European energy reform

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# Briefing paper prepared for the Oxera Economics Council

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# 1 Introduction

This briefing paper has been prepared for the forthcoming meeting of the Oxera Economics Council (OEC) which will focus on the topic of **European energy reform**.[1] The central aim of the paper is to provide the necessary context and background information necessary to facilitate a discussion on the policy priorities for the reform of European energy policy.

After providing an overview of the key policy priorities and the recent events influencing current energy policy debates, the paper discusses three thematic 'deep dives'.

This briefing paper is therefore structured as follows.

- Section 2 provides an overview of the European energy transition requirements, touching on the recent energy crisis and some of the key emergency measures adopted in Europe. It then discusses the main **market failures** in the energy sector, outlining the policy tools available to address them.
- Section 3 discusses the **electricity sector challenges**, specifically those relating to the integration of large amounts of intermittent renewable generation while phasing out thermal generation using fossil fuels.
- Section 4 covers the **gas sector challenges**, specifically the phasing out of natural gas and the transition to low-carbon gases and hydrogen in particular.
- Section 5 discusses the **infrastructure financing challenges** of funding large scale, capital intensive technologies, e.g. nuclear power and carbon capture and storage (CCS). Such technologies may be necessary for decarbonisation, and perhaps even desirable from a social welfare perspective. However, their value is not fully reflected in market prices.
- Section 6 includes some **overarching themes and questions to focus the discussion** with the OEC and other invited guests.

[1] The meeting is scheduled for 15 November, 12:00 to 16:00 CET, and will take place at *Comet Meetings – Louise, Stefaniaplein 20, Brussels*. Attendance is by invitation only and will comprise the members of the OEC, Oxera representatives and selected other guests.

# 2 Decarbonisation, the energy crisis, and the energy transition

This section provides an overview of the European energy transition requirements, touching on the recent energy crisis and some of the key emergency measures adopted in Europe. The main market failures and the main policy tools available to address them are summarised below.

## 2.1 Decarbonisation and net zero

At the time of signing the 2015 Paris Agreement, many governments across the world committed to ensure that global warming remains limited to between 1.5 and 2 degrees above pre-industrial levels.[2] The then 28 member states of the European Union committed to achieving greenhouse gas emission reductions[3] of 40% (relative to 1990 levels) by 2030.[4] Since then, both the UK[5] and the EU[6] have committed in legislation to achieving net zero carbon emissions by 2050—that is, the effective elimination of carbon emissions.

As regards the current 27 member states (i.e., excluding the UK), the European Parliament recently approved targets requiring at least a 55% reduction in emissions by 2030[7] and an increase in the share of renewable energy to at least 42.5%, with an additional indicative aim to collectively reach 45%.[8] The corresponding interim emission reduction targets for the UK is 59% by 2030.[9]

Emissions are 'net zero' so long as any remaining gross emissions are fully offset by carbon sinks, either natural or 'engineered'. Reaching net

[2] United Nations Climate Change, 'Nationally Determined Contributions (NDCs)' (accessed 5 November 2020).
[3] Greenhouse gas emissions refer to several different gasses with significant global warming potentials, but are principally focussed on carbon dioxide. Hereafter the terms 'CO2', 'carbon emissions', or simply 'emissions' are used to refer to greenhouse gasses and their carbon dioxide equivalents collectively, unless otherwise specified.
[4] https://www4.unfccc.int/sites/submissions/INDC/Published%20Documents/Latvia/1/LV-03-06-EU%20INDC.pdf (accessed 5 November 2020).
[5] Department for Business, Energy & Industrial Strategy (2019), 'UK becomes first major economy to pass net zero emissions law', 27 June.
[6] European Parliament, the Council (2021), 'REGULATION (EU) 2021/1119 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 30 June 2021 establishing the framework for achieving climate neutrality and amending Regulations (EC) No 401/2009 and (EU) 2018/1999 ('European Climate Law')', July.
[7] European Commission, '2030 climate & energy framework' (accessed 31 October 2023).
[8] Council of the European Union, 'Renewable energy: Council adopts new rules', Press release, 9 October 2023. Official Journal of the European Union (2023), 'DIRECTIVE (EU) 2023/2413 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 18 October 2023 amending Directive (EU) 2018/2001, Regulation (EU) 2018/1999 and Directive 98/70/EC as regards the promotion of energy from renewable sources, and repealing Council Directive (EU) 2015/652', 31 October.
[9] Based on the average annual emission target for the UK's Sixth Carbon Budget (2028-32). See Climate Change Committee (2020), 'Sixth Carbon Budget', 9 December.

zero will require significant reforms in each sector to minimise carbon emissions wherever possible and funding offsets where the complete elimination of carbon emissions is not feasible. Significant progress in decarbonisation has already been made across the EU and the UK. For example, the most recent evidence available suggests that net carbon emissions across the EU-27 and the UK will be 32.5% (for 2022) and 42.8% (by the end of 2023) below 1990 levels, respectively.[10] While these targets are based on emissions from *production* of goods and services, it is important to note that including the emissions embedded in goods and services *consumed* in the EU-27 and the UK result in total emissions being, respectively, around 23% and 43% higher still.[11]

In addition to the challenges of decarbonisation, European economies have recently been greatly affected by the energy crisis triggered by the invasion of Ukraine in February 2022 and the associated reduction in the availability of Russian pipeline gas. The resulting uncertainty, both in the short and long term is, among other things, related to:

- the availability of Russian pipeline gas supplies;[12]
- the supply–demand balance in the liquified natural gas (LNG) market;
- the pace of fossil fuel demand reduction driven by energy efficiency measures; and
- the transition to renewable and low-carbon energy sources more generally.

These factors motivated a large number of short-term market interventions to reduce energy prices. Given that the member states themselves were frequently responsible for the design and (rapid) implementation of these measures as well as the risk of insufficient policy coordination suggests that the overall impact of of these measures is uncertain.

The current European energy market design, broadly defined,[13] has proved itself to be resilient insofar as market prices for electricity and gas have reflected the scarcity of energy. That said, concerns were

[10] European Commission (2023), 'EU Climate Action Progress Report 2023', 24 October; Climate Change Committee (2020), 'Sixth Carbon Budget', 9 December.
[11] Our World in Data, based on 2020 data.
[12] And Europe's demand for Russian gas after the end of the conflict.
[13] For the purposes of this briefing paper the term 'energy market design' encompasses the market arrangements and regulations pertaining to carbon, electricity, gas, and hydrogen as well as other policies and measures directed at facilitating investment in energy infrastructure.

raised over market manipulation, especially in the gas sector,[14] and the number of REMIT decisions with sanctions did increase significantly during 2022.[15] Nevertheless, the evidence available on the functioning of the main European gas hub, the Title Transfer Facility (TTF), showed that this market remained resilient and liquid, with prices and price differentials with neighbouring hubs reflecting the scarcity of gas as well cross border capacity constraints (e.g. pipelines and LNG import capacity).[16]

However, given the extent of emergency measures implemented by member states enabled by the European Commission's framework for emergency interventions,[17] it is clear that concerns over the tensions between the future security of energy supplies, the net zero target, and the reliance on short-term (i.e., 'spot') markets are still not fully resolved.

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## 2.2 Energy crisis measures

Coinciding with the lifting of COVID-19 restrictions in the second half of 2021, wholesale gas and electricity prices began to rise. The upward pressure on energy prices was even more pronounced following the start of the war in Ukraine and in light of a tight gas market. Price movements in this period are shown in Figure 2.1 below.

In fact, wholesale gas prices reached unprecedented levels in 2022 and this quickly translated into higher electricity prices. Gas generators are usually the marginal technology and therefore these plants have a strong influence on market prices across Europe.[18] High prices on electricity wholesale markets resulted in higher retail prices, raising urgent concerns over the impact these would have on consumers.

[14] See for example Financial Times (2021), 'Gazprom's low gas storage levels fuel questions over Russia's supply to Europe', 27 October.
[15] See ACER REMIT quarterly reports for Q3 2023, Q4 2022, and Q4 2021.
[16] Oxera (2022), 'The European gas market", 13 December, pp. 25-34.
[17] See for example European Commission (2022), 'Proposal for a Council Regulation on an Emergency Intervention to Address High Energy Prices', 9 September.
[18] For more details on the link between gas and electricity markets, and the so-called system marginal price mechanism, see for example Oxera (2022), 'Stepping on the gas: European emergency measures to deal with high energy prices', Agenda, November.

Figure 2.1 European gas prices (TTF front-month) Q1 2021–Q3 2022 (€/MWh)


Source: Bloomberg.

As a result of the high gas prices, one of the crisis measures adopted at the end of 2022 was the market correction mechanism (MCM) as highlighted in Figure 2.2 below. The MCM effectively established a price cap on TTF futures, but has since been extended to also apply to prices on other hubs. A number of risks were identified with the MCM, but the impact of this measure has so far been limited largely because the level of the price cap has been set at a very high level (currently €180/MWh), thereby ensuring that it would only be triggered infrequently.[19] Since coming into effect on 15 February 2023, EU gas prices have reduced to levels seen in early 2022 and this has meant that the perceived risk of the MCM being triggered has remained low.

Nevertheless, in general, applying price caps in competitive markets can increase the risks of adverse unintended consequences.[20] The first of these is that price caps could lead to a reduction in supply, which in the event of a tight gas market could undermine the ability of the market to attract the supply necessary to meet demand. This would pose risks to the continuity of supply, potentially resulting in a lower overall 'buyer

[19] Oxera (2022), 'The European gas market", 13 December, pp. 3-5, 58-63.
[20] Bulow, J. and P. Klemperer (2012), 'Regulated prices, rent seeking, and consumer surplus', Journal of Political Economy, v120(1), February.

surplus' (analogous to a consumer surplus, but recognising that the buyers may not be the end consumer of gas).[21]

In addition, price caps result in a windfalls to existing buyers (or users) that have contracted supplies in advance, and this would result in a lower overall buyers surplus since it won't necessarily be the buyers with the highest willingness to pay that would be able to access the remaining supply.

Furthermore, the difference between the market price and the level of the price cap may induce buyers to spend resources (i.e. time, money) to procure supplies through other means, potentially also leading to transactions at or above the prevailing market price in venues or settings where the relevant authorities are not able to enforce the price cap. In the case of the MCM, this risk could be manifested as transactions not taking place on the main gas exchanges (e.g. ICE) but instead migrating to other trading venues (e.g. over-the-counter, OTC) or perhaps taking place outside the EU altogether. In turn this could result in less liquid trading on the main gas exchanges and thereby increase the costs to consumers long-term. In any event, the additional costs imposed on buyers seeking to work around the price cap could further reduce the overall buyer surplus.

### 2.2.1 Policy interventions and the 'missing money' problem

In order to mitigate price increases and minimise detrimental effects on consumers, European countries adopted a large number of different measures—the European Union Agency for the Cooperation of Energy Regulators (ACER) counted a total of 439 measures implemented by EU member states between July 2021 and February 2023.[22] Overall, there has been limited coordination between member states, especially in the early stages of the crisis. This therefore led the European Commission to issue several guidelines and proposals, with a view to establishing a 'common' response to the crisis, given that the European energy market is already highly interconnected.

The measures adopted to ease price pressures can be classified into four broad categories: retail market interventions, wholesale market

[21] The design of the MCM did take this risk in to account by specifying that the, say, the TTF price would be higher than a reference price tied to LNG cargoes, the presumed marginal source of supply.
[22] ACER (2023), 'ACER's inventory of 400+ energy emergency measures seeks to aid policy makers going forward', 20 March (accessed 28 October 2023). ACER (2023), 'Assessment of emergency measures in electricity markets', July.

interventions, security of supply interventions and energy consumption reduction. Some examples are provided in the figure below.[23]

### Figure 2.2 Examples of emergency measures

| Examples of emergency measures adopted by European countries | | | |
|---|---|---|---|
| **Retail market interventions** | **Wholesale market interventions** | **Security of supply interventions** | **Energy demand reduction** |
| **Direct (cash) support**<br>• a €300 lump-sum payment as part of September pay cheque in Germany<br>• a cash transfer to low income households and pensioners in Portugal<br>**Removal of various surcharges and levies**<br>• removal of the renewables surcharge in Germany<br>• removal of '*oneri generali di sistema*' in Italy<br>**Retail price caps**<br>• the Energy Price Guarantee in the UK<br>• a price cap for domestic clients, SMEs and industrial users in Germany | **Gas markets**<br>• cap on wholesale gas prices, the so-called Market Correction Mechanism (MCM) introduced at the EU level<br>**Electricity markets**<br>• inframarginal revenue cap, introduced at the EU level and in different European countries<br>• cap for gas used in electricity generation in Spain and Portugal | **Diversification of gas supplies**<br>• new contracts with exporting countries<br>• expansion of regasification capacity<br>**Gas storage filling**<br>• EU filling target of 80% for 2022 and 90% for subsequent years<br>**Fuel switching measures**<br>• postponement of nuclear and coal phase-out plans in Germany<br>• 'maximisation' of power production from coal plants in Italy | **Short-run measures**<br>• temperature limits in buildings in Spain and Italy<br>• awareness campaigns<br>• Sobriety Plan in France<br>**Long-run measures**<br>• subsidies for energy efficiency, renewables and low-carbon technologies<br>• ban on fossil fuel boilers from 2026 in the Netherlands<br>• more funds to the existing subsidy programme for energy efficiency renovations in France |

Notes: SMEs stands for Small and Medium Enterprises.
Source: Oxera.

During the crisis, the measures were mostly targeted at short-term 'fixes' applicable to market mechanisms that were thought not to be serving consumers' interests. Alongside this there were the targets and measures introduced as part of the REPowerEU plan to increase the targeted share of renewable energy in consumption across a wider set of sectors.[24]

In general, all emergency measures imply some trade-offs: short, medium and long-term objectives are unlikely to be perfectly aligned, and a careful balance between security of supply, affordability and

[23] For a more detailed discussion see also Oxera (2022), 'Stepping on the gas: European emergency measures to deal with high energy prices', Agenda, November.
[24] European Commission (2022), 'COM(2022) 230 final', REPowerEU Plan, May. Other initiatives adopted as part of the REPowerEU plan included (i) the introduction of dedicated REPowerEU chapters in recovery and resilience plans, (ii) the EU Solar Strategy, aiming at doubling solar photovoltaic capacity by 2025 and installing 600GW by 2030, (iii) the Solar Rooftop Initiative and (iv) a recommendation on permitting procedures and power purchase agreements.

energy transition needs to be found. This is challenging at the best of times, and even more so during a rapidly unfolding crisis.

Based on a recent assessment from ACER,[25] on balance, the emergency measures adopted by member states contributed to the affordability of electricity for end consumers, while some member states' interventions undermined their long-term policy objectives (e.g. completing the energy transition and increasing market integration). Notable examples include **fuel switching measures**—for example, delaying coal phase outs and restarting coal and lignite plants—that contributed to lower gas use and increased emissions. Other measures can also have broader and longer-term effects. For example, the **construction of new gas infrastructures**, in particular new regasification terminals, or signing new long-term gas contracts, may result in a risk of greater 'lock-in' to gas, risking further delaying the energy transition in future. Moreover, should gas demand decrease in line with the latest decarbonisation projections, there is also a risk of stranded or underutilised assets.

On balance, the emergency measures contributed to the affordability of electricity for end consumers, but some undermined long-term policy objectives.

ACER also found that, in the short-term, the lack of policy coordination on emergency measures affected cross-border trade and increased price divergence. This was for example the case of the **Iberian price cap on gas used in electricity generation**. The mechanism was introduced in June 2022 in Spain and Portugal, whereby gas-fired generators received a subsidy to cover the difference between the cap and wholesale gas prices (but without an accompanying cap on generators' electricity market offers).[26] This measure was originally planned to apply for one year, but has since been extended to the end of 2023.[27]

The main objective of the Iberian price cap was to reduce retail electricity prices by lowering the effective fuel costs of the marginal electricity generation technology, thereby reducing inframarginal rents. In turn, this would avoided the need for other measures to redistribute generators' 'windfall' profits to consumers and/or support payments for vulnerable customers.

However, price caps may also increase exports to neighbouring countries as they put downward pressure of prices in one market area and thereby increase the price differentials with neighbouring market

[25] ACER (2023), 'Assessment of emergency measures in electricity markets', July.
[26] European Commission (2022), 'State aid: Commission approves Spanish and Portuguese measure to lower electricity prices amid energy crisis', 22 June.
[27] European Commission (2023), 'State aid: Commission approves prolonged and amended Spanish and Portuguese measure to lower electricity prices amid energy crisis', April.

areas. Indeed, these effects have been reported in the case of Spain.[28] In particular, electricity flows from Spain to France increased by around 316% between June and December 2022 compared to average flows in the same months over the period 2017-21, according to ACER's assessment.[29,30]

A further risk associated with the implementation of measures such as the Iberian price cap is the risk of inadvertently increasing windfall profits for generators whose gas purchases and/or electricity sales were hedged prior to the start of the crisis. A variety of hedging instruments are available, and it is very challenging for policy makers to account for all permutations of hedging strategies in the design of market interventions targeted at achieving 'acceptable' market prices. There remains a risk that some generators may be paid an unnecessary subsidy.

Beyond the Iberian price cap, there were many other examples across the EU of member states implementing **inframarginal revenue caps** whose objectives were to limit windfall profits resulting from higher wholesale electricity prices. These revenue caps were often applied to inframarginal generators such as coal, nuclear, solar and wind plants that are typically not price setting. The intention was therefore to limit the unexpected profits that would otherwise have been received during the crisis while also not interfering with the price formation in wholesale markets. As already mentioned, wholesale electricity prices are frequently dominated by the offers of gas-fired power plants that reflect the variability of the price of their fuel inputs. As it happens, a significant share of inframarginal plants continue to be subsidised, and so these measures also had the benefit, from the perspective of member states' governments, of reducing their subsidy payments in some cases.

While recognising that the precise form of price or revenue caps will strongly impact the overall costs and benefits of these measures, and that the prevailing market price level matters, a general problem associated with these and other interventions is that they increase the

[28] See for example Centre for Economic Policy Research (2022), 'The Iberian electricity market intervention does not work for Europe', VoxEU, 29 August.
[29] ACER (2023), 'Assessment of emergency measures in electricity markets', July, section 6.3.
[30] During 2022 the availability of the French nuclear fleet was also adversely affected by, for example, maintenance outages and operating limitations related to higher river temperatures. These contributed to lower nuclear power output during this period and, alongside the conditions in the Iberian gas market, were likely to have exaggerated the reported increase in cross-border flows from Spain to France attributed to the Iberian price cap mechanism alone. See Clean Air Task Force (2023), 'The 2022 French nuclear outages: Lessons for nuclear energy in Europe', 24 July.

risk of **'missing money'** (or the expectation of missing money). This term refers to the existence of a gap between market prices and the long- and short-run costs of energy production.

In an efficient commodity market that is sufficiently liquid and competitive, prices would reflect the costs of investment and operation of the production capacities needed to ensure reliable, flexible, and 'green' energy supplies. To achieve this, it is necessary to have spot prices that are sufficiently differentiated across time and space to reflect the demand and supply of energy as well as the external costs of incremental carbon emissions. Volatile prices across different time frames (e.g. hours, days, months, and years) and market areas thereby signal the need for different types of resources (i.e. power plants, storage, and demand side flexibility) required to deliver the right amount of energy at the lowest cost, reliably, and flexibly.

Missing money can arise for a variety of reasons including:[31]

- interventions by policy makers designed to reduce high or volatile prices (as discussed above);[32]
- inefficient market design and implementation caused by poorly defined property rights (e.g. network access rights), missing markets (e.g. lack of markets for short-term flexibility or balancing, poor liquidity in forward markets for hedging and risk management), and lack of policy coordination between adjacent market areas;
- absence of retail market offers that apply 'time of use' (or 'dynamic') tariffs and which could otherwise encourage demand-side flexibility;
- subsidies and other 'out of market' transactions that interfere with price formation by enabling, for example, capacity expansion that is not aligned with demand.[33]

[31] While these examples of missing money are focussed on wholesale energy markets, the problem of missing money can also apply to other commodity markets as discussed in section 2.3.4.
[32] Price volatility and price spikes in energy markets, and especially in electricity markets where the costs of electrical storage are significant, are essential to allow capital intensive production facilities with large sunk costs but low variable costs to recover their investments plus a reasonable return on invested capital. The frequency and magnitude of price spikes also influence the expectations of future prices, thereby allowing producers to hedge their risks using forward contracts. It follows that interventions which reduce prices and price volatility will also make forward markets less efficient.
[33] Policy makers' interventions in electricity and other energy markets are often driven by the desire to ensure, for example, a high level of security of supply and to minimise the impact on market prices. To the extent that the impact on missing money of policy interventions is not taken into account, this would increase inefficient market outcomes.

Seen in this light, price and revenue caps, amongst other interventions, can have a variety of unintended longer-term effects that adversely impact on market efficiency. In particular, if governments are expected to intervene to cap prices when these increase above a certain level or when they become too volatile, this can disincentivise investment, resulting in a 'vicious circle' of further policy interventions, subsidisation, and regulatory failure.

Alongside market interventions aimed at producers, **retail price caps** were also used by member states to limit the impact of gas and electricity price increases on consumers.[34] For example, in Germany retail electricity prices for consumers, small and medium enterprises as well as industrial users were subject to a cap that applied to a share of consumption related to customers' historical demand levels.[35] This mechanism sought to strike a balance between the competing objectives of limiting the impact of higher prices on customers while retaining incentives to reduce demand 'at the margin' as a consequence of higher retail prices experienced during the crisis.

### 2.2.2 A longer-term perspective post-crisis

While most of the measures introduced during the crisis where targeted at the short/medium-term, this also opened up a broader discussion on longer-term reforms. In particular, additional interventions are currently under discussion and have been put forward as part of the Commission's proposals for reform of the electricity market design.[36]

Proposed reforms seem targeted at introducing 'bolt on' measures in response to the specific challenges without necessarily integrating them fully into the existing market framework.

Overall, the proposed reforms to the electricity market design—such as mandating the use of specific support schemes (CfDs) for renewables or the introduction of a low-carbon flexible capacity incentive (some of which are discussed in more detail in the following sections)—seem targeted at introducing 'bolt on' measures in response to the specific challenges without necessarily integrating them fully into the existing market framework.

At the same time, there appears to be a tendency towards a lower reliance on market signals, with a greater role played by subsidies and state-backed mechanisms. However, at the moment, the ability of the current market design to deliver the decarbonisation objective while

[34] Retail price caps were in many European countries (including UK) in place long before the energy crisis.
[35] Bundesregierung (2022), 'Energy price brakes are entering into effect', 24 December.
[36] European Commission (2023), 'Commission Staff Working Document Reform of Electricity Market Design. SWD(2023) 58 final', 14 March. See also Oxera (2023), 'Electricity market design reform—schemes for low-carbon generation', July.

ensuring security of supply and affordable prices for consumers seems not to have been assessed comprehensively.

### 2.3 Policy objectives, market failures and policy instruments

As set out in sections 2.1 and 2.2, any future programme of European energy reform would need to take account of multiple policy objectives, market failures, and other challenges.

First among these is the objective of reducing carbon emissions and completing the energy transition. The latest evidence from the IPCC has highlighted the scale of the challenges of climate change and the widespread changes already observed in Earth's atmosphere, oceans, and biosphere caused by anthropogenic emissions since the start of the industrial revolution.[37]

Another key policy objective of European energy reform would be to ensure reliable and affordable energy supplies to enable European economies to continue to grow and to meet the needs of their citizens.

Taken together, these objectives highlight that EU energy reform is primarily directed at incentivising investment and scaling up renewable and low-carbon technologies while also phasing out existing technologies that are incompatible with net zero and ensuring energy efficiency. To get a sense of the scale of this challenge, and as discussed further in section 5, the estimated cumulative European investments in electricity generation, renewable hydrogen, and network in the period 2021–2050 could be in the region of €2.8–5.6 trillion.

The EU energy reform is directed at incentivising investment and scaling up renewable and low-carbon technologies, while also phasing out existing technologies that are incompatible with net zero.

There are broadly four classes of policy instruments that are targeted at the net zero challenge: carbon pricing, emission performance standards, investment subsidies, and research and innovation funding.[38] These are discussed in turn below.

[37] IPCC (2023), 'Climate change 2023 synthesis report: Summary for policymakers', 20 March.
[38] Sector-specific market failures and other challenges are discussed in sections 3, 4, and 5 covering transitions in electricity, gas, and low-carbon infrastructure, respectively.

### 2.3.1 Carbon pricing

Carbon pricing policies often take the form of a cap-and-trade mechanism ('carbon trading') or carbon taxes, and both are used extensively in the EU.[39]

The **EU ETS** is a cap-and-trade system where policymakers set a limit (or 'cap') on the emissions that can be made each year by the sectors or companies covered by the mechanism, and reducing that cap over time ensures that emissions overall also reduce. Within the cap, EU emission allowances (EUAs) are allocated directly to qualifying facilities or by auction, and the EUA price (i.e. the carbon price) is directly related to the scarcity of EUAs issued relative to companies' expected emissions in a given compliance period. Given that the ultimate goal of net zero is to limit the quantity of emissions, a cap-and-trade system can be argued to be better targeted than a carbon tax.

In contrast, a **carbon tax** does not regulate the quantity of emissions directly, but rather applies an administratively determined charge per unit of emissions. The effectiveness and efficiency of carbon taxes in reducing emissions therefore depend crucially on the carbon tax rates used, how well targeted they are to particular sectors, how responsive they are to the changing market conditions, and how consistently and widely they are applied. In particular, if carbon taxes vary greatly between countries where cross-border trade in goods and services is possible, then the problem of 'carbon leakage' would be expected to be more severe since firms could more readily transfer their production to neighbouring countries with lower carbon tax rates.[40]

Carbon taxes are currently used by at least 20 European countries, with 'headline' carbon tax rates ranging from around 2–115 €/tCO2.[41] These are levied on different greenhouse gases, such as carbon dioxide, methane, nitrous oxide, and fluorinated gases, and the scope of each country's carbon tax often differs from others, resulting in varying shares of greenhouse gas emissions covered by the tax. Countries often apply multiple excise taxes to sources of carbon emissions at different implicit or explicit tax rates. It is important to note that after accounting for exemptions and coverage restrictions the average emissions-

[39] This section does not consider the role of voluntary carbon markets in carbon pricing, though it is recognised that as these markets mature they may also be integrated or linked with other carbon trading platforms.
[40] A recent study in the Netherlands founds that a significant minority (c.34%) of industrial sectors (NACE-4) would face some material risk of intra-EU carbon leakage from the introduction of a national carbon pricing measure (e.g. a carbon tax or fuel excise tax). Trinomics (2022) 'Risk of carbon leakage in Dutch non-ETS sectors', 14 April.
[41] https://taxfoundation.org/data/all/eu/carbon-taxes-in-europe-2023/

weighted carbon price can be significantly lower (by anything up to 70%) than the headline carbon tax rate.[42]

In comparison, under the EU ETS, carbon is currently trading at around 80–90 €/tCO2e and provides a single price per tonne of CO2 equivalents that is applied uniformly across the sectors covered by the scheme throughout the EU.[43] Carbon trading thereby provides a consistent price signal that can, for example, enable investment in renewable or low-carbon technologies, incentivise fuel switching in the production of electricity, and incentivise energy efficiency improvements with less risk of carbon leakage.[44] Carbon trading also enables carbon emission reductions to be achieved at the lowest overall cost since EUAs can be traded in liquid and competitive markets.[45]

The economic properties of these carbon pricing policies also differ in some other important respects, as follows.

First, given that carbon trading is a quantity mechanism and a carbon tax is a price mechanism, their relative effectiveness and efficiency will be affected differently by uncertainty over the level of emissions and the cost of emission reduction measures in the counterfactual scenario. For example, given that carbon prices adjust to clear the market for emission allowances in a carbon trading mechanism, it follows that if the quantity of emission allowances available is high (low) relative to counterfactual emissions in future compliance periods then carbon prices could be much lower (higher) than expected. Alternatively, in the presence of a carbon tax it is the quantity of emission reductions that adjusts as the costs of emission reduction measures change. Consequently, for a given carbon tax rate, if the cost of emission reductions increases (decreases) then the quantity of emission reductions would be lower (higher) than expected.

In a carbon trading mechanism, carbon prices adjust to clear the market for emission allowances. For a carbon tax, it is the quantity of emission reductions that varies as the costs of emission reduction measures change.

Second, and relatedly, the revenues that are raised by either a carbon trading or carbon tax mechanism would also be affected by the level of uncertainty in future periods. The elasticity of carbon abatement costs

[42] Rafaty, R. et al (2020), 'Carbon pricing and the elasticity of CO2 emissions', 30 November.
[43] Price based on the EUA December 2023 futures contract traded on ICE. Note that EUAs are traded on multiple platforms and there are, strictly, a variety of different carbon prices depending on the precise instrument or contract being traded and the trading venue used, e.g. futures can be traded bilaterally, over-the-counter (OTC), or on an exchange. However, the prices for specific contracts generally trade within a narrow range across platforms due to the level of overall market liquidity.
[44] The risk of carbon leakage is greater for those sectors and industries that are exposed to competition from outside the EU, such as the production of aluminium, steel, and a variety of other industrial products such as basic chemicals and some motor vehicles. To mitigate this risk the EU is introducing a carbon border adjustment mechanism (CBAM) that would seek to adjust of differences in carbon prices in third countries relative to the EU ETS.
[45] Oxera (2021), 'Carbon trading in the European Union', February.

with respect to carbon emission reductions is therefore a critical parameter to consider when assessing the merits of either mechanism.[46] Finally, and notwithstanding their benefits in terms of providing a basis for carbon pricing, both the EU ETS and carbon taxes (as typically implemented in the EU member states and described above) may be limited in their ability to incentivise investment in new green technologies since they may provide investors with a somehow limited degree of revenue certainty. In the ETS case, the carbon price is affected by macroeconomic shocks and other energy transition policies (e.g. renewable energy subsidies) that would reduce electricity sector emissions that are an important driver of EUA demand. The introduction of carbon contracts for differences would be one way to address this limitation. In the case of carbon taxes, revenue certainty for investors in green technologies could also be improved by imposing greater obligations on member states to reduce emissions in sectors covered by the Effort Sharing Regulation using harmonised carbon pricing policies.

### 2.3.2 Emission performance standards

Alongside carbon pricing, another class of mechanisms targeted at the reduction of carbon emissions in the energy sector are emission performance standards (EPSs). Typically these measures require qualifying installations to comply with emission intensity limits per unit of output (e.g. expressed in grammes of $CO_2$ per kWh). Alternatively, emission performance standards can be implemented as minimum requirements that can be used as qualifying criteria for inclusion in other incentive schemes.

Examples of these schemes in the UK and/or EU include:

- an emission intensity limit for coal fired power plants combined with an obligation to shut down those plants that exceed the limit after a certain date;
- an emission intensity limit for coal fired power plants which, if exceeded, would disqualify plants from receiving support under a capacity remuneration mechanism if the annual emissions also exceeded a given threshold (with the effect of limiting their operating hours);
- an emission intensity limit requirement applicable to combined heat and power plants to qualify as 'efficient' and that, if met,

[46] More generally, it has been shown that under uncertainty the expected efficiency of price and quantity mechanisms depends on the relative slopes of the marginal benefit and marginal cost functions. See Weitzman, M. (1974), 'Prices vs. quantities', Review of Economic Studies, v41(4), October, pp. 447-491.

would allow such plants to qualify for other incentives or funding; and

- a proposed emission intensity limit, expressed as a share of gas volumes, applicable to methane leaks from upstream natural gas pipelines, storage, and LNG terminals which, if exceeded, would be subject to a surcharge.

The key feature of emission performance standards is that they impose a 'burden' on energy production facilities with higher emissions, thereby also providing an implicit subsidy for greener, less emission intensive facilities. However, emission performance standards do not necessarily provide an incentive that is directly proportional to the resulting emissions created or avoided. Also, emissions performance standards generally do not raise significant revenue for authorities since there often are not any surcharges or taxes applied directly to those plants with the higher emissions.

EPSs impose a 'burden' on energy production facilities with higher emissions, also providing an implicit subsidy for greener facilities. However, their incentive is not necessarily directly proportional to the resulting emissions created or avoided.

### 2.3.3 Subsidies

Green energy subsidies are frequently deployed across the EU. Subsidies to renewable energy sources are particularly widespread and are tied to renewable energy targets, expressed as a percentage of energy consumption, agreed at EU level that are binding on individual member states. Subsidies are also used extensively outside the EU, and the recent introduction of the US Inflation Reduction Act has highlighted some of the challenges of 'competing' subsidy regimes in the energy sector (see Annex 1).

While a growing share of renewable energy sources consumed can obviously help to reduce carbon emissions, subsidies for renewable energy technologies are also closely tied to the objective of reducing their costs that result from greater deployment, 'learning effects', and technical innovation. Indeed, the EU has become a leader in renewable energy markets globally, indicating that investment in this sector is also part of a deliberate industrial strategy.[47] Equally, renewable energy subsidies represent a large share of total state aid in the EU.

In the last 20 years EU member states (including the UK) have gained significant experience of deploying a variety of subsidy mechanisms for renewable and low-carbon energy producers and generators, including the following.

[47] European Commission (2021), 'EU's global leadership in renewables', July.

**Power purchase agreements (PPAs)**—these agreements are typically bilateral long-term contracts between a generator and an off-taker, which can include governments or other state-owned entities acting as a 'single buyer'. PPAs are often stand-alone contracts (and not part of a wider scheme) and as such can be tailored (e.g. pricing, grid access, availability) to the specific requirements of a particular plant or project. The administrative costs of negotiating these contracts have generally limited their application to larger plants and to regions where markets are not fully liberalised and where markets are not competitive.

**Feed-in tariffs (FITs) and feed-in premia (FIP)**—FITs have typically been used to provide subsidies to renewable energy producers and they are generally tailored to the particular technologies rather than individual installations. Such schemes are generally underpinned by legislation where the responsibility for setting and updating tariffs rests with an appointed public authority. In the case of FIPs, the authority set the premium to be paid on top of the revenues from energy sales.

The ability of these schemes to attract new investment relies heavily on the level of tariffs that apply to individual technologies, the ability to secure grid connections and other permits, and the perceived level of commitment to renewable energy expansion and the affordability of the scheme from the perspective of government.

**Renewable energy obligations with 'green' certificates**—certificate schemes are quantity mechanisms that require governments to establish obligations on retailers and other end customers to purchase a certain quantity of certificates (often expressed as a share of their demand) from renewable energy producers who are issued with certificates in proportion to their output.

The ability to trade certificates (and to hold certificates for use in future compliance periods) then results in a market price which provides an additional source of revenue to generators from the sale of certificates that is additional to the sale of energy. The ability of these schemes to attract new investment relies primarily on the expected market price of certificates and the downside risks to future energy prices that can arise from fuel price volatility or sudden changes to energy policies.

**Hybrid certificate schemes**—these schemes are a variant of the certificate schemes mentioned above, which also allow retailers (those with the obligation to purchase certificates) to avoid having to purchase certificates exclusively from the renewable energy producers. Instead, under these hybrid schemes the retailers are allowed to make a 'buyout' payment (whose level is set by a public authority) in lieu of acquiring a certificate. This has the effect of limiting the exposure of retailers to a high certificate price, while those retailers that hold certificates can receive a 'dividend' through annual distributions from the buyout fund.

**Contracts-for-differences (CFDs)**—these schemes can be seen as variants of the FIP schemes mentioned above, but which adjust the 'premium' to offset the volatility in energy prices such that the total per unit revenue received by the generator is aligned with the costs of energy production. Specifically, a (two-way) CfD is a long-term contract that defines a 'strike price' (expressed in €/MWh) that the generator is entitled to earn for each MWh produced. If the specified 'reference price' (e.g. the spot market price) is below the strike price, the generator receives the difference (i.e. the premium). Conversely, if the reference price is below the strike price, the generator pays back the difference (i.e. it receives a negative premium).

The ability of CfD schemes to attract new investment relies heavily on the level of the strike price that apply to individual plants,[48] the perceived level of commitment to renewable energy expansion and the affordability of the scheme from the perspective of government.

The effectiveness and efficiency of the different mechanisms described above have, in practice, differed greatly. The varied experiences of energy producers, consumers, and governments has to a large degree been driven by the different levels of experience and capability on the part of the governments and authorities implementing them. Over time, this has improved. Importantly, the widespread use of competitive tenders for the allocation of subsidies has greatly improved the effectiveness and efficiency of these mechanisms.

> The widespread use of competitive tenders for the allocation of subsidies has greatly improved the effectiveness and efficiency of CfDs.

### 2.3.4 Research and innovation funding

Alongside deployment of renewable energy technologies, it is widely recognised that funding research and innovation are key to realising productivity gains in the energy sector and thereby meeting the net zero 2050 target at lowest cost.

For example, electricity sector emissions are a key driver of the EU ETS price in part because annual increases in the share of renewable generation lead to lower expected demand for EUAs. Also, generators

[48] CfDs as a renewable energy subsidy mechanism were introduced in the 2010s in Great Britain and these took the form of private-law contracts that were mainly allocated through competitive tenders. Since then CfDs have become widely used in the EU.

are able to switch fuels (e.g. between coal and gas-fired power plants) in response to commodity prices. This can materially affect volatility in carbon prices. Furthermore, future trends in carbon prices are also likely to reflect the long run marginal costs of, say, green hydrogen to the extent it is expected to be the marginal technology necessary to complete the energy transition and to enable, for example: the production of 'green' steel (via production of Direct Reduced Iron); green fertilisers (via production of green ammonia); and the development of seasonal hydrogen storage to allow very high penetration of intermittent renewable electricity, principally solar and wind.

Consider the perspective of a European steel producer that is contemplating multi-annual investments in green steel technology in the 2030s once the EU's carbon border adjustment mechanism (CBAM) is established.

The costs that will be sunk in the process and the expectation of increased unit production costs mean that the investment would only be viable if the expected discounted sum of future avoided EUA purchases by the steel producer are at the level of the expected present value of its incremental costs.[49] In principle, and subject to expectations of long-term continuity and stability in EU ETS policies, carbon prices should over time rise to the levels necessary to incentivise such transformational investments.

Furthermore, it follows that to the extent research and development (R&D) funding and other subsidies (such as those discussed in section 2.3.3) are able to offset the costs that would otherwise need to be recovered via higher ETS prices, then carbon prices would in principle be lower and this would be to the benefit of consumers.

[49] The incremental costs would include the steel producer's investment programme plus any unrecovered operating costs that would depend on expectations of future market conditions and price formation in the steel market.

# 3 Electricity sector transition challenges

The electricity sector faces the so-called ‘**energy trilemma**’, as a balance between multiple, and often conflicting, objectives is required to meet a multiplicity of policy objectives. The three key dimensions are:

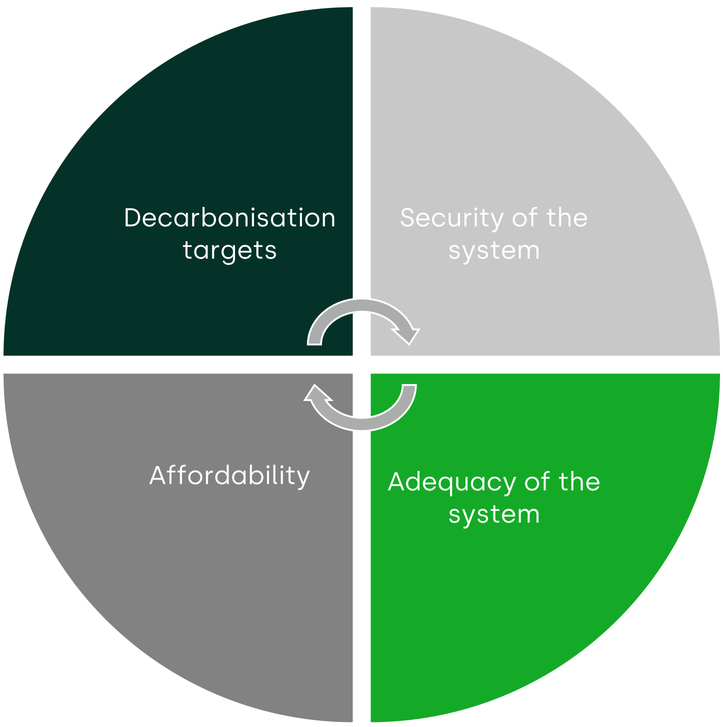
- security of supply, that in the case of electricity takes the form of ensuring the adequacy and security of the system;
- environmental goals, namely decarbonising the electricity production; and
- affordability.

Some of the key themes and policy tools (in green) behind these objectives are summarised in the figure below. As it will be discussed later, while renewable energy sources (RES, such as solar and wind energy) can contribute to some of these objectives, they may also put pressure on others.

Figure 3.1 Finding the right balance between multiple objectives

- Ensure adequate RES investments
- Flexibility sources
- RES support schemes (existing, planned and future ones)
- PPAs market

- Ancillary services and redispatching markets
- Participation of new/broader set of production and demand side technologies
- Local flexibility markets (new role for DSOs)




- Reduce electricity bills
- Competitiveness of the industrial sector
- Ensure the right incentives are in place (e.g. demand reduction, load shifting)
- Measures to deal with price spikes and volatility

- Long term price signals
- Long term instruments/ contracts
- Capacity remuneration mechanisms
- Auction mechanisms for storage capacity

Notes: PPAs stands for Power Purchase Agreements. Items in green represent tools.
Source: Oxera.

The section focuses on the challenges and consequences of integrating large amounts of renewable energy within the electricity markets.

### 3.1 Integrating renewable sources into the electricity grid

The electricity system underwent significant changes in the last decade and further reforms are expected to take place in the coming years, and at an accelerating rate, driven primarily by net zero targets. While the current market design has worked well with a system mostly based on fossil fuels and large thermal plants, the integration of growing shares of RES further poses new challenges.

This is due to the main peculiarities of RES, whose production is typically intermittent, distributed geographically depending on the availability of renewable energy sources (frequently far from consumption centres) and compared to 'traditional' thermal plants are more frequently connected at the distribution level. The latter implies that the electricity system operator (ESO)—the entity responsible for balancing demand and supply in real time—has more limited visibility of the power produced by these facilities. Moreover, RES are characterised by close to zero marginal costs but high upfront investment costs.

The remainder of this section discusses the key challenges that long-term integration of RES into the electricity system poses on various actors along the value chain. It then presents the key tools available as well as reforms currently under discussions to mitigate these challenges and speed up the decarbonisation of the power sector.

### 3.2 Key challenges posed by higher shares of RES

Higher shares of RES connected to the grid are inherently changing the way electricity is produced and the whole electricity system operated. This in turn has an impact on the various market players and poses challenges on various segments of the electricity value chain.

First of all, due to the so-called merit order effect, according to which units with lower costs are dispatched first,[50] RES generally crowd out plants characterised by higher marginal costs, which usually mean thermal plants (especially gas and coal-fired plants). As the share of RES in the system increases, thermal plants operate in a smaller number of hours, therefore these may not be able to recover their fixed costs and get out of the market. As a result, higher RES typically results in **lower dispatchable capacity**, i.e. those plants that can ramp up and

[50] See for example Oxera (2023), 'Decoupling electricity and fossil fuel prices: bright idea or lights out?', Agenda, April.

down at short notice to respond to sudden changes in demand, unless other mechanisms are in place to ensure their profitability.

Similarly, a higher share of RES in the system implies **different residual load patterns during the day**.[51] In particular, in certain hours residual load is much lower (compared to today) or even negative, e.g. during the central hours of the day, when solar production is higher. This can also lead to the so-called **over-generation** phenomenon, when electricity production is higher than demand in a specific point in time. This requires the ESO to take 'corrective' measures[52] to balance supply and demand, including for example RES curtailment. At the same time, when insufficient storage capacity is available on the system, RES can result in a steeper load curve towards the evening, when solar output decreases and demand is typically increasing.

In turn, these characteristics imply that when RES penetration increases, there is a **higher need for flexible sources or technologies** able to provide 'back-up' capacity close to real time and/or contribute to load shifting, i.e. transferring demand away from hours with low RES in-feed to hours with higher RES availability.[53]

At the same time, higher RES generation generally implies **more volatile prices**. This is because when RES are abundant, prices are typically low (close to zero, in line with RES marginal costs, or at times even zero or negative). However, when RES production alone is not enough to meet demand, other (thermal) plants are dispatched to cover the gap, resulting in significantly higher wholesale prices.

[51] Residual load (or residual demand) refers to net demand after accounting for intermittent generation produced at a local level. Given that both underlying (true) demand and intermittent generation are both volatile and generally uncorrelated, the volatility of residual demand can be more volatile than underlying demand.
[52] These include for example increasing storage withdrawals (i.e. increasing demand), reducing imports, when/where possible, or curtailing down RES.
[53] A recent study from the National Renewable Energy Laboratory (NREL) shows the strong relationship between RES penetration and storage deployment. See NREL (2022), 'Storage Futures Study. Key learnings for the coming decades', pp. 19-20.

## Figure 3.2 Correlation coefficients of half-hourly generation for different technologies

| | Offshore | Onshore | Gas | Nuclear | Biomass | Coal | Hydro pumped | Run of river | Solar |
|---|---|---|---|---|---|---|---|---|---|
| Offshore | 1 | | | | | | | | |
| Onshore | 0.79 | 1 | | | | | | | |
| Gas | -0.33 | -0.29 | 1 | | | | | | |
| Nuclear | -0.21 | -0.21 | 0.02 | 1 | | | | | |
| Biomass | -0.03 | -0.04 | 0.15 | -0.23 | 1 | | | | |
| Coal | 0.13 | 0.17 | 0.34 | 0 | -0.04 | 1 | | | |
| Hydro pumped | -0.01 | 0.03 | 0.53 | 0.04 | 0.08 | 0.29 | 1 | | |
| Run of river | 0.28 | 0.26 | 0.34 | -0.36 | 0.22 | 0.31 | 0.42 | 1 | |
| Solar | -0.21 | -0.1 | 0.11 | 0.1 | 0.05 | -0.11 | 0.12 | -0.2 | 1 |

Note: Based on generation data for Great Britain in 2018. Greater positive correlations are coloured dark green, lower correlations are coloured either yellow (positive) or orange (negative). Greater negative correlations are coloured red.
Source: Oxera analysis based on data from ENTSO-E transparency platform.

### 3.2.1 Impacts on the system operator

Since most RES are intermittent and non-dispatchable (e.g. solar, wind and hydro run-of-river) they increase the already complex task of the system operator to balance supply and demand in real time. This is mostly due to two separate but interrelated drivers:

- as discussed, RES crowd out dispatchable capacity, making it uneconomical to operate. This means that, going forward, an increasing share of thermal plants that has historically provided back-up capacity and ancillary services to the ESO will no longer be available. This therefore poses a challenge for the **adequacy and security of the electricity system**.
- due to their intermittency, RES are more difficult to forecast and, in-feeds at time of delivery can deviate significantly from their scheduled output. This in turns requires the ESO to procure **higher reserve margins**, to ensure that enough resources are available to balance the system close to real time, if needed.

As already discussed, the first implication is the greater need for flexibility by electricity systems dominated by RES. However, this alone would not be enough, as the system also need to retain the resources necessary to resolve network bottlenecks and to balance supply and demand. This generally translates into regulators and policymakers aiming to 'open' so-called balancing and redispatching markets to new sources, including certain forms of RES, storage, smaller thermal units as well as demand aggregators).[54] Historically large thermal and hydro plants have been the key players in these markets, allowing for upwards and downwards variations at short notice to the ESO.

### 3.2.2 Impacts on electricity (transmission and distribution) networks

As anticipated, RES development frequently takes place in more 'favourable' locations, i.e. where the relevant renewable energy source is more abundant (e.g. Scotland for offshore wind or South of Italy for solar photovoltaics). This means that RES plants are more widely dispersed than conventional thermal plants and **frequently far from consumption centres** (e.g. as is typically the case for offshore wind).

Since RES do not always locate close to demand, higher RES frequently results in **more (local) congestions**. Moreover, RES are **increasingly connected to lower voltage grids**, i.e. at the distribution level, which implies lower visibility and less 'direct' control by the ESO.

This poses new challenges, not only on the network itself—originally designed to be unidirectional with flows from large centralised power plants connected at the transmission level to end users connected at the distribution network level, but more recently increasingly needing to accommodating bi-directional flows—but also for network operators, whose role and responsibilities are evolving rapidly. In particular, a **higher level of coordination** is now required between distribution system operators (DSOs) and the transmission system operators (TSOs). Moreover, DSOs are more frequently being tasked to procure **local ancillary services**, to ensure that their local network is 'on balance' in real time.[55]

More broadly, energy networks play a key role in enabling the energy transition, by allowing a higher proportion of RES to be integrated into the system. While distribution networks are key to transport electricity within a country or between market areas, and connecting production sites with demand, transmission networks and interconnections allow

[54] See for example a recent reform in Italy that led to the adoption of the new *Testo Integrato del Dispacciamento Elettrico* (TIDE). ARERA (2023), 'Delibera 345/2023/R/eel', July.
[55] See for example the case of Italy, where ARERA, the energy regulator, introduced the possibility of pilot projects to procure local ancillary services. Two projects recently approved involve e-distribuzione and Areti. ARERA (2021), 'Delibera 352/2021/R/eel', August. ARERA (2023), 'Delibera 365/2023/R/eel', August. ARERA (2023), 'Delibera 372/2023/R/eel', August.

for market integration, enabling RES to be shared across wider regions allowing for additional gains from cross-border trade.[56]

A major challenge for the decarbonisation of the electricity system is that significant investments in new technologies—i.e. RES, low-carbon flexibility sources (including storage and demand response) and networks—are needed in a 'coordinated' way. If the development of one of these technologies lags behind, it can represent a bottleneck for the others, thereby slowing down the pace of the transition towards a decarbonised system. Put differently, the electricity system is increasingly characterised by a wider range of technologies that are highly complementary and whose expansion would ideally be coordinated to enable the system outputs (see Figure 3.1) to delivered at lowest cost.

A major challenge for the decarbonisation of the electricity system is that significant investments in new technologies—i.e. RES, low-carbon flexibility sources and networks—are needed in a 'coordinated' way.

As regards network capacity, this opens the **discussion between anticipatory investments** (expanding the network before demand materialises to enable timely connections) as well as load-related investments for which network operators need to be more responsive to meet new connection requests. Moreover, another challenge lies in ensuring that sufficient network capacity is available to connect and integrate new RES into the system, while at the same time ensuring **affordability for final consumers**.

### 3.2.3 Impact on electricity generators and investors

While conventional thermal plants are characterised by 'high' variable costs (mostly fuel costs and CO2 emission allowances costs), RES have **close to zero marginal costs but high upfront investment costs**. This structural difference poses an investment/financing challenge for new RES, as these have high fixed costs, that need to be recovered over the life of the asset.

RES development requires long-term investment signals as well as long-term instruments to provide revenue visibility to generators and investors. While short-term (or spot) markets have worked well, long-term (forward) markets are generally not been sufficiently liquid to allow market risks to be hedged much beyond 2 to 3 years ahead.[57] As anticipated, one of the typical market failures is the so-called '**missing market**' problem, i.e. when investment risks are not efficiently allocated

[56] See for example Oxera (2019), 'Smarter incentives for transmission system operators. Volume 2', section 2.1. See also Oxera (2020), 'La roadmap per la riforma dei mercati elettrici: prospettive e sfide per l'Italia', November, pp. 22, 46-49.
[57] See for example ACER (2022), 'ACER's Final Assessment of the EU Wholesale Electricity Market Design', April.

or externalities are not duly accounted for. This also extends to cases where hedging instruments are not available to cover for future interventions or market events that can negatively impact investors' profits.[58]

Moreover, RES generators and investors are exposed to certain pricing challenges. These take the form of two different but related issues. On the one hand, one of the policy objectives and ultimate goals behind increasing RES production is ensuring that their benefits, in particular in the form of lower prices, are passed on to consumers. On the other hand, when RES frequently represent the marginal technology, wholesale prices are often likely to be reduced to their marginal costs, resulting in price cannibalisation. This in turn can have two effects:

RES generators and investors are exposed to pricing challenges: ensuring that benefits from RES production, in particular in the form of lower prices, are passed on to consumers, while avoiding price cannibalisation.

- it limits the potential for RES plants to recover their capital costs, therefore undermining incentives to build new RES capacity;
- especially when combined with the threat of regulatory interventions to mitigate high prices or price volatility, this can lead to the so-called 'missing money' problem, that is often thought to prevent a sufficient expansion of 'firm' and 'flexible' capacity, needed to ensure the adequacy of the system.[59]

### 3.3 Main tools available and proposed reforms under assessment

Under the current market design, various tools are already available to address these market and regulatory failures. At the same time, some reforms and additional instruments are currently under discussion at the EU level and in the UK to further expand the toolkit of policymakers and regulators.[60]

As seen in section 2.3, in addition to market-based instruments and price signals, various tools are available to support the decarbonisation process. These can be broadly classified in three categories: subsidies, market-based mechanisms and economic regulation of prices, revenues or profits. The remainder of this section discusses the various tools available, based on the objectives that they can contribute to.

[58] See for example Oxera (2020), 'La roadmap per la riforma dei mercati elettrici: prospettive e sfide per l'Italia', November, section 1.3.3.
[59] Ibid, section. 1.3.1.
[60] See for example Oxera (2023), 'Decoupling electricity and fossil fuel prices: bright idea or lights out?', Agenda, April. Oxera (2023), 'Electricity market design reform—schemes for low-carbon generation', July.

### 3.3.1 Scaling up RES capacity

One of the key enablers of RES expansion is visibility on future cash flows and some certainty around future revenues, to ensure that capital costs will be recovered. While spot prices can be quite volatile, different types of long-term instruments can be used to enable investment. These typically take the form of either:

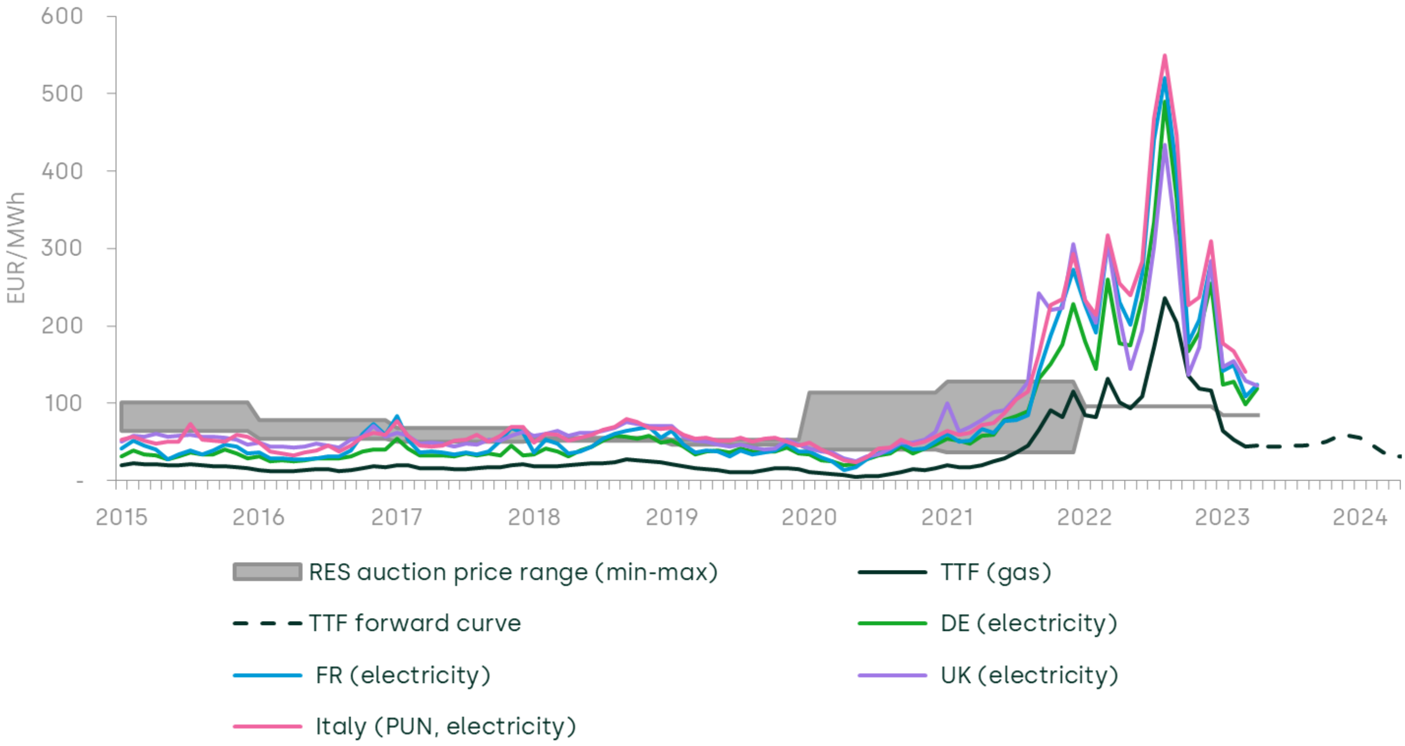
- **RES support schemes**, subsidy schemes that can provide (partial or complete) revenue certainty to RES producers or their investors. As such, in the EU, these instruments are subject to the state aid discipline and they need to be notified to the European Commission.[61]
- **Power purchase agreements** (PPAs), i.e. bilateral long-term contracts between a generator and an off-taker (often an industrial client). These are contracts whose duration and pricing clauses can be tailored to the specific needs of the parties involved.
- **Trading in forward markets or on exchanges** that, when sufficiently liquid, allows market players, including generators, to hedge against volume and price risks.

Each of these are described in turn below.

Meanwhile, it is important to note that in recent years RES costs have declined significantly, as shown in Figure 3.3 below, and RES support schemes have enabled this trend by allowing developers to gain more experience of RES deployment and increasing competition between projects.

[61] European Commission (2022), 'Guidelines on State aid for climate, environmental protection and energy 2022', Official Journal of the European Union, C 80/1, 18 February.

Figure 3.3 Wholesale prices and RES auction prices




Notes: monthly averages. For electricity baseload day-ahead prices and the Prezzo Unico Nazionale (PUN) for Italy are used. Weighted average auction prices based on IRENA data. The range covers solar photovoltaic and onshore wind between 2015 and 2021 and offshore wind between 2020 and 2023.
Source: Oxera analysis on Bloomberg, Gestore dei Mercati Energetici and IRENA data.

## RES support schemes

While a variety of mechanisms have been used historically, more recently the so-called **two-way contract-for-difference** has become a key reference point for the design of new schemes.[62] As seen in section 122.3, two-way CfD is a long-term contract that defines a specific 'strike price' (expressed in €/MWh) that the generator is entitled to earn for each MWh injected into the grid over a given number of years. The generator will be compensated (will have to pay back) any positive (negative) difference between the strike price and the 'reference price' (often a 'day-ahead' market price for intermittent RES technologies).[63]

[62] For a broader discussion on RES support schemes see von Bebenburg, C., Vitelli, R., Mikovic, P., Robins, N., 'Incentivising behavioural changes: Subsidies vs regulation', Concurrences, forthcoming.
[63] For more details, see for example Oxera (2020), 'Making a difference: supporting investment in low-carbon electricity generation', October.

These have been widely used in both the UK and in the EU. As these proved a powerful tool during the recent price crisis,[64] the Commission recently proposed that two-way CfDs become the primary tool for the allocation of RES subsidies.[65] While these represent a notable improvement, as they allow for both a revenue guarantee and an upper limit on the revenues that generators under a CfD scheme can earn, the precise design of these mechanisms can vary significantly with commensurate impacts on efficiency incentives. In particular, in order to mitigate the risks that RES are exposed to, it is important that:

- two-way CfDs are designed in a way that prevents the 'produce and forget' approach, which is a reference to the need for incentives on RES operators to, as far as possible, export power to the network when system needs and market prices are high, and to reduce their exports when prices are low;[66] and
- the strike price is set at an appropriate level[67] that balances the need to incentivise investments while reducing the overall costs to end users.

It is important that (i) two-way CfDs are designed in a way that prevents the 'produce and forget' approach, and (ii) the strike price is set at an appropriate level that incentivises investments while reducing overall costs.

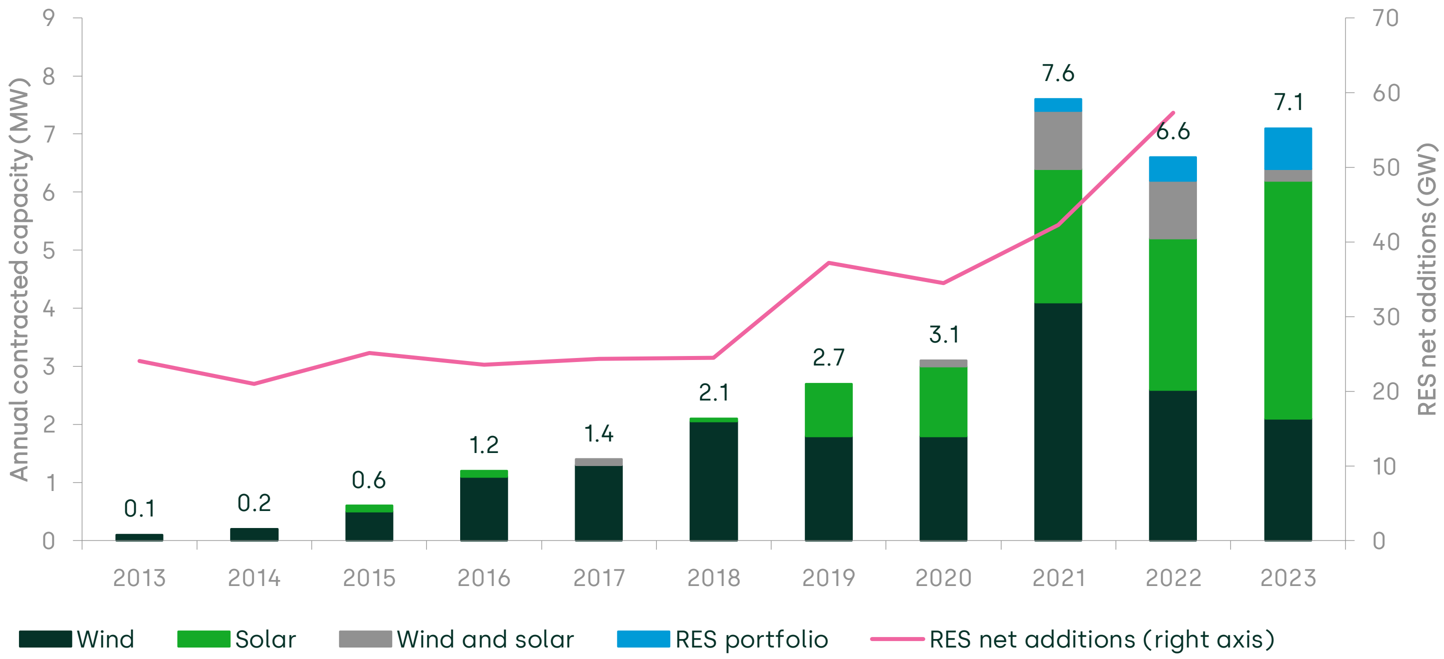
## Power Purchase Agreements

An alternative solution for RES operators is to enter into long-term contracts independently of government support by signing PPAs with one or more off-takers. The expansion of this market is one of the objectives of the REPowerEU plan[68] and the more recent reforms of the electricity market design proposed by the Commission, on which the Council recently found an agreement (on the general approach).[69]

[64] See for example Commission de Régulation de l'Énergie (2022), 'La CRE réévalue les charges de service public de l'énergie à compenser en 2023 à – 32,7 Md€', November.
[65] European Commission (2023), 'Commission Staff Working Document Reform of Electricity Market Design. SWD(2023) 58 final', 14 March. See also Oxera (2023), 'Electricity market design reform—schemes for low-carbon generation', July.
[66] For more details and some examples on alternative CfD designs that have been proposed see Oxera (2023), 'Electricity market design reform—schemes for low-carbon generation', July.
[67] The strike price is increasingly set through competitive bidding processes, in particular for larger installations and more 'mature' technologies, although some exceptions are allowed. When support is allocated through bidding processes and the auction is competitive, then in principle the strike price should broadly reflect the average cost of investments.
[68] As part of the REPowerEU plan the Commission issued a recommendation on speeding up permitting and facilitating PPAs. Moreover, this was complemented by a Staff Working Document, providing guidance to member states on these two topics. See European Commission (2022), 'Commission Recommendation of 18.5.2022 on speeding up permit-granting procedures for renewable energy projects and facilitating Power Purchase Agreements. C(2022) 3219 final', May. European Commission (2022), 'Commission Staff Working Document Guidance to Member States on good practices to speed up permit-granting procedures for renewable energy projects and on facilitating Power Purchase Agreements. SWD(2022) 149 final', May.
[69] Council of the European Union (2023), 'Reform of electricity market design: Council reaches agreement', October.

The PPA market in Europe experienced a significant growth in recent years, gaining further interest in light of the energy crisis with record-high wholesale prices, as can be seen from the figure below.

Figure 3.4 Recent growth of the PPA market in Europe




Source: Oxera based on RE-Source platform's Renewable Energy Buyers Toolkit, link (last accessed 17 October 2023) and IRENA data. IRENA data for 2023 are not available yet.

However, some barriers still prevent its full potential, including for example the difficulty for smaller firms or consumers to access the market and the potential scale of the counterparty risks to which generators may be exposed to. For this reason, as part of the electricity market design reform, the Commission proposed new measures to expand the PPA market, including the possibility for Member states to provide state guarantees, on market terms, for PPAs.[70]

## Forward markets

Finally, forward markets are another area of attention, as today are frequently illiquid for products with longer duration (i.e. more than 1-3

[70] European Commission (2023), 'Commission Staff Working Document Reform of Electricity Market Design. SWD(2023) 58 final', 14 March. See also Oxera (2023), 'Electricity market design reform—schemes for low-carbon generation', July.

years ahead of delivery).[71] As seen, this creates a missing market problem, as generators (and investors) face difficulties in hedging their production. One of the Commissions' proposals aims to increase liquidity, creating virtual trading hubs, complemented with accessible long-term transmission rights (LTTRs). Since a hub may 'attract' operators from multiples neighbouring bidding zones, this is expected to provide a more liquid market for hedging.

### 3.3.2 Scaling up low-carbon 'firm' capacity and flexible resources

As discussed earlier in sections 3.1 and 3.2, a highly decarbonised electricity system needs significant low-carbon capacity that is both dispatchable (i.e. firm) and flexible. However, electricity markets often do not provide sufficient incentives to invest in these technologies, as expected price levels may not guarantee an appropriate remuneration to these assets. Similarly to RES, the key tools generally available to ensure that these resources are deployed and remain in operation include capacity remuneration mechanisms (CRMs) and *ad hoc* support schemes for low-carbon flexibility sources.[72]

#### Capacity remuneration mechanisms

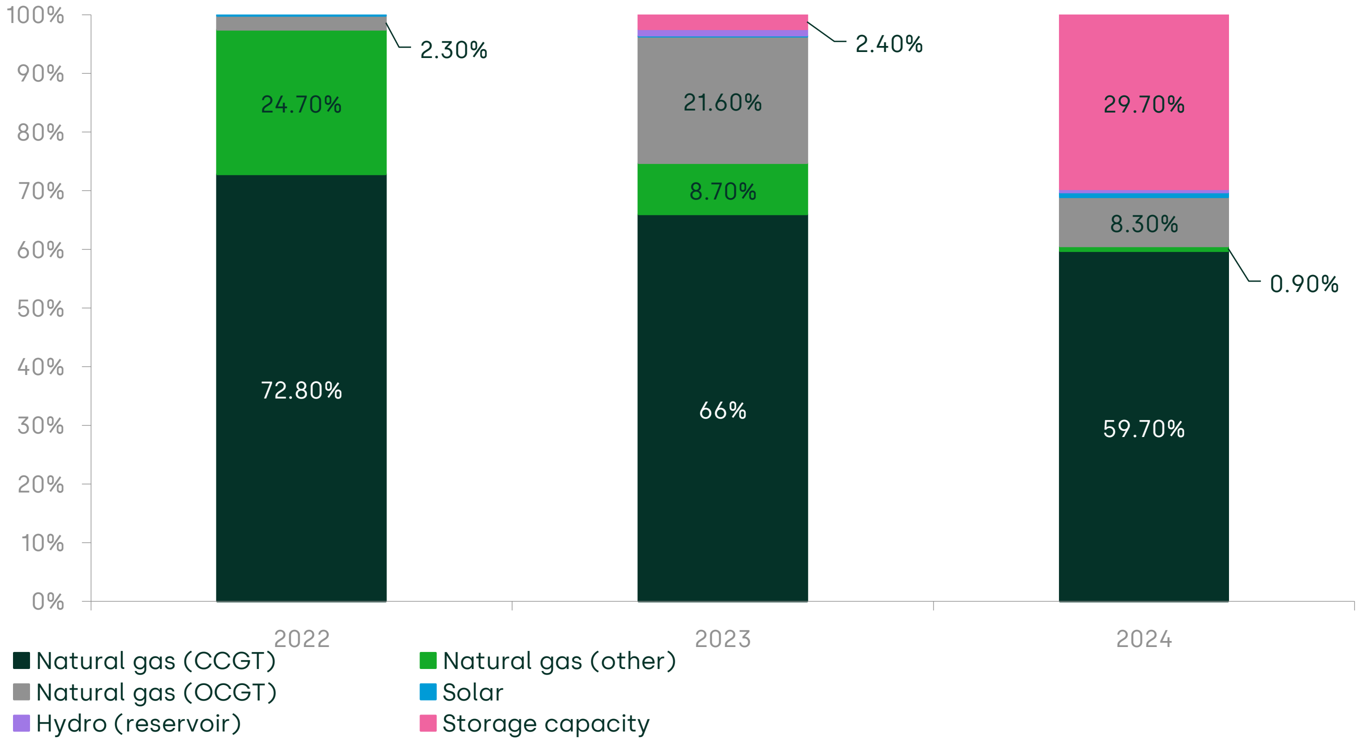
CRMs represent a specific form of subsidies that are used to ensure the adequacy of the electricity system and incentivise the development of storage capacity and other flexibility sources. When a CRM is established, selected generators (and consumption units) receive a 'capacity payment' (in €/kW) for their availability. In turn, they are required to offer their capacity in the wholesale market.

While CRMs are open to a variety of technologies, they are not always perceived as entirely 'technology neutral' as they are often, in practice, 'skewed' towards enabling the availability of thermal capacity. The key parameter that is incentivised by CRMs is the ability to deliver the committed capacity in times of system stress. In light of this, RES participation is usually low, however storage and demand side response (DSR) have been playing a greater role in more recent auctions. For example, in the latest auction of the Italian CRM, for delivery from 2024,

[71] ACER (2022), 'ACER's Final Assessment of the EU Wholesale Electricity Market Design', April.
[72] For more details, see von Bebenburg, C., Vitelli, R., Mikovic, P., Robins, N., 'Incentivising behavioural changes: Subsidies vs regulation', Concurrences, forthcoming.

storage accounted for approximately 30% of the new-build capacity selected, representing more than 1.1 GW in total.[73]

Figure 3.5 New-build capacity supported through the Italian CRM




Source: Oxera based on Terna (2019), 'Mercato della capacità. Rendiconto degli esiti – asta madre 2022'. Terna, 'Mercato della capacità. Rendiconto degli esiti – asta madre 2023. Terna (2022), 'Mercato della capacità. Rendiconto degli esiti – asta madre 2024'.

CRMs can also incorporate emission performance standards that require eligible units to comply with certain CO2 emission limits. According to the Regulation (EU) 2019/943, from 1 July 2025 at the latest, existing generation capacity[74] that emits more than 550g of CO2 per kWh of electricity produced should not be allowed to participate in CRMs.[75] Some mechanisms already incorporate this emission

[73] European Commission (2020), 'State Aid SA.53821 (2019/N) – Italy, Modification of the Italian capacity mechanism', C(2019) 4509 final, 14 June. Terna (2022), 'Mercato della capacità. Rendiconto degli esiti – Asta madre 2024'.
[74] Namely generation capacity that started commercial production before 4 July 2019.
[75] REGULATION (EU) 2019/943 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 5 June 2019 on the internal market for electricity (recast), 16 June 2019, article 22.

performance standard, e.g. the Italian scheme approved in 2020.[76] However, an amendment to the 2025 deadline is currently under discussion as part of the electricity market design reform, as the Council proposed a derogation to this requirement, under certain conditions and until 31 December 2028.[77]

*Ad hoc* support schemes for storage and low-carbon flexibility sources

In addition to the possibility to participate to CRM schemes, the Commission has recently proposed new tools to support the development of low-carbon flexibility sources. These include the possibility of *ad hoc* support schemes, with beneficiaries selected through a competitive process.[78]

It is worth mentioning that similar schemes have already been approved under state aid rules in some member states, e.g. in Greece and Romania.[79] More recently also the Italian government pre-notified a similar measure.[80]

### 3.3.3 Scaling up network capacity

Energy networks play a key role in enabling the integration of a growing share of RES into the system. If the network expansion is not sufficiently coordinated with RES growth, the former becomes a bottleneck, which in turn poses the risk of slowing down the decarbonisation process.

Given the significant growth of RES projects being proposed, ensuring a timely connection to the grid is becoming an increasingly relevant issue in various countries, including for example the UK and Italy. Similarly, the challenges experienced by electricity (and, more broadly, energy) networks as the system decarbonises, are a highly discussed topic

[76] In case this limit is not met, existing capacity can participate in the CRM if it commits not to emit more than 350 kg $CO_2$ of fossil fuel origin on average per installed kWe, for any given delivery year. European Commission (2020), 'State Aid SA.53821 (2019/N) – Italy, Modification of the Italian capacity mechanism', C(2019) 4509 final, 14 June.
[77] Council of the European Union (2023), 'Reform of electricity market design: Council reaches agreement', October. Council of the European Union (2023), 'Proposal for a REGULATION OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL amending Regulations (EU) 2019/943 and (EU) 2019/942 as well as Directives (EU) 2018/2001 and (EU) 2019/944 to improve the Union's electricity market design - General approach', October.
[78] European Commission (2023), 'Commission Staff Working Document Reform of Electricity Market Design', SWD(2023) 58 final, 14 March, para. 5.4.
[79] See for example European Commission (2022), 'State Aid SA.64736 – RRF - Greece - Financial support in favour of electricity storage facilities', C(2022) 6461 final, 5 September. European Commission (2021), 'State Aid SA.57473 (2021/N) – Greece, RRF - Pumped Hydro plant – Amfilochia', C(2021) 9753 final, 20 December. European Commission (2023), 'State Aid SA.102761 (2022/N) – Romania RRF – State aid scheme aimed at developing electricity storage in Romania, C(2023) 1957 final, 21 March.
[80] Italian Government (2023), 'Italian Implementation Plan, Annual monitoring report'.

among regulators. Possible tools to ensure that full benefits of RES are reaped include the following.

- **Network expansions and reinforcements**, to increase available capacity. As investment needs are frequently very significant,[81] these can pose a threat to the affordability of network charges. To mitigate tariff increases, some of the interventions may be financed through public grants.
- **Digitalisation of the network**, developing so-called smart grids, which allow features such as better real-time monitoring, remote control and a more active participation of consumers to energy markets (e.g. because of better data availability).[82]
- **New features built into the regulatory frameworks**, better able to support the transition, such as the use of broader tools to deal with uncertainty, so-called uncertainty mechanisms, as well as the transition towards regulatory frameworks that ensure an equal treatment of capital and operating expenditures, e.g. TOTEX models.[83]
- **more flexible connection agreements**, e.g. using 'interruptible' or 'flexible' (instead of 'firm') capacity to ensure that available network capacity is better utilised.

[81] See for example the latest ten-year network development plan of Terna, the Italian electricity TSO. Terna, 'Piano di sviluppo della rete' (accessed 18 October 2023). Increasing investment needs to support the path towards a Net Zero emissions system are a common feature also in other markets. This is for example evident in the UK, where in the current price control (RIIO-ED2) ex ante total expenditure (TOTEX) allowances for electricity DSOs were higher than during the previous regulatory period. See for example Oxera (2022), 'RIIO-ED2 Draft Determinations', July.
[82] For example, the Italian Recovery and Resilience Plan allocated €4.11 billion to electricity networks, out of which €3.61 billion specifically targeted to the digitalisation of the distribution grid, in order to integrate an additional 4GW of distributed generation from RES, including through smart grids, and provide connection to approximately 1,850,000 consumers. Italian Government (2021), 'Piano Nazionale di Ripresa e Resilienza', April. See also Oxera (2021),' Different plans, common challenges: national recovery and resilience plans in the EU', May.
[83] See for example the new ROSS ('Regolazione per Obiettivi di Spesa e di Servizio') that will be introduced from 2024 for Italian energy networks. ARERA (2023), 'Delibera 163/2023/R/com', April. See also Oxera (2021), 'Methodology review for a regulatory framework based on a total expenditure approach ('ROSS-base')', December.

# 4 Gas and hydrogen transition challenges

For the EU to reach its climate goals, there is a need to cut the use of fossil fuels and switch to energy from renewable sources. This includes replacing natural gas, currently used in electricity generation, heating and various industrial processes with green alternatives. Some of this might be achieved via electrification and decarbonisation of the electricity sector (see section 3).

Nevertheless, it is expected there will be a role for renewable and low-carbon gases, including hydrogen, to replace natural gas due to the challenges and costs of electrification in some use cases. IRENA's 1.5°C global warming scenario by 2050 envisages that renewable- and low-carbon hydrogen could meet up to 12% of global final energy consumption.[84]

Hydrogen can be produced without carbon emissions, if produced by renewable energy sources (see Box 4.1 below). There are two principal classes of hydrogen use cases.

There are two principal use cases for hydrogen: (i) as a direct industrial input into industrial processes like ammonia and Direct Reduced Iron production, (ii) substituting for gas (and other fossil fuels) as an energy source.

- Hydrogen is already, or is soon going to be, used as a **direct industrial input into certain industrial processes** like ammonia production, which in turn can be used to produce fertilisers, and Direct Reduced Iron production, which in turn can be used to produce 'green' steel.
- Hydrogen can also play an important role in substituting for gas (and other fossil fuels) as an **energy source**. It can play a role in decarbonising heating and electricity generation, and it can be used to produce synthetic fuels or e-fuels for heavy transport applications. In the future, hydrogen may also be used to provide seasonal energy storage (similar to gas storage) to supplement renewable electricity plants during winter periods with high demand and limited wind or solar availability.

The remainder of this section discusses the current scope of the EU's policy targets for transitioning to the hydrogen economy and the scale of the transition challenge. It then details the specific policy and regulatory questions that arise in each segment of the value chain,

[84] https://www.irena.org/Energy-Transition/Technology/Hydrogen

given the ambitions for the EU hydrogen economy, and how it relates to the longer-term challenge of phasing out natural gas assets.

### 4.1 Policy context and scale of the transition challenge

The EU's hydrogen and decarbonised gas market package envisages that the share of renewable and low-carbon gases in the EU will increase from just 5% today to 66% by 2050.[85] The Commission's hydrogen strategy[86] identifies transitioning towards a hydrogen economy as an integral part of the EU's decarbonisation. The hydrogen strategy defines some of the key green objectives for EU member states and hard-to-abate industries (like the steel and other subsectors within heavy industrial and long-haul transport).

These initial targets have since been increased by more ambitious targets proposed in response to the Russia-Ukraine war induced gas supply crisis. These were outlined in the REPowerEU plan[87] and sector-specific targets have subsequently been adopted in the Renewable Energy Directive.[88]

Together, the hydrogen strategy and REPowerEU objectives now form the plans that define key milestones for the EU in developing its prospective hydrogen economy. These include:

- production of 10 megatonnes per year (MT/y) of renewable (or green)[89] hydrogen by 2030 in the EU;
- imports of 10 MT/y of green hydrogen by 2030; and
- sector-specific targets for industrial users and the transport sector.[90]

The targets are also supported by various funding instruments specifically targeting green hydrogen technologies. This includes state aid financing approved through the first two rounds of the Important

[85] European Council, Council of the European Union, 'Infographic - Fit for 55: shifting from fossil gas to renewable and low-carbon gases', Infographics (accessed 3 November 2023).
[86] European Commission (2020), 'A Hydrogen Strategy for a climate neutral Europe', 8 July.
[87] European Commission (2022), 'COM(2022) 230 final', REPowerEU Plan, May.
[88] Official Journal of the European Union (2023), 'DIRECTIVE (EU) 2023/2413 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 18 October 2023 amending Directive (EU) 2018/2001, Regulation (EU) 2018/1999 and Directive 98/70/EC as regards the promotion of energy from renewable sources, and repealing Council Directive (EU) 2015/652', 31 October. European Commission (2022), 'REPowerEU Plan', 18 May and its adoption by the EU Council. See for example European Council, Council of the European Union, 'Infographic - Fit for 55: how the EU plans to boost renewable energy', Infographics (accessed 3 November 2023)..
[89] Green hydrogen is hydrogen obtained through electrolysis. See the box below for a more detailed description of the different types of hydrogen production.
[90] Recent agreements on the renewable energy directive between the European Council and Parliament. See for example European Council, Council of the European Union, 'Infographic - Fit for 55: how the EU plans to boost renewable energy', Infographics (accessed 3 November 2023).

Projects of Common European Interest (IPCEIs) on hydrogen[91] and the establishment of the European Hydrogen Bank (more details are provided on funding measures below).[92]

There are also various ongoing initiatives that suggest that the EU-level policy objectives are supported by member states and key industry stakeholders. Across Europe, governments and regulators have identified carbon-neutral hydrogen as a critical source of energy for meeting net zero targets, and at least 16 member states have also adopted their own national hydrogen strategies.[93] There are also various ongoing hydrogen projects and feasibility studies being developed by market players. Most notable is perhaps the plan of a group of national gas transmission network operators (TSOs), to repurpose existing gas networks and develop a trans-European hydrogen transport network—referred to as the European Hydrogen Backbone Initiative (discussed below).[94]

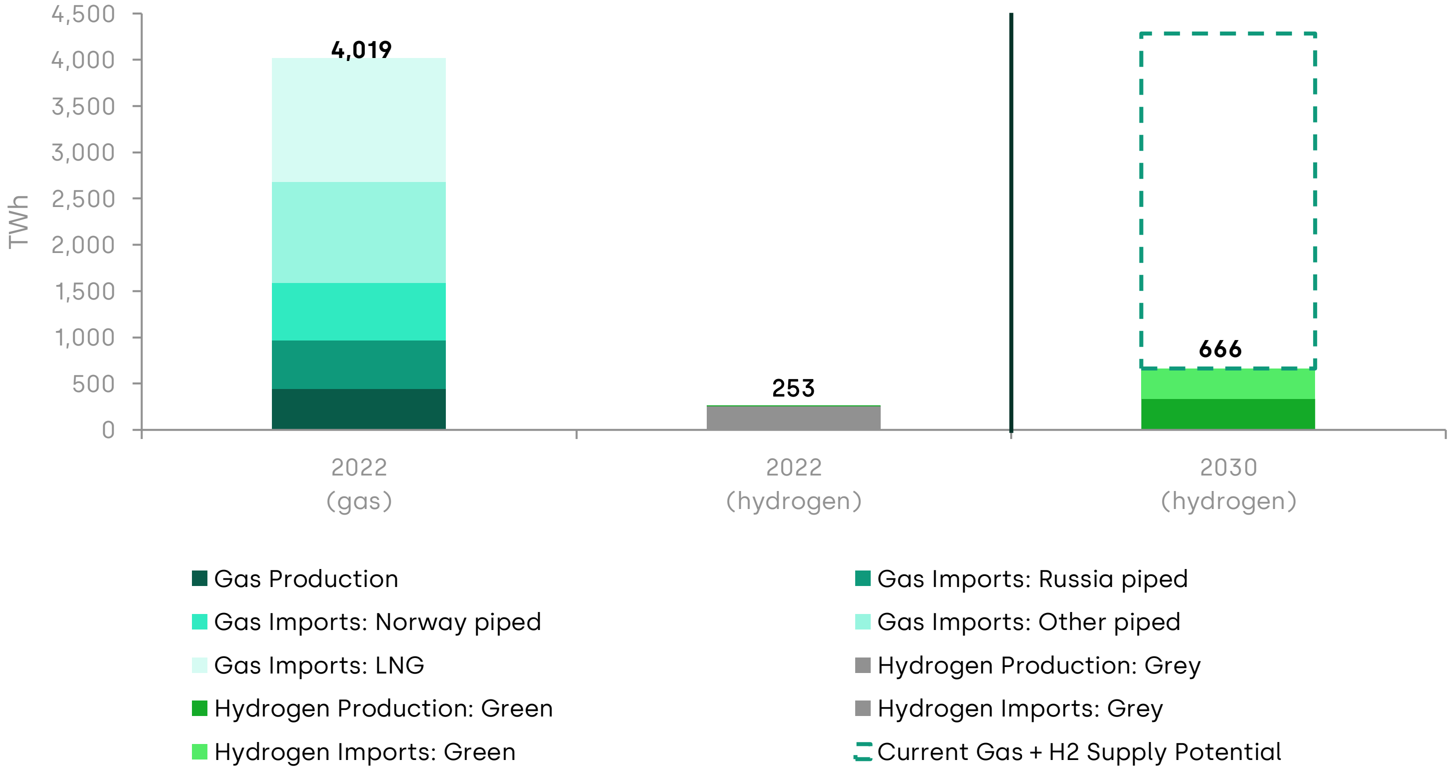
Notwithstanding the enthusiasm shown by policymakers and industry, current demand for hydrogen is still a fraction of natural gas demand and the extent of its competitiveness and scale in the future remains uncertain. At the moment, there is no established market, no significant transport infrastructure nor storage capacity, and great uncertainty about future levels of demand and supply remains. Compared to the EU's current policy, competing visions for the future of hydrogen emaphasise local production and consumption to satisfy specific industrial customers that have few, if any, low-carbon alternatives to continued fossil fuel use, and reliance on imports to meet a substantial share of future hydrogen demand.

As shown in the figure below, less than 5% of the EU's (still small-scale) hydrogen supply takes the form of green hydrogen. The EU targets for green hydrogen supply by 2030 (20 MT of production and imports) are also only a fraction of current gas and (predominantly grey) hydrogen supply combined (c.8%). There is thus significant scope for current gas demand (from heating, energy, inputs to industry and as transport fuel)

[91] European Commission (2022), 'State Aid: Commission approves up to €5.2 billion of public support by thirteen Member States for the second Important Project of Common European Interest in the hydrogen value chain', September.
[92] European Commission (2023), 'COM(2023) 156 final. COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS on the European Hydrogen Bank', 16 March.
[93] Ibid, p. 1.
[94] European Hydrogen Backbone (2022), 'A European Hydrogen Infrastructure Vision Covering 28 Countries', April.

to be substituted for by green hydrogen or other competing green alternatives. The exact role of hydrogen therein remains uncertain.

Figure 4.1 Gas and hydrogen supply: current vs planned (2030)




Note: Conversion ratios of 9.6 TWh/bcm and 33.3 TWh/MT used for gas and hydrogen, respectively. See definition of grey and green hydrogen categories in the Box below.
Source: Oxera analysis based on European Commission, International Energy Agency and EU gas TSO data.[95]

[95] Gas data for 2021 from the European Commission (2022), 'Quarterly report on European gas markets', over quarters 1 to 4. Hydrogen data for 2022 from the International Energy Agency (2023), 'Global Hydrogen Review'. European Commission (2023), 'On the European Hydrogen Bank', 16 March. Hydrogen 2030 targets based on EU targets (discussed above). Gas conversions based on ratios used by Gas for Climate (2023), 'Assessing the benefits of a pan-European hydrogen transmission network', March 2023.

The core EU policy and regulatory challenge as it relates to the gas–hydrogen nexus is thus two-fold:

- **how to scale up a nascent hydrogen market** at the socio-economically optimal rate and to the optimal scale—achieving this would require efficient investment incentives on the supply side being coordinated with measures providing a high degree of certainty over the developmet of demand; and
- **phasing-out natural gas** usage and divestment of (natural) gas infrastructure in a coordinated manner—maintaining security of supply during this transition while also ensuring affordability and managing the risks of asset stranding are key challenges in this regard.

The challenge for the gas–hydrogen nexus is two-fold: how to scale up a nascent hydrogen market at the socio-economically optimal rate and to the optimal scale and phasing-out natural gas usage and divestment of (natural) gas infrastructure in a coordinated manner.

Both dimensions of this interlinked policy and regulatory challenge are discussed in turn below.

### 4.2 Developing the hydrogen value chain

The main market failures or barriers to the optimal development and scale of the green hydrogen economy, are:

- **negative externalities of un-priced (or under-priced) carbon emissions**, and how to best incorporate these across sectors;
- **innovation market failures** that inhibit a still nascent green hydrogen industry from developing at the socially optimal speed and to the optimal scale. The latter relates to financial frictions, insufficient 'learning by doing' and knowledge/technology transfer, first mover disadvantages and lock in effects; [96] and
- **coordination problems between demand and supply**. For example, for potential producers to invest in a technology that is not yet cost competitive and is still unproven requires some degree of certainty over future off-takers, the infrastructure to reach end-users, and clarity around longer-term regulation and incentives.

[96] See for example the justification of support provided to developing the hydrogen economy in the USA: the White House (2023), 'The Economics of Demand-Side Support for the Department of Energy's Clean Hydrogen Hubs', 5 July. The policy brief relies on the underlying academic work by Armitage, S.C., Bakhtian, N. & Jaffe, A.B (2023), 'Innovation Market Failures and the Design of New Climate Policy Instruments', NBER Chapters in: Environmental and Energy Policy and the Economy, volume 5.

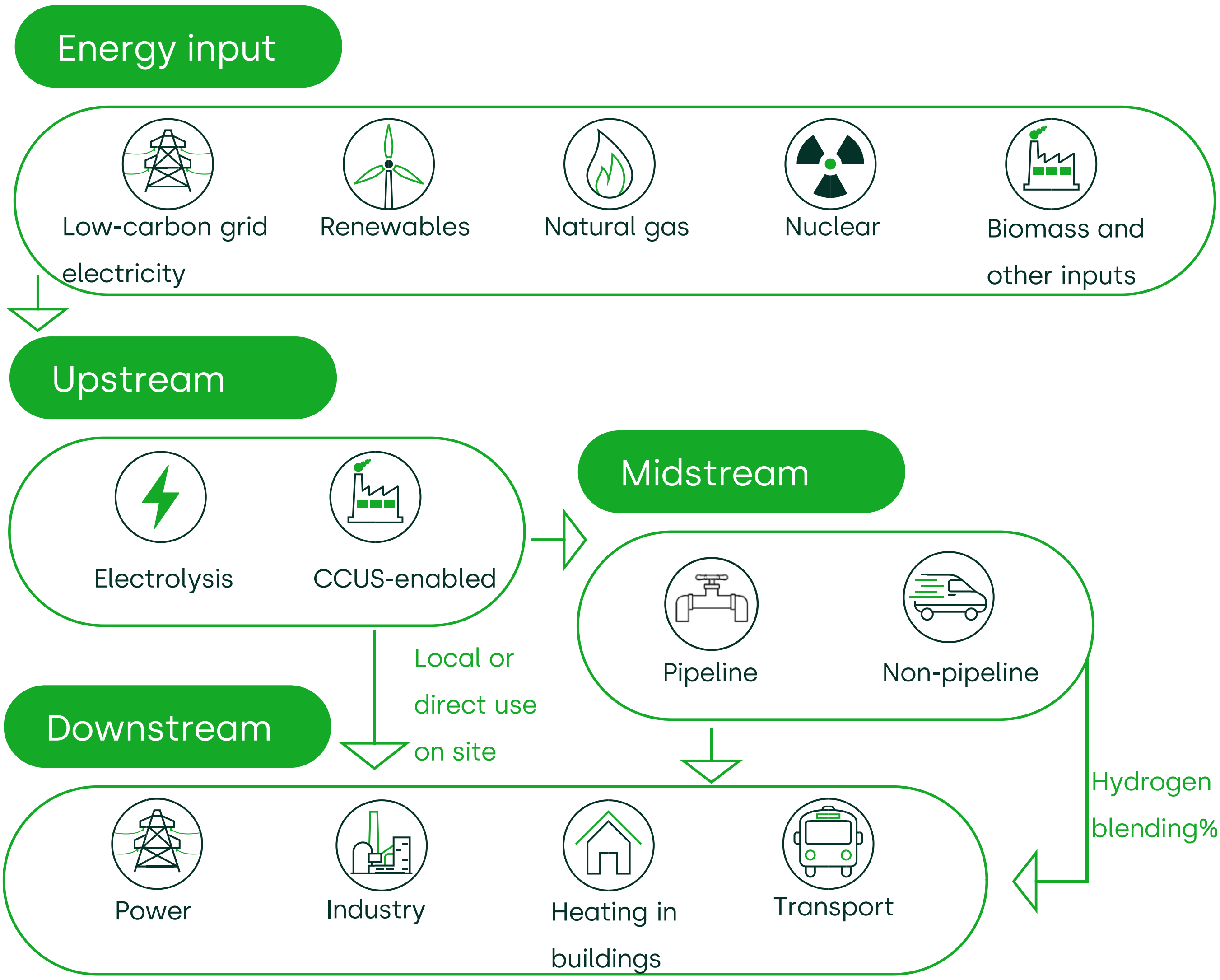
The overarching policy and regulatory challenge is that the challenges faced in the different parts of the value chain cannot be addressed in isolation, or sequentially Indeed, establishing a green hydrogen market requires simultaneously coordinating among potential future suppliers, investors in the necessary infrastructure and storage facilities, and as yet unknown classes of consumers.

The main policy and regulatory challenge is a complex coordination problem. However, there is also a risk of regulatory failure.

However, there is also a risk of regulatory failure. First, it is important that the hydrogen market regulations and incentives are not considered in a vacuum, independent of other green alternatives and existing (fossil) commodity markets. Second, the possible regulation of the network components (transmission and storage) also entails particular challenges, resulting from the fact that it is not yet clear (i) who will build the relevant infrastructure (nor how it will be funded and/or regulated) and (ii) where it will need to be built. Moreover, the development of hydrogen infrastructure may be closely linked to the phasing out of the existing natural gas infrastructure, which poses additional challenges and requires further coordination.

Each of these themes is discussed in more detail below, signposting the regulatory challenges and potential trade-offs that are likely to occur across the different parts of the value chain.

Figure 4.2 The hydrogen value chain




Source: Oxera

The hydrogen value chain can be broadly categorised into three different segments:

- **Upstream (production).** The large majority of the 95MT global hydrogen produced today (c.99%) is from unabated grey hydrogen (i.e., from fossil fuels—mostly natural gas).[97] Low emission hydrogen production ('blue' hydrogen), with carbon capture, utilisation and storage (CCUS) accounts for 1 MT per annum (c.1%), whilst green hydrogen accounts for just 0.1% of current global production.[98] It is worth noting that unlike fossil

[97] IEA (2023), 'Global Hydrogen Review, June, p. 64.
[98] IEA (2023), Ibid, pp. 65 and 68.

fuels (which are finite natural resources, extracted from fixed locations), hydrogen is a manufactured product. In principle, green hydrogen could be produced anywhere there is abundant supply of (renewable[99]) energy and water.

- **Midstream (transportation and storage).** Hydrogen is highly flammable and difficult to store and transport due to its very high energy density per unit *mass* and very low energy density per unit *volume* compared to, say, natural gas.[100] While hydrogen can be transported by pipeline, on liquefied hydrogen tankers (for relatively smaller volumes), or in high-pressure tube trailers (for relatively shorter distances) this is significantly more expensive than for natural gas due to the high levels of compression required. Ongoing trials and experiments in Europe and elsewhere are testing the commercial viability of blending hydrogen with natural gas and its transport through the existing gas network.[101]
- **Downstream (usage).** While most of the grey hydrogen (where excess carbon is not captured) produced today is used either as a feedstock or as a by-product of other industrial processes, the EU hydrogen strategy envisages other use cases for carbon-neutral hydrogen—including electricity generation, heating, and fuelling different modes of transportation (e.g. heavy goods vehicles, buses, trucks, maritime shipping and aviation).

[99] As discussed above, for hydrogen to contribute to reaching the net zero target by 2050, the energy used to produce hydrogen should come from sources that do not emit $CO_2$.
[100] Office of Energy Efficiency & Renewable Energy (2000), 'Overview of Storage Development: DOE Hydrogen Program', May.
[101] See for example, ACER (2021), 'Transporting pure hydrogen by repurposing existing gas infrastructure: overview of existing studies and reflections on the conditions for repurposing,' July. The UK Government is also conducting an indicative assessment of the value for money case for blending up to 20 per cent hydrogen into the existing gas distribution network. See GOV.UK (2023), 'Hydrogen blending into GB gas distribution networks', September..

**Box 4.1 The main types (or 'colours') of hydrogen**

There are several processes for generating hydrogen, with differing production and carbon costs.

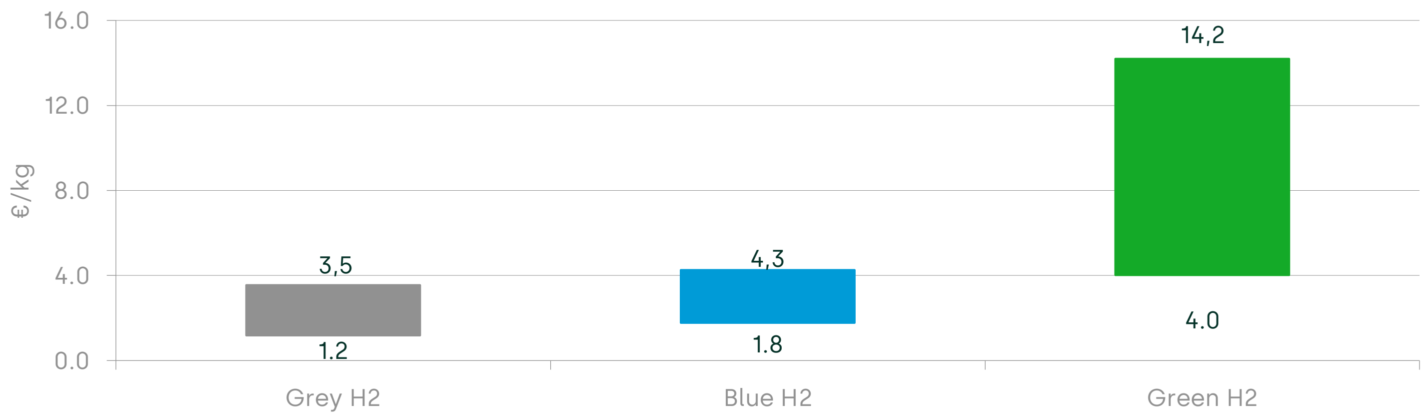
- **'Grey' hydrogen** is produced by reforming hydrocarbons, typically from natural gas. It is currently the cheapest process available to produce hydrogen, but generates similar or greater levels of carbon emissions as the direct use of natural gas. The same process is currently used in the majority of industrial applications that require hydrogen as a specific input.
- **'Blue' hydrogen** is generated through a combination of grey hydrogen production processes with the addition of CCUS, to reduce or eliminate direct carbon emissions. Compared to grey hydrogen, this increases the cost of production.
- **'Green' hydrogen** is generated through electrolysis of water, sometimes also referred to as 'electricity-based hydrogen'. This is currently the most expensive form of production, but it does not have any direct carbon emissions. The total carbon cost of producing green hydrogen depends on the underlying electricity mix used for the electrolysis. Green hydrogen production thus requires significant amounts of dedicated renewable and low-carbon generation.

Note: Further subcategorision based on the energy inputs (e.g. nuclear) are sometimes also used. Simplified, high level categories suffice here.
Source: Oxera

### 4.2.1 Upstream challenges

The production **costs of different hydrogen technologies** today are driven mostly by (i) the cost of the underlying energy source and (ii) the maturity of the technology. Both blue and green hydrogen are yet to reach commercial maturity and be deployed at scale. Today their costs are thus significantly greater than the traditional fossil-fuel-based (or 'grey') hydrogen, where carbon is not captured, or in fact direct natural gas use. Indicative cost differences from the IEA for 2021 are shown below. These costs thus do not reflect the effects of the Russia-Ukraine war and energy crisis, which significantly, but likely temporarily, substantially increased the cost of gas (and in turn the production cost of grey hydrogen).

Figure 4.3 Hydrogen production costs, by type (2021)




Note: Converted to EUR using the European Central Bank average exchange rate over 2021, equal to 1.1827 USD/EUR.
Source: IEA (2023), 'Global Hydrogen Review', June, pp. 80-81.

However, the cost of green hydrogen may fall significantly in the coming years, and could potentially compete directly with grey hydrogen by 2030 (though the true extent of the cost reductions to be achieved is uncertain). The **expected cost reduction of green hydrogen** is projected to be mostly driven by the reduced cost and increased availability of electrolysers (and potentially further decreases in the cost of renewable energy production). For example, the IEA expects that:

- compared to 2023, electrolyser costs could decrease by 60% by 2030, due to economies of scale and mass production—akin to the 80% reduction in solar photovoltaic (PV) costs between 2010 and 2020;[102]
- in regions with conditions conducive to solar generation, e.g. many parts of Africa, the Americas, the Middle East and Oceania, green hydrogen from solar PV could fall as low as 1.6 €/kg by 2030 (which would be in the lower range of current grey hydrogen production costs);

[102] IEA (2023), 'Global Hydrogen Review', June, pp. 74 and 80.

- in north-west Europe, where conditions are conducive to wind renewable generation, green hydrogen prices are expected to fall below 2.1 €/kg by 2030.[103]

However, these scaling and learning-by-doing effects will not necessarily happen automatically, through pure market forces.

Potential entrants' main barriers to entry can be characterised as (i) a first mover disadvantage (or innovation market failures) and (ii) broader uncertainty.

Potential entrants' main **barriers to entry** can be characterised as (i) a first mover disadvantage (or innovation market failures) and (ii) broader uncertainty. The first industrial producers of green hydrogen will need to invest in R&D to deploy the technology at scale and reduce costs to a competitive level. On the contrary, subsequent entrants to the market will benefit from the lower marginal costs enabled by research carried out by the first movers. There is also general uncertainty around the hydrogen economy, in terms of technological feasibility of production, the nature of government support and the extent of future demand.

For policy makers, the challenge at the heart of the supply-side transition is optimising the trade-off between the speed of transition and minimising financial and environmental costs.

For policy makers, the challenge at the heart of the supply-side transition is optimising the trade-off between the **speed of transition and minimising financial and environmental costs**. A quicker transition will enable society to benefit from the transition to green hydrogen sooner, and support the earlier establishment of consumer demand for hydrogen. However, a swift transition is likely to require substantial direction and investment from government, crowding out the potential for private sector competition and innovation. By contrast, if the time is used effectively, a longer transition may enable the construction of production facilities and accompanying supply-side infrastructure to be carried out more efficiently.

The speed at which green hydrogen becomes competitive in practice depends on a number of factors, such as the speed of the technology's development (which includes overcoming first mover disadvantages, and enabling learning by doing and economies of scale effects), the extent to which un-priced carbon is incorporated into competing fossil fuels (like gas), as well as the cost and availability of renewable energy.

There are several policy tools that could be used to facilitate and/or accelerate supply-side development directly:

[103] Ibid, pp. 80-81.

- **Carbon pricing**—the EU ETS is the most immediately relevant, existing mechanism in this regard.[104] The mechanism has been revised and strengthened recently, for example tightening the volume of the EU ETS allowances, reducing free allowances and expanding the scope of sectors covered by the EU ETS (e.g., now also including the maritime transport). These changes may have material impacts on the carbon price in future. If this were to be the case, it could also increase the speed at which green hydrogen becomes cost competitive for potential industrial consumers (at least relative to fossil fuels).[105]
- **Subsidies**, which aim to make the price of hydrogen competitive, so as to induce first mover entry by suppliers. The main sources of subsidies at the EU level are (i) the first two IPCEI rounds on hydrogen, which were approved under the state aid discipline and allowed the financing of a number of projects aiming to, among others, use renewable hydrogen in industrial applications[106] and (ii) EU-wide innovation fund grants.[107] Whilst the latter is technology neutral, the former is hydrogen-specific.[108] These measures are complemented by state level initiatives and other state aid measures that can be adopted (following a notification process to the Commission).
- **Innovation funds, incentivising R&D and 'crowding in' private investment**. The commitment that public funds will be invested in the hydrogen sector decreases the perceived uncertainty of potential asset stranding for private lenders. This represent a way to 'crowd in' private capital by de-risking investments.[109] At the EU level, there are various similar measures, among which the **European Hydrogen Bank** is a notable example.[110] This has

[104] For example, IEA estimates that show green hydrogen becoming cost competitive are based on the assumption that the carbon price will be between 15 and 140 USD/t$CO_2$e by 2030, compared to the current EU ETS price of around 96 USD/t$CO_2$e. IEA (2023), 'Global Hydrogen Review', June, p. 81. World Bank, 'Carbon pricing dashboard' (accessed 31 October 2023).
[105] See for example European Parliament, 'Revision of the EU emission trading system (ETS)', Legislative Train Schedule (accessed 31 October 2023).
[106] The various projects, covering the whole clean hydrogen value chain, received a total of €10.6 billion over the two approval rounds. European Commission, 'IPCEIs on hydrogen' (accessed 31 October 2023). European Commission (2022), 'State Aid: Commission approves up to €5.4 billion of public support by fifteen Member States for an Important Project of Common European Interest in the hydrogen technology value chain', Press release July. European Commission (2022), 'State Aid: Commission approves up to €5.2 billion of public support by thirteen Member States for the second Important Project of Common European Interest in the hydrogen value chain', Press release, September.
[107] European Commission, 'Innovation Fund' (accessed 3 November 2023).
[108] Although IPCEIs have already been approved in other 'thematic areas', e.g. microelectronics and batteries.
[109] For example, the Commission expects the €10.6 billion in in IPCEI funding to unlock another €15.8 billion in private investments. European Commission, 'IPCEIs on hydrogen' (accessed 31 October 2023).
[110] For a broader discussion on other forms of public funding that can be combined with EU Innovation Fund grants see for example European Commission, 'Innovation Fund' (accessed 31 October 2023).

been recently established to provide a range of financial support, e.g. innovation grants and concessional loans, for renewable hydrogen production within the EU and internationally, with the broader aim of creating an EU hydrogen market and establishing a full hydrogen value chain in Europe, while also cooperating with partner countries.[111] A first round of auctions of the Hydrogen Bank, backed by €800 million from the Innovation Fund, are expected to take place towards the end of 2023.

- **Emission performance standards or consumption targets**, that enforce the use of low/no emission energy sources. The updated EU Renewable Energy Directive[112] requires that by 2030 (i) 42% of the hydrogen used by industry should come from renewable sources (and 60% by 2035) and (ii) at least 1% of renewable fuels from non-biological sources (RFNBOs, a group of renewable fuels other than biofuel, consisting mostly of green hydrogen) used in the transport sector— alongside a broader target of 29% for the use of renewables in the transport sector.[113]

Firstly, it is worth noting that some of these measures are relatively interventionist and imply that hydrogen will form a key part to the EU's net zero energy mix. Put differently, compared to technology-neutral policy levers like carbon pricing or technology-neutral subsidy schemes, green hydrogen-specific state-aid, grant funding or quotas are incentivising a specific energy source.

This approach is perhaps motivated by the assessment that some hard-to-abate sectors effectively have no viable alternatives to hydrogen in the long run, and that achieving economies of scale in the production of hydrogen will help make key industrial sectors more competitive. As the Commissions notes, it has developed 'a fully-fledged legislative framework for the production, consumption, infrastructure development and market rules for a future hydrogen market, as well as binding

[111] European Commission (2023), 'COM(2023) 156 final. COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS on the European Hydrogen Bank', 16 March, pp. 5-6.
[112] European Commission (2022), 'REPowerEU Plan', 18 May and its adoption by the EU Council, as discussed here: https://www.consilium.europa.eu/en/infographics/fit-for-55-how-the-eu-plans-to-boost-renewable-energy/.
[113] Recent agreements on the renewable energy directive between the European Council and Parliament, as discussed on the Commission's website at https://www.consilium.europa.eu/en/infographics/fit-for-55-how-the-eu-plans-to-boost-renewable-energy/ and https://www.consilium.europa.eu/en/press/press-releases/2023/10/09/renewable-energy-council-adopts-new-rules (accessed 7 November 2023).

quotas for renewable hydrogen consumption in industry and transport.'[114]

Second, policy-makers and regulators also need to consider the ways in which the various mechanisms interact. For example, two of the main mechanisms at the EU level, the existing carbon pricing scheme (EU ETS) and the funding mechanism of the Hydrogen Bank (i.e. the Innovation Fund) are interlinked fiscally. The Innovation Fund is financed through the sale of EU ETS allowances, and the budget of future public grants available will thus depend on the carbon price.

Hydrogen-specific subsidies and consumption targets also create practical challenges. For example, they necessitate certification standards and defining exactly how and when hydrogen production (in the EU or abroad) is indeed renewable, or green, and contributes to net zero targets. For example, the first two Delegated Acts on Renewable Hydrogen, accompanying Renewable Energy Directive, (i) details exactly when hydrogen or fuels produced from electricity can be defined as fully renewable (thus categorised as RFNBOs), and (ii) provides a methodology for calculating life-cycle greenhouse gas emissions for RFNBOs, to determine whether they meet the Renewable Energy Directive's minimum greenhouse gas emission saving threshold of 70% (compared to fossil fuels).[115] Without such additional measures, potential producers (or importers) would not be able to access the various state support packages and incentives, or contribute to member states targets.

Furthermore, for green hydrogen production to increase (and not merely displace) the volume of renewable energy available in the EU, the first Delegated Act has also outlined an '**additionality principle**.' This requires that any renewable hydrogen production facility should secure new, or additional, renewable energy to power its electrolysers.[116] This can be done in one of two ways:

- **Direct line connection** to a new (additional) renewable energy production facility and does not use grid electricity, or

[114] European Commission (2023), 'COM(2023) 156 final. COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS on the European Hydrogen Bank', 16 March, p. 1.
[115] See European Commission, 'Renewable hydrogen production: new rules formally adopted', June (accessed 7 November 2023).
[116] The Commission estimates that c. 500 TWh of renewable electricity will be required to meet the 2030 ambition of producing 10 MT/y of green hydrogen. Thus, while electricity demand for hydrogen production is currently negligible, it will ramp up significantly towards 2030 with the expected mass rollout of large-scale electrolysers.

- **A grid connected setup**, if the electricity sourced is demonstrably renewable and 'additional'.

Grid connected setups, in particular, will eventually need to meet various criteria to demonstrate practically that they meet these criteria (from 2028[117] and with limited exceptions).[118] These include proving:

- **Additionality.** For production facilities that come into operation, PPAs with renewable energy suppliers must be new. That is, electricity suppliers must have come into operations no more than 36 months before the hydrogen facility.
- **Temporal correlation.** The hydrogen will need to be produced either (i) within the same hour as it is consumed by the hydrogen production facility or (ii) in an hour where there is less demand (practically, when the price is below €20/MWh or 36% of the EU ETS carbon price).
- **Spatial correlation.** The renewable electricity suppliers must either be (i) in the same bidding zone as the hydrogen production facility, or (ii) in a neighbouring bidding zone where electricity prices are equal or higher than that of the production facility's bidding zone.[119]

EU policy makers have thus already started grappling with the interactions of hydrogen-specific measures to broader EU policy objectives and incentive schemes (notably net zero targets, increasing aggregate renewable energy uptake, and necessary certification practicalities). Interactions with other sectors, like gas and competing renewable energy sources, as well as potential economic regulation and competition issues in an eventually mature hydrogen economy similarly require careful consideration. These aspects are discussed more broadly below.

### 4.2.2 Midstream challenges

There are two distinct, although likely related, midstream challenges: (i) establishing and scaling the hydrogen network appropriately and (ii)

[117] Renewable hydrogen production facilities operational before 2028 are exempted from these rules for 10 years, up until 1 January 2038.
[118] Electricity from the grid can also be considered to be fully renewable if (a) the hydrogen production facility is located in a 'bidding zone' where (i) 90% of the electricity mix is renewable electricity or (ii) the emission intensity of electricity is lower than a certain threshold (i.e. 18 $gCO_{2e}/MJ$ ), or (b) the grid electricity consumed by the hydrogen production facility reduces the need for re-dispatching renewable electricity generation (i.e., is consumed during an imbalance settlement).
[119] For a summary see Backer McKenzie (2023), 'Europe: EU publishes rules on "renewable" hydrogen', March.

phasing out the natural gas network in a coordinated manner. These are discussed in turn below.

### Establishing and scaling hydrogen network

Once produced, hydrogen needs to be transported to end consumers. This typically happens through pipelines (in gaseous form) or using non-pipeline means, such as road and rail vehicles and shipping (in gaseous or liquid form). In pipelines, hydrogen can either be transported as an admixture into existing pipelines used for natural gas, i.e. combined or 'blended' with natural gas, or within a separate and dedicated infrastructure, as 'pure hydrogen'.

The most economic form of transport, and thus accompanying upfront infrastructure investments required, depends on the distance and volume of hydrogen transported. At a high level the following considerations hold true.

- **Pipelines** are more appropriate for high-volume transportation to clustered industrial users over medium-to-long distances.
- **Trucks** may be more appropriate for refuelling remote end-users in the transport sector, and may prove to be more economical to transport small quantities (e.g. up to 10 t/day) over short distances (up to 200 km).[120]
- **Shipping** liquified hydrogen (or hydrogen converted into derivatives like ammonia or methanol) may prove more economical if it could be produced at scale, at a much lower cost, and need to be transported over long distances, e.g. across oceans.

Independent of whether the bulk of future EU supply is imported (through shipping) or piped from sources within EU borders (potentially up to North Africa and Eastern Europe), the future hydrogen market is expected to exhibit some of the same **network features** as the current gas network:

- natural monopoly characteristics of the network;
- the importance of secure transport within the network, and a large social benefit to ensuring that this is operated safely.

The hydrogen network may also share significant physical overlaps with the existing gas network, e.g. through repurposing existing gas

[120] ACER (2021), 'Transporting pure hydrogen by repurposing existing gas infrastructure: overview of existing studies and reflections on the conditions for repurposing,' July.

transportation assets. For example, through the European Hydrogen Backbone Initiative, European gas TSOs envisage that the future hydrogen network would be constructed primarily through the reconversion of existing gas networks (for around 60% of the planned hydrogen network), while the remaining 40% will consist of new pipelines/infrastructures. The TSOs expect that the network will gradually cross the entire European territory.[121]

The Commission envisions that the EU gas market design will form the basis for the regulation of a mature hydrogen market. However, there are also unique characteristics of the future hydrogen economy that likely entail novel solutions.

On this basis, the Commission envisions that the EU **gas market design** will form the basis for the regulation of a mature hydrogen market.[122] This is likely to imply that existing European network codes for gas and electricity transmission would act as blueprints for the future hydrogen network—including for example the application of mechanisms such as the third-party access to the network.

However, there are also **unique characteristics** of the future European hydrogen economy that require careful consideration and likely entail novel solutions, to tweak and integrate the traditional regulatory models for gas networks. The two primary distinguishing features are the following.[123]

- **Hydrogen is a manufactured product.** It can be produced anywhere, when abundant renewable sources are available (over and above what is required for electricity generation), along with transport connections to large demand centres. This means that, as opposed to a finite resource that needs to be extracted from specific natural deposits, green hydrogen can be produced competitively in many places. Its production will thus not enjoy the same resource rents and will not necessarily generate the same cash returns that oil and natural gas industries have experienced historically. In turn this would imply that the profits and cash flows that can be leveraged to fund the network build-out may not be sufficient (thereby placing a greater onus on policy-makers to facilitate it).
- **The non-existent hydrogen market**. At the time the current regulatory framework for natural gas was developed, a

[121] With an estimated length of about 53,000 km by 2040. See European Hydrogen Backbone (2022), 'A European Hydrogen Infrastructure Vision Covering 28 Countries', April.
[122] European Commission (2021), 'Proposal for a Directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen (recast)', COM(2021) 803. See for example European Parliament (2023), 'EU Directive on Gas and Hydrogen Networks', April.
[123] See similar discussions in Scheibe, A. and Poudineh, R (2023), 'Regulating the future European hydrogen supply industry: A balancing act between liberalization, sustainability, and security of supply?', October, The Oxford Institute for Energy Studies, OIES Paper: ET26.

European cross-border natural gas pipeline network was already in place. In contrast, for hydrogen there is still significant uncertainty around (i) the most economical sources of supply (both within Europe and through imports), (ii) demand centres, and (iii) the best way to interconnect them (e.g. via pipelines or shipping imports, and if through pipelines, on which locations).

This means that policymakers will likely need to take a more active role in the establishment of transport infrastructure across the EU, defining who will build and operate the required network(s). If network infrastructure is to be built through private investments, it will require careful consideration of the **upfront investments** required for the network to be built at an appropriate speed and scale (as a necessary condition for connecting supply and demand, and establishing the hydrogen market in the first place). However, it will also require some degree of clarity on the timing and nature of future regulation, e.g., given that regulated returns would act as a cap on the upside for investors on *a priori* risky investments, while not necessarily protecting from the downside.

The challenge to policymakers is how to provide this **upfront clarity and investor certainty** in an environment where the main sources of supply and demand, as well as the optimal long-run market structure, are still unknown. There can be a range of optimal market structures[124] that imply different trade-offs between (i) economies of scale in production, but requiring large and costly distribution network, and (ii) smaller, decentralised, production centres with relative diseconomies of scale, but requiring smaller and less expensive distribution networks.

The EU envisions that initially **individual clusters** will develop around demand centres, which can later be interconnected as and when the industry matures and demand grows. The Commission has taken the view that the initial stage of developing hydrogen transport facilities will focus on 'point-to-point' connections between production and demand sites, in industrial clusters and coastal areas.[125] ACER has suggested a similar step-by-step approach to building the EU hydrogen transport

[124] The optimal eventual market structure could range from individual industrial clusters or localised mini-grids, to an interconnection of various clusters (a 'hub-and-spoke' model) or multi-modal transport system, to a pan European infrastructure similar to the current electricity and natural gas grids. See Scheibe, A. and Poudineh, R (2023), 'Regulating the future European hydrogen supply industry: A balancing act between liberalization, sustainability, and security of supply?', October, The Oxford Institute for Energy Studies, OIES Paper: ET26.
[125] European Commission (2020), 'A hydrogen strategy for a climate-neutral Europe', p. 14.

networks, sequenced with the development of demand and supply, and first focussing on distribution within industrial clusters.[126]

The Commission has suggested that these closed distribution systems could be regulated in a similar way to direct lines and closed distribution networks in the current EU Gas and Electricity Directives. These provide for exemptions on issues such as exclusive access and vertical integration.[127]

Longer term, when **longer-distance transport** will be required for the second phase of development of the nation- or EU-wide hydrogen transport networks, **new regulation** will need to be introduced to provide more comprehensive oversight on the sector. Some of the main elements of the current gas network regulation that may become relevant include for example:

- access rights;
- vertical unbundling; and
- network infrastructure financing through regulated tariffs.

While the Commission has made it clear that 'hydrogen infrastructure should be accessible to all on a non-discriminatory basis',[128] the introduction of detailed regulation will be at the discretion of national regulatory authorities, and will ultimately depend on developments in the hydrogen market over time.

For example, if vertically integrated companies are found to be abusing their market position and denying access to network infrastructure to upstream competitors, regulatory interventions such as unbundling may be needed.[129] Germany has already passed regulations that require vertical unbundling between production and distribution[130], and existing vertical unbundling rules (as stated in the gas directive)[131] already apply to hydrogen blending within gas pipelines.

[126] As also discussed in a study recently published by ACER. VIS (2023), 'Study on requirements and implementation of ENTSOG'S CBA for hydrogen infrastructure'.
[127] ACER (2021), 'When and How to Regulate Hydrogen Networks?', February, p. 6.
[128] European Commission (2020), 'COM(2020) 301 final. COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS A hydrogen strategy for a climate-neutral Europe', July.
[129] ACER (2021), 'When and How to Regulate Hydrogen Networks?', February, p. 4.
[130] See for example Clifford Chance (2021), 'Focus on Hydrogen: Germany Implements First Pure Hydrogen Midstream Regulation and Introduces Definition for Green Hydrogen', 28 June, p. 2.
[131] European Commission (2021), 'Staff Working Document, Evaluation Report accompanying the accompanying the Fourth Gas Package', SWD (2021) 457 final, December, p. 41.

The specific regulations required will also need to be nimble, requiring close monitoring and adapting with the development of the market structure. For example, import infrastructures for shipping (which will be in the form of liquified derivatives) will require clear definition and certification to be considered under hydrogen regulation. Similarly, the unbundling and third-party access rules for converting facilities will need to be aligned with those of other transport infrastructures (like pipelines). Here, the existing rules for LNG terminals could act as blueprint, but may need to be adapted.[132]

Furthermore, given the risks and the, so far, limited cost recovery potential of the nascent hydrogen market infrastructure, the traditional model of **cost-reflective tariffs** (alone) may disincentivise the necessary upfront investments required to build the network. During the early stages of network build out, the costs will be significant and the potential return highly uncertain, which would result in high tariffs to be borne by a still small customer base.

Alternative, or compensatory, measures that could be considered include:

- **Subsidies or grants**, similar to supply-side grants, including for example existing mechanisms like the EU Hydrogen Bank, state aid or co-financing via the EU's Connecting Europe Facility (already used for natural gas infrastructure).[133] Alternatively, tax credits could be used to subsidise hydrogen tariffs directly in member states, e.g. similar to the USA's Clean Hydrogen Production Tax Credit.[134]
- **Opt-in tariff regimes**. In Germany, network companies have the option to participate in a proposed opt-in regulation, where participants would be regulated under the proposed hydrogen regulatory regime and receive a pre-determined return on equity through network tariffs. This opt-in feature allows investors to determine their own trade-off between risk and return.[135]

[132] See for example the discussion in Scheibe, A. and Poudineh, R (2023), 'Regulating the future European hydrogen supply industry: A balancing act between liberalization, sustainability, and security of supply?', October, The Oxford Institute for Energy Studies, OIES Paper: ET26, pp. 14-15.
[133] European Commission, 'Energy Infrastructure: Projects of Common Interest (CEF Energy)' (accessed 31 October 2023).
[134] Congress.GOV, 'H.R.5376 Inflation Reduction Act of 2022' (accessed 31 October 2023).
[135] For example, investors who are cautiously optimistic might prefer a pre-determined return on capital through the proposed regulation, and those with more confidence in the growth of hydrogen demand might decide to operate without regulation on price and returns. For more details on the opt-in regulation, see Eversheds Sutherland (2021), 'Germany sets regulatory framework for green hydrogen production and hydrogen grid projects', 6 July.

### Coordination with natural gas network phase out

One of the main risks facing existing gas assets is **asset stranding**, as fewer and fewer customers may use (and thus pay for) the gas grid. Assets may thus need to be decommissioned before they are fully depreciated. The regulatory tools to deal with these risks are however already widely understood and implemented, including for example:

- shortening asset lives, to increase annual depreciation charges in the short term, to allow investment recovery;
- changing the depreciation policy, bringing cash flow allowances forward to reflect the expected customer base;
- adjusting the RAB indexation method from real to nominal, to decrease future charges;
- uplifting the cost of capital, to compensate networks for the stranding risks.[136]

However, the phase out of natural gas assets should not be considered in isolation, given the role that **repurposing existing gas networks** could play in both (i) reducing asset stranding and (ii) decreasing the costs of the hydrogen network rollout. ACER's review of existing studies suggests that conversion should be technically possible, although it has some practical challenges, and less costly than building new hydrogen pipelines.[137] However given the uncertainties around the extent (and locations) of the nascent hydrogen market's development, ACER has emphasised that the timing of investments should be driven by market developments. It has signposted certain of the key conditions that would need to be met before conversions occur:

- the availability of parallel lines of existing transport networks, at least one of which can be converted for pure hydrogen use;
- ensuring the security of supply of natural gas to consumers, both during and after conversion; and
- the development of a hydrogen market in the specific areas where conversion is taking place.

As with the issue of vertical unbundling of hydrogen production and transport, regulation can also play a role in managing **cross-subsidisation** between gas and hydrogen network users. Whilst some have noted that merged tariff models across gas and hydrogen assets

[136] See for instance CEER (2020), 'CEER Note on Stranded Assets in the Distribution Networks', 3 July, and Oxera (2021), 'Regulatory tools applied to gas networks to accommodate the energy transition – Note prepared for Firstgas, Vector and Powerco', 26 August.
[137] ACER (2021), 'Transporting pure hydrogen by repurposing existing gas infrastructure: overview of existing studies and reflections on the conditions for repurposing, July.'

could be considered, given the unique challenges and interlinkages between existing natural gas and future hydrogen assets,[138] they could lead to unintended consequences for consumers[139] and distorted incentives for the efficient allocation of resources.[140]

To avoid cross-subsidisation, ACER and the Council of European Energy Regulators (CEER) recommend using independent cost-recovery instruments, such as a separate regulatory asset base, to remunerate hydrogen assets.[141]

### 4.2.3 Downstream challenges

Policymakers should also consider **transition fuels and infrastructures** in the short term. For example, the most notable distinction between the UK and EU hydrogen strategies is their view on the roles of grey or blue hydrogen (gas/coal with CCUS) as a potential transition fuels in builling the hydrogen economy.

Policy-makers should also consider transition fuels and infrastructures in the short term.

- The UK has committed to a 'twin track' approach, supporting both low-carbon and renewable hydrogen. In the shorter term, the deployment of CCUS-enabled hydrogen capacity is expected to deliver cost-effective low-carbon hydrogen production at scale, while driving investment across the value chain and facilitating the development of hydrogen technologies to reach the stage of commercialisation.[142]
- In contrast, the priority for the EU is to develop green hydrogen, with blue hydrogen playing a smaller role as transitionary technology in the shorter term, given concern around stranding risks for low-carbon hydrogen assets. This is echoed in the EU

[138] Scheibe, A. and Poudineh, R (2023), 'Regulating the future European hydrogen supply industry: A balancing act between liberalization, sustainability, and security of supply?', October, The Oxford Institute for Energy Studies, OIES Paper: ET26.
[139] For example, similar models assume that the current consumers of gas will be the same as those who will eventually consume hydrogen, while this is in fact uncertain, and may result in certain segments of gas consumer, e.g. households, subsidising the tariffs of the initial consumers of hydrogen, e.g. likely industry.
[140] For example, if the profits from transporting gas are used to subsidise the development of a hydrogen network, this could facilitate initial operations of the hydrogen network with no guarantee of its long-term stand-alone viability and thereby the stability of supply for users.
[141] ACER (2021), 'When and How to Regulate Hydrogen Networks?', February, p. 8.
[142] For example, in May 2021, the Department for Business, Energy and Industrial Strategy (BEIS) already initiated the so-called CCUS Cluster Sequencing, a process that determines the natural sequence for locations to deploy CCUS. This aim is to identify at least two CCUS clusters that are suited to deployment in the mid-2020s. In the longer-term (from the mid-2020s onwards), the scale of production for electrolytic hydrogen in the UK is expected to ramp up, as the costs of electrolysers decrease further.

hydrogen strategy and some of the early-mover member states like Germany and Italy.[143]

As with grey hydrogen production, a transitional consideration on the network side is the extent to which **blending through existing gas pipelines** can be used to develop the hydrogen market in the short-term (as opposed to waiting for pure hydrogen pipelines to be built).

Technically, there is a limit to the degree of blending with natural gas that is possible before modifications are required on the network infrastructure and/or consumer-side installations. Alternatively, expensive filtration to separate out the blended gas at the point of use would be needed. Moreover, hydrogen consists of smaller, less dense molecules and is more flammable, thus requiring different design modifications than those catered for by gas pipelines. Some of the projects that have started exploring the feasibility of blending[144] have local exemptions to existing legislative restrictions on the blended gas and are permitted to inject up to 20% hydrogen.[145]

It is worth noting that many of the decisions that will determine the transition pathways of the various green energy sources alternative to natural gas, like hydrogen, may be taken in the short term. This means that, despite the fact that the optimal scale and speed of the hydrogen's economy is not yet known, policymakers need to outline some **long-run visions** for how a mature market for hydrogen will be structured and operated. Indeed, some long-term vision for the market development is required to provide the certainty for potential market participants, as well as to informs the policy and regulatory tools to be developed. The EU has made significant progress on both these fronts, as discussed above.

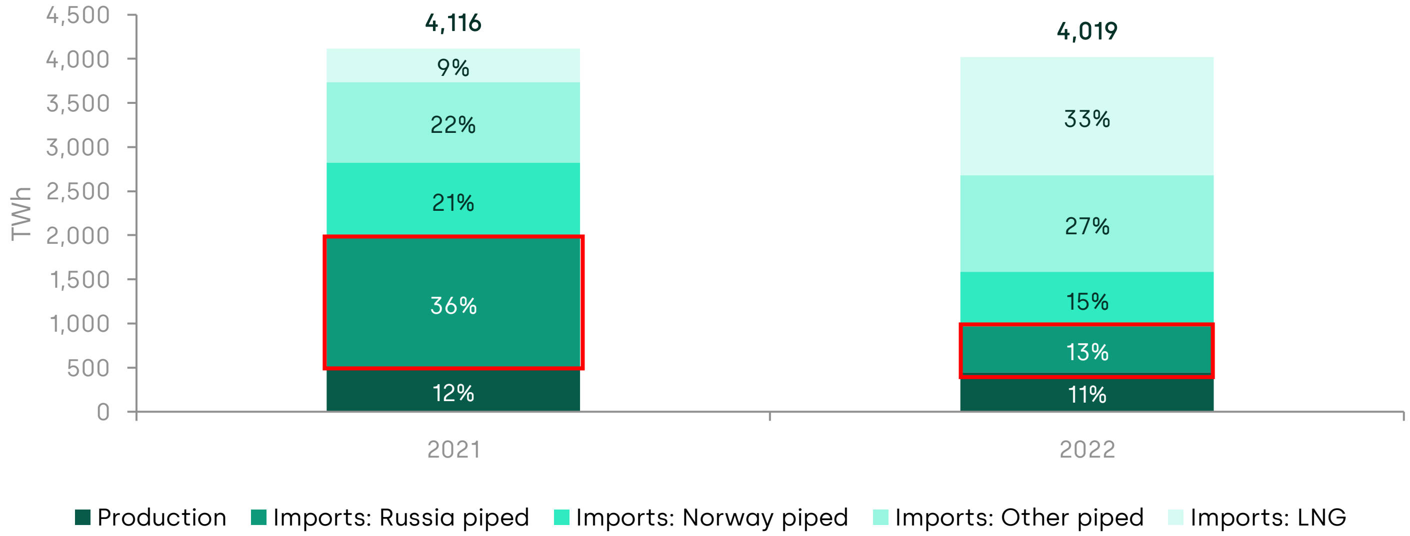
Several decisions that will determine the transition pathways of hydrogen may be taken in the short term. However, short term flexibility and continued adaptation to as yet unknown unknowns will remain key.

However, short-term flexibility and continued adaptation to as yet **unknown unknowns** will remain an important consideration. This is illustrated by recent initiatives to reduce the EU's reliance on Russian

[143] For example, the German federal government, in its National Hydrogen Strategy published in June 2020, stated that it believed that only renewable hydrogen is sustainable in the long term. Similarly, the Italian government as part of the Italian Recovery and Resilience Plan has prioritised investments in the production of renewable hydrogen in brownfield sites (so-called 'hydrogen valleys'), renewable hydrogen use in hard-to-abate industries, the development of industrial plants for the production of electrolysers, use in the transport sector and R&D on hydrogen. German federal government (2020), 'The National Hydrogen Strategy', June, p. 2. Italian government (2021), 'Piano Nazionale di Ripresa e Resilienza. Part 2: Description of reforms and investments – Component M2C2', section 3.1, 'Production of Hydrogen in brownfield sites (Hydrogen Valleys)'.
[144] GRYHD in France and HyDeploy in the UK. See respectively ENGIE, 'The GRYHD demonstration project' (accessed 3 November 2023). HyDeploy (accessed 3 November 2023).
[145] Dolci et al. (2019), 'Incentives and legal barriers for power-to-hydrogen pathways: An international snapshot', International Journal of Hydrogen Energy, May, 44(23).

piped gas. The pre-crisis (2021) level of gas imports from Russia was around 1,500TWh (or 36% of total supply), which dropped to just over 500TWh in 2022 (13%)—mostly replaced be increased LNG imports. The gas supply crisis has resulted in its own (*a priori* unexpected) short-term challenges and opportunities, and may create further opportunities for the expansion of green alternatives to natural gas, including hydrogen.

Figure 4.4 Decreased reliance on Russian piped gas, 2021 vs 2022




Source: Oxera analysis based on European Commission (2022), 'Quarterly report on European gas markets.'

Relatedly, while the EU has identified green hydrogen as one of the cornerstones of its net zero energy mix, it is important that the 'option value' of a **flexible transition process** is accounted for. For example, given the relative infancy of the technology to produce green hydrogen, if a technology emerges that enables the production of hydrogen at small scale more competitively than previously expected, historical commitments to a large distribution network should not necessarily preclude the ability to take advantage of this going forwards. Similarly, if other technologies (e.g. biofuels, district heating or electrification) prove more cost effective at scale, the EU's development pathway should remain flexible to adjusting the role of green hydrogen.

While the EU has identified green hydrogen as one of the cornerstones of its net zero energy mix, it is key that the 'option value' of a flexible transition process is accounted for.

# 5 Infrastructure investment challenges

The transition towards new energy systems is requiring and will require significant investments over the course of the coming years. For reference, the cumulative investment needed into electricity generation and renewable hydrogen alone (i.e. not taking into account grid investments) are estimated to be within a range of €2.2–€5.0 trillion over 2021–2050 in Europe, depending on the transition scenario.[146] In terms of grid investments, the Commission estimated that to fulfil the objectives of the REPowerEU, grid investments of €584 billion are needed in the EU by 2030.[147]

Given that the transition is a market-wide effort, significant investments at all levels of the energy value chain are needed.

Given that this transition is a market-wide effort, significant investments at all levels of the energy value chain are needed, for a variety of asset categories: (i) **production assets**, which are destined to provide for the energy demand; (ii) **network assets**, which are necessary to properly dimension networks and adapt them to new usages; and (iii) **flexibility assets**, which are needed to ensure that networks remain in balance despite the significant changes in the energy mix that is expected to occur in the coming years.

Each of these asset categories are confronted with specific market failures. As a result, the appropriate financing constraints and the instruments needed to alleviate these are not necessarily identical from one asset category to the other, and perhaps not even between different assets within the same category.

At the same time, significant uncertainties remain around what the future energy system will look like.

At the same time, and as outlined in previous sections, **significant uncertainties** remain around what the future energy system will look like. For instance, the role of technologies that are still in their infancy today in the decarbonised energy system of 2050 necessarily remains very uncertain for reasons related to the uncertainties associated with their eventual technical performance, safety, public acceptance, and costs. Meanwhile, there may exist a natural bias amongst policymakers and market participants today towards the adoption of today's mature technologies, such that these could attract most of the financing available. It follows that there remains a risk that the dimensioning of existing technologies within the future energy system might be

[146] BloombergNEF (2022), 'Europe's Path to Clean Energy: A $5.3 Trillion Investment Opportunity', Blog Article.
[147] European Commission (2022), 'Commission Staff Working Document implementing the REPowerEU action plan: investment needs, hydrogen accelerator and achieving the bio-methane targets', 18 May, p. 16.

inappropriate compared to what would be the optimal energy system (as analysed ex post by policymakers in the future). In other words, the optimal allocation of capital is extremely challenging, suggesting that the risk of asset stranding and affordability concerns around the cost of the energy transition could be high, compared to the expected benefits of today's unproven technologies in terms of their impact on the optimality of future energy systems.

## 5.1 The market failures hindering financing for different categories of assets and how to address them

In order to unlock investments, it is necessary to design financing instruments that address the market failures affecting each asset category. Because these market failures are different from one category to the other, the financing instruments might be different as well; even within certain categories, some instruments might be more suited for specific assets than for others, given their technological maturity, use in the system and/or technical characteristics.

### 5.1.1 Production assets

Low-carbon energy production technologies suffer from **several market failures**, resulting from their capital-intensive nature, long asset lives and current energy market designs giving rise to merit-order effects and price cannibalisation: funds committed upfront are locked-in for a long period until payback and profitability is ensured through uncertain market revenues. These are sometimes compounded by lack of credible commitments on long-term transition planning and the continuity of state support, coordination failures resulting in network constraints, and the mispricing of externalities rendering these technologies less appealing than they would otherwise have been.

For example, some low-carbon production technologies such as solar, wind, and nuclear are particularly affected by these market failures. Indeed, these technologies have the peculiarity of being particularly capital-intensive and having practically very low marginal costs while at the same time having limited flexibility on a stand-alone basis, unlike conventional thermal generation. The current electricity market design, which relies on marginal pricing is ill-suited for these technologies since they rely on inframarginal rents in order to recoup fixed costs over their operating life. Their ultimate profitability therefore depends on prices that they essentially take rather than set, creating long-term uncertainty for investors as soon as funds are committed to the production unit.

To a large extent, the key issue with most of these technologies (nuclear being a significant exception) is to ensure that these investments can be recouped over the lifetime of the assets, i.e. to **manage the uncertainty** arising from price formation on markets. If such assurances can be given, then it is likely that funds will be found to finance investments, as many of these technologies (in particular wind and solar) are already mature.

The key issue is to ensure that these investments can be recouped over the lifetime of the assets, i.e. to manage the uncertainty arising from price formation on markets.

Current proposals for a reformed electricity market largely take stock of the lessons learnt over the past two decades (over which schemes such as feed-in tariffs and premia became largely dominant in the EU) and therefore revolve around the idea that low-carbon technologies usually need a form of **support** in order to be attractive to investors. As a result, proposals revolve around the idea of providing revenue certainty to these generators by generalising the use of **contract-for-difference mechanisms**, a form of feed-in premium that has already been largely adopted by European countries (as discussed in section 3.3). **PPAs** can provide a similar form of revenue certainty, although they involve counterparty risk more so than state-backed CfDs. Crucially, these contracts are generally long-term, creating a form of two-way commitment between the producer and the off-taker.

Some reform proposals even go as far as proposing **to split the wholesale market** as it is currently designed based on the dichotomy between different kinds of generators (renewable vs non-renewable, or dispatchable vs non-dispatchable).[148] The split wholesale markets would then be tailored to the specificities of the generators participating in each market. For example, Greece proposed a split market where non-dispatchable and nuclear plants would participate in a day-ahead market where participants would submit bids based on volumes and be remunerated through CfDs, whereas dispatchable units would participate in a day-ahead market resembling the current design.[149] Such proposals involve significant changes compared to the current market design, where all generators compete in the same wholesale markets and price is formed on the basis of marginal costs, with some generators benefitting from CfDs separately.

Reform proposals embed financing support for low-carbon production capacity through long-term contracts such as CfDs or PPAs. The key question is whether these mechanisms will be sufficient to unlock required investments.

In a way, reform proposals for production embed financing support for low-carbon production capacity in the form of operating support through long-term contracts such as CfDs or PPAs, shielding production from revenue risk and ensuring that long-term return targets are achievable. As discussed in section 3, some degree of innovation exists

[148] See for example Oxera (2023), 'Decoupling electricity and fossil fuel prices: bright idea or lights out?', Agenda, April.
[149] Council of the European Union (2022), 'Proposal for a power market design in order to decouple electricity prices from soaring gas prices—Non-paper by Greece', 22 July.

with regards to the way support is calculated and awarded to producers: the key question going forward is whether these mechanisms will be sufficient to unlock a level of investment commensurate with the needs to carry out the transition.

### 5.1.2 Networks assets

Financing network investments poses a different kind of challenge compared to production assets given the sheer **scale of the investment programmes** to be carried out. Network operators, especially electricity network operators, will therefore be required to significantly expand their balance sheets in order to finance these programs. Some network operators have already tapped into the potential offered by new financial instruments such as 'green bonds' in order to raise financing for new assets, with RTE in France (who raised €850m in January 2022 in order to finance offshore windfarm connections and interconnection capacity) adding to a list already comprising National Grid in the UK, Terna in Italy, or TenneT in the Netherlands and Germany.

Recently, network operators have been able to raise sufficient funds to meet the **financing needs** associated with investment programmes. It is likely that investor interest in such investments remains strong, as network assets are usually subject to price control regulation such that, in principle, long-term cost recovery is assured by the regulatory contract between the regulator and network operators.

It is likely that investor interest remains strong as, in principle, cost recovery is 'assured' by regulation. However, the scale of investments and a higher level of risk for certain assets might lead to higher returns expectations.

However, the significance of certain investment programmes (e.g. in electricity), or the unproven or uncertain nature of others (e.g. conversion of gas networks to hydrogen) creates a challenge in terms of regulatory acceptance. Indeed, the scale of investment programmes, as well as what might be a higher level of risk for certain assets (e.g. offshore transmission assets), might lead to higher returns expectations from investors that may not be fully reflected in regulatory allowances in the short or medium term, which might pose **financeability challenges** for network operators (i.e. an inability to meet financing costs under the regulatory allowance) and, therefore, reduce the attractiveness of such investments.

This is especially true in times of heightened uncertainty around interest rates and high inflation, as some regulators might seek to limit the increase in customer bills by limiting the increase in cost of capital allowances within the regulatory framework, or by curtailing the breadth of investment programmes.

The issue at hand for networks investments is primarily one of regulatory acceptance.

Overall, the issue at hand for network investments is primarily one of **regulatory acceptance**: acceptance that investment programmes are set to increase, and acceptance that there may be an increase in networks' cost of capital given transition requirements. Ultimately, there is a need to ensure buy-in from consumers who are set to see their bills increase as a result of these dynamics. To some extent, and as described in section 3, it is also likely that network investments will be 'pulled' anyway by investments elsewhere in the system (as is the case for offshore transmission assets, for example), such that 'proactive' network extensions might be limited to investments necessary for system adequacy and interconnections. When this occurs, it will be necessary for regulators to continue ensuring that long-term returns expectations are met.

Network assets related to newer low-carbon technologies such as carbon capture usage and storage or hydrogen are specific in that they are subject to **coordination failures**. Their usage is not guaranteed due to the technologies they serve being in their inception. As a result, the observations above apply to them as well insofar as some EU countries are considering regulating them through the dominant regulatory model applied to gas and electricity network operators (the so-called RAB-WACC model) from the get-go.[150] Compared to other established network assets, though, developers of these network assets might face difficulties in ensuring that the infrastructure is adequately used, with an impossibility to realise significant upsides if the technology is successful due to the regulated model. As a result, other countries have warned that such networks should not be immediately regulated, and that priority should be given to the **development of integrated solutions** depending on business needs, with regulation being applied when and as necessary.[151] If this view is followed, hydrogen networks would initially be developed as private networks: financing would be dependent on the need for these networks to be developed as part of wider industrial projects. Third-party access could be regulated on a negotiated basis as a lighter form of regulation in the first instance, with stronger forms of regulation applied only later as the network matures and integrates.

[150] For example, this is the case in the UK for carbon capture, usage and storage, or in the Netherlands, where the current natural gas TSO is set to play an important role with regards to the development of hydrogen networks. Department for Business, Energy & Industrial Strategy (2022), 'Carbon Capture, Usage and Storage—An update on the business model for Transport or Storage', January. Clifford Chance (2023), 'Focus on hydrogen: regulatory developments in the Netherlands', April.
[151] This recommendation has been made by France with regards to the development of hydrogen networks. See for example Commission de régulation de l'énergie (2021), 'Contribution de la Commission de régulation de l'énergie à la consultation publique pour la révision des règles de l'Union européenne en matière d'accès au marché et aux réseaux de gaz', June, pp. 3–4.

### 5.1.3 Flexibility assets

Finally, as energy systems are destined to accommodate an ever-increasing share of renewable energy in the coming years, flexibility will be needed to maintain the overall system balance.

This will need further investments, aimed at developing **new storage solutions** (e.g. batteries or hydrogen) or maintaining **flexible generation units** for supply management (e.g. conventional thermal generators used for short-term, dispatchable reserve production). It is worth nothing that these two different types of solutions currently stand at two very **different stages of development**: new storage solutions are largely not yet viable at scale, and still require significant development and innovation investments before becoming commercially viable, while flexible generation units are already commercially available.

Separately, new storage solutions may also be **subject to a form of cannibalisation** once their uptake becomes sufficiently high. Indeed, storage solutions generate a profit from exploiting the spread between prices observed in low-demand periods and those observed during high-demand periods. As more storage comes online, the price spread will tend to narrow, as storage will help bring prices down in high-demand periods. In other words, storage solutions will become less profitable as more storage capacity becomes available.

Consequently, financing needs and requirements are quite different for these two types of solutions. Flexible generation units can already be financed under current **balancing market mechanisms**, although they are set to become costlier as they are phased out and become less likely to be called for production. Separately, in order to ensure overall system adequacy and replace missing money problems, European countries have set up **capacity remuneration mechanisms**, under which certain generation units are used as part of a strategic reserve called in case of a severe stress of the electricity system, and are remunerated for this through state support, financed by electricity bills or fiscal levies.

Nascent (long-duration) storage solutions, however, are still unlikely to be viable under current market or capacity remuneration mechanisms. Some solutions do exist for them to unlock the financing necessary to progress them towards commercial viability: either through **state support**, where the state could intervene in order to cover the funding gap that still exists for these technologies, mostly by providing low-cost capital through grants or subsidised loans; or by creating **new, innovative contracts** that would enable these technologies to be competitive despite high costs in their inception phase. For example, contracts-for-difference can be designed in such a way so as to incentivise co-investment (or, at the very least, co-location) between renewable capacity and battery capacity. Other forms of CfDs, such as carbon contracts-for-difference can be used to compensate the differential between the use of carbon-emitting technologies and the use of low-carbon gases, especially for hydrogen. On the long term, if the cannibalisation effects of storage do materialise, it might be the case that storage assets might require an ongoing form of support in order to ensure their long-term profitability, even after they reach maturity.

Overall, it is certain that the financing of the energy transition will require a significant coordination of efforts by all parties involved in the value chain. Current market mechanisms, as well as the reforms considered, seem to indicate that responsibilities will be split along these lines: given the breadth of investment needs, it seems that private investment is expected to be called upon to provide the bulk of initial financing. Reformed market mechanisms, regulation and/or state support, on the other hand, will be called upon to ensure that investors can earn the appropriate long-term return expected in exchange of the financing provided. However, how these mechanisms will be designed exactly depends on the wider discussion on market reforms; and given the breadth of investment needs, it is still unclear to what extent these mechanisms will be able to unlock the financing necessary to achieve a full-fledged transition towards new energy systems.

## 5.2 Guiding investments under uncertainty: system optimality and affordability

The mechanisms described previously that are to be used to encourage investments in the energy transition need to be funded; over time, costs will be recovered from consumers, or from taxpayers directly and at the time of investment, depending on how investments are supported. Undoubtedly, achieving the energy transition will require **significant investment outlays**: ideally, the transition would be achieved while minimising its costs and its impact on consumers' bills, in order to ensure **affordability**.

Undoubtedly, achieving the energy transition will require significant investments. However, the path towards the future energy system is uncertain.

However, the path towards the future energy system is uncertain. It is unclear what the optimal energy system is to achieve carbon neutrality while ensuring network reliability and supply and demand adequacy. Some technologies that are being explored today might not live up to the expectations while others might not have been explored enough. As a result, it is likely that capital may be misallocated as progress toward a new, transition-compatible energy system is made. Yet, despite this context of radical uncertainty with regards to what the future holds,

It is likely that capital may be misallocated. Yet, despite this context of radical uncertainty with regards to what the future holds, investments need to be undertaken today.

investments need to be undertaken today. In other words, mistakes are in all likelihood inevitable, but doing nothing is not acceptable either.

Schematically, and as a thought experiment, one can consider two different future energy systems in the context of the energy transition:

- **The minimum regrets system**, where the risk that investments become stranded (and, as such, investments in new, unproven technologies) is minimised and investment in existing, mature technologies is favoured through the use of technologically neutral, minimum subsidy auctions. Such a system may be expected to be sub-optimal from a welfare perspective and from the point of view of future policymakers and consumers. Importantly, this system may turn out not to be sufficient to achieve net zero, although it might still achieve significant reductions in carbon emissions compared to today's system. While it may appear less costly in the short-term, it is possible that such a system could also prove to be lower 'value' over the long-term if system outputs (e.g. decarbonisation, energy supply, quality of service) are lower, and costs remain higher, than end users would prefer.
- **The optimal system**, where all objectives (achievement of carbon neutrality, overall capacity adequacy and flexibility as well as efficient allocation of capital) of the energy transition are met. Such a system would be expected to be costlier in the short- to medium-term than the minimum regrets system described above due to more assets being stranded (or underutilised), greater innovation effort, and the costs of incentives directed at ensuring timely investment. On the other hand, it would meet other objectives better, with welfare maximisation at least cost possible. Importantly, the emphasis on innovation that is implicit in the development of the optimal system would be expected to result in a time path of emissions from the present to 2050 that would result in a significant reduction in the *cumulative* emissions compared to the minimum regrets system described above.

In all likelihood, the actual future energy system will not be the minimum regrets system. At the same time, the optimal system is unlikely to be achieved in practice.

In all likelihood, the actual future energy system will not be the minimum regrets system: there is a wide recognition that a mix of technologies, including innovative and unproven technologies, is necessary to achieve a balanced and resilient system fit for carbon neutrality. State aid guidelines for attributing support to electricity generation technologies, for example, allow for a wide range of exemptions to the technological neutrality principle, allowing countries to hold technology-specific auctions. At the same time, the optimal system is unlikely to be achieved in practice, as it would require perfect foresight, coordination, and planning in order to be implemented.

The question is therefore **how to best allocate capital** in order to build the future energy system: proposed investment mechanisms have been designed in a way such as to let market forces play their role, and reform proposals still rely on markets to play a significant role in the coming years. However, these mechanisms remain guided by public authorities, who are monitoring closely some support schemes and are setting the policies accompanying the energy transition. Yet, markets and public authorities may have different 'views' on how investments should be allocated. For example, the mispricing of negative externalities and the significant potential for positive externalities may lead private investors to favour minimum regret solutions, creating potential discrepancies with the policy goals set by authorities. For newer technologies, the issue is further compounder by the coordination failures along the value chain and between supply and demand, which may further hinder the investment effort.

> The question is how to best allocate capital in order to build the future energy system.

Depending on the wider institutional setting and regulatory regimes in place across different member states, sectors and domains, market outcomes may be expected to favour technologies with lower capital costs, shorter payback periods, and less technological or regulatory uncertainty. To the extent that this results in a reliance on mature technologies the overall costs may be lower and perceived as affordable, but the end result may fall short of expectations on one or more dimensions in terms of what a transition-compatible energy system should achieve.

On the other hand, public authorities may have a specific goal in mind as regards what energy system would be appropriate for the future, but might implement solutions that turn out to be costly or inefficient compared to the optimal system.

The reality, in all likelihood, is that because of the **uncertainties**, the formation of the future energy system is going to involve **trial and error** and a degree of **fragmentation** of national approaches to the ultimate goal of carbon neutrality. As the lessons are learned with regards to what approaches are the most efficient to achieve the multiple objectives of the energy transition, some investments will become partially or entirely stranded in the future if they prove inefficient to help the energy transition effort. Just like existing fossil fuel assets are at risk of becoming partially stranded, some clean technologies may become partially stranded if they fail to live up to the expectations placed on them. This will create additional costs to the system compared to both

> In all likelihood, because of the uncertainties, the formation of the future energy system is going to involve trial and error and a degree of fragmentation of national approaches

the minimum regrets and optimal systems. These costs will be all higher as different paths to carbon neutrality are being explored by different countries, and policies are subject to future changes as lessons are being learnt.

The fact that uncertainties are set to put energy systems on a difficult path between the minimum regrets system and the optimal system only reinforces the **affordability challenge**. Consumers might have the perception that solutions being put in place require financial efforts from them in the short to medium term to improve long-term welfare, something to which they might not consent to, especially if these efforts cover stranded costs that might be retrospectively seen as policy mistakes.[152] At the same time, investors might not be willing to commit to the costliest solutions if uncertainties remain strong regarding future potential or the treatment of stranded costs, with this issue affecting newer technologies such as hydrogen more so than mature ones. This raises the question of **risk allocation** between investors and consumers: current proposals to incentivise investment have transferred some risks from investors to consumers (e.g. revenue risk in the case of renewable electricity generation under CfDs), and further transfers in the same direction might occur in the future, at the expense of consumers. At the same time, if such risks are not transferred, it might be the case that investment will fall short of what is needed to achieve the transition in a way that balances the multiple objectives of the energy system.

The fact that uncertainties are set to put energy systems on a difficult path between the minimum regrets system and the optimal system only reinforces the affordability challenge.

[152] This could be the case even if some forms of support end up being in favour of consumers: at the height of the energy crisis, CfDs have helped mitigating the increase in electricity prices, given that strike prices could be much lower than wholesale market prices.

# 6 Questions for discussion

Oxera proposes to structure the discussion around three overarching themes and the subsidiary questions summarised below.

To facilitate the navigation through the briefing paper, references are provided to relevant sections in this briefing paper that are relevant for of the questions.

A. During the energy crisis of 2022, European countries implemented a wide variety of short-term measures that included interventions to control wholesale and retail market prices, direct support to consumers, and mandatory gas storage requirements.

- Given that European energy markets continued to function during the crisis and the risks of uncoordinated policy interventions, in hindsight were all these disparate measures necessary? Relevant sections: 2.2.
- Under what conditions would measures such as price caps and other short term market interventions be justified? Relevant sections: 2.2.
- Did (or will) the energy crisis measures lead to lasting improvement in security of supply? Relevant sections: 2.2.
- Does the European response to the energy crisis provide a good example for how to respond to future crises? Relevant sections: 2.2, 3.3 and 5.1.

B. Completing the energy transition and achieving climate neutrality will require significant investment in new infrastructure.

- Given the volatility of carbon prices derived from the EU ETS can it provide the long-term price signals necessary to incentivise the investments required? Would it be better to adopt a carbon tax? Relevant sections: 2.3.
- Is the problem of 'missing money' in the European energy sector exaggerated and have current EU energy reform proposals adequately addressed this problem (or will they address it)? Relevant sections: 3.2, 3.3 and 5.1.
- Given that a variety of energy sector investment subsidy mechanisms have been tried in the past, is the use of competitively tendered CfDs the 'optimal' way to subsidise

clean energy in future? Relevant sections: 2.3.3, 3.3.1 and 4.2 and 5.1.

- The energy transition will require significant investment in grids to accommodate new renewable and low carbon energy sources, but grids are typically considered to be natural monopolies and are regulated accordingly. Do grid operators need to be restructured and regulations revised to ensure timely investment in new infrastructure, and if so how? Relevant sections: 3.2.2, 3.3.3, 4.2.2, 5.1.2 and 5.2

C. Alongside more infrastructure, completing the energy transition will require investment in new technologies and creation of entirely new markets and supply chains such as for green hydrogen.

- Is the current combination of public subsidies and carbon pricing sufficient to support the development of a new market for hydrogen? Relevant sections: 4.2.
- As new technologies mature, supply chains become more complex, and market conditions change so policies and regulations are likely to need to adapt. Given that regulatory uncertainty can disincentivise investment, how should policy makers trade off certainty for consumers and investors against retaining policy flexibility? Relevant sections: 4.2, 5.1 and 5.2.

# A1 US Inflation Reduction Act

The Inflation Reduction Act (IRA) is a wide ranging piece of US legislation that came into effect in August 2022. Selected measures provided for in the IRA that relate to the energy sector include those to:[153]

- increase investment in renewable and low carbon energy sources (i.e. 'clean' energy sources) such as wind, solar, CCS and green hydrogen that could enable the US to reduce its carbon emissions by around 42% by 2030 (relative to 2005 emissions);
- establish production and investment subsidies taking the form of tax credits to manufacturers and suppliers of renewable energy products, components, and materials;
- establish tax credits to subsidise the sale of electric vehicles by those manufacturers that comply with 'local content requirements';
- subsidise clean energy production at specified rates per kWh of energy.

Official estimates of cumulative IRA subsidies (including loans, tax credits, incentives, and other expenditures) that are expected to be granted over the period 2023–32 are $391 billion, or approximately €370 billion.[154] This budget could include:[155]

- $198 billion support for clean energy;
- $37 billion in support for manufacturing of clean technologies and products;
- $36 in support of clean fuels and vehicles;
- $27 billion in support for buildings energy efficiency and electrification;
- $75 billion for environmental improvements (air pollution, waste, conservation), transportation, and other infrastructure.

With the exception of subsidies to renewable and low carbon generation, it has been estimated that the subsidies available in the US

[153] REPEAT (2022), 'Preliminary report: The climate and energy impacts of the Inflation Reduction Act of 2022', August.
[154] Committee for a Responsible Federal Budget (2022), 'CBO scores IRA with $238 billion of deficit reduction', 7 September.
[155] Ibid.

are broadly similar to those available in the EU for some technologies or purposes.[156]

Meanwhile, as regards EU state aid for environmental protection, renewable energy, and energy efficiency, annual expenditures have been between €60-70 billion since 2016.[157] Extrapolating this figure for the coming decade would imply cumulative EU subsidies of between €600-700 billion on 'clean energy'. The estimates cited in the introduction to section 5 suggest that the expenditures on renewable energy and hydrogen in the EU in the period to 2050 could be substantially higher than this figure.

That said, it is important to note that the IRA subsidy estimates are based on figures published by the US Congressional Budget Office (CBO) that is not an independent forecaster. Also, since a large share of IRA funding is through the use of tax credits, its overall fiscal impact will depend on uptake of these incentives whose total value remains uncapped.[158] Furthermore, subsidies for beneficiaries that qualify within the coming decade would be eligible for support throughout the lifetime of their facilities, but the CBO has not accounted for IRA related subsidy costs beyond 2032. As a result, it has been widely reported that the 'true' cost of the IRA may be over $1.2 trillion, or around €1.1 trillion.[159]

Some of observations that are relevant to the issues discussed throughout this briefing paper include the following.

First, both the EU and the US deploy many of the same mechanisms as part of their overall policy frameworks directed at decarbonisation as well as the expansion of renewable and low carbon energy technologies. However, there are important differences in the detailed design and implementation of specific policies. For example, as already mentioned above, both the EU and the US have in place large subsidy programmes for green technologies and these operate largely at the federal level in the US whereas in the EU these programmes are administered both by member states and through EU programmes. Also, these subsidy programmes are structured differently, with the EU and the US each placing different emphasis on the subsidy measures used (e.g. use of direct grants or tax credits). In the case of carbon pricing,

[156] Bruegel (2023), 'How Europe should answer the US Inflation Reduction Act', February, p. 6.
[157] European Commission (2023), 'State aid Scoreboard 2022', 24 April, p. 77.
[158] European Parliament (2023), 'EU's response to the US Inflation Reduction Act', June.
[159] Jansen, J. et al (2023), 'For climate, profits, or resilience? Why, where and how the EU should respond to the Inflation Reduction Act', 5 May, p. 3.

both the EU and the US have cap-and-trade schemes that share several common design features, although in the US these are administered at the state level. While the overall effectiveness of EU and US policies differ, it is not necessarily obvious whether the IRA will be performing better than the equivalent EU scheme.

Second, in contrast to the point made above, what seems to be more certain is that the IRA's impact on US emission reductions (through deployment of clean energy technologies) could be significant and, as such, these will contribute to lower emissions globally. Furthermore, the IRA is expected to contribute to the development of key technologies that will be central to completing the energy transition and climate neutrality. In turn this could help to reduce the cost of these technologies further.

Third, the EU and the US have recently placed greater emphasis on the impact that each other's climate and energy policies could have on their international competitiveness, trade flows, and energy security. For example, the EU's CBAM and the US IRA's inclusion of local content requirements and targeted manufacturing subsidies are recent examples of policies whose merits and potential adverse impacts are actively being debated. Similarly, the potential impact of the IRA on reducing US energy prices (especially the impact on electricity prices of falling clean energy technology costs) may also adversely affect the international competitiveness.

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