Energy and climate transition: How to strengthen the EU's competitiveness

A study for

BUSINESSEUROPE

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Foreword by BusinessEurope

European business and industry firmly support an ambitious EU energy and climate agenda. This is demonstrated by the massive private and public investments which have already been put into modernising and making our economy, industries and value chains more sustainable. This is a seismic shift which will benefit our society for decades to come.

At the same time, the recent energy crisis has intensified the competitive pressure on European businesses, particularly in the hard-to-abate sectors. European industry is now at risk of losing its worldwide market share to competitors with lower production costs and, on average, much higher carbon intensity. Uncompetitive European energy prices, which are projected to remain higher than those of our major competitors over the coming decades, are playing a major part in this decline. The result is a fundamental risk to our long-term competitiveness and Europe's ability to invest in the transition to a low-carbon economy.

The following report analyses this potential competitiveness gap in a global context and the possible ways to close it, based on a detailed study of the EU energy market until 2050. The analysis consists of two scenarios, both assuming that the EU reaches climate neutrality by 2050 but at very different costs and consequences for our society.

This in-depth analytical work outlines the scale of challenges ahead of us, and the obstacles that must be overcome. It shows that our common European goals are still achievable if the right decisions are made in time. We hope that the study will inspire policymakers to consider a new growth model for a successful energy and climate transition, based on affordable decarbonised energy and a competitive business environment in the EU. The European business community is ready to play its part in this essential work.

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Context: BusinessEurope wishes to inform its position on the EU's Net-Zero agenda through an economic analysis of the key issues regarding industry competitiveness and security of supply

The energy crisis shed light on the conditions of success for the EU's Net-Zero transition

- The energy crisis highlighted the global dependency of the EU energy system as well as the vulnerability of the EU's economy to energy market shocks, energy security of supply and supply chains disruptions.
- High energy prices severely affected the competitiveness and production levels of EU industries and companies during and after the energy crisis.
- Going forward, the next stage of decarbonisation in industry, transport and buildings will require significant investment in decarbonised technologies, that may be challenging in the current macroeconomic context.
- The EU energy and climate policy framework has evolved rapidly over the past 5 years with numerous texts and initiatives as well as major packages such as the Fit for 55.

The next phase of the Net-Zero transition requires addressing some key questions

- What could future energy demand and supply look like over the horizon of the Net-Zero transition?
- Are there any security of supply issues, and to what extent, in case the EU is unable to develop the required renewable and low-carbon energy supply?
- How will energy prices evolve in the EU compared to other key geographies?
- How will energy costs impact the competitiveness of EU industries compared to third countries?
- What principles could guide energy and climate policy in the EU in years to come to deliver a cost effective and competitive Net-Zero transition?

Our mandate: Model the evolution of the European energy system and energy cost evolution to 2050 and assess key issues associated with the next phase of the energy transition

Study focus and approach

- We model the EU energy system transition towards 2050, analyse the energy production prices and the costs associated with energy infrastructures and highlight security of supply issues.
  - 2 scenarios are modelled including one that takes stock of potential issues, delays, and challenging trends from recent years.
- Energy costs are used to analyse the evolution of production costs for a sample of EU energy intensive industries in 2030.
  - Comparing these costs with those in other geographies highlights competitiveness issues faced by some EU businesses due to energy and carbon costs.
- We analyse the relevant policy framework and provide a set of takeaways for possible areas of policy action to enhance the current framework.

Study's content

1. Modelling Net-Zero transition pathways for the EU energy system
2. Impact of Net-Zero transition costs on energy and cost of doing business in the EU
3. Review of the relevant policy framework for security of supply and competitiveness
4. Key takeaways for policy action

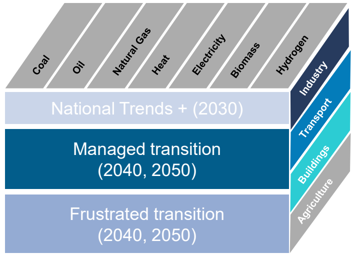
Contents

1.
Executive Summary

Scope and goal: The study assesses the impact of different policy responses to current challenges while achieving Net-Zero in 2050

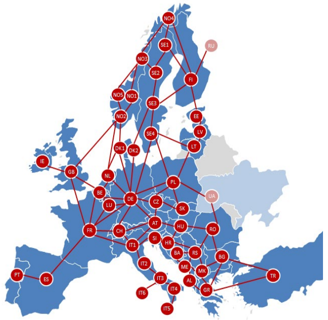
Energy system modelling

- Demand projection per sector and energy carrier
- *Inputs: demands in buildings, transport, industry, shares of fuels, efficiencies, energy prices, etc*
- *Outputs: final energy demand per carrier and sector*



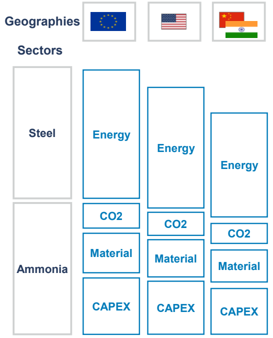
Power system modelling

- Plant level least cost hourly dispatch of the EU interconnected power system
- *Inputs: demand, nuclear capacity, emissions constraints, etc*
- *Outputs: dispatch, prices, etc*



Cost of doing business

- Bottom-up costs of production in selected energy intensive industries
- *Inputs: quantities of fuel and material per unit of production, labour costs, investment costs, etc*
- *Outputs: cost breakdown for 1 ton of end product*



In both Net-Zero pathways, emissions need to decrease drastically towards 2040, with a quasi-tripling of the annual historical rate of emissions reduction (from 45Mt/y over 1990-2021, to 150Mt over 2021-2040).

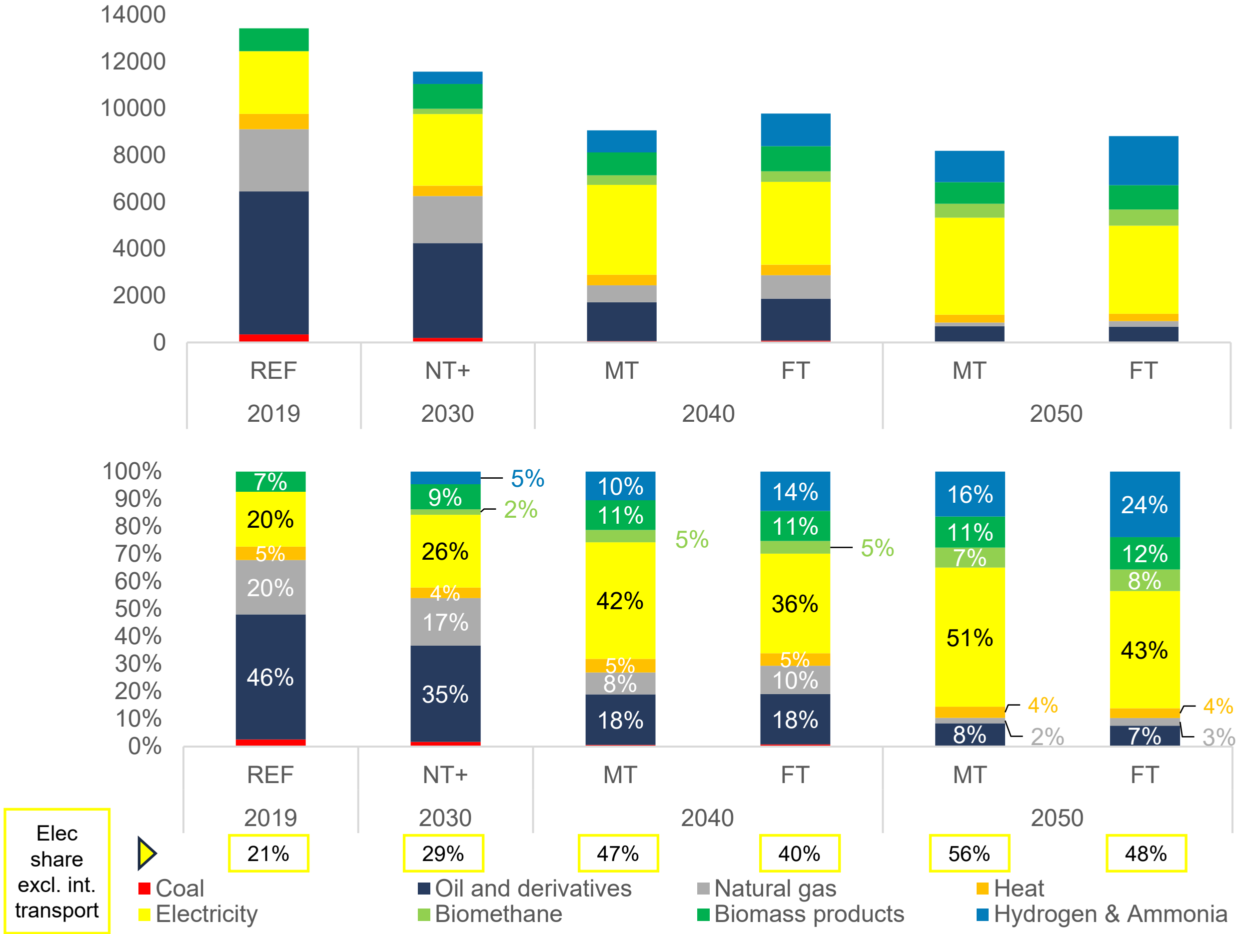
- The '***Managed Transition***' scenario is intended to show how policies addressing the headwinds affecting the deployment of critical infrastructures and decarbonised technologies can reconcile the objectives of security / affordability with achievement of climate targets.
- The '***Frustrated Transition***' scenario is intended to analyse the impact of policies that are delayed and/or insufficient against rising value chain and infrastructure bottlenecks, resulting in rising costs and competitiveness issues for industrials, while meeting decarbonisation goals.
- In the *Frustrated Transition* scenario, the current issues delaying the transition and headwinds are maintained throughout the transition towards Net-Zero: network/storage infrastructures deployment delays, challenges with electrification slowing down electric vehicles and heat pumps uptake, lack of business case to electrify some industries, roadblocks affecting wind supply chains, etc.

EU energy demand: Reaching Net-Zero requires penetration of decarbonised vectors at more than 90%, low carbon fuels needed to complement direct electrification

Electricity increasingly dominates the mix with hydrogen required as a complement in particular in the *Frustrated Transition* scenario

- In both scenarios, electrification plays a growing and critical role to decarbonise the economy ending a decades-long reliance on fossil fuels as the predominant carrier of energy.
- Electricity becomes the single largest energy carrier supplying final demands in both scenarios, reaching more than 3,700 TWh and 4,100 TWh in the *Frustrated Transition* scenario and *Managed Transition* scenario, respectively in 2050.
- The *Frustrated Transition* scenario continues to rely on other carriers to a larger extent, especially low carbon hydrogen and derivatives (24% - 2,100TWh in 2050), to make up for a slower direct electrification in all sectors.

Final energy demand by carrier [TWh and %] – EU27



Sources: CL analysis based on ENTSOE/ENTSOG 's draft TYNDP24, including energy demand from non-energy uses and international transportation
Notes: [1] Presented final energy demand includes demand from non-energy uses in industry (feedstock) as well as demand from international transportation (aviation and shipping). Electrification rates excl. demand from international transport are reported below the graph. [2] 'REF' refers to historical reference; 'NT+' in 2030 is based on best estimates of national TSO's as reported in draft TYNDP 2024

Energy supply: Greater reliance on imported low carbon fuels such as H2 and biomethane in the *Frustrated Transition* scenario comes with greater supply risks

The two scenarios differ in the extent to which they rely on imports of low-carbon fuels:

- In the ***Managed Transition*** scenario, direct electrification is accompanied by strong growth of RES-E production domestically and adequate infrastructure development.
- In the ***Frustrated Transition*** scenario, substantial imports are required to cover demand for hydrogen and biomethane, increasing the risk associated with potential disruptions and / or supply price shocks from extra-EU imports.

Security of supply monitor:	Electricity	H_2 Hydrogen	Biomethane	Biomass (incl. biofuels)
MT	▪ Renewable and flexibility capacity ramp up with Net-Zero targets ▪ The combination of demand flexibility, storage and emission-free thermal plants is projected to ensure an adequate level of security of supply	▪ EU production ramps-up to cover c. 60% of EU demand ▪ Imports are required to cover demand towards 2050, but lies within estimated extra-EU potentials	▪ Ramp-up of domestic capacities covers 100% of demand ▪ Strong policy support and coordination of infrastructure investments ensure the security of biomethane supplies	▪ Limited demand growth towards 2050 , with demand on the lower end of EU supply potential estimates ▪ No major supply bottlenecks anticipated at this level of demand
FT	▪ Flexible and renewable capacity ramp up too slowly to enable steady least-cost development ▪ This comes at the cost of potential occasional curtailment of demand, particularly industrial, in periods of system stress	▪ EU production ramps-up to cover c. 45% of EU demand ▪ Additional import needs could be more challenging to source given extra-EU potentials. ▪ Piped imports would need to be complemented by shipping	▪ Development of EU production covers 80% of EU demand ▪ Meeting demand requires imports with no certainty on availability of such volumes	▪ Reaching net-zero entails a marked increase in the use of biomass products ▪ Needs lie within supply potentials, but mobilisation requires additional investment and potential imports

Security of supply risk: low ■■■■■ high

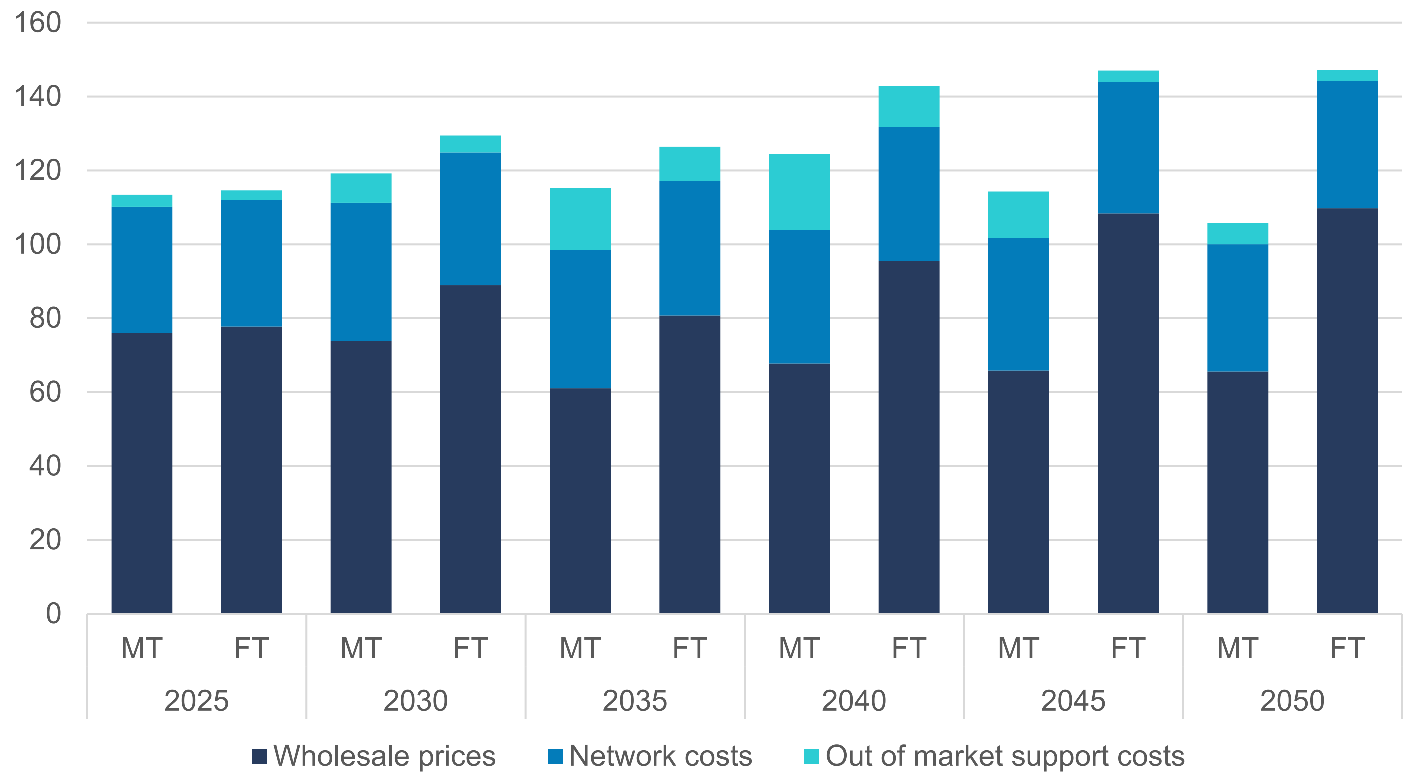
Scope: EU27

Electricity end user prices: Total system costs (incl. network, flexibility and low carbon capacity support) are projected to be flat or decreasing in the *Managed Transition* scenario

In the *Managed Transition* scenario, optimised location of RES-E roll out, increased market integration and efficient development of infrastructures and flexible capacities allow to contain total electricity costs:

- The price paid by the final consumers reflects the total system costs of delivering electricity from the grid to the end-users (incl. **market prices**, as well as **network infrastructure costs and out-of-market support** complementing market remuneration[1]).
- In the ***Managed Transition*** scenario, power system costs are projected to be stable or slowly decreasing on average in the EU.
- In contrast, in the ***Frustrated Transition*** scenario, power system costs are projected to increase by up to 30% by 2050 compared to current levels.

Industry retail power prices, excluding taxes – average EU27 (EUR/MWh real 2022)



Notes: We only apply transmission network costs reflecting costs for consumers connected to the transmission network. Total network investment costs are converted into retail costs using a regulated rate of return of 5% and a normative lifetime of 40 years.

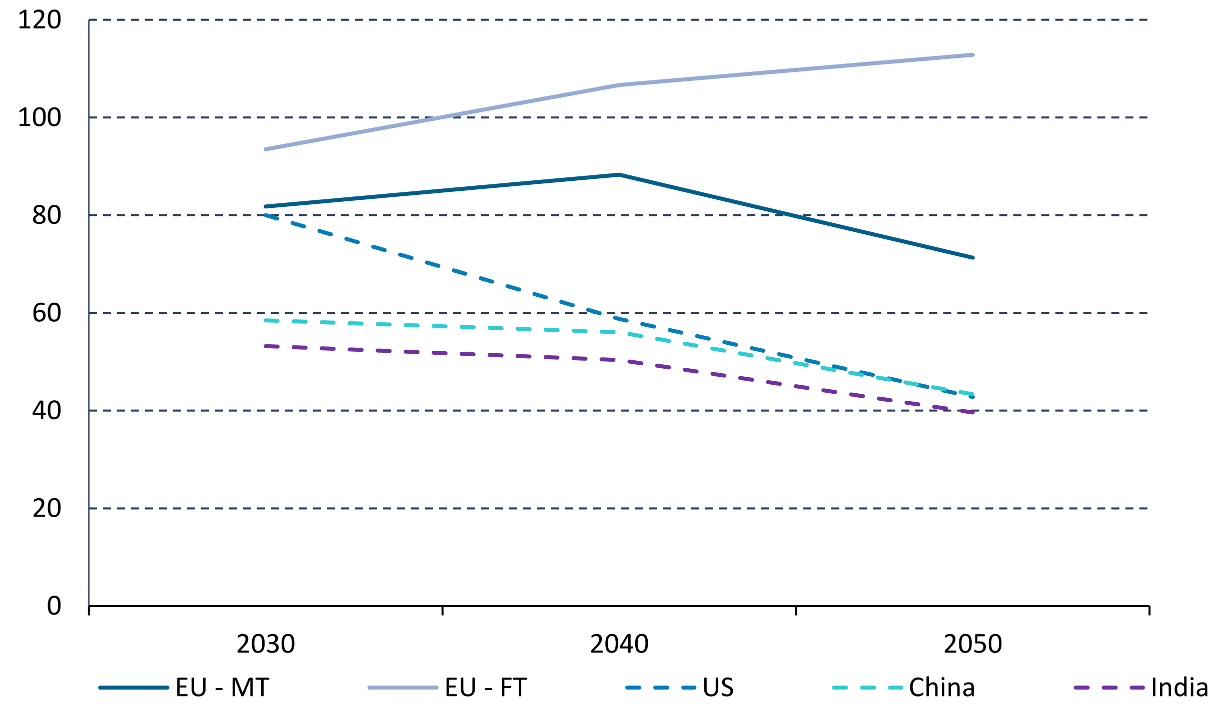
Note: [1] Out-of-market remuneration includes capacity market remunerations, contract-for-differences and feed-in-tariffs for renewables or storage systems, etc. They drop significantly from 2045 due to wholesale price increasing, especially in the FT scenario, limiting the need for extra remuneration
Source: CL analysis

EU electricity wholesale prices are projected to continue showing a competitive disadvantage compared to the US, China and India

EU wholesale electricity prices' historical competitiveness gap does not subside, but the *Managed Transition scenario* allows to lower the competitiveness gap.

- The energy crisis has increased the historical competitiveness gap between EU wholesale electricity prices and third countries.
- In the ***Managed Transition*** scenario, average EU electricity generation costs are projected to level down and would not increase the competitiveness gap with the US and China in 2040 and 2050.
- In the ***Frustrated Transition*** scenario, average EU electricity generation costs are projected to increase the competitiveness gap with the US and China in 2040 and 2050.
- Depending on generation mixes across the different member states, generation costs are higher/lower than the EU average.

Electricity generation costs (incl. out-of-market support, excl. network costs) in a selection of jurisdictions (EUR/MWh)[2] – 2030-2050



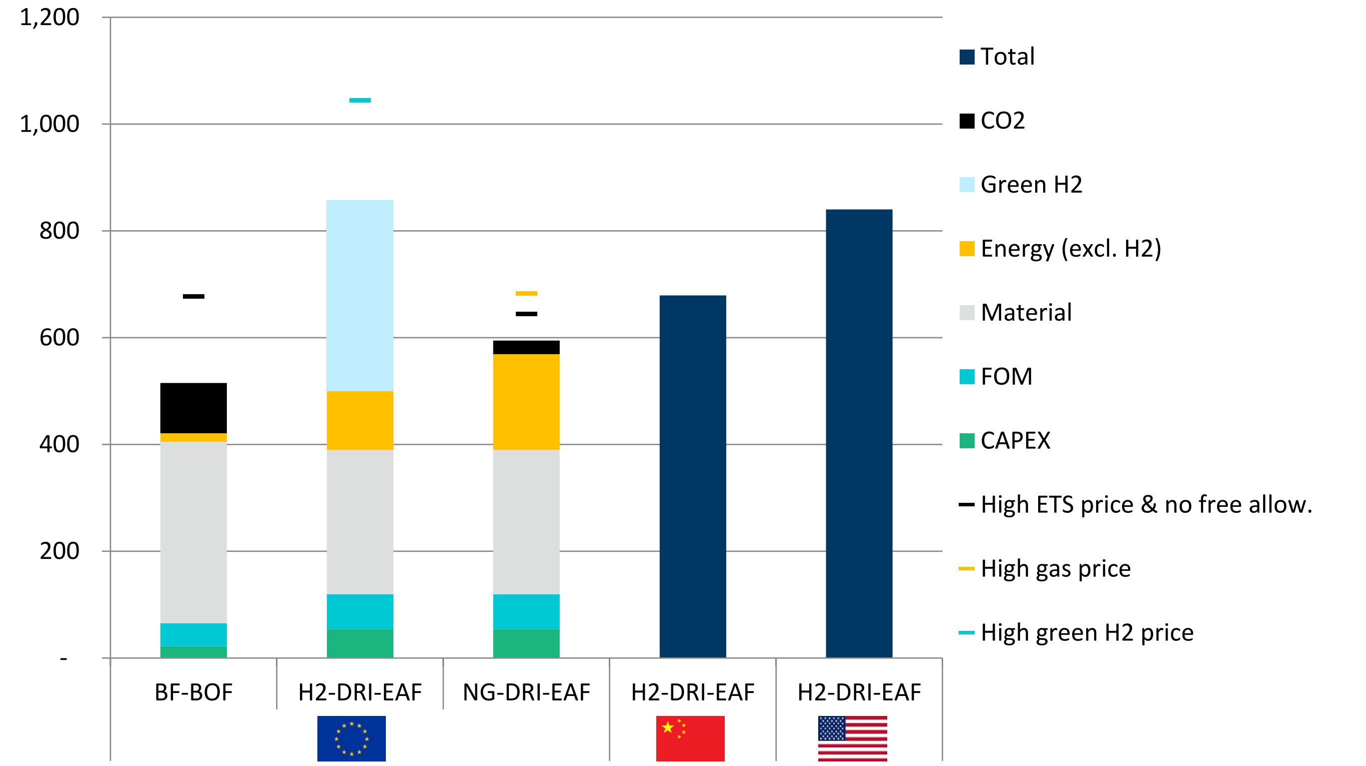
Notes: [2] Total procurement costs are computed based on levels of generation by technology multiplied by average LCOEs of each technology in previous 10 years.
Sources: [2] LCOEs and generation levels per technology in the US, China, and India are taken from the WEO23, IEA (APS scenario). For the EU, costs are taken from CL modelling.

Case study: Green steel production faces a competitiveness gap even with CBAM and will require policy support

Even with CBAM, imports of carbon-intensive (BF-BOF) steel remains the most competitive in 2030 while green crude steel (H2-DRI-EAF) in the EU can only compete with Chinese or US counterparts in case of green H_2 costs reductions

- Even without free allowances and with a high natural gas price, green H_2 based steel remains less competitive than carbon-intensive steel by 2030 under our assumptions. Policy support is thus needed to ensure competitiveness.
- EU green steel (H2 DRI EAF) is projected to be up to 25% more expensive than Chinese green steel in 2030 but could have similar costs as US-produced green steel.[1]
- Ensuring the availability of input materials – and particularly scrap steel – will be crucial for a competitive EU steel industry going forward.

Crude steel production costs sensitivities, EU compared to US and China, 2030 [€/t]



<u>Cost components</u>: Material costs (iron ore, scrap, coking coal, alloying elements & more). Energy costs (electricity incl. network costs and out-of-market support, natural gas, PCI coal). H2 (green H2). CO2 (effective ETS costs accounting for free allowances). CAPEX (annualized CAPEX, WACC 10%). FOM (Maintenance and labour costs).

Note: [1]China and US steel are assumed to be imported to the EU and carry additional transport costs. CBAM is applied for direct emissions only. We consider that only the EU has a carbon price. Energy cost contribution includes costs for electricity, H2, natural gas and PCI coal, depending on the process. H2 costs considered are derived from slide 53, CO2 prices from slide 56.The high H2 price sensitivity considers the average of the green H2 prices from the literature presented in section 1 (ca. 8 €/kg). The sensitivity with high CO2 prices, considers the CO2 price for 2030 of the FT scenario (147 €/t CO2) and no free allowances. Calculations do not include any direct subsidies or public support mechanisms. BF-BOF…blast furnace and blast oven furnace; H2/NG-DRI-EAF…hydrogen/natural gas based direct reduction of iron and electric arc furnace

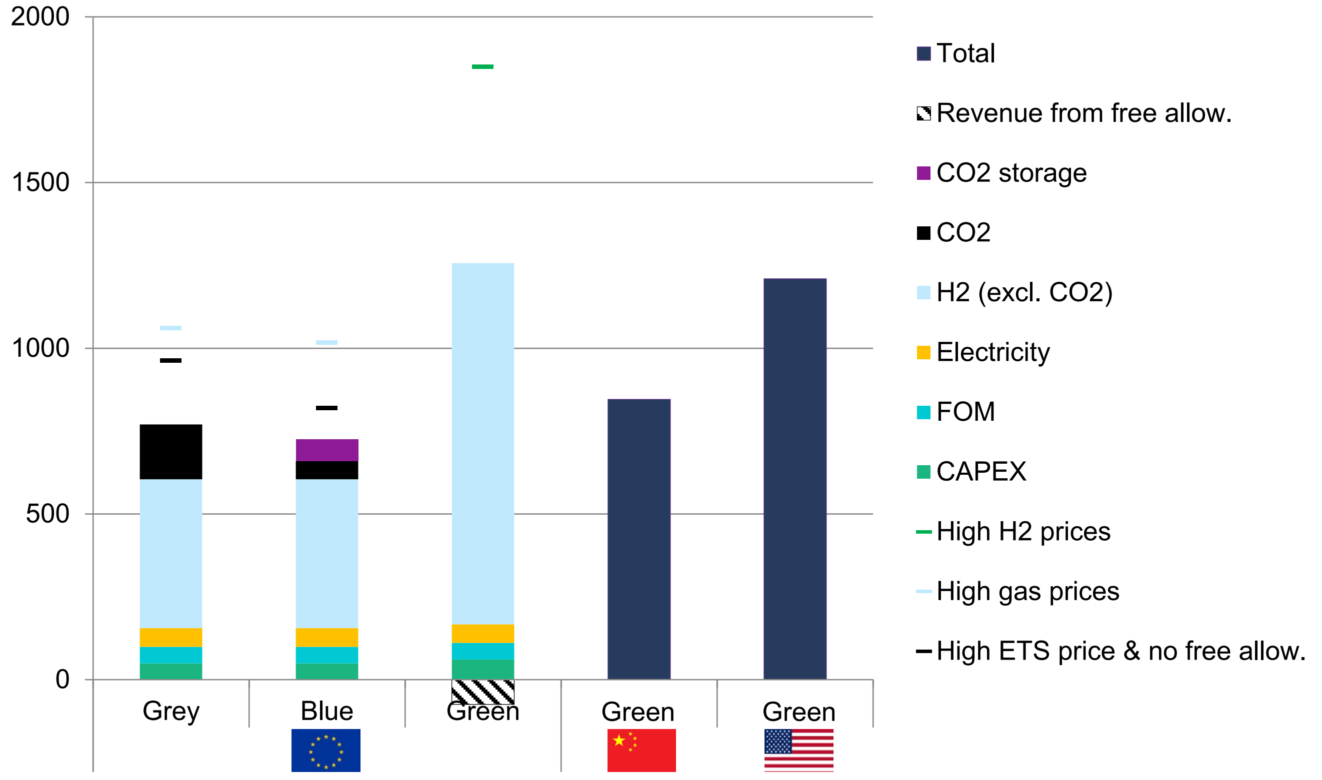
Case study: Low carbon ammonia production faces competitiveness gap even with CBAM and will require policy support

Green H2 based ammonia cannot compete with grey or blue production routes without policy support or significant H2 costs decreases

- Even without free allowances and a high ETS price, green H2 based ammonia would only be competitive with the Grey production route if green H2 prices would decrease to c. 3€/kg.
- With CBAM costs on grey and blue routes, Chinese green H2 based ammonia would be the most competitive option. EU green ammonia would be c. 45% more expensive than Chinese green ammonia, while being competitive with US green ammonia.[1]
- However, EU importers are likely to circumvent CBAM, as ammonia's downstream products are currently not covered and can easily be transported.

The analysis shown on the right is based on greenfield cost, i.e. considering CAPEX for a new installation in all 3 production processes (grey, blue, green).

Ammonia production costs sensitivities, EU compared to US and China, 2030 [€/t]



Cost components: Electricity costs (electricity incl. network costs and out-of-market support). H2 (green or grey H2). CO2 (effective ETS costs accounting for free allowances). CAPEX (annualized CAPEX, WACC 10%). FOM (Maintenance and labour costs). CO2 storage (cost of carbon storage). Revenue from free allowances (for green route only, corresponding to sale of free allowances for green H2).

Note: : [1]China and US ammonia is assumed to be imported to the EU and carry additional transport costs. In 2030, free EU allowances reach 50% of their previous level. Modelled ammonia production unit is assumed to produce 1 million tonnes per year, with a CAPEX of 378 M EUR for the Haber-Bosch process and 90 M EUR for retrofitting the Air Separation Unit for Green NH3. H2 costs considered are derived from slide 53, CO2 prices from slide 56.The high H2 price sensitivity considers the average of the green H2 prices from the literature presented in section 1 (ca. 8 €/kg). The sensitivity with high CO2 prices, considers the CO2 price for 2030 of the FT scenario (147 €/t CO2) and no free allowances. The high gas price scenario considers a gas price of 60€/MWh. Calculations do not include any direct subsidies or public support mechanisms. NH3….ammonia

Key takeaways: Net-Zero, security of supply and competitiveness can be reconciled through enhanced EU-level coordination, planning, and support for an efficient transition

1 Ensure the efficient implementation of current energy and climate policies through enhanced coordination and monitoring

A cost-effective energy transition can be realized through further cooperation across policy areas, ensuring the consistency and predictability of the decarbonised energy investment framework, and addressing barriers to implementation.

1. Foster a whole system approach to energy system planning and enhance coordination mechanisms across countries to ensure a cost-effective transition.
2. Coordinate and streamline funding and financing instruments for energy system decarbonisation (e.g. with an EU Climate Bank on the model of the Hydrogen bank).

2 Address the energy price competitiveness gap and security of supply challenges

Reconcile decarbonised energy deployment with competitiveness and security of supply by securing access to critical materials, de-risking supply chains, and ensuring adequate deployment of flexibility and critical infrastructures through timely investment.

3. Developing a policy framework to plan and support timely investments in critical infrastructures is key to further integrate the EU energy market and ensure competitive decarbonised energy access and benefit sharing across Europe.
4. De-risking value chains and addressing planning/permitting barriers is critical to scale up decarbonised energy supply and limit financing costs.
5. The framework for Security of Supply monitoring should be improved to take a full system approach across energy vectors and reflect new challenges.

3 Support an efficient transition of industrial sectors and reinforce policies to mitigate the risk of carbon leakage

Amplify policy support to de-risk and accelerate the uptake of decarbonised technologies in industry and address competitiveness issues for industries facing international competition.

6. The framework to monitor industrial competitiveness and assess carbon leakage risks could be broadened to include risks associated with energy costs competitiveness.
7. CBAM regulation could be enhanced to address competitiveness issues for exports and downstream products.
8. Allocation of energy transition costs and benefits of decarbonised technologies investments across sectors could be better coordinated at EU-level.
9. Demand-side measures could support EU-based low-carbon industrial manufacturing.

2. Energy system Net-Zero pathways

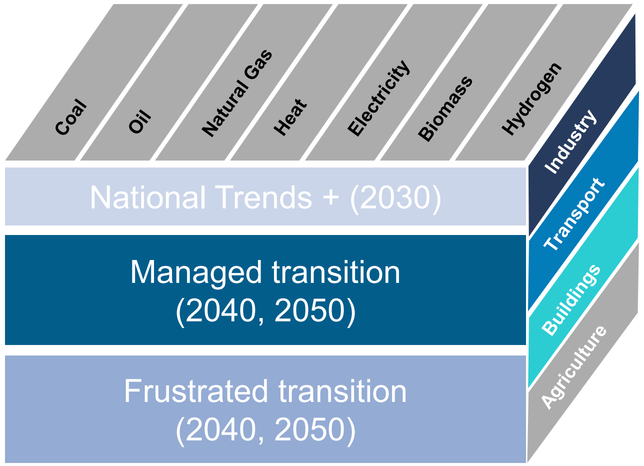
2.1

Approach

The EU energy system is modelled in 2 steps, total energy demand per sector followed by a focus on the electricity system

Phase 1: Energy system modelling

- 2 scenarios of final energy demand across 7 energy carriers (Coal, Oil, Natural gas, Heat, Electricity, Biomass, Hydrogen & Ammonia) and all economic sectors (industry, transport, buildings, agriculture).
- The TYNDP 2024 dataset – Global Ambition and Distributed Energy scenarios – is the basis for the modelling, modified with latest trends based on literature and expert judgement.
- The modelling is a bottom-up calculation of per vector/sector demand depending on total production levels, efficiency of technologies, shares of technologies, etc.

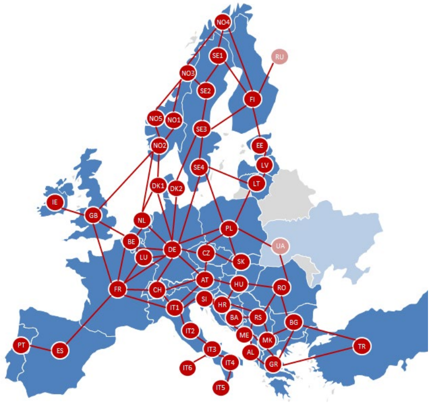


- Annual power demand
- Emission from power sector

Phase 2: Power system modelling

Inputs

- The electricity demand (from phase 1)
- The emission constraints (from phase 1)
- Generation capacities (RES & conventional)
- Flexibility capacities
- Hourly load profiles per bidding zones
- Net Transfer capacities between bidding zone



Unit-based least cost hourly dispatch of EU interconnected system

Outputs

- Dispatch per technology
- Cross-border flows
- Emissions
- Flexibility activated
- Energy not served
- Energy curtailed
- Fuel consumption
- Average costs for electricity generation

Two case studies are developed:

- Sweden case study
- Ireland case study

Note: A technical appendix containing an in-depth presentation of the methodology and the modelling capabilities used to perform phase 1 and phase 2 is available on request. Phase 1 uses the Energy Transition Model Software and phase 2 uses the PLEXOS® Software. Energy demand scenarios are largely based on exogenous assumptions of electrification deployment and efficiency of appliances, based on the TYNDP's input and a benchmark of existing scenarios.

The study assesses the impact of different policy responses to current challenges while achieving Net-Zero in 2050

Current issues

Increased policy ambitions	Challenging macroeconomic environment	Achievements and roadblocks to decarbonised energy uptake
• Fit for 55 • REPowerEU • Climate target 2040	• Covid crisis • Russia's invasion of Ukraine • Energy crisis • Tension on supply chains, in the metals and critical materials markets resulting in high prices and construction costs	• Delays with EV and heat pumps uptake • Acceleration of solar deployment • Roadblocks of wind power supply chains • Network/storage infrastructures delays and massive investment needs • Negative prices and curtailment of RES-E

2 Net-Zero pathways separated by policy response

'Managed transition' scenario

*The Managed transition scenario is intended to show **how policies addressing the headwinds** affecting the deployment of critical infrastructures and decarbonised technologies and supporting an efficient allocation of the costs of the energy transition can reconcile the objectives of security / affordability with achievement of climate targets*

'Frustrated transition' scenario

*The Frustrated transition scenario is intended to analyse **the impact of policies that are delayed and/or insufficient** against rising value chain and infrastructure bottlenecks, resulting in rising costs and competitiveness issues for industrials, while meeting decarbonisation goals*

Policy response

Role of policies as enablers of an efficient transition (examples)	Accelerating infrastructure buildout	Reducing financing costs	Safeguarding competitiveness	Protecting consumers
	Key roadblocks in infrastructure (power and H2) are addressed through coordinated policy action to anticipate development of critical infrastructures.	Policies reducing risks for investors and off-takers reduce financing costs and facilitate development of capital-intensive technologies.	Supporting industrial decarbonisation and targeted support to address cost disadvantage for sectors at risk of carbon leakage (e.g. improved CBAM).	Tension between climate policies and economic impact is managed through policies supporting an efficient and just allocation of costs.

Note: Scenarios are not predictions. They intend to show the outcome of possible futures based on multiple assumptions. Results are only consistent in relation to those assumptions. Should new developments (policy, macroeconomic context, technological breakthroughs or other) warrant a review of any of the inputs used in this study, the results (energy demands, supply, prices, imports or other) would necessarily change.

On the demand side, both Net-Zero pathways imply a marked switch to electricity in end-uses. Electrification delays entail lasting fossil gas demand and higher CCS needs

'Managed transition' (MT) scenario

- *The share of electricity in final energy demand reaches 56% in 2050.*
- *Electrification in buildings and transport reaches 85% and 92% respectively.*
- *Stronger policy support for fuel switching allow industry to cover 46% of final demands (incl. feedstock) through electrification.*

'Frustrated transition' (FT) scenario

- *The share of electricity in final energy demand reaches 48% in 2050.*
- *Electrification in buildings and transport is slower than expected but remains in line with current trends showing high adoption rates.*
- *Lack of policy supporting fuel switching and tighter electricity supply only allow power to reach 37% of industry's demand (incl. feedstock) .*

		New demand usages				Electrification		From fossil gas to H_2		Carbon
		Share of EVs in passenger cars	Share of HPs in households heating mix[1]	Buildings efficiency (% heat demand decrease from 2019)	Electric heating in chemicals[2]	Electricity in FED (*excl. international transport*)	Electricity in **industrial FED** *(incl. feedstock)*[3]	Natural gas demand (*TWh*) / reduction *(from 2019 levels)*	H_2 in **industrial FED** (*incl. feedstock*)	**Carbon capture and storage** (Mt CO2-eq)
	2019	0%	15%			21%	24%	-	-	0
MT	*2050*	92%	84%	-40%	50%	56%	46%	140 / -97%	27%	178
FT	*2050*	80%	78%	-35%	35%	48%	37%	250 / -95%	34%	243
		Assumption	*Assumption*	*Assumption*	*Assumption*	*Result*	*Result*	*Result*	*Result*	*Result*

Note: all indicators are given for the EU27 countries, in %. A technical appendix containing an in-depth presentation of the methodology and the modelling capabilities used to perform phase 1 and phase 2 is available on request. FED…Final Energy Demand
[1] Only includes heat pumps in individual households, not heat pumps employed in district heating. [2] Excl. fertilizers manufacturing. [3] Refers to the share of electricity in total energy demand for both energy and non-energy (feedstock) uses.

Domestic H2 and biomethane production is similar in both scenarios, while the development of renewables in power is delayed in the *Frustrated Transition scenario*

Scenario ***'Managed transition' (MT)***

- *High deployment of RES in electricity due to infrastructure roadblocks being lifted and high electricity demand with industrial production levels comparable to historical levels.*
- *H2 and biomethane production develops to reach maximum potential due to sound policy push and cost decreases.*

Scenario ***'Frustrated transition' (FT)***

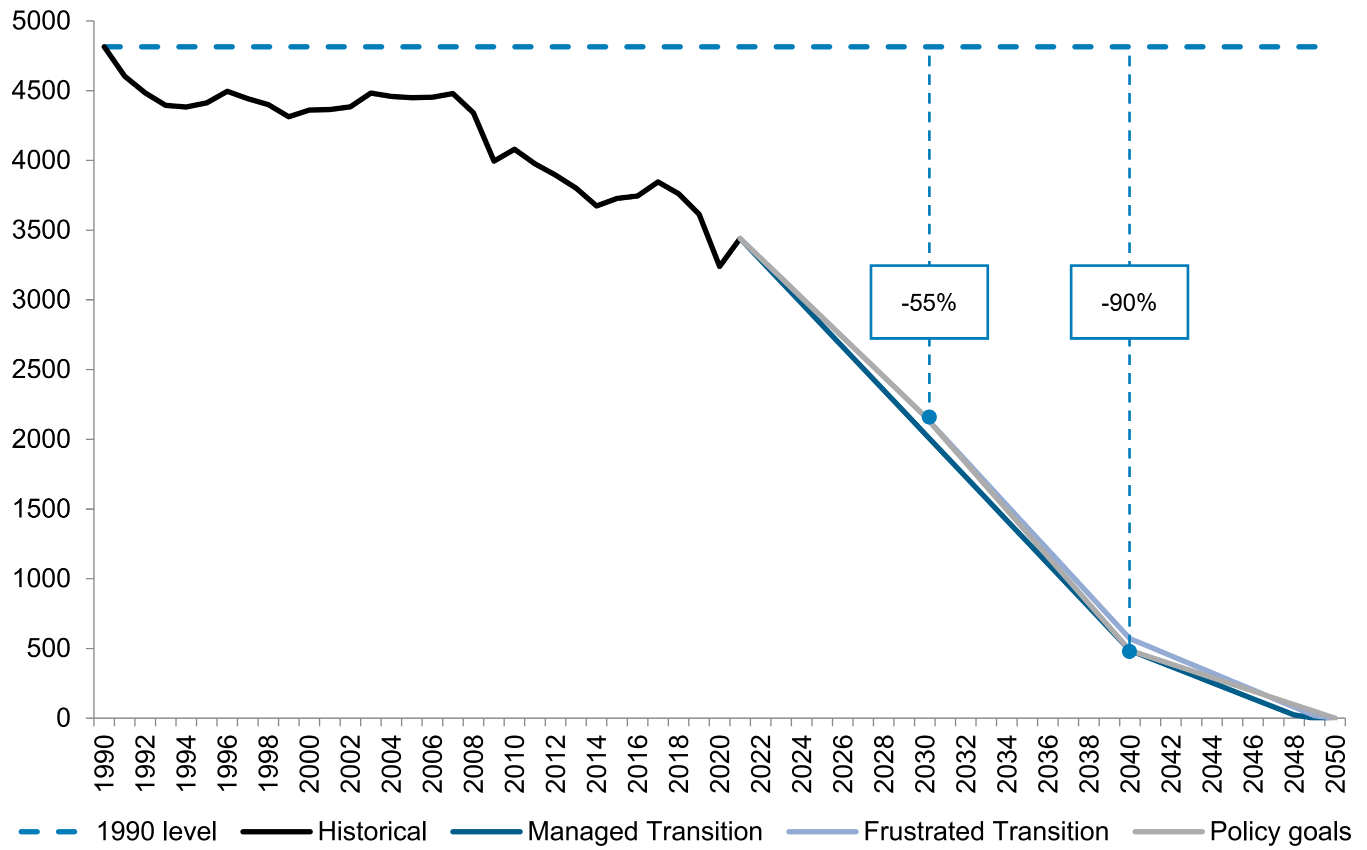
- *Slower deployment of RES in electricity due to infrastructure roadblocks delays and higher costs.*
- *H2 and biomethane production develops to reach a similar production levels as in the Managed Transition scenario, but remains misaligned with demand levels (higher than in MT) due to limited direct electrification and thus calling for higher import levels.*

		EU low carbon H_2 production *(TWh)*	Annual EU biomethane production	Wind capacity	Solar capacity
	2020	-	-	180 GW	130 GW
MT	2050	1,200 TWh	750 TWh	990 GW	1,570 GW
FT	2050	1,300 TWh	800 TWh	870 GW + suboptimal locations	1,420 GW + suboptimal locations
		Assumption	*Assumption*	*Modelling + Assumption*	*Modelling + Assumption*

Note: Scope: EU27. At the end of 2023, installed capacity for wind stood at 22GW and 260GW for solar. A technical appendix containing an in-depth presentation of the methodology and the modelling capabilities used to perform phase 1 and phase 2 is available on request.

In both Net-Zero pathways, EU emissions decrease 3 times faster than historically to meet with 2030, 2040 and 2050 targets

Total annual GHG emissions incl. LULUCF & CCS – EU 27 [Mt CO_2-eq]



In both decarbonisation pathways, emissions reduction need to accelerate drastically towards 2040, with a quasi-tripling of the annual amount of emissions reduction (from 45Mt/y over 1990-2021, to 150Mt over 2021-2040).

- Policy goals are defined as the -55% emissions reduction in 2030 (Fit for 55 package), and a reduction of -90% in 2040 (preliminary target discussed by the European Commission at the date of this report).[1]
- By construction, both Net-Zero pathways *broadly* comply with the policy targets, with a slight transitory delay in 2040 in the *Frustrated Transition* scenario.
- In the *Managed Transition* scenario, all policy goals are met. In the *Frustrated Transition* scenario, the 2040 target is missed by approximately 100 MtCO2-eq, but Net-zero by 2050 is reached.

Abbreviations: GHG … Greenhouse Gases, LULUCF … Land Use, Land Use Change and Forestry, CCS…Carbon capture and storage.
Sources: Eurostat, Greenhouse gas emissions by source sector (source: EEA), and Compass Lexecon modelling.
Note: [1] The 2040 target has been recommended by the European Commission but is not agreed yet.

2.2

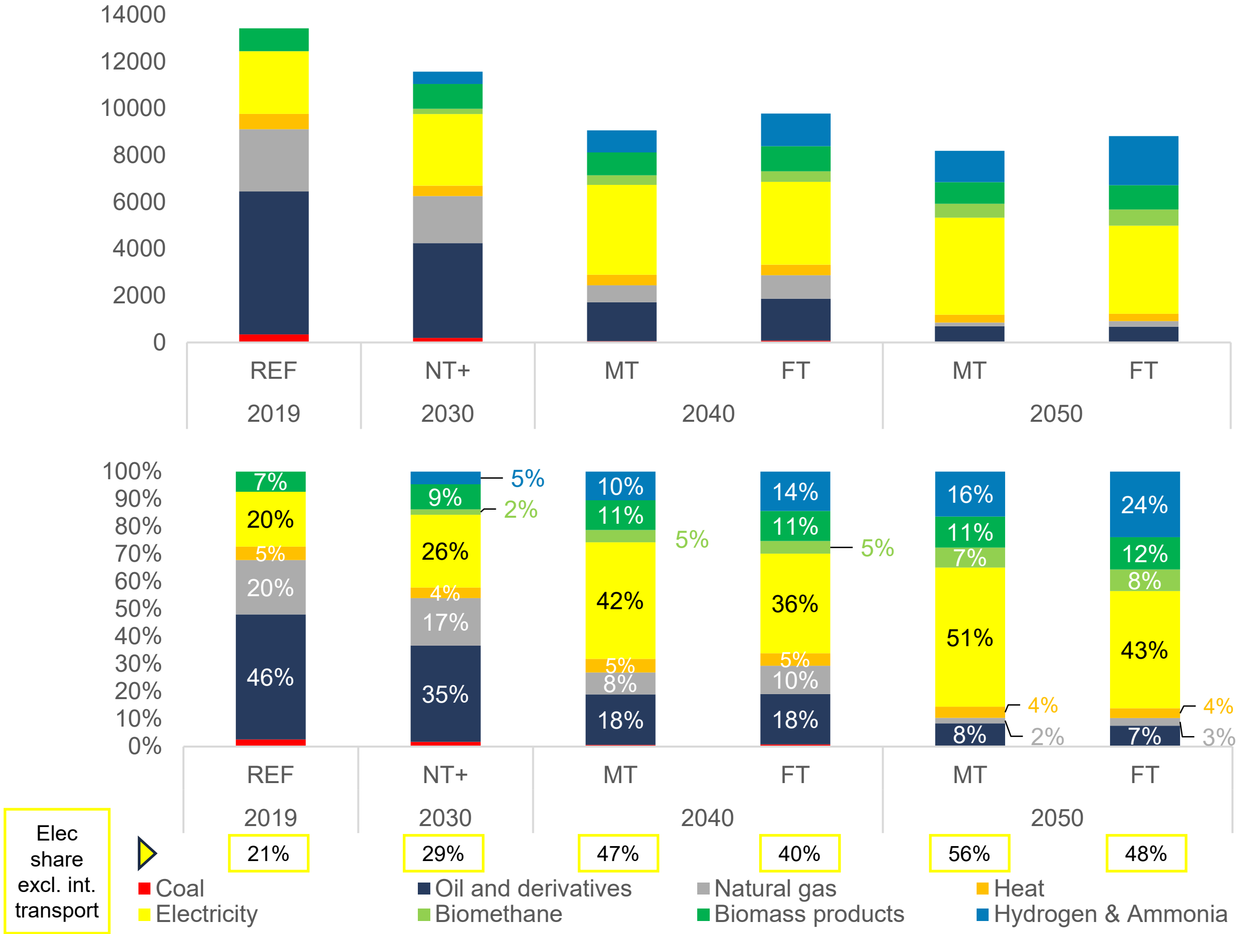
Key trends and issues with final energy demand

EU energy demand – Reaching climate targets requires more than 90% penetration of decarbonised vectors, low carbon fuels are needed where electrification is insufficient

Electricity increasingly dominates the mix with decarbonised hydrogen and biogas/mass required as a complement in particular in the *Frustrated Transition* scenario

- In both scenarios, electrification plays a growing role to decarbonise the economy ending a decades-long reliance on fossil fuels as the predominant carrier of energy.
- Electricity becomes the single largest energy carrier supplying final demands in both scenarios, reaching more than 3,700 TWh and 4,100 TWh in the *Frustrated Transition* scenario and *Managed Transition* scenario, respectively in 2050.
- The *Frustrated Transition* scenario continues to rely on other carriers to a larger extent, especially decarbonised hydrogen and derivatives (24% - 2,100TWh in 2050), as well as biogas/mass to make up for a slower direct electrification in all sectors.

Final energy demand by carrier [TWh and %] – EU27



Sources: CL analysis based on ENTSOE/ENTSOG ‘s draft TYNDP24, including energy demand from non-energy uses and international transportation
Notes: [1] Presented final energy demand includes demand from non-energy uses in industry (feedstock) as well as demand from international transportation (aviation and shipping). Electrification rates excl. demand from international transport are reported below the graph. [2] ‘REF’ refers to historical reference; ‘NT+’ in 2030 is based on best estimates of national TSO’s as reported in draft TYNDP 2024

EU energy demand – Deep electrification in the *Managed Transition scenario* achieves further efficiency gains limiting indirect electrification associated with H2 demand

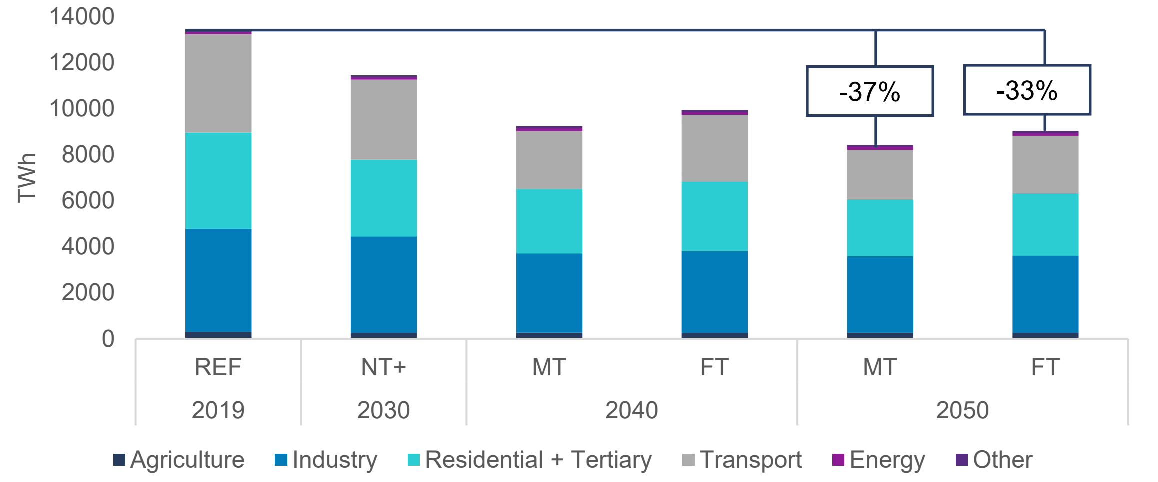
Deep electrification and energy efficiency improvements in transport and buildings drive down overall energy demand

- Most energy efficiency gains occur in the timeframe to 2040 as improvements become incrementally more difficult.
- The largest part of the overall decrease in energy consumption stems from electrification in transport (EVs) and buildings (insulation, heat pumps) – together reducing demand by around 3,500 TWh depending on the scenario.
- In addition, the industrial sector's decarbonisation efforts achieve further notable demand reductions of c. 1,000 TWh in the timeframe to 2050 with similar production levels as in 2019 in most sectors (except refineries).

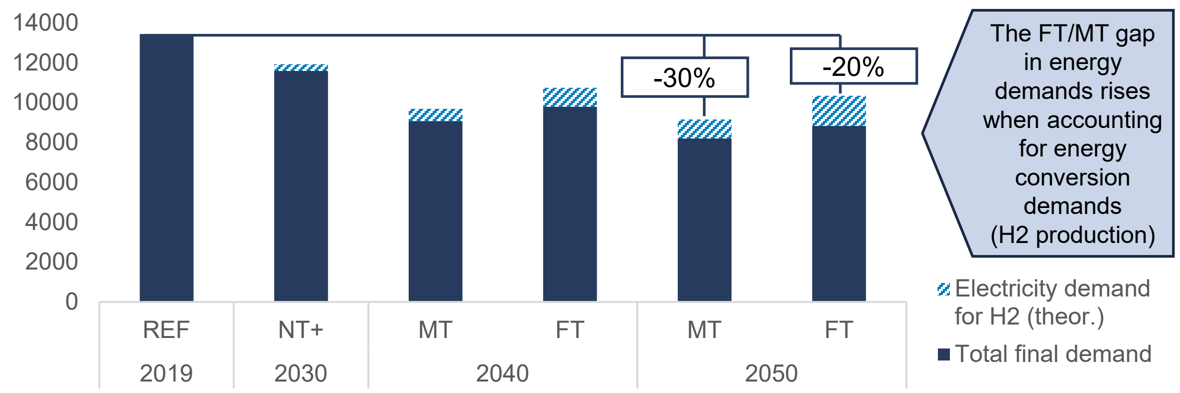
Policies to foster direct electrification in transport and buildings, with increased efficiencies from insulation and EV motors, allow to reach further efficiency gains in the *Managed Transition scenario*

- Technological innovations and adequate support policies allow for more pronounced decrease in energy usage in the *Managed Transition* scenario – resulting in a more than 600 TWh gap in 2050.
- This gap rises even further when considering energy needs for energy conversion – particularly H2 electrolysis – which is greater in the *Frustrated Transition* scenario.

Final energy demand by sector [TWh] – EU27



Energy demand incl. electricity demand for H2[1] [TWh] – EU27



Sources: CL analysis based on ENTSOE/ENTSOG 's draft TYNDP24, including energy demand from non-energy uses and international transportation
Note: [1] The illustration serves as a proxy assuming that all H2 is generated through electrolysis. [2] See assumptions on activity levels and employed technologies in the different sectors in the appendix. The bottom graph shows the theoretical electricity need implied by the H2 demand assuming all H2 is produced domestically through electrolysis. 'REF' refers to historical reference; 'NT+' in 2030 is based on best estimates of national TSO's as reported in draft TYNDP 2024

Industrial electrification faces multiple challenges, and the Managed Transition scenario captures the effect of policies supporting investment when technologically feasible

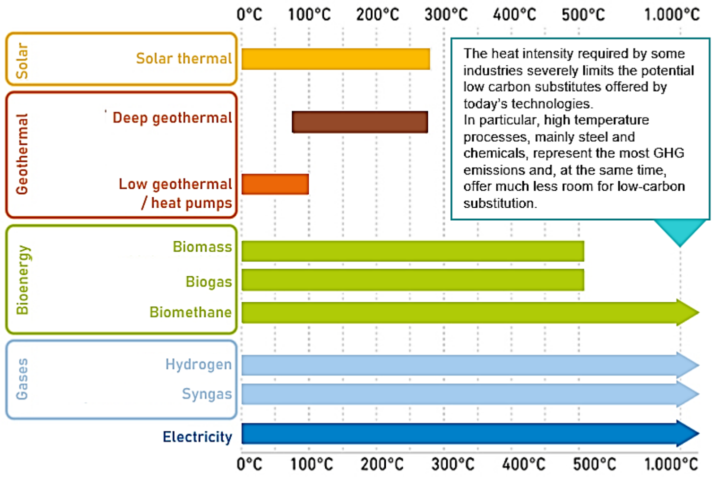
Technologies to decarbonise industrial sectors are not yet mature in all sectors

- The most CO2 intensive industries (steel, chemicals and cement) are challenging to decarbonise given current business cases.
- Existing solutions are insufficient for some industries, requiring breakthrough technologies, which may need years or decades to be commercially available.
- Moreover, lack of required infrastructure (CO_2, H_2) is hindering decarbonization of industrial processes in many cases.

Economic and financial barriers are a key deterrent

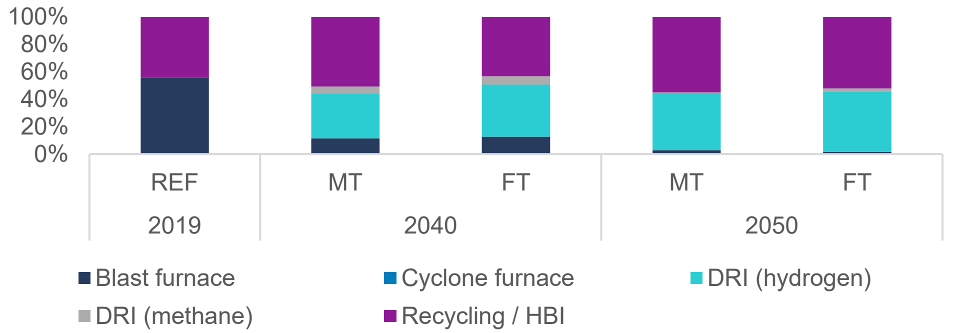
- Given the high CAPEX involved, economic and financial incentives are needed.

Suitability of alternative energy sources by industrial heat application

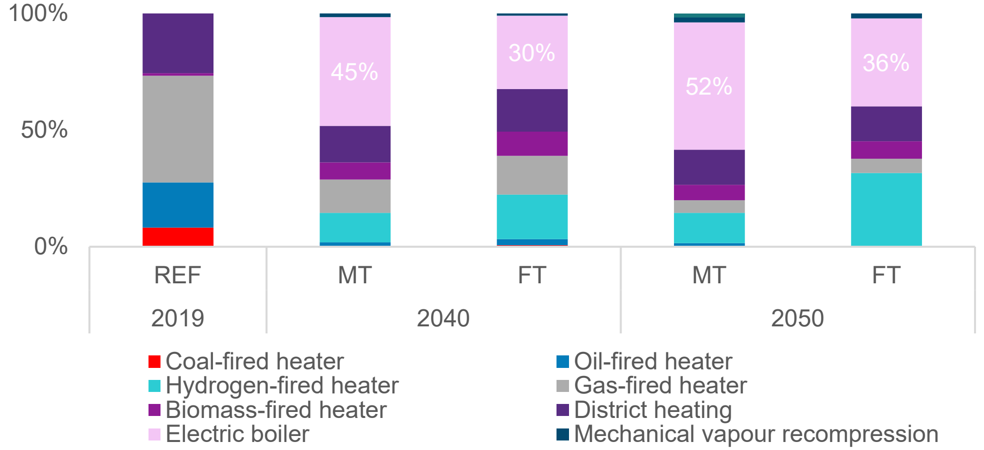


The *Managed Transition* entails fast tracking of electrification of industrial energy uses when technologically feasible

Steel production route shares – EU27



Chemicals industry heat production – EU27



Sources: Honoré (2019). Decarbonization and industrial demand for gas in Europe ; Madeddu et al (2020). The CO2 reduction potential for the European industry via direct electrification of heat supply (power-to-heat) ; Gerres et al (2018). A review of cross-sector decarbonisation potentials in the European energy intensive industry, Rekker, Kesina and Mulder (2023). Carbon abatement in the European chemical industry: assessing the feasibility of abatement technologies by estimating firm-level marginal abatement costs ;

In industry, Net-Zero pathways reach electrification levels of between 40% and 50% of final energy demand including feedstock

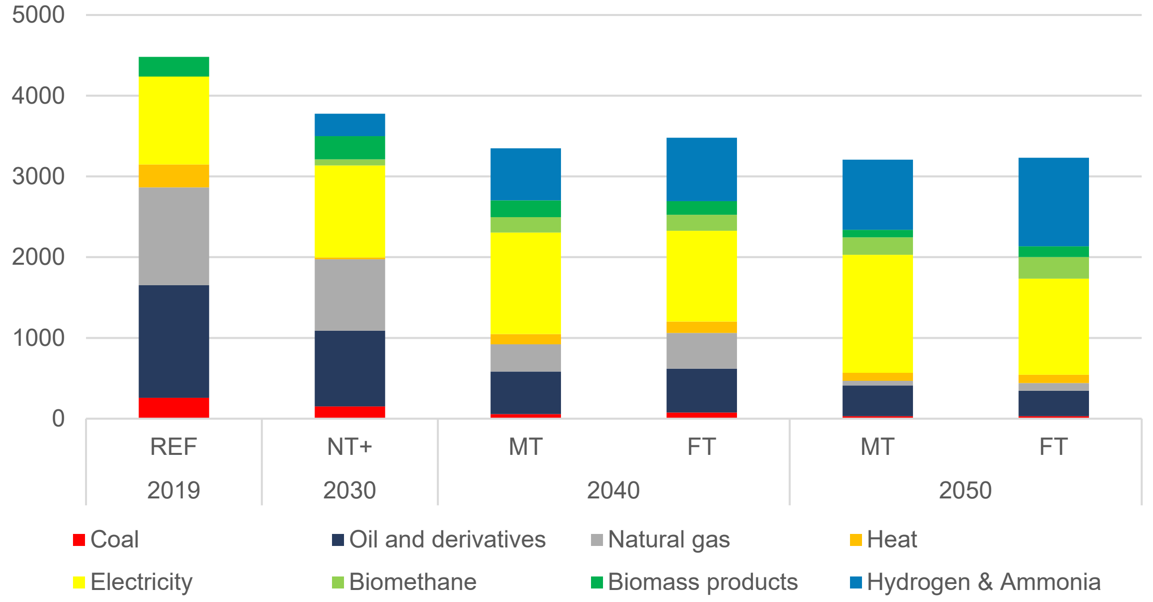
Electrification takes place in both scenarios, but is fast tracked in the *Managed Transition* scenario

- The industry sector's electricity consumption increases from around 1,100 TWh today to around 1,500 TWh and 1,200 TWh by 2050 in the *Managed Transition* and *Frustrated Transition* scenarios, respectively.

Hydrogen becomes a major energy carrier and feedstock in both scenarios, but with greater importance for the *Frustrated Transition*

- Hydrogen as a feedstock and energy carrier experiences a remarkable ramp-up, reaching around 850 TWh and 1,100 TWh in the *Managed Transition* and *Frustrated Transition* scenarios, respectively.
- Key drivers are the uptake of hydrogen-fired high-temperature heaters, utilization of hydrogen in fertilizers, but also new technologies such as hydrogen based direct reduction of iron in steel production.
- The greater role of hydrogen in the *Frustrated Transition* scenario is first and foremost a result of lower penetration of electrified heating.

Industry – final energy demand per carrier, incl. feedstock [TWh] – EU27



Industry – shares of electricity in the mix [%] – EU27

	2019	2030	2040		2050	
	REF	NT+	MT	FT	MT	FT
Electricity	***24%***	***30%***	***38%***	***32%***	***46%***	***37%***
Other	76%	70%	62%	68%	54%	63%

Notes: [1] Final energy demands include the demands for both energetic and non-energetic (feedstock) uses. (ii) No hydrogen demand is reported in 2019 since hydrogen used as a feedstock in fertilizers is historically mostly produced through on-site SMR and thus attributed to natural gas demand. 'REF' refers to historical reference; 'NT+' in 2030 is based on best estimates of national TSO's as reported in TYNDP 2024

Buildings' efficiency improvements are higher in the *Managed Transition scenario* while heat pumps reach deep penetration levels in both scenarios

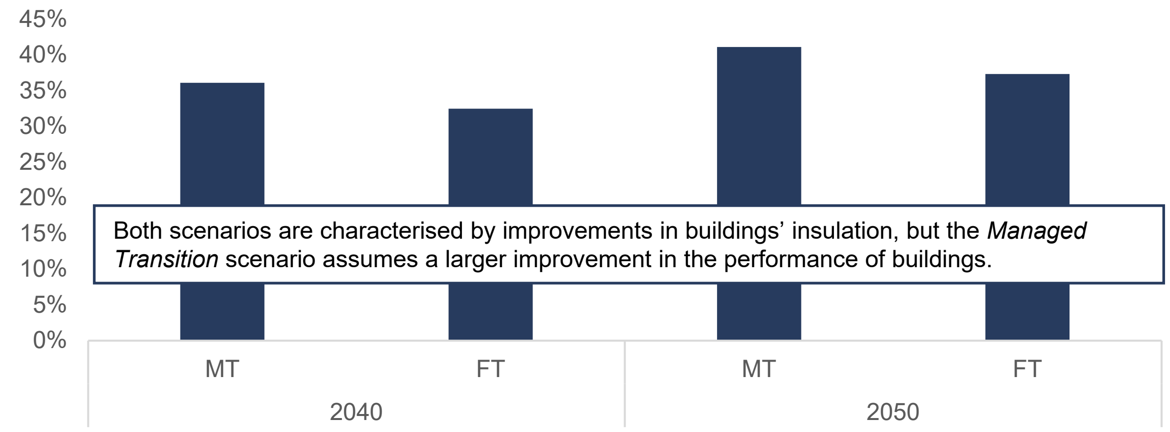
Building renovation still faces many barriers

- While there has been progress on implementation, it has been slower than planned**.** As a result, the overall efficiency of buildings in Europe has stagnated over the last few years, despite the targets set by the European Commission.
- In addition, energy efficiency behaviours noticed during the energy crisis have yet to be confirmed as structural across the board.

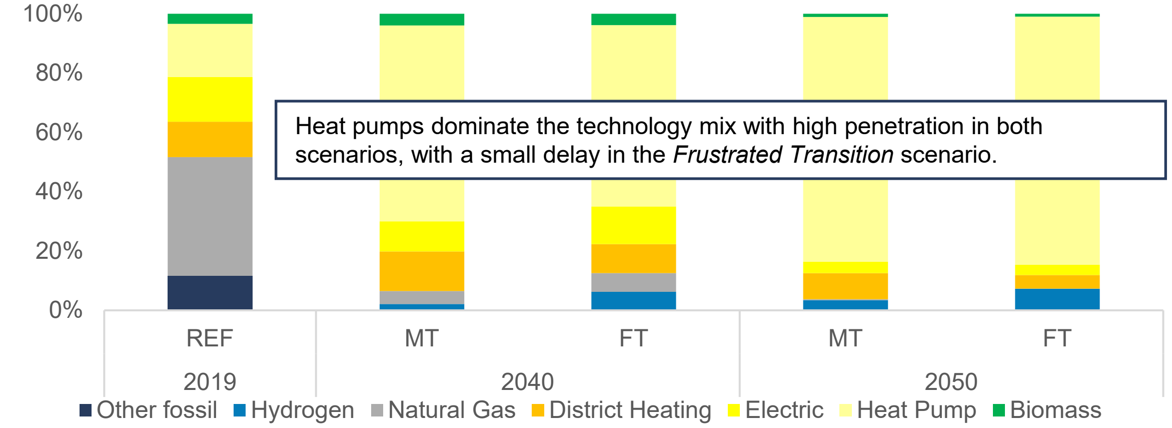
EU regulations on buildings have evolved and funding has increased

- Decarbonisation of buildings relies on electrification through heat pumps (REPowerEU sets a 10M units target for 2030) and smart electrical appliances.
- The National Recovery and Resilience Plans (NRRPs) approved in the aftermath of COVID in 2021, increase financing for renovation.
- The Renovation Wave initiative is a priority under the Green Deal and the EU recovery plan. Following the NRRPs, the revision of the Energy Performance of Buildings Directive (EPBD) has been adopted in April 2024, to amplify the current measures and send the right investments signals.

Insulation: heat demand reduction per building v. 2019 levels [%] – EU27



Buildings heating technology mix [% of buildings] – EU27



Note: The presented figures refer to commercial & public buildings. Structurally similar assumptions apply to residential buildings.

Sources: European Commission (2021). Renovation Wave ; Trinomics (2016). Boosting Building Renovation: What potential and value for Europe? ; BPIE (2014). Setting the 3% target for public buildings renovation ; Zebra (2020). Energy efficiency trends in buildings ; Pilar de Arriba Segurado (2021). Energy renovation of buildings in Spain and the EU. Lessons learned and main recommendations

Buildings' energy demand almost halves by 2050 compared to its 2019 level as a result of heat pumps roll out and renovations

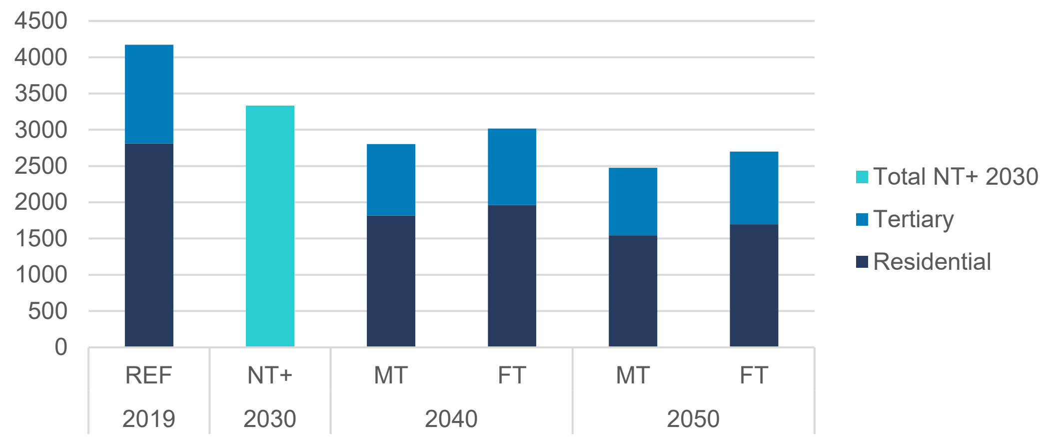
In buildings, progress on renovations and deployment of heat-pumps materially drives down energy demand in both scenarios, but to a greater extent in the *Managed Transition* scenario

- Compared to its 2019 level the consumption of energy in buildings reduces by more than 40% by 2050, coming down from above 4,000 TWh to around 2,500 TWh in both scenarios.
- More pronounced progress on building insulation yields a slightly stronger decrease in the *Managed Transition* scenario, leaving the two scenarios at a discrepancy of around 200 TWh in 2050.

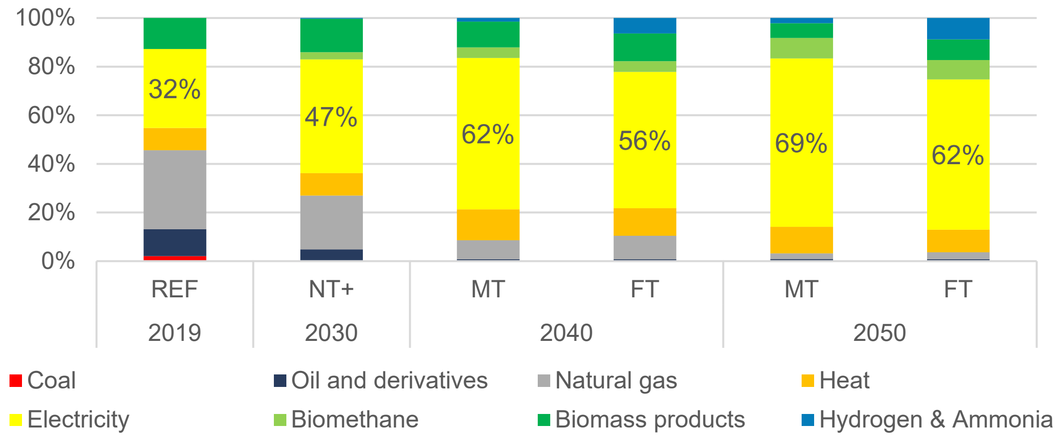
The uptake of heat pumps induces a sharp decline in oil and natural gas usage in the buildings sector - electricity constitutes >60% of energy demand in 2050

- Supplying more than 1,500 TWh of energy to the buildings sector in 2019, fossil fuels diminish to around 100 TWh by 2050, with coal and oil products being phased out entirely.
- This development is heralded predominantly by the electrification of heating but reinforced through the electrification of further appliances (e.g. stoves).
- By 2050 electricity alone makes up between 62% and 69% of energy demand in the residential and tertiary sectors.

Final energy demand of buildings [TWh] – EU27



Energy mix in buildings [TWh] – EU27



Note: The presented figures refer to the aggregation of commercial & public and residential buildings, they do not include ambient heat used thanks to heat pumps.

Transport electrification faces challenges both for passenger transport and freight, and will require H2 and low carbon fuels

Electric vehicles are supported by a range of European, national, and local policies

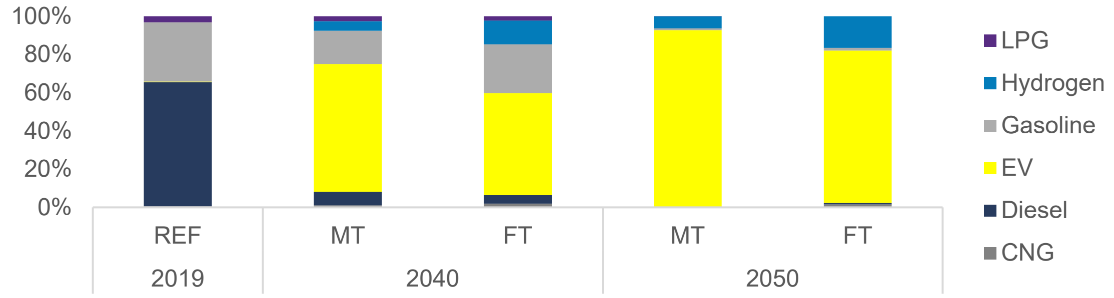
- In 2022, the EU Parliament agreed on a 55% CO_2 emission reduction for new cars and 50% for new vans from 2030 to 2034 compared to 2021 levels and 100% CO_2 emission reductions for both new cars and vans from 2035.
- As part of the Fit for 55 package, ICE sales ban was adopted in March 2023.
- National policies support electric mobility and are critical to enable a rapid penetration of electric vehicles. A number of EU countries will target a ban on ICE sales from 2030, or even 2025.

Electrification of light road transport is accelerating, but faces uncertainties

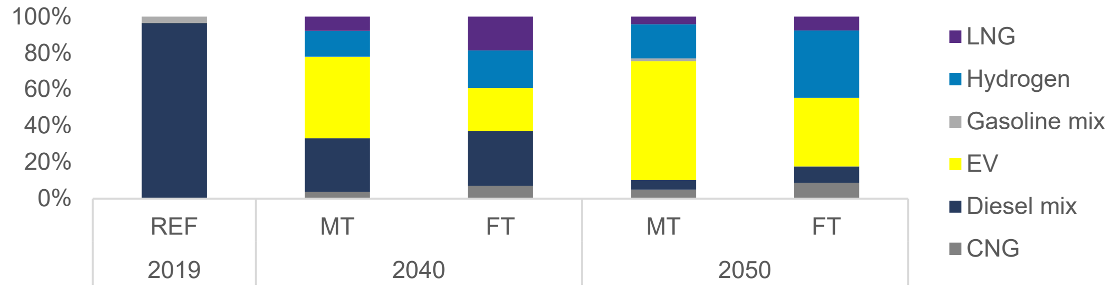
- Electrification of light road transport in Europe is increasing, with high heterogeneity between countries.
- However, there is no consensus on policy support for electric vehicles.

Decarbonisation requires significant electrification in both scenarios but uncertainties on the pace of electrification of the fleet and the ability to electrify long-haul transport are factored in the *Frustrated Transition* scenario

Passenger car technology mix [%] – EU27



Freight truck technology mix [%] – EU27



Notes: Gasoline/Diesel mix include the use of bioethanol/biodiesel. ICE…Internal Combustion Engines
Sources: Coltura, GASOLINE VEHICLE PHASEOUT ADVANCES AROUND THE WORLD ; Electrive (2023). EU Member States adopt ICE sales ban almost unanimously

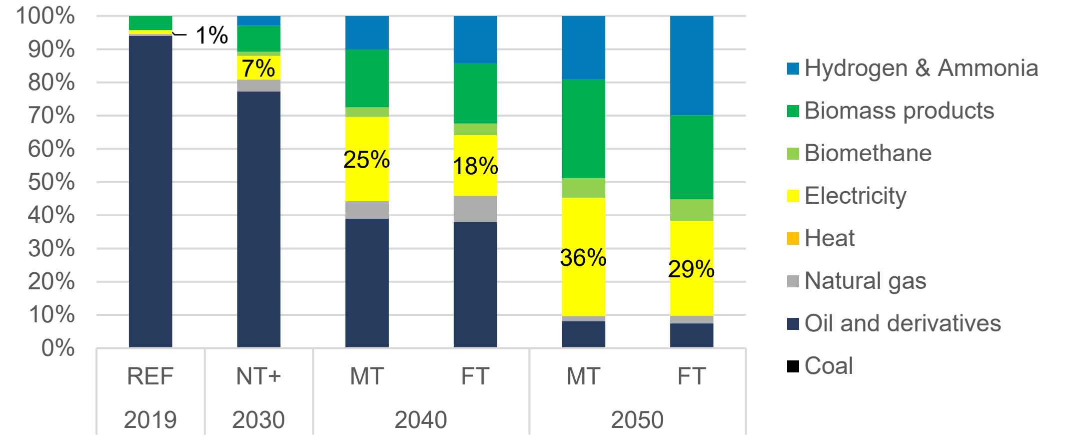
Transport energy demand halves thanks to the roll-out of electric vehicles in passenger transport

Higher electrification and efficiency gains lead to lower final demand in the *Managed Transition* scenario, as the fuel landscape shifts towards low-carbon options

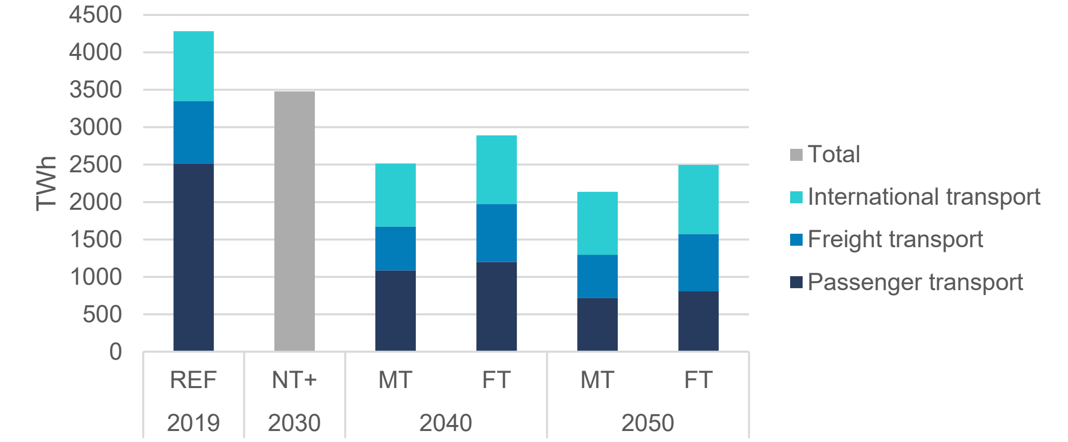
- The historic dominance of oil derivatives as transport fuels is gradually decreased, leaving diesel, gasoline and their relatives with only a small fraction of total demand in 2050.
- High efficiency gains for electric vehicles in the *Managed Transition* scenario result in similar absolute demands for electricity in the transport sector across both scenarios, despite a significantly higher electrification rate in the *Managed Transition* scenario.
- The gap in final energy demand between the scenarios is covered to a large extent by the increased use of hydrogen and its derivatives as fuels in the *Frustrated Transition* scenario.

The most substantial reduction occurs in passenger transport with further decreases in the freight sector, but limited change in international transport

Energy mix in transport sector [%] – EU27



Final energy demand by transport subsector [TWh] – EU27



Notes: figures include energy demand for international aviation and shipping.

2.3

Key trends and issues regarding low carbon energy supply

Biomethane domestic production increases and meets demand in the *Managed Transition* scenario, whilst imports are necessary in the *Frustrated Transition* scenario

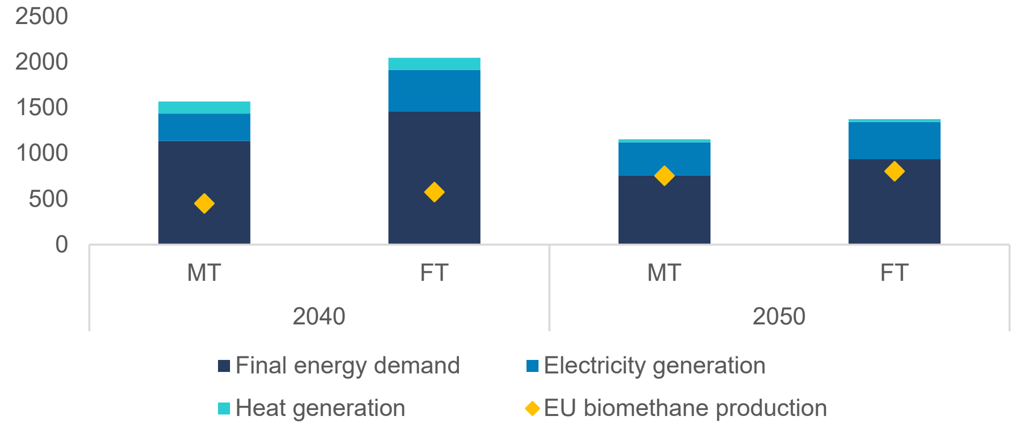
EU biomethane production ramps up to around 800TWh in 2050, but strong demand growth could lead to import dependence depending on the progress of direct electrification

- In the *Managed Transition* scenario, EU biomethane production is sufficient to meet domestic biomethane demand (both in 2040 and 2050).
- In the *Frustrated Transition* scenario, however, only 80% of biomethane demand can be covered domestically, resulting in imports of around 200 TWh in 2050.

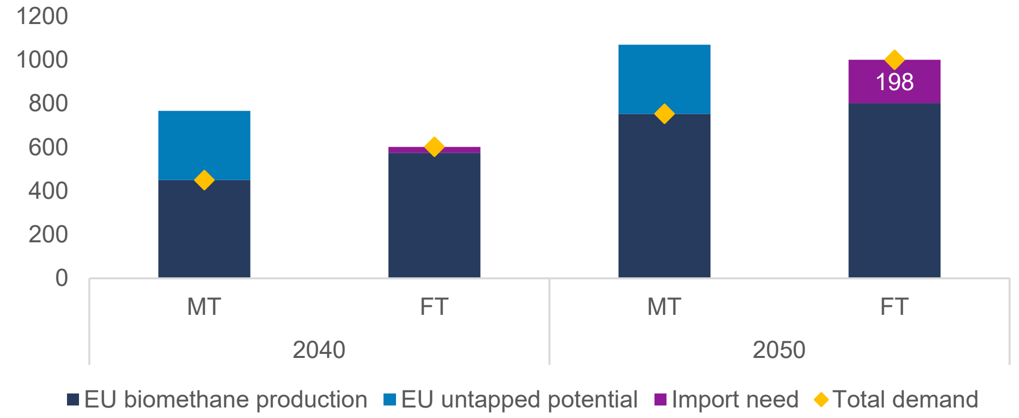
The EU's import needs in the *Frustrated Transition* scenario may be partly covered with imports from Ukraine, as well as other import routes.

- In addition to domestic production, the EU aims to build biomethane cooperations with neighbouring countries, explicitly highlighting a strategic partnership for renewable gases with Ukraine.
- Building on estimated biomethane export potentials, EU imports from Ukraine may suffice to cover most of import needs by 2050[1] – however subject to major uncertainties.
- There is limited information on other EU import potentials for biomethane. Turkey may be among the largest producing EU-neighbours, with 175 TWh by 2050. But given the scarcity of biomass and own decarbonisation targets, future export potentials are highly uncertain.[2] The same holds for other trade partners.[3]

EU methane demand [TWh]



EU biomethane demand and import need [TWh]



Sources: Compass Lexecon based on own modelling, EC (2023). EU-Ukraine Strategic Partnership for Renewable Gases ; IEA Bioenergy (2022). Sustainable potentials for renewable gas ; Engie (2021). Geographical analysis of biomethane potential and costs in Europe in 2050

Note: [1] Ukraine's export potentials based on IEA Bioenergy (2022). [2] According to Marconi, Rosa (2023), Turkey's biomethane potential in 2019 could offset 34% of domestic natural gas use. The country plans to reach net-zero emissions by 2053. [3] The EU and Algeria have a strategic energy partnership since 2013, however, including ambitions to reduce methane emissions in the oil and gas industry.

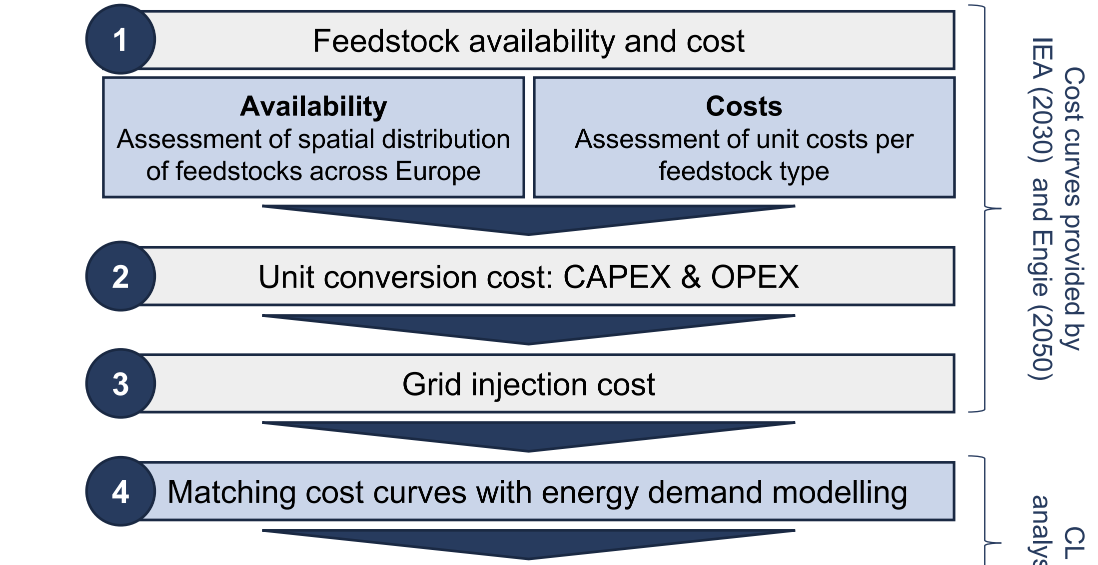
Biomethane costs are projected to remain above natural gas costs thus creating challenges for the fuel switch needed for decarbonisation

Biomethane prices evolution is uncertain as different drivers will shape the evolution of the market in Europe

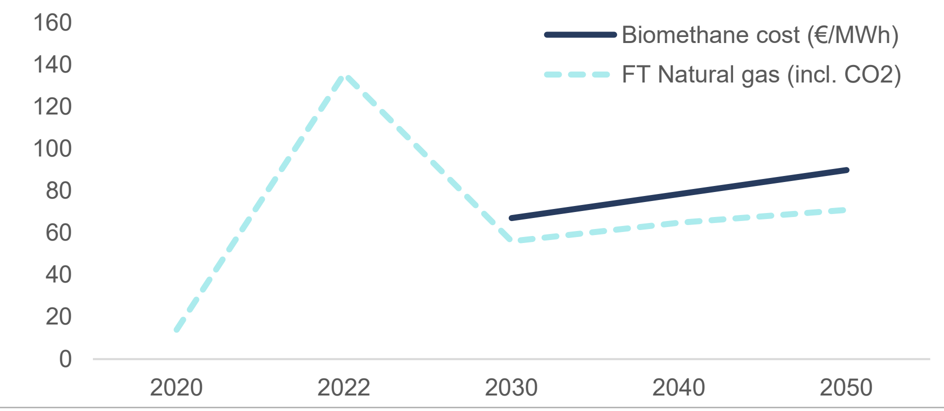
- Although technologies of production are well known, the market itself is nascent in Europe, consisting of subsidy-driven national sub-markets.
- Biomethane is thus not considered as a commodity and the price projection is based on production costs publicly available, with significant uncertainty.
- No differentiation is considered given similar production levels between both Net-Zero pathways, as lower biomethane demands leave additional potentials in the Managed Transition untapped.

Projected biomethane prices show a premium over natural gas + CO2 prices, thus creating challenges for the fuel switch needed to reach decarbonisation

- Based on the sources used as reference, Biomethane prices could rise from 70€ in 2030 to 90€/MWh in 2050.
- With IEA gas price assumptions around 30€/MWh from 2030 onwards and CO2 prices above 100€/t.



Total cost of biomethane (€$_{2022}$/MWh)



Sources: Compass Lexecon analysis based on Engie (2021) and IEA (2022).

Note: Given existing pipeline infrastructure connecting the EU with potential sources of imports no extra cost is assumed for imported volumes in the *Frustrated Transition* scenario. That means that relying on imports would not be costlier but result in a higher risk of failing climate ambitions should expected import levels not materialise.

Low carbon H_2 domestic production fails to match the growth of demand in the *Frustrated Transition* scenario, creating need for substantial imports

Starting from small volumes today, EU low carbon H_2 production sees a ramp-up, surpassing 800TWh in 2040 & 1,200TWh in 2050.

2030	Considering recent delays in RES-E, the EU's ambition to domestically produce 330 TWh (10Mt)[1] of renewable H_2 will be challenging to reach using a strict interpretation of renewable H_2 (but mostly fulfilled when considering blue H_2).[2]
2040 - 2050	In the long run, with growing demand and RES-E capacities, domestic low-carbon H_2 production continuously rises, reaching above 1,200 TWh in 2050, in line with existing studies[3]

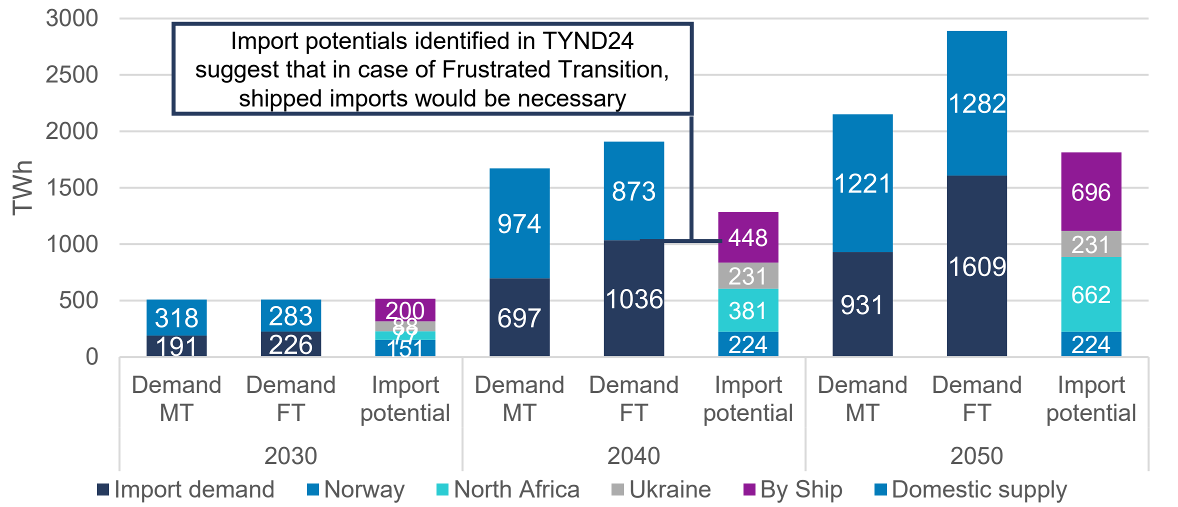
Policy support will be necessary for domestic low carbon H2 production to replace grey H_2.

- While SMR of natural gas is currently the main form of H_2 production, the rapid growth in RES-E generation could allow a shift towards low-carbon H_2 production.
- Future balance between SMR + CCS and electrolysis will depend on policy support and achieved CAPEX reductions in electrolysers and CCS units.

Supply of H_2 relies heavily on the availability of piped imports.

- Cost-competitive supply will rely on piped imports, particularly in the *Frustrated Transition* scenario. By 2050, delayed electrification could lead to more than 600TWh in additional import needs compared to the Managed Transition scenario.
- H_2 imports will likely be dominated by piped volumes from North Africa, the Middle East, Norway and Ukraine using retrofitted methane pipes, complemented by purpose-built H_2 pipes.
- Conversion losses (e.g. for conversion to NH_3 and back) make shipped H_2 more costly (ca. +2 €/kgH_2), rendering them only competitive in certain cases.

Hydrogen domestic production and imports [TWh]



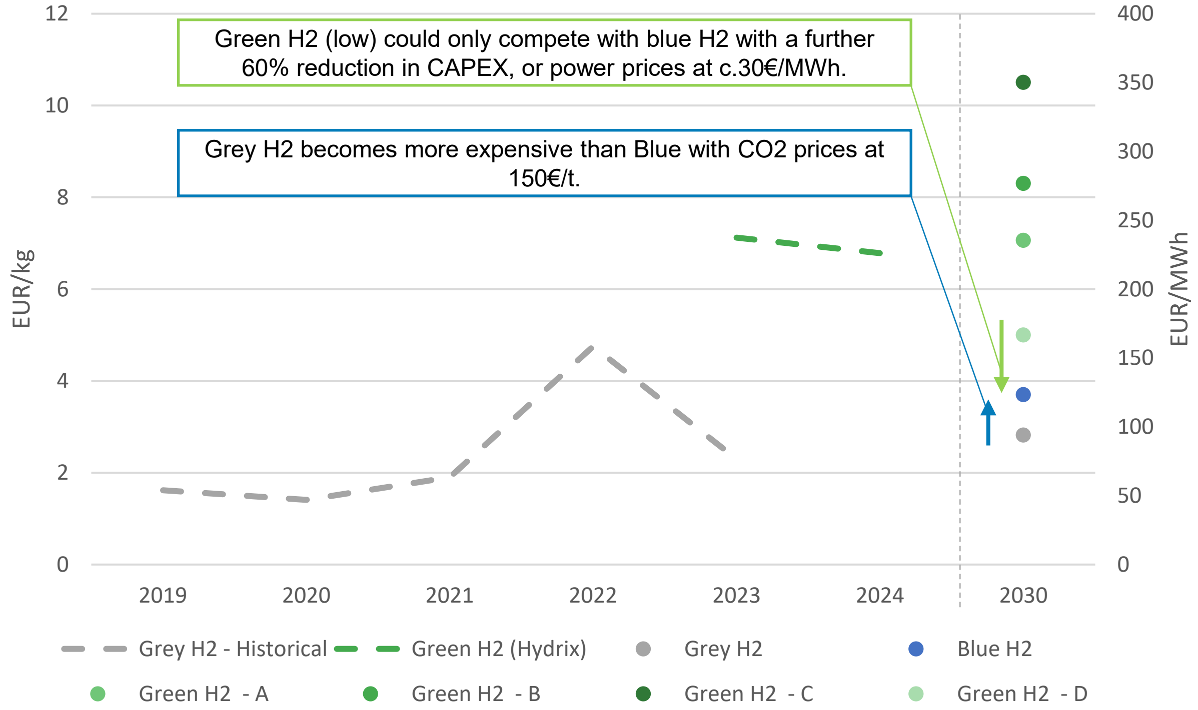
Abbreviations: SMR … Steam Methane Reforming, CCS … Carbon Capture and Storage, RES-E … Renewable Electricity, LCOH … Levelized Cost Of Hydrogen, NH3…Ammonia.
Note: [1] EU hydrogen strategy [2] Following the definitions in the EU delegated act H_2 produced from SMR with CCS is currently not classified as *renewable,* unlike H_2 produced from renewable electricity.[3] Notably, estimates from the EC 2040 target Impact Assessment SWD(2024) 63 final.

Low carbon H_2 costs projections show need to support green H2 to reach competitiveness while blue H2 could be a complementary solution

The costs of Green H_2 could remain higher than Grey and Blue H_2 in the absence of additional support by 2030

- With the expected policy measures (the phase-out of free allocations and an increase in carbon prices), **Green H_2 is currently not forecast to be competitive in 2030**.
  - Because electrolysis costs heavily depend on the location and associated captured power prices we consider a range of sources. Lowest costs reported in recent literature project a 5€/kgH_2 in 2030 for green H_2.
- **Reaching parity with Blue H_2 could be achieved** with a c. 60% reduction of CAPEX for electrolysers, or an electricity price input of c. 30 €/MWh, all else equal.
  - As a comparison, the EC estimates a 12% CAPEX reduction for electrolysers between 2030 and 2040.
  - The IEA WEO 2023 forecasts a LCOE of 32 EUR/MWh for offshore wind, in the NZE 2030 scenario.
- Uncertainties remain concerning the actual CAPEX for carbon capture units. **Blue H_2** could be as economical as grey H_2 with CO2 prices at 150€/t, and could be **a complementary solution** to fast-track industrial decarbonisation.

Hydrogen prices for EU production (EUR/kg), 2019-2030



Note: Historical H2 prices are extracted from Hydrogen Europe (2023): decarbonised Hydrogen Monitor for grey H2 and EEX Hydrix for green H2. Hydrix data for 2023 commence in May. 2024 data are based on data from Jan 2024 through early May 2024.

Grey and Blue H2 prices for 2030 are extracted from Trinomics assessment of policy instruments for hydrogen in the Netherlands (2023). The technology CAPEX and OPEX are extracted from the European Commission 2040 Impact Assessment (2024). Carbon capture is estimated to absorb 90% of emissions for the Blue H2.

Green H2 prices for 2030 are from 4 sources detailed in note below.

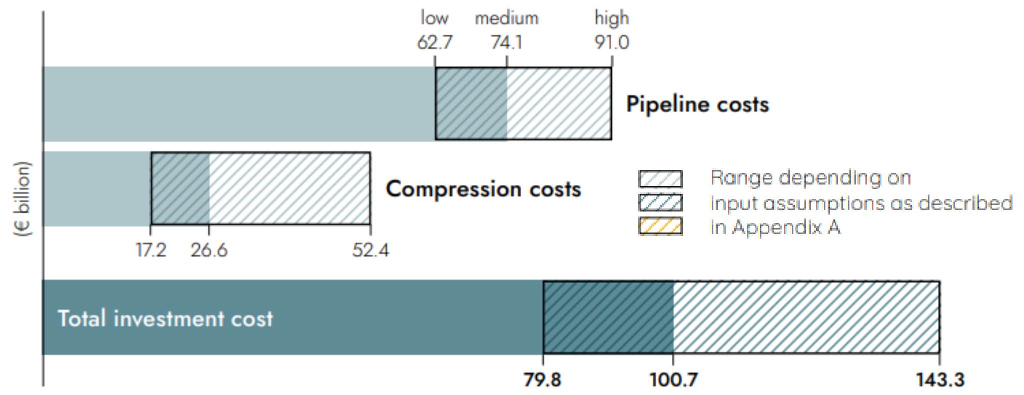
Abbreviations: LCOH … Levelized Cost Of Hydrogen, RES-E … Renewable Electricity, Blue H2 is derived from SMR + CCS, Green H2 is electrolytic H2.
Sources: Technology costs based on European Commission (2024): 2040 Climate target plan impact assessment. IEA (2023): WEO 2023. Green H2 prices historical: EEX Hydrix; Green H2 prices 2030: A – Trinomics (2023): Assessment of policy instruments for hydrogen in the Netherlands, B - CE Delft / TNO (2023): Afnameverplichting groene waterstof, C - TNO (2023): Effecten van een productiesubsidie voor elektrolysers, D – BCG (2023): Turning the European Green Hydrogen Dream into Reality

Low carbon H_2's transport and storage infrastructure will need to develop on time through both greenfield investments and repurposing of existing gas infrastructure

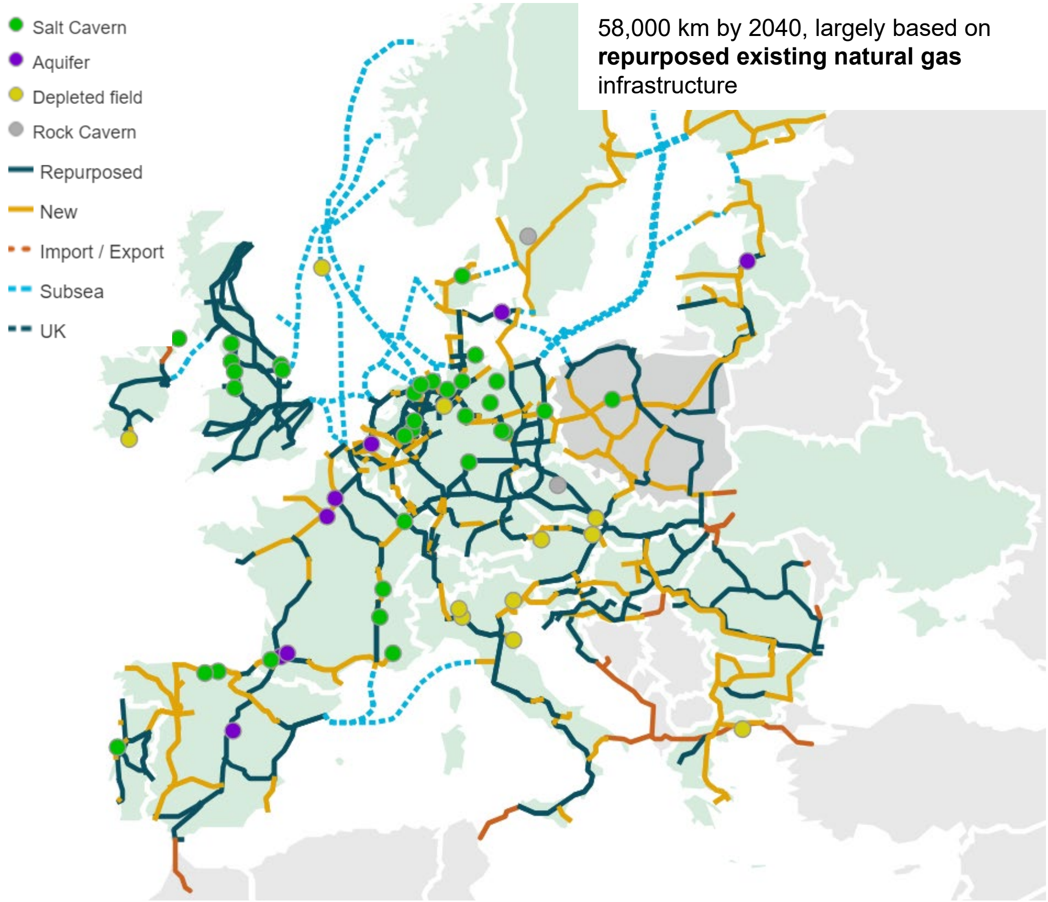
The H_2 infrastructure will play a central role in the EU's decarbonisation, especially for hard-to-abate sectors. Minimising costs will require careful planning and repurposing of existing gas infrastructures.

- Given recent developments in the global economic picture – whether COVID, geopolitical, or climate-related, 2023 cost estimates for the H_2 infrastructure showed a substantial increase (average of 40%) compared to 2019 estimates.
- A transport cost of between 0.15-0.30€/kgH_2.1000km in onshore pipelines and 0.24-0.45€/kgH_2.1000km in subsea offshore pipelines could be needed to compensate for investment in compression and pipes;[1]
- Further policy support will be needed to ensure a timely development of H_2 infrastructure

Estimated CAPEX of the EU hydrogen Backbone 2040 (bn€ real 2019)



Map of EU Hydrogen Backbone 2040



Note: [1] We apply latest cost increases of 40% in EHB 2023 to the estimate of €0.11 – €0.21 /kgH2.1000km (€3.3 - €6.3 per MWh) and €0.17 - €0.32/kgH2.1000km (€4.5 - €8.7 per MWh) in subsea offshore pipelines provided by the EHB on 2019 figures in EU Hydrogen Backbone 2022.
Source: EU Hydrogen Backbone 2022, EHB 2023

Biomass demand is in line with domestic sustainable supply potentials, although increased reliance on biomass in the *Frustrated Transition* could create challenges

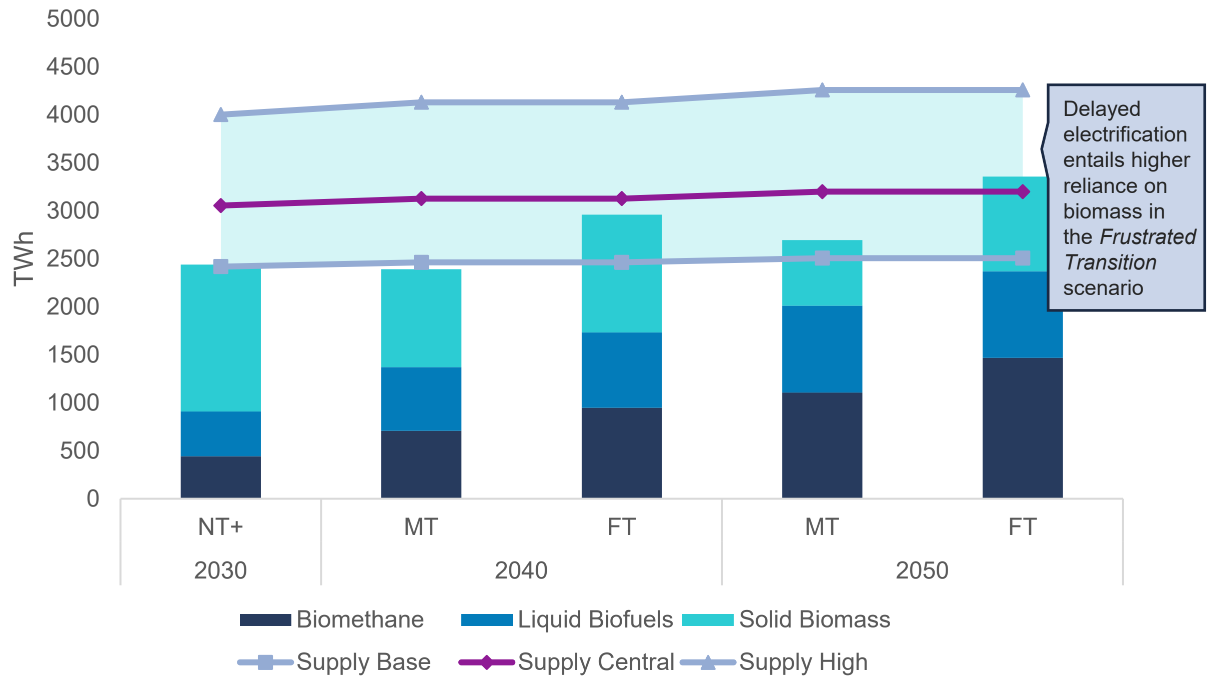
Sustainable Biomass

- Under its Renewable Energy Directive (RED II) the EU defines sustainability criteria for biomass used in power and heat generation or as transport fuels, aiming to ensure sustainable use of land and effective emission reductions.
- A provisional agreement reached on its revision (RED III) is set to continue to promote a shift towards advanced biofuels (non-recyclable waste and residues).

Delayed electrification entails higher reliance on biomass to meet Net-Zero targets in the *Frustrated Transition* scenario

- Sustainable EU supply potentials of biomass remain stable over time as stringent sustainability criteria balance out improvements in forest management and enhanced yields through technological progress.
- Realising the Central/High supplies shown in the graph requires additional R&D to enhance yields as well as improved land management strategies, coupled with investments in supply chains to mobilise these resources.
- The increased reliance on biomass in the *Frustrated Transition* scenario runs the risk of falling short of climate goals in case sustainable supply potentials fail to be mobilised as projected.

Biomass primary demand and sustainable EU supply potentials [TWh]



Note: **Primary biomass demands** take into account conversion efficiencies of 58/68% for biomethane and 60/70% for liquid biofuels in 2030/2050 based on TYNDP24. **Sustainable supply potentials** are based on estimates from dedicated studies by Imperial College London and Material Economics. 2040 supply potentials follow a linear interpolation. *Base supply* refers to supply that can be mobilised using state-of-the-art technology and practices as of today. The *central supply* scenario assumes improvements in crop and forest management practices, while the *high supply* scenario additionally assumes substantial improvements in available technologies to improve yields.

Abbreviations: RED … Renewable Energy Directive
Sources: CL analysis based on own modelling, Imperial College London (2021), Material Economics (2021), European Commission
Note: Displayed supply potentials include biomass supply in the UK, though these potentials are limited compared to the total magnitude.

CO_2 market prices evolution is uncertain and depends on overlap of policies driving carbon abatement and future evolution of the EU Emission Trading Scheme

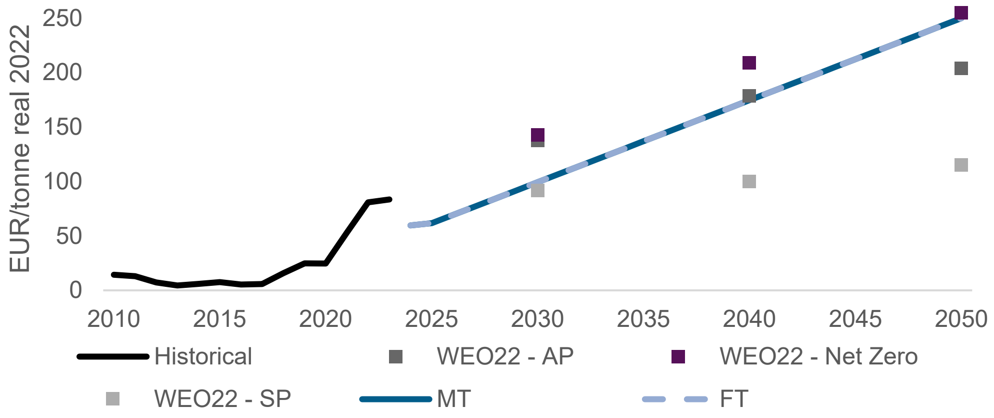
Carbon price evolution in the ETS is uncertain and will depend on industry's abatement costs, policy overlaps and design changes

- For ETS-covered sectors, the 2030 climate target translates to a -62% emissions reductions compared to 1990 levels. Under current ETS parameters the cap reaches 0 in 2039, we assume continuity of the market and / or a carbon pricing scheme after 2040.
- If no more allowances are auctioned as soon as 2039, compliance entities could only rely on previously banked allowances in the absence of major changes in design.

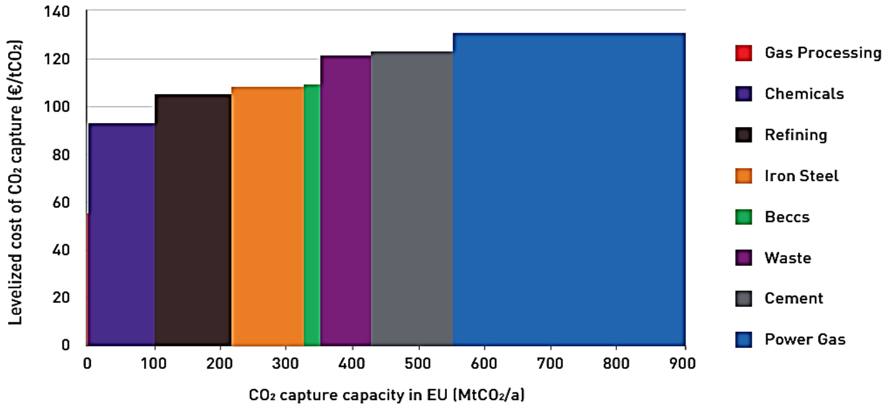
Costs of the industrial carbon management infrastructure could impact the costs of e-fuels, chemical feedstock costs and CO_2 prices

- Development of an adequate CO_2 network could cost around a cumulated 10-23 bn€ by 2050, with a need for a pipeline network spanning around 15,000-19,000 km by 2050.[1] In addition, carbon capture unit costs could amount to 95-120 €/tCO2 by 2030.[2]
- The European Commission estimates that CCS needs similar to this study could entail annual investment needs of around 2 bn€/y between 2030-50.
- Those costs will impact e-fuels production, waste treatment costs, chemical feedstock and CO_2 prices (should removals be included in the ETS).

EU-ETS price assumption based on IEA (EUR/tonne real 2022)



Levelized cost of CO_2 capture in the EU 2030 (EUR/tCO_2 real 2023)



Abbreviations: CCS … Carbon Capture and Storage, ETS…EU Emission Trading Scheme
Sources: [1] JRC (2024), [2] International Association of Oil and Gas Producers (2023), [3] 2040 CTP Impact Assessment (2024)

Natural gas prices are assumed based on the IEA to level down from their crisis peak by 2030, but remain at higher levels then pre-crisis

According to the IEA, gas demand towards 2050 is constant or decreasing globally

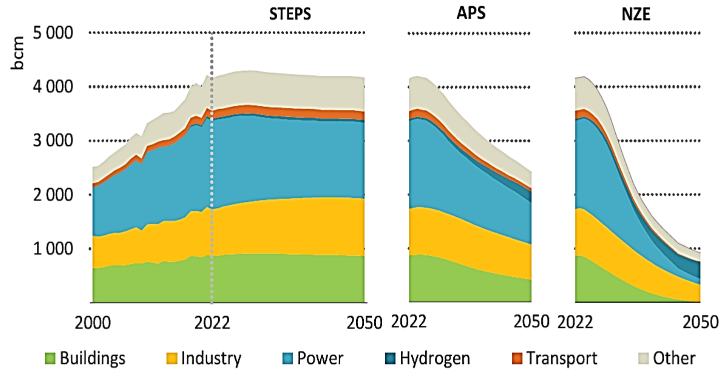
- In addition, for Europe, the Russia – Ukraine war has already reshuffled commercial roads and the EU's rapidly decreasing consumption will be served going forward by LNG imports and pipeline imports from North Africa.
- There is no direct threat to the continuous natural gas supply to the EU market.

Gas prices in Europe are slowly recovering from the energy crisis

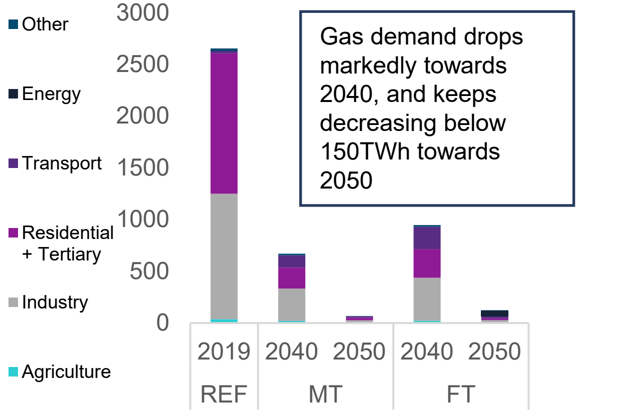
- Natural gas prices are projected to stay relatively high in the middle of the decade as global gas markets continue to adjust
- From 2026 onward, the maturity of the LNG global market is projected to ease gas market balances, bringing prices down to around 30 €/MWh over the period. These prices are conservative compared to WEO 2023 projections just below 20€/MWh in 2050.

EU gas prices remain the same in both scenarios, due to the global nature of the market and demand being largely driven by Asian demand.

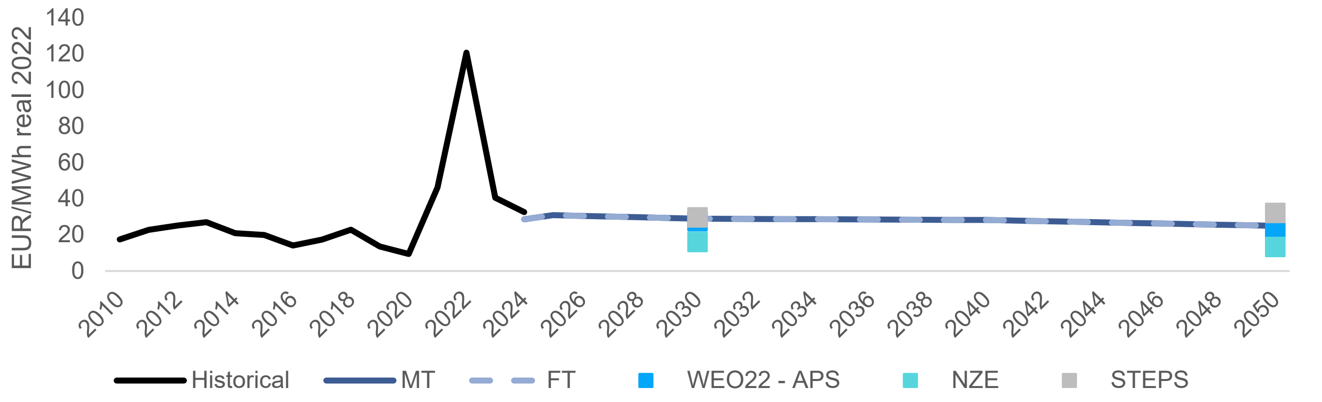
Global natural gas demand [bcm] – 2000-2050



Final natural gas demand [TWh] - EU27



Gas price (EUR/MWh real 2022)



Abbreviations: LNG … Liquified Natural Gas
Sources: IEA, WEO 2022 & WEO 2023, CL analysis based on ENTSOE/ENTSOG 's TYNDP24
Notes: Reported figures include final demands for non-energy (feedstock) uses.

2.4
Main takeaways

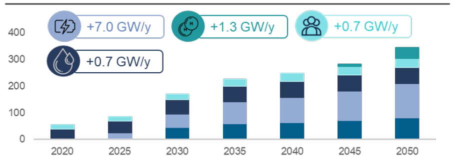
Enhancing the EU’s energy security of supply requires timely policy support to foster electrification and low carbon and renewable domestic energy production

Timely scaling up of different flexible resources is critical

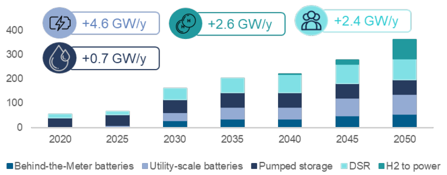
The development of a range of flexible resources, incl. large-scale batteries, DSR, EVs and heat pumps, as well as hydro clean H2 is needed to cover growing flexibility needs in the power system and ensure security of supply.

In case of delays, higher costs options and DSR / demand destruction from industry will be required to maintain the necessary margins in the system – resulting in higher power prices.

Flexibility capacity in Europe, 2020-2050 - MT [GW]



Flexibility capacity in Europe, 2020-2050 - FT [GW]

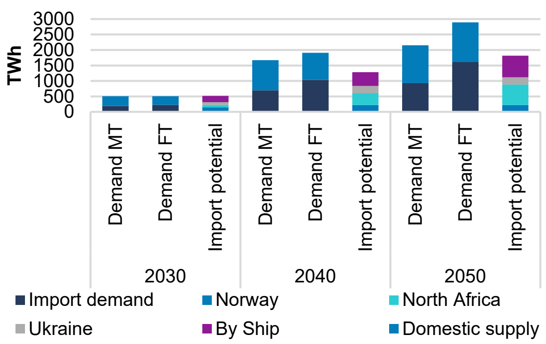


Accelerating direct electrification and diversifying H2 supplies

Direct electrification wherever possible is key to contain the dependence on H2 imports from third countries.

Diversifying supplies across geographies and - where economic - facilitating the realization of domestic electrolysis potentials are needed to ensure resilience of the EU’s H2 supply.

Hydrogen domestic production and imports [TWh]

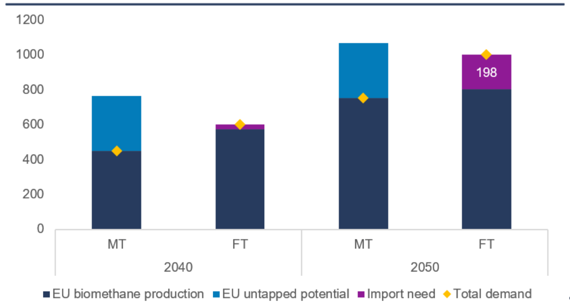


Mobilizing domestic biomethane potentials and building strategic partnerships with third countries

In the *Managed Transition*, biomethane needs can be met with domestic supplies without exhausting potentials.

In the *Frustrated Transition*, strong policy support for the mobilization of a greater share of domestic potentials or the creation of strategic partnerships with potential exporters would be needed.

EU biomethane demand and import need [TWh]

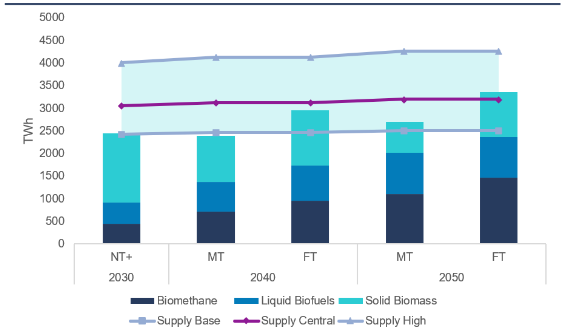


Enhancing biomass yields while ensuring sustainability

Electrification can limit primary biomass demands to a level achievable using known methods and practices.

Increased reliance on biomass, as in the *Frustrated Transition* scenario, while guaranteeing sustainability would require additional R&D to enhance yields, improved land management and investment in supply chain mobilisation.

Biomass primary demand and sustainable EU supply potentials [TWh]



Greater reliance on imported low carbon fuels such as H2 and biomethane in the Frustrated Transition scenario comes with greater supply risks

The two scenarios differ in the extent to which they rely on imports of low-carbon fuels:

- In the ***Managed Transition*** scenario, direct electrification is accompanied by strong growth of RES-E production domestically and adequate infrastructure development.
- In the ***Frustrated Transition*** scenario, substantial imports are required to cover demand for hydrogen and biomethane, increasing the risk associated with potential disruptions and / or supply price shocks from extra-EU imports.

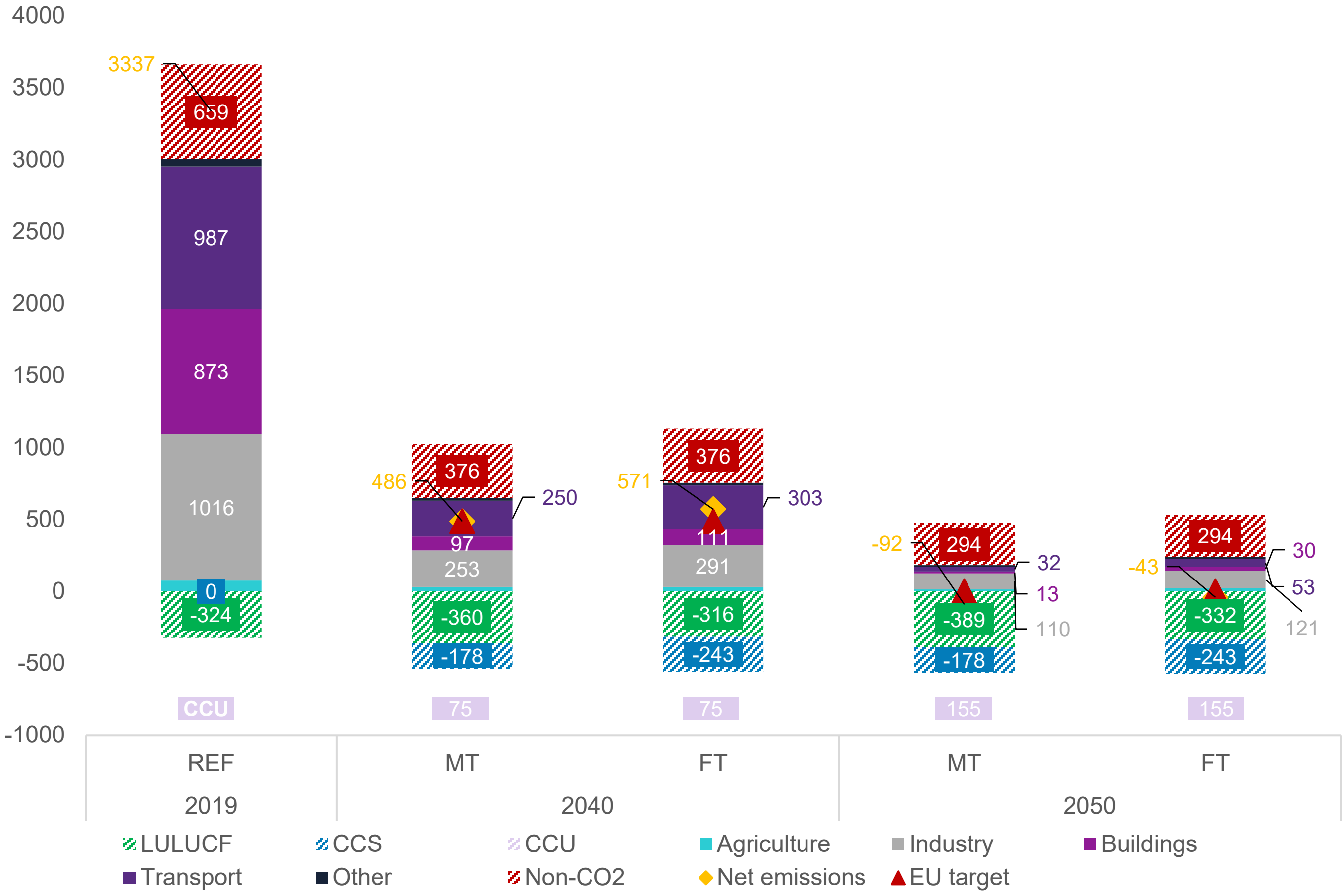
Security of supply monitor:	Electricity	H_2 Hydrogen	Biomethane	Biomass (incl. biofuels)
MT	▪ Renewable and flexibility capacity ramp up with Net-Zero targets ▪ The combination of demand flexibility, storage and emission-free thermal plants is projected to ensure an adequate level of security of supply	▪ EU production ramps-up to cover c. 60% of EU demand ▪ Imports are required to cover demand towards 2050, but lies within estimated extra-EU potentials	▪ Ramp-up of domestic capacities covers 100% of demand ▪ Strong policy support and coordination of infrastructure investments ensure the security of biomethane supplies	▪ Limited demand growth towards 2050 , with demand on the lower end of EU supply potential estimates ▪ No major supply bottlenecks anticipated at this level of demand
FT	▪ Flexible and renewable capacity ramp up too slowly to enable steady least-cost development ▪ This comes at the cost of potential occasional curtailment of demand, particularly industrial, in periods of system stress	▪ EU production ramps-up to cover c. 45% of EU demand ▪ Additional import needs could be more challenging to source given extra-EU potentials. ▪ Piped imports would need to be complemented by shipping	▪ Development of EU production covers 80% of EU demand ▪ Meeting demand requires imports with no certainty on availability of such volumes	▪ Reaching net-zero entails a marked increase in the use of biomass products ▪ Needs lie within supply potentials, but mobilisation requires additional investment and potential imports

Scope: EU27

Security of supply risk: low ■ ■ ■ ■ ■ high

EU emissions – In both scenarios, industrial carbon management plays a role to offset agricultural and industrial emissions

Total annual GHG emissions by sector incl. LULUCF & CCS – EU 27 [Mt CO_2-eq]



A combination of carbon removals and significant gross emission reductions across the entire economy will be needed to achieve the proposed emission reduction targets in 2040 (-90% vs. 1990) and 2050 (Net-Zero).

- Substantial efforts across all sectors lead to a gross emission reduction (incl. LULUCF, excl. CCS) to around 200 Mt CO_2-eq in 2050.
- Yet, already in 2040 sizeable contributions of CCS technologies are required to ensure compliance with the 90% emission reduction target.
- The extent to which such industrial carbon capture and storage is required heavily depends on LULUCF contributions.
- Higher reliance on biomass as an energy carrier (limiting the level of LULUCF contribution) coupled with slightly lower penetration of low-carbon processes in industry result in elevated CCS needs in the *Frustrated Transition* scenario.

Abbreviations: GHG … Greenhouse Gases, LULUCF … Land Use, Land Use Change and Forestry, CCS … Carbon Capture and Storage, CCU … Carbon Capture and Utilization
Sources: EU Commission modelling for 2040 climate target plan and Compass Lexecon modelling
Notes: Non-CO2 emissions and LULUCF contributions are informed by projections in the European Commission's modelling for the 2040 climate target plan. CCS contributions in each year are capped at the maximum level resulting from the European Commission's scenarios.

3.

Power system Net-Zero pathways

3.1
Approach

Modelling approach and key assumptions: two scenarios reflecting different policy responses to current challenges

***'Frustrated transition' (FT)* scenario**

- Slower deployment of RES in electricity market due to infrastructure bottlenecks and permitting and licensing delays
- Nuclear capacity based on ENTSOE best estimate, reflecting investment challenges
- Some interconnection projects delayed due to lack of supportive policy framework to ensure efficient planning and costs and benefits allocation

***'Managed transition' (MT)* scenario**

- Stronger deployment of RES in electricity market due to policies addressing infrastructure bottlenecks and permitting and licensing delays, and fostering cross countries collaboration to optimize potential
- New development of nuclear capacity in countries supportive, driven by support policies
- Timely development of interconnections in line with latest published ENTSOE plans

	MT scenario assumptions	FT scenario assumptions
Power demand	From FED modelling based on TYNDP 2024 (slide 15)	From FED modelling based on TYNDP 2024 (slide 15)
Nuclear	Exogenous assumption (99GW 2050) New nuclear in France + TYNDP24 BE adapted to recent announcements	Exogenous assumption (65GW 2050) New nuclear in France + TYNDP24 Best Estimate
RES and flex	Economic optimisation with minimum level TYNDP24 2030 Best estimate	• Same as MT but factoring delays and suboptimal geographic development resulting in reduction of RES and flexible resources development
Interconnections	Exogenous - TYNDP24 including invest candidates	Exogenous - TYNDP24 including invest candidates + 5 years delays
Commodities	Exogenous and identical based on IEA WEO22 Net Zero scenario CO2: increase to 250 €/t in 2050 Gas: gas relatively stable at c.30€/MWh over 2030-2050	

Notes: FED…Final Energy Demand, TYNDP…Ten-Year Network Development Plan by ENTSOE-G, WEO…World Energy Outlook by International Energy Agency

3.2

Key trends and issues in the power system

Interconnection capacity development is key for the transition to a decarbonised power system, uncertainties concerning delays and actual level of interconnection achieved

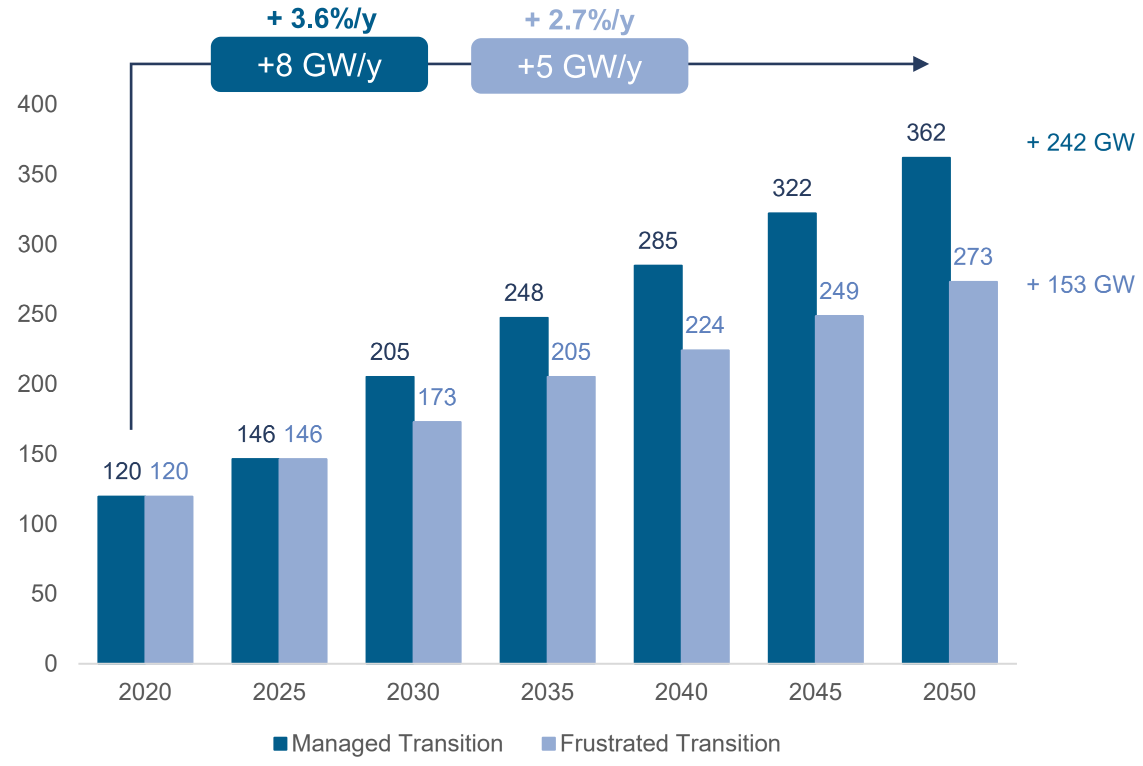
An important investment in interconnection capacity is needed to integrate renewables and achieve Net-Zero targets

- The development of interconnections has been flagged as a priority investment by the EC in its ambitious push to develop renewables.
- The revised Trans-European Networks for Energy (TEN-E) policy has identified priority corridors where new projects can benefit from funds from the Connecting Europe Facility.
- Our assumptions for the development of interconnection capacity are based on the TYNDP 2022, with projections based on the assessment of system needs and cost-benefit analysis.

Policies supporting timely investment and accelerated permitting are key

- The *Frustrated Transition* scenario assumes a slower interconnection capacity development, with around 40% less capacity being built between 2020 and 2050 (+5GW/y versus +8GW/y in the MT).
- This reflects a more challenging regulatory environment where securing financing (from both private investors and public funds) and permitting may prove more challenging and with the lack of a supportive policy framework to ensure efficient planning and costs and benefits allocation.
- Consequences on electricity prices are presented in slide 51.

Interconnection capacity in Europe, 2020-2050 [GW]

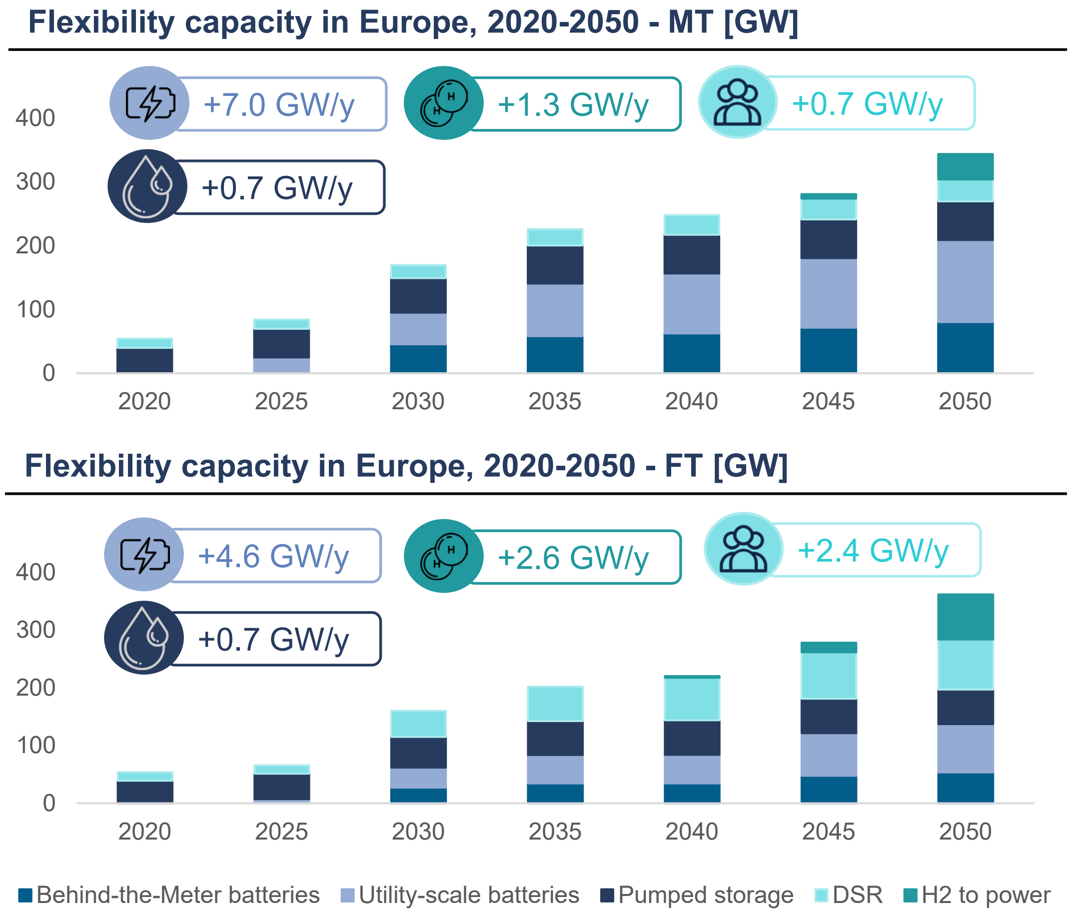


Notes: Interconnections (IC) can have different capacity depending on the direction of travel due to the properties of current. Here, the IC capacity is equal to the average of the capacity in both direction for all lines and summed up. Scope: EU27 + AL, BA, CH, GB, SEM, ME, MK, NO, RS

A framework to support timely and efficient flexibility resources development is key to contain prices and limit volatility

Lack of policy support and regulatory framework for the development of a cost-effective mix of flexible capacities results in higher security of supply risks and power system costs

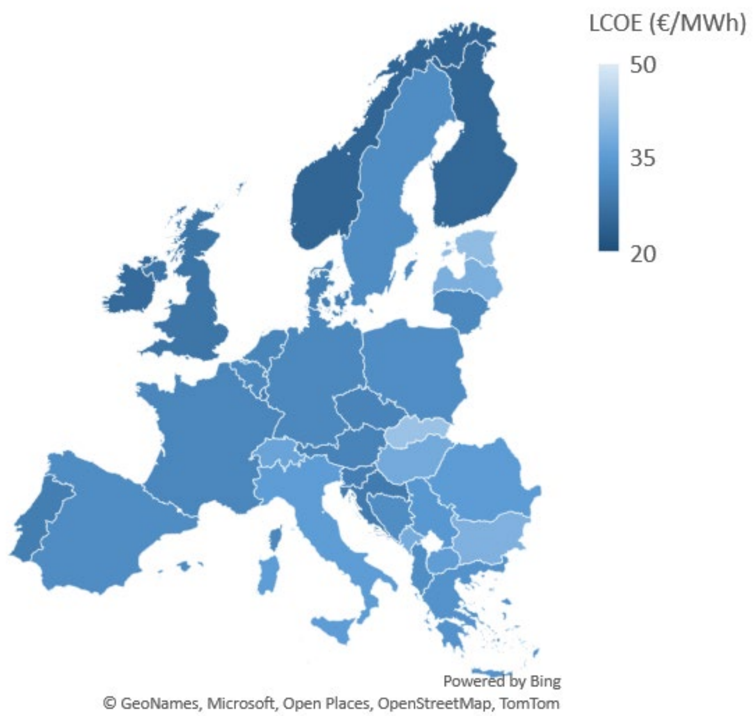
- The development of batteries in the *Managed Transition* scenario is stronger across the different types of flexible resources, with e.g. +7GW of batteries per year between 2025 and 2050.
- In the *Frustrated Transition* scenario, higher costs and the lack of a supportive policy framework lead to delays in the development of a diverse range of flexible resources.
- As a consequence, high and volatile prices lead to an increase in DSR with the risk of demand destruction in the longer term to matin security of supply: DSR capacity increases by 2.4 GW/y.
- In addition, further development of H2 to power capacity is needed to ensure security of supply, straining even more the H2 supply chain and entailing higher costs for the power system.



Abbreviations: DSR … Demand Side Response
Source: CL modelling

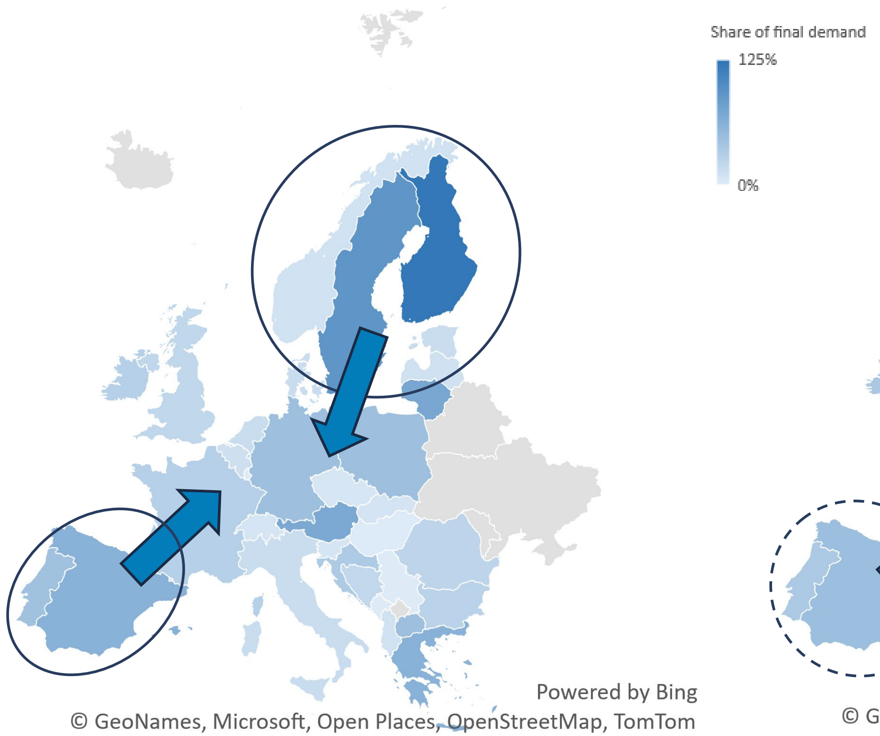
RES-E development can be optimised through cross country collaboration mechanisms targeting least cost areas combined with transmission capacity expansion

Onshore wind LCOE – Both scenarios

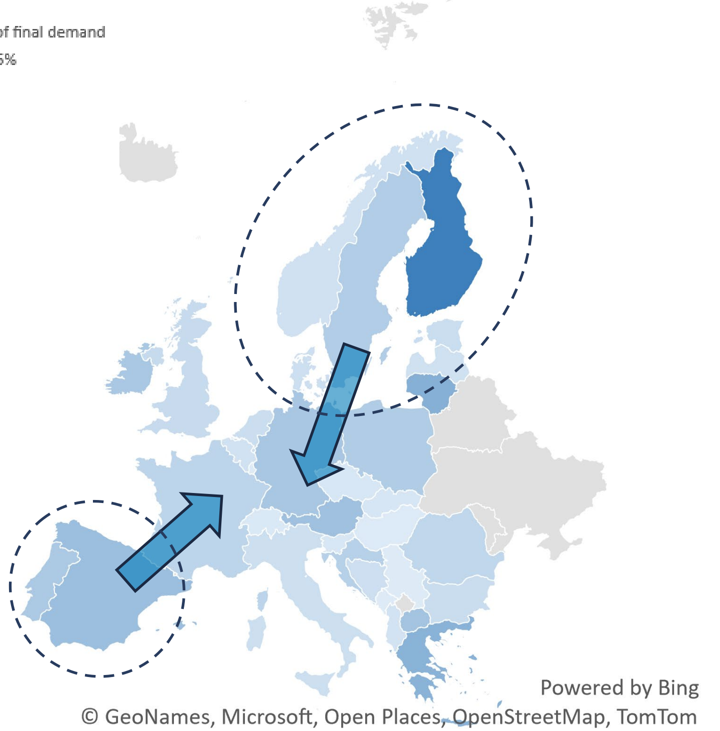


Onshore wind potential is particularly important in the North of Europe, where wind is abundant

Onshore wind capacity – MT scenario



Onshore wind capacity – FT scenario



Onshore wind development is projected to be stronger e.g. in Iberia and in the Nordics in the *Managed Transition* scenario, given the stronger potential for exports to central Europe and cross-country collaboration mechanisms

Abbreviations: LCOE … Levelized Cost of Electricity
Note: LCOE constitutes the total cost over the lifetime of a generation asset per unit of generation

Wholesale power prices can be contained thanks to a policy mix supporting efficient growth of renewable and low carbon capacities, timely development of flexibility and market integration

In the long run, policies supporting the timely and efficient cross-country development of RES-E and other decarbonised energy supply, as well a flexible resources and transmission infrastructure can reduce prices by up to 40%

- Between 2030 and 2035, gas prices and renewable development drive the wholesale power prices down in both scenarios, before stabilising in the *Managed Transition* scenario while increasing in the *Frustrated Transition* scenario.
- Lower level of electrification of the energy demand, continued RES-E, storage and infrastructure roadblocks result in a stabilisation of EU average power prices around 110 €/MWh in the *Frustrated Transition* scenario, with largely varying situations across Member States.
- With policies able to lift roadblocks and support RES-E development in least-cost geographic areas and further market integration, wholesale prices are contained around 65€/MWh from 2040 in the *Managed Transition* scenario.

Average EU power price (EUR/MWh real 2022) – 2025-2050

Note: The average price is a weighted average of national market prices, weighed by the demand in each country. The range is the maximum and minimum yearly average price projected in a country / market zone for that year.

For end-users, total system costs (incl. network, flexibility and low carbon capacity support mechanisms) are more competitive in the *Managed Transition* scenario

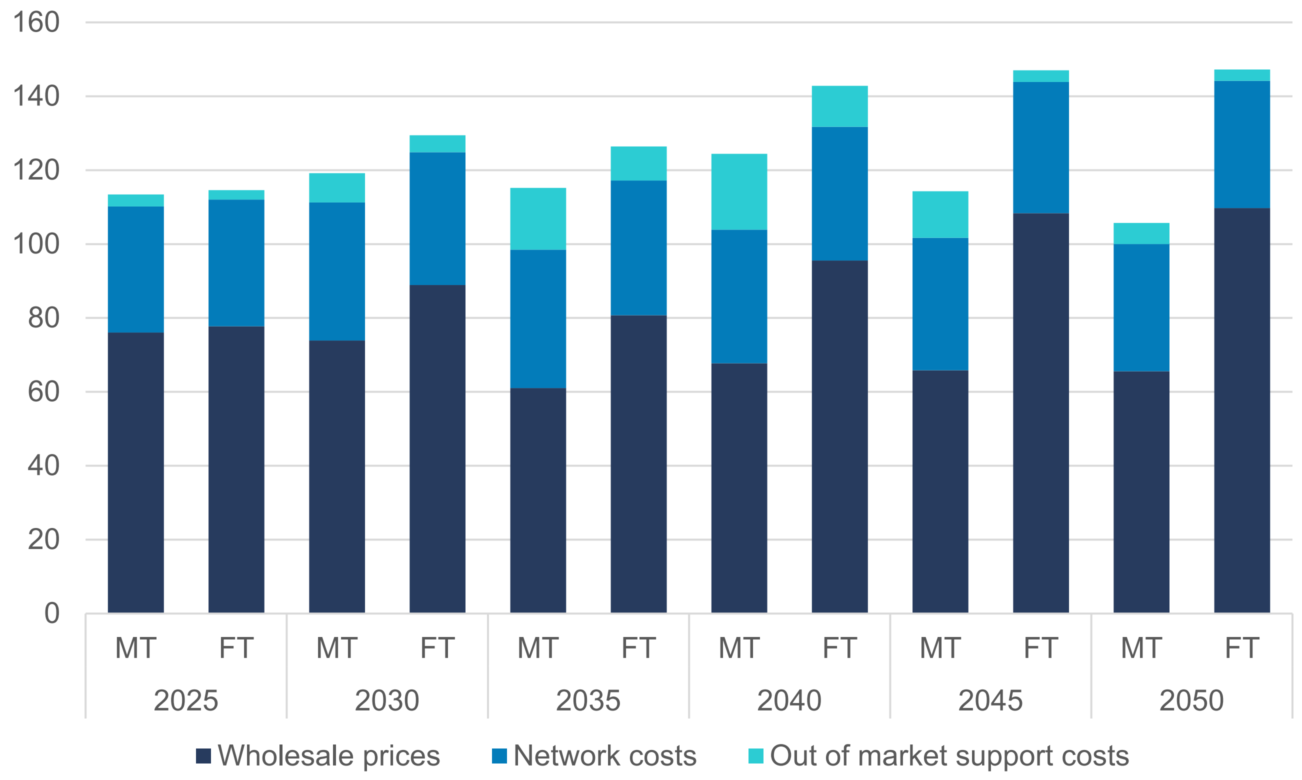
The final price paid by the final consumers reflects the total system costs of electricity supply

- These total system costs include market prices, as well as network infrastructure costs and out-of-market support complementing market remuneration.[1]
- The sum of all these costs is the total cost of building, maintaining and operating the power system, thus the total cost of meeting power demand.

The *Frustrated Transition* scenario results in higher total system costs despite lower network and out-of-market costs

- The *Frustrated Transition* scenario is characterised by a lower renewable capacity, that leads to lower grid development needs and operation costs for networks.
- In addition, a higher wholesale market price limits the need for out-of-market remuneration.
- However, overall, the *Frustrated Transition* scenario results in a more expensive power system for the end consumer, with ~40 €/MWh difference with the *Managed Transition* scenario by 2050.

Industry retail power prices, excluding taxes – average EU27 (EUR/MWh real 2022)



Notes: We only apply transmission network costs here, assuming that the industries considered are connected to the transmission network and are therefore exempted from distribution tariffs. Total network investment costs are converted into retail costs using a regulated rate of return of 5% and a lifetime of 40 years.

Note: [1] Out-of-market remuneration includes capacity market remunerations, contract-for-differences and feed-in-tariffs for renewables or storage systems, etc. They drop significantly from 2045 due to less RES capacity being built in both scenarios, and wholesale price increasing in the *Frustrated Transition* scenario, limiting the need for extra remuneration
Source: CL modelling

3.3

Case studies

In Ireland, the low level of interconnection leads to higher power prices despite strong renewable penetration

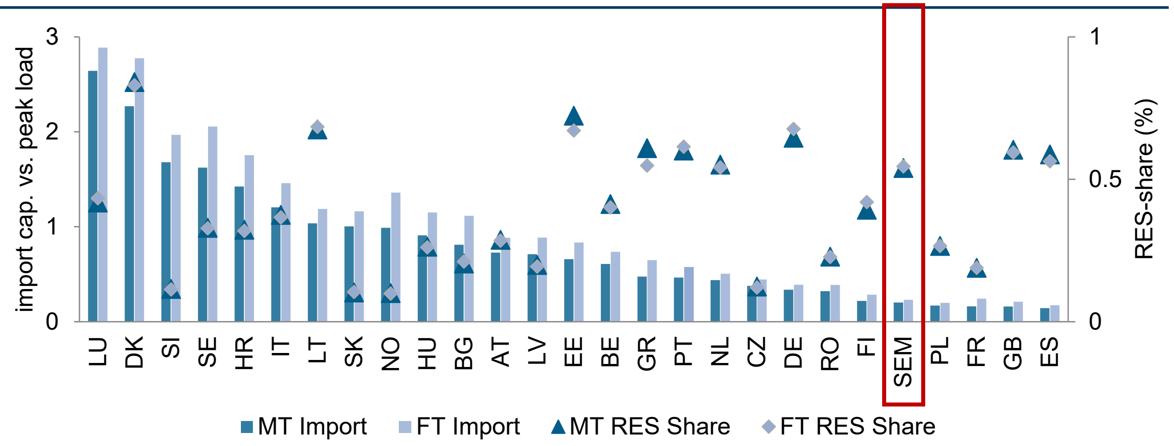
Ireland has a large RES penetration while being a relatively isolated power system

- The island of Ireland forms a single wholesale electricity market constituted by the Republic of Ireland and Northern Ireland. It is called SEM, for “Single Electricity Market” of Ireland.
- The island has a large share of generation from RES (~54% in 2025 in both scenarios) ranking it in the top 30% of EU countries.
- However, the island is currently only connected with Great Britain through two interconnectors for a total of 900MW. This is only 20% of yearly peak demand in the *Managed Transition* scenario (v. 23% in the *Frustrated Transition* scenario) in the short-run (2025).

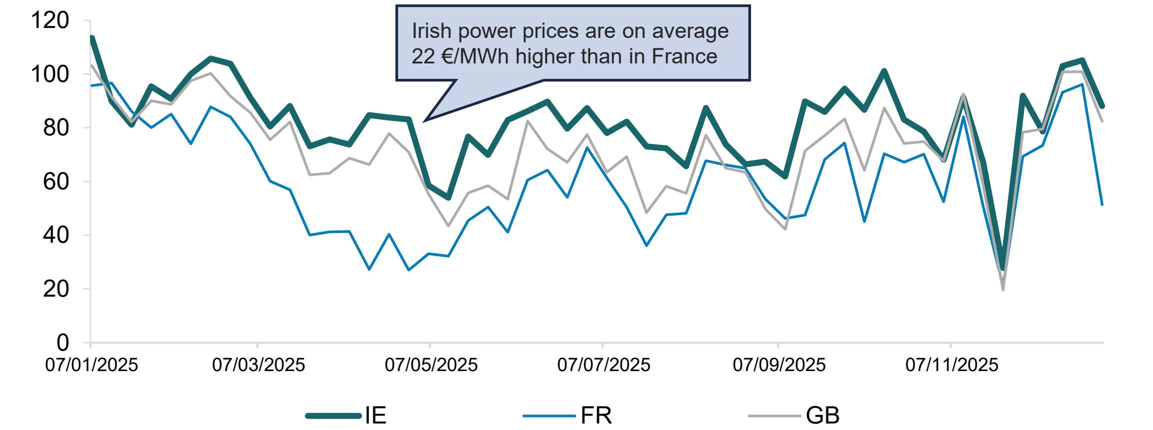
This isolated situation leads to Ireland experiencing higher power prices despite an ambitious renewable program

- Despite having a large renewable capacity, the SEM experiences higher power prices than other EU countries due to its lack of interconnection capacity. Power prices are projected to be 13% higher than in GB (+10 €/MWh) and 36% higher than in France (+22 €/MWh) in 2025 in the *Managed Transition* scenario.
- The Celtic Interconnector between Ireland and France is likely to contribute to reducing power price differences between the Irish market and other EU markets.

Import capacity vs. peak load and RES-E share[1] – Ireland 2025



Power price average prices - 2025 MT (EUR/MWh)



Note: [1] RES-E share includes wind, solar, hydro and other RES. GB…Great Britain
Source: CL modelling

In Ireland, a stronger development of interconnection in the *Managed Transition scenario* would have substantial domestic and international benefits by unlocking RES potential

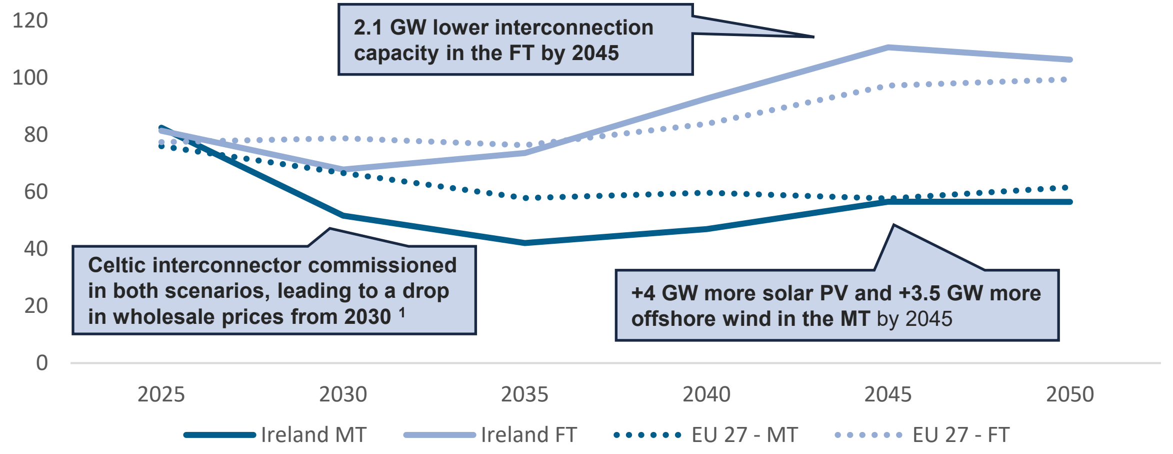
The Irish case study illustrates in the Managed Transition the benefits of further interconnection development and renewable integration through reduced prices

- Because in the *Managed Transition* scenario interconnection is more developed, Ireland experiences below average electricity prices from 2030 onwards in the *Managed Transition* scenario. This illustrates the strong benefit from already planned infrastructure developments such as the Celtic Interconnector.
- A more supportive policy framework in the *Managed Transition* scenario would enable the development of Ireland's high offshore wind potential:
  - To the benefit of all EU consumers - which can be seen by a further reduction in prices;
  - Creating opportunity for hydrogen production and industry electrification.

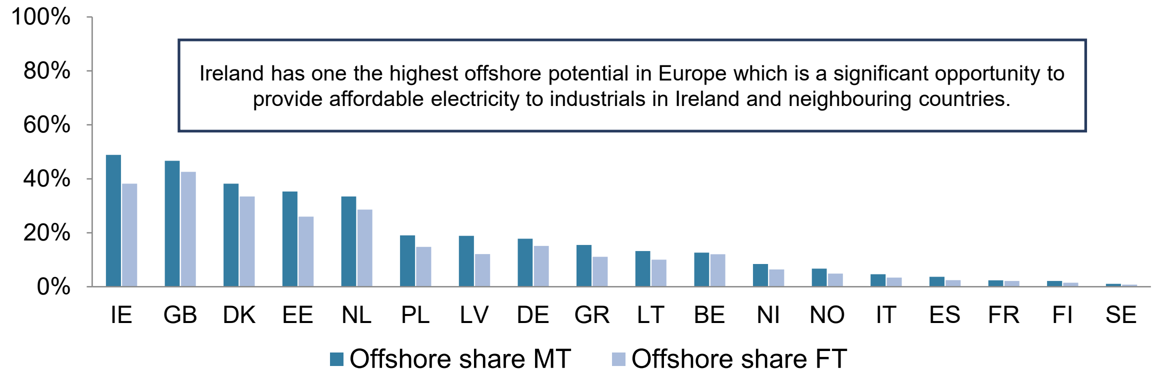
Further interconnection and renewable development would generate extra benefits both for Ireland and other European countries

- Further development of interconnection and offshore wind can reduce power prices with both domestic and international benefits. [2]
- The same applies to other isolated markets with high renewable potential, such as the Iberian peninsula and Baltic countries.

Average weighted price, FT and MT scenario – 2025-2050 (EUR/MWh)



Offshore generation to total electricity production – 2030 (%)



Note: [1] The Celtic interconnector is expected to become operational by 2027, thus the model includes it in the 2030 run. Greenlink interconnector is assumed to be online from 2025 in both scenarios. [2] Despite welfare benefits of higher level of interconnection, we assess interconnectors projects primarily based on balance between costs and benefits in our modelling
Source: CL modelling

In Sweden, further grid development and better RES integration in the *Managed Transition* would reduce Swedish power prices and price divergence between zones

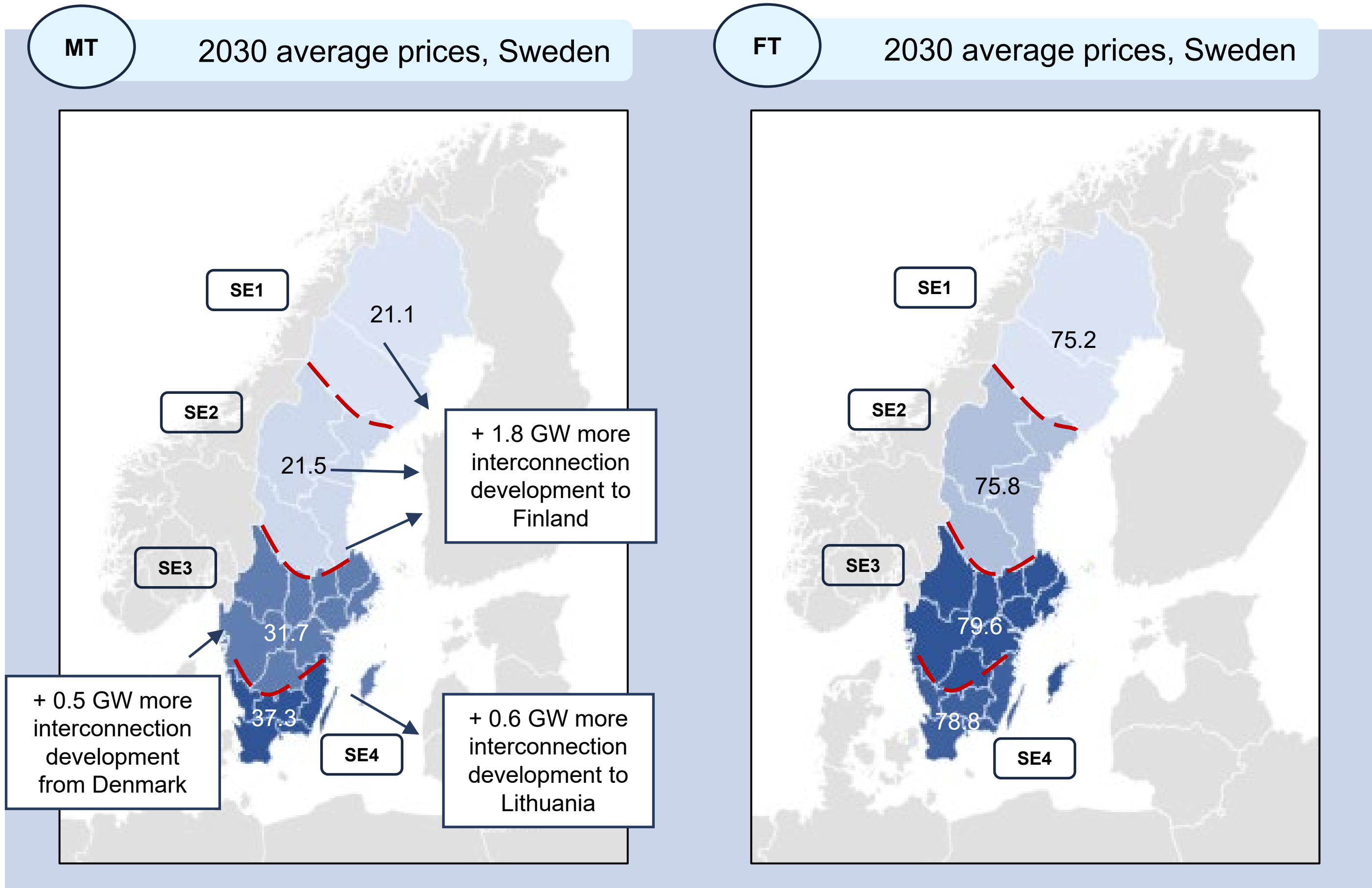
By 2030, power prices are reduced in the *Managed Transition* scenario, due to higher renewable capacity, domestic grids investment and interconnections

- Power prices average 28 €/MWh in 2030 in the *Managed Transition* scenario, compared to 77 €/MWh in the *Frustrated Transition* scenario.
- This is a reflection of a higher renewable development in the Nordic region[1] (142GW vs 136GW) as well as higher domestic and interconnection capacity[2] (8.7GW vs 6.9GW).

Price divergence between zones in Sweden highlights the need for further development of domestic network and flexible resources

- Sweden is, like several other markets in Europe, divided into several market zones, with different market prices.[3]
- The current price spreads between zones are projected to continue to 2030, due to a higher renewable capacity in the north.
- This highlights the need for coordinating renewable development and flexible resources and infrastructure investment.

2030 prices in Swedish zones, MT and FT (EUR/MWh)



Note. 1) Norway + Sweden + Finland 2) Not counting interconnection between national market zones. Hours with negative prices also increase. 3) Price differences happens when interconnection capacity is saturated, leading to different marginal generators in different zones.
Source: CL modelling

In Sweden, future power prices will depend on development of renewable capacity flexible resources, and interconnection in the Nordics and with the rest of Europe

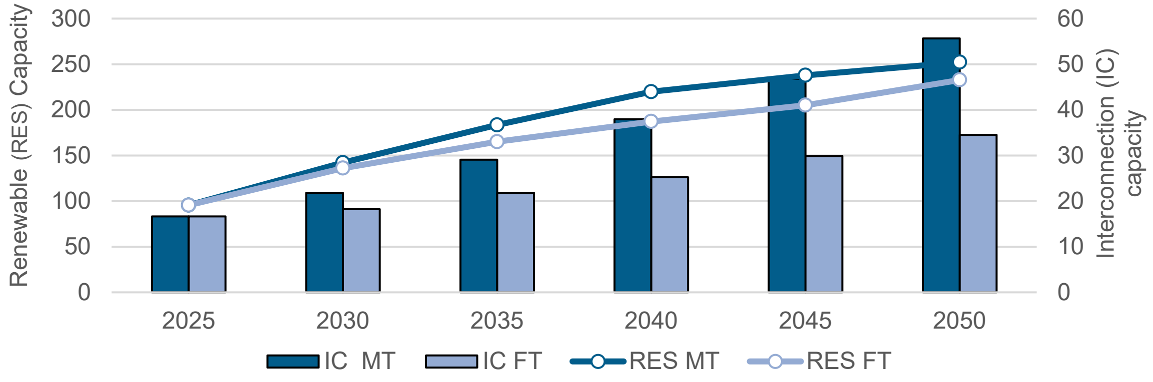
Between 2030 and 2050, we project an important development of renewable capacity in both scenarios

- The Nordics[1] already have important renewable capacity, mainly hydropower in Norway.
- They also have important wind resources, leading to the projection of important renewable development in both scenarios, mainly onshore and offshore wind, leading to a projected capacity of 240-255 GW by 2050.

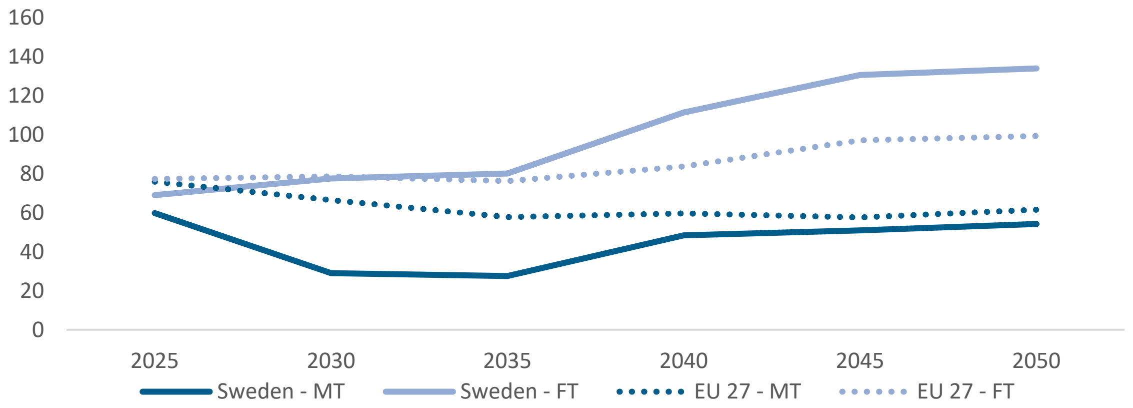
Future power price in Sweden will depend on policies and infrastructure development in the Nordics and neighbouring markets

- Power price in Sweden in both scenarios are projected to be below average particularly in the short-run because of already high renewable and hydro capacity.
- However, several factors will impact the price evolution going forward: grid development within the Nordics and with other European countries, as well as the development of flexible resources and renewables.
- With adequate policies the *Managed Transition* scenario shows that Sweden and the other Nordic countries can harness their RES resource to both benefit domestic consumers and European consumers through lower prices.

Renewables and interconnection in the Nordics, 2025-2050 (GW)



Average power price in Sweden, 2025-2050 (€/MWh)



Note. 1) Norway + Sweden + Finland
Source: CL modelling

3.4
Main takeaways

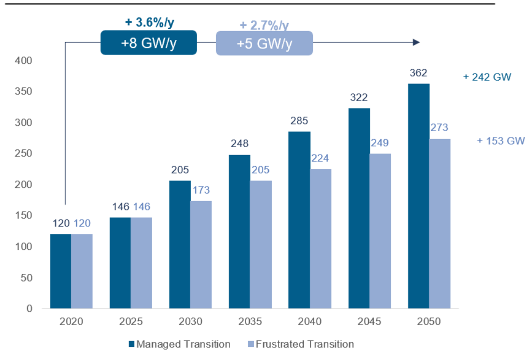
Decarbonising the power system requires increased market integration through timely infrastructure investments, and least-cost low-carbon and flexible generation deployment

Fast tracking interconnections and development of offshore grids is key

Significant **investment in interconnection capacity** is needed to integrate renewables and achieve Net-Zero targets but permitting and construction delays and regulatory risks create important uncertainty on future interconnection capacity.

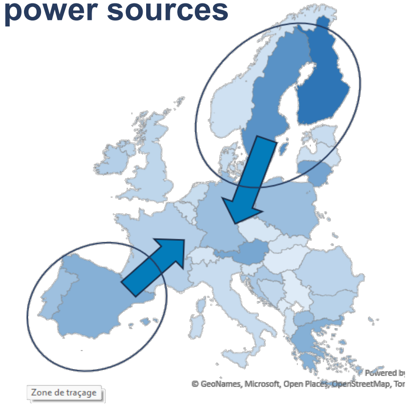
The *Frustrated Transition* scenario reflects the impact of a lower interconnection capacity development, with around 40% less capacity being built between 2020 and 2050.

Interconnection capacity in Europe, 2020-2050 [GW]



Supporting RES development where potential is maximum and considering all low carbon power sources

In both scenarios, the development of renewable and low-carbon installed capacity is scaling up.
Even considering delays and roadblocks, RES capacity increases by 1400 GW in the *Frustrated Transition* scenario, where the mix comprises 30% of low-carbon thermal generation (nuclear, biomass and biogas), highlighting the **need to support all sources of renewable and low carbon electricity to achieve decarbonisation**

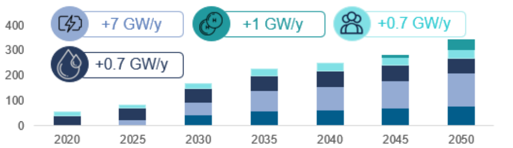


Fostering development and market participation of flexibility

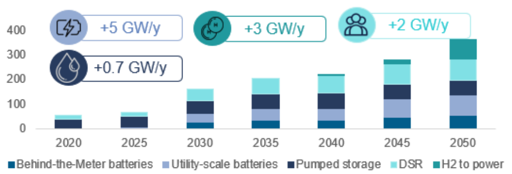
Without the proper market framework and business models to promote the development of flexibilities (storage and demand response) in the power system, there is a risk that the development of flexible resources will lag behind with e.g. **70GW of batteries less by 2050.**

In both scenarios, a **strong development of DSR contributes to mitigating power price volatility**

Flexibility capacity in Europe, 2020-2050 - MT [GW]



Flexibility capacity in Europe, 2020-2050 - FT [GW]

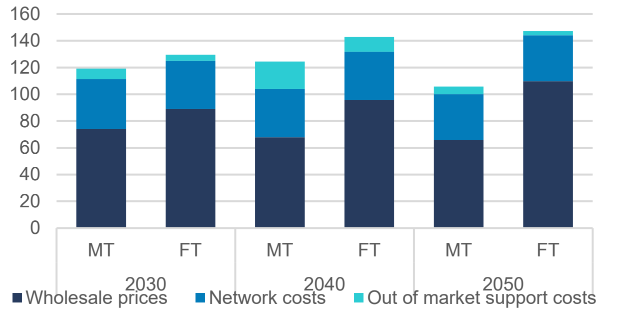


A policy push supporting RES deployment and market integration could reduce wholesale power prices and total system costs

Coordinated policy targeting market integration, RES-E and flexible capacity roll-out result in:

- **30% lower total costs for electricity** (including infrastructure costs) in 2050; and
- **40 % lower wholesale electricity prices** on average in the EU.

Industry retail power prices, excluding taxes – average EU27 (EUR/MWh real 2022)



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4.

Impact of Net-Zero pathways on energy and carbon costs for EU industrials

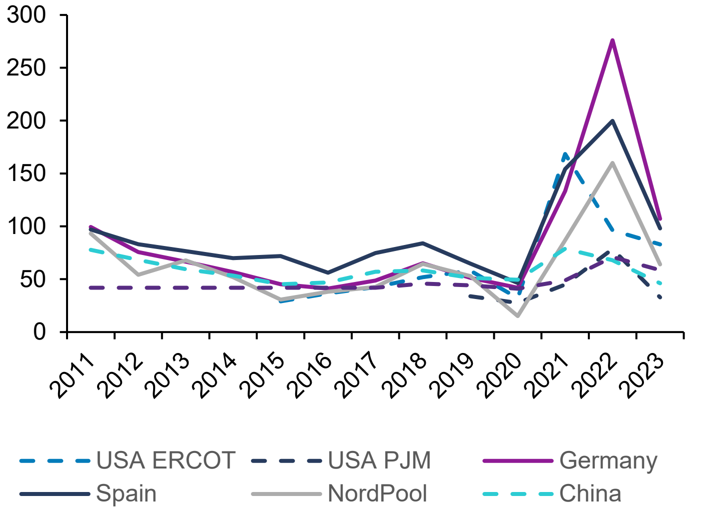
4.1
Approach

The approach considers historical trends in competitiveness and leverages bottom-up cost models to analyse the impact of energy and carbon costs on the medium-term competitiveness of two energy-intensive industries

1

Historical competitiveness of EU energy

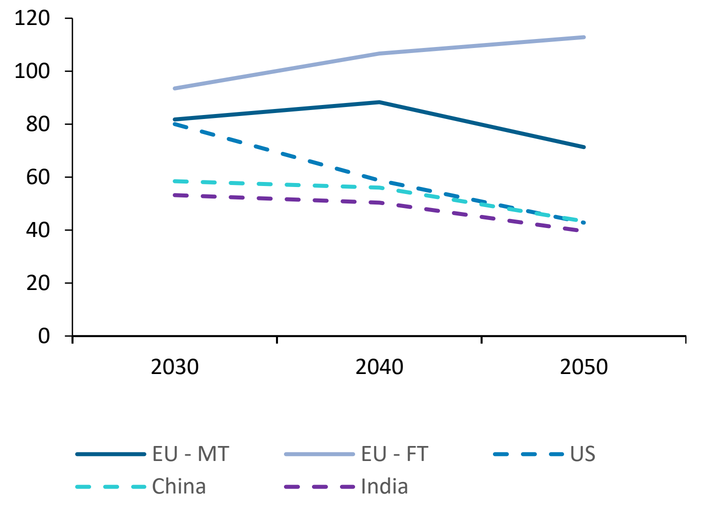
Historical monthly spot electricity price[1] (USD/MWh 2023)



2

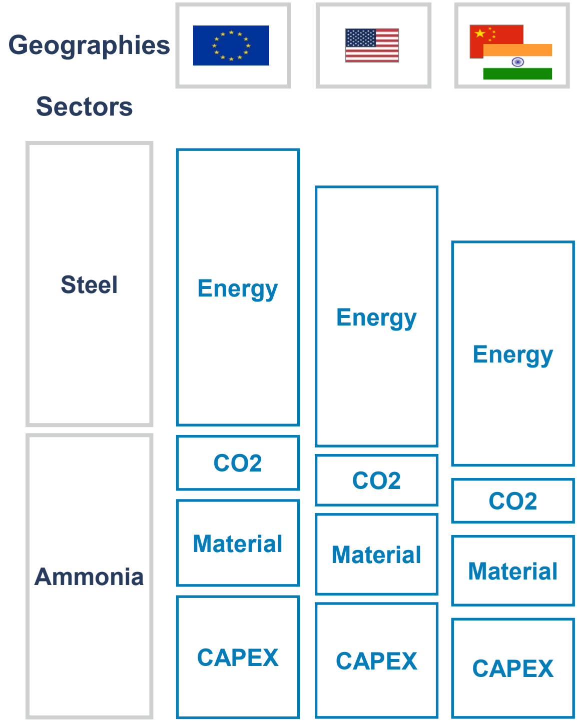
Looking forward, projection of EU energy costs based on robust sources and modelling

Electricity generation costs (including out-of-market support, excl. network costs) in a selection of jurisdictions based on IEA (EUR/MWh)[2] – 2030-2050



3

Bottom-up cost models for two industries



4.2

Key trends and issues regarding competitiveness

Coal and gas prices saw a sharp increase in the EU in the post-pandemic period, widening the historical gap with the US and China with a major impact on competitiveness

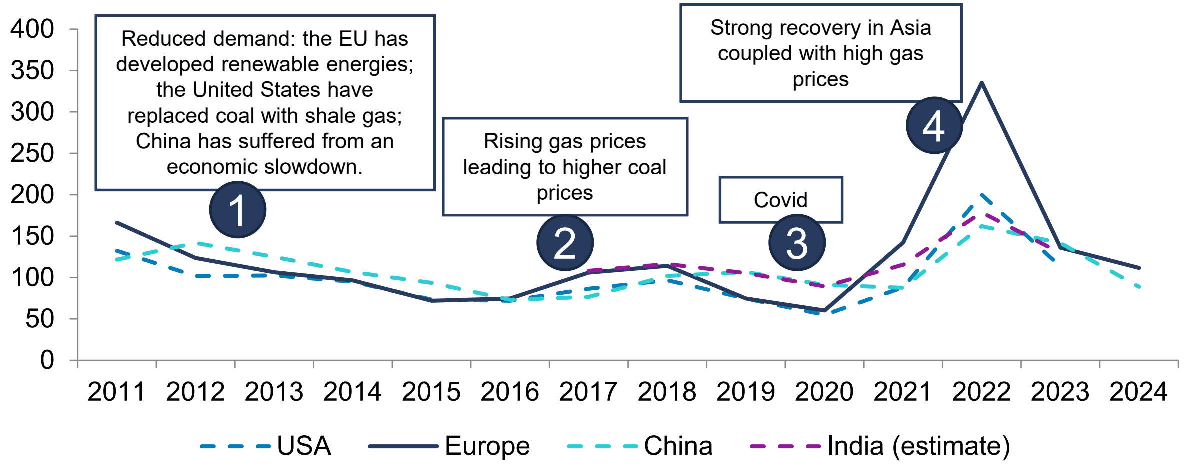
The competitiveness of coal imports into Europe has deteriorated sharply in relation to the United States

- As a result of the reduction in global supply due to the pandemic, the Chinese embargo on Australian coal, and the announcement of an EU embargo on Russian coal, the average difference in coal prices between France and the United States is 17% over the period 2015-2021.

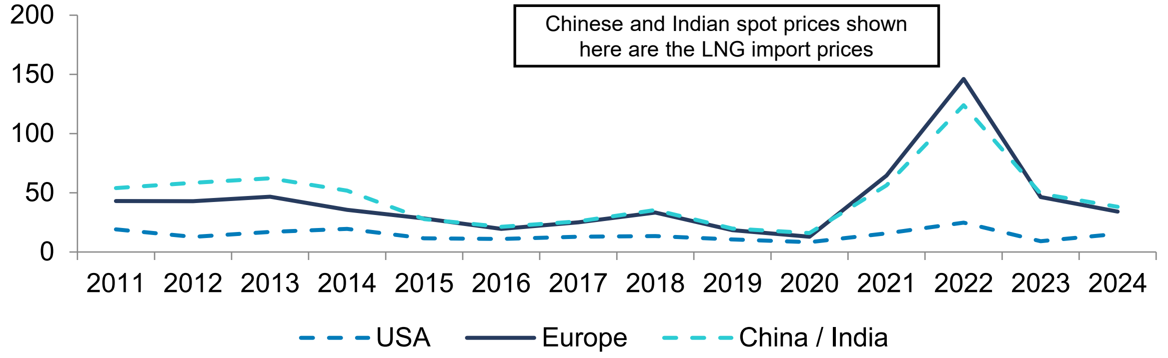
The recent surge in gas prices had a major impact on the EU's competitiveness vis-à-vis the United States

- Europe's competitiveness with the United States has deteriorated sharply following Covid recovery and Russia's invasion of Ukraine and has not fully recovered since.
- The price of LNG in Asia does not diverge significantly from European prices (due to a strong recovery in Asian demand, putting upward pressure on prices), but the price of pipeline gas is regulated at a low level.

Annual historical coal price[1] (USD/tonne 2023)



Historical monthly gas price[2] (USD/MWh 2023)



Notes: [1] China Qinhuangdao spot prices, average monthly price for 2000-2005, weekly prices 2006-2021, 5,500 kilocalories per kilogram NAR, including cost and freight (CFR). For 2022 and 2023 figures, yearly average of the spot price. US Central Appalachian coal spot price index (FOB). Europe coal ARA CIF (Amsterdam-Rotterdam-Antwerp). [2]: PEG for France, NCG for Germany, Henry Hub for USA et ICIS DES assessment for China
Sources: FTI-CL analysis, Energy Market Price, BP Statistical review of World Energy, Zhengzhou Commodity Exchange, IMF World Economic Outlook Database, IEA, Bloomberg, Energy Market Price, ICIS

Electricity and CO2 prices are significantly higher in Europe than in the US, China or India

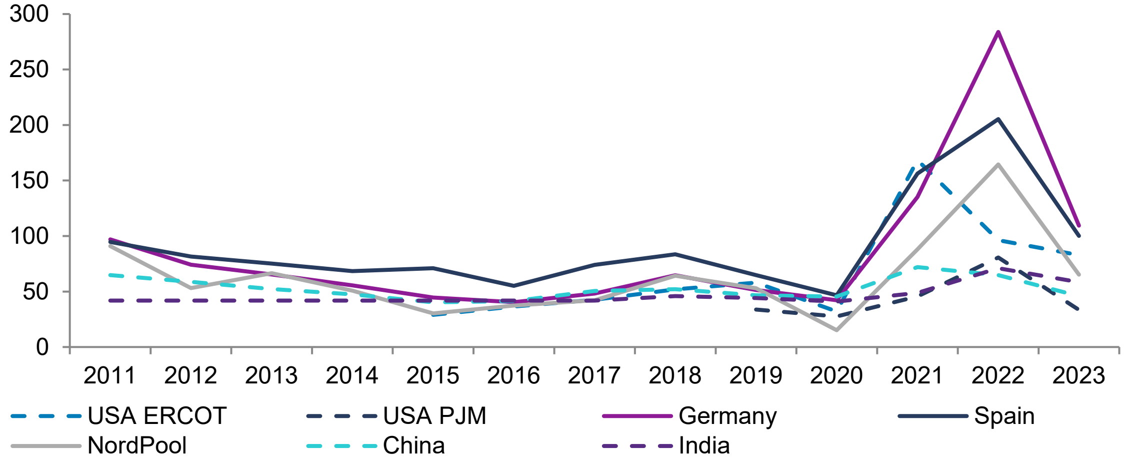
Historically, the price of electricity has been strongly correlated with the cost of gas power plants and has risen sharply with gas prices - with EU electricity being sold at a large premium over other jurisdictions

- European electricity prices typically include a premium over US prices due to fossil fuel prices premiums and are higher than in other jurisdictions due to the EU ETS.
- In China, the electricity market has not yet been fully liberalised and is 70% dependent on coal, which is subsidised.
- In India, half the power production is derived from coal plants, with coal prices being amongst the lowest in the scope.

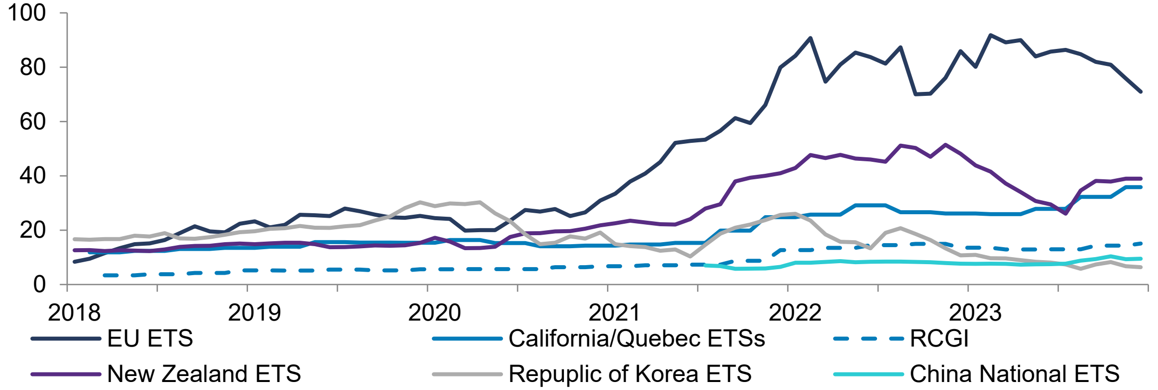
Most countries do not have carbon pricing while among jurisdictions with market-based pricing, the EU has the highest CO2 costs in the world

- Major competitors of the EU such as China, India or the US do not have industrial carbon pricing in place (China only has an ETS for power sector).
- Amongst jurisdictions equipped with a market-based carbon pricing system the EU ETS registers the highest prices, especially since 2020.

Historical monthly spot electricity price[1] (USD$_{2023}$/MWh)



Selected historical carbon ETS prices - 2018-2023[2], (EUR$_{nom}$/ton)



Notes: [1] Chinese price is based on an estimate of the generation cost of a coal power plant in China, assuming a carbon cost for China, as implemented in 2021. Same methodology is applied for India (without a carbon price). [2]: RCGI is the Regional Greenhouse Gas Initiative covering US states in the North-East. ETS…Emission Trading Scheme
Sources: [1] FTI-CL analysis, Energy Market Price. [2] ICAP Carbon Price Viewer

The recent EU energy crisis highlighted the impact of rising energy and material costs for EU industry, adding to other challenges

In addition to rising energy costs, industrial companies in Europe face a number of challenges towards Net Zero

Rising interest rates and financing costs have impacted the decarbonised energy value chains

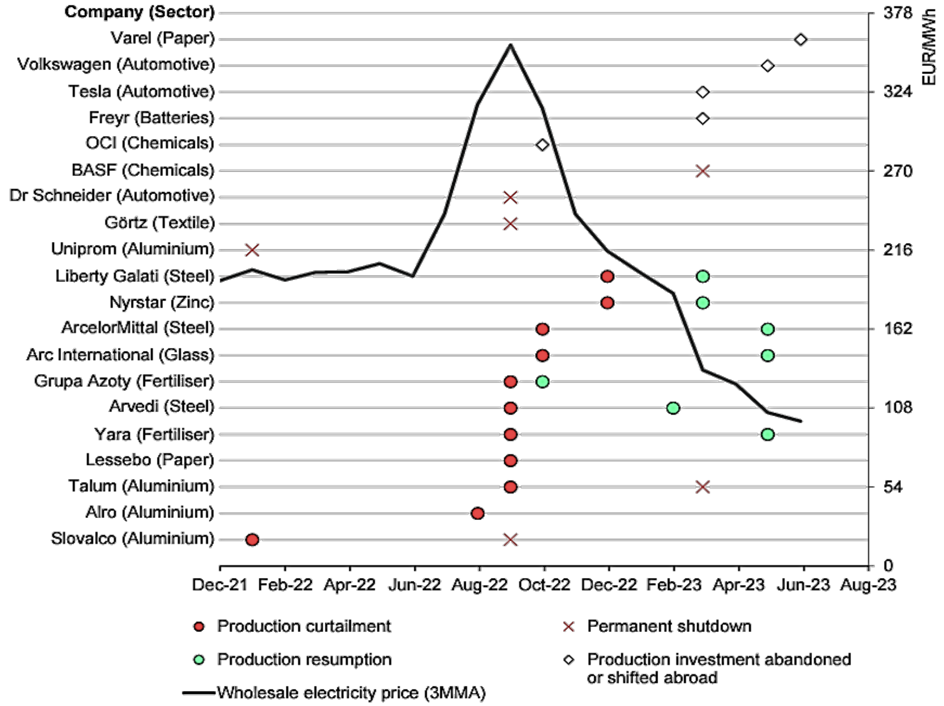
High energy prices have undermined the competitiveness of EU industries facing global competition

Europe's **dependency on imports for critical materials** and **lack of integrated supply chains for clean technologies**

CBAM and free allocation phase-out are expected to increase industrial production costs in the EU, and raise a number of design and implementation questions

In the wake of the energy crisis, companies in Europe have announced curtailment, permanent shutdowns and abandoning of investment plans

EU industry production curtailments & shutdowns during the energy crisis



Source: IEA (2023), Electricity Market Report Update

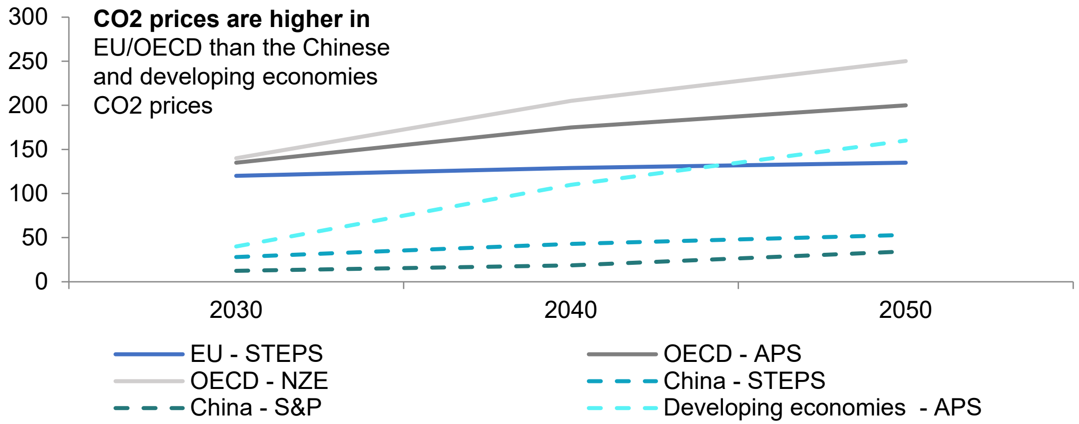
Energy prices in Europe are projected based on IEA commodity prices to continue showing a competitive disadvantage compared to the US, the Middle East, and China

China and India are expected to reach Net-Zero GHG emissions 10 to 20 years later than the EU and the USA

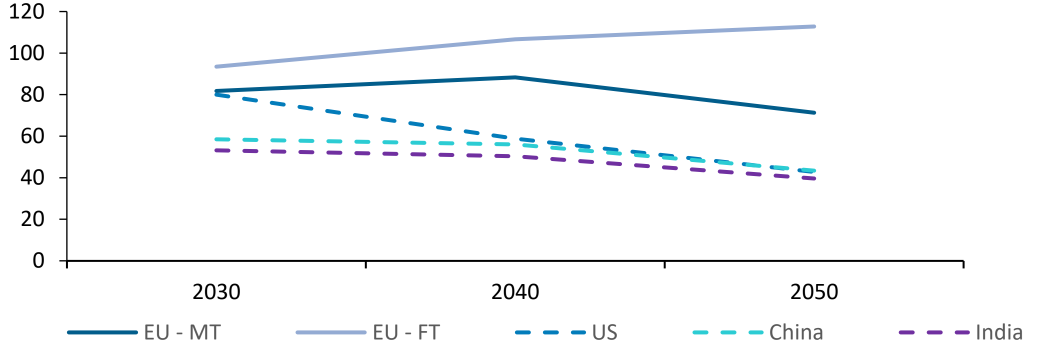
All commodities show a lasting competitive disadvantage for the EU compared to the USA and China.

In addition, CO2 prices in China and the US shown below might not necessarily be paid by industrials (as of today there is no CO2 pricing for industrials in those jurisdictions).

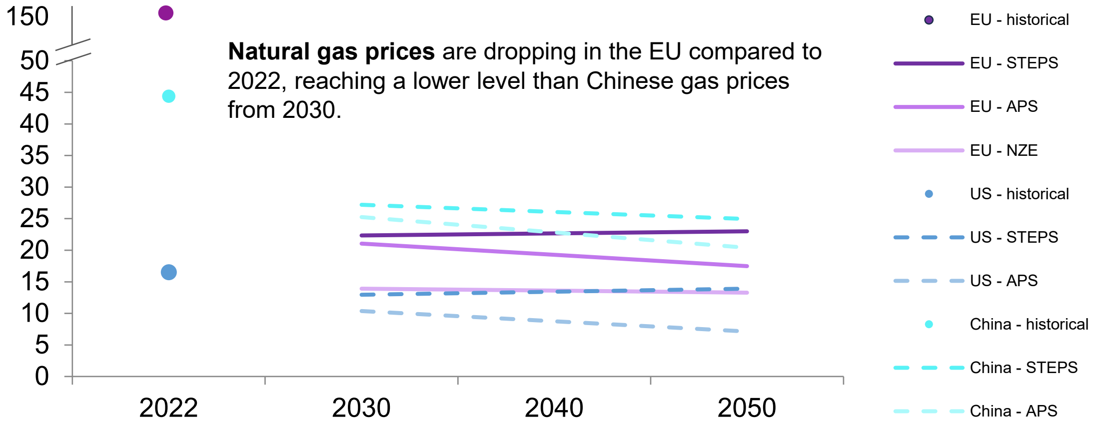
Evolution of CO2 prices in WEO scenarios[1], USD/tonne of CO2



Electricity generation costs (including out-of-market support, excl. network costs) in a selection of jurisdictions (EUR/MWh)[2] – 2030-2050



Nat. gas prices WEO scenarios in a selection of jurisdictions (EUR/MWh 2022)[3] – 2030-2050



Abbreviations: DE … Developing Economies; NZE … Net-Zero Emissions; STEPS…Stated Policies; APS..;Announced Pledges

Sources: [1]: IEA, World Bank, S&P Global 2. LCOEs and generation levels per technologies for the US, China, and India taken from the WEO23, IEA (APS scenario). For the EU, costs are derived from CL modelling.

Notes: [1]: prices are 2022 euros. Carbon prices showed here may not necessarily reflect carbon costs for some categories of end-users as distributional policy effects might play a role. [2]Total procurement costs are computed based on levels of generation by technology multiplied by average LCOEs of each technology in previous 10 years. [3] Natural gas prices are weighted averages expressed on a gross calorific-value basis. The US natural gas price reflects the wholesale price prevailing on the domestic market. The European Union and China natural gas prices reflect a balance of pipeline and LNG imports. The LNG prices used are those at the customs border, prior to regasification. MBtu = Million British thermal unit. 1 MBtu = 0.293 MWh

4.3

Case study: Crude steel production

Steel - Production of ‘green’ steel is modelled via the DRI-EAF route and compared with the traditional Blast Furnace system

Steel has been carbon-intensive historically, but technological progress has led to the development of new methods that significantly reduce the carbon impact of steel production

- We assess the impact of decarbonation policies via three reference pathways for production of steel from primary iron ore and scrap.

BF-BOF

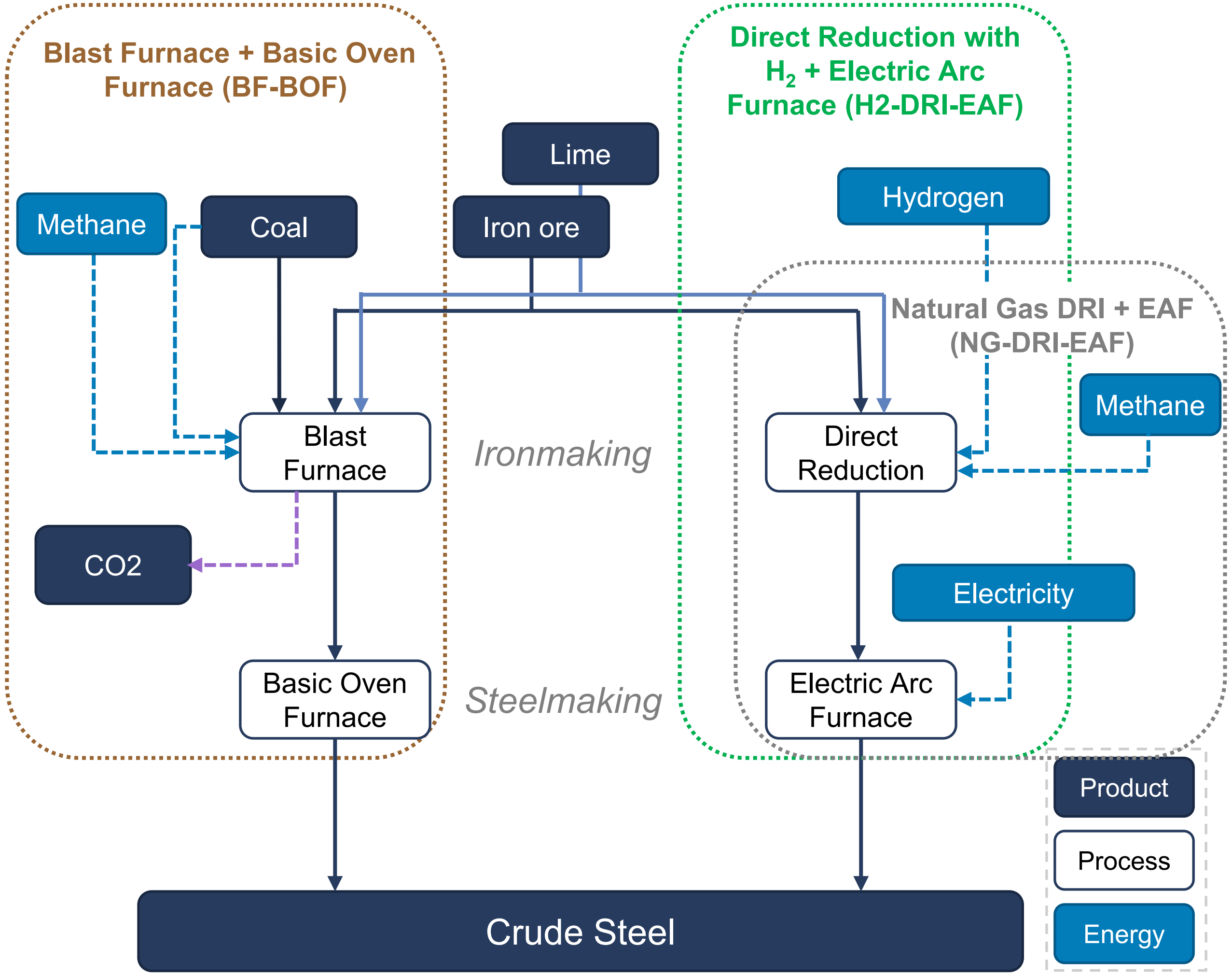
- Based on enriching iron ore with coal in a Blast Furnace (BF) then boiling it in a chemically Basic environment using an Oven Furnace (BOF).
- BF-BOF is the most used technology for steel production and is very CO2 intensive, due to the use of coking coal and thermal heating using methane & coal.

NG-DRI-EAF

- Direct reduction (DRI) ovens use hydrogen (or methane) to generate a chemically reductive environment to enrich iron, that is then melted via electric arc furnaces (EAF).
- When using natural gas as a reducing agent the process continues to emit CO2, but less than the BF-BOF route, while requiring significant amounts of electricity.

H2-DRI-EAF

- When using low-carbon hydrogen as a reducing agent the chemical process no longer emits CO2, but requires significant amounts of H2 and power. The carbon content of steel will depend on those of the H2 and power used.



Sources: Laguna, et al. (2021), Carbon-free steel production: Cost reduction options and usage of existing gas infrastructure ; World Steel Association (2023), World Steel in Figures 2023 ; New Steel Construction (2020), The carbon footprint of steel
Note: The model is used to calculate costs for EU, US and CN, with varying energy costs based on own modelling for EU and IEA WEO23 projections for US and China.

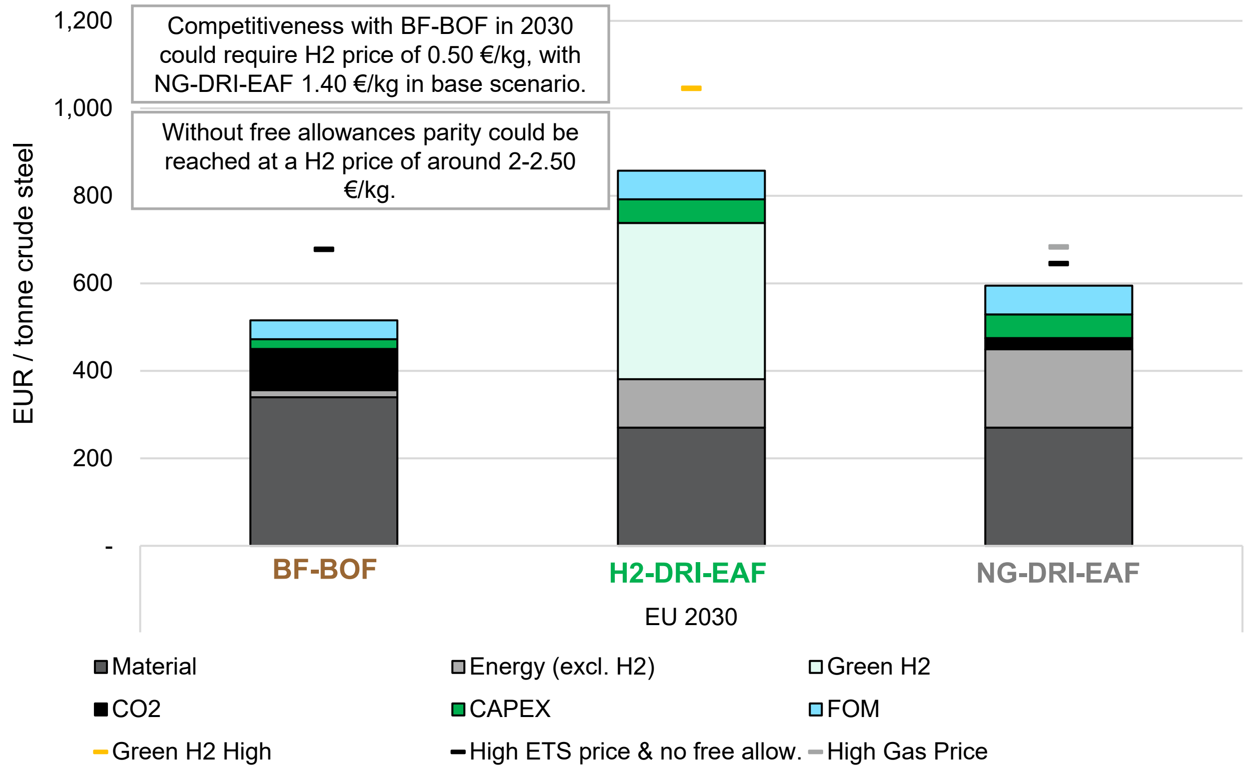
Steel - H2-DRI steel production could be more expensive than grey alternatives by 2030 due to high costs for green H2

Even in the absence of free allowances for CO2 intensive production routes H2-DRI based steel might find it difficult to reach competitiveness with carbon-based alternatives

- Under the assumptions of this study, H2 based steel is the least competitive production route within the EU in 2030, reaching 860 €/t steel (or up to 1050 €/t with high green H2 prices).
- Both BF-BOF and natural gas based DRI-EAF routes present substantially more economic alternatives.
- Even in scenarios without free allowances for CO2 intensive routes or with a high natural gas price, H2 based steel fails to reach parity.

As H2 prices required for H2-DRI-EAF to break even might be unattainable in the medium- to long-run, additional policy support is needed to create business cases for green steel

Breakdown of unit costs per category for the BF-BOF, NG-DRI-EAF, H2-DRI-EAF routes & Sensitivities, 2030 (EUR_{2022} / t crude steel)



<u>Cost components</u>: Material costs (iron ore, scrap, coking coal, alloying elements & more). Energy costs (electricity incl. network costs and out-of-market support, natural gas, PCI coal). H2 (green H2). CO2 (effective ETS costs accounting for free allowances). CAPEX (annualized CAPEX, WACC 10%). FOM (Maintenance and labor costs).

Note: The level for free allocations is taken from Agora Energiewende (calculated via fall-back process emissions for reduction gas) and reduced by 50% to account for the progress of free allowance phase-out in 2030. The modelled BF-BOF/DRI-EAF assumes CAPEX of 16/79 €/t crude steel. Input H2 price for green route corresponds to low range of green H2 prices shown in section 1, reaching 5 €/kg H2. The high green H2 price sensitivity considers the average of the green H2 prices from the literature presented in section 1(ca. 8 €/kg). The sensitivity with high CO2 prices, considers the CO2 price for 2030 of the FT scenario (150 €/t CO2) and no free allowances. The high gas price scenario considers a gas price of 60€/MWh. Calculations do not include any direct subsidies or public support mechanisms, but competitiveness would be directly affected by policy measures such as providing support for decarbonisation through investment subsidies, CCfDs…

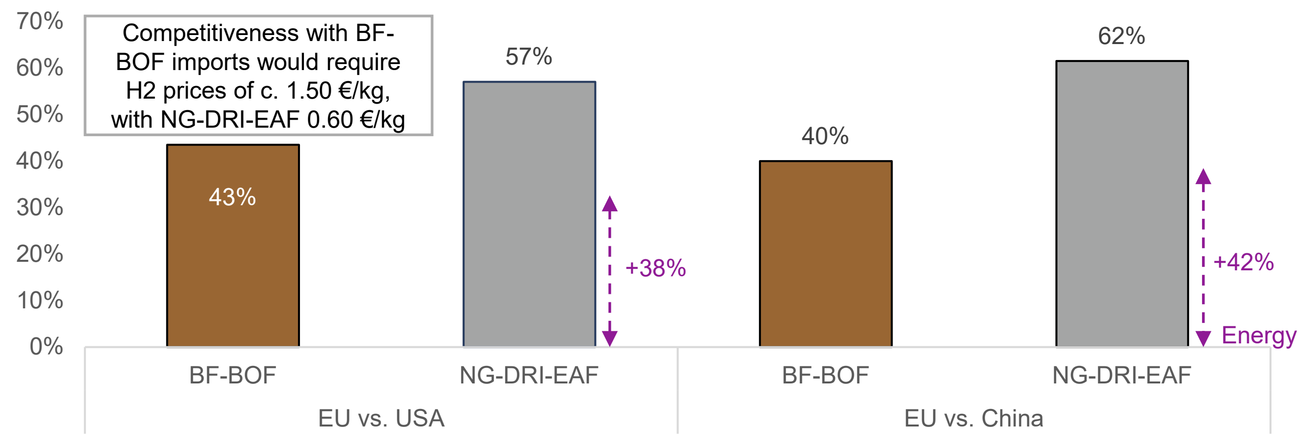
Steel - High costs of H2 and electricity could constrain competitiveness of EU H2 based steel production relative to imports even with CBAM

EU could match US produced H2 steel but might struggle to render domestic H2 steel competitive against either green imports from China or grey imports from around the world

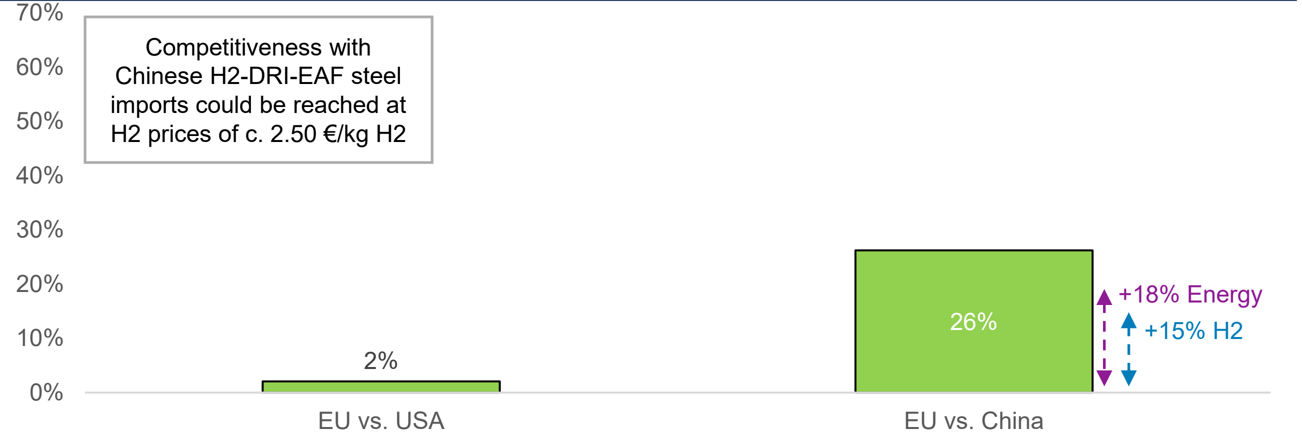
- A gap of around 40% could open up relative to BF-BOF steel imports, and up to 60% for natural gas based DRI-EAF.
- While EU H2-DRI steel might be competitive against its US counterpart, significant reduction in H2 prices would be required to become economical relative to Chinese imports.
- The competitiveness gap is mostly driven by comparatively high EU energy prices. Cheaper labour and financing costs due to state subsidies in China result in further divergence.

In addition to cheap energy, ensuring the availability of input materials – and particularly scrap steel – will be crucial for a competitive EU steel industry going forward

Cost gap EU H2 based vs. carbon-based imports subject to CBAM, 2030 [%]



Cost gap EU H2 based vs. H2 based imports, 2030 [%]



Note: Competitiveness gap equals EU production cost over foreign production cost in a given year. China and US steel are assumed to be imported to the EU and carry additional transport costs. CBAM is considered for direct emissions only. We consider that only the EU has a carbon price, from now until 2050. Energy cost contribution includes costs for electricity, H2, natural gas and PCI coal, depending on the process.

4.4

Case study: Ammonia production

Ammonia: Decarbonisation paths would be conditional on policy support due to high green H2 costs and lacking carbon storage infrastructure

Ammonia is currently synthetised from two elements, hydrogen and nitrogen. Its CO2 emissions stem from the H2 synthetisation occurring upstream using natural gas both as feedstock and energy source

- The current ammonia synthetisation process is nearing its theoretical CO2 emissions' floor.

Full decarbonisation based on green H2 as an input to ammonia production will increase costs

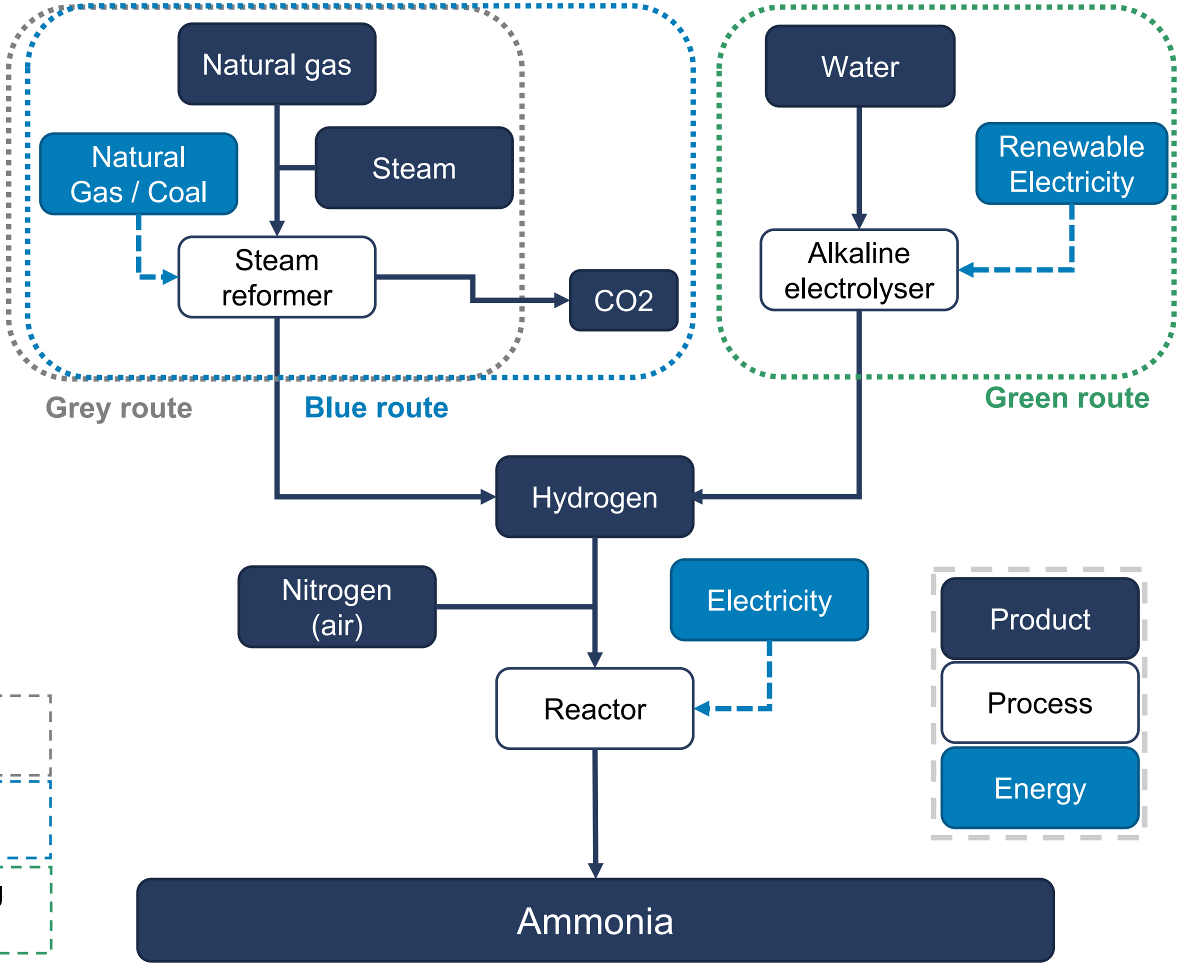
- The cost of producing H2 from electricity and ultimately the cost of H2 in the future is highly dependent the availability of affordable RES-E production.
- H2 transport infrastructure will also play a role on the cost of H2.

In addition, decarbonising the ammonia industry requires to replace current steam methane reformers with installations adapted to low-carbon H2 input, which cannot be achieved with simple refurbishments

The Grey route will use **natural gas** as its primary source of energy as it is the most common across ammonia plant in Europe.

The Blue route* will use **natural gas** as its primary source of energy, combined with **67% CCS.**

The Green route will source green H2 from **own electrolysers** (high CAPEX but decreasing with time), with **renewable power only**.



Sources: Hasan Khademi and Lotfi-Varnoosfaderani (2021), Sustainable ammonia production from steam reforming of biomass-derived glycerol in a heat-integrated intensified process: Modeling and feasibility study ; Fertilizers Europe, Green ammonia and low-carbon fertilizers
Note: The model is used to calculate costs for EU, US and CN, with varying energy costs based on own modelling for the EU and the IEA WEO23 projections for the US and China.
*The Blue route takes Grey H2 and captures 2/3rd of emissions which are stored, while 1/3rd is emitted and subject to the EU ETS.

Ammonia - Competitiveness of green ammonia will depend on policy support for green H2 supply chain

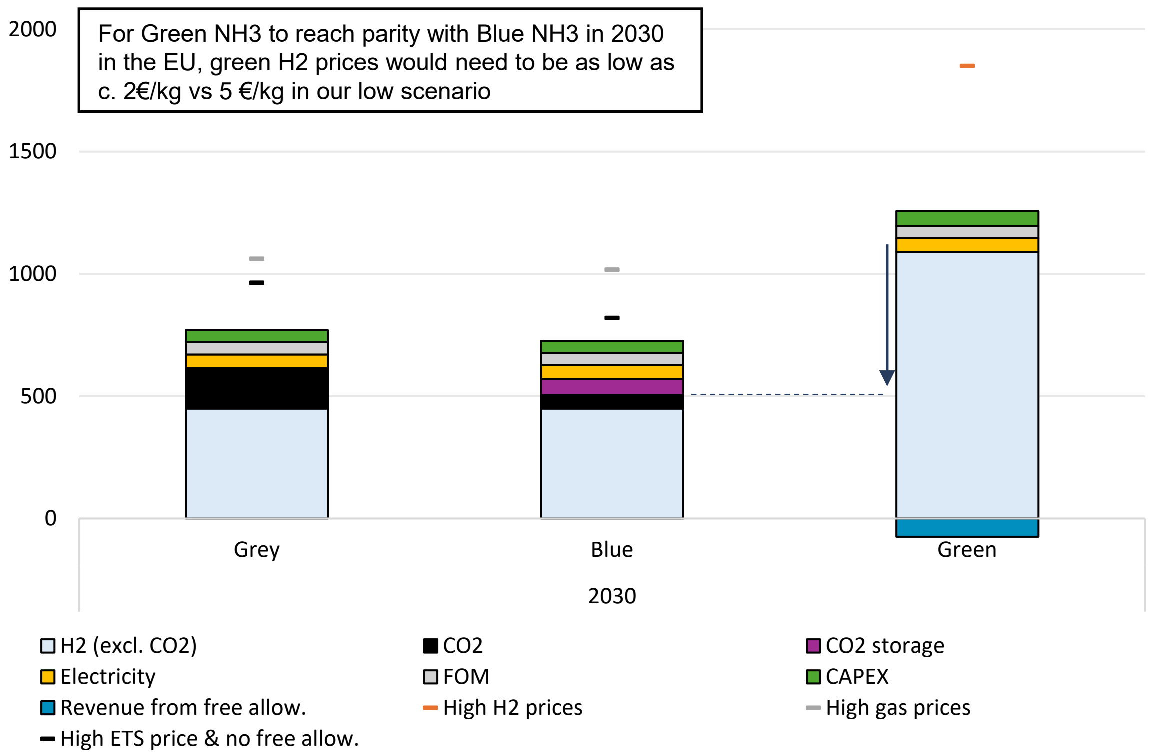
Even with relatively optimistic green H2 cost assumptions, green H2 based ammonia might find it difficult to reach competitiveness with grey or blue production routes

- Under the assumptions of this study green H2 based ammonia is the least competitive production route within the EU in 2030, reaching c. 1300 €/t ammonia (or up to 1800 €/t with high green H2 prices).
- Both grey H2 based ammonia production routes (with and without carbon storage) present substantially more economic alternatives.
- In scenarios without free allowances and with high natural gas price, green H2 based ammonia would reach parity with Grey provided that green H2 prices would decrease to c.3€/kg.
- Green H2 based ammonia would be competitive with the most competitive (blue) route with input prices of around 2€/kg.

As H2 prices required for green ammonia to break even might be unattainable in the medium- to long-run, additional policy support is needed to create business cases for green ammonia.

The analysis shown on the right is based on greenfield cost, considering CAPEX for a new installation in all 3 cases.

Ammonia production costs in EU, from the Grey, Blue and Green routes, 2030 (EUR / t NH3)



Cost components: Electricity costs (electricity incl. network costs and out-of-market support). H2 (green or grey H2). CO2 (effective ETS costs accounting for free allowances). CAPEX (annualized CAPEX, WACC 10%). FOM (Maintenance and labour costs). CO2 storage (cost of carbon storage). Revenue from free allowances (for green route only, corresponding to sale of free allowances for green H2).

Note: In 2030, free EU carbon allocations reach 50% of their previous level, corresponding to EU benchmark. Modelled ammonia production unit is assumed to produce 1 million tonnes per year, with a CAPEX of 378 M EUR for the Haber-Bosch process and 90 M EUR for retrofitting the Air Separation Unit for Green NH3. H2 costs considered are derived from slide 53, CO2 prices from slide 56.The High H2 price sensitivity considers the average of the green H2 prices from the literature presented in section 1 (ca. 8 €/kg). The sensitivity with high CO2 prices, considers the CO2 price for 2030 of the FT scenario (147 €/t CO2) and no free allowances. The high gas price scenario considers a gas price of 60€/MWh. Calculations do not include any direct subsidies or public support mechanisms, but competitiveness would be directly affected by policy measures such as providing support for decarbonisation through investment subsidies, CCfDs…

Ammonia - High costs of green H2 and electricity could constrain competitiveness of EU green H2 based ammonia production relative to imports even with CBAM

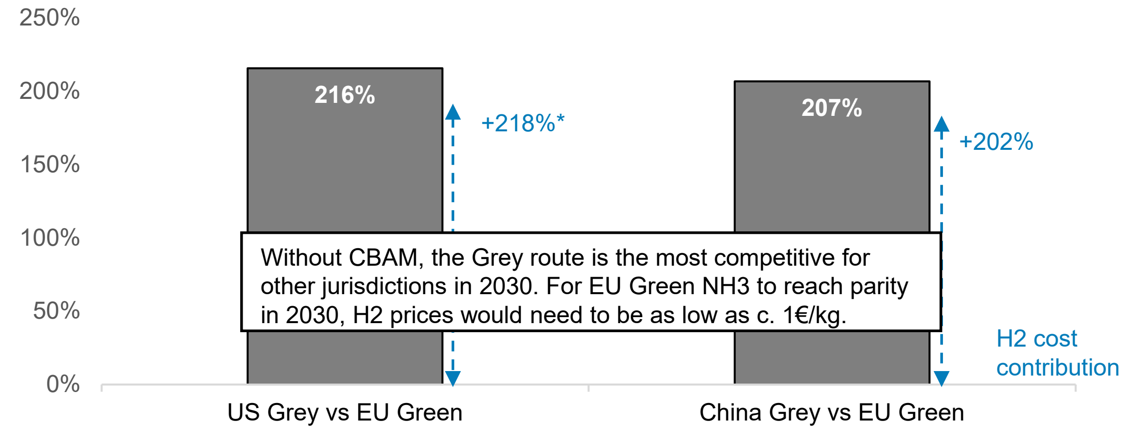
Without CBAM, green H2 EU production would be 3 times more expensive than US or Chinese grey H2 based productions

Under an assumption of perfect CBAM, green H2 becomes the most competitive option in China and the US for the EU market, but EU competitiveness still requires policy support

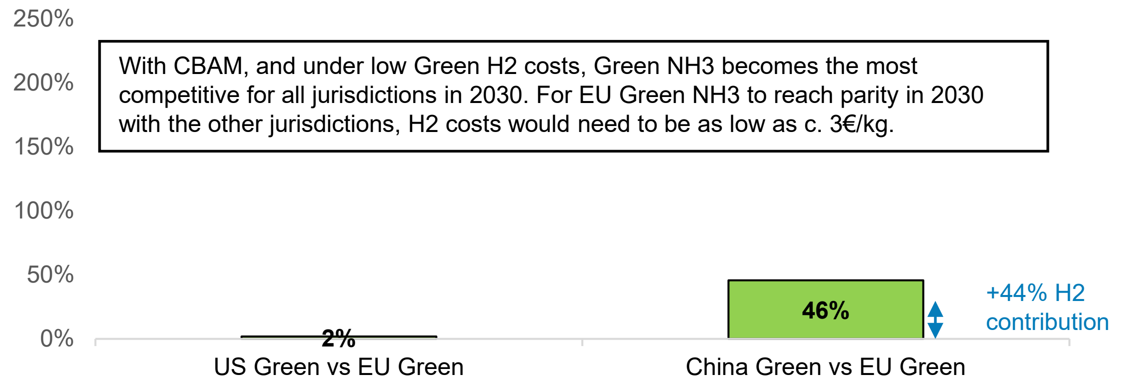
- A gap of up to 50% could open up with Chinese green H2 based ammonia.
- While EU green H2 ammonia might be competitive against its US counterpart, significant reduction in H2 prices would be required to become economical relative to Chinese imports.

Importantly, EU importers could circumvent CBAM, as ammonia downstream products are not covered

Cost gap EU green ammonia v. grey imports, 2030 (%)



Cost gap EU green v. green imports, 2030 (%)



Note: Competitiveness gap equals EU decarbonised production cost over foreign production cost. China and US ammonia are assumed to be imported to the EU and carry additional transport costs. CBAM is assumed to apply perfectly to ammonia carbon content and renders green NH3 in the US and China more competitive than c-intensive options. We consider that only the EU has a carbon price, from now until 2050. Like for the EU, foreign H2 prices are based on 'true' production costs and do not factor in subsidies.
*overall cost difference between the EU and the US is smaller than H2 cost gap due to the addition of transport costs for imported US ammonia.

4.5
Main takeaways

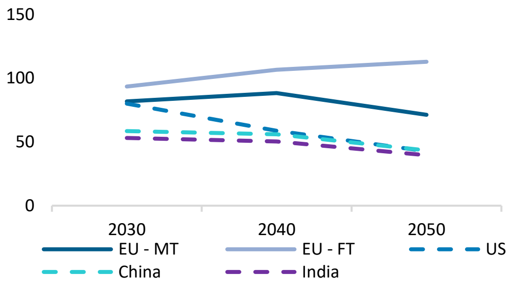
The analysis highlights the risks associated with a lack of coordination of policy efforts to address the competitiveness gap

Energy price competitiveness gap is unlikely to recede

The **competitiveness gap** between EU energy prices and main trading partners **could remain up to 2050,** absent compensation measures.

Electricity generation could remain substantially more expensive in the EU than in the USA, China and India.

Electricity generation costs (including out-of-market support, excl. network costs) in a selection of jurisdictions (EUR/MWh)² – 2030-2050

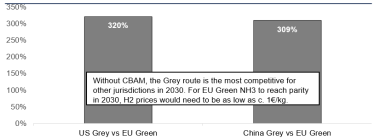


Industry's competitiveness gap is unlikely to resorb

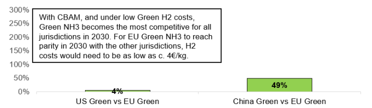
The case studies focussing on steel and ammonia show that **low-carbon production risks not being cost competitive with production in China**, and to a lesser extend in the USA.

Whilst production costs might be similar in the USA, the difference is more substantial in China in 2030.

Ammonia competitiveness gap between the Green route in EU and the Grey route (without CBAM) in the other jurisdictions, 2030 (%)



Ammonia competitiveness gap between the Green route in EU and the Green route (with CBAM) in the other jurisdictions, 2030 (%)

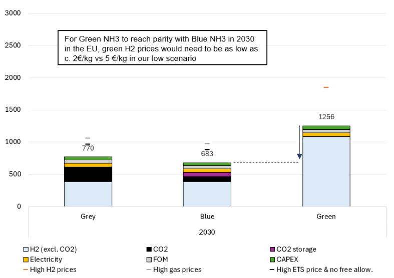


Switch to low-carbon production processes unlikely to be economical as of 2030

The gradual phase-out of free allocation **increases production costs of the carbon intensive processes without necessarily triggering a switch to low-carbon processes**, *in the absence of additional support measures*.

Ensuring competitive low-carbon electricity and H2 prices is crucial to ensure viability of low-carbon alternatives, together with measures facilitating investment.

Ammonia production costs in EU, from the Grey, Blue and Green routes, 2030 (EUR / t NH3)

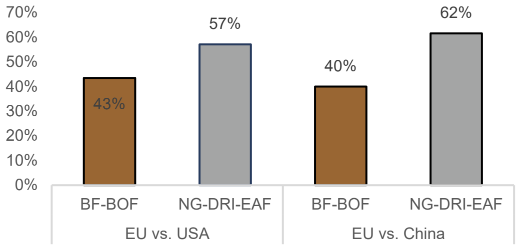


CBAM addresses carbon leakage, but energy prices continue to create competitiveness gap

CBAM, if implemented appropriately, can **help resorb the competitiveness gap created by carbon costs**. However, there is a risk of EU importers circumventing CBAM through import of downstream products.

Additional measures to contain energy prices for sectors at risk of carbon leakage and to support investment in decarbonised technologies will likely be necessary.

Cost gap EU H2 based vs. carbon-based imports subject to CBAM, 2030 [%]



Note: Competitiveness gap equals EU production cost over foreign production cost in a given year. China and US steel are assumed to be imported to the EU and carry additional transport costs. CBAM is considered for direct emissions only. We consider that only the EU has a carbon price, from now until 2050. Energy cost contribution includes costs for electricity, H2, natural gas and PCI coal, depending on the process.

5.

The policy framework for energy and carbon costs and competitiveness

5.1
Approach

Introduction: The European policy framework addressing decarbonisation, energy policies and competitiveness

Based on discussion and inputs from BusinessEurope, the following slides present some of the key EU-level policies and initiatives that impact the supply, demand, prices and infrastructure costs of renewable and low carbon energy in the EU.

The objective is to identify the most relevant EU policies, initiatives and funding*. The framework for the analysis distinguishes between:

1 Competitive supply of renewable and low carbon energy

A. Policies affecting the supply of solar, wind, biomass-fuelled and nuclear power

B. Policies affecting the supply of low carbon H2

C. Policies affecting the supply of other fuels such as e-fuels, biofuels and biomass for energy

2 Competitive development of infrastructures

A. Policies affecting the energy network infrastructures (transmission, distribution of power, H2 and CO2)

B. Policies affecting the storage facilities (Power, H2, CO2)

3 Competitive end-use decarbonisation & focus on industry

A. Policies affecting the incentives for energy demand flexibility

B. Policies affecting carbon pricing and the value of decarbonisation investments

C. Policies affecting the financing of decarbonisation investments: de-risking through Carbon contracts for difference, Government guarantees, direct subsidies

* The analysis concentrates on a selection of the most relevant policies, to the best of our knowledge and some measures may thus be missing.

5.2

Key trends and issues with the current policy framework

The EU framework covers key areas to reach Net-Zero, including the development of low carbon energy supply and supporting infrastructures, and decarbonisation of end uses

Critical topic	Policies
Supply of low carbon energy	
Renewable energy sources	RED III, R&LCFVCIA, NZIA, EMR, NEP, RoP, EU SRI, EU SPVIA, EU WPAP
Battery / storage	NZIA, EMR
Hydrogen	R&LCFVCIA, NZIA, EU Energy Platform, Hydrogen Accelerator, ECHA, CHP, HPFC
Alternative fuels, biogases…	R&LCFVCIA, NZIA, NEP, Biomethane Industrial Partnership, Biomethane Action Plan
CCUS	NZIA, EU Hydrogen Strategy
Nuclear	NZIA, EMR
Infrastructure for low carbon energy	
Electricity storage	EMR, REPowerEU Communication, Commission Recommendation Energy Storage
Demand Response	EMR, EU Grid Action Plan, Commission Recommendation Energy Storage
Electricity grid	EU Grid Action Plan, TEN-E
Gas / fuels infrastructure	Hydrogen and decarbonised gas market package, AFIR, RefuelEU Aviation, TEN-E
Offshore grid	TEN-E
Cross-border infrastructure	TEN-E
CO2 infrastructure	TEN-E
Hydrogen infrastructure	TEN-E, Hydrogen and decarbonised gas market package, AFIR
End-use decarbonisation with focus on industry	
Demand Side Response	Electricity Directive, EED, Digitalising the energy system
CO2 pricing and management	Revised ETS, CBAM, EU Industrial Carbon Management Strategy
Decarbonisation investments	Revised ETS, Taxonomy, CSRD, CSDDD, National REPowerEU plans
Critical raw materials	CRMA

EMR: Electricity Market Reform, TEN-E: Revised TEN-E Policy, R&LCFVCIA: Renewable and Low-Carbon Fuels Value Chain Industrial Alliance, NEP: New Energy Partnerships, RoP: Recommendation on Permitting, EU SRI: European Solar Rooftop Initiative, EU SPVIA: EU Solar PV Industry Alliance, EU WPAP: European Wind Power Action Plan CHP: decarbonised Hydrogen Partnership, HPFC: Hydrogen Public Funding Compass, EED: Energy Efficiency Directive, ECHA: European decarbonised Hydrogen Alliance, AFIR: Alternative Fuels Infrastructure, CSRD: Corporate Sustainability Reporting Directive, CSDDD: Corporate Sustainability Due Diligence Directive, CRMA: Critical Raw Materials Act.

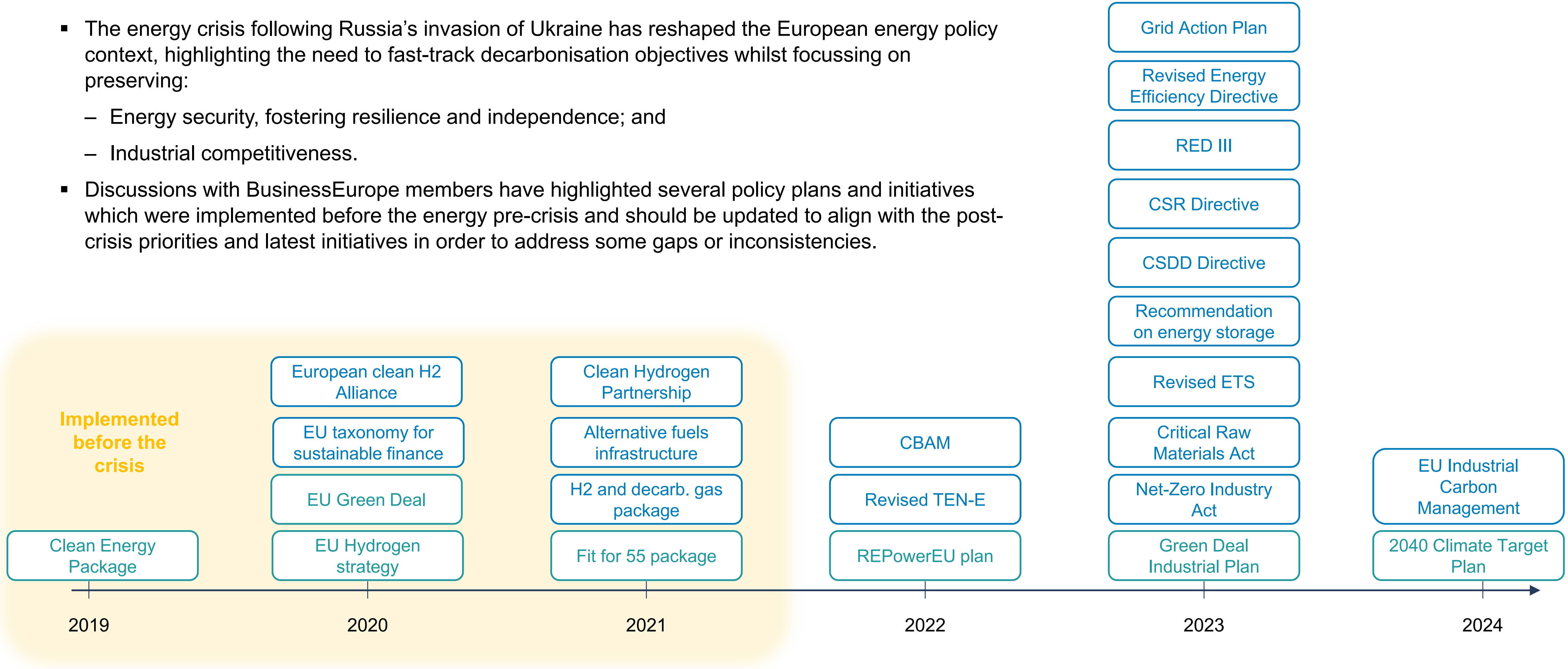
Some recent EU policies aim to accelerate decarbonised technologies deployment, foster greater energy independence, and address supply chain issues

EU Regulation	*Latest reforms' outcomes (non-exhaustive)*
Electricity Market Reform	• Aim to further develop PPAs and CfDs to accelerate on RES-E and low carbon capacities and flexibility deployment • Support for PPA costs supported by end-users and public guarantees on long-term contracts with renewables
Renewable Energy Directive *REDII (2018/2001) > REDIII (2023/…)*	• Increase in the targeted share of RES in the EU's gross energy consumption in 2030 (from 32% to 42.5%). • Strengthen criteria for the sustainability of biofuels and prohibiting the use of all biomass from primary and highly biodiverse forests
Effort Sharing Regulation *Fit for 55 package*	• New objective of -40% GHG emissions compared to 2005 in 2030 (previously -29%) in the EU • Emissions reductions are shared among member states based on GDP per capita and minor adjustments
Emission Trading Scheme Directive *Fit for 55 package*	• Increased emissions reductions goals (from -43% to -62% in 2030 compared to 2005) • Faster reduction in the number of allowances in the market (-4.4% per year until 2030) and extension to cover new sectors (maritime) • Creation of ETS 2 for building, road transport and fuels
Land Use, Land Use Change and Forestry Regulation *LULUCF I (2018/841) > Fit for 55 Package > LULUCF II (2023/ 839)*	• Objective of GHG removal by the LULUCF sector totalling 310 MtCO2eq in 2030 for the EU
The EU Taxonomy on Sustainable Finance *Delegated Act adopted in 2023*	• Reform of the ESG rating providers system to ensure better and more reliable ESG ratings. • Classification system sets out criteria for investment activities aligned with Net-Zero emissions goals, using technical screening criteria.
Energy Taxation Directive (ETD) *Fit for 55 Package*	• Introduction of tax rates based on the energy content and environmental impact of energy products rather than on volume • Widening of the tax base to include energy contents and processes that were previously not in scope
Net-Zero Industry Act *Proposed in 2023 – Exact measures subject to change*	• Defines strategic Net-Zero technologies and sets a benchmark for their manufacturing to meet at least 40% ofthe EU's annual deployment needs by 2030 • Improves conditions for investment in net-zero technologies by enhancing information, reducing the administrative burden to set up projects and simplifying permit-granting processes
Critical Raw materials Act (CRM Act) *Proposed in 2023 – Exact measures subject to change*	• Objective is to reduce the EU's reliance on third countries for strategic raw materials by setting 2030 "inside EU" targets: • 10% of the of the annual consumption must be extracted, 40% must be processed, and 15% must be recycled in the EU. • No more than 65% of the annual consumption of a strategic raw material must come from a single third country.

Source: Analysis based on European Commission and European Council materials, the list is non exhaustive and is a selection of relevant recent policies aiming to highlight main texts according to our analysis.
Note: Other texts have been voted with specific focus on hard-to-abate transportation sectors with FuelEU Maritime, ReFuelEU, CO2 emissions for cars and AFIR Alternative fuel Infrastructure, etc
* Fit for 55 Package was published by the Commission in July 2021.

Several policies implemented before the energy crisis could be updated, to reflect some of the post-crisis priorities and latest initiatives

- The energy crisis following Russia's invasion of Ukraine has reshaped the European energy policy context, highlighting the need to fast-track decarbonisation objectives whilst focussing on preserving:
  - Energy security, fostering resilience and independence; and
  - Industrial competitiveness.
- Discussions with BusinessEurope members have highlighted several policy plans and initiatives which were implemented before the energy pre-crisis and should be updated to align with the post-crisis priorities and latest initiatives in order to address some gaps or inconsistencies.



Legend: Strategy / Plan | Initiative / Directive

The EU policy framework and its implementation a national level need a coordinated approach to address objectives of enhancing security of supply and competitiveness

Discussions with BusinessEurope members have highlighted some areas where the EU policy framework is incomplete and could benefit from more coordinated EU level strategies and better planning to ensure cost-efficiency

- The key critical issues to reach Net-Zero identified in the study are generally already addressed in the European policy framework.
- However, the current framework could be completed, e.g. with some additional targets in certain areas, and a focus on ensuring a cost-effective approach. An example is the framework for CCUS, which needs to be further developed.
- Moreover, the different initiatives and texts do not have the same level of maturity / do not have the same "*binding*" value: for instance, the European framework for DSR is still preliminary.
- Some key areas need to be reinforced, with e.g. the current framework for infrastructure investments not providing enough support considering the large investment needs.

In addition, the European framework and its implementation at the national level could be better aligned

- Following the REPowerEU plan, Member States had to submit an updated NECP by June 2023.
- The European Commission published an EU-wide assessment of the NECP progress report in December 2023 (21 plans had been submitted by then, with some countries still missing).
- The EC concluded that the updated NECPs were not aligned with the EU-wide targets, and in particular:
    - Draft NECPs are not yet sufficient to reduce greenhouse gas emissions by at least 55% by 2030 & current measures would only lead to a reduction of 51%.
    - For renewable energy, the current drafts would lead to a share of 38.6-39.3% of renewable energy by 2030, compared to the 42.5% target.
    - For energy efficiency, the current drafts would lead to 5.8% energy efficiency improvements, compared to the target of 11.7%.

Source: European Commission (2023), National energy and climate plans

The European policy framework could address some inconsistencies – some examples

- Discussions with BusinessEurope members and policy experts allowed us to identify some **examples of inconsistencies within the European policy framework**. These examples illustrate that the different targets / initiatives of the European framework need to be designed with consistency to provide stability and appropriate incentives.

Industrial RFNBO quota

Situation / issue: Industrial RFNBO ('green hydrogen') quota outlined in Article 22a of RED III:

> "*Member States shall ensure that the contribution of renewable fuels of non-biological origin used for final energy and non-energy purposes shall be at least 42 % of the hydrogen used for final energy and non-energy purposes in industry by 2030, and 60 % by 2035. For the calculation of that percentage, the following rules shall apply:*
>
> *(a) for the calculation of the denominator, the energy content of hydrogen for final energy and non-energy purposes shall be taken into account (…)*"

The formula includes only green hydrogen in the numerator while the denominator includes H2 from all production sources. But uncertainties over relative costs of H2 from electrolysis and H2 from SMR + CCS could lead to additional low carbon (blue) H2 use.

Solution: To ensure a swift and cost-effective ramp-up of the EU low-carbon H2 market, RED III should ideally be revised to allow blue H2 to be included in the numerator and contribute to the 42% target while ensuring continued European production.

Nuclear as decarbonised technology

Situation / issue: The EU stated intentions in favour of green hydrogen coming from nuclear electricity. However, other EU texts related to hydrogen do not take into account the contribution of nuclear to the EU's decarbonisation objectives.[3]

Solution: A consistent view on the role of nuclear in achieving decarbonisation should be reflected in the European policy framework.

Common Agricultural Policy

Situation / issue: Common Agricultural Policy (CAP) with its accompanying climate requirements impacting biofuels was designed before the Fit for 55 package was completed. Both are not fully consistent.[1]

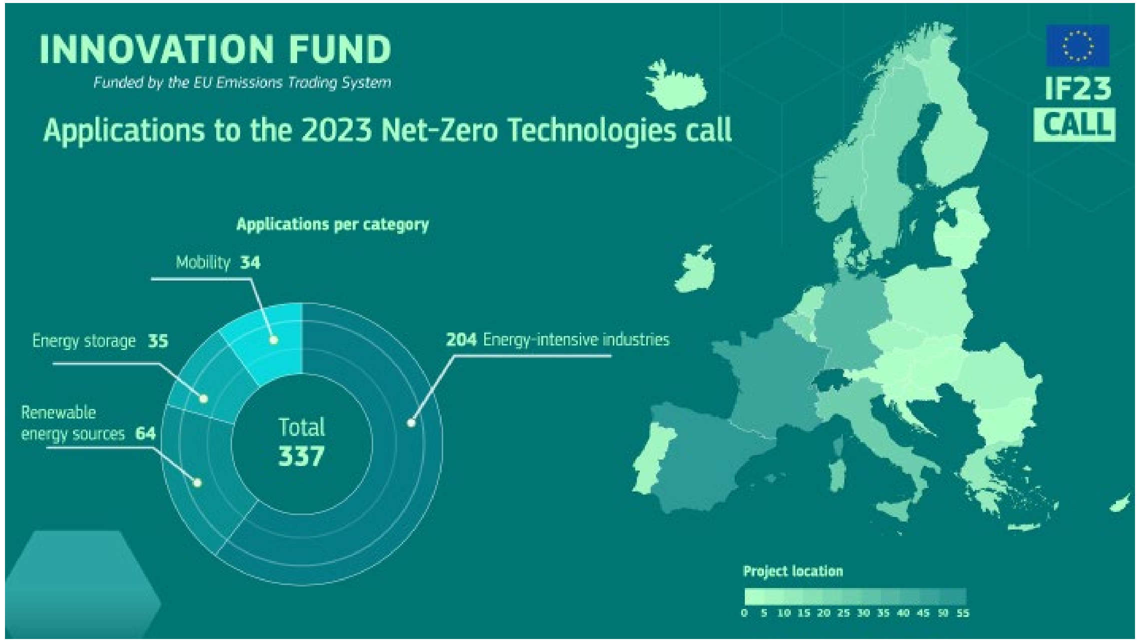
Solution: The CAP could be revised to ensure agriculture contributes further to Net-Zero objectives set in the European packages, with e.g. support schemes for farmers to create a market for EU made low-carbon fertilisers.

Source: [1] Euractiv (2024), EU biofuel policy, stable after two decades of fluctuation? ; [2] European Scientific Advisory Board on Climate Change (2024), Towards EU climate neutrality ; [3] Euractiv (2023), France calls for 'coherence' in sea of EU hydrogen rules

Funding needs could significantly exceed available means as of today: the example of the IF23 call

The Innovation Fund 2023 call for proposal has received 337 applications from all EU countries, with regional disparities

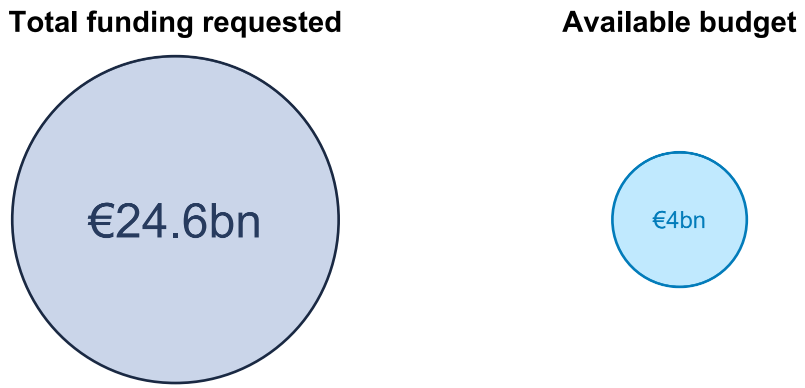
- Most of the applications come from Western and Central Europe, with Spain, France and Germany representing the majority of the applications.



*The Innovation Fund is an example of a funding gap, but the same issue also appears with **other EU instruments** (CEF-E, InvestEU, etc.).*

The total funding requested vastly exceeds the available budget

- The funding call was 5 times oversubscribed, with applications worth more than €20bn having to be turned down.



The timeline raises questions

- The call was launched in November 2023, with a deadline in April 2024.
- Applicants will be informed of the results in Q4 2024 and funding will be available in Q1 2025.
- Given the recent increase in decarbonisation objectives and the pressure on EU competitiveness, the timeline could have been shortened, with more than one year between the call and the availability of the funds.

Source: European Commission (2024), Innovation Fund: Overwhelming response to the 2023 net-zero technologies call

5.3
Main takeaways

A wide multi-faceted policy framework to support Net Zero is already in place but could be completed with a greater focus on competitiveness and energy security issues

Our review of energy and climate policies, initiatives and tools shows that a **wide, multi-faceted policy framework is already in place.**

The policy framework already addresses all major areas identified as critical (i.e., renewable and low-carbon energy supply, energy infrastructure and end-use decarbonisation).

However, **the current policy framework is not sufficient to ensure that the planned decarbonisation will support competitiveness of EU industry and maintain security of supply**

The EU **policy framework for security of supply** could be enhanced given the new international context through enhanced monitoring and planning methodologies and coordinated policy action

The EU lacks a policy framework to **address competitiveness issues** in the energy transition

The current framework to monitor and assess industrial competitiveness and carbon leakage risks should be **broadened to address risks associated with energy costs competitiveness**

Funding and financing instruments for energy system decarbonisation could be better coordinated and streamlined

A **framework to plan and support timely investments in critical infrastructures** is key to further integrate the energy market and ensure competitive decarbonised energy access across Europe

6.

Key takeaways for policy action

Key takeaways: Net-Zero, security of supply and competitiveness can be reconciled through enhanced EU-level coordination, planning, and support for an efficient transition

1 Ensure the efficient implementation of current energy and climate policies through enhanced coordination and monitoring

A cost-effective energy transition can be realized through further cooperation across policy areas, ensuring the consistency and predictability of the decarbonised energy investment framework, and addressing barriers to implementation.

1. Foster a whole system approach to energy system planning and enhance coordination mechanisms across countries to ensure a cost-effective transition.
2. Coordinate and streamline funding and financing instruments for energy system decarbonisation (e.g. with an EU Climate Bank on the model of the Hydrogen bank).

2 Address the energy price competitiveness gap and security of supply challenges

Reconcile decarbonised energy deployment with competitiveness and security of supply by securing access to critical materials, de-risking supply chains, and ensuring adequate deployment of flexibility and critical infrastructures through timely investment.

3. Developing a policy framework to plan and support timely investments in critical infrastructures is key to further integrate the EU energy market and ensure competitive decarbonised energy access and benefit sharing across Europe.
4. De-risking value chains and addressing planning/permitting barriers is critical to scale up decarbonised energy supply and limit financing costs.
5. The framework for Security of Supply monitoring should be improved to take a full system approach across energy vectors and reflect new challenges.

3 Support an efficient transition of industrial sectors and reinforce policies to mitigate the risk of carbon leakage

Amplify policy support to de-risk and accelerate the uptake of decarbonised technologies in industry and address competitiveness issues for industries facing international competition.

6. The framework to monitor industrial competitiveness and assess carbon leakage risks could be broadened to include risks associated with energy costs competitiveness.
7. CBAM regulation could be enhanced to address competitiveness issues for exports and downstream products.
8. Allocation of energy transition costs and benefits of decarbonised technologies investments across sectors could be better coordinated at EU-level.
9. Demand-side measures could support EU-based low-carbon industrial manufacturing.

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