter, ensuring the participation of consumers in the market through efficient market signals
- Visibility on flexibility needs by system operators

The gradual rollout of smart meters (already completed in several EU countries), and implementation of big data management, enables distribution system operators (DSOs) to address local grid imbalances, congestion, and voltage problems, driven by the massive development of renewable energy sources.

Additionally, EU distribution grids need modernisation because of system ageing. It is estimated that 40– 55% of assets could be more than 40 years old by 2030.[10] In the context of climate change, investments are required to increase the resilience of grids against severe weather conditions. Cyber-security measures, including access control and account management, data protection and malware protection, should be implemented.

As a result of the described trends, most new lines will be added to the distribution rather than transmission networks (3.2 million km, a 30% increase between 2021 and 2050).

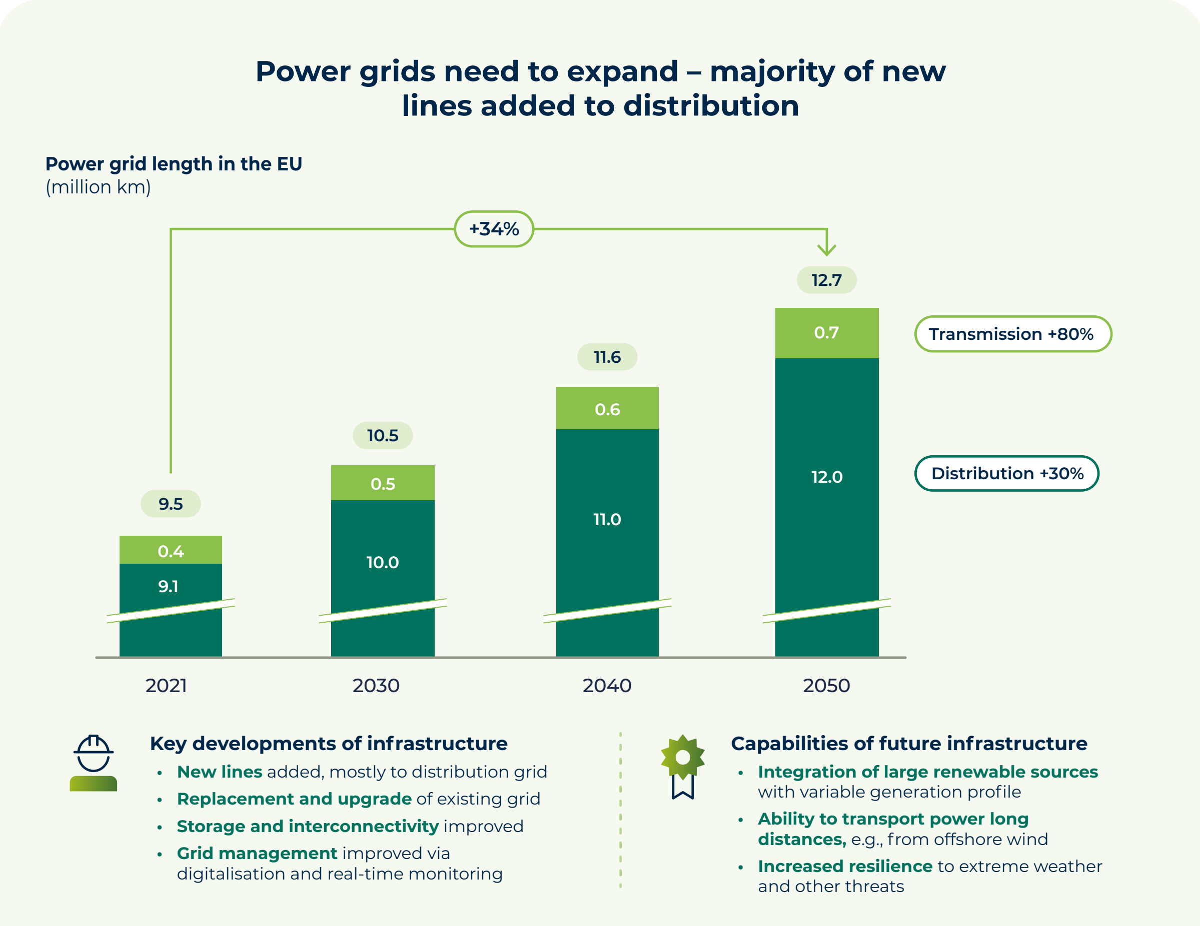


Figure 17: Power grids need to expand

Source: IEA Announced Pledges Scenario, transmission network operators, distribution network operators, Eurelectric, BCG analysis

For reference, below are the grid length projections for the EU, as per the IEA.[5]

No.	Source	Grid type	Grid length during year indicated (thousand km)	
			2022	2050
1	IEA World Energy Outlook 2022	Transmission grid	500	800
2	IEA World Energy Outlook 2022	Distribution grid	11,000	13,000

EXPERT
CORNER 4

Digital and scaled distribution grids

The energy sector continues the decentralisation trend at an unprecedented rate, with network connections and energy feed-in increasing exponentially. Electricity is not only consumed by more customers but it is also fed back into the grid from numerous decentralised generation points. Electricity infrastructure companies worldwide need to invest hundreds of billions of euros to make grids fit for the change, with E.ON alone already contributing over €30 billion by 2027 across Europe.[14] The distribution system will take two-thirds of capital investments in power infrastructure, according to the European Commission.

Network expansion not only costs more it also takes time, people and equipment. After all, the grid was initially designed to distribute energy to consumers in a one-way flow. To manage the new, more complex energy system while ensuring a reliable electricity supply, networks need to become smarter, optimised with digital tools and physical expansion. The optimum mix depends on the local configuration. In some cases, advanced network management solutions and flexibility can squeeze out some of the grid capacity required, in others capacity buildout is needed right away.

Zooming in, the picture gets clearer. Take, for example, a small district in the south of Germany (Bavaria) with 80,000 inhabitants, that aims to be net-zero by 2040 due to a massive proliferation of solar PV, electric vehicles (EVs), batteries and heat pumps. The grid now has to distribute 7 MW at peak and already receives 120 MW feed-in (i.e., already 17 times higher than the maximum load). By 2040, that same network will require a distribution capacity increase by a factor of 10 and a back-feed by a factor of 5. That means a 'smart' physical expansion must be carried out, with a sizable replacement of the secondary substations with digital ones, additional cables and software to reinforce network capabilities.

The energy transition will call for completely new delivery capabilities on top of investments. E.ON estimates they will have to perform one connection every seven seconds in 2030. To manage this task and operate the complex system, the distribution service operators (DSO) will incur higher operational costs than before to digitise and hire the essential personnel.

Conclusion

Scaled and smart power networks enable EU industries to remain competitive by ensuring timely and reliable access to energy. Rolling out the necessary capital and operational expenses at the right speed requires a modern regulatory mindset, starting with a clear treatment of anticipatory investments that reduces the risk of assets deployed based on forecasted new generation and demand. Crucially, regulation must ensure returns on investment that are in line with the financial environment, recognise timely capital and give flexibility to adapt operational expenses to the evolving system needs.

Power grid expansion until 2030

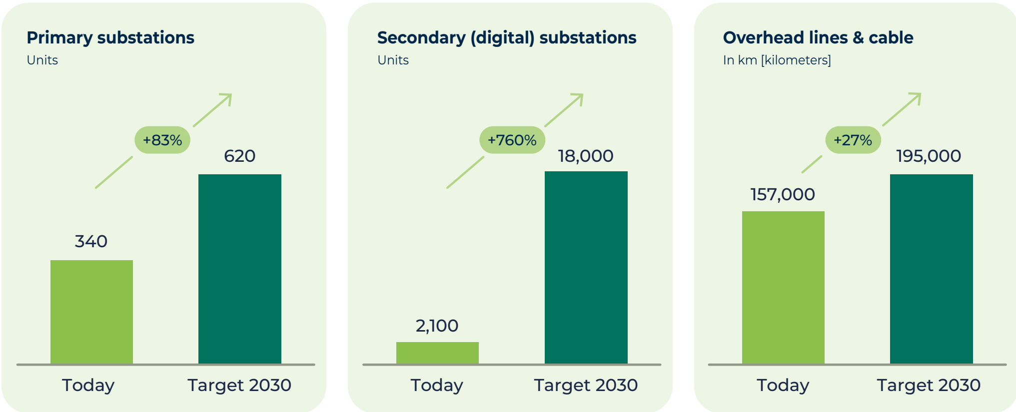
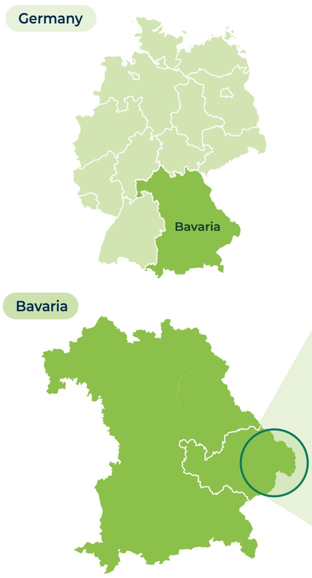


Figure 18: Power grid expansion until 2030

Source: Bayernwerk, part of E.ON Group, as of October 2022

Case study: Bavaria



District Freyung-Grafenau

78,600 population **984 km²** area

	Today	2040
PV power	100 MW	650 MW
Electric cars	100	33,700
Home battery shortage	480	15,000
Heat pumps	500	12,000
Grid usage	**7 MW**	**70 MW**
Back-feeding	**120 MW**	**620 MW**

Figure 19: Case study: Bavaria

Source: Bayernwerk, part of E.ON Group

The need for flexibility in the power system is expected to reach 24% of total EU electrical demand in 2030, and 30% of total EU demand by 2050.[15] Flexibility requirements are going to be met by a combination of technologies, ranging from batteries, interconnectors, mechanical energy storage, hydrogen, software, or pumped hydro storage. A recent study shows that a failure to fully active flexibility from buildings, electric vehicles, and industry in 2030 would require €11.1 billion–€29.1 billion higher investments annually in the distribution grid; and come with additional 15.5 TWh (61%) renewable curtailment corresponding to €2.7 billion additional peak generation capacity annually.[16]

ENTSO-E assumes capacity growth of battery storage from 126 GW in 2030 to 174 GW in 2040[7] and demand-side flexibility.

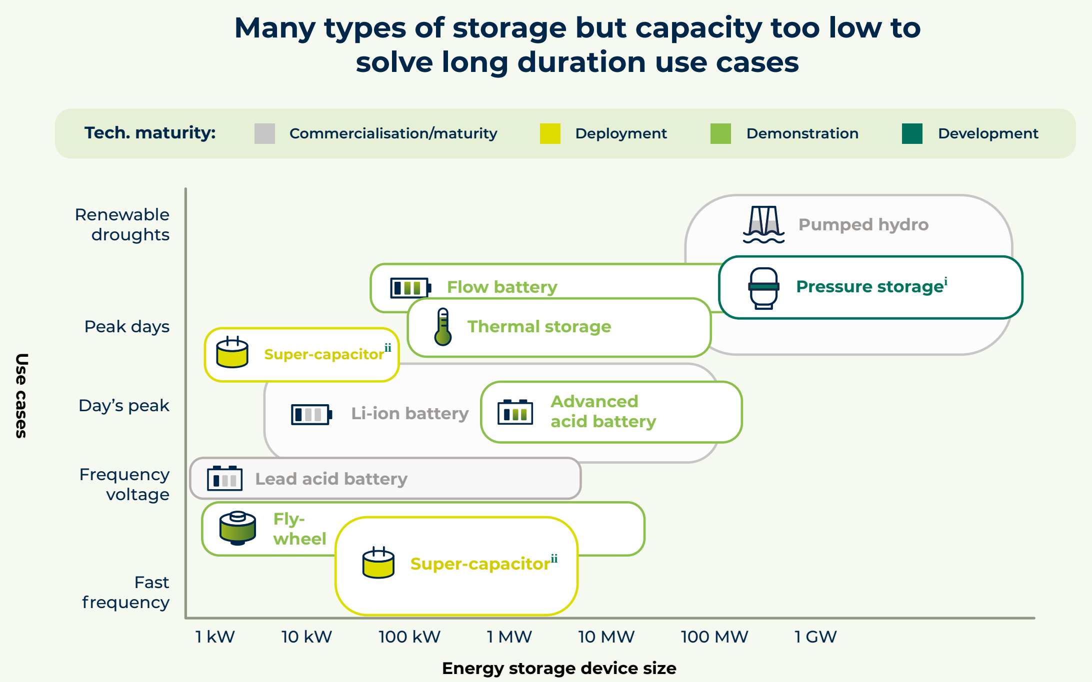


Figure 20: Mapping power storage technologies

Source: Bayernwerk, part of E.ON Group

EXPERT CORNER 5

UPM

Demand-side flexibility

In the future electricity system, more and more flexibility will be needed to balance the system as the share of weather-dependent electricity generation grows. Changes within the day (e.g., in wind power production) cause an additional need to balance the electricity system. Alongside all potential for flexibility through hydropower and storage solutions, there is an increasing need to optimise electricity consumption in industrial processes to maximise the potential of demand-side flexibility.

Over the decades, UPM Energy, the second largest energy producer in Finland, has learned to save to anticipate consumption and price spikes and adjust its consumption accordingly. This has required investments in measuring and steering processes but also increased understanding of electricity market functioning and electricity price variations in different marketplaces.

The main source of demand-side flexibility has been developed within electricity-intensive parts of the papermaking process. Electricity consumption of UPM's mills is optimised based on market forecasts and intra-day needs without compromising deliveries to customers. Sub-processes can be steered in a way that the paper machine is constantly running but total electricity consumption can be varied to a large extent. This enables optimisation of power demand in relation to the electricity system demand and has proven very cost efficient, as electricity consumption peaks can be timed to the hours with less demand and lower prices.

The example of UPM shows that industry can participate in energy initiatives. It is not just about saving electricity; it is about when and how you use it. Innovations that help optimise electricity production and consumption are key. Functioning electricity markets in combination with clear price signals are key enablers to incentivise demand-side development within industrial processes.

EXPERT
CORNER 6

VOLVO

Power requirements for charging infrastructure

Introduction

In this case study, we will explore how the Volvo Group, a leading player in the automotive industry, has harnessed data to assess the power requirements for public charging infrastructure for battery electric trucks. Specifically, we will examine the experiences in Sweden and France, with ongoing work in wider Europe, including Germany. The case study highlights the importance of data-driven insights in facilitating the development of efficient and sustainable charging networks to support the energy grids in managing flexibility, assisting energy transition cost efficiency – both from the perspective of users and grid operators.

Relevant evidence

The Volvo Group has utilised real-time data from its fleet of trucks to gain valuable insights into their movement patterns, stoppages and duration. Extrapolation of truck volumes, with real unique data of routes, across the entire fleet has enabled the assessment of energy and power needs during real stoppage times and geographical locations, as the figures for Sweden and France below illustrate.

20% population opportunity + night charging

VOLVO

Power	Hex	Peak power
20–35 MW	2	20–35 MW
15–20 MW	1	15–20 MW
10–15 MW	7	10–15 MW
5–10 MW	30	5–10 MW
3–5 MW	75	3–5 MW
2–3 MW	350	2–3 MW
1–2 MW	500	1–2 MW
< 1 MW	250	< 1 MW

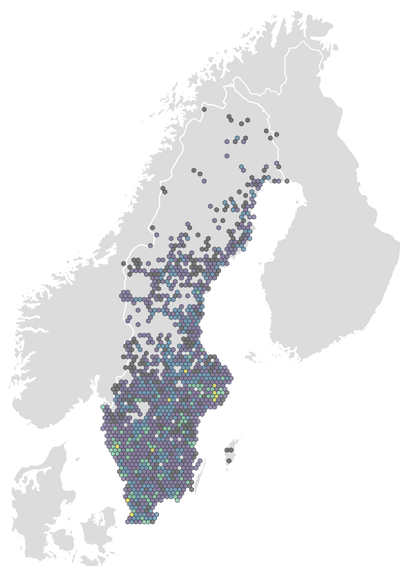


Figure 21: Power needs of night charging in Sweden

Note: Data provided by Volvo Group

VOLVO

20% rolling truck population: opportunity + night charging

Power	Hex	Peak power
30–40 MW	3	30–40 MW
20–30 MW	18	20–30 MW
15–20 MW	25	15–20 MW
10–15 MW	85	10–15 MW
5–10 MW	346	5–10 MW
3–5 MW	566	3–5 MW
2–3 MW	747	2–3 MW
1–2 MW	473	1–2 MW
< 1 MW	82	< 1 MW

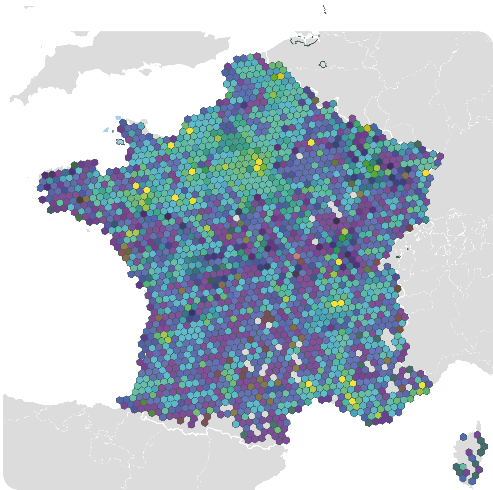


Figure 22: Power needs and night charging in France

Note: Data provided by Volvo Group

EXPERT CORNER 6

Power requirements for charging infrastructure

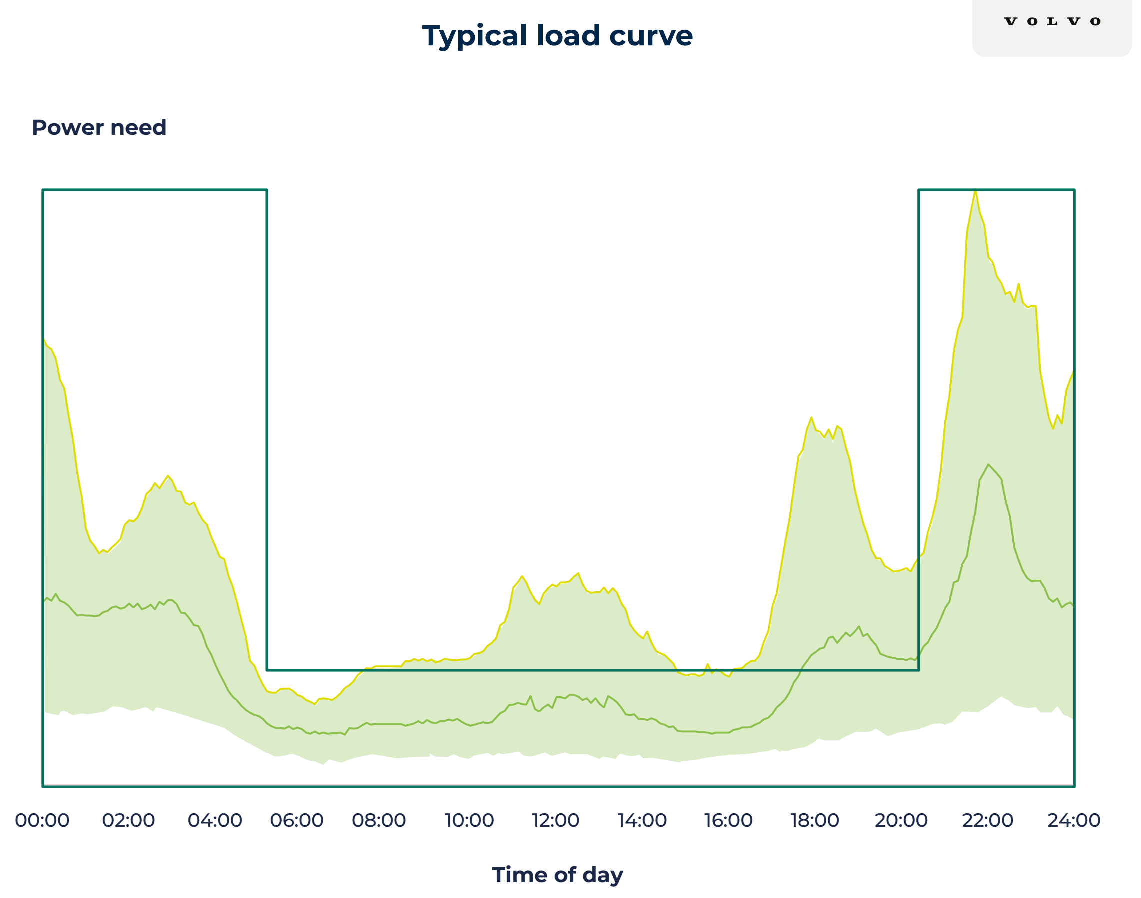


Figure 23: Typical load curve

Note: Data provided by Volvo Group

These analyses have led to the identification of suitable locations for charging stations, determined the required number of charging points, and estimated power needs.

Illustratively, in Sweden this showed that for 20% of the fleet that is easiest to electrify, having moderate daily energy needs, about 2% of Swedish grid capacity (peak) would be required, most of it connected at 10+ kV distribution levels. The pattern usage during the day is often W-shaped – allowing potentially for the optimisation of grids if the capacity access is no longer planned based only on peak usage. At 100% electrification and distances of 600–700 km, the impact would grow more steeply. The latter underlines the critical importance of managing existing grid capacity access by sharing data, innovating incentives for grid use optimisation, and forecasting the anticipatory need for investments over the following 8–10+ years.

The data-driven approach considers not only the power requirements but also the strategic placement of charging infrastructure, to optimise productivity and support seamless operations with power grids.

The Volvo Group's commitment to data-driven solutions extends to wider similar work in other European countries, where similar analyses are being conducted. This work demonstrates a forward-looking approach, ensuring that infrastructure development aligns with the growing demand for electric trucks in the region and the need to collaborate on implementing innovative grid access products for distribution. This will lead to the electrification of transport this decade, instead of waiting for the 2030s or 2040s.

Conclusion

The Volvo Group's case study illustrates the pivotal role that data analysis plays in shaping the future of sustainable transportation. By leveraging real-time data from its fleet of trucks, the Volvo Group can make informed decisions about the development of public charging infrastructure and provide timely advice to energy infrastructure developers, and start to collaborate with grid operators to optimise grid operations. In addition, the methodology used by Volvo Group is adaptable and can be extended to other regions, making it scalable to EU-wide application. This case study underscores the importance of informative data sharing between industry leaders and grid operators to expedite the expansion of the electric vehicle charging network to manage such flexible load power grids. The implications for policymakers are twofold:

1. Enable collaboration between industry and grid players on flexibility data by providing incentives

2. Enable and encourage grid operators to offer capacities not just based on peak usage – e.g., through flexible time-use tariffs systems and other incentives allowing more returns if capacity access is managed well without additional buildout only.

2.1.2.4. Implications on infrastructure from locations of supply and demand

New supply from within the EU is driven by key locations of wind and sun, as well as the space available for building such generation. Demand is driven by the location of industrial clusters, which traditionally were close to the source of energy. Relocation is happening, as one can see in the aluminium smelter of Alcoa[17] or Rio Tinto in Iceland,[18] so the EU needs a framework that makes relocation within Europe more attractive than moving outside.

2.2. Natural gas infrastructure

2.2.1. Situation today

The EU's gas transmission grid has a total length of over 200,000 km. It is made up of a network of high-pressure pipelines that transport natural gas at pressures of up to 100 bar.

Natural gas transmission grid operators are regulated. Their remuneration for managing the grid includes return on the regulated asset base, regulatory depreciation and OPEX efficiency incentives. Returns for transmission system operators (TSOs) are usually relatively stable and predictable.

Currently, a limited number of gas grid development projects are being completed in Europe, with no new projects in sight. Instead of laying new pipelines, TSOs are primarily investing in refurbishing infrastructure, connecting existing networks to new LNG terminals, and preparing grids to inject biomethane, carry hydrogen, or carry CO_2. Future projects are expected to be linked with commissioning dedicated hydrogen pipelines.

The EU gas distribution network has a total length of 2 million km. All 100% of residential customers and 99% of industrial and commercial gas users are connected to local distribution grids.

2.2.2. Development

Both heavy and light industries are expected to halve natural gas consumption by 2050 in favour of other fuels – hydrogen, biomethane and e-methane, as shown in Figure 24.

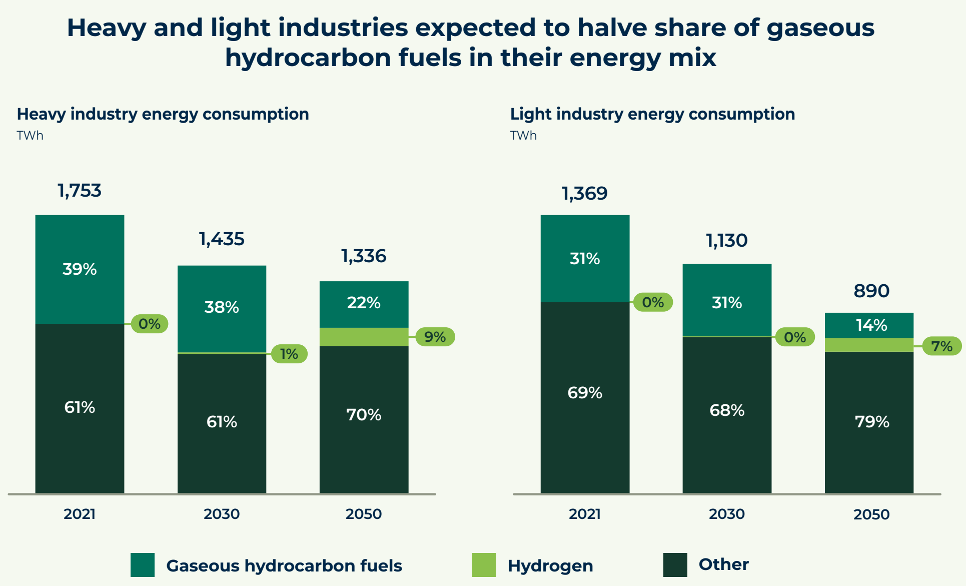


Figure 24: Heavy and light industry energy demand, TWh

Source: Shell Sky 2050

However, depending on source and scenario, different paces of electrification of industry are modelled, leading to different shares of power, gas and other carriers in the energy mix. For reference, the below graph presents scenarios modelled by Eurelectric, with a strong focus on electrification.[4]

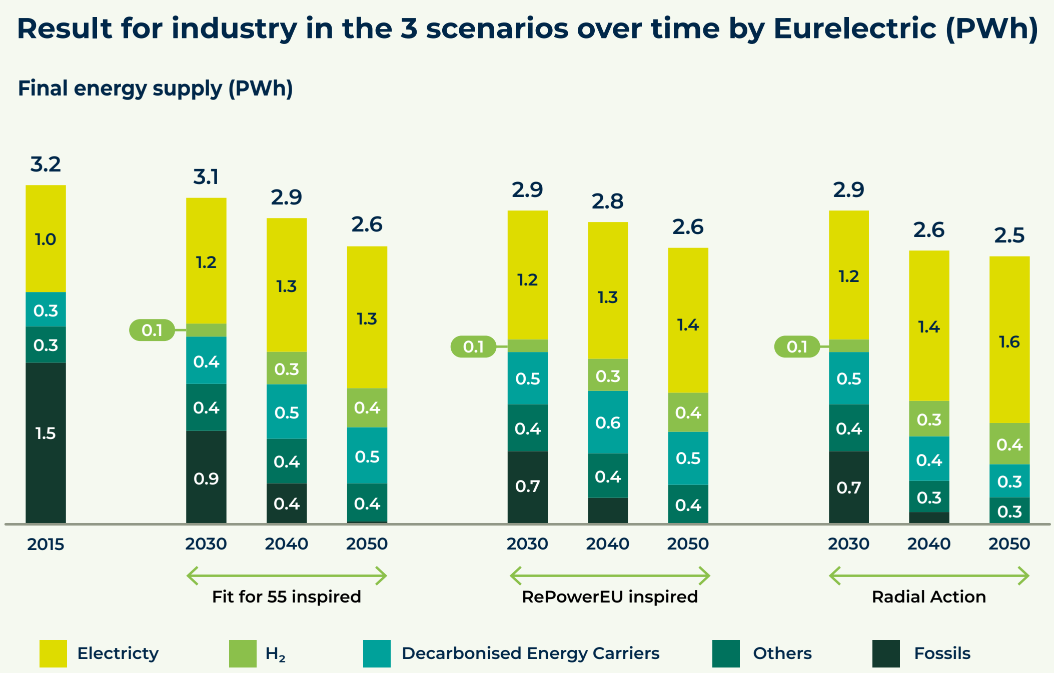


Figure 25: Result for industry in the three scenarios, Eurelectric, PWh

No major infrastructure investments for natural gas are expected in the coming years based on market demand, with the notable exception of the Trans-Adriatic Pipeline expansion in the southern gas corridor and connecting offshore gas in Romania (Neptun Deep). The last wave of large-scale EU-level investment was a short surge of additional LNG import terminals and cross-border connections, including the Baltic Pipe.

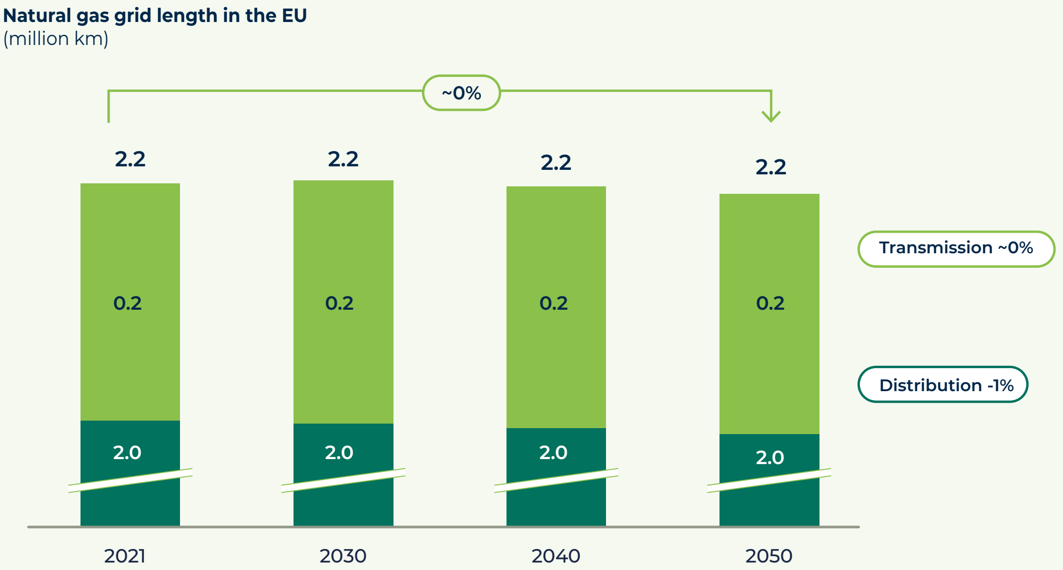
This lack of market-driven pipelines investment in large-volume gas markets of Europe is particularly visible on a national level. For example, German pipeline growth has been minimal (0.7% compound annual growth rate [CAGR] from 2012 to 2020). Future pipeline growth in Germany is also expected to be minimal, with forecasts for 2020 to 2030 showing investments of €7 billion to €8 billion for pipeline additions totalling 1,620 km.

In the interim, driven by energy security concerns, Germany is using floating storage and regasification terminals (FSRUs) to help to replace piped Russian gas supplies with LNG. Three FSRUs are working at the Wilhelmshaven, Brunsbuettel and Lubmin ports after Germany arranged their charter and onshore connections.[19] Wilhelmshaven, Mukran and Stade are due to add more FSRU ships for the 2023/24 winter. On one hand, the investment signals policy commitment to long-term gas imports and natural gas grid need; on the other, Germany has adopted a law which lets permits for LNG FSRUs expire by end of 2043 showing its commitment to net-zero policy in Europe.[19]

In relation to markets like Germany, for lower-volume gas markets of Europe – such as Hungary, Romania, Czech Republic, Bulgaria, Greece, Poland, and Croatia – we observe industry analysts considering investments in gas infrastructure driven by energy security. That gas market infrastructure may benefit in short-term regional decarbonisation, as the gas may be replacing coal on a regional level.

Gas storage remains a critical asset, providing flexibility for the industry, with a capacity that has stayed largely stable between 2013 and 2020. Gas storage capacity is expected to be fully allocated in the immediate future, supported by new EU-driven gas filling regulations. The market is likely to decline after 2030 - due to decreasing demand for natural gas (-75–90% according to Shell Sky 2050 and IEA APS until 2050, respectively) – then pick up as demand for hydrogen gas increases. Salt caverns – part of the gas storage ecosystem in Europe – may be retrofitted to meet the increasing hydrogen storage demand, while depleted field storages could be used for storing regasified LNG (as long as LNG is needed). The European gas storage market has historically amounted to 20–25% of natural gas demand. As the natural gas market volume declines, sufficient porous gas storage volumes need to remain to support methane market development (including biomethane and synthetic methane), even if some of the salt caverns are repurposed. Decline in gas demand does not automatically mean less storage in the coming years given, for example, needs of the developing biomethane market and energy security.

Heavy and light industries expected to halve share of gaseous hydrocarbon fuels in their energy mix



Key developments of infrastructure

- **Infrastructure largely to remain unchanged despite natural gas volumes drop** by 90% over 2021–2050
- **No significant developments** of transmission or distribution grid beyond 2025
- **Minor sections** of grid **repurposed for hydrogen**
- **Biomethane** partially making up for dropping natural gas volumes, subject to **competitiveness**

Capabilities of future infrastructure

- **Maintained ability to handle peak loads**
- **Ability to integrate new biomethane sources** to the existing natural gas grid

Figure 26: Natural gas grid length in the EU, million km

Source: IEA Announced Pledges Scenario, transmission network operators, distribution network operators, Eurelectric, BCG analysis

2.3. Biomethane infrastructure

2.3.1. Situation today

Biogas is produced by the decomposition of organic matter, such as agricultural waste, biowaste and crops, which is put into a biogas plant under exclusion of oxygen. As a result, a mixture of gases is released consisting of 45–85% methane and 25–50% CO_2. Biogas may be upgraded to biomethane and injected into the natural gas grid.

Production of biomethane to grow 10× under RePowerEU

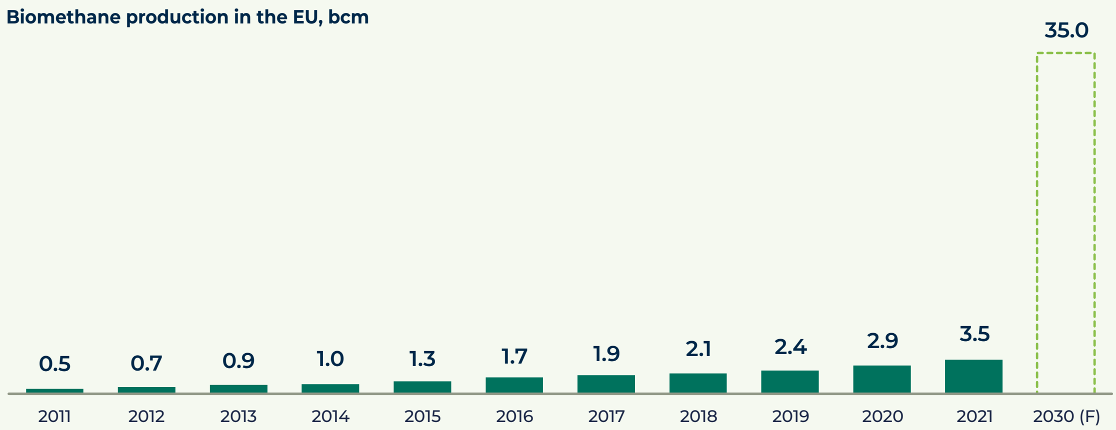


Figure 27: Biomethane production in the EU, real values and 2030 (bcm)

Source: European Biogas Association, EBA Statistical Report 2022, RePowerEU

The majority of existing biogas plants are small-scale and located in agricultural areas. This often poses challenges from a gas network access standpoint. In 2020, there were around 20,000 biogas plants operating in the EU, of which around 1,000 injected biomethane into the natural gas grid. Other biogas plants produced electricity and heat locally.

Grid connection represents a potential additional cost, if biomethane is to be injected into gas networks rather than used locally, with TSO networks being more cost intensive. Proximity to the gas network is a significant cost factor, and to be cost-effective, plants must generally be located very near to gas grids. Typical network connection costs are around $3 per MBtu, split roughly equally between pipeline infrastructure and grid injection and connection costs, although this will vary significantly depending on the length of the pipeline.[20]

2.3.2. Development

Biomethane infrastructure buildout needs to address the following challenges:

- **Grid connection**
  The cost of grid connection can vary depending on length, topography and compressing power. That is why the cost of a connection can be between half a million or several million euros per installation. Thousands of multiple facilities need to connect to maximise potential, shared across developers and networks, to grow biomethane production tenfold by 2030, as the figure above shows.

- **Grid reinforcements**
  Investments are needed in network and dispatch centres to ensure there is no congestion at a local level. Congestion is most likely to happen at the distribution level in summertime (April to October) and at nights or weekends. Transmission networks will also need to address the injection of decentralised biomethane production.

Biomethane is a complement to electricity and hydrogen for heavy goods vehicles, where batteries or hydrogen are not available to offer sufficient range. Liquefaction plants are needed to support a pan-European filling network as required in AFIR (alternative fuels infrastructure regulation).[21] The existing pipeline network is to enable the use of biomethane in heavy goods transportation. Total biomethane network costs in 2050 are estimated to be up to €9.7/MWh, of which biogas pipes cover €5.0/MWh and grid injection and connection costs add €4.7/MWh per year.[22]

EXPERT
CORNER 7

VOLVO

Biomethane as fuel for heavy transport

Biomethane is an important complement to batteries and hydrogen in heavy goods transport and can offer negative emissions. Volvo Trucks in Norway and Finland operate on liquid biomethane, upgraded from biogas made from manure. The manure is collected from farmers, digested, upgraded and liquefied.

The biomethane harvested from farmers is then used by Finnish diary producer Valio and the Norwegian food and beverage company to transport the milk from the farmer to the dairy and from dairy to stores. This is a fantastic example of sector synergy, and it already provides negative greenhouse gas emissions if the biogas is digested from manure.

Biomethane is an important complement to batteries and hydrogen in the hard-to-abate transportation truck applications, since it offers higher volumetric energy content than batteries or hydrogen. Biomethane will also be needed long-term in the heaviest applications, such as the transportation of transformers, alternators and gearboxes for wind turbines, timber, or some heavy construction trucks with many axles and limited space on board for energy storage.

2.4. Hydrogen infrastructure

2.4.1. Situation today

Currently, hydrogen pipelines exist in small pockets within the EU and are privately owned, dedicated to supply industrial consumers with hydrogen as a feedstock. None have been designed so far to carry hydrogen as a commodity. As the demand for hydrogen as a vector of energy grows, this will change in the long term. There is a challenge ahead to rapidly expand a regulated network of hydrogen pipelines, which has already been highlighted by the European Hydrogen Backbone (EHB) initiative.[23] We see projects, which form part of the EHB, being developed by EU gas transmission operators, together with industry and energy suppliers across Europe in Germany, Denmark, the Netherlands, Belgium and Italy. In some countries, such as Spain, within EU-wide network planning, hydrogen infrastructure is being developed locally, exploring exports via shipping instead of pipeline systems.[24] A national hydrogen grid is already under construction in Belgium and the Netherlands.[24] The decision to build a hydrogen national grid in the Netherlands was taken in June 2022. Recently, a plan was made to consider building an underwater hydrogen pipeline between Barcelona and Marseille to provide hydrogen via the south of France to a future, wider EU network. In Germany, a core network is also under discussion.

European grid players are examining a backbone study to clearly identify industrial demand, which will avoid stranded assets if demand is not developing to the extent and in the locations where the H_2 networks would be installed. A good example is the Enagás Spanish hydrogen backbone study, as well as demand studies by German and Danish grid players.

2.4.2. Development

Multiple alternative studies and academic analyses assess the necessary investments in European hydrogen infrastructure. For example, the EHB study estimates five times the volume (2,600 Twh) of hydrogen consumption in 2050 than Shell Sky 2050 (492 TWh) or IEA APS (484 TWh) (see Methodology 15). In this publication, we have descaled the length of the hydrogen system in line with considerably lower volumes identified in IEA APS and Shell Sky scenarios (see Methodology 15).

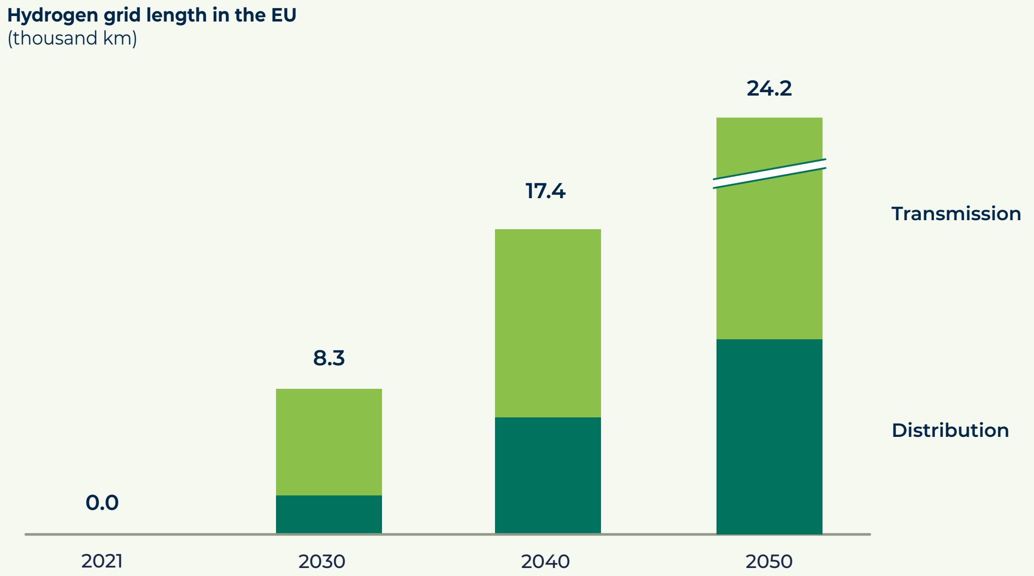
In addition, hydrogen can be produced locally from a primary energy, and so differs significantly from natural gas which has to be produced where it can be extracted from the gas fields. Balancing local hydrogen production with imports is therefore critical for economic and strategic reasons.

The EU's hydrogen strategy is clear on the role of hydrogen as a key energy transition vector: 'Hydrogen can be used as a feedstock, a fuel or an energy carrier and storage, and has many possible applications across industry, transport, power, and buildings sectors. Most importantly, it does not emit CO_2 at the point of use and generates almost no air pollution when used. It thus offers a solution to decarbonise industrial processes and economic sectors where reducing carbon emissions is both urgent and hard to achieve.'[25] The industry, with policy support, is working to create the scale required to reduce the cost of hydrogen production to levels needed for energy-intensive industries and for the transport sector to decarbonise. The revision of the Alternative Fuel Infrastructure regulation; of the Renewable Energy Directive (RED); of the gas directive and regulation; and the adoption of the RED based delegated acts ('additionality' and on the calculation of CO_2 emissions savings) are instrumental. The RED and the RED-delegated acts are currently translated into a certification system which will help to demonstrate compliance with the requirements set out under RED and the related delegated acts. The gas package will bring a definition of 'low-carbon' hydrogen; that definition will be operationalised by another delegated act. Together, all these should accelerate hydrogen market development.

From emerging investments in the Netherlands, Germany and Belgium, even with policy support by the respective governments, the time between the initiation of policy support and initial operations of hydrogen infrastructure may be 6–10 years, so we can assume that other EU developments in this decade may be slow-paced. This implies that rapid, wider policy support beyond Benelux and Germany will be required to accelerate hydrogen development.

Currently, an EU-wide hydrogen infrastructure comparable to the natural gas grid that would enable cross-border flows, and thereby access to low-carbon molecules, does not exist. As appears from policy direction (the EU gas package), and efforts by EU gas transmission operators driven by EU energy policy, the infrastructure will largely be based on repurposing existing sections of the natural gas grid (60% of the dedicated grid according to the EHB study; we note that repurposing may range between 25% to 90% according to wider studies[26]), with new lines being added to the system where needed (see Methodology 17 for a detailed breakdown based on individual asset analysis considering natural gas market security of supply, utilisation levels of the routes, alternatives and the emerging hydrogen volumes outlook).[27] Supply and demand balancing (hourly, daily, seasonally) will require hydrogen storage of about 10% of annual hydrogen demand. While additional storage may be needed, there is a high uncertainty in the storage/demand ratio, as one can see in the Methodology 16 in the appendix. Storage development will require timely and anticipatory development. To meet the full energy demand of the EU, hydrogen imports and transfers into demand clusters via import terminals for hydrogen carriers will be required on top of a trans-EU pipeline network.

Dedicated transport and storage facilities need to be developed for hydrogen industry



Key developments of infrastructure

- **Repurposing** of sections of **natural gas grid for hydrogen** (60% of dedicated grid)
- **New pipelines** (40% of dedicated grid) built
- **Dedicated storage capacity** developed
- **Import infrastructure,** e.g., ports, to be developed

Capabilities of future infrastructure

- Ability to transport **hydrogen long distances in cost-effective way**
- Ability to **manage changes in hydrogen demand** over the course of a year
- Enabling **pan-European market**

Figure 28: Hydrogen grid length in the EU-27, thousand km

Source: IEA Announced Pledges Scenario, BCG analysis

The investment cost (see Methodology 15), which is relatively small compared to the overall EU energy transition, includes subsea pipelines and interconnectors, linking countries to offshore energy hubs and potential export regions such as Norway. Since the estimated investment figures from the EHB contain non-EU27 countries such as the UK and Norway, investments are downscaled using estimates of hydrogen volume from Shell Sky 2050 and IEA APS (see Methodology 17).

Considering onshore pipelines, the levelised transport cost for the entire EHB amounts to €0.11–0.21 per kg of hydrogen when transporting it over 1,000 km.[28] The EHB assumes that the majority of hydrogen transport will be via onshore hydrogen pipelines. Alternatively, if hydrogen is transported exclusively via more expensive subsea offshore pipelines, levelised costs of transport would amount to €0.17–0.32/kg over 1,000 km.[28] As a note of caution, industry interviews of industrial gas players indicate that, in their experience they may be too optimistic if all pipelines are newly built.

We must also be cautious of not only developing hydrogen transmission grids at the distribution level. This means that pipelines transporting gaseous hydrogen will not go far enough to economically address all the multiple applications and usages which are to be spread across a country, especially for smaller-volume mobility applications and industrial usage. Therefore, a more comprehensive approach to infrastructure is needed to supplement EHB's pipeline infrastructure views, including the use of other distribution means like localised electrolysis, trucks, smaller distribution grids, or transporting hydrogen as other hydrogen derivatives such as ammonia or methanol.

Some industry experts, caution that it is important to prioritise the interconnection within the H_2 basins, then between H_2 clusters, and to study a backbone project once the industrial demand is clearly identified to avoid stranded assets.

EXPERT CORNER 8

MAERSK

Synthetic fuels – low-carbon methanol role in shipping, knock-on anticipatory investments and regulatory certainty requirements

Introduction

Maersk, the world's second largest container shipping company, has embarked on an initiative to transition away from fuel oil and align with the greenhouse gas reduction targets. Central to this transformation is the adoption of renewable methanol as a synthetic shipping fuel, also known as 'e-methanol', which is composed of waste carbon dioxide (CO_2) and 'low-carbon hydrogen' generated through the renewable energy-driven process of splitting water molecules. This is part of an ambitious targets of achieving net-zero greenhouse gas emissions by 2040 and transporting a minimum of 25% of ocean cargo using low carbon fuels by 2030.

Breaking 'chicken and egg' through commitment – evidence relevant to policy recommendations

Over the past two years, Maersk has demonstrated its commitment to a low-carbon future by ordering 25 vessels designed to run on low-carbon methanol. Of these, 19 are currently under construction and expected to set sail by 2024 and 2025 (media sources). Maersk estimates that this strategic shift will lead to an annual reduction of approximately 2.3 million tonnes of CO_2 emissions, marking a significant step towards its goal of carbon neutrality by 2040. The first ship, named Laura, to be operated on low-carbon methanol, was launched in 2023 in the presence of the European Commission's President. To fuel the 740 ships of its fleet, Maersk will need an average 80–100 GW of low-carbon electricity.

To bolster its green methanol supply chain, Maersk initiated an extensive project in Spain in 2022, with the support of the Spanish government, aimed at establishing large-scale production of low-carbon methanol by 2030. The project is now anchored in a startup company, C2X, backed by Maersk parent company A.P. Moller Holding as a majority shareholder and Maersk as a minority shareholder. Projects extend beyond Spain, with a goal to produce 3 million tonnes of low-carbon methanol annually by 2030. This includes a project in Egypt, where C2X and the government of Egypt recently signed a framework agreement for boosting production of low-carbon fuel, adding to the global network of sustainable fuel production facilities, with bunkering global corridors on key maritime routes of trade.

Conclusion

Maersk has been undertaking these anticipatory investments together with industry partners amid regulatory uncertainties for e-methanol, despite the lack of sufficient CO_2 and hydrogen infrastructure across the EU. In doing so, Maersk has taken a risk, breaking the chicken and egg dilemma by creating demand for e-methanol. This approach by Maersk underscores the company's leadership in the maritime industry's transition towards sustainable and eco-friendly practices, yet more is to be done. Further regulatory certainty for infrastructure to secure sufficient CO_2 and hydrogen to be able to trade and transport ingredients for e-methanol in Europe will be key.

EXPERT CORNER 9

Synthetic methane and other synthetic fuels

Synthetic methane, often referred to as e-methane, has the potential to emerge as a competitive fuel in the energy transition. Synthetic methane uses renewable energy to produce hydrogen (H_2), which is combined with CO_2 to produce synthetic gas (methane) before blending it into existing gas transport, export and receiving facilities. The CO_2 – effectively acting as an H_2 carrier – may come from various sources: industrial emitters (under EU regulation permissible until 2041), bio CO_2, direct air capture (DAC) or even circular via carbon capture and transport (CCT). Synthetic methane can potentially replace upstream fossil fuel supplies with renewables-based H_2 (rH_2) supply, CO_2 logistics and a methanation process step. By utilising existing infrastructure, such as natural gas pipelines and storage facilities, synthetic methane can be seamlessly integrated into the energy mix. This also applies to synthetic liquid fuels such as synthetic aviation fuels. The technical maturation efforts required to commercialise this value chain will be i) methanation (combining the CO_2 and H_2 to form CH4) scale-up, ii) H_2 production cost reduction, and iii) CO_2 capture, transport, and integration at scale. Currently, synthetic methane and other synthetic destination fuels are significantly more expensive to produce than their fossil, low-carbon, and biofuel counterparts. Effective regulatory frameworks are required to incentivise society to switch over to synthetic types of renewables.

As renewable energy becomes a primary contributor to the electricity grid, large-scale energy storage, including hydrogen storage, is crucial for maintaining a reliable energy supply. Particularly in Europe, salt caverns offer a promising, cost-efficient large-scale storage solution – from the ENTSOG database, we can see the emerging trend of utilising salt caverns for hydrogen storage in Northwestern Europe, including countries like France, Germany, the Netherlands and Poland.[6]

Where countries do not have access to salt caverns, we may need to consider alternatives such as liquid hydrogen storage, pipelines (linepack), or alternatives liquids (e.g., ammonia, toluene). Further underground storage options are being explored in pilot studies, including depleted fields.

A recent EU map by ENTSOG shows 36 projects in Europe considering hydrogen storage (see ENGIE Expert Corner)

The complexity of hydrogen storage and the HyPSTER project

What is it – introduction to the project

HyPSTER stands for hydrogen pilot storage for large ecosystem replication. Officially launched in January 2021, the project aims to use salt cavern storage to connect hydrogen injection by electrolysis for industrial and mobility uses. It will also test the technical and economic reproducibility of the process to other sites throughout Europe. HyPSTER is located in Étrez at the heart of the Auvergne-Rhône-Alpes region and is part of the French regional hydrogen strategy along with other significant projects (Zero Emission Valley, the construction of hydrogen production units and filling stations in the region of Bourgogne-Franche-Comté, the Chemical Valley). These projects make the development of a local hydrogen hub to reduce atmospheric and noise pollution possible, thanks to a transition towards hydrogen mobility alongside decarbonising other local uses.

Evidence relevant to our policy recommendations

The project's objective was to test the production and storage of renewable hydrogen in a salt cavern on an industrial scale, as well as examining the technical and economic replicability of this process at other sites in Europe. HyPSTER is thereby paving the way for true industrialisation in the sector.

Renewable hydrogen will be produced from local renewable energies (photovoltaic, hydroelectric) and a 1 MW electrolyser. Eventually, the installation will produce 400 kg of hydrogen per day. By 2026, hydrogen production and storage will gradually amplify, until the salt cavern's full capacity is used up, i.e., almost 50 tonnes. This is equivalent to the daily consumption of 2,000 buses. It will become the largest French site for salt cavern gas storage, supplying the region's industrial players and hydrogen filling stations.

Anticipatory infrastructure development

The hydrogen produced on-site will be distributed by trucks in the region within a radius of 150 km mobilising key public and private players in the region for two kinds of use:

1. Decarbonising industrial uses of hydrogen consumers by switching from a supply of grey to green hydrogen.

2. Power hydrogen refuelling stations for green mobility

The objective of the project is also to massify uses in order to optimise the price of hydrogen for final consumers. In addition, Étrez is well-positioned for European gas carriers to contribute to the EHB. HyPSTER will ensure the flexibility of the network and the security of supply in a cross-border context, with potential hydrogen exports to Germany.

Conclusion

Thanks to hydrogen underground storage facilities acting as an intermediary between intermittent production and variable hydrogen demand, many other hydrogen projects will be able to be developed at a European scale. In the future, renewable gases (biomethane, e-methane, hydrogen) will replace natural gas. Gas storage will also be 100% renewable. The HyPSTER project marks an important step in adapting infrastructure.

2.5. Carbon capture, utilisation and storage (CCUS) infrastructure

2.5.1. Situation today

The CO_2 capture and storage industry in the EU is in an emergent phase. In that sense, EU CCUS infrastructure development is lagging behind the US, where large-scale transportation of CO_2 by pipeline has been an established industrial process since the early 1980s. The shape of the EU's CCUS industry will be determined by the location of industrial facilities that capture CO_2 and the locations where CO_2 can be safely and permanently stored.

Although there are currently few CO_2 pipelines of note in the EU, multiple projects have already been announced and sanctioned by EU member states that recognise CO_2 pipelines as critical infrastructure for a net-zero future. To achieve the Green Deal objectives by 2030, the EU must rely on mature technologies to decarbonise industry. One efficient and advanced technology which needs to be developed is CO_2 capture, storage and transport. To scale up investments in CCUS, the capture, transport and storage of CO_2 needs to be incentivised 'in sync'.

2.5.2. Development

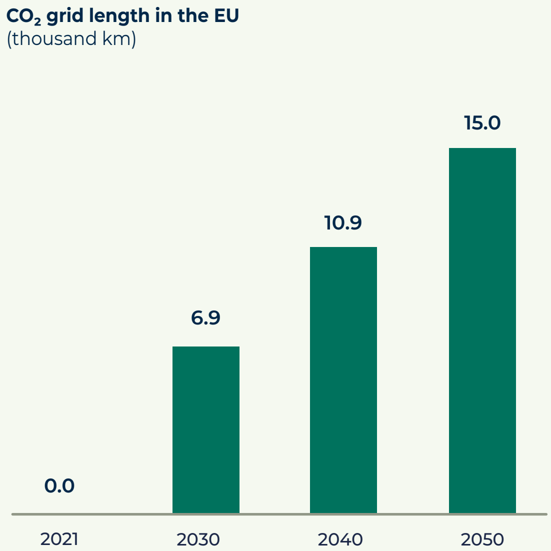
CO_2 plays a key role in all net-zero scenarios (IPCC, EU Scientific Board, IEA). The Net-Zero Industry Act (NZIA) has set a 50 million net t/year target for annual EU-wide CO_2 storage by 2030. This is partly driven by the need for strategic autonomy to address unavoidable CO_2 emissions. Reaching that EU target will require material investments and is not without risk of failure.

Deployment of CO_2 storage will be determined predominantly by geographic location (available knowledge about reservoir structure availability of reusable infrastructure), the type of fields (depleted oil and gas fields are cheaper than deep saline aquifers), and the share of offshore storage facilities (more expensive than onshore). Concerns such as safety or public acceptance may also heavily influence development decisions. Given the fact that CO_2 capture capacities are not likely to be distributed uniformly across the EU, a pipeline system will be needed; the size of that system is currently uncertain.

An emerging CO_2 network of at least 2,900 km is already planned. The North Sea region benefits from neighbouring European industrial regions and ports such as Aberdeenshire, Amsterdam, Antwerp-Bruges, Dunkirk, Le Havre, Nord-Pas-de-Calais, Rotterdam, Ruhr, the UK's east coast and Wilhelmshaven. In 2023, there was positive momentum for EU CO_2 infrastructure projects with several key announcements, including an offshore pipeline 'heads of agreement' between Equinor and Wintershall Dea (900 km) to connect Germany and Norway; a new 1,000 km onshore pipeline project by OGE in Germany to connect industries to the port of Wilhelmshaven; and 'heads of agreement' between Equinor and Fluxys to connect Belgium and Norway through an offshore pipeline (1,000+ km).[29]

It has been confirmed in interviews with industry experts that most CO_2 transportation will be completed by pipelines instead of alternatives like shipping. There are multiple factors that can influence the final shape of the CO_2 pipeline system, e.g., distance, industrial density, surface development, and cultural or environmental sensitivity of surface areas. Despite the availability of suitable ships, like those used for LNG, this method will be too expensive, especially in the initial phase of industry development. In 2023, only two ships for large-scale transportation of CO_2 are on order through the Northern Lights projects, showing how undeveloped CO_2 shipping is in the EU.

Dedicated CO_2 transport and storage facilities need to be developed



Key developments of infrastructure

- **Transportation grid cost** will depend on location (off- or onshore) and share of shipping
- Majority of costs are likely to be linked to **CO_2 capture,** with differences per technology process
- **Storage cost** will be driven by location of facilities (off- or onshore)

Capabilities of future infrastructure

- **CO_2 grid in 2030** will likely not be a ready, interconnected system, but rather a **collection of uni-directional networks** (e.g. industry to North Sea)
- **CO_2 grid in 2050** will be much more complex and developed, to handle increased quantities of captured CO_2
- Industry is in **early development stage**, with EU CO_2 strategy expected at the end of 2023

Figure 29: CO_2 grid length in the EU, thousand km

Source: IEA Announced Pledges Scenario, BCG analysis

Pipelines are the most effective method for transporting large quantities of CO_2; economies of scale will drive cost reductions as the industry matures

Transportation method	Typical capacity
Pipelines	890–10,000 tonnes/day
Shipping	~46,000 tonnes/vessel
Rail	80–83 tonnes/car

Transportation costs per mode

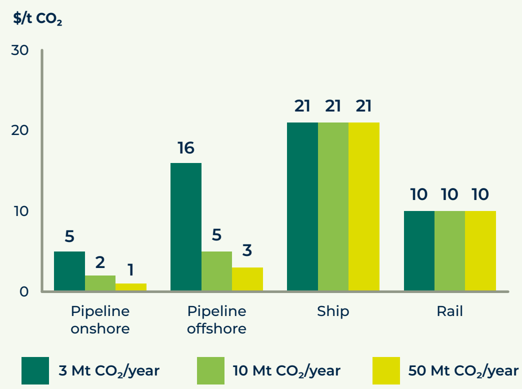


Figure 30: CO_2 transportation methods comparison

Source: Techno-Economic Models for Carbon Dioxide Compression, Transport, and Storage & Correlations for Estimating Carbon Dioxide Density and Viscosity

EXPERT
CORNER 11

Delta Rhine Corridor

What is it – introduction to the project

The Delta Rhine Corridor (DRC) is an important cross-border energy infrastructure project with open access that will contribute to the EU's climate and energy security objectives. The ambition of the DRC project is to provide transport of hydrogen via the Rotterdam energy hub to industry in the Netherlands and Germany. CO_2 from Germany and the Netherlands would be transported to storage facilities in the North Sea and on to CO_2 users.

A partnership consisting of BASF, OGE, Gasunie and Shell has signed a letter of intent to jointly advance this project, with a possible start of operations in 2028. Public consultation on the project has commenced in the Netherlands, led by Gasunie.

Evidence relevant to our policy recommendations

The DRC project would help achieve the net-zero targets of the EU and member states through cross-border transportation of H_2 and CO_2. It would also strengthen industrial competitiveness, innovation and jobs in the Netherlands and Germany, as industries need to cost-effectively access H_2 and CCUS to decarbonise.

The Dutch government has recognised the added value of this project for society and declared it a project of national interest. This entitles the project to a centralised government-coordinated permitting process, which will simplify the permitting process and support planning acceleration to achieve a start of operations as early as 2028. The application for a project of common interest by the EU is currently under review. The outcome is expected after summer 2023.

Anticipatory infrastructure development

Infrastructure is designed to solve the 'chicken and egg' problem. H_2 ramp-up and CO_2 utilisation and storage must be preceded by infrastructure, due to long planning times for infrastructure construction (8–10 years). In addition, the lead time is important in order to connect industries immediately. For the implementation of the DRC project, a possible public-private collaboration could help to minimise risk in the project planning and reduce uncertainty in demand development. Other options, as are currently being discussed in Germany for hydrogen within the Kernnetz initiative, are private investments in the infrastructure with a government risk hedge fund for the initial phase (e.g., so-called dena model). Such advanced integrated infrastructure projects can have a multiplier effect on the energy transition of industry.

Conclusion

The DRC enables European industries to decarbonise with H_2 and carbon management, while keeping competitive industries in the EU.

Ravenna CCS

Introduction – what is the Ravenna Carbon Capture and Storage (CCS) project

Operated as a collaboration between Eni and the Italian utility service provider Snam, the Ravenna CCS project is aimed at establishing Italy as a pioneer in carbon capture and storage within the Mediterranean region, for a cluster of industrial users. The project successfully started phase 1 site preparation and construction in January 2023. Specifically, phase 1 targets the annual capture of approximately 25,000 tonnes of carbon dioxide/year – from Eni's natural gas treatment plant near Ravenna, with subsequent injection into a depleted offshore gas field. Phase 1 has secured CO_2 storage license from Italian authorities, confirming its commitment to stringent environmental standards.

Relevance to policy learnings – creating cluster ecosystem for industrial emitters

The CCS project's significance extends beyond its initial technical achievements. Phase 2, slated to commence in 2026, will aim to enable the storage of 4 million tonnes of CO_2 annually. Eni and Snam are actively engaged in discussions with challenging-to-decarbonise industries in the region, spanning sectors such as cement, steel, fertilizer, and chemicals, working to create an ecosystem. The project has already taken concrete steps towards realizing phase 2 via a letter of intent signed by four emitters located in the Ravenna industrial area. This heightened interest from both local and international emitters correlates with the increasing carbon prices witnessed under the European Emission Trading System (ETS) and the climate legislation embodied in the European Commission's 'Fit for 55' package. Further policy support to create more clusters enabling CCUS ecosystems would be beneficial.

Conclusion

The Ravenna CCS project represents an innovative initiative poised to support industries' critical sustainable carbon management. By effectively utilising offshore depleted gas reservoirs in the Adriatic Sea off the coast of Ravenna for carbon storage, plus creating a transport network for CO_2, the project taps into colossal storage potential exceeding 500 million tonnes and enabling CO_2 storage for over 50 years. This not only provides a solution for immediate needs but also holds the key to enabling industries to transition.

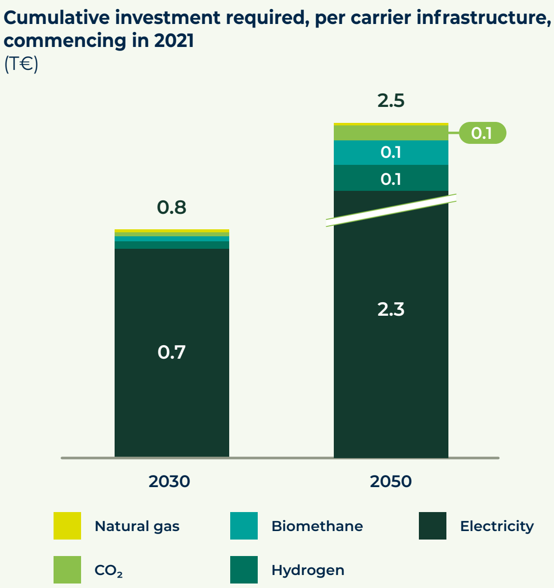
3. High investments needed to achieve necessary target infrastructure

This chapter analyses the investment perspective for infrastructure by carriers in chapter 3.1 before we look at the impact of failing to mobilise these investments in chapter 3.2.

3.1. Target infrastructure requires significant investments

Building and upgrading the EU’s energy infrastructure will require a total investment of €0.8 trillion by 2030, and up to €2.5 trillion by 2050. In line with other publications, we assume no discount factor for the investments necessary. All investments are expressed in real year-2021 euros unless otherwise stated. The breakdown of the cumulative investments needed into each carrier can be found in the Methodology Section.

Total investments in infrastructure to reach €2.5 trillion by 2050



Main cost buckets

- **Upgrades and expansion** of existing power grid
- **Power storage**
- **CO_2 capture, storage and transport**
- **Hydrogen grid and storage**
- Natural gas grid extensions to connect **biomethane generation**
- **Repurpose** investments from natural gas grids into acceleration of hydrogen, **biomethane and CO_2**

Consequences of no investment

- System will **not be able to fully integrate non-emitting sources**
- System costs will go up **via compensations for curtailment** (forced stopping generation by operator)

Figure 31: Cumulated investments in infrastructure 2030, 2050 (T€)

Source: IEA Announced Pledges Scenario, transmission network operators, distribution network operators, Eurelectric, BCG analysis

These investments will fundamentally change energy cost composition – see Figure 31.

There is a consensus that, up to 2050, the cost of power generated by renewable energy sources will drop further and be well below conventional sources. This will be enabled by economies of scale and technology development, especially in offshore wind.

However, simultaneously, electricity system costs are likely to increase. This will be driven by a need to deliver balancing services which traditionally were part of the generation costs.

For natural gas networks, the transported volume is expected to decrease significantly, adding to the potential for per-MWh cost increase. This trend will be partially offset by repurposing portions of the transmission and distribution network to hydrogen networks. It is also expected that sections of obsolete infrastructure will be decommissioned and removed from the regulated asset cost base. In our modelling, decommissioning costs are not included, as shown in the Methodology Section.

Paradigm shift: Tasks shift from generators to DSOs and TSOs

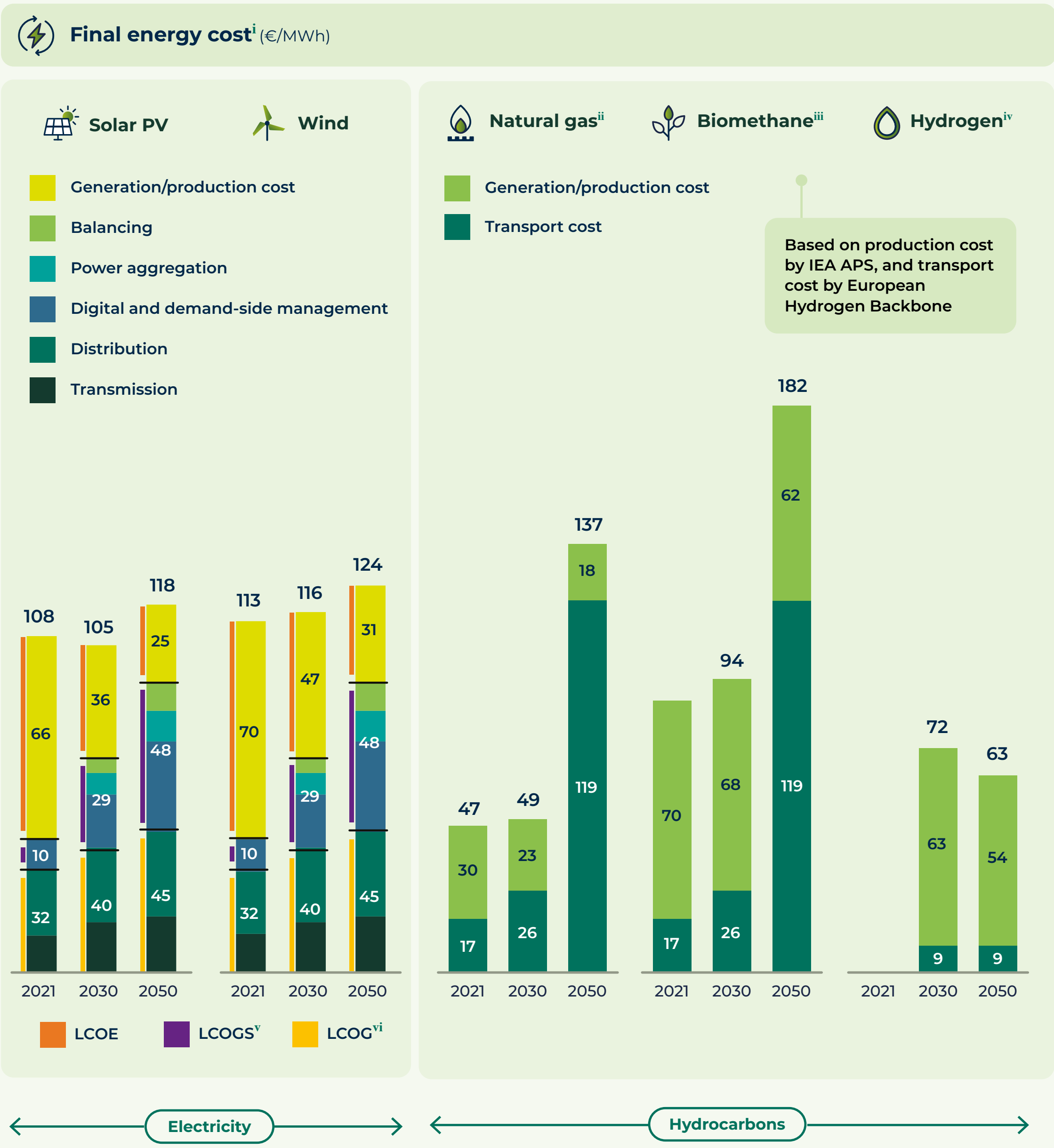


Figure 32: System costs for power

i) Actual costs to end customers will depend on how regulatory arrangements will allow for the allocation of transport costs; larger industrial players are connected to the transmission system and, therefore, are only subject to some of the costs.

ii), iii), iv) Production prices as per IEA APS, sourced via ENTSOS TYNDP 2024 scenario data. Increase in natural gas transport cost due to declining volume and cost of legacy grid. Hydrogen transport cost assumed at highest value per European Hydrogen Backbone for 2040, assuming 1,000 km transport distance

v) LCOGS = levelised cost of grid services;

vi) LCOG = levelised cost of grid

Source: IEA Announced Pledges Scenario, BCG analysis

3.1.1. Power infrastructure

Expanding grids is as much or even more a global challenge as it is an EU-wide challenge. The EU is in a privileged situation, as we have the largest interconnected grid worldwide and we have a single market. Nevertheless, we need to invest in grid expansion to deliver sustainable power in a reliable and economical way to end users.

To meet decarbonisation targets, annual anticipatory investments in the EU's power grid infrastructure need to range between €70 billion and €84 billion. According to BCG modelling, 60% of that sum will be spent on distribution grids, 25% on transmission grids, and the rest for cross-border connections and storage.[30]

Investment needs are likely to accelerate past 2030 to accommodate a growing share of renewable sources, and then continue at that pace until 2050. In countries where the share of photovoltaic (PV) power is high, the required build-up of energy storage will also be high to compensate for increased variability in the energy system. Scaled correctly, energy infrastructure will allow for the integration of different renewable sources and provide enough flexibility to efficiently deliver energy to the customer.

3.1.1.1. Transmission

New additions to transmission grids are likely be 'electricity highways', such as HVDC (high-voltage direct current) lines, to connect offshore wind farms with large electricity consumers in other parts of a country or even across borders. This reflects one of the fundamental challenges of the grids – the location of generation sources needs to be optimised for weather conditions, and not for proximity of offtakers (as was the case with traditional generation sources). Such factors significantly increase the required infrastructure investment costs.

3.1.1.2. Distribution

Investments in distribution grids will focus on enabling the integration of new renewable energy sources. Key cost buckets will include:

- Adding new power lines, reinforcement of existing lines and adding transformer capacity – close to 50% of total investments.
- Modernisation and digitalisation of the grid, to improve grid management and enable the real-time reaction of operators to changing grid conditions – close to 40% of total investments.

Resilience to adverse weather conditions and other threats – 10% of total investments.[10]

3.1.1.3. Digital

Digitalisation is a major lever to enhancing the performance of the grid infrastructure. Investments in digital solutions have grown by 11% p.a. between 2015 and 2022, and today have a share of around 20% of all grid investments. Going forward, we assume the level of investments in digital will need to grow continuously. High investments are needed to keep up with continuing technical progress and because the lifetime of digital solutions is typically significantly shorter than that of classic grid hardware.

Pekka Lundmark
President and CEO, Nokia

'Digitalisation can make energy grids more reliable, more flexible and more efficient, cutting costs and squeezing the maximum possible value from assets. Connectivity enabled by mission-critical network and cloud solutions can bring European energy infrastructure to the next level of intelligence, automation and sustainability.'

ERICSSON

Ericsson and the power of digitalisation

The transition of the electricity system, with increasing amounts of volatile and distributed resources, will require ever-more digitalisation of the entire value chain of electricity – from production and distribution to final consumption. Communication networks, especially 5G, will be critical for the future of energy systems, as they provide higher levels of reconfigurability for power grids, which may allow local networks to work separately from the main network and help renewable energy installations operate more dynamically and efficiently. The connected and automated smart grid supported by 5G mobile networks will be crucial for handling the bi-directional energy flow from prosumers as well as greater fluctuation in power production from less predictable renewable generation. Advanced capabilities, such as artificial intelligence (AI), interoperable network platforms, and digital twins, will accelerate the pace of transition, enable large-scale flexibility trading, increase data insights, and enhance the cybersecurity of critical power sector infrastructure.

In the automated, connected smart grid, large data volumes and real-time data flow from smart meters, sensors and energy users, which are critical for managing flexibility and predictability. Sharing and using data will be necessary to fully integrate the digitalised energy system of the future. Energy operators need to access data from large energy users, especially when the transport sector and heavy industries become fully electrical, to plan and control production and distribution. Therefore, access to reliable user data through harmonised interfaces is crucial, where all industries will be dependent of and integrated in the EU's electricity system.

Examples of use cases in the various domains of the energy grid are predictive maintenance and remote site inspections, automated grid fault detection and load flow control, AI-generated predictability, and end-user flexibility solutions.[31]

The entire information and communication technology industry will have a role to play in the transformation of energy networks, as described in the roadmap that was developed by Digital Europe.[32]

EXPERT
CORNER 14

SIEMENS

Improving grid capacity utilisation thanks to software solutions: The example of TransnetBW

By 2030, Germany aims to source at least 80% of its electricity from renewables. The result is a fundamental change in the overall conditions for Germany's transmission system operators (TSOs), since electricity production from wind and solar power fluctuates significantly, depending on the weather. The more renewable power connected to the grid, the more challenging it will be for grid operators to forecast electricity generation and keep it in balance with demand.

Additionally, large-scale wind turbine systems are concentrated on Germany's northern coast, but the electricity is also needed in the industrial centres in southern and western Germany, where large numbers of conventional power stations are being decommissioned. This means that more and more electricity has to be transported across great distances. That is causing increasing bottlenecks in electricity transmission – i.e., situations where there's not enough grid capacity to transport the electricity being produced.

TransnetBW, one of Germany's four national transmission system operators, is turning to innovative grid software technology to ensure grid stability. Among several innovative solutions to improve capacity utilisation of the existing grid, TransnetBW has introduced dynamic line rating. This approach takes advantage of the fact that overhead lines can transport up to 50% more electricity when it is windy and in cooler ambient temperatures.

To make the most of this potential, TransnetBW measures parameters like wind speed and ambient temperature right at the power poles. This data is then used to calculate the maximum possible load flows in the various weather situations, to therefore maintain the amount of slack in the overhead lines within the specified technical limits.

Innovative solutions deployed in the grid allow TSOs to improve grid capacity utilisation and avoid resorting to 'redispatching' to prevent electricity outages, despite the bottlenecks in the transmission system. Managing these bottlenecks is indeed costly: the German Federal Network Agency reports that redispatching costs in 2020 amounted to €1.4 billion. This is paid for by consumers via grid fees.

Grid boosters raise the capacity limits on lines and therefore increase the capacity utilisation of the existing network, while leaving the security level unchanged.

The challenge that TSOs like TransnetBW face is that for decarbonisation of the energy system to succeed, a lot more is needed than just PV systems and wind turbines. Regulators are being called on to facilitate the necessary adjustments to existing infrastructure simultaneously with rapid grid expansion. Players in the energy industry need to work together more intensively, and the industry needs smart solutions such as grid software, to overcome increasing grid complexity.

EXPERT CORNER 15

Connecting everything and everyone across the energy grid

In the energy sector, 90% of the emission reduction necessary to reach net-zero by 2050 will require advanced digital technologies. This is because digitalisation allows distributed energy resources, such as wind turbines and solar panels, to be integrated into smart grids, bringing more renewables online. Connecting all grid applications, sensors and equipment in real time, combined with edge computing for applications with very low latency requirements, enables greater grid automation. Digitally charged smart grids can deal with distributed generation and storage, distribution system protection, remote circuit breaker/recloser operation, advanced metering infrastructure, demand response, synchrophasors in distribution networks, dynamic line rating and much more. However, digitalisation does not solely benefit the breadth and capacity of the grid. Secure wireless connectivity also allows wide area situational awareness and fleets of remote-operated drones, which can greatly improve human oversight of assets – meaning the grid stays at optimum efficiency for longer. One example is predictive maintenance, where AI and machine learning can predict which components in an asset need to be repaired or replaced even before efficiency drops. This is particularly useful when those assets are in an inaccessible position, such as a wind turbine many kilometres offshore. It reduces costs, while optimising asset life cycles and power quality. Elsewhere, powerful connectivity allows field workers to use virtual reality to guide them through repair processes, inspections of assets and training modules and offers new, advanced collaboration features.

Examples of deployments in Germany and in Italy

In Germany, Nokia supplies a private wireless solution to 450connect, a network used by over 150 providers of power, water, gas and heat distribution. This mega-project will cover 90% of all German households and businesses, connecting up to 18 million devices through more than 1,700 radio sites, for smart metering and automation in the distribution networks. This connectivity will increase the efficiency of operations, enable consistent integration of renewable energy sources to the grid and further secure the energy supply. In Italy, Nokia contributed to the digital transformation of Acea's smart grid. Acea, a multi-utility leader serving the region of Rome and central Italy, is leveraging Nokia's mission-critical solutions – from IP (Internet Protocol) to high-capacity optical systems and from data centres to secondary substations connected through LTE (long-term evolution) and fibre. Acea ensures advanced automation and remote-control services for critical grid assets as well as the communications foundation for IoT (Internet of Things) device growth, smart city, and future evolution to 5G low-latency and high-bandwidth applications.

Further supporting renewables with connectivity

Beyond enabling integration of renewables into the grid, digitalisation also positively impacts renewable energy generation and operation. For instance, an autonomous and reliable data and communication network covering the entire offshore wind farm area delivers real-time data of turbines, pitch motors, weather, staff presence and vessel proximity, and reduces time to deployment and maintenance costs. Sensors, advanced analytics, AI and IoT help ensure every blade in a wind turbine can be positioned in an optimal way, taking into consideration weather conditions to improve wind capture. Connecting solar farms helps keep solar production optimal and extends the life cycle of solar assets. Private wireless networks with remote-controlled drones deliver necessary data for scene analytics to detect hot spots in solar panels, dirt build-up, required vegetation management, and allow grid control systems to have granular control over the solar panels, inverters, and circuit breakers/reclosers.

3.1.1.4. Investment gap in power grids

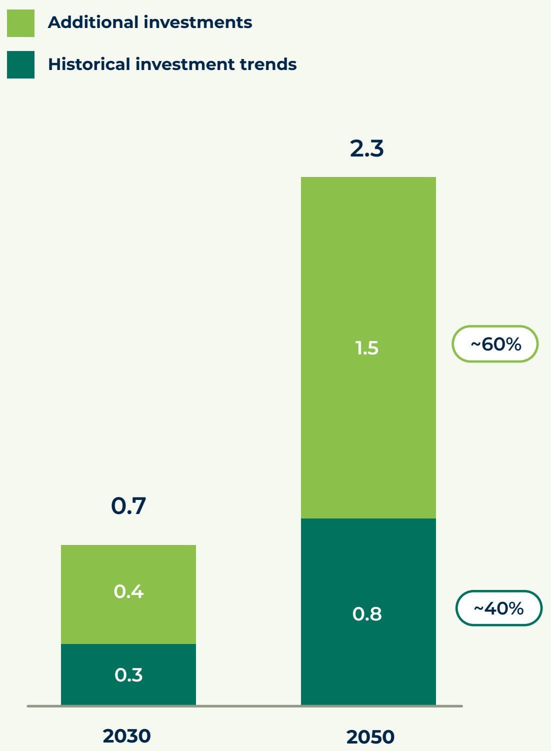
In the 2010-2018 period, investments in power grids for the EU-27 countries were in the range of:

- For transmission grids – €6.6-9.5 billion
- For distribution grids – €15.6-22.5 billion[33]

If investments in grids were to continue at their historical rate until 2050, there would be a 60% funding gap in the target investment range, as projected by this publication. This means that spending on grid investments must more than double on an annual basis compared to historical trends if the EU is to reach its climate targets.

Investments in power grids need to more than double compared to historical trends

Cumulative investment required in power grids, historical average 2010-2018 and additional required (€ trillion)



Historical trends

- **Total electricity network investments,** including transmission and distribution, have **risen in the period 2010-2018 from €24 billion to €32 billion p.a.**
- The main factors impacting investment level are **transported volume** and **network length**

Additional investments

- System operators will need to **more than double their CAPEX spending on grids** to reach ambitious climate targets
- **Actual proportions** of historical vs additional spending may **vary depending on range of costs included in the historical data**

Figure 33: Investments required in electricity infrastructure (€ trillion)

Source: IEA Announced Pledges Scenario, transmission network operators, distribution network operators, Eurelectric, BCG analysis

3.1.1.5. Comparison of projections of this publication to other studies

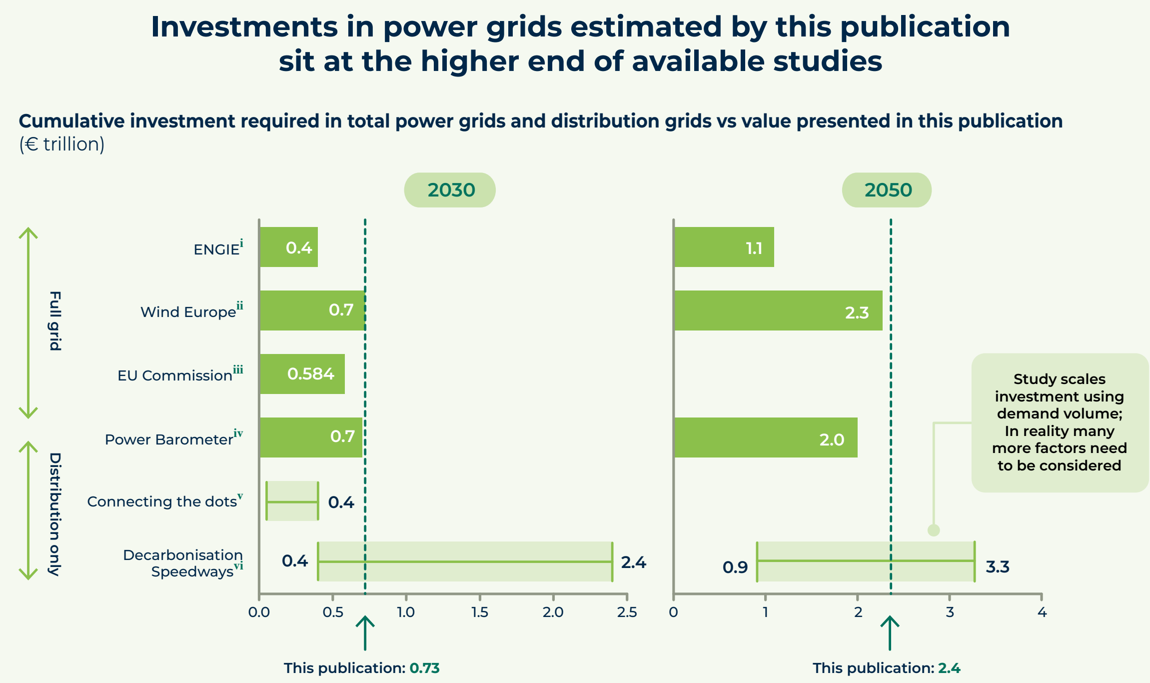


Figure 34: Range of cumulative investments (€ trillion)

Sources:

i. ENGIE - Building Decarbonization Pathways for Europe, 2023;

ii. WindEurope - Getting fit for 55 and set for 2050, 2021;

iii. EU Commission - An EU Action Plan for Grids, 2023;

iv. Eurelectric: Power Barometer, 2023

v. Eurelectric - Connecting the dots, 2021;

vi. Eurelectric - Decarbonisation Speedways, 2023. Graph shows total range of four scenarios provided by Decarbonisation Speedways – each of these scenarios scales investments using historical figures and volume increase. BCG analysis

There is no general consensus regarding the level of investment required in power grids. Cumulative investments until 2050 foreseen by this publication sit at the higher end of the ranges provided by studies of Wind Europe,[34] the European Commission,[35] and above estimates of ENGIE,[36] as shown in Figure 34. Compared to studies that only cover distribution networks, estimates in this publication are below the ranges indicated by Eurelectric. This may be because Eurelectric's studies are based on the growth of final electricity demand, taking an approach based only on EUR/TWh and disregarding other factors. Given that in areas with high natural resources (wind and PV), the availability of land can be assessed with high accuracy, anticipatory investments into the grid that connects these regions would be a significant accelerator to the buildout of energy generation.

3.1.2. Natural gas infrastructure

In the EU, most large transmission network expansions are already in progress or completed. Distribution grids will also not add significant new pipelines, instead focusing on maintenance of the existing stock. Some investments in gas infrastructure, such as LNG-receiving terminals, may occur. A significant number of new gas infrastructure facilities were commissioned over the past year, with a notable emphasis on the buildup of new LNG import capacities, boosting energy security in the EU. The new FSRUs have been commissioned in Germany, Finland, the Netherlands and Italy in the second half of 2022 and first half of 2023. The topology of the European network is in short term, noting the changing long-term role of gas in Europe. For example: Brunsbuettel Hafen and Stade FSRUs in Germany; Musel LNG terminal in Spain; Le Havre FSRU in France are to be commissioned in the short term to allow for European gas network resilience.

The main challenge for the gas grid will be managing the costs of maintaining legacy infrastructure, as gas volumes transported by this infrastructure are expected to drop by 75-90% from 2021-2050. This means that the significant cost of an over-scaled grid will need to be recuperated from the market through radically higher transportation costs. As shown in Figure 32, the transportation cost for natural gas, including both transmission and distribution network will increase from €17/MWh in 2021 to €119/MWh in 2050 at EU level, reflecting this paradigm shift. For a detailed breakdown of the illustrative EU-level calculation, please refer to Methodology 9.

Some sections of the natural gas grid (both transmission and distribution, where the larger offtakes are connected) may be repurposed to transport hydrogen. However, this will apply to a small share of the grid (1%), not enough to solve the issue of rising costs. The natural gas grid will not phase out significantly, but will instead be used for energy security and partly for the transport of biomethane. Some volumes of biomethane are expected to be injected into the existing natural gas grid but will not replace the drop in volume of natural gas.

Managing the decline of gas infrastructure and its costs as natural gas volumes are radically dropping will be one of the key challenges for policymakers' in years to come.

3.1.3. Biomethane infrastructure

Biomethane is injected in the existing natural gas grid or used to generate power and heat onsite at the source. This publication assumes that the cumulative total infrastructure system CAPEX of biomethane will be €52 billion in 2050 (see Methodology 10), covering about 1.1 million kilometres of pipeline grid infrastructure (see Methodology 13). For a full breakdown of all assumptions and studies used for this calculation, please refer to Methodology 10 to Methodology 14.

The main challenge of biomethane transport infrastructure development is that the vast majority of generation sources are in rural areas, where the gas grid is not easily accessible. Therefore, adding extensions to the existing natural gas grid to connect new generation sources is likely to be the largest cost. Where electric charging is not available, biomethane offers a valuable alternative in the transportation sector. Careful planning of biomethane transported via gas networks therefore needs to be aligned with the planning of charging and refuelling infrastructure for heavy good vehicles, where feasible and in line with Alternative Fuels Infrastructure Regulation (AFIR) implementation.

3.1.4. Hydrogen infrastructure

This publication assumes that development of hydrogen grids and storage will require a cumulative investment of €25 billion by 2030, and €88 billion by 2050. For a detailed breakdown of these investment numbers, please refer to Methodology 15 in the Appendix. The price of hydrogen and its availability will determine the strength of the business case for its implementation. Currently, there are differing views regarding the scale of its adoption. For example, the European Hydrogen Backbone (EHB) study estimates a five times larger volume of hydrogen production in 2050 than Shell Sky 2050 or IEA APS. That is why we descale the investment volume, which is explained in Methodology 15.

This publication assumes a level of adoption in line with the IEA's Announced Pledges Scenario, and scales investments required in the infrastructure accordingly. Based on these scenarios, it is assumed that in the initial phase of development of the industry until 2030, annual investments will range from €2-4 billion, split 50/50 between grid and storage development. Post-2031, investments in the grids are likely to slow, bringing total annual investments down to €3 billion, with 66% of annual investments going into storage (see Methodology 15).

The majority of costs will be linked with repurposing existing natural gas grids and building new lines to create an interconnected system. Hydrogen can also play a role in transportation, particularly for heavy road vehicles, as mandated by AFIR. Refuelling stations benefit from the economies of scale of energy-intensive industries, as many of them rely on heavy transport. The planning process of locating refuelling stations will need to be synchronised with the buildout of an interconnected system for hydrogen, enabling the network to benefit from the rollout of hydrogen to hard-to-abate industries. Thus, mobility benefits from access to hydrogen and its flexibility.

Storage also needs to be factored in: Up to 10% of annual hydrogen demand will need to be stored to ensure safe operation of the system. Higher ranges are also possible (see Methodology 16).

For reference, the table below presents ranges of cumulative investment required to develop the hydrogen industry, from reputable, publicly available sources, demonstrating that we have been conservative in our assumptions, given lower volumes of hydrogen demand expected under scenarios used in this publication.

No.	**Source**	**Cumulative investment at time point (€ billion)**		
		2030	**2040**	**2050**
1	Kotek et al.[37]	-	15-21	-
2	Guidehouse[23]	-	43-81	-
3	European Commission[38]	-	-	180-470
4	European Hydrogen Backbone	-	80-143	-
5	ENGIE report[36] (incl. hydrogen and other gases)	54	114	174
6	Hydrogen Europe Study[39]	120	-	-
7	ENTSOG[6]	78	-	-
8	ENTSOE[40]	42	90	-

With regard to hydrogen storage CAPEX, this publications assumes a conservative value of $1200/MWh from Gaffney Clyne.[41] However, different (lower investment) values are possible, as the table below depicting values from a historical life cycle cost assessment[42] demonstrates.

No.	**Source**	**Storage CAPEX (€/MWh)**		
		Low	**High**	**Average**
1	Salt caverns	440	690	510
2	Porous media	110	450	200

3.1.4.1. No 'new' investment gap in molecules – similar budget must be spent on new gases

Unlike power grids, there is a slowdown in natural gas grid investments in favour of acceleration in hydrogen, biomethane and CO_2.

Historically (2010-2018), the average annual investment in gas grids in the EU was €9 billion. If investments in natural gas grids were to continue at that pace, the cumulative investment until 2050 would be €262 billion. This publication estimates the aggregated investment required for the development of decarbonised molecule (hydrogen, biomethane, CO_2) infrastructure at €229 billion by 2050. This estimation is scaled for the energy mix development as projected by the IEA Announced Pledges scenario.

As a result, there is no investment gap in creating a new decarbonised molecule infrastructure, if historical investment rates are kept up. If investments are re-directed from further development of natural gas grids towards the decarbonisation of molecules, the total investment would not need to increase compared to historical trends.

For reference, the table below presents the range of cumulative investment required to develop decarbonised molecule infrastructure (hydrogen, biomethane – without CO_2), based on publicly available sources.

No.	Source	Cumulative investment at time point (€ billion)		
		2030	2040	2050
1	ENGIE report[36] (does not include CO_2 infrastructure)	54	114	174

3.1.5. Carbon capture, utilisation and storage (CCUS) infrastructure

This publication assumes a cumulative investment (CAPEX only) of €105 billion until 2050, with annual investments in the range of €2.5-5 billion, in CO_2 capture, pipeline infrastructure and storage. The cumulative investment consists of storage (€11 billion), transmission (€16 billion) and capture (€78 billion). For a detailed breakdown of costs, please refer to Methodology 21.

The largest cost bucket (65% of total investment) is linked with the build-up of capture capacities. It is hard to predict the pace of infrastructure rollout, but it may be assumed that it will accelerate to catch up with ambitious EU targets. The range of CAPEX is significant and depends on which type of emission sources are being decarbonised.

Storage costs are likely to make up to 15% of total investments. Projects currently in development, such as Northern Lights in Norway, may be used as a proxy for assessment of storage CAPEX. However, a much wider and more diverse set of storage sites will need to be developed to meet CO_2 storage needs in the EU. Costs of CO_2 transportation systems (pipelines) make up 20% of the total required investment.

For reference, the table below presents ranges of cumulative investment required to develop a CO_2 transmission system, from reputable, publicly available sources such as the EU-commissioned ARUP report.

No.	Source	Cumulative investment at time point (€ billion)	
		2030	2050
1	EU-commissioned ARUP report [Transmission Network Only][43]	4.8-17.6 [low vs high scenario]	17.6-28.4 [low vs high scenario]

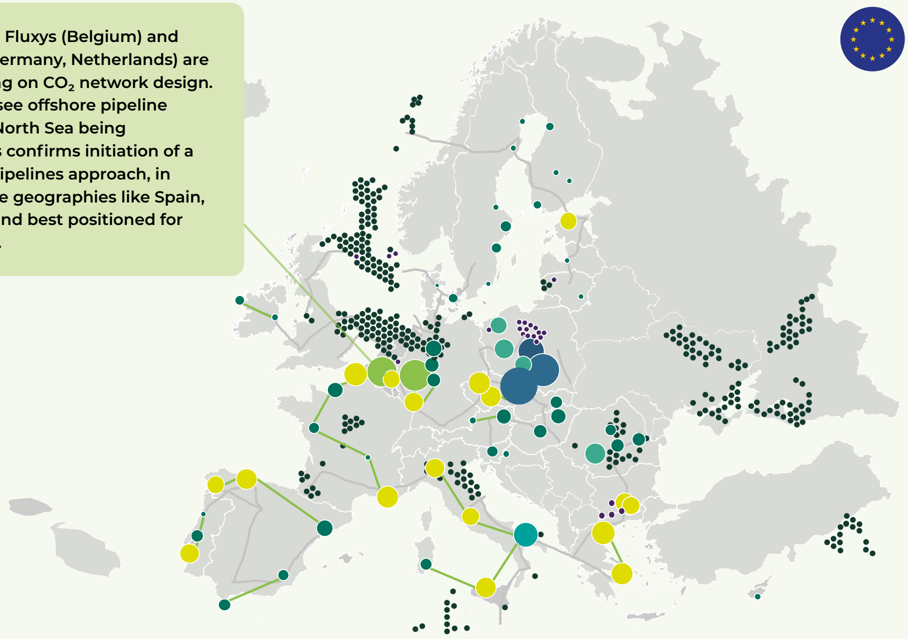
The investment ranges above refer only to transmission systems, converted using the exchange rate GBP:EUR 1:1.16, and multiplied by a factor of 2 (increase of high-grade steel price 2010-2023) to reflect current prices more closely.

The figure below shows an overview of the CCUS ecoystem in Europe currently under development.

Map with EU potential for CO_2 / CCUS ecosystem:

The 2010 EU ARUP study pipeline network design remains plausible – we observe potential for both onshore and offshore CO_2 storage and transport, and clustering of CO_2 in certain hubs

Terega (France), Fluxys (Belgium) and Gasunie/OGE (Germany, Netherlands) are inter alia working on CO_2 network design. In addition, we see offshore pipeline systems in the North Sea being considered. This confirms initiation of a European CO_2 pipelines approach, in addition to some geographies like Spain, Baltics and Ireland best positioned for shipping of CO_2.



- Oil and Gas fields
- (0-10 MTa) CO_2 emitters
- (11-20 MTa) CO_2 emitters
- (21-30 MTa) CO_2 emitters
- (31-40 MTa) CO_2 emitters
- (40 & above MTa) CO_2 emitters
- Aquifer
- Illustrative CO_2 pipeline connections in line with EU ARUP study 2010

Key assumptions:

1. Gas fields and aquifers based on BCG CCUS hub tool (2023). We note that onshore depleted fields may not be intended for CO_2 storage in Denmark and Germany; in France we see onshore being considered.
2. EU ARUP 2010 illustrative pipeline layout included – shipping hubs were not considered in 2010, but may emerge, e.g., in Southern Europe. Given 2010 layout, there is not EU-to-Norway CO_2 pipeline included yet.
3. Large CO_2 emitters centres based on BCG database (2023)

Figure 35: Planned CCUS infrastructure in Europe

Sources: BCG analysis; EU ARUP 2010 study on CO_2 networks; BCG CCUS hub tool; BCG database large emitters EU; non-exhaustive overview of oil and gas fields – ERT experts pointed to presence of additional aquifer stores potential in UK, NL, Denmark and Norway .

3.2. Sufficient level of investments and speed of deployment are crucial to succeed

3.2.1. Investing less will cost more

This publication and the underlying modelling cover a broad range of topics, building on a spectrum of studies and fundamental models as a foundation. Therefore, we show the ranges of the different input parameters that have been used. All parties are interested in finding the optimal solution, a solution where we can achieve the under 1.5°C target in a cost-optimised way. We understand that cost optimisation can have very different meanings; at ERT we are looking at all the costs in the context of supplying the required energy volume and energy mix to the consumer.

Failing to achieve the investments required as described in this publication, will trigger even higher costs in the future.

3.2.1.1. Failing to improve energy efficiency

In this publication we assume a massive reduction of energy intensity (-60% until 2050). This corresponds to a reduction of the final energy consumption by 10 PWh as shown in Figure 7. To reach this goal, massive investments are needed along the entire value chain, from generation to transmission and distribution, and more specifically on the end-use side in all sectors (buildings, transport and industry). The financial means are available; what is required is a context where investments to improve energy efficiency pay off.

Failing to attract these investments will leads to failing on the 1.5°C target in Europe, or a relocation of consumers, especially energy-intensive industries, to countries outside of the EU. This would negatively impact the global ambition to reach the 1.5°C target and lead to a deindustrialised EU. Not reaching the 1.5°C target will lead to even higher adaptation costs. Adaptation is more costly than mitigation, as we know from the latest AR6 Intergovernmental Panel on Climate Change (IPCC) report from April 2023.[8]

3.2.1.2. Failing to build the power infrastructure in time

Failing to provide the power infrastructure will lead to a combination of higher costs for energy consumers (not just power consumers) and higher carbon emissions. ENTSO-E has quantified this for the transmission system.[7] We are not aware of a similar calculation for the distribution system, but given the fact that the majority of renewable power is injected at a distribution system level, the impact of failing to build out the distribution system is likely to be much more significant.

Addressing the system needs will lead to lower system costs and therefore lower consumer prices. This will result in socio-economic welfare gains of €5 billion p.a. until 2030, and to €9 billion p.a. until 2040.[40] These gains far outweigh the cost of investing in Europe's grid and power system.[40]

The reduction in generation costs is largely related to a decrease in thermal generation, mainly gas. The curtailment of renewable energy is significantly reduced, by 42 TWh/year in 2040, and replaces more expensive and carbon-intensive thermal generation. A more efficient use of the EU generation mix translates into a significant reduction in CO_2 emissions of 31 Mt p.a. in 2040, helping the EU achieve its Green Deal objectives.

IPCC AR6: 'Even without accounting for all the benefits of avoiding potential damages, the global economic and social benefit of limiting global warming to 2°C exceeds the cost of mitigation in most of the assessed literature'.

3.2.1.3. Public and private investments are needed to provide the required investments

Assessments by the European Central Bank based on DSGE models predict that the effect on aggregate investments of raising the EU carbon price from €85/t CO_2 in 2021 to €140/t CO_2 in 2030 (in line with IEA WEO APS) will cause i) up to 1.2% lower GDP in 2030, ii) up to 2.7% lower private consumption in 2030, and iii) up to 3% lower aggregate investment in the baseline scenario based on historic growth.[44] In their scenario, the green transition adds more costs to producers than it triggers growth. One reason is that increased green public investments crowd out other, private capital expenditures with higher growth, dampening overall aggregate investments.

This assessment is in stark contrast to other studies used by the European Commission, which sees higher growth perspectives emerging from green investments. In their assessment, public investments into the green transition do not start in a steady state where they crowd out private investments, but they pave the way for private investments to follow. This is also illustrated by the BCG publication 'Follow the Capital', where the share of public investment is high initially, but gradually declines until 2030 (see Figure 36).

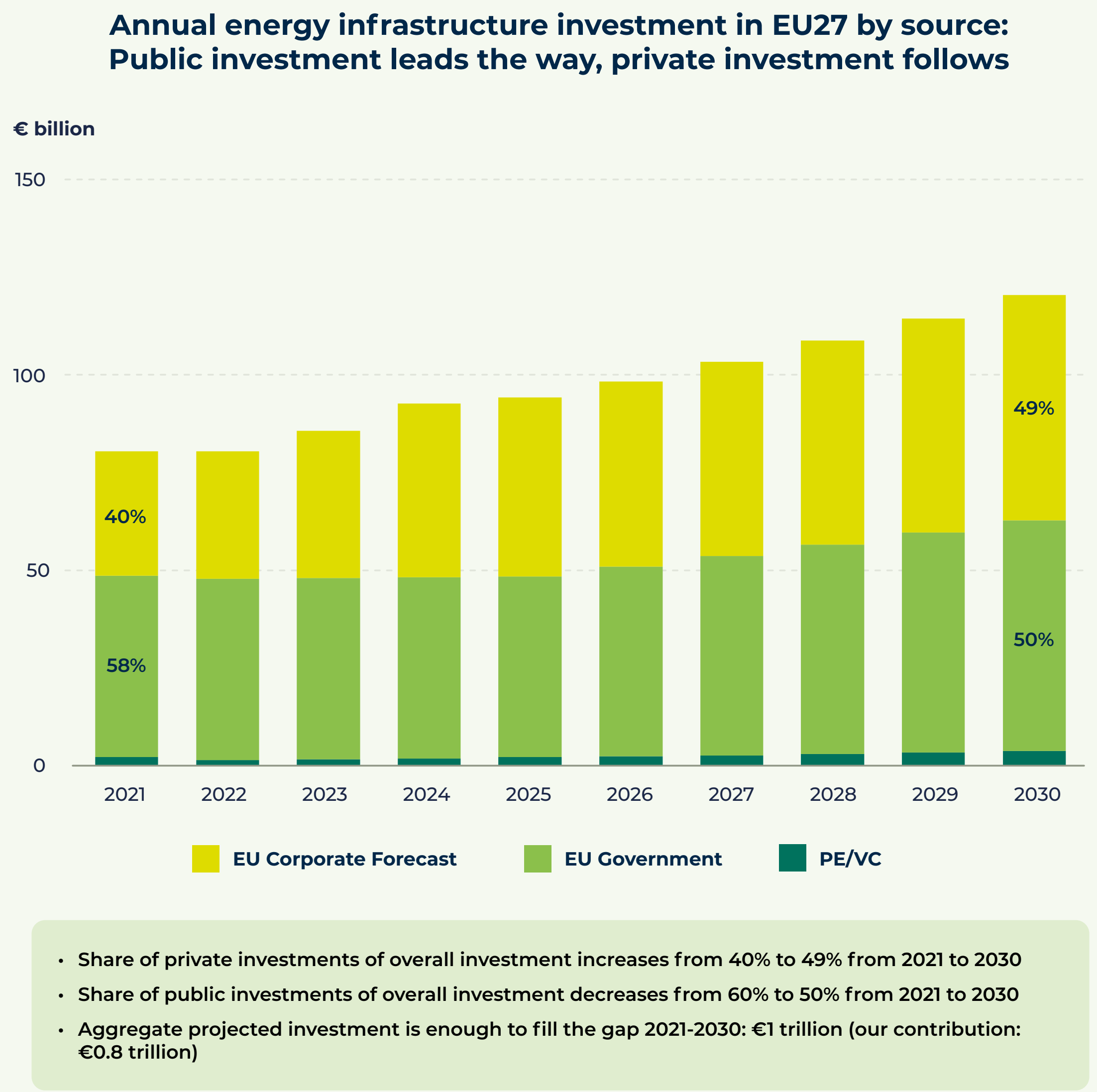


Figure 36: No investment gap until 2030

Sources: BCG analysis; EU ARUP 2010 study on CO_2 networks; BCG CCUS hub tool; BCG database large emitters EU; non-exhaustive overview of oil and gas fields – ERT experts pointed to presence of additional aquifer stores potential in UK, NL, Denmark and Norway .

The cumulative investment need estimated by this publication is €0.8 trillion from 2021 until 2030. The BCG 'Follow the Capital' report estimated that roughly €1 trillion will be cumulatively invested into energy infrastructure until 2030, with a roughly equal split between EU private corporate investments and EU government investments. This demonstrates two fundamental insights:

1. Both corporate and public investments are needed equally to close the investment gap and there is no significant 'crowding out' effect. Public investments pave the way for more private investments, which will follow once they have a positive business case.

2. Capital itself does not seem to be the defining obstacle to close the investment gap, as there is enough projected investment to fill the investment gap identified in this publication. On the contrary: It is necessary to create the incentives for private players to trigger the necessary investments by changing the regulatory framework, as elaborated in chapter 4.

3.2.2. Speed of deployment is critical

A sharply increasing pace of the development of renewable energy generation puts a strain on the grid and permitting process, and highlights the importance of anticipatory investments. In the US, grid connection requests grew by 40% in 2022 – nearly 2,000 GW of solar, wind and storage projects were in queues to connect to transmission grids, more than the installed capacity of the country's entire power plant fleet.[45] Similarly, in the UK, Spain and Italy, there is more than 150 GW of wind and solar projects in each country queued to receive grid connections.

It is probable that some of these applications are speculative or opportunistic (to reserve connection rights for future projects). Given limited information about available capacity, developers request capacity to test the availability of the grid, causing an inflation of applications, especially when no permit is required to enter the queue. However, this does not invalidate the fact that there are far more applications than operators can process.

As a result of this influx of connection requests, the waiting time to obtain a grid connection increases, from a couple of years in the US to up to 15 years in the UK.[11] Such long waiting times increase the risk that these projects will never be built. Some investors are faced with huge bills for grid upgrades or reinforcements, presented by operators as conditions of connection.

These issues need to be addressed by a set of targeted policies and measures, to strengthen grids and create connection capacity availability ahead of the need to integrate new generation sources. Policies should also aim at enabling network operators to increase the pace of processing connection requests. EU legislation has already provided solutions and assessed permitting for combined investments in renewable energy and grids. member states need to swiftly implement this in their legislation and their practical governance.

4. Regulatory actions to support infrastructure transition

From the previous chapters we have concluded how essential infrastructure is to the energy transition in the EU to achieve both its ambitious climate goals and to provide the basis for competitive industry to operate outside of Europe.

We have structured our input around three topics:

Jean-Pierre Clamadieu
Chairman, ENGIE

'Let's unite as European industry to bring the "Fit for 55" framework to its successful conclusion, and from there, let's shift our attention and devote all our energy to accelerate its implementation.'

1. **Accelerate permitting and enhance private investment:** Accelerating permitting processes is crucial to pick up speed. We appreciate that permitting for renewable generation assets is faster than for conventional energy generation. However, developers will only apply for permits if they can expect a grid connection. This makes the permitting of power grids vital for triggering the investments needed in grids and generation. There is also a need for the permitting of gas grids to support the transition to decentralised and digitalised grids based on renewables, while fostering collaboration between public and private stakeholders in the energy sector.

2. **Adjust market design to match the future energy portfolio:** The adjustment of the market design is necessary as we are connecting more and more renewables, which are fundamentally different to conventional power generation as (i) they are high in CAPEX and low in OPEX; (ii) their generation profile is determined by wind and sun; and (iii) most of the assets are connected at distribution level. It is also a necessity because we are shifting the energy mix from molecules to electrons, and electrons are much more difficult to store. The power prices on the exchange are often determined by gas and oil because of the merit order system. On a typical day the wholesale electricity price is usually set by gas roughly 80% of the time, despite only making up around 13% of the gross power produced,[46] although this balance is likely to change over the next years.[3] Renewables cannabilise each other, as they all produce when the wind is blowing and the sun is shining. This leads to capture rates that disincentivise new build and deteriorate the returns for assets already in operation. contracts for difference (CfDs) secure the power price for a certain period, but the production from assets under CfD still impact the power price on the exchange as well as the capture rate of unsubsidised assets. Consequently, older assets that are out of subsidy will have lower returns.

   European regulations have used unbundling in the past to create more transparency and competition. In the new world, grids will need to assume many more tasks, such as aggregation of generated power coming from distributed generation, balancing, storage and demand side management. All of these services were not in scope when unbundling was implemented; as a result, services are not valued correctly and do not attract investors, yet they are essential for the energy transition. Lastly, resilience of supply has moved to the top of the agenda. Power grids that connect countries (interconnectors) allow for power flow in both directions, helping high-price markets obtain supply from lower-price markets. Depending on the wind and sun and on the demand profile, the flow direction may change several times during a day. This not only helps to bring prices down, it also creates resilience, as all connected countries mutually profit. Regulation can help more interconnectors be built and improve the way their capacities can be contracted for longer periods of time. In the context of the above, we will share ideas on how to adjust the power market.

3 Low capture rates mean that the price that these assets can achieve on the (merit order) power market is below the average market price.

3. **Think and plan pan-European:**

   The European Single Market is a key strength and a competitive advantage for Europe. These are testing times, shaped by the aftermath of the COVID-19 pandemic, war in Ukraine and geopolitical tensions between the US and China. The EU has to focus on restoring growth and competitiveness. The fastest route to that is to renew the dynamic of European integration, including the completion of an 'energy union that truly connects energy markets across EU member states.

   Cross-border flows of energy carriers and CO_2 need to be enabled through harmonisation of technical standards and certification schemes between member states. This fosters investment and addresses short- and long-term energy transition challenges while maintaining cohesiveness in the Single Market and enhancing cross-border cooperation. Thinking and planning pan-European, meaning allocating the planning and decision of each process to the most efficient level, is crucial for strengthening the energy union with a unified market.

Infrastructure transition will need support through regulations

Accelerate permitting and enhance private investment

Accelerate permitting of power grids

- **A.I** Streamline the permitting process
- **A.II** Develop a priority-based approach to grid permitting
- **A.III** Allow private grid development in power

Accelerate permitting of gas grids for new gases and CO_2

- **A.IV** Build targeted infrastructure for new gases and CO_2
- **A.V** Allow private grid development in molecules

Adjust market design to match the future energy portfolio

Market design for power to match the future energy portfolio

- **B.I** Prioritise affordability of low carbon production in EU
- **B.II** Support long-term price signals
- **B.III** Increase market liquidity
- **B.IV** Link COO stepwise to time of generation
- **B.V** Renumerate in a predictable way to incentivise anticipatory investments
- **B.VI** Support technologies that reduce price volatility (hydro pumping, batteries, interconnectors etc.)
- **B.VII** Create a market for demand-side flexibility through digitalisation

Market design for natural gas

- **B.VIII** Introduce support mechanism for green gases
- **B.IX** Establish European Guarantee of Origin for green gases
- **B.X** Prepare policies for the remuneration of gas grids considering much lower utilisation

Market design for biomethane, hydrogen and CO_2

- **B.XI** Increase cooperation between network operators across energy vectors and invest in cross-sector planning
- **B.XII** Incorporate a "learn as you go" mentality to policymaking
- **B.XIII** Increase policy attention to nascent CO_2 sector

Think and plan pan-European

Improve cross-border cooperation

- **C.I** Strengthen Single Market and cross-border cooperation through transnational PPAs
- **C.II** Address any market reform with preliminary impact assessment study
- **C.III** Invest in pan-European infrastructure planning to incentivise both on- and offshore interconnector planning
- **C.IV** Encourage harmonisation of technical standards for more interconnection
- **C.V** Ensure strategic location of demand centres for hydrogen and CO_2

Figure 37: Proposed regulatory changes

COO = Certificate of Origin

4.1. Accelerate permitting and enhance private investment

The need to accelerate permitting of infrastructure and enhance private investments is critical in areas where new construction or major modification is needed. This is key in two areas:

1. **Accelerate permitting of power grids**
2. **Accelerate permitting of natural gas grids**

Both permitting processes are important, but are fundamentally different in their characteristics. In power we are looking at two parallel movements with strong growth: (i) the build-out to expand and strengthen the grids; and (ii) digitalisation to make grids smarter to enable them to manage the new tasks that they need to assume. Digitalisation will require new business models and new forms of renumeration.

In gas grids, we are primarily looking at permitting for new technologies that are not currently available at scale (hydrogen, biomethane and carbon), at the repurposing of existing grids, and at a moderate build-out of the natural gas grid.

4.1.1. Accelerate permitting of power grids

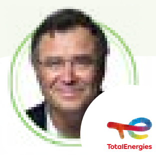
The investments needed in power grids identified by this publication can only be deployed if the projects are permitted quickly and if there is a business case for doing so. Today, we are looking at permitting timelines of 9-12 years for a typical 110 KV line in Germany[47] and 10 years in the case of the Nord-Süd link in Germany. The costs depend on the technology that is being permitted (i.e. overhead vs underground) and cable path. The revenue depends to a large extent on the market design, which will be covered in chapter 4.2.

4.1.1.1. Streamline the permitting process

Acceleration of the deployment of grid technologies is explicitly mentioned in the Net-Zero Industry Act (NZIA), and grids are considered a strategic net-zero technology.[48] We further welcome that the latest European grid action plan aims to address the issue of long permitting processes on the European level.

ERT RECOMMENDATIONS:

1. **Accelerate permitting:** Permitting for both transmission and distribution systems needs to be accelerated. This is about speed and ensuring that the right set of criteria are applied to avoid time-consuming blockages. Permitting is always about balancing interests. In the case of infrastructure this is typically a balance between particular local interest and the societal interest at large.[4] Evidence from Germany suggests that keeping consultation deadlines between conflicting parties tight is one way to both balance interests and achieve faster permitting processes.[49]



Patrick Pouyanné
Chairman of the Board and CEO, TotalEnergies

'Permitting will never go fast if the decisions are being pushed down to the local level. The energy transition is of national, even European, importance, so this is where the decisions should be taken.'

2. **Elevating the permitting decision and guideline setting:** Several countries in Europe have made modifications to their permitting process structure. What has worked best is to elevate permitting decisions to a higher administrative level that is in a better position to balance local and societal needs. What often does not get enough attention is the fact that if we fail on the national target, this will also be detrimental to local interests. A delay in the transition therefore contributes to missing out on both social and local interests. It is clear that national regulators should not need to decide about every distribution connection. However, in some cases such as the mass deployment of smart meters, national guidelines might make sense. It is important that permitting decisions are made on the most efficient level. In the crisis mode triggered by the lack of Russian pipeline gas, it was possible to permit LNG terminals, as varied permitting authorities recognised and attributed key priority in permitting. We need to maintain this sense of urgency as the climate crisis is just as eminent.

4 Keeping a 1.5°C scenario within reach

4.1.1.2. Develop a priority-based approach to grid permitting

We know which regions have good resource availability and where the demand centres are. Therefore, we have a high degree of certainty of where the grid needs to be reinforced and built out.

ERT RECOMMENDATIONS:

1. **Set up priority-based grid build-out:** With the knowledge of future centres of generation and demand centres we can trigger anticipatory investments in the grid at marginal risks. We can also prioritise the sequence in which grid applications are treated. We encourage policies that prioritise the building of grid infrastructure, such as in the latest revision of the Renewable Energy Directive (RED), rather than dealing with permitting requests on a first come, first served basis (which do not take into account which request is more important than another). A good starting point for such an approach is the list of Projects of Common Interest (PCIs) from the European Commission, where the EU grants accelerated permitting processes and special regulatory solutions for projects that contribute to a) implementation of priority energy infrastructure corridors; b) towards better energy security; and, c) that support member states, national climate and environmental policies.

4.1.1.3. Allow private grid development in power

As grids need to take over tasks that go beyond the classic transport of electrons from large generation through the transmission system and distribution system to the connected consumers, there are new business models arising, now and in the future. This should be seen as an opportunity to attract new money and contribute to the 'growth case' grid infrastructure. To seize this opportunity we need to allow current players to expand their offerings and allow new players into the quasi monopoly. The US addressed this topic in 2022 through the Federal Energy Regulatory Commission (FERC) that issued a Notice of Proposed Rulemaking (NOPR) taking a step towards enabling the development of this >$500 billion grid. It reversed 2011's Order No. 1000, which created a significant advantage for incumbent transmission operators to monopolise transmission projects within their regions. The significance of the unaddressed issues provides a view of the regulatory complexity and challenges ahead, as it avoids the primary challenge of the build-out: siting and permitting issues.

Patrick Pouyanné
Chairman of the Board
and CEO, TotalEnergies

'Investments into grids are urgently needed. However, the needs for financing new infrastructure are gigantic. Public money cannot do it all, so there is a need to develop an adequate framework to attract investors.'

Therefore, collaboration across sectors and along the entire supply chain is critical to ensure timely investments on the supply, infrastructure and offtake side. This includes public-private partnerships, with private investors driving energy infrastructure at least initially. In the power market, we can are observing examples of these public-private partnerships:

- **NeuConnect:** In power, see the example of NeuConnect, a privately-financed and lead power interconnector between the UK and Germany.[50] Financial markets are recognising the viability of such solutions.

- **Energy Islands:** In Denmark, we can see a public-private collaboration emerging on building 'Energy Islands'. The planned Danish islands will have a minimum capacity of 3 GW (Gigawatts), with potential for expansion to 10 GW of offshore wind, and would likely be at least partially characterised as critical infrastructure.[51] As such, the Danish state will take a majority ownership stake, while partnering with one or more private actors to leverage private competences in project development, technology, finance, innovation and sustainable leadership.

- **Delta Rhine Corridor:** The Delta Rhine Corridor case study (see Expert Corner 11) addressed the potential of privately co-led consortia, with its integrated value chain approach.

ERT RECOMMENDATIONS:

1. **Encourage non-discriminatory access to faster regulatory approval processes for private infrastructure projects:** To enhance private investments in grid development, private infrastructure projects should have the same opportunity to access faster regulatory approval processes as public ones. Acknowledging that private power interconnectors such as NeuConnect can also be Projects of Common Interest (PCIs) is crucial to give private development projects a viable business case.

2. **Allow for private players such as RES developers to (co-)develop energy infrastructure:** In the framework of forthcoming EU-level regulation on renewable power, private players are often in a position to move faster. Hence, they should be able to (co-) develop energy infrastructure.

4.1.2. Accelerate permitting of gas grids for new gases and CO_2

The investments needed for molecule-based infrastructure are small compared to those into the power infrastructure (10%), but these still need streamlined coordination and planning processes across the EU to enable the transition towards a decentralised and digitalised grid predominantly based on renewables and other low-carbon molecules.

4.1.2.1. Build targeted infrastructure for new gases and CO_2

EU policy should encourage the acceleration of permitting and financing of necessary infrastructure to support the energy transition.

ERT RECOMMENDATIONS:

1. **Accelerate permitting:** Improve speed and regulatory certainty of permitting for gas grids for new gases and CO_2.

2. **Establish pan-European regulation:** Particular attention should be given to promoting cross-border collaboration, setting product quality standards to promote safe transportation networks and optimising the use of existing interconnectors. This includes environmental rules / go-to-areas for permitting of CCUS. Once these are set, permitting can be accelerated.

4.1.2.2. Allow private grid development in molecules

This can be observed within the hydrogen or CO_2 market: For hydrogen or CO_2 markets to develop, end users must be ready for their use, transport must be built out, low-carbon power must become widely available, and electrolysers must be built on a large scale – all in the correct order.

ERT RECOMMENDATIONS:

1. **Enable private players to co-develop energy infrastructure:** In the framework of forthcoming EU-level regulation on renewable gases including hydrogen and CO_2, enabling private players to co-develop energy infrastructure is key. Learning from the gas industry in Europe, where small private hydrogen networks exist in potential pipe-to-pipe competition, the EU should refrain from overregulation. Subsidies provided by governments should not only remunerate CAPEX but also performance and digitalisation to ensure an effective system is in place.

2. **Encourage privately co-led energy infrastructure in unregulated space that is time-limited until a regulated approach is deemed necessary in accordance with the energy acquis:** Similar thinking could be considered for encouraging privately co-led and financed power networks, where a regulated approach does not deliver in a timely enough manner. This is critical in the first decade at least for building out energy infrastructure at a before unseen pace

and precedence. The Delta Rhine Corridor case study addressed in this publication confirms the power of privately co-led consortia, with its integrated value chain approach.

4.2. Adjust market design to match future energy portfolio

Today's energy prices in Europe are amongst the highest in the world. Depending on the industry, the share of energy costs as share of total costs varies. Generally, high energy costs are making it increasingly difficult for players in Europe to be cost competitive. Energy costs are a product of physical availability but even more so of policies and market design.

The current European energy markets have served us well. They have helped us through the first winter after the Russian invasion of Ukraine, achieving both an optimised dispatch to consumers and efficient mobilisation of energy.

However, recent developments have exposed consumers and EIIs to volatile and high prices. In the current market structure, we would expect to see more volatility and higher prices as the share of renewables increases in the energy mix.

Emergency measures such as price caps are important, but not suited to resolve the challenges coming from the fundamental transition.

The power market design has two fundamental functions:

1. Encourage new investments needed in the power sector for:
   i) New generation delivering decarbonised production capacities and providing security of supply
   ii) Infrastructure build-out to deliver the new services
2. Reliably provide consumers with power at affordable prices

When taking action, it is important that measures are not retroactive, to avoid policy insecurity. On the other hand, frequent policy updates are needed as we progress in the energy transition. Consequently, we need a market design where different concepts co-exist. In the energy transition, a multitude of changes are happening simultaneously:

- We are moving from **extracted** (fossil) energy that is available at very selected locations to **engineered** energies harvesting resources that are available in most countries.
- We are moving from a high **dependence** on global energy trade to a **resilience** in the flow of energy, as we can produce more energy in Europe than we need.
- We are moving from energy costs driven by **OPEX**, to costs driven by **CAPEX,** often heavily influenced by the global learning rate, bringing down manufacturing costs.
- We are moving from **global trade of goods** to a world where we want to decouple from global markets and have a deep integration of the **local supply chain** in Europe (Critical Materials Act).

SIEMENS

Jim Hagemann Snabe
Chairman, Siemens

'It is a shift from OPEX to CAPEX, which is excellent: OPEX are a never-ending stream of costs for imported oil and coal. CAPEX is a one-time investment in our future infrastructure. Infrastructure investments drive growth and create jobs – like after World War II, where infrastructure investments enabled European competitiveness.'

- We are moving from an energy world dominated by **molecules** to a world of **electrons.** Molecules are easy to store – electrons are not.

- We are moving from thermal power plants delivering **base loads** to wind and solar power, which deliver **variable generation** profiles.

- Therefore, we need to move the balancing from **generation dispatching** to balancing in the **grid and enable demand-side flexibility.**

The future market design should not be seen as a residual of all these developments, but as a shaping force. Using the current market design with merit order will lead to increasing self-cannibalisation of renewables and limit their deployment. The market design defines the outcome, and thus defines how quickly and efficiently we can decarbonise.

Therefore, the market design needs to be a reflection on where we want to be in the future. Given all the changes that are happening at the same time, there will be many uncertainties regarding the pathway. Therefore, moving with fast, small steps and keeping sight of the guiding principles is more important than a perfectly designed solution from the start.

4.2.1. Market design for power

Market design needs to encourage the huge amount of investment necessary for delivering new, decarbonised production capacities and providing security of supply in a system where vKariable renewable energy is supposed to become the dominating source of power. When taking action, we should focus on the buildout of new assets to create a forward-looking approach.

As mentioned above, the EU's current electricity market is based on several integrated day-ahead and intraday power markets. Large parts of the requirements set out in the electricity market design, which are essential for demand-side flexibility and long-term contracts to smooth out volatile prices, are still far from being fully implemented by the member states.[52] On the same note, we see value in the timely ratification of the updated electricity market design as published in March 2023, and subsequent implementation by member states.

4.2.1.1. Prioritise affordability of low-carbon production in EU

Affordable low-carbon production in the EU is key to ensure that EU industries remain globally competitive. First and foremost, the EU's biggest lever to ensure the affordability of low-carbon production is expanding the production of green energy. As the European Commission's JRC report underlines, the price of power in the current market structure will continue to be set by high gas and carbon prices in the short term, even if these represent just a small part of the portfolio of power production.[12] This means that there will be a gap between the levelised cost of low-carbon power (its variable cost is very low or close to zero) and the wholesale price set by the variable costs of marginal technologies (natural gas, coal, biomethane, etc). This will also stay when more low-carbon production comes to the market. PPAs can help in alleviating this dilemma, but only if they are available and transactable atK sufficient scale. Markets with a high supply of PPAs form the sell-side have shown that the price of electricity approaches the LCOE.

ERT SUGGESTIONS:

1. **Incentivise sufficient green generation** with government-backed offtake schemes, enabled by an infrastructure that provides power aggregation, storage andK balancing and manages demand-side flexibility for the increasing power volume. The current market design leads to low capture rates for renewable generation, which disincentivises new build and makes investment decisions for EIIs especially hard.

2. **Create a market that transforms long-term offtake into liquid products** with various shorter tenures. Potential instruments to achieve this goal could be CfDs (see 4.2.1.2) or PPAs (market-based or government-backed), which should, however, be optional. Which instrument tackles the challenge of transforming the need for long-term offtake into liquid products best should be shown in the market.

3. **Support industry initiatives targeting electrification and energy efficiency gains.** As shown in our analysis, a lower energy efficiency is vital to meet the higher power demand of the future. Industry initiatives that target electrification and energy efficiency gains should thus be welcomed and supported.

4.2.1.2. Support long-term price signals

Renewables are the lowest cost of power supply, but they require high upfront investments (CAPEX).[5] These investments will be made if the investor sees a direct link between the investment and the returns. For this, investors and lenders, e.g. banks, need long-term price signals from a credible buyer for the power produced.

The market design reform agreement does address both investment uncertainty and difficulties of accessing affordable renewable energy for consumers, with regulatory measures aiming at incentivising forward markets and longer-term contracts, including power purchase agreements (PPAs) and two-way contracts for difference (CfDs). The reform aims at incentivising flexibility and demand response, and particularly large storage facilities. While the current reform is a strong start, it should be further improved. Ideas for improvement can be found in chapter 4.2 and also in the Arcelor Expert Corner.

Regarding PPAs, there is a requirement to provide more long-term price signals for investors through additional instruments such as long-term contracts, avoiding distortions in the electricity markets. The development of PPAs[6] would alleviate part of the weakness of the current market design. Today, PPAs account only for a marginal share of EU electricity markets (less than 5%). Their development and expansion would provide security of supply and price stability to both the producer and the end user. PPAs are important because they enable large industrial users to secure green power directly at competitive prices and therefore to decarbonise; and because they help attract the private financing needed to reach the EU's renewable targets.

PPAs can be made more attractive for the market by simplifying accounting treatment of PPAs especially for buyers. These companies source green power for their own use but need to be careful that they do not show large P&L swings resulting from energy price swings due to accounting technicalities.

Furthermore, some interested buyers are unwilling or unable to provide large credit support, which sellers and sellers' banks need to lend against PPA income. A government guarantee mechanism (as established in Norway under the GIEK scheme) can make these transactions easier.

ERT RECOMMENDATIONS:

1. **Incentivise development of government-backed PPAs:** The EU can support PPA's uptake by providing a backing; for instance, through a floor price for the generator in case of bankruptcy of the offtaker, this can be for the full period or only for the last few years of the contract. This not only reduces the risk for suppliers but also allows players that are not investment grade to access the PPA market.

2. **Enable CfDs as a voluntary tool:**[7] CfDs are seen as the silver bullet for long-term price signals and the only product for government-supported offtake, but there are points in the design of double-sided CfD auctions that need to be considered in the evolution of the CfD design:

   i) CfD volumes are by definition trades on the exchange. Consequentially, we will see more variable generation in the merit order. This will result in higher volatility in the market and a low capture rate for all renewable generation that is not shielded by a CfD.

5 In contrast to fossil power that has low CAPEX and high operating costs (OPEX).

6 A PPA is a long-term energy supply agreement concluded directly between a power producer and a power consumer.

7 We do note that there are individual ERT members that would like to see CfDs as mandatory, and not an optional instrument.

ii) Power generated under a CfD regime has to be traded on the short-term merit order market on the exchange. This will lead to increasing price volatility with extended periods of zero and sub-zero prices. In this case, the regulator / government backing the contracts would need to pay the full strike price or more.

iii) CfDs would need to be issued for a very long period, as the commercial lifetime of a project is likely limited to the term of the CfD, given the low capture rates that are a consequence of a broader usage of CfDs.

iv) Some CfDs that have recently been issued have exemptions, i.e. that the generator receives no payment in case the market price is below zero for a period longer than x. Here the CfD becomes a victim of a lack of interconnection and the success of renewables, as it is the high penetration of renewables combined with ‘must run’ resources that drives the prices below zero.

v) CfD contracts will be in competition with other forms of offtake (if not mandatory). As they are government-backed, they come with a high creditworthiness, which means that they will outcompete commercial PPAs on an ‘all other thing equal’ basis.

vi) The date of the CfD auction and the potential FID date need to be close together to ensure that the developer can secure firm prices before going into an auction. With that we minimise the risk that auctions are returned due to cost developments. Price indexes are a less efficient approach to the same challenge.

vii) Give the specificities of CfD contracts, we would suggest openness to other forms of government-backed offtake and suggest that CfDs are not mandatory.

3. **Long-term transmission contracts:** For those players that want to enter into physical offtake agreements (rather than virtual) it is essential that they can also contract the transmission capacity across border. For this, transmission system operators (TSOs) must auction longer-term transmission rights.

4.2.1.3. Increase market liquidity

Market liquidity refers to a broad range of products with a high trading frequencey (high volume) in the power market. This is a prerequisite for transparent and competitive pricing. Today roughly 50%[53] of the power volume is either traded over the counter (OTC). As Europe is split into many different trading zones, the liquidity in these markets is limited, Germany being the largest.

Bilateral renewable PPAs have a term of 10 years or more and cover 70-80% of the respective generation, as this is what the banks need to provide the debt. An increasing number of these agreements would constrain the liquidity of the power market. This problem will relax once we have reached the full build-out with renewables because then we will see many subsequent PPAs (PPAs that are be signed after the first long-term offtake agreement, which will be much shorter in tenure. But this full build-out of renewables should not be expected any time soon.

One reason for the high share of OTC transactions today (and thus a reason for the reduced liquidity) is the way transactions on the exchange need to be secured. Price variations today trigger margin calls, even if the transaction will only be consumed in the distant future. This methodology is logical and consistent with the role that an exchange plays. The exchange brings buyers and sellers together and does not have the role of risk aggregator. Today, the smooth functioning of the electricity and gas market is affected by increased levels of margining requirements, translating into extremely high cash liquidity pressure for market participants. This situation triggers more and more participants to exit the regulated markets for OTC transactions, reducing liquidity and increasing the risk of a systemic default.

ERT RECOMMENDATIONS:

1. **Develop tools to derisk trade of renewable power:** The risk profile for renewable power is different to conventional, as there is no risk that the supply of fuels will be cut off or that the price of the fuel will peak unexpectedly. What we have is a volume risk, as not all wind or sun years are equally good, and we have a profile risk especially in wind, as the hourly distribution can only be predicted with a statistical certainty. So generally speaking, the risk of a default on the generation side is highly unlikely. On the consumer side, the demand for power will not disappear even in the event of an insolvency of an individual offtaker. For the risks in the context of renewable power, we encourage facilitating the creation of an insurance product for which would need a clear demarcation of renewable power. We have similar constructs in the labour market where a collective insurance assumes the unemployment payments in case of insolvency of the employer.

2. **Accept non-cash collaterals or limiting margining calls.** This approach also addresses the derisking similar to 1) but would then shift risk to the exchange. This is not in the scope of exchanges as they are defined today and would require a fundamental restructuring of the sector.

Additional information supporting the need for EU support on improving market liquidity: The liquid market typically is a reference to the spot market, but financial fulfilment and a time horizon of up to six years ahead are also available for trading at EEX covering 19 European markets.[54] Project developers typically need a 10-year or longer offtake contract to secure debt financing. So what we are looking at is a mechanism to convert long-term contracts into contracts that match the typical hedging and contracting horizon of power buyers.

Buyers of the long-term contracts must account for them under IFRS 9 or 16 or under IAS 37.[55] Depending on the type of contract, a PPA can be a lease, an executory contract, a derivative or an embedded derivative. This defines whether the future payments from the PPA are recognised in full or in part as a liability, recorded in the statement of financial position at fair value, or incurred using accrual accounting. Consequently, changes in market prices would require impairments or would affect the penalty's carrying value until the penalty is paid, with such changes being recognised in profit or loss.

Recognising that there are many options for how to account for the PPAs, we have chosen a simplified approach to quantify the commitments made by the offtaker. We calculate the net present value of the future payments from the PPA, with an initial PPA of 10 years, and subsequent PPAs of 5 years.

The payment obligations on the books of the buyers for power from EU renewables would exceed the sum of all liabilities on the books of the 47 European AAA companies by 2031 and exceed the debt in the balance sheet of these players by 2026. So clearly, the investment grade private players in Europe do not have the capacity to assume liabilities of this magnitude.

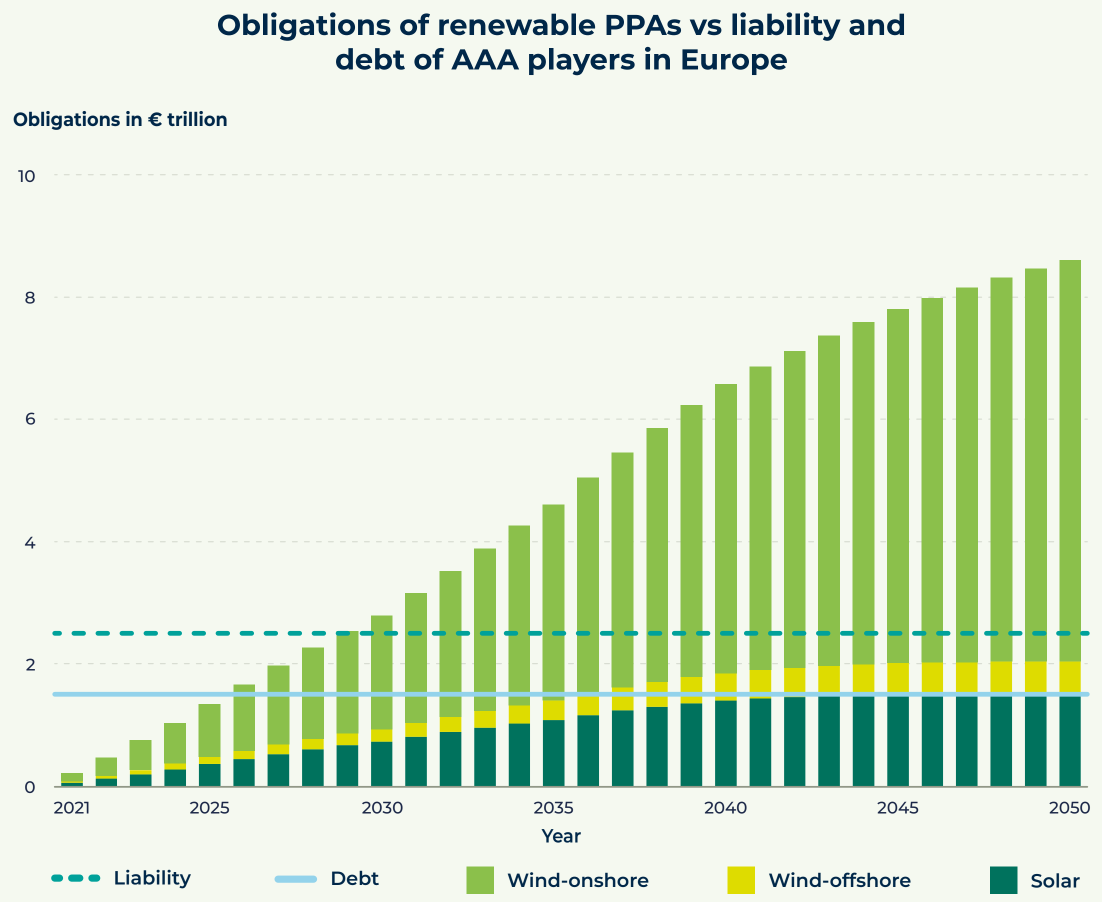


Figure 38: Liabilities of PPA and investment grade players in EU

Sources: S&P, Capital IQ, BCG analysis

4.2.1.4. Link certificates of origin stepwise to time of generation

Green certificates or Certificates of Origin (COO) are virtual products that are generated during renewable power production. The COOs are traded independently from the power and currently have an unlimited shelf time. So players can decarbonise their production during the night shift with COO from solar power.

To produce 'real' green goods, the generation and consumption must take place at the same time (power systems always need to be balanced); this methodology is also called hourly matching or 24/7. The EU has implemented this for green hydrogen. It would be consistent to do this for all usages of COO; doing this hastily before there is a real market for COO would defy the purpose. Here a stepwise rollout with a transparent implementation schedule would be favoured. At first, the term for COO could be a month, while at later stages the time could go all the way down to an hourly level. Focussing on incremental progress assures an agile process that incorporates 'learning by doing' costs along the way.

ERT RECOMMENDATIONS:

1. **Connect green certificates to low-carbon energy:** Consuming green certificates in real time would not only reflect the physical reality of power balancing and supply, but also increase the value that can be captured through demand flexibility and green power storage. This allocation of value would incentivise players to invest in flexibility technologies.

4.2.1.5. Remunerate in a predictable way to incentivise anticipatory investments

Grids are assuming new tasks; this applies in particular to distribution systems. Digitalisation is a key enabler of these services. Currently these new services are not adequately reflected in the Regulated Asset Base (RAB) methodology. The current market design rewards investments primarily based on CAPEX, while investments in digital solutions that mainly reduce OPEX are unattractive. Consequently, investments in these services cannot be funded.

Leonhard Birnbaum
CEO, E.ON

'Today, we lack the incentives to make necessary grid investments. Incremental investments into grids are not enough in a number of jurisdictions, we need to rebuild grid reserves.'

Anticipatory investment in grids is key; therefore, a new regulatory approach that does not disincentivise investments based on forecasts is required. No build-out of new generation-side technologies and no transformation of the demand side is possible without the required grid infrastructure in place. But anticipatory investments can only occur once grid regulation becomes predictable, meaning that there is no regulatory uncertainty in the remuneration of capacity growth and grid services. Investments could have avoided part of the significant redispatching costs. In Germany alone, 2022 redispatching costs were €4.2 billion, up from €2.3 billion in 2021. By remunerating new grid services, the EU can further enhance digitalisation to serve the development of European energy infrastructure.

ERT RECOMMENDATIONS:

1. **Focus on regulation that de-risks anticipatory investments and improve grid management:** Evolving regulatory models need to fully recognise investments based on forecast new generation and demand and provide output-based incentives to improve operational decisions and boost digitalisation. For investments to materialise based on forecast new supply and demand, the regulatory treatment must clarify aspects such as temporary underutilisation or the recognition of associated operational expense increases for the operation and digitalisation of those assets.

2. **Improve data access:** For digitalisation to happen, access to real-time data from different shareholders is key. For example, a utility company might share real-time grid data with regulators to ensure compliance with energy efficiency standards. Transnational utility companies can remotely adjust the output of renewable energy sources like wind turbines or solar panels based on real-time data, ensuring optimal energy production. To create flexibility and predictability, sharing of energy-related data is ideally incentivised within the EU through harmonised interfaces and protocols, involving all industries and end users.

3. **Allow for a flexible approach to unbundling:** Unbundling describes the regulatory effort to separate the business of generators, grid operators and retailers. In the future, many new tasks previously taken care of by energy generators, such as balancing, dispatching and also partially storage, will need to be taken over by DSOs and TSOs. Since many of these activities cannot be performed by VRE generation, a regulatory approach that prevents market power while allowing horizontal synergies to be captured should be favoured. One example would be to allow grid operators to also operate storage facilities.

The above-mentioned 'twin track approach' incentivises energy operators to progress digitalisation through market regulations. Additionally, it contributes to optimising costs within the energy system of the future.

4.2.1.6. Support technologies that reduce price volatility (hydro pumping, batteries, interconnectors)

In an energy system with a greater share of renewables in the final energy mix, storing enough green power to reduce energy prices becomes essential. Power storage through various technologies (see

Figure 20) can happen if the grid is still in its early stages, but with costs coming down, batteries are moving from grid services to balancing services.

ERT RECOMMENDATIONS:

1. **Label green energy loaded into batteries/hydro pumping as green when dispersed:** For hydro pumping and batteries to support the energy transition and the deployment of green power, we would encourage a regulation that considers green energy being loaded into the battery as green power when it is discharged. This incentivises investment in storage and becomes even more important as and when green certificates need to be consumed at the time of generation.

Demand-side flexibility based on market approach could be a precious available resource that can be activated quickly and usually does not require major CAPEX investment. In 2016, the European Commission assessed that access to all flexibility options would directly translate into a reduction of wholesale electricity supply costs by around €50 billion in 2030.[8]

Offtakers could time their offtake depending on when energy is available at the lowest price, e.g. industrial beer producers could brew flexibly at a time when energy costs are lowest. There are different solutions that provide flexibility, energy communities and prosumers or flexible energy pricing to provide market signals, for instance.

ERT RECOMMENDATIONS:

1. **Include flexibility provisions in market design:** The inclusion of flexibility provisions in the ongoing revision of the electricity market design is positive and should be supported. Demand flexibility, like power has a time-dependent value. Establishing local markets where this flexibility can be traded would result in a better utilisation of the grids and significantly less redispatching. It would also give those that are less flexible a more cost-effective access to base load.

2. **Establish a pan-European regulatory framework:** A regulatory framework that enables the development of flexibility services at an EU level is vital to a harmonised approach that favours fast software rollout. For system operators and market participants, a stable and harmonised framework at EU level is key to enabling the development of flexibility services, while considering the different realities across Europe.

4.2.2. Market design for natural gas

Existing natural gas infrastructure is crucial in structurally reducing Europe's energy costs in the short to medium term, and ensuring energy security. The EU gas transport network was initially designed for East-West and North-South flows. Current tensions have revealed bottlenecks for West-East and South-North flows. Certain Central European countries, which are traditionally heavily dependent on Russian supplies, remain relatively detached from the LNG flows arriving in the West. A functioning gas infrastructure is necessary to secure a wide and diversified availability of supply to minimise the risks of a potential gas supply disruption, with resulting negative impacts on both energy security and economic, social costs for households and businesses. Appropriate adjustments are needed, and are progressing as for example shown in the ENTSOG Winter Supply Outlook from 2023/2024,[56] to ensure the EU is able to receive gas in a flexible and demand-driven manner. In particular, we observe the need for targeted installation of a sufficient number of LNG import terminals and a strengthening of gas interconnections and eliminate on of existing bottlenecks to allow flows from the South and West of Europe to reach demand in Central and Northern Europe, noting the changing role of gas long-term.

8 European Commission, Impact Assessment accompanying the EU Electricity Market Design.

4.2.2.1. Introduce support mechanism for green gases

Access to the existing gas grid alone will not be sufficient to enable the EU to reach targets for renewable gases.

ERT RECOMMENDATIONS:

1. **Establish production support mechanisms:** Mechanisms that support production, rather than tariff discounts on grids (also representing a cross-subsidy), are needed to scale up the market. This includes CfD-like mechanisms.

4.2.2.2. Establish European Guarantee of Origin for green gases

There needs to be a push for the establishment of a genuine European Guarantee of Origin/Proof of Sustainability market for renewable gases (biogas, H_2).[9] This would allow for the physical delivery of gases to be separated from their production and enable renewable gas flows across various European regions, helping to develop further investment in the biogas and hydrogen markets and addressing the EU's current energy supply challenges. It is important to note that a free market is a prerequisite for a successful green transition; too many prescriptions should be avoided.

ERT RECOMMENDATIONS:

1. **Introduce European Guarantee of Origin / Proof of Sustainability:** Support European renewable production by introducing a European Guarantee of Origin for renewable gases, eliminating the need to administer multiple national schemes.

2. **Set up flexible requirements as to what is low-carbon gas in the market build-up:** The requirements for low-carbon hydrogen and green gas of non-biological origin should be kept flexible enough to enable the initial creation and satisfaction of demand, as well as cost-efficient production and transport, enabling market build-up until the market matures in the 2030s and initial investments are paid back (see 4.2.3.2).

4.2.2.3. Prepare policies for the remuneration of gas grids considering much lower utilisation

The EU needs to prioritise a stable wholesale supply by avoiding market interventions, so that global natural gas suppliers aren't compelled to price in such regulatory risks. Gas market interventions should be targeted and for temporary periods only, to avoid disrupting the price signals that drive investment. In particular, the EU should focus on mitigating future disruptions and resulting high prices with approaches that prioritise the transparent and uninhibited functioning of the energy market.

ERT RECOMMENDATIONS:

1. **Introduce remuneration schemes that address the upcoming lower utilisation of grids:** For example, through dedicated charges for preparing decommissioning where appropriate.

2. **Improve financing of infrastructure for energy security to avoid stranded assets:** While taking steps to avoid stranded assets in the future, specific limited regasification capacity (such as floating storage regasification units) is needed to secure the EU's gas supply and ensure liquidity in the market.

9 ERT flagship publication 'Renewing the Dynamic of European Integration: Single Market Stories by Business Leaders' (December 2021): see the story 'From the get – G.O.' by the CEO of TotalEnergies, page 130-133 (https://ert.eu/wp-content/uploads/2021/12/ERT-Single-Market-Stories_WEB-low-res.pdf)

3. **Introduce policies supporting new supply of renewable gases:** Introduce policies that in increase new supply of renewable gases (e.g, improvements to planning and permitting for renewables; clear signals from the EU regarding the role of gas in the medium term; or energy efficiency and infrastructure that underpins existing LNG supply and debottlenecking of flows between EU member states). This would ensure the diversification of EU import sources (LNG, H_2) and help secure long-term supplies with contracts, while avoiding creating new international dependencies.

4.2.3. Market design for biomethane, hydrogen and CO_2

4.2.3.1. Increase cooperation between network operators across energy vectors and invest in cross-sector planning

Across biomethane, hydrogen and CO_2 infrastructure, strong planning coordination between ENTSOs is a must. In practice, this has been put in place and should continue, extending to offshore grids for CO_2 and hydrogen. This requires special attention to the management and upkeep of storage and pipeline infrastructure for facilitating trade in biomethane through regulatory cross-sectoral approaches.

ERT RECOMMENDATIONS:

1. **Link power grid regulation to molecule grids:** Power grid regulation may need to be linked more closely to molecule grids, at least in integrated planning. Integrated infrastructure planning includes identifying producers 'and offtakers' needs (the grid has to develop in line with demand, allow existing gas TSOs to refurbish/repurpose their pipelines to speed up the network development) for example, cross-commodity advantages like hydrogen storage may need clear financial support, to the benefit of the power market, in their initial years of development. This can be a form of government support, or regulatory support like we see being considered in Germany addressing the issue of initially low usage of hydrogen grids versus the network being built up (so-called DENA model).

2. **Facilitate cross-sectoral collaboration:** Market dialogue about technical requirements and network codes should be facilitated (e.g, purity in H_2 pipelines needs to be decided on with customers and dominant hydrogen quality in mind, discussion on how cross-border trade can be enabled)

3. **Grant non-discriminatory third-party access to gas infrastructure where no pipe-pipe competition is feasible, or the nature of resources is scarce;** avoid 'gold-plated' rules: To build up an H_2 network, we will need a priori, non-discriminatory third-party access to infrastructure for H_2 production facilities, import facilities including conversion, storage, and end-users, harmonised technical standards to enable the grids to grow together, and integrated network planning that enables the demand-oriented build-up. Access rules should be flexible and encourage investments.

4. **Develop certification schemes:** Certification schemes in line with RED III need to be in place since H_2 is mostly seen as a compliance option for different targets. The open questions, such as the definition of low-carbon hydrogen in the gas package, need to be answered.

4.2.3.2. Incorporate a 'learn as you go' approach to policymaking

In many new nascent sectors such as hydrogen and CCUS, it is difficult to draft a perfect regulatory framework from scratch. Instead of trying to engineer sector-specific goals and milestones, it is important to remain agile and incorporate a 'learn as you go' approach to policymaking, that always keeps track of the overarching goal of decarbonisation.

ERT RECOMMENDATIONS:

1. **Assure frequent review of policy, while maintaining a balance with the necessary stability needed for long-term investment:** Given the fast pace of development, frequent reviews of policy will be required, including potentially enabling unbundling rules to be exempted in some cases, during initial build-up years (e.g, until 2032), as industries will need close collaboration to build new value chains, avoiding barriers to efficiency and to competitive development in non-regulated activities.

2. **Facilitate twin track anticipation:** Another issue that will require frequent review of policy measures is the twin track of dropping gas volumes on one side and rebalancing costs from commodity to infrastructure costs as part of the invoice on the other side. The issue of dropping gas volumes is already being anticipated in some Nordic countries, where in CEO interviews we have seen mention of grid operators opening discussions on how to repurpose and decommission parts of natural gas grids. As a minimum, at policy level the industry and grid operators need to address terms like 'decommissioning' as part of tasks of grid operators, and clarify objectives for phasing out unabated fossil gas in Europe by 2049.

An example of where policy review would be useful while maintaining basic stability of the regulations, is the Delegated Act based on article 27.3 ('additionality') of the RED, for the following reasons:

The current provisions of the act only foresee a report on the impact by 1 July 2028. It would be useful to require a biannual report on its impact, with conclusions on how it has helped or blocked projects, so as to emerge with recommendations to adapt specific rules if necessary, while ensuring that early projects are not disadvantaged. The act includes detailed requirements on the correlation in time and location between renewable electricity generation and renewable hydrogen production, that must represent additional capacity as far as power mix is below 90%, particularly post a short transitional period ending in 2028. This regulation could potentially delay large-volume green hydrogen production until 2030, by when the renewable share in some bidding zones is expected to have increased significantly.

The act's requirement for electrolysers to produce hydrogen only when electricity is nearly simultaneously generated ('correlated') by new renewable energy plants (monthy until 2030, hourly afterwards) could lead to operational inefficiencies. During periods of calm and cloudy weather, or insufficient storage or grid capacity, electrolysers would remain idle, thus increasing hydrogen production costs and disrupting continuous supply to industries. The act imposes stringent limiting criteria on green hydrogen producers that may prove unnecessary or too detailed.

The ongoing revision of the gas and hydrogen decarbonisation package, including a detailing process for adoption of a Delegated Act on low carbon hydrogen, presents an opportunity to review/revisit the RED Delegated Act under article 27.3 and consider global progress on hydrogen certification (e.g, in comparison to markets in the US and Asia) enabling a more conducive environment for the growth of the hydrogen economy, thereby aligning with the broader ambitions of the REPowerEU initiative and global competitive EU Single Market.

4.2.3.3. Increase policy attention to the emerging CO_2 sector

The emerging carbon capture, utilisation and storage (CCUS) sector needs policy attention to encourage investment in CO_2 capture, support the development of cross-border CO_2 transport infrastructure of all modes that connects capture facilities to large-capacity onshore and offshore storage sites in and outside the EU, and promote investment in CO_2 storage capacity. All these policy steps must be accelerated and addressed in a coherent legislative approach built on the integration of policy choices along the full value chain. Examples of the regulatory challenges to be reviewed and addressed are the role of CCUS within the ETS; the level playing field across free allocation benchmarks in the regulation for using new technologies that partly reduce or fully eliminate greenhouse gas emissions. The upcoming Industrial Carbon Management Strategy will consider supporting financing the creation of an EU-wide CCUS ecosystem, including pipelines and storages. These are important preconditions for CCUS to contribute in a meaningful way to the EU's efforts to meet its net-zero targets, alongside decarbonisation publications to be delivered through biomethane and hydrogen.

ERT RECOMMENDATIONS:

1. **Establish an entire CCUS supply chain:** We recommend the establishment of enabling measures at European and national level for the rapid development of the entire CCUS supply chain, in terms of both public financial support and regulatory framework. In particular, the EU should define support models for CCUS that facilitate coordination in the development of the different parts of the supply chain. Furthermore, adequate de-risking mechanisms should be provided, particularly in the early stages of project development. A comprehensive supply chain also requires the geographically well-balanced development of injection capacity throughout the EU. This ensures competitiveness of the industry both in Northern Europe and in the Mediterranean area, with consequent economic and employment benefits.

2. **Support the development of cross-border transport and storage in Europe:** Cross-border transport and storage of CO_2 that's currently constrained by the London Protocol[57] should be incentivised.

3. **Work out industry standards for CO_2 specification:** The specification as to what purity the captured CO_2 needs to have in order to access transmission and storage needs to be based on industry-wide standards without overregulating the emerging market. One example of such an assessment is the CO_2 specification in Australia drafted by the global CCS Institute.[58] Industry-wide CO_2 specifications will reduce the cost and complexity of capturing and utilising CO_2 and therefore lead to a wider adoption of CCUS technology in the industry. Moreover, it enables safe operation of CCUS networks because security risks like corrosion and fracture controls are minimised. On the other hand, It is important to refrain from over-regulation and not require CO_2 to have, for example, food- or research-grade purity.

4.3. Think and plan pan-European

The EU is globally unique in the size and strength of its Single Market.

We suggest building on this strength by addressing both short- and long-term challenges in the energy transition (e.g, security of supply, affordability and decarbonisation). Renewed EU integration is vital for achieving robust global competitiveness and a European Union that can again accelerate growth.

Thinking pan-European is crucial to strengthen the EU energy union and is most important in two areas:

1. Improving cross-border cooperation

2. Crisis resilience

4.3.1. Improve cross-border cooperation

The current fragmentation and country-by-country approach on support schemes (for biofuels or hydrogen, for example), or in response to rising energy prices, is challenging the overall cohesiveness and the implementation of the EU's Green Deal. Thus, better cooperation across borders is necessary to ensure efficient infrastructure development. The EU should look to establish a single energy union with a common market, harmonised permitting and tax systems, and a simple, stable and predictable regulatory framework to facilitate investment.

4.3.1.1. Strengthen the Single Market and cross-border cooperation via transnational PPAs

ERT RECOMMENDATIONS:

1. **Incentivise transnational PPAs:** The Commission should incentivise transnational PPAs, e.g, by pushing the TSOs to grant cross-border transmission rights beyond one year. These mechanisms should include the participation of cross-border capacities in national mechanisms, following the provisions[10] set by the Clean Energy Package.

4.3.1.2. Address any market reform with a preliminary impact assessment study

ERT RECOMMENDATIONS:

1. **Assess any market reform with a preliminary impact study:** The ERT welcomes the approach taken by the Commission to carefully address any power market design reform with a preliminary impact assessment study.

4.3.1.3. Invest in pan-European infrastructure planning to incentivise both on- and offshore interconnector planning

Transmission systems are critical for (i) the connection of large power generation and industrial offtakes, (ii) avoiding curtailments by balancing across larger geographies, and (iii) reducing the price differential between markets, which is why we fully support an interconnection target of at least 15% by 2030.[59] Lack of interconnections, together with differences in the energy mix of the member states, is reflected in wide price differences between countries. The ability of TSOs to connect hybrid offshore wind/interconnector developments, supply multiple markets and balance freely between these markets, is an important enabler for the uptake of hybrid projects. Other market design options should also be evaluated in addition to the Transmission Access Guarantee. A pan-European mindset is required to find ways to deal with off shore energy islands that have interconnectors in different power markets.

ERT RECOMMENDATIONS:

1. **Interconnect EU electricity systems:** Connecting Europe's electricity systems will allow the EU to boost its security of electricity supply and to integrate more renewables into energy markets. This target should be seen in the context of the alignment of markets' energy prices and referenced to their peak demand. The European Commission expert group on electricity interconnection had its 17th and most recent meeting over four years ago. We encourage the Commission to put more emphasis on this pressing issue. Today, the construction of interconnections between two countries requires the agreement of the respective nations' TSOs, a challenge that hampers their development. The European Commission should therefore ensure better coordination between TSOs and DSOs and plan these interconnections in Ten-Year Network Development Plans.

2. **Use ENTSO-E and ACER effectively:** ENTSO-E and ACER are bodies that can provide detailed modelling and direct efforts to where transmission systems are most needed. EU network planning should be pan-regional through alliances of network operators and country governments. The North Seas Energy Cooperation is a good model; in 2023 it will complete the first ever joint cross-border grid exercise for both power and hydrogen.

10 The provisions are contained in Art. 26 of the Electricity Regulation (https://eur-lex.europa.eu/eli/reg/2019/943/oj) and the methodologies mentioned therein.

3. **Include EU industry in decision-making:** The voice of EU industry should be an important part of this integrated planning and permitting discussion – the onshore/offshore network corridors of the 2030s are being created today, where understanding and seeing the needs of industry is critical to the work of grid players and policymakers.

4.3.1.4. Encourage harmonisation of technical standards for more interconnection

Standards for the treatment of gases differ between member states. For example, gas odorisation is carried out within the French transport network, while in other countries it either does not take place or happens downstream in the distribution network, which prevents interconnection. The market for renewable gases (biogas, hydrogen) remains as fragmented as the support schemes in each Member State.

ERT RECOMMENDATIONS:

1. **Encourage harmonisation of technical standards:** An EU-wide harmonisation of technical standards would facilitate more interconnection between countries.

4.3.1.5. Ensure strategic location of demand centres for hydrogen and CO_2

To accelerate the green industrial transition in Europe, attention to 'demand centres', also referred as 'strategic clusters' is essential. Outside the energy infrastructure discussion, use of the term 'clusters' is very common. There are more than 200 clusters active in Europe in areas such as agricultural services, food processing, forestry, livestock processing and wood products registered on the European Cluster Collaboration Platform. For energy infrastructure, 'clusters' particularly in demand centres around nascent markets such as low-carbon hydrogen and carbon capture, transport and storage, can play a pivotal role in decarbonising industries and creating early markets and cost-effectiveness of infrastructures necessary for the deployed technologies.

We see this emerging, e.g, around industry demand situated near European ports (Rotterdam, Antwerp). Around these ports, we see low-carbon hydrogen and CO_2 clusters emerging – these clusters focus on renewable and low-carbon hydrogen production, addressing emissions in sectors where electrification is impractical, like chemicals and steel. By concentrating production, distribution, and demand, hydrogen clusters promote network efficiencies and synergies. The North Sea coast, with its heavy industries and abundant wind energy, is an ideal region for a large-scale hydrogen network, offering both renewable hydrogen production possibilities.

Around CO_2, synergies are apparent as well – many smaller industrial facilities collectively contribute significant emissions, making individual carbon capture uneconomical. To tackle this, clusters allow multiple facilities to share carbon capture infrastructure and knowledge, reducing costs and emissions on a larger scale. These clusters offer economies of scale and opportunities for shared learning, contributing to the green industrial transition. In our use of terms, we sometimes also refer to the clusters as hubs or (hydrogen, energy) valleys.

ERT RECOMMENDATIONS:

1. **Ensure strategic location of demand centres:** Going forward, EU-level strategies and funding are vital to facilitate (cross-border) cluster development. The development of clusters, for example facilitating both carbon capture and hydrogen, requires political support and funding. Strategic clusters will deliver better low-carbon products faster and at a lower cost, turbocharging growth and diversification to support decarbonisation.

2. **Set EU priorities and targets:** To enable the creation of clusters, the EU may consider priorities and targets, e.g, for the production and consumption of low-carbon hydrogen and CO_2 capture and transport, as well as cross-cluster collaboration. Cluster strategies that go beyond Member State borders are desirable for efficiency and learning across the EU.

5. Appendix

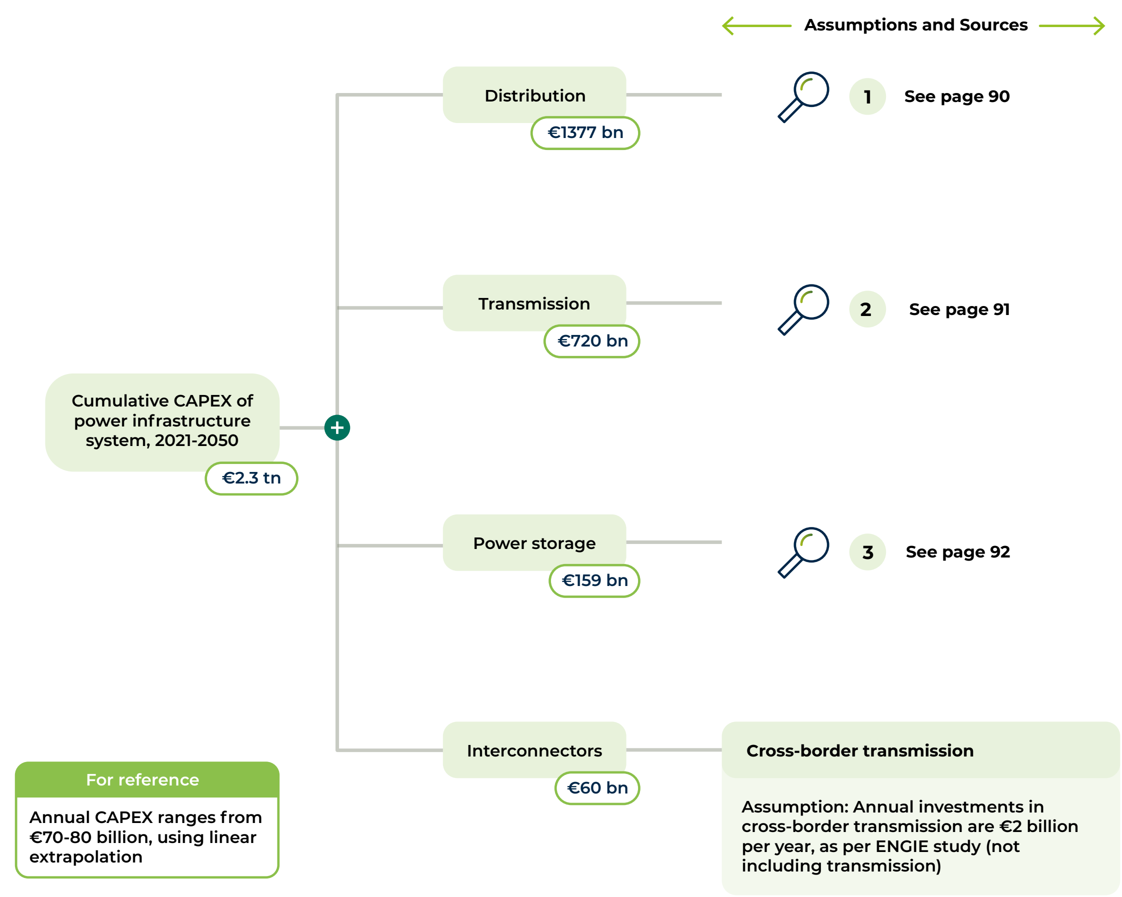
5.1. Methodology

Unless otherwise mentioned in this publication, the values quoted are from the IEA.[5] We are using the Announced Pledges Scenario (APS). Unless not explicitly stated, we are modelling only CAPEX with nominal values (no discounting). Whenever values from other studies are used, a bibliography reference is made [X]. Several bibliography references refer to values derived from the BCG Methodology, which can be found on the following pages.

As of now, we show the detailed methodology for the calculation of the costs of CO_2 infrastructure. In the future, there will be a detailed methodology for the key results of this publication.

Power grids: Total infrastructure system CAPEX 2021-2050

Modelling **only CAPEX, nominal values** (no discounting), values in 2021 EUR



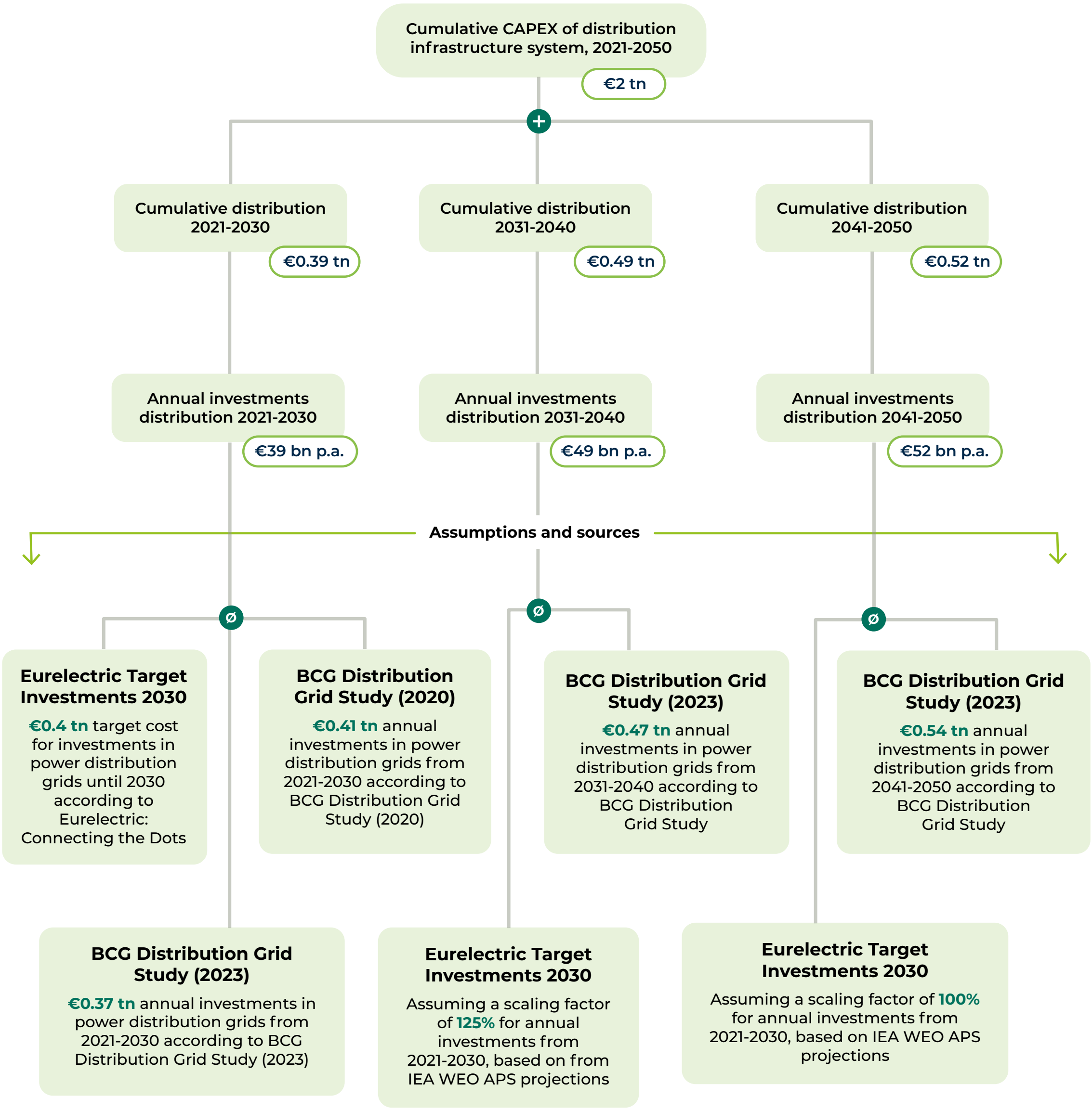
Methodology 1: Power grids: Total infrastructure system CAPEX

Note: Values may not add due to rounding

Source: ENGIE: Building Decarbonization Pathways for Europe (2023)

Power grids: Cumulative distribution CAPEX 2021-2050

- Modelling **only CAPEX, nominal values** (no discounting)
- We used target data of €400 billion investments in distribution grids from 2021-2030, coming from the Eurelectric: Connecting the Dots study, using linear extrapolation to derive annual investments
- Using Eurelectrics's value of €40 billion annual investments from 2021-2030 and scale with a factor of 125% using IEA WEO APS projections for 2031-2040
- Using previously derived €50 billion annual investments from 2031-2040 and scale with a factor of 100% using IEA WEO APS projections for 2041-2050

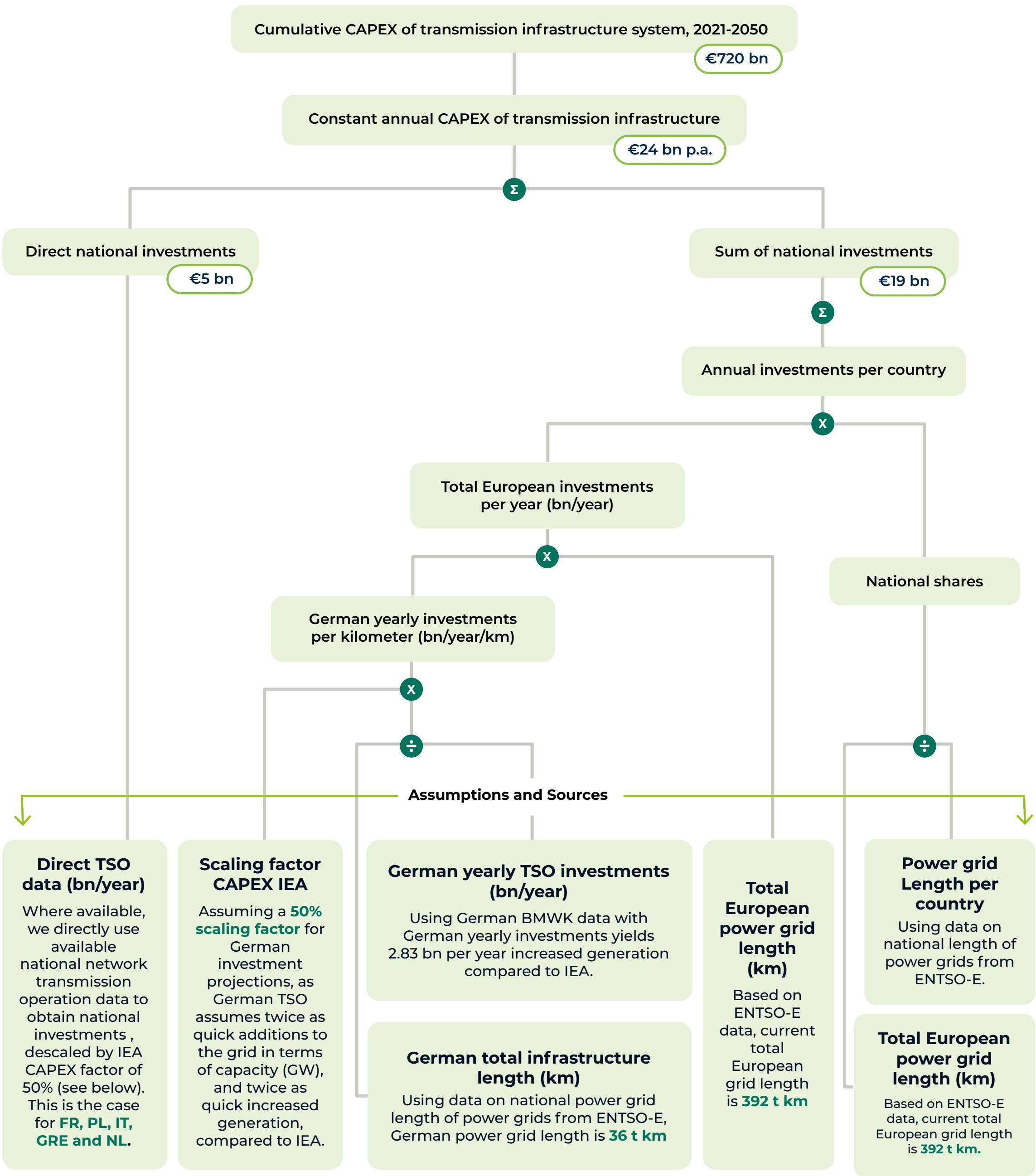


Methodology 2: Power grids: cumulative distribution CAPEX 2021-2050

Note: Values may not add due to rounding

Power grids: Cumulative transmission CAPEX 2021-2050

- Modelling **only CAPEX, nominal values** (no discounting)
- For estimating the investments in the transmission networks, we choose a bottom-up approach. We took direct national investments per year in the transmission grid per country and aggregated them for Europe.
- Where data was available, we used data directly from network transmission operators. Where no data was available, we approximated annual investments based on German BMWK data, assuming that yearly cost per kilometer was the same across countries



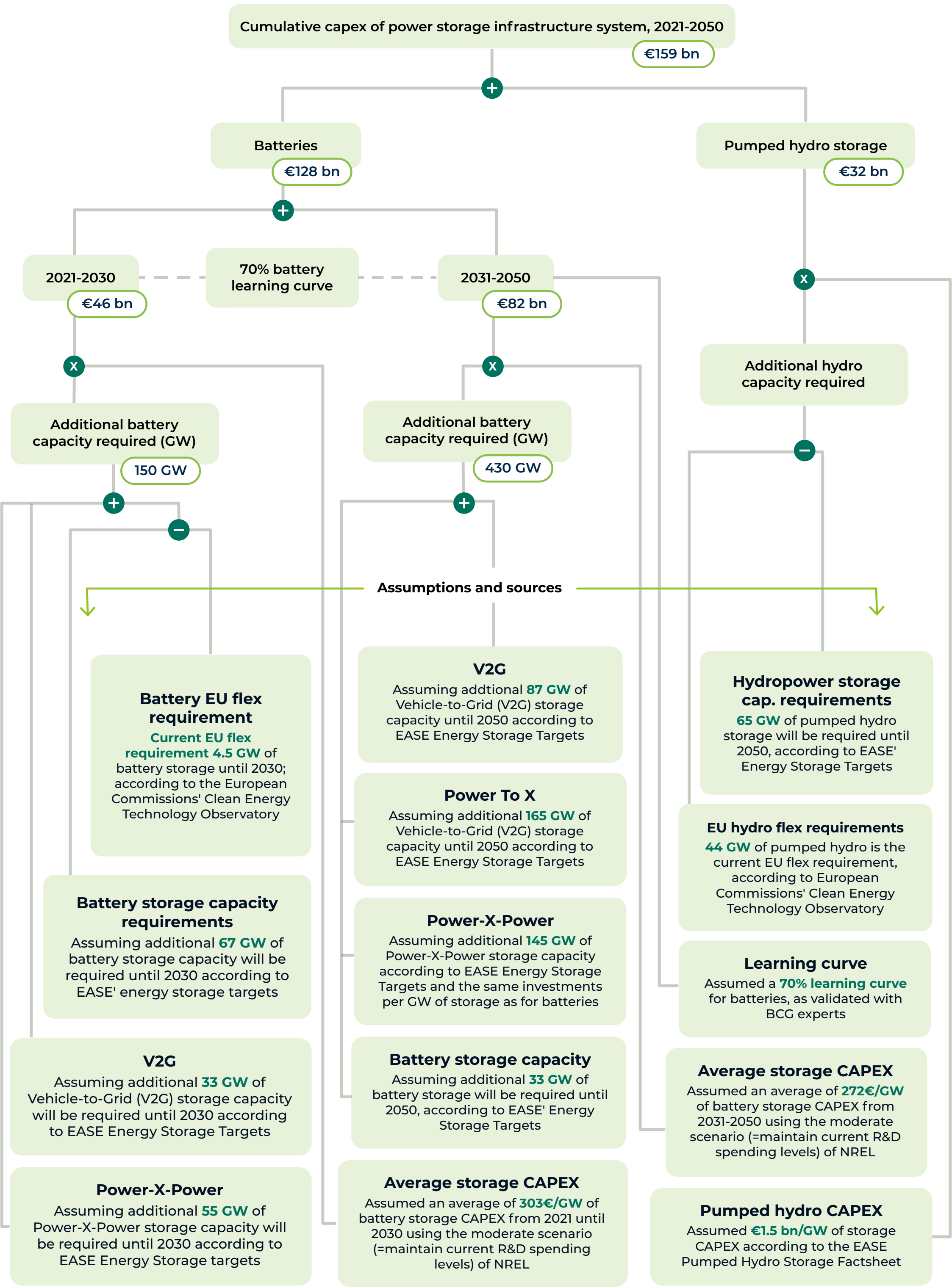
Methodology 3: Power grids: Cumulative transmission CAPEX 2021-2050

Note: Values may not add due to roundingSources: National TSO

Sources: for PL, FR, IT, GRE, NL; BMWK: An Electricity Grid for the Energy Expension; ENTSO-E: Power Stats

Power grids: Cumulative energy storage CAPEX 2021-2050

- Modelling **only CAPEX, nominal values** (no discounting) expressed in real 2021 EUR.



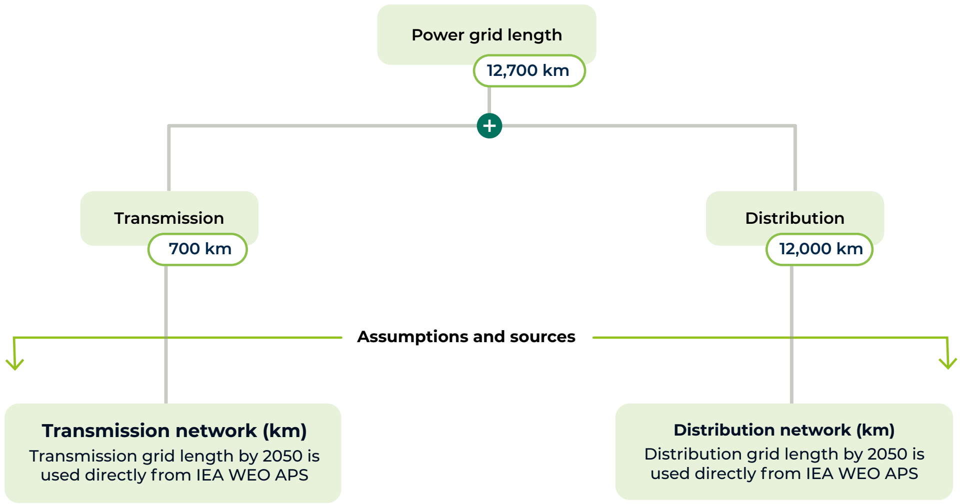
Methodology 4: Power grids: Cumulative energy storage CAPEX 2021-2050

Note: Values may not add due to rounding

Sources: National TSO sources for PL, FR, IT, GRE, NL; BMWK: An Electricity Grid for the Energy Expension; ENTSO-E: Power Stats

Power grids: Total grid length 2050

- Modelling **only CAPEX, nominal values** (no discounting)



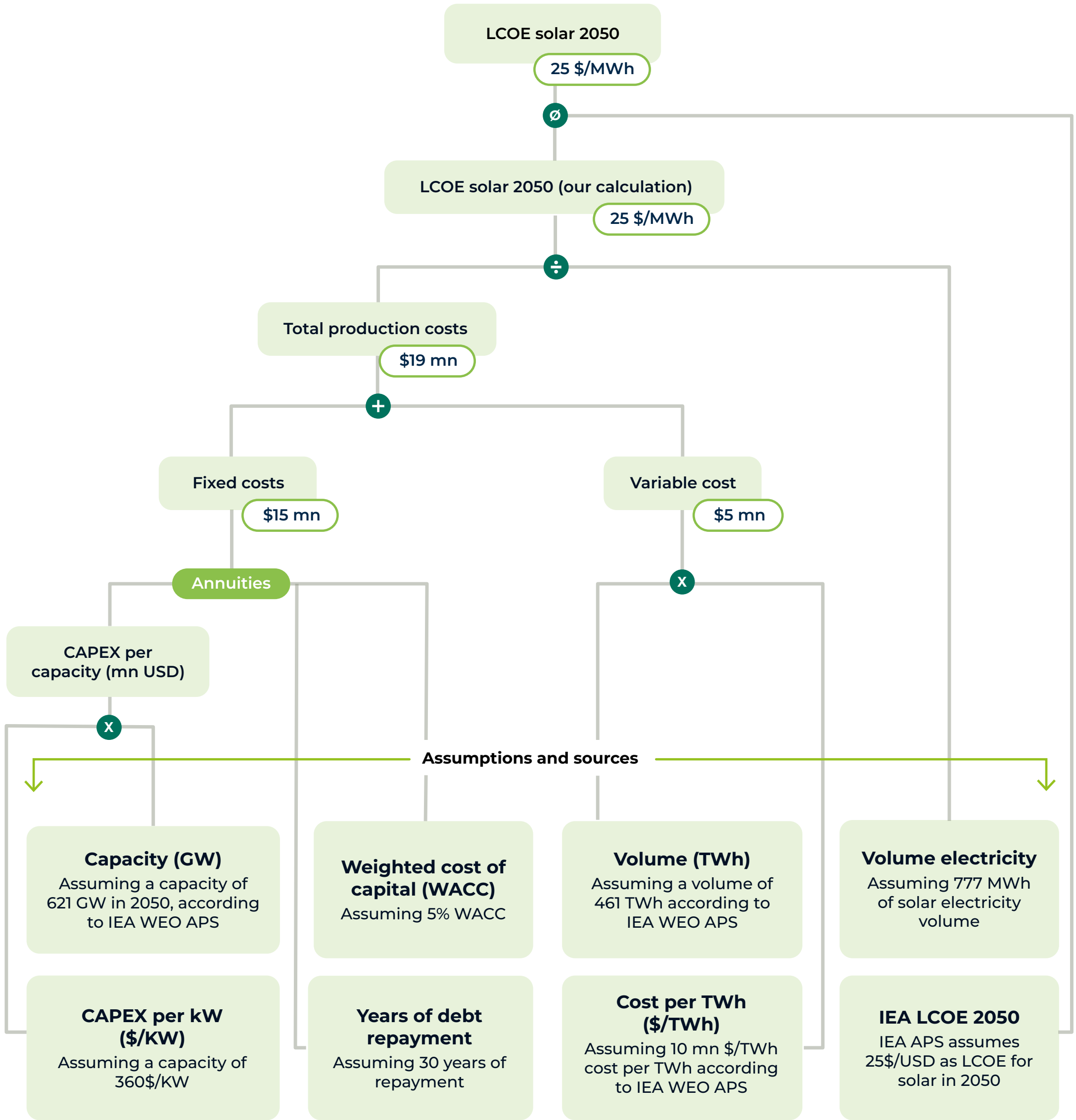
Methodology 5: Power grids: Total grid length 2050

Note: Values may not add due to rounding

Sources: National TSO sources for PL, FR, IT, GRE, NL; BMWK: An Electricity Grid for the Energy Expension; ENTSO-E: Power Stats

LCOE Solar 2050

- Modelling **only CAPEX, nominal values** (no discounting)



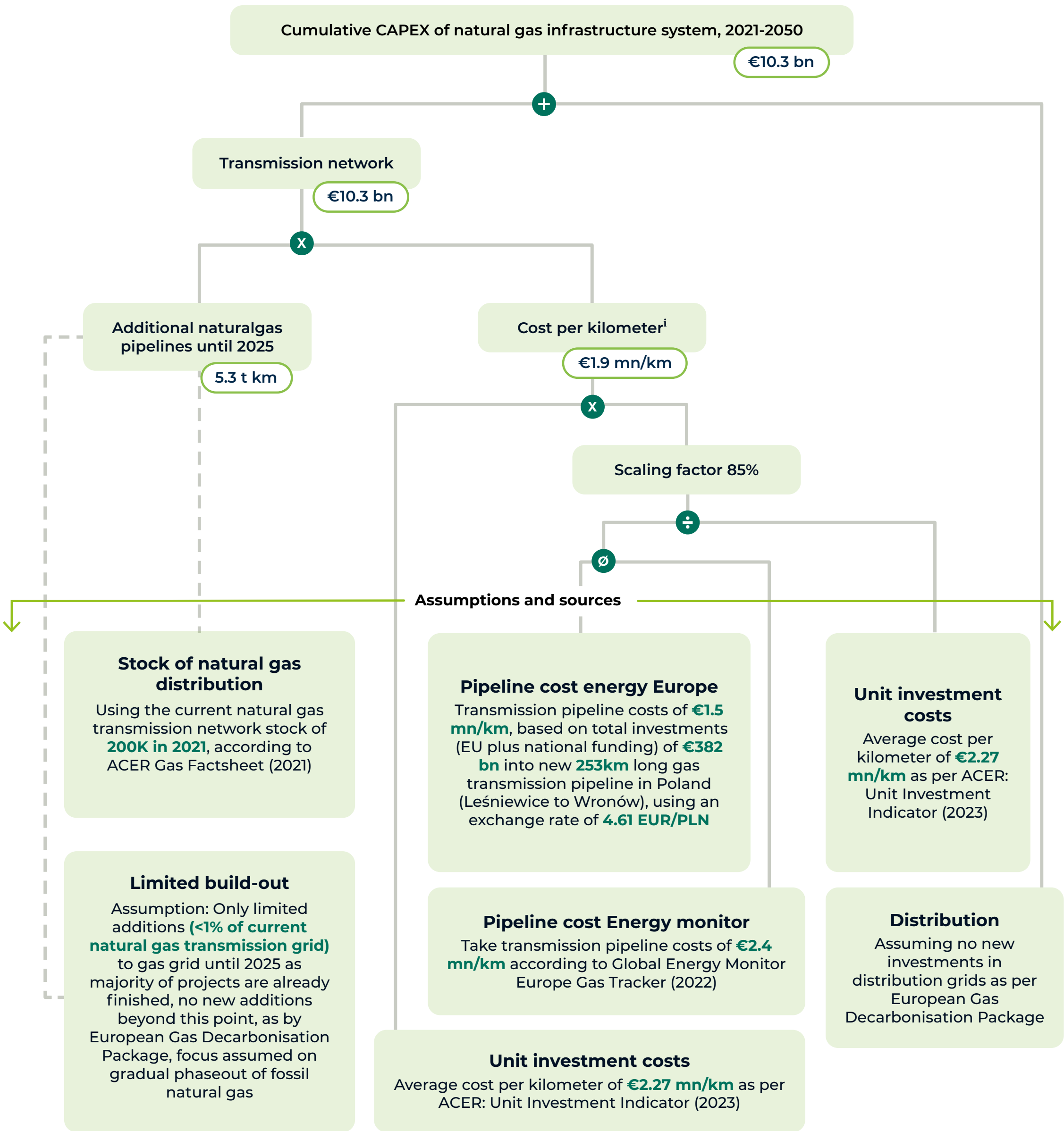
Methodology 6: Power: LCOE solar 2050

Note: Values may not add due to rounding

Natural gas: Total infrastructure system CAPEX 2021-2050

Scope and approach

- Modelling **only CAPEX, nominal values** (no discounting)
- This is about **new, additional** investment. While we acknowledge that some OPEX cost buckets such as maintenance can concern CAPEX, we assume that this sum is negligible
- Data from the 243 km long gas transmission pipeline in Poland is used to triangulate global pipeline costs with the most recent and representative European gas transmission pipeline project
- We assume no decommissioning costs at this point, since they will mostly fall into OPEX
- The amount of repurposed natural gas pipelines **until 2025 on EU scale** is negligible, which is why **they do not affect additional investments** in the national gas grid **from 2021 to 2025**



Methodology 7: Natural gas: Total infrastructure system CAPEX 2021-2050

i. Includes both onshore and offshore pipelines, mostly high pressure

Source: ACER Natural Gas Factsheet (2023); ACER Unit Investment Indicator (2023), Global Energy Monitor Europe Gas Tracker (2022), European Commission: €124 million European funding for the construction of a section of a gas transmission pipeline in Poland (2023)

Note: Values may not add due to rounding

Natural gas: Only limited buildout until 2025

"The new rules will make it easier for renewable and low-carbon gases to access the existing gas grid, by removing tariffs for cross-border interconnections and lowering tariffs at injection points. [...]

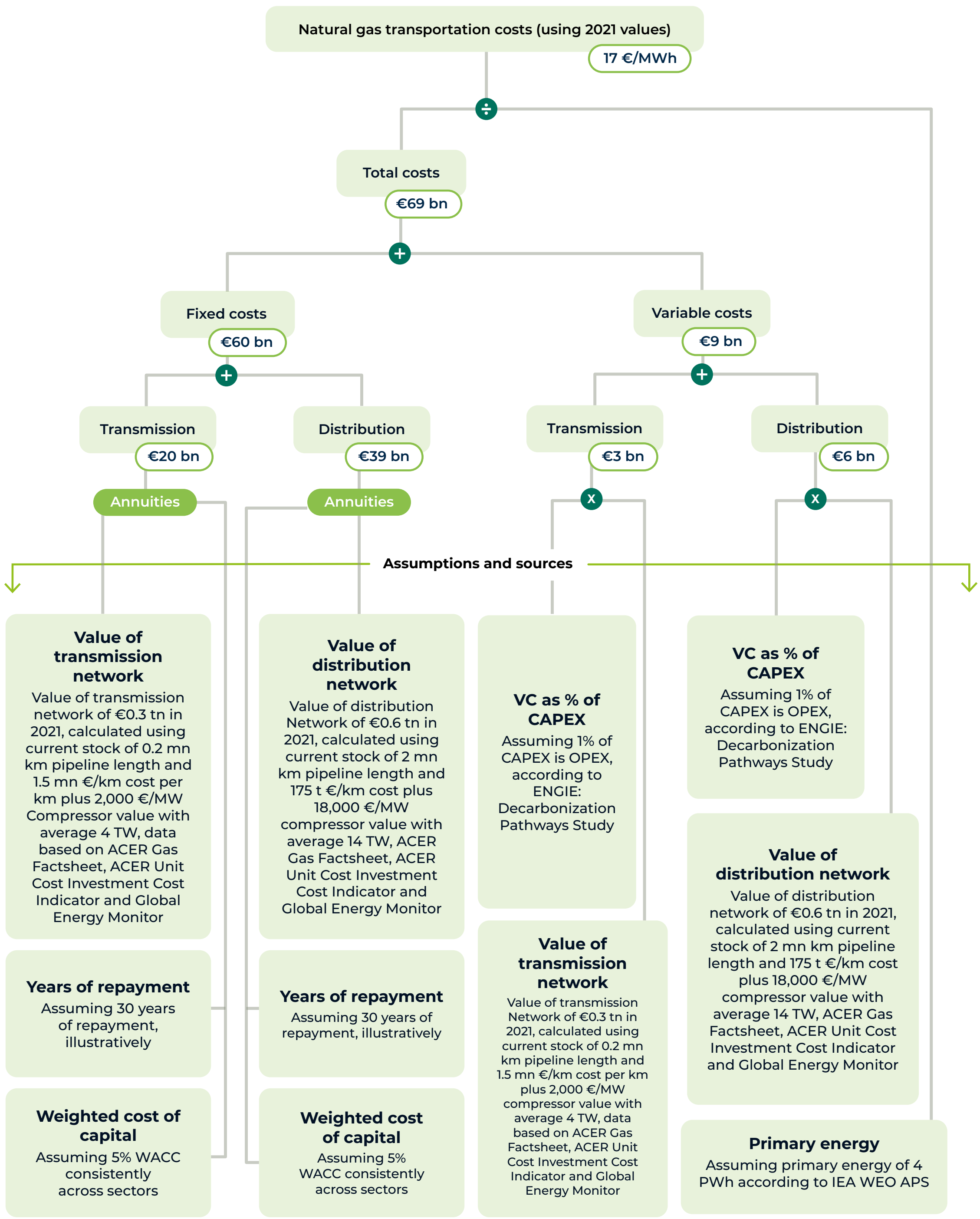
In order to avoid locking Europe in with fossil natural gas and to make more space for clean gases in the European gas market, the Commission proposes that long-term contracts for unabated fossil natural gas should not be extended beyond 2049."

The European Commission’s press release on the European Gas decarbonisation package

Methodology 8: Natural gas: Only limited buildout until 2025

Natural Gas: Transportation costs, including distribution and transmission, 2021

- Modelling **only CAPEX, nominal values** (no discounting)
- Illustrative figures, not taking into account detailed national regulation across Member States.



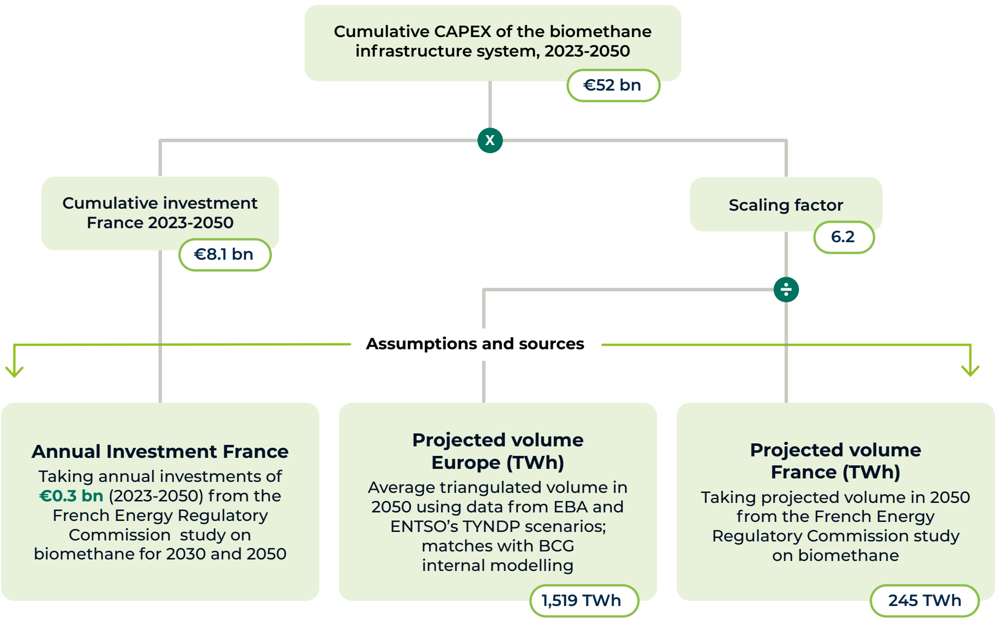
Methodology 9: Natural gas: Transportation costs, 2021

Note: Values may not add due to rounding

Sources: ACER Natural Gas Factsheet (2023); ACER Unit Investment Indicator (2023), Global Energy Monitor Europe Gas Tracker (2022), ENGIE: Decarbonization Pathways Study

Biomethane: Total infrastructure system CAPEX 2023-2050

- Modelling **only CAPEX, nominal values** (no discounting)
- **French Biomethane Study** is the **only** study taking into account economies of scale effects, leading to **lower cumulative CAPEX** compared to other approaches. Economies of scale decrease required investments through learning-by-doing cost reductions, less expensive reverse flows from 2040 and future deployment of production techniques such as pyro-gasification, hydrothermal gasification or methanation
- We consider the French biomethane network as representative for Europe
- It's a vast network with relatively large biomethane opportunities; a detailed explanation of this is given on the respective methodology slide
- We use both ENTSO and European Biogas Association (EBA) values because IEA APS does not provide any estimates for biomethane volume in 2050



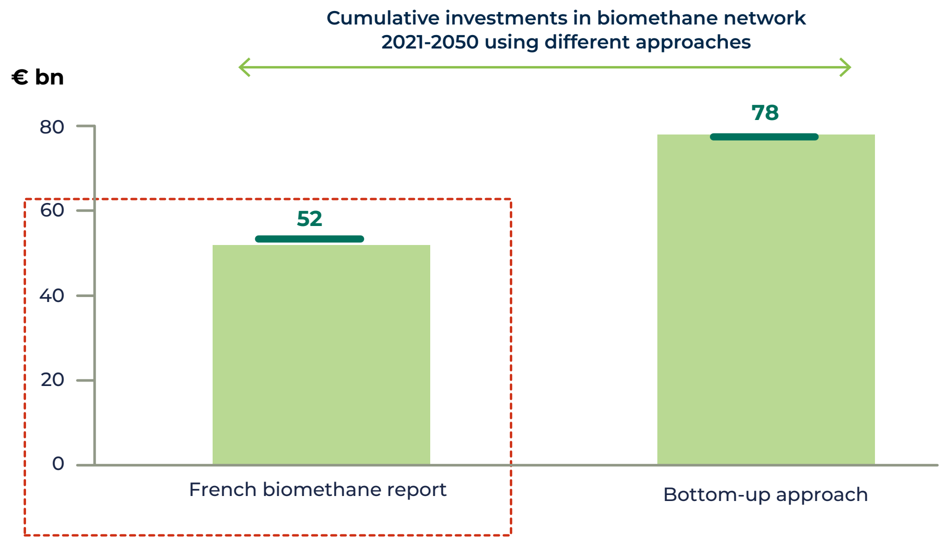
Methodology 10: Biomethane: Total infrastructure system CAPEX 2023-2050

Source: French biomethane report ('Avenir des infrastructures gazières aux horizons 2030 et 2050, dans un context d'atteinte de la neutralité carbone'); triangulated with values from European Biogas Association and ENTSO's Ten Year Network Development Plan.

Note: Values may not add due to rounding

French biomethane report is the only source taking into account network effects, leading to lower annual investments

- French biomethane report[i] calculates annual investments in biomethane infrastructure for France, which is then scaled to EU level
- Bottom-up approach uses current annual production per biomethane plant and scales it to projected biomethane plants need to deliver volume in 2050



- **French biomethane report** is the only report accounting for **economies of scale effects**
- Bottom-up approach is too high because it assumes fixed annual production per plant

Methodology 11: French biomethane report accounts for network effects

Source: French biomethane report ('Avenir des infrastructures gazières aux horizons 2030 et 2050, dans un context d'atteinte de la neutralité carbone'); triangulated with values from the European Biogas Association and ENTSO's Ten Year Network Development Plan.

Note. Cost of generation is not considered

Country	GMV [i]	O2030 BV [ii]	B BCM 2021 [iii]	B PLANTS [iv]	AVG. GWh/ plant [v]
Germany	77	97	1.1	250	40-50
Italy	65	98	0.2	25	40-50
France	38	107	0.4	375	10-15
Netherlands	27	114	0.3	60	40-50
Denmark	1.7	144	0.6	50	100-110
Sweden	0.7	107	0.1	70	<10

Methodology 12: French biomethane report lies within ranges of other studies

- France used as an illustrative median biomethane market from the six most promising biomethane markets in Europe. We have analysed France against a number of features of the natural gas and biomethane market, and as the above table illustrates, we find that the French natural gas / biomethane system is illustrative for biomethane developments in terms of gas infrastructure and market system.
- This is illustrative evidence to this report using the French costing of biomethane transition as a proxy for European costing developments. We note that French estimates may overestimate the cost, particularly for smaller markets.

i Gas market volume (Statistical Review of World Energy 2023, bcm, 2022)

ii Outlook 2030 biomethane volumes (biomethane m3/capita, BCG)

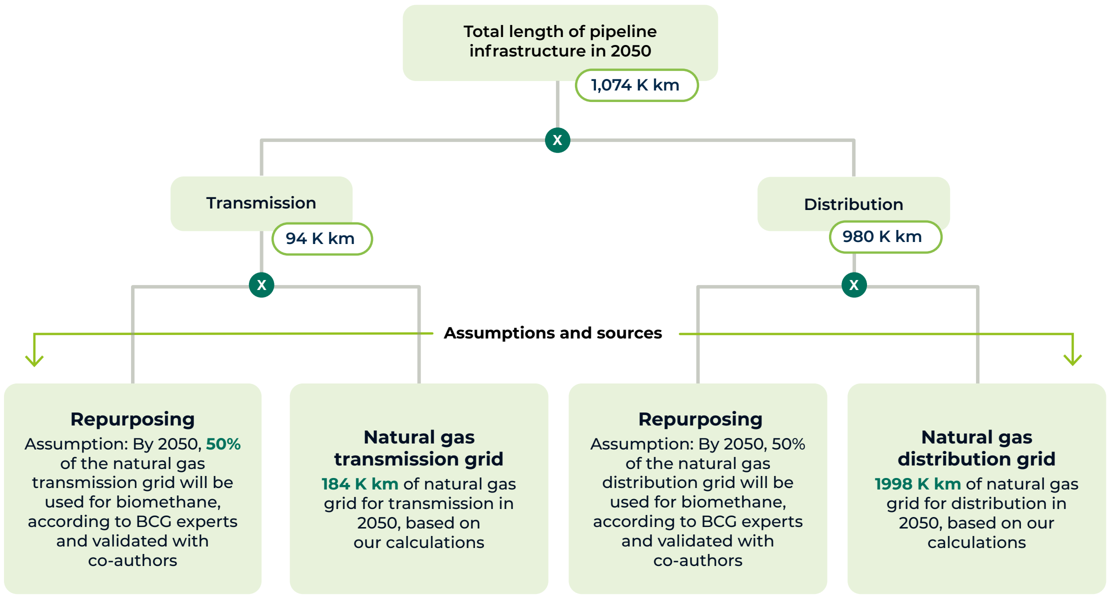
iii Biomethane bcm 2021 (BCG)

iv No. of biomethane plants 2021 (BCG)

v Average GWh/plant (2021, BCG)

Country	Energy transition: biomethane qualitative market features	Natural gas storage facilities	Natural gas interconnections
Germany	2010-20 subsidy scheme retracted since poorly designed incentives favoring unsustainable energy crop Gov't has signaled ambition to increase production[ii]; favorable regulatory updates expected to continue	Significant	High interconnectiviy incl. Netherlands, France, Belgium, Norway, Austria, Poland
Italy	National target to reach 3.5 Mtoe (~120 mn MMBtu) RNG by 2030 (vs 0.7 mn MMBtu in 2020) More attractive subsidy scheme (potential rates of 21-25 USD/MWh)	Significant	Medium connectivity with main flows to/ from Austria, and from Northern Africa and Caspian region
France	National target to reach 10% RNG in gas grid by 2030 (~150 mn MMBtu vs ~17 in 2021) Attractive new mandatory certificate mechanism	Significant	Medium connectivity with main flows Belgium, Germany
Netherlands	National target to reach 2bcm (~75 Mio MMBtu) RNG by 2030 (vs ~10 mn MMBtu in 2021) Tender-based subsidy scheme (SDE++) launched	Significant	High interconnectiviy with Belgium, Germany, UK
Denmark	Danish Energy Agency predicts 44 mn MMBtu in '30 (17 mn MMBtu in '21); gov't has signaled ambition incease.[ii] A new tender-based subsidy scheme will be launched in 2024 (previous scheme non-tender)	Limited	Limited connectivity with Germany, and Sweden
Sweden	National target to reach 34 mn MMBtu by '30 (vs ~6.8 mn MMBtu in '21), CAPEX subsidy of $ 15 mn per plant[i] Benefit of ~24USD/MMBtu (11USD/ MMBtu premium1 and 13USD/MMBtu CO_2 tax exemption vs petrol)	Limited	Limited connectivity with Denmark

Biomethane: Total pipeline system length 2050



Methodology 13: Biomethane: Total pipeline system length 2050

Note: Values may not add due to rounding

LCOE of biomethane 2050

Approach

We use ENTSO's TYNDP biomethane LCOE of **66.2 €/MWh in 2050** based on Danish industry expertise data, and cross check with BCG internal modelling

Assumptions

Under the assumption of

- 5 % WACC
- 20 years lifetime
- 8.7 MW output per plant

BCG internal modelling matches ENTSO's TYNDPs LCOE of **66.2 €/MWh**

Ranges given by BCG model:

- 8% WACC, depending on EU country
- 15-20 years lifetime

Outcome

This number matches with BCG internal modelling, with following caveats:

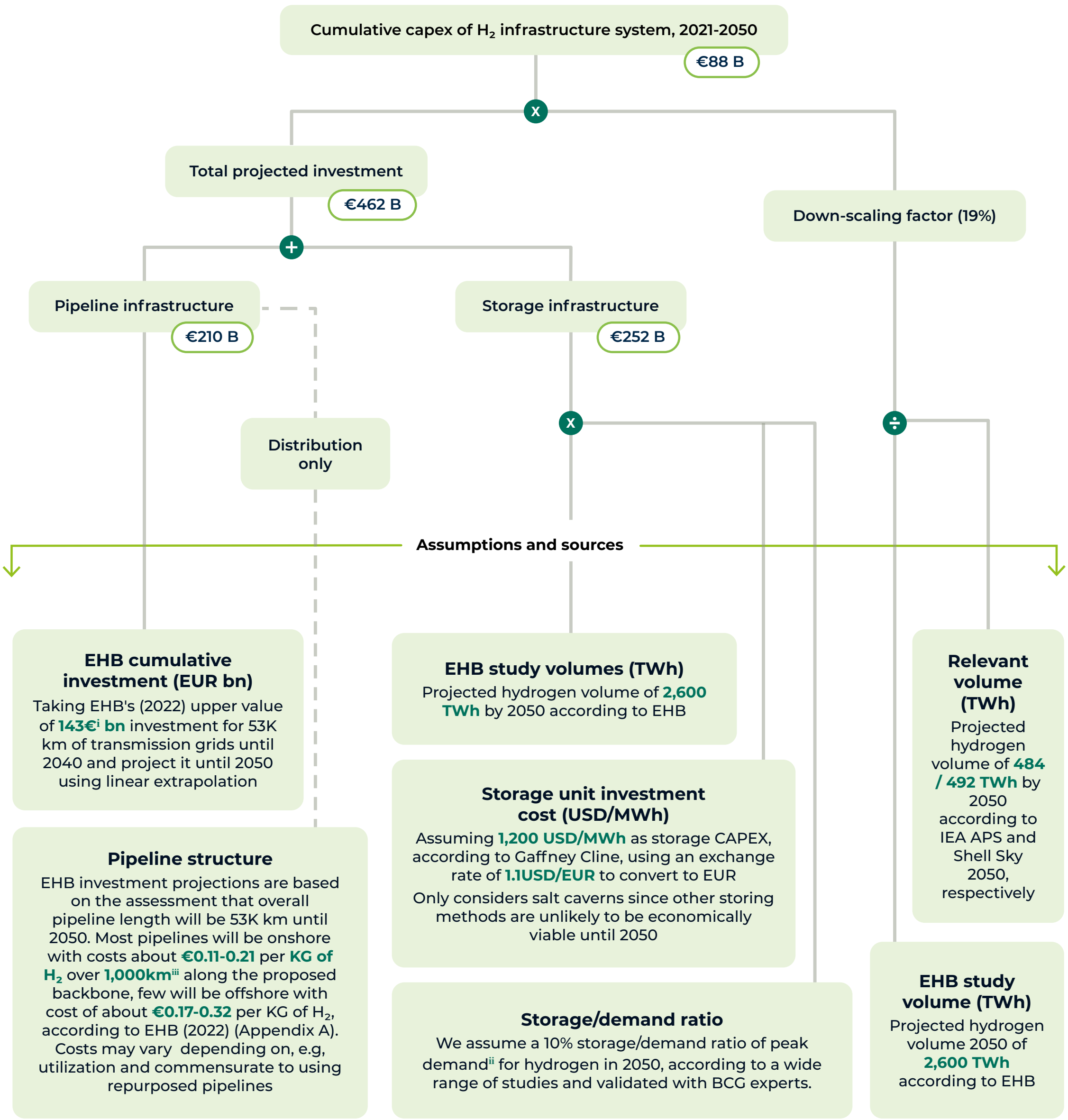
- Final production cost for biomethane could go from **60 €/MWh** to **110 €/MWh** depending of the cost associated with feedstocks and scale of the plant. Feedstock can represent, e.g, a range reflecting biomethane manure vs biomethane straw (assuming specific yields for every of those feedstocks)

Methodology 14: LCOE of biomethane 2050

Hydrogen: Total infrastructure system CAPEX 2021-2050

Scope and approach

- Modelling only **CAPEX, nominal values** (no discounting)
- EHB assumes five times higher hydrogen volumes for 2050 than Shell Sky 2050 and IEA APS, hence investment values are triangulated and downscaled using Shell Sky 2050 and IEA data, for Shell Sky 2050, this concerns end use, no feedstock.
- EHB figures have been descaled to be conservative, so we considered inter alia:
  - Potentially slow-paced pick-up of industrial demand leading to stranded assets
  - Potentially slow-paced repurposing of natural gas pipelines due to market and technology dynamics
  - Smaller geographical footprint excluding UK



Methodology 15: Hydrogen: Total infrastructure system CAPEX, 2021-2050

i. For a detailed breakdown of EHB's hydrogen transmission grid numbers, please refer to the methodology slide on pipeline requirements

ii. Please refer to the next methodology slide on the hydrogen storage/demand ratio to see an overview of the studies

iii. We took 1,000 km as an acceptable proxy for the typical distance of transport in the future given the North Sea – Germany scenario of transport

Note: Values may not add due to rounding

Sources: European Hydrogen Backbone Study (EHB), Gaffney Cline: Underground Hydrogen Storage; The Royal Society: Large Scale Electricity Storage; IEA APS; Shell Sky 2050

Market demand TWh	Storage demand TWH	Storage/ demand ratio	Remarks/source
n/a	n/a	11%	Gas storage experience global, GECF
n/a	n/a	22%	Gas storage experience EU, GECF
n/a	n/a	16%	Gas storage experience US, GECF
n/a	n/a	34-60%	Hystoris: 34-60% of the overall annual hydrogen demand
n/a	n/a	8-25%	8%-25% of overall annual hydrogen demand in Europe
n/a	n/a	11%	For an optimised system – (e.g., the North Sea grid) – 11-18% of produced H_2 (328 GW with 3500 hours; versus 30 to 60 PJ storage)
85	8	9.4%	The H21 North of England project estimates that 8 TWh of inter-seasonal hydrogen storage would be required to support an 85 TWh hydrogen transmission system servicing the North of England, including the major conurbations of Leeds, Bradford, Wakefield, Huddersfield, Hull, Liverpool, Manchester, Teesside, Tyneside and York
n/a	n/a	20-25%	TNO estimated 20-25% of the annual hydrogen demand as the storage need for the Netherlands
n/a	n/a	10-22%	Blanco et al. assessed that most advanced climate scenarios model the need for (electricity) storage up to 6% of the total electricity production. Gas for Climate models 7,112 TWh of electricity production by 2050, which would correspond to 426 TWh of storage required. If all of that storage was met by hydrogen, it corresponds to approximately 22% of the EHB 2050 hydrogen annual demand
n/a	n/a	33%	The North Sea Wind Power Hub Integration Routes modelled between 180 TWh and 270 TWh of annual hydrogen use in the power sector (regional) with a corresponding need for 60-100 TWh of hydrogen storage, representing an approximately 33-37% storage/demand ratio
262	72.8	27.8%	TN Strom DE – strong electrification
690	47	6.8%	TN H_2 G DE – green molecules win, less electrification
14,190	1,200	8.5%	IEA NET Zero Roadmap: A Global Pathway to keep the 1.5°C Goal in Reach – 2023 Update

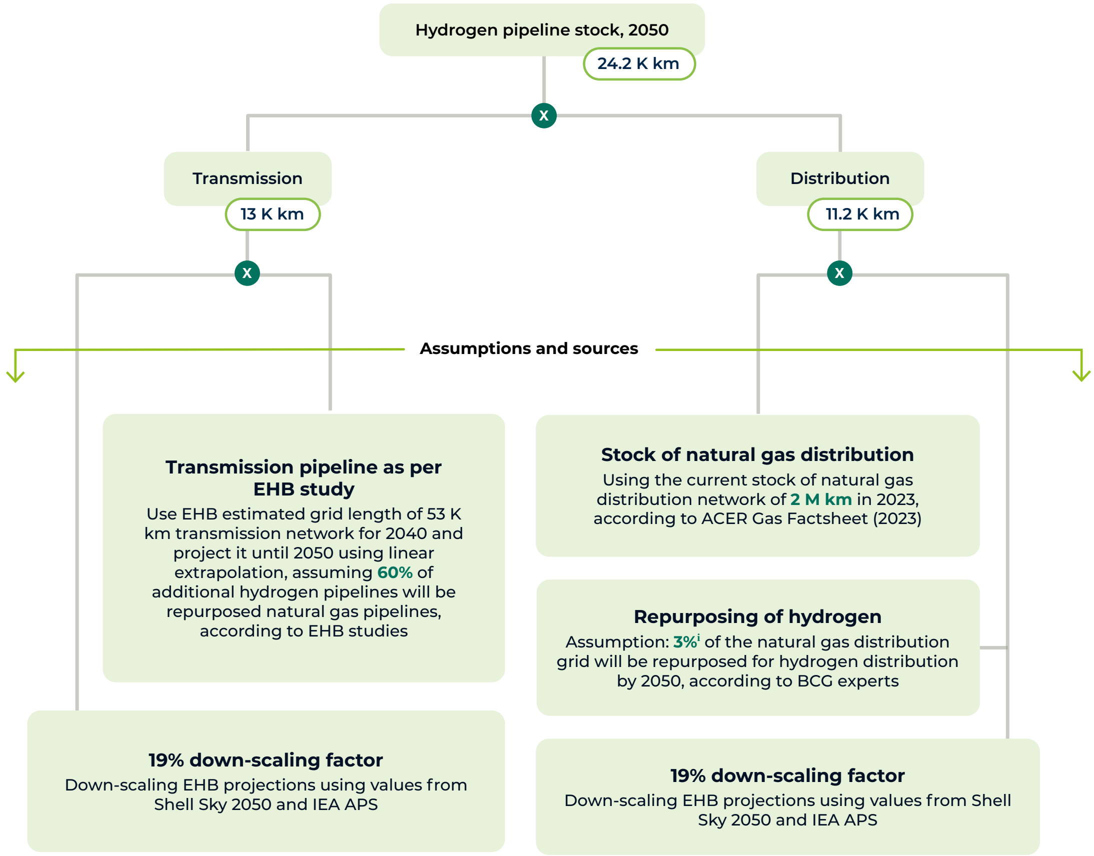
Methodology 16: Hydrogen: Ranges of storage/demand ratios

- From literature study (table overview below), a wide range of sources appears. The storage estimates, as they concern a future, vary between 6.8% and 43%. For this study, **a BCG expert estimate of 10% is used illustratively**, as uncertainty is large. This figure was discussed with hydrogen experts at leading hydrogen storage investors in Europe at Flame 2023, and was found reasonable.
- Hydrogen salt caverns are at this time seen as the best economic option, where available. This concerns, e.g., as example for Europe salt formations in Northwestern Europe. Many ongoing and planned pilots are aimed at demonstrating hydrogen storage in salt caverns. In Europe, this includes HyCAVmobil by EWE; HyPSTER by Storengy; HyGeo by Teréga; H_2@Epe by Uniper; Green Hydrogen Hub by Gas Storage Denmark; HYPOS by VNG; HyStock by Gasunie. In the US, pilots are being conducted. Globally, salt caverns are already being used, e.g., in the US and UK, so it's a proven technology.

Hydrogen: Total pipeline requirement 2050

Scope and approach

- EHB covers 28 countries in Europe and 31 energy network operators
- Further details on scoping see EHB



Methodology 17: Hydrogen: Total pipeline requirement 2050

i. Please refer to the next slide to see a detailed reasoning behind this assumption

Note: Values may not add due to rounding

Sources: European Hydrogen Backbone Study (EHB), Shell Sky 2050, IEA APS; European Union Agency for the Cooperation of Energy Regulators (ACER): Gas Factsheet

Repurposing of hydrogen – only limited distribution uptake

- Qualitative evidence from discussions on the role of hydrogen at distribution level, where it would largely replace natural gas for heating purposes, shows very limited uptake. We included an **illustrative 3% assumption** at present.
- We provide a quote from the Directive of the European Parliament and of the Council to show that as it stands – pending a few exceptions of testing of hydrogen use with households – **distribution grids will not be used for hydrogen.** In some cases, smaller industry may be connected to distribution.

> "For instance, where today natural gas is widely used for space heating purposes, this demand is expected to be met largely by other energy carriers, such as through electrified space heating appliances, in the future. [...]. As the precise decarbonisation trajectories, role of energy carriers and their use cases will also depend on local starting points, endowments and circumstances, they should not be prescribed in detail. Efficient markets will ensure that, given local endowment and circumstances, consumers incentivised by other policy instruments are empowered to choose the decarbonisation options most suited to their particular use-case."

European Commissions press release on the European gas decarbonisation package

Methodology 18: Repurposing of hydrogen: Only limited distribution uptake

LCOE of hydrogen 2030

Approach

- We took ENTSO's TYNDP H_2 LCOE in **2030 of 63.5 €/MWh** based on IEA APS scenario and cross-checked with BCG-internal modelling.
- The IEA APS prices of H_2 (SMR CCUS) assume that blue hydrogen will set the benchmark for competitive green hydrogen.

Assumptions

Green H_2 can meet the IEA APS prices under the assumption of:

- 8% WACC
- 15 years lifetime
- 1,500 USD/KW CAPEX (PEM)
- 65% efficiency, full load
- 20 USD/MWh electricity price
- 75% capacity factor

Ranges available under the BCG modelling suite:

- 6-8% WACC, depending on EU country
- 15-20 years lifetime

Outcome

- IEA APS LCOE generally matches the BCG-internal modelling subject to access to competitive prices of power, and economies of scale/supply chain build-up leading to cost reductions.

Methodology 19: LCOE of hydrogen 2030

LCOE of hydrogen 2050

Approach

- We took ENTSO's TYNDP H2 LCOE in **2050 of 54 €/MWh** based on IEA APS scenario and cross-checked with BCG-internal modelling.
- Our assumptions for the LCOE in 2050 slightly change, reflecting the high uncertainty in estimating parameters of a novel technology.
- The IEA APS prices of hydrogen (SMR CCUS) assume that blue hydrogen will set the benchmark for competitive green hydrogen.

Assumptions

Green hydrogen can meet the IEA APS prices under the assumption of:

- 8% WACC
- 15 years lifetime
- **650** USD/KW CAPEX (PEM/ALK) (- 60% compared to 2030)
- Taking into account potential economies of scale
- **69%** efficiency, full load (+6% compared to 2030)
- Taking into account higher efficiency due to technological progress
- **30** USD/MWh electricity price (+50% compared to 2050)
- Taking into account potentially higher prices for power
- 75% capacity factor

Ranges available under the BCG modelling suite:

- 8-10% WACC, depending on EU country
- 15 years lifetime
- 500-800 USD/KW CAPEX (PEM)
- 70% efficiency, full load
- Electricity price depends on geography
- 20-30% capacity factor for typical grids; in a high renewable grid, 75% could be feasible

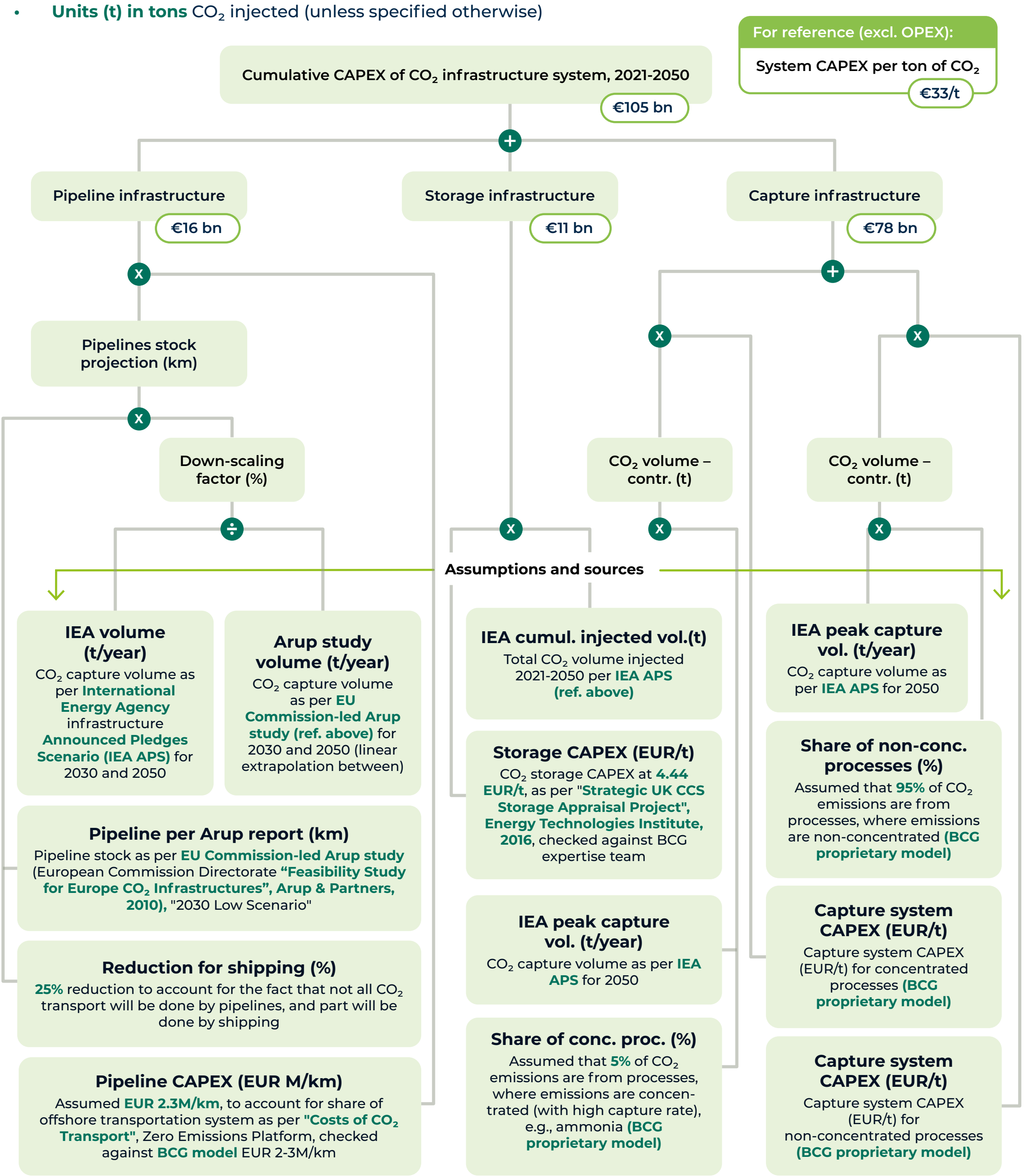
Outcome

- IEA APS LCOE generally matches the BCG-internal modelling subject to access to competitive prices of power, and economies of scale/supply chain build-up leading to cost reductions.

Methodology 20: LCOE of hydrogen 2050

CO_2: Total infrastructure system CAPEX 2021-2050

- Modelling **only CAPEX, nominal values** (no discounting)
- **Storage** includes injection wells and platforms. Estimations are conservative as they assume mostly offshore developments; onshore storage costs would be lower, and we see this option being explored, e.g., in the French, CO_2 strategy.
- **Capture** includes compression, assuming that it can be invested in by the industry or operators.
- The European Commission-led Arup Study was used to source a reasonable assumption on the **EU pipeline network** based on 2010 industrial clusters – given European industrial developments, this may give some limited underestimation of the needed scale of the the EU CO_2 network. That study considers both the onshore and offshore layout of the EU CO_2 network, and is referred to in the recent (2023) EU CO_2 regulatory framework consultation.
- **Shipping CAPEX** is left out, as the pipeline system is descaled by 25% to account for this.
- **Units (t) in tons** CO_2 injected (unless specified otherwise)



Methodology 21: CO_2: Total infrastructure system CAPEX 2021-2050

Note: Values may not add due to rounding

5.2. Definitions

Power = electricity or electrons

Variable renewable energy (VAR) = wind and sun

Renewable power = VRE + hydro + power from biogas or other green feedstock

Zero-carbon power = renewable power and nuclear power

Low-carbon gases = green H_2, blue H_2, pink H_2, biomethane

Low-carbon fuels = ammonia, synthetic fuels

Energy = power, gas, liquid or solid carrier

Fossil energy = natural gas, oil, coal

5.3. Abbreviations

DG	European Commission's Directorate-General
DSO	distribution system operator
EC	European Commission
GW	gigawatt
GWe	gigawatt of electric energy
GWh	gigawatt-hour
kWh	kilowatt-hour
Mtoe	million tonnes of oil equivalent
MWh	Megawatt-hour
TWh	terawatt-hour
LV	low voltage, <1 kV
MV	medium voltage, 1 kV to <45 kV
HV	high voltage, 45 kV to <300 kV
EHV	extra high voltage, 300 kV to 750 kV
UHV	ultra high voltage, >800 kV
CEEAG	EU Climate, Energy and Environmental Aid Guidelines
CEER	Council of European Energy Regulators
CfD	contract for difference
CO_2	carbon dioxide

CSP	concentrated solar power
dena	Deutsche Energie-Agentur
ERT	European Round Table for Industry
ETS	emissions trading scheme
EU	European Union
EV	electric vehicle
FiP	feed-in premium
FiT	feed-in tariff
GDP	gross domestic product
GHG	greenhouse gas
IRENA	International Renewable Energy Agency
JRC	Joint Research Centre
LCOE	levelised cost of electricity
LNG	liquefied natural gas
MS	member state
MV	market value of the electricity
NECP	National Energy and Climate Plans
NRA	national regulatory authority
OTC	over the counter
PHS	pumped hydropower
PPA	power purchasing agreement
PV	photovoltaic
REDII	REDII Renewable Energy Directive recast
RES	renewable energy sources
RES-E	renewable energy sources - electricity
SME	small and medium-sized enterprise
TSO	transmission system operator
VPPA	virtual power purchasing agreement
VRE	Variable Renewable Energy
FE	final energy
PE	primary energy

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