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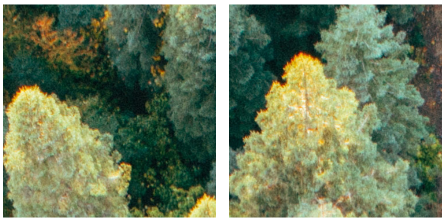

COST-EFFECTIVE DECARBONISATION STUDY

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Executive Summary [1]

1. Introduction and objectives of the study

The EU has consistently identified three core objectives of its energy policy; sustainability, competitiveness and security of supply. At least in theory, these have been viewed to be an equilateral triangle, with all objectives being equally important and to be given equal weight in policymaking.

However, in reality, at different points in time, the three priorities have been given different levels of focus. In 'pre-Kyoto' times, competitiveness and energy security were the main focus of European energy policy, with the development of the Internal Energy Market and the initiatives to develop infrastructure, notably to ensure that all Member States could access multiple suppliers of natural gas.

Since 2009, when the EU's 'new energy policy' was agreed at the 2005 Hampton Court Summit and translated into the ETS, Renewable Energy and Energy Efficiency Directives, the priority has unequivocally been sustainability - achieving the EU's commitments to the Kyoto and then Paris agreements.

The authors of this study would like to underline from the outset that they fully agree with this prioritisation. Dealing with climate change and thus rapidly decarbonising our energy system is unquestionably the greatest energy challenge we face. According to the IPCC's 2018 Report[2], in order to limit global warming to 1.5°C above pre-industrial levels, we need to cut global GHG levels by around 45% by 2030 and reach net zero by 2050. A 2°C warming requires a 20% cut by 2030 and carbon neutrality by around 2075.

Seen from this perspective, the EU's initial 2030 energy and climate targets adopted in the 'Clean Energy Package' - a 40% CO2 cut by 2030 and a renewable energy target of 32% - can only be seen as inadequate, certainly if we remain committed to the 1.5°C objective. The Green Deal targets of a 55% GHG cut by 2030 and carbon neutrality by 2050 represent a fair - even ambitious - response.

In order to address global climate change and its contribution to it, the EU is therefore focusing not only on the ultimate goal of climate neutrality, but equally establishing an ambitious trajectory for GHG reductions. This is important for two reasons. First, decarbonising the economy will involve massive structural changes and investments, as discussed below. It will require decades to complete, so it is important to start early. Second, the quicker that CO2 is avoided, the stronger the effect in terms of preventing climate change, as CO2 stays in the atmosphere for decades before being dissolved in oceans or used by plants. Thus, every extra tonne saved now pays dividends later. In this light, any policy that accelerates the phase-out of coal and uses natural gas as a cost-effective transition, together with and subsequently substituted by renewable energy sources, will inevitably be a highly cost-effective decarbonisation policy. The social consequences of any such accelerated phase-out must, however, be fully incorporated into such a development.

[1] We would like to extend our thanks to Ronnie Belmans, Professor, Faculty of Engineering and Science KU Leuven, and Alberto Pototschnig, part-time Professor at the FSR, for their comments and support in elaborating this study. Any errors remain those of the authors.

[2] https://www.ipcc.ch/2018/10/08/summary-for-policymakers-of-ipcc-special-report-on-global-warming-of-1-5c-approved-by-governments/

Europe, and the EU in particular, has consistently led the world in taking practical steps to meet its climate commitments, and this must continue. This will no doubt remain the case, but the results of the US election obviously gives renewed hope that a more determined global approach can emerge.

Thus, achieving the EU's climate commitments must remain the foundation of the EU's energy policy moving forward. It is both the starting point and foundation on which any finding or commentary in this study is based upon. However, this does not mean that the two other objectives of EU energy policy - competitiveness and security of supply - should be ignored.

The cost of energy is an essential element of competitiveness for many companies. Evidently, these include energy-intensive companies such as chemical, steel, metals and cement, where energy typically represents 20-40% of the total cost[3]. This is however equally important for companies where energy costs are less decisive but nonetheless important and which operate under tight margins; car manufacturers for example. It makes no sense to increase energy costs in the EU for such enterprises to the extent they relocate outside Europe, where GHG is not taxed, as this would, almost certainly, simply increase the global GHG resulting from the manufacture.

Equally, electricity costs have increased for EU citizens in recent years. The total electricity price for household consumers, i.e. including all taxes and levies, was substantially higher (17 %) in the second half of 2019 than in the first half of 2008 when adjusted for inflation[4]. In some Member States, this increase has been significantly greater[5]. Support for the EU's decarbonisation agenda remains strong - a recent European 'Eurobarometer survey indicated that 91% of citizens state that climate change is a serious problem in the EU[6]. However, societal responses to rapid energy price increases in the past demonstrate that this is an important issue for EU citizens. In order to meet the EU's Green Deal objectives, billions of Euros will need to be invested - according to the Commission about € 3.5 trillion in the period 2021-2030[7]. At a time where many other countries are failing to take robust action to deal with climate change, limiting increases in energy prices for citizens remains important. A rapid and sustained increase in electricity and gas prices, not seen in other countries, is likely to bring challenges in terms of maintaining public support to the decarbonisation agenda.

Security of energy supply equally remains a vital issue for EU citizens. The transition must be undertaken in a manner that continues to guarantee very high energy security. The challenges in this respect are changing rapidly, natural gas issues becoming far less a concern, and grid stability/cybersecurity rising on the agenda.

The next stage of the EU's energy decarbonisation agenda will bring unprecedented change, with an acceleration of the shift towards renewable electricity, the decarbonisation of transport, and the rapid emergence of sustainable molecules, amongst them hydrogen.

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3 https://www.energystar.gov/sites/default/files/buildings/tools/ENERGY%20STAR%20Guide%20for%20the%20Cement%20Industry%2028_08_2013%20Final.pdf

4 https://ec.europa.eu/eurostat/statistics-explained/index.php/Electricity_price_statistics

5 Eurostat: https://ec.europa.eu/eurostat/statistics-explained/index.php?title=File:Development_of_electricity_prices_for_household_consumers,_2008-2019_(EUR_per_kWh).png

6 https://ec.europa.eu/commission/presscorner/detail/en/IP_20_331

7 https://ec.europa.eu/clima/sites/clima/files/eu-climate-action/docs/com_2030_ctp_en.pdf

The Commission has recently published its Energy Sector Integration and Hydrogen Strategies, together with signalling numerous additional policy initiatives, such as the revision of the ETS, renewable and energy efficiency Directives, and a carbon border tax. These initiatives, in the context of the Green Deal, will set the basis for the EU's energy system for the next decade or longer. The manner in which these will be implemented in practice will form the basis of the next stage of the decarbonisation of our energy system, and are likely to have a profound effect on energy prices and competitiveness.

It is vital that these initiatives are designed and implemented in a manner that ensures that the EU meets its GHG objectives. It must be the basis of the measures adopted. However, it is equally important that they are implemented in an objective manner based on best available evidence, which is likely to lead to a cost-effective decarbonisation, for the reasons mentioned above. Public support for decarbonisation in the face of continually rising electricity and gas prices should not be taken for granted.

The aim of this study is therefore firstly to review existing policies to consider whether they have achieved the 'triangle' of energy objectives. This is the focus of chapters two, three and four.

Secondly, the core of this study is to review the available evidence that the Commission, the Parliament and the Member States will need to take into account in reaching decisions on this 'optimal equilateral triangle' approach. In particular the study benchmarks and peer reviews a wide range of scientific, academic and industry studies and literature in order to attempt to provide an objective review - or 'consensus analysis' - regarding the likely future costs and other challenges relevant to the different technologies and energy options that will need to make up the EU's energy future. This is the focus of chapters five, six and seven.

To do this, the study (in particular, chapter five of the main report document) first examines a number of key studies from reliable sources[8] to consider the extent to which different decarbonisation scenarios are compatible with one another and therefore, the extent to which they provide a reliable and robust framework for considering decarbonisation scenarios. This analysis in fact shows a high degree of inconsistency between the different decarbonisation paths envisaged by different agencies/bodies, with wildly different expectations on energy demand, and the resultant energy mix.

It is difficult to draw precise conclusions from this observation, aside from acknowledging that there remain many variables in terms of how the EU will need to decarbonise its energy system in a manner achieving all of the objectives of sustainability, competitiveness and energy security. If anything, it reinforces the central observations made below. First, a technology-neutral approach is required to any decarbonisation policy as it is simply impossible to 'pick winners', due not least to the unforeseeable nature of technological change over the next three

[8] Notably, the study benchmarks and peer-reviews the following studies: IEA "World Energy Outlook 2020" (October 2020), IRENA "Global Renewables Outlook – Energy Transformation 2050" (April 2020), IEA "The Future of Hydrogen" (June 2019), IRENA "Hydrogen: A renewable energy perspective" (Sept. 2019), BloombergNEF "Hydrogen Economy Outlook" (March 2020), BloombergNEF "Global Gas Report 2020" (Aug. 2020) and BloombergNEF "Sector Coupling in Europe: Powering Decarbonization" (Febr. 2020). Since these studies do not include future costs for turquoise hydrogen (from Methane Pyrolysis with CCU plants), the study benchmarks and peer-reviews the following sources exclusively for the future costs of turquoise hydrogen: ThinkStep "GHG Emissions in the EU Energy market today and in 2050" (Oct. 2018), B.Parkinson et al. "Levelised cost of CO2 mitigation from hydrogen" (Energy & Environmental Science, Nov. 2018), Gas for Climate & Guidehouse "Gas Decarbonisation Pathways 2020-2050" (April 2020) and Zukunft Erdgas & Poyry "Hydrogen from natural gas – the key to deep decarbonisation" (July 2019).

decades. Second, the market, fully internalising the (progressively increasing) cost of carbon content of energy sources and vectors must be the basis of determining the EU's future energy mix, not political or regulatory decisions. The wildly different estimations illustrated in chapter five of the main report document demonstrate vividly the futility of a regulatory-based approach to predicting future decarbonised energy markets.

The study then examines consensus views on expected developments and estimates regarding the future cost of renewable electricity (chapter six of the main report document) and hydrogen technologies (chapter seven of the main report document). Obviously, concentrating only on these two energy vectors provides an incomplete picture, but the approach has been chosen given that renewable electricity and zero-carbon hydrogen and other carbon-neutral molecules[9] (together with CCS/CCU and nuclear electricity for those countries that choose this path) will (on the basis of currently predictable technology development) make up the overwhelming lions' share of EU energy demand post-2050.

We suggest that this information is vital in determining the correct policy approach to promoting different energy technologies.

The EU is currently at the beginning of a new 'energy technology cycle' with the development of the low and zero-carbon hydrogen market. As we have learned with the experience of developing the wind and PV markets, a key challenge to the cost-effective design of an energy policy at the beginning of a new technology cycle is timing: getting the balance right between initial R&D/demonstration of new technologies to lower costs ('technology push'), and creating demand through production subsidies ('market pull').

With the benefit of hindsight, the EU could have ensured a far more cost-effective development of the renewable electricity market by investing, say €10Bn in R&D and industrial demonstration on wind and PV from 2008-2012, and then increasing rapidly production subsidies. Given that over the last few years the EU has typically spent €70 Bm p.a. on renewable electricity subsidies[10], if this could have been reduced by say even 20%, the savings would have been considerable, freeing up resources for other priorities. This is not to criticise the EU's policy in this respect (which as explained below has brought many benefits), but to say that we must learn from the experience.

With respect to the future hydrogen market, developing an EU hydrogen strategy that ensures that the relative timing of R&D/demonstration and production subsidies is optimal will be crucial. On the one hand, we must be sure to have the changes in place in due time to ensure that the EU's gas system is zero-carbon by 2050, and that it makes its correct contribution to the decarbonisation transition. On the other hand, as explained further in detail below, there are factors regarding hydrogen indicating that an approach of <u>first</u> R&D/demonstration, funding and <u>second</u> production subsidies is likely to be a cost-effective approach.

In addition, the 'consensus' figures regarding the relative expected future costs of the different forms of low and zero-carbon hydrogen and their GHG content (green, blue, turquoise..) that are set out in the table below give strong grounds to argue that (i) a 'colour-blind' policy approach to R&D/demonstration funding and (ii) enabling the Internal Energy Market principles, based on competition between energy sources/vectors fully reflecting their

[9] Henceforth in this executive summary we limit references to low and zero carbon molelcules to hydrogen, for the sake of brevity.

[10] Commission's Staff Working Document, COM(2019)1 final Part 1/4, accompanying the report on "Energy prices and costs in Europe",p.216, figure 164 https://ec.europa.eu/energy/sites/ener/files/documents/swd_-_v5_text_6_-_part_1_of_4.pdf

externalities (notably GHG content) through life-cycle guarantees of origin, will bring the most cost-effective energy transition.

The purpose of this study is not to propose a specific answer or trajectory regarding this balance of policies, but to highlight the main facts relevant to this decision, the importance of getting the balance correct, and the issues to take into account to permit policymakers to determine the correct balance.

2. Achievement of the 2020 objectives and the challenge of meeting the Green Deal.

When the '20-20-20' objectives were adopted and translated into legally binding renewables targets per Member State, they were ground-breaking, and considered highly ambitious. In fact, to achieve the 20% renewable energy objective by 2020, it meant that the EU would need to install, every year between 2010 and 2020, the same wind and PV capacity that it had installed in total in the past. The 20% GHG reduction objective was world-leading in its ambition, and the ETS pioneering (see chapter two of the main report document).

The EU has met and exceeded its core GHG target, with a 23% GHG emissions reduction in 2018 as well as its renewable energy objective. Any qualification of success or failure of the '20-20-20' objectives must start with this observation. It has provided the EU with the foundations needed to realistically aim at meeting the Green Deal's objectives. In addition, it has established an (albeit imperfectly) functioning ETS system, which is again a solid foundation for the future.

Furthermore, the EU's energy change has created a whole new industrial sector; the number of jobs which have been created in the RES sector has, according to the Commission, increased from 1 million in 2009 to 1.5 million in 2018.

The European Commission stresses the 'Energy Efficiency First' principle as the foundation of its energy policy, with good reason. However, it is this area where the EU has shown the most difficulty in delivering. The latest available data in 2018 (15% energy efficiency in 2018), shows that the 20% energy efficiency target will probably not be met by the end of 2020. The COVID-19 pandemic may artificially and temporarily depress energy demand in the EU, but the overall trend remains disappointing. Equally, it is worth reflecting that during the 2009-2020 period the EU underwent a severe economic crisis (demand generally fell during crisis years but increased during 'normal' years of economic growth).

With respect to the 20% target for renewable energy in final energy consumption, as mentioned above, this will be met, but not in all Member States. This has come at a cost, with subsidies amounting to €70 Bn per year[11], early support schemes characterised by over-compensation, and a national-based system of RES-E support meaning that capacity is situated at sub-optimal geographical locations. Such comments are of course easy to make with the benefit of hindsight, and support schemes, now mostly based universally on tenders, are now efficient and delivering competitive prices.

Overall, we consider it fair to conclude that the EU has made a success of its early RES policy: achieving its target, and laying a strong foundation for the next stage of market development. Above all, the EU's kick-starting of demand for PV and wind led to the industrialisation of production for these technologies, economies of scale, and lower costs (albeit for PV, these have been achieved notably in China. This has led to renewable electricity capacity being

[11] https://ec.europa.eu/energy/sites/ener/files/documents/swd_-_v5_text_6_-_part_1_of_4.pdf

installed across the globe. Renewable energy is increasingly competitive with fossil fuel generation, although care needs to be taken when making such calculations to take account of the fact that wind and PV are intermittent (thus taking average yearly cost of production on the basis of hours operated into account) and to include all relevant system costs - notably storage and system balancing.

It is fair to say that these cost reductions are, at least to a very significant extent, a direct consequence of the EU's 20-20-20 initiative - at best, they would have happened far slower in the absence of the EU's action. Seen in this light, it is fair to point out that globally, the 20-20-20 initiative indirectly resulted in GHG savings far greater than the simple 23% GHG reduction in the EU. European citizens should be proud of the leadership that they have shown here.

In terms of energy security, during the period 2010-2020 the EU has focused on the issue of diversifying sources of gas supply, especially for those countries largely or completely dependent on a single supplier. The EU adopted a new infrastructure planning approach, with EU funds for energy infrastructure projects in the EU's interest. This has proved very successful indeed. The number of gas suppliers has increased between 2012 and 2018 for all Member States located in Southern, Central and Northern European regions.

All countries now have supply options, which will further increase once additional on-going projects are completed. This has had an unsurprising positive effect on the relative competitiveness of gas supplies in countries previously characterised by limited liquidity options; the average import price for Southern, Central and Northern Member States was 13% higher than Western Member States in 2013, this reduced to 5% in 2018:

Given that EU's Member States' energy security and diversity are also being increased by their investments in renewable electricity, the security of gas supplies is no longer a significant focus of EU energy policy. Again, EU citizens can be satisfied with what its energy policy has delivered on this issue.

Achieving the Green Deal objectives of a 55% GHG cut by 2030 represents a step-change in terms of ambition compared to the 20-20-20 objectives. If one assumes that Member State's renewable electricity objectives (established on the basis of the pre-Green Deal 40% GHG cut for 2030) need to increase in proportion to the GHG increase from 40% to 55%, then renewable electricity will need to make up around 67% of EU electricity demand by 2030, compared to around 30% today[12]. This will require the level of newly installed wind and PV capacity per annum to double in the 2020-2030 period compared to 2010-2020. Equally, the energy efficiency target will need to increase from 32.5% to 36% or more. Further analysis of the energy policies towards 2030 is presented in chapter three.

This analysis of the renewable electricity and energy efficiency objectives needed to achieve the Green Deal target of 55% is of course an over-simplistic extrapolation based on existing estimates for the original 2030 target. It is nonetheless a reasonable illustration of the scale of the challenge ahead of the EU to achieve this goal. It also underlines the importance of integrating cost-effectiveness into the Commission's preparation of the 2021 legislative energy and climate package. More details can be found in chapter four of the main report document.

[12] https://ec.europa.eu/eurostat/statistics-explained/index.php/Electricity_generation_statistics_–_first_results#Production_of_electricity

3. Expected costs of renewable energy technologies in the future.

The study has analysed the expected costs of renewable electricity, peer-reviewing an important cross-section of available literature on the topic. This is included in chapter six of the main report document. In this area, a relatively uniform position emerges:

Technology	Levelised costs today (The year reported is relative to the estimate, not to the publication year of the source)	Levelised costs 2030	Levelised costs 2050
Utility-scale solar	45 – 58 - 160 EUR/MWh (IRENA, 2019) [13] 29.75 – 42.5 EUR/MWh (regional averages, IEA, 2019) [14] 33.15 - 42.5 EUR/MWh (BloombergNEF, H1 2020) [15] 26.35 – 31.45 – 35.7 EUR/MWh (Lazard, 2020) 11.2 EUR/MWh (Portugal, world record bid, Aug. 2020)	14.9 EUR/MWh (worldwide “PV best” values, IRENA) 21 – 38.5 EUR/MWh (regional averages, IEA) [16] 14.4 – 33.15 EUR/MWh (worldwide estimates, BloombergNEF) 17.85 EUR/MWh (estimate for Australia, BloombergNEF) 10 EUR/MWh (arbitrary estimate for “very low cost” conditions)	18.7 EUR/MWh (worldwide “PV average” values, IRENA) 3.825 EUR/MWh (worldwide “PV best” values, IRENA) 13.6 EUR/MWh (estimates for Algeria, Spain and an unspecified location, BloombergNEF) 10.2 EUR/MWh (estimate for Australia, BloombergNEF)
Rooftop-scale solar	55.3 –140.3 EUR/MWh [17] (Germany, IEA, 2018/2019) 80.75 – 157.3 EUR/MWh [18] (France, IEA, 2018/2019) 93.5 – 191.3 EUR/MWh [19] (Japan, IEA, 2018/2019) 62.9 – 193.0 EUR/MWh (Lazard, 2020)	-	-

[13] Worldwide 5th percentile, average and 95th percentile by IRENA, 2019
[14] Range derived from different regional average estimates (EU, China, India and USA) in 2019 by IEA.
[15] Worldwide weighted-average by BNEF, H1 2020. Based on whether it is fixed axis PV or a tracking PV.
[16] Range derived from different regional average estimates (EU, China, India and USA) by IEA through a linear interpolation of 2019 and 2040 regional data for both STEP and SDS scenarios.
[17] LCOE range for Germany by IEA, 2018/2019
[18] LCOE range for France by IEA, 2018/2019
[19] LCOE range for Japan by IEA, 2018/2019

Onshore wind farm	32 - 45 – 92 EUR/MWh (IRENA, 2019) [20] 29.75 – 46.75 EUR/MWh (IEA, 2019) [21] 37.4 EUR/MWh (BloombergNEF, H1 2020) [22] 22.1 – 34 – 45.9 EUR/MWh (Lazard, 2020) 16.9 EUR/MWh (Saudi Arabia, world record bid, 2019) [23]	17 EUR/MWh (worldwide "wind best" values, IRENA) 29.75 – 44.5 EUR/MWh (regional averages, IEA) [16] 23.8 – 40 EUR/MWh (estimates for China and Japan, BloombergNEF)	19.55 EUR/MWh (worldwide "wind average" values, IRENA) 9.35 EUR/MWh (worldwide "wind best" values, IRENA) 22.1 EUR/MWh (estimate for Germany, BloombergNEF) 14.45 – 28.05 EUR/MWh (estimates for China and Japan, BloombergNEF)
Offshore wind farm	76 – 97.8 – 133 EUR/MWh (IRENA, 2019) [24] 63.75 – 110.5 EUR/MWh (IEA, 2019) 78 EUR/MWh (BloombergNEF, H1 2020) [25] 58.7 – 73.1 – 88.4 EUR/MWh (Lazard, 2020) 42.5 EUR/MWh (UK, world record bid, 2019) [26]	36 – 46 – 96 EUR/MWh (G20 country values, IRENA) 45.9 – 81.6 EUR/MWh (regional averages, IEA) [16]	- [27] 34.85 EUR/MWh (estimate for Germany, BloombergNEF)

- Both onshore wind and solar PV are currently competitive with other electricity generation technologies (e.g. fossil-fuel based) on the basis of the cost of electricity delivered to the grid and can be assumed to become increasingly cheaper.
- By 2030, a significant further decrease in the assumed average levelised costs for utility-scale solar, onshore wind and offshore wind is expected and to further reduce by 2050. Key drivers of this cost-reduction are lower CAPEX due to technology improvements resulting, inter alia, in improved capacity factors.

In terms of the technical potential of renewable electricity production, the following represents an overview of estimations:

[20] Worldwide 5th percentile, average and 95th percentile by IRENA, 2019
[21] Average estimate for EU by IEA, 2019
[22] Worldwide weighted-average by BNEF, H1 2020
[23] World record price, Saudi Arabia's Dumat Al Jandal, 2019
[24] These levelised cost estimates are worldwide 5th percentile, average and 95th percentile estimates (IRENA, 2019)
[25] Worldwide weighted-average by BNEF, H1 2020
[26] Lowest price awarded to UK offshore wind auction
[27] The levelised costs values for offshore wind used in IRENA "Global Renewables Outlook: Energy Transformation 2050" (2020) are not explictly reported.

Technology	Technical potential today	Technical potential 2030	Technical potential 2050
Total (Solar PV + Wind)	480 TWh (IEA WEO 2020 SDS scenario)	1361 TWh (IEA WEO 2020 SDS scenario) Not reported explictly (IRENA TES scenario) 1367 TWh (ELEC and H2 "A Clean Planet for All" scenarios)	Not reported explictly (IRENA TES scenario) 1548 TWh ("A Clean Planet for All" ELEC scenario) 1802 TWh ("A Clean Planet for All" H2 scenario)
Solar PV	118 TWh (IEA WEO 2020 SDS scenario)	444 TWh (IEA WEO 2020 SDS scenario) Not reported explictly (IRENA TES scenario) 412 TWh (ELEC and H2 "A Clean Planet for All" scenarios)	Not reported explictly (IRENA TES scenario) 683 TWh ("A Clean Planet for All" ELEC scenario) 804 TWh ("A Clean Planet for All" H2 scenario)
Wind (both onshore and offshore)	362 TWh (IEA WEO 2020 SDS scenario)	917 TWh (IEA WEO 2020 SDS scenario) Not reported explictly (IRENA TES scenario) 955 TWh (ELEC and H2 "A Clean Planet for All" scenarios)	Not reported explictly (IRENA TES scenario) 865 TWh ("A Clean Planet for All" ELEC scenario) 998 TWh ("A Clean Planet for All" H2 scenario)

- The technical potential of renewable electricity from solar and wind in the EU is set to more than double by 2030 and to continue to increase very strongly by 2050.
- Potential electricity uses are assumed to slightly increase by 2030 compared to today. However, by 2050 electricity uses, and thus demand, are expected to increase significantly, because of increasing electrification and potentially because of increasing use of electricity as feedstock for synthetic fuel conversion (e.g. hydrogen, ….):

One important potential constraining factor to the increase of RES-E capacity relates to grid issues, notably the possible future inability to increase network capacity sufficiently quickly to bring electricity produced in new areas (far offshore) to demand centres. This threatens to increase grid costs and even lead to widespread curtailment. In addition, wind and PV is by definition, intermittent. In Germany in 2018 more than €1 Bn in system costs were incurred to deal with curtailment as peak renewable electricity could not be consumed or stored. In 2018 around 38% of Germany's electricity was sourced from renewables, whereas even under the 40% 2030 GHG cut scenario, Germany aims at approximately a 65% renewable share of its electricity system. If a combination of adequate transmission capacity, effective regulatory solutions, and cost-effective storage is not addressed actively, there must inevitably be a concern that grid costs will rise, resulting in significantly increasing electricity costs.

As part of this study, FSR researchers reviewed literature to attempt to determine scenarios and forecasts of expected balancing and storage costs for renewable electricity, but failed to identify sufficient data to draw conclusions. This is itself is an important observation, and additional work needs to be completed on this issue so that the EU urgently adopts a forward-looking and cost-effective approach to ensuring that infrastructure/storage options exist in time to prevent curtailment becoming the default option, which would threaten additional rapid increases in renewable electricity investment.

In the view of the authors, this gives rise to possibly the most important conclusion from this study. Aside from energy efficiency, which must remain the EU's highest energy priority, it is clear that renewable electricity will form the backbone of the EU's decarbonised energy system[28]. By its very nature, renewable electricity will be cheaper than zero-carbon hydrogen (which is a vector that stores renewable electricity). The most important and immediate priority for the EU in ensuring a cost-effective decarbonisation of its energy system must therefore be to identify and eliminate infrastructure and other bottlenecks that are likely to constrain the cost-effective production and use of renewable electricity moving forwards.

4. Hydrogen

Together with renewable electricity, hydrogen is undoubtedly the most important area where regulatory decisions taken by the current Commission and the Member States are likely to have a profound effect in terms of competitiveness of EU energy supplies over the coming decades.

During this Commission, the EU will set the framework for the development of the EU's future low and zero-carbon hydrogen market. Ensuring that this policy is set on the basis of an objective understanding of the facts - and above all, a recognition of the uncertainties that exist in establishing and interpreting these facts - will be crucial in establishing a framework that at the same time puts the EU on a secure path to a decarbonised gas system by 2050, but equally maintains competitiveness. For all carbon-neutral fuels, carbon neutral hydrogen is a prerequisite/intermediate product. Examples are ammonia, alcohols (methanol, ethanol, …), methane, ethane, ethylene, some of them being direct input for chemical reactions (eg ammonia for fertilisers).

This study seeks to set out some of these key facts. However, we would like to underline that many of these 'facts' are in fact estimations and predictions, and should not therefore be viewed as fact *per se.* As explained in more detail below, it is important in attempting to interpret these estimations to understand that they are, by their very nature, imprecise. This and further material mentioned below is included in chapter seven of the main report document, focused on the costs of hydrogen technologies.

In this study, the terminology 'grey', 'green', blue, and turquoise hydrogen are used. Grey hydrogen refers to hydrogen produced from natural gas via steam methane reforming ('SMR'), where the resultant CO2 is vented into the atmosphere. Green hydrogen refers to production from water via electrolysis using renewable electricity (thus being a zero-carbon option). Blue hydrogen refers to production from natural gas via SMR, using carbon capture and storage of the CO2 emissions (not all the CO2 can be captured and stored, so this is a low carbon option. Turquoise hydrogen refers to production from natural gas using pyrolysis (when powered by renewable electricity this process is also a zero-carbon option, providing that any fugitive methane emissions from the natural gas used are offset.)

Researchers at the European University Institute ('EUI') have peer-reviewed a wide selection of different studies that estimate the future costs and relevant externalities of different forms of hydrogen. They present below a mean/average or 'consensus' approach based on these studies. In this manner, we attempt to provide an objective illustrative picture of average

[28] We do not ignore the potential of nuclear electricity to contribute to a zero-carbon energy system, in those countries that chose this option. However, this energy source has not been considered in this study.

industry/academic predictions for the key data that will need to be taken into account by the EU in future policy settings. We fully recognise the imperfection of such an approach, but suggest that it is an important additional tool.

Indeed, the very diversity of key data/predictions of future hydrogen costs contained in literature is in itself an important finding, as it demonstrates the high level of uncertainty surrounding future hydrogen cost trends and the ETS prices needed to catalyse market penetration of low and zero-carbon hydrogen primarily for substituting grey hydrogen and where needed an energy source. The following factors can be identified that render any current prediction regarding future hydrogen/ETS switching costs, and the potential future balance between green, blue and turquoise hydrogen by their very nature uncertain:

Technological maturity.

The level of technological maturity of low and zero-carbon hydrogen is at a low level; electrolysis being the most mature (currently at small commercial scale), CCS also being at large demonstration level and pyrolysis at relatively small-scale demonstration level. As these are scaled up we can expect the CAPEX to reduce significantly, but estimations vary.

Future energy costs and availability

Unlike with respect to renewable electricity, which is a CAPEX driven business model (wind and sunshine being free), low and zero-carbon hydrogen production is an OPEX dominated business, as the production cost of the hydrogen is driven by renewable electricity, natural gas and (for those countries that chose to go down this route) nuclear electricity costs. Any prediction regarding the future cost of low and zero-carbon hydrogen therefore requires assumptions of the cost of RES-E and natural gas. In the case of renewable hydrogen, it also requires assumptions as to the number of hours per year that 'cheap' RES-E is available, to build in electrolysis plant capacity factors. Many estimations that renewable hydrogen will be competitive with blue or turquoise hydrogen in the medium term rely on ambitious price reduction and load factor increases - the IEA for example, estimates that for green hydrogen to be competitive with blue or turquoise hydrogen by 2030, it will require renewable electricity supplies at €10-20 MWh for 4000 hours p.a [29]. If one assumes that this will be available, renewable hydrogen is likely to be competitive, but such load factors and prices for EU generated electricity will be at best challenging.

Finally, estimations regarding the future quantity of renewable hydrogen that can be supplied to the EU market also requires assumptions regarding the physical availability of sufficient quantities of renewable electricity. If a new renewable or turquoise hydrogen plant buys renewable electricity to power it from the market, this reduces the renewable electricity available for other purposes, but increases the overall demand for electricity. If the marginal electricity supplier in a given electricity market is gas or coal, which therefore meets the additional electricity demand resulting from the renewable electricity taken out of the market to power new hydrogen production, the net result of the 'renewable' or 'turquoise' hydrogen production is the production of additional fossil fuel electricity generation. In reality, therefore, in this scenario it may be more correct to classify this new hydrogen as grey. This can be overcome by requiring new renewable/turquoise hydrogen to source the renewable electricity from newly produced 'additional' renewable electricity based on a corporate power purchase agreement or direct lines, that does not therefore count to any renewable electricity targets (but the resultant certified renewable hydrogen would count to any renewable energy targets). This

[29] IEA "World Energy Outlook 2020" (October 2020) and IEA "Future of Hydrogen" (June 2019). All rights reserved.

is one of the issues that the Commission will need to address when designing a robust accounting and compliance system (e.g., based on GOs) with respect to renewable energy and wider hydrogen guarantees of origin.

Water issues

Electrolysis, by definition, requires the use of significant quantities of fresh clean water. The production of green hydrogen using PV in very sunny areas, and thus benefiting from the cheapest renewable energy costs predicted for the future, would by definition be produced in areas where water stress exists, or is expected to develop. In the EU taxonomy rules, this is one issue that must be addressed in determining the 'do no significant harm' requirement. Further study is required whether this may well be a limiting factor for renewable hydrogen production in geographic areas where green hydrogen could in theory be produced most competitively, such as Southern Europe or imported hydrogen from Morocco (or the cost and GHG consequences of desalination should at least be taken into account).

Customer inertia

Predictions regarding the future demand for low and zero-carbon hydrogen are inherently unstable. Whilst demand for hydrogen as a feedstock can be reasonably predicted (assuming the industry does not gradually relocate outside the EU), the use of hydrogen as an energy vector, notably in energy-intensive industry, transport and buildings, is difficult to predict. It depends, for example, on technological progress (whether electric trucks will become an option) and customer inertia (whether households will in reality be willing to install heat pumps or will rather prefer to keep hybrid gas boilers?):

Any hydrogen policy must factor in this uncertainty, and build into policy setting the fact that predicting today the future cost of green, blue and turquoise hydrogen, as well as the ETS prices needed to result in the penetration of low and zero-carbon hydrogen into the market is, by its very nature, imprecise.

However, within the limits of these acknowledged uncertainties, FSR researchers have calculated the following average or 'consensus' findings of expected costs of different hydrogen technologies and ETS switching costs needed to catalyse market penetration of renewable and low carbon hydrogen[30]. This is divided according to the nature of the hydrogen consumed, where two distinct markets exist (i) hydrogen used as an industrial feedstock notably in the production of fertilisers, methanol and steel (thus replacing grey hydrogen) and secondly as an energy source.

[30] The current costs of hydrogen derived from natural gas (through steam methane reforming technology, also called “grey hydrogen”) finds ‘little consensus’ between different sources, although it is a fully commercial technology. This is due to the fact that its costs depend significantly on the assumptions on natural gas prices. In the “A hydrogen strategy for a climate-neutral Europe” COM(2020) 301 final document, grey hydrogen costs are assumed at 1.5 EUR/kgH2 (38.1 EUR/MWh), disregarding the cost of CO2. Similar values are assumed for Europe in 2030 (also disregarding the cost of CO2), according to IEA “Future of hydrogen” (2019). However, costs of 1 EUR/kgH2 (25.4 EUR/MWh) are also assumed also for Europe in the report “Gas Decarbonization Pathways 2020 – 2050” (April 2020) by Gas for Climate & Guidehouse. Finally, ThinkStep reports a cost estimate of circa 0.8 EUR/kgH2 (20.3 EUR/MWh) in one of their latest works. This uncertainty is reflected in the calculation of the ETS prices required to lead to the substitution of grey hydrogen.

Scenario	Current technological maturity	Minimum and average levelised cost assumption across all sources [31] Today	Minimum and average levelised cost assumption across all sources [31] 2030	Minimum and average levelised cost assumption across all sources [31] 2050	Direct GHG emissions [kgCO2e/kgH2]
Domestic green hydrogen based on utility scale PV	Commercial	€2.15* -3.45/kg H2 €54.5 – 87.6/MWh	€0.9* - 2.1/kg H2 €22.8 – 53.3/MWh	€0.5* - 1.4/kg H2 € 12.7 – 35 .8/MWh	0
Domestic green hydrogen based on offshore wind	Commercial	€3.3* -4.9/kg H2 €83.4 –124.5/MWh	€1.7* - 2.6/kg H2 €43.1 – 66.0/MWh	€1.3* - 1.65/kg H2 € 33.0 – 41.9/MWh	0
Domestic blue hydrogen	Demonstration (e.g. Port Jerome refinery, Repsol SMR plant)	€1.0 - 1.7/kg H2 €25.4 - 43.2/MWh	€1.0 - 1.95/kg H2 [32] €25.4 – 49.5/MWh	€1.0 - 1.7/kg H2 €25.4 – 43.2/MWh	0.8 - 1.5
Domestic turquoise hydrogen	Demonstration (e.g. Carbotopia, Bosch)	-	€1.2 - 1.4/kg H2 €30.5 - 35.6/MWh	€0.7 - 1.2/kg H2 €17.8 – 30.5/MWh	0 - 2.5

* On the basis of the very lowest cost estimations of renewable electricity prices, based notably on the lowest ideally sited PV, the number for green hydrogen falls significantly to the minimum values reported (e.g. €0.9/kg H2 at a cost of electricity of 10 EUR/MWh by 2030 [33]).

Three scenarios of hydrogen production costs are identified, based on the three different hydrogen production technologies previously identified (‘green’, ‘blue’ and ‘turquoise’ hydrogen).

[31] Both the minimum and average levelised costs assumptions of domestic green hydrogen, identified across all sources examined, were updated with respect to “newer” renewable electricity costs assumption. More details are explained in chapter seven.
[32] This average levelised cost by 2030 is higher than the average of recent estimates, due to a smaller number of estimates points available and a higher average natural gas price assumption. We do not take responsibility for whether such average natural gas price assumptions will indeed realise. Therefore, the reader is advised to consider the range of levelised costs indicated rather than the punctual average estimate.
[33] It would not be surprising for such electricity costs of 10 EUR/MWh to realise in multiple sites already by 2030, given that it is the case already for the recent worldwide record solar PV bids in Portugal.

FSR Researchers first included an assessment of the current technological maturity of these three technologies. In order to do so, the most recent evidence on the technological maturity of these technologies in EU was collected from media, governmental sources (e.g. IEA "Clean Energy Technology Guide" (2020)) and experts' opinions. FSR researchers labelled 'commercial' technologies those which include at least one project commercially operating in a relevant environment[34]. They labelled as 'demonstration' technologies those not yet demonstrated commercially, but for which a prototype project has already been concluded.

FSR researchers collected available estimates on levelised costs of these three scenarios (the ratio between the total costs of production and the total hydrogen output, normalised per unit of hydrogen kilo) from recognised sources (i.e. IEA, IRENA and BloombergNEF for green and blue hydrogen; academic studies and consultancy studies for turquoise hydrogen)[35]. Then, the average levelised costs figures were derived, as a first approach focused on identifying a 'consensus' among these sources.

Finally, estimates on direct GHG emissions were based on two key sources (i.e. IEA "Future of hydrogen" (2019) report and an academic study which performs a literature review of LCA data relative to hydrogen production). The ranges are reported in this table, whereas the 'average' estimates reported by these sources were used for the following calculations of equivalent ETS prices (0 kgCO2e/kgH2 for green hydrogen, 1 kgCO2e/kgH2 for blue hydrogen and 1.35 kgCO2e/kgH2 for turquoise hydrogen).

Additional information on the costs of imported green hydrogen and imported blue hydrogen is available in chapter seven of the main report document[36].

On the basis of these figures, FSR Researchers then estimated the equivalent ETS prices for both substitutions of grey hydrogen and of natural gas combustion[37]:

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34 TRL 9 according to IEA's Technology Readiness Level classification

35 Due to the absence of EU-specific estimates, FSR researchers included worldwide-specific estimates while specifying the underlying assumptions identified as critical (CAPEX, fuel costs, ….).

36 The interest in import scenarios arises since the EU regional hydrogen strategy and national hydrogen strategies by MSs identified imports as a necessary element towards fully unlocking potential demand towards hydrogen, which is rather weak. Therefore, understanding the effective cost-competitiveness of imported hydrogen vs domestic hydrogen based on currently-available estimates would be fundamental towards understanding the feasibility of these strategies and misjudged cost assumptions.

What emerges from available evidence is that there is a larger amount of cost estimates available only for imported green hydrogen by 2050, whereas by 2030 only one data point is available. Only one estimate is also available for imported blue hydrogen by 2030 and 2050, showing little attention towards this possible scenario. These few estimates by 2030 and 2050 seem to hint that the costs of imported hydrogen are significantly uncertain and vary greatly depending on assumptions on production and transport costs. However, for imported green hydrogen the 'consensus' or average costs estimate seems to hint that imported hydrogen is, on average, more expensive than even the upper estimate of domestic production costs. This would be a sign that the business case of international hydrogen trading, which is pointed out as a necessary element in national and regional hydrogen strategies towards fully unlocking potential demand towards hydrogen, is rather weak.

37 More details on the methodology used can be found in chapter seven of the main report document.

Scenario	Levelised cost assumption	Equivalent ETS prices for substitution of grey hydrogen Today [EUR/tCO_2]	Equivalent ETS prices for substitution of grey hydrogen 2030 [EUR/tCO_2]	Equivalent ETS prices for substitution of grey hydrogen 2050 [EUR/tCO_2]	Equivalent ETS prices for substitution of natural gas combustion * Today [EUR/tCO2]	Equivalent ETS prices for substitution of natural gas combustion* 2030 [EUR/tCO2]	Equivalent ETS prices for substitution of natural gas combustion* 2050 [EUR/tCO2]
Domestic green hydrogen based on utility scale PV	Average	215 - 300	75 - 170	0 - 80 **	400 - 505	205 - 305	95 - 195
	Minimum	70 – 150	0 - 10 **	0 **	205 - 310	10 - 115	0 – 55 **
Domestic green hydrogen based on offshore wind farm	Average	375 – 460	135 - 225	20 – 115	620 – 720	275 - 375	130 – 235
	Minimum	195 - 280	25 – 120	0 – 70 **	375 - 480	145 – 245	80 - 185
Domestic blue hydrogen	Average	25 – 105	55 - 145	25 – 105	145 – 245	180 – 225	145 – 245
	Minimum	0 – 30 **	0 – 30 **	0 - 30 **	35 – 135	35 – 135	35 – 135
Domestic turquoise hydrogen	Average	-	0 – 80 **	0 – 50 **	-	95 – 200	65 – 165
	Minimum	-	0 – 50 **	0 **	-	65 – 165	0 – 90 **

* These calculations are based on the calculated energy switching cost. They do not therefore take account of the cost of modifying plant and equipment (e.g. converting steel furnaces to hydrogen. Thus, they are likely to appreciably under-estimate the real switching costs required).

** Whenever the resultant ETS switching costs were negative, implying cost-competitiveness conditions even in absence of carbon pricing, a value of zero was reported above.

Once again, we acknowledge the illustrative value of the data. Nonetheless, we would argue that it represents a valid 'snapshot' of the gradually emerging consensus of the best available estimation of current and future costs of the different forms of renewable and low-carbon hydrogen and the ETS costs needed to catalyse substitution.

On the basis of this data we would make the following eight observations that we consider relevant to the discussion on the forthcoming regulatory and market support measures for renewable and low-carbon hydrogen currently under preparation:

1. On the basis of ʻconsensusʼ and lowest costs estimates, green hydrogen is currently more expensive than blue hydrogen. However, by 2030, it may be competitive with blue hydrogen and turquiose hydrogen.

However, this will only be the case in the event that hydrogen could be produced using utility scale PV, which requires further study regarding potential effects on water stress.

By 2050, green and turquoise hydrogen may be in similar cost bands, but this assumption also requires the availability of utility scale PV in sunny areas.

In terms of expected average levelised cost of green, blue and turquoise hydrogen now, in 2030 and in 2050, an average/'consensus' of studies finds that green hydrogen is currently far more expensive than blue hydrogen:

- green based on utility-scale solar PV €3.45/kgH2, green based on offshore wind farm €4.9/kgH2, blue €1.7/kgH2)[38].

When considering instead lowest possible costs estimates, the same conclusion is drawn:

- green based on utility-scale solar PV €2.15/kgH2, green based on offshore wind farm €3.3/kgH2, blue €1.0/kgH2).

The picture changes by 2030. Green hydrogen based on utility-scale solar PV, blue hydrogen and turquoise hydrogen overlap in terms of costs ranges, whereas green hydrogen based on offshore wind farm results uncompetitive compared to these three options.

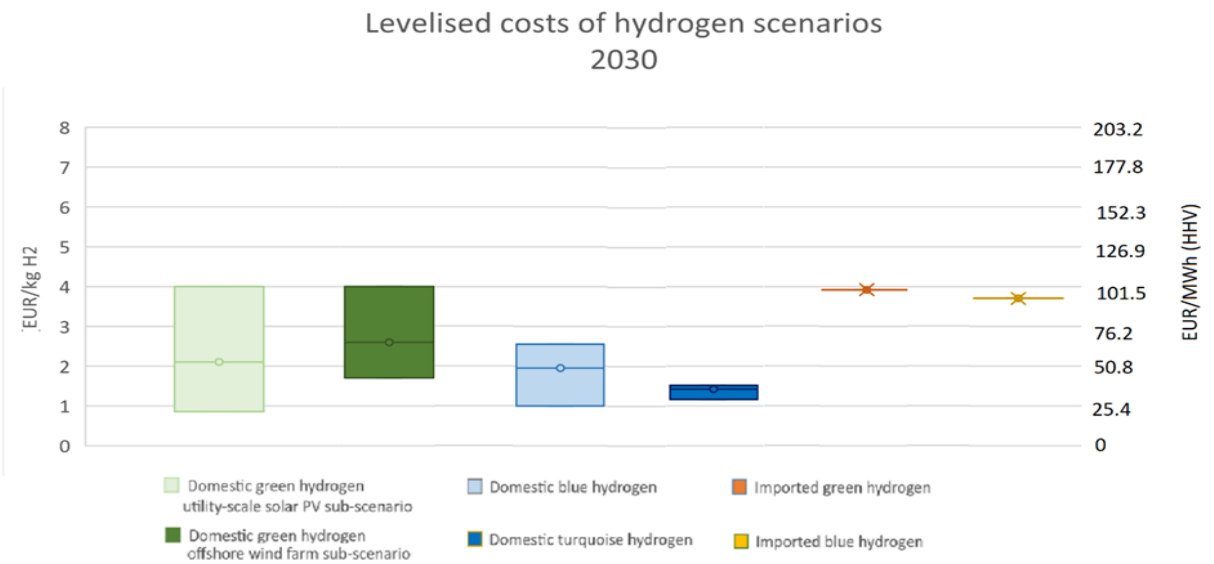
- average figures: green based on utility-scale solar PV €2.1/kgH2, green based on offshore wind farm €2.6/kgH2, blue €1.95/kgH2, turquoise €1.4/kgH2)
- lowest possible costs assumptions: green based on utility-scale solar PV €0.9/kgH2, green based on offshore wind farm €1.7/kgH2, blue €1.0/kgH2, turquoise €1.2/kgH2)

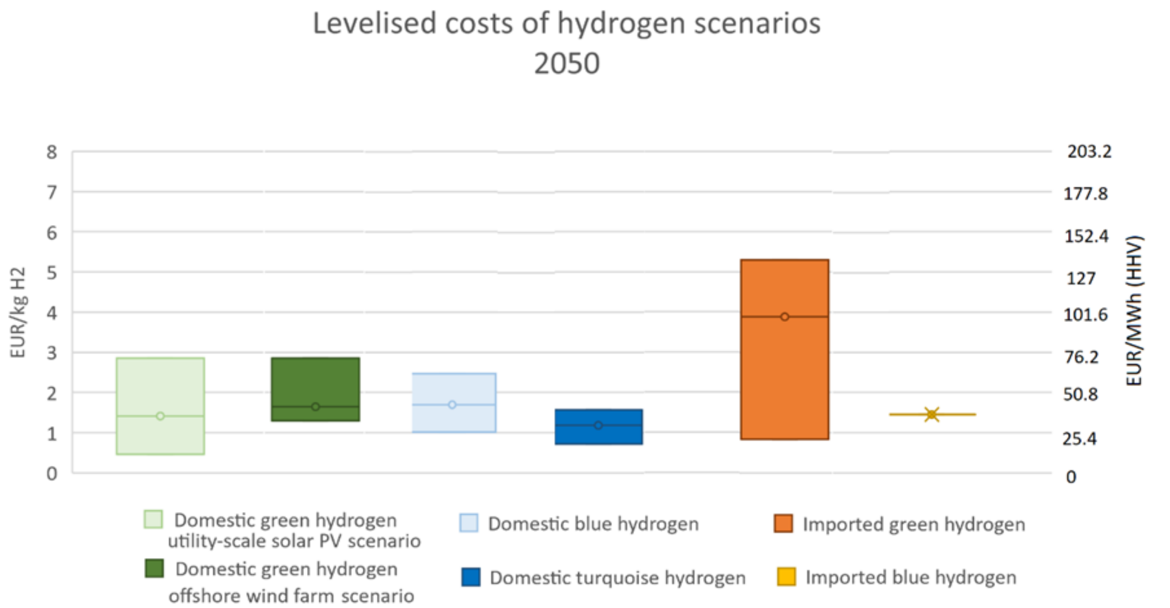
For 2050 only green and turquoise hydrogen is considered as only zero-carbon option will remain relevant. At this point consensus figures indicate that green and turquoise may be in similar cost bands:

- average/'consensus' costs: green based on utility-scale solar PV €1.4/kgH2, green based on offshore wind farm €1.65/kgH2, turquoise €1.2/kgH2)
- lowest possible costs assumptions: green based on utility-scale solar PV €0.5/kgH2, green based on offshore wind farm €1.3/kgH2, blue €1.0/kgH2, turquoise €0.7/kgH2)

The numbers represent an average of the predicted levels, and very large variations exist. Much depends, as mentioned above, on the availability of cheap RES-E over long periods to justify low green H2 cost predictions, which may or may not be reasonable.

It is important to note, however, that for green hydrogen to be competitive with turquoise hydrogen in 2050, current 'consensus' predictions require that it will use the very low cost of renewable electricity from utility-scale PV from sunny areas outlined above.





Thus, the question whether the EU's future requirements for zero-carbon hydrogen can be sourced from utility-scale PV is important. There are two important questions to be considered here.

First, as mentioned above, renewable hydrogen uses a lot of clean water. The areas where sun is plentiful (the very low PV cost predictions are predicated on production in very sunny areas) risk to suffer from water stress moving forward. The EU's emerging taxonomy rules make it clear that water stress is one of the issues to be considered under the 'do no significant harm' test.

If this is the case, then either the renewable hydrogen could not be produced in these areas, or it would have to be produced using desalinated clean water produced using renewable energy which would significantly add to the cost of the hydrogen. Of course, an alternative would be to produce the cheap PV in 'sunny areas' and to transport it to 'rainy' ones, where the green hydrogen could therefore be produced, but this also raises its own difficulty in terms of additional transmission lines.

These issues obviously arise whether the hydrogen is produced in the EU, or imported. In any event they illustrate that further study on these challenges is required before concluding that plentiful cheap PV from sunny areas will be available to power all the hydrogen that the EU will need in the future and that renewable hydrogen will automatically be a competitive option in 2030 or 2050.

2. Turquoise hydrogen represents an exciting potential zero-carbon option for the EU, but the technology needs to be matured.

As explained above, the 'consensus figures' generated above and literature expects turquoise hydrogen to be one of the cheapest forms of zero-carbon hydrogen in the future, and potentially the cheapest, appreciably so. However, it should be noted that this technology is at a lower level of technological maturity[39], which needs to be developed quickly to confirm these findings; it is not possible to guarantee today that these low figures will be confirmed.

For this reason, no figures to the cost of turquoise hydrogen are provided for today. In order for the technology to be available already by 2030, additional efforts will be needed to advance its development (see below).

Turquoise hydrogen, or pyrolysis, converts natural gas into hydrogen and carbon dioxide and 'pressurises' the carbon dioxide to form solid carbon graphite[40]. The resultant graphite can be used in industry (tyres, batteries) as well for soil improvement, increasing its ability to absorb

[39] TRL 6, according to IEA ETP Clean Energy Technology Guide

[40] https://www.ammoniaenergy.org/articles/methane-splitting-and-turquoise-ammonia/; https://arpa-e.energy.gov/sites/default/files/1%20Scale%20up%20BASF.pdf

CO_2. It can therefore contribute to the circular economy aims of the EU[41], as well as industrial independence for graphite for EV car production, identified as a priority by the Commission.[42]

The pyrolysis reaction to produce hydrogen can be powered either by natural gas (when the direct CO_2 emissions are relatively important) or by renewable electricity. When using renewable electricity to power the reaction, the resultant hydrogen is zero-carbon in nature, subject to the issue of fugitive methane emissions. When the reaction is powered by renewable electricity, if the natural gas used as feedstock is carefully sourced and traced, such fugitive methane emissions are very limited and could easily be offset, especially as carbon capture technologies improve. If that occurs, the resultant hydrogen should therefore be considered zero-carbon in nature.

Finally, producing 1 kg of zero-carbon hydrogen will in all likelihood require far less energy when produced via prolysis than through electrolysis, due to the fact that the chemical reaction used for pyrolysis requires the equivalent of 13-26% of the energy needed by the reaction used in electrolysis[43].

This technology therefore represents an important potential option for zero-carbon hydrogen in the future, but is currently at a low level of technological maturity, and additional R&D and demonstration investment is required before this can be confirmed.

3. The expected ETS prices needed for low and renewable hydrogen to substitute grey hydrogen and fossil fuels are potentially high. Providing production support in the form of tenders and contracts for difference for low-and zero-carbon hydrogen before ETS prices have increased, and the hydrogen consuming industry is fully exposed to the ETS, will therefore require potentially high subsidy levels.

Researchers at the FSR have drawn estimations of the future ETS prices needed to catalyse the replacement of grey hydrogen by green, blue and turquoise hydrogen. These are mathematical calculations based on the average predicted cost of hydrogen (green, blue, and turquoise), minimum predicted costs and the abovementioned assumptions regarding natural gas/renewable electricity prices[44].

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[41] With respect to the potential use of graphite resulting from pyrolysis as a soil improver that captures CO_2, see, for example, Potentials, Limitations, Co-Benefits, and Trade-Offs of Biochar Applications to Soils for Climate Change Mitigation, Alexandre Tisserant and Francesco Cherubini. https://www.mdpi.com/2073-445X/8/12/179

[42] https://www.ft.com/content/8f153358-810e-42b3-a529-a5a6d0f2077f

[43] https://www.efzn.de/fileadmin/documents/Niedersaechsische_Energietage/Vortr%C3%A4ge/2019/NET2019_FF1_04_Bode_Rev1.pd f ; https://www.sciencedirect.com/science/article/pii/S2590174520300155

[44] As previously mentioned, a range of possible grey hydrogen values was considered (€0.8 - €1.5/kgH2 or €20.3 – €38.1/MWh) in order to account for the relevant impact on costs from the uncertainty on future natural gas prices. This adds another layer of complexity, not examined in this study, related to identifying the main drivers behind natural gas prices and identifying possible scenarios.

They illustrate large ranges between the upper and lower estimates, commensurate with the wide ranges in expected future technology costs. The potential range of ETS prices predicted to be required in 2030 at average costs conditions to lead to the substitution of 'grey' hydrogen by low or zero-carbon hydrogen are as follows:

- green hydrogen based on utility-scale solar PV to substitute grey hydrogen (€75–170/tCO2),
- green hydrogen based on offshore wind farm (€135–225/tCO2),
- blue hydrogen (€55–145/tCO2)
- turquoise hydrogen (€0–80/tCO2).

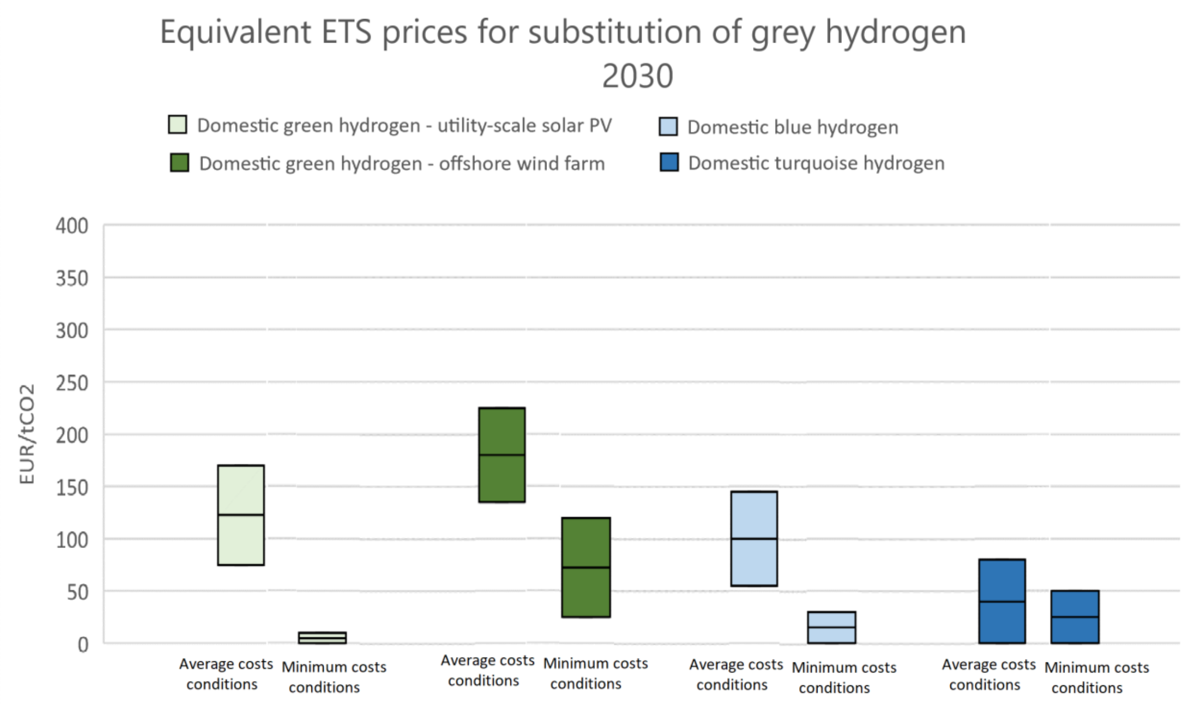
Using predicted lowest cost conditions the potential range of ETS prices predicted to be required in 2030 are as follows:

green hydrogen based on utility-scale solar PV to substitute grey hydrogen (€0–10/tCO2),

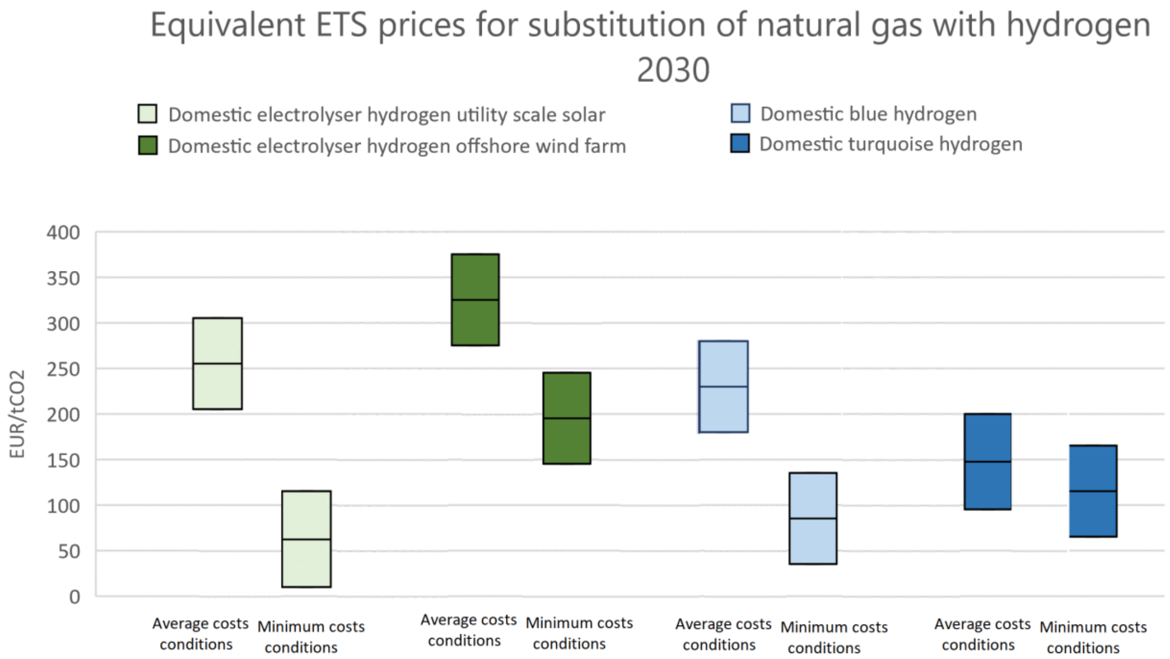
green hydrogen based on offshore wind farm (€25–120/tCO2),

blue hydrogen (€0–30/tCO2)

turquoise hydrogen (€0–50/tCO2) change significantly.



Researchers at the FSR have also drawn estimations of the future ETS prices needed to catalyse the replacement of natural gas by green, blue and turquoise hydrogen. These are mathematical calculations based on the average predicted cost of hydrogen (green, blue, and turquoise), minimum predicted costs and the abovementioned assumptions regarding natural gas/renewable electricity prices. [45]



They illustrate a number of important factors that will need to be monitored carefully and taken into account by the Commission and the Member States in determining the optimal support policies to kick-start the market.

Firstly, the ETS prices needed to catalyse penetration of low and renewable hydrogen into the 'grey' feedstock market are potentially significant, meaning that important subsidies may well be needed if the Commission's objective of replacing all grey hydrogen by low/zero-carbon hydrogen by 2030 is to be achieved. The ETS prices needed to result in low and zero-carbon hydrogen replacing fossil fuels as an energy source will in any event be very significant.

Secondly, commensurate with the technology cost options set out above, policies insisting that renewable hydrogen alone replaces the 10 MT of grey hydrogen used in the EU as a feedstock (fertilisers, methanol, steel…) will almost certainly require far greater production subsidies in the form of tenders than a technology-neutral approach given the uncertainties regarding future renewable electricity costs. The following numbers have been calculated by FSR researchers regarding the expected subsidies required to substitute 10 MT grey hydrogen with green, blue and turquoise hydrogen on one hand, and the subsidies required to lead green, blue or turquoise hydrogen to substitute 10% of the EU's current energy demand:

[45] A range of possible natural gas prices was considered (€3.24 – €23/MWh or €0.9 – €6.4/GJ). Similarly to the case of ETS equivalent prices for substitution of grey hydrogen, by considering a range of possible values we account for the relevant impact on costs from the uncertainty on future natural gas prices. This adds another layer of complexity, not examined in this study, related to identifying the main drivers behind natural gas prices and identifying possible scenarios.

Substitution of grey hydrogen demand (2030) at ‘consensus’/average costs conditions

- 7.1 – 15.0 Billion EUR (in the scenario of total substitution of grey hydrogen with green hydrogen of utility-scale solar PV sub-scenario at an ETS price of 75 – 170 EUR/tCO2);

- 12.4 – 20.3 Billion EUR (in the scenario of total substitution of grey hydrogen with green hydrogen of offshore wind farm sub-scenario at an ETS price of 135 – 225 EUR/tCO2);

- 4.5 – 11.5 Billion EUR (in the scenario of the total substitution of grey hydrogen with blue hydrogen at an ETS price of 55 - 145 EUR/tCO2);

- 0 – 5.9 Billion EUR (in the scenario of total substitution of grey hydrogen with turquoise hydrogen at an ETS price ranging from negative values to 80 EUR/tCO2)[46].

Substitution of grey hydrogen demand (2030) at lowest costs conditions

- 0 – 0.7 Billion EUR (in the scenario of total substitution of grey hydrogen with green hydrogen of utility-scale solar PV sub-scenario at an ETS price of 0 – 10 EUR/tCO2);
- 2.6 – 10.5 Billion EUR (in the scenario of total substitution of grey hydrogen with green hydrogen of offshore wind farm sub-scenario at an ETS prices of 25 - 120 EUR/tCO2);
- 0 – 3.0 Billion EUR (in the scenario of the total substitution of grey hydrogen with blue hydrogen at an ETS prices of 0 – 30 EUR/tCO2);

- 0 – 3.8 Billion EUR (in the scenario of total substitution of grey hydrogen with turquoise hydrogen at an ETS price ranging from negative values to 50 EUR/tCO2).

[46] Methane pyrolysis is currently at the pilot stage and is less technologically mature than the other two hydrogen technologies. Therefore, estimates regarding turquoise hydrogen can be considered less credible than for the other three hydrogen supply options.

Substitution of natural gas demand (2030) at ‘consensus’/average costs conditions

- 38.9 – 67.2 Billion EUR (in the scenario of substitution of natural gas combustion with green hydrogen of utility-scale solar PV sub-scenario at an ETS price of 145 – 250 EUR/tCO2);
- 73.9 – 100.5 Billion EUR (in the scenario of substitution of natural gas combustion with green hydrogen of offshore wind farm sub-scenario at an ETS price of 275 – 375 EUR/tCO2);
- 48.3 – 75.2 Billion EUR (in the scenario of the total substitution of natural gas combustion with blue hydrogen at an ETS price of 180 - 280 EUR/tCO2);
- 25.5 – 53.7 Billion EUR (in the scenario of total substitution of natural gas combustion with turquoise hydrogen at an ETS price of 95 – 200 EUR/tCO2).

Substitution of natural gas demand (2030) at lowest costs conditions

- 10.7 – 38.9 Billion EUR (in the scenario of substitution of natural gas combustion with green hydrogen of utility-scale solar PV sub-scenario at an ETS price of 40 – 145 EUR/tCO2);
- 38.9 – 65.4 Billion EUR (in the scenario of substitution of natural gas combustion with green hydrogen of offshore wind farm sub-scenario at an ETS price of 145 – 245 EUR/tCO2);
- 9.4 – 36.3 Billion EUR (in the scenario of the total substitution of natural gas combustion with blue hydrogen at an ETS price of 35 - 135 EUR/tCO2);
- 17.5 – 44.3 Billion EUR (in the scenario of total substitution of natural gas combustion with turquoise hydrogen at an ETS price of 65 – 165 EUR/tCO2).

As mentioned above, the lowest estimates for renewable hydrogen rely on the use of very cheap utility scale PV, and further study is required whether this will be available at the necessary scale required for EU hydrogen production.

It should be noted that these numbers in fact are likely to significantly underestimate the ETS prices needed to lead energy-intensive industries such as steel, cement and chemicals to substitute fossil fuels with low and zero-carbon hydrogen. First, many such industries use coal as a fossil fuel; these numbers are calculated on the basis of natural gas. Second, it only takes into account fuel switching costs, and not the costs of modifying the plant to use hydrogen instead of coal or natural gas, which are predicted to be very significant.

4. The lowering of technology costs through massive R&D and industrial demonstration support for all three low and zero-carbon hydrogen technologies should be considered to be the highest priority for the EU's hydrogen strategy. Support should be 'color-blind' at this stage of the technology and decarbonisation cycle.

A policy of first massive R&D and demonstration support and second production subsidies should be carefully considered by the EU.

These numbers demonstrate *inter alia* the level of uncertainty regarding the future of the EU's hydrogen market. It is not possible today to determine with accuracy the size of the low and zero-carbon hydrogen market in 2030 and 2040, yet alone 2050, nor the relative share of green, blue and turquoise. Additional uncertainty is included in the forecast of grey hydrogen prices, which like turquoise and blue hydrogen depends significantly on the uncertainty natural gas prices. On the basis of this data (again, underlining its illustrative nature), a logical approach would be to focus on blue and turquoise hydrogen until 2030 and then focus on zero-carbon turquoise and green hydrogen. However, any such approach needs to be balanced with the imperative of ensuring that zero-carbon hydrogen capacity develops quickly enough so that <u>all</u> relevant hydrogen demand can be supplied by zero-carbon sources by 2050.

In any event, these findings illustrate that under any scenario it is highly likely that green, blue and turquoise hydrogen will all be important in the energy transition, and that both green and turquoise hydrogen may be important in a fully decarbonised system.

Whilst blue hydrogen - CCS - may be seen as the 'poor relation' of the three 'colors' of hydrogen because it can never be truly zero carbon[47], it will in any event be important in the run-up to 2050. Not least, CCS will need to play a 'transition' role in reducing GHG in the medium term, capturing and storing emissions from fossil fuel-powered manufacturing plants (steel, cement, chemicals…) prior to the final decarbonisation step of converting these plants to hydrogen as a fuel source.

In addition, as explained above, turquoise hydrogen has considerable potential to be a very important technology to deliver zero-carbon hydrogen in the future, and may well be a cheaper zero-carbon option than green hydrogen. However, it is at a relatively early stage of technological development, which requires acceleration to be at an industrial scale by 2030, and thus also merits focus.

In such circumstances, it is self-evident that lowering the technology costs of all three technologies should be considered to be the highest priority for the EU's hydrogen strategy. The quicker that costs can be lowered through R&D and demonstration funding, the lower that production subsidies will be.

We suggest that the above indications give rise to two tentative conclusions.

<u>First</u>, that R&D and demonstration funding at a massive scale makes more sense over the next 5-10 years than massive hydrogen production subsidies (tenders, cfds..). ETS prices need to increase to avoid very high production subsidies, and the industry that will actually use hydrogen needs to be fully exposed to the ETS system (see below) before pursuing a subsidy-based approach. It remains to be seen whether the EU will be able to take this step in the near future, even with a carbon border adjustment mechanism/tax (see below).

Furthermore, low and zero-carbon hydrogen CAPEX costs are expected to decline significantly and rapidly with technological development given their current low technological maturity. Technological advances, rather than production economies of scale, will be the key element in reducing CAPEX costs.

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[47] It is not possible to capture all the CO2 with the steam methane reforming approach.

In the light of this, a policy of <u>first,</u> massive R&D and demonstration support and <u>second,</u> production subsidies (once production costs have declined and ETS prices have increased and are applicable to relevant industry), seems to make sense in terms of cost-effectiveness.

In addition, these estimations and observations strongly indicate that a policy of 'colour blindness' is required when designing Horizon/ETS Innovation Fund programs. Blue hydrogen (CCS) will be needed in the transition, and turquoise hydrogen, whilst currently at a low level of maturity, may well be a very important (and possibly the cheapest) zero-carbon option for the EU in the very long term and needs to be matured as quickly as possible. The current initial approach of the Commission, focusing on green hydrogen [48] is, of course, important in the light of any potential need to develop peak-shaving electrolysis capacity to balance increasing intermittent renewable electricity levels. However, moving forwards, a technology-neutral approach, which appears to be followed in the current ETS Innovation Fund call in principle, will be essential.

5. A policy of pursuing production subsidies at an early stage of the development of the hydrogen market may not therefore be the best use of public funds if the aim is to catalyse cost reductions.

A key element of the Commission's Hydrogen Strategy is to 'kick-start' the supply of low-carbon, and in particular renewable hydrogen, either through quotas (presumably on grey hydrogen consumers/energy-intensive industry) or via production subsidies. In this latter respect, the Commission's Hydrogen Strategy refers to 'contracts for difference' for hydrogen, granted almost exclusively through tenders by the Member States (using funds from the European Recovery Plan, Cohesion Funds or nationally financed subsidies).

Such a policy may have two distinct objectives. First, to lay the foundations for a future hydrogen market in terms of capacity - it is not possible to wait until the 'last-minute' (2040…) to completely transform a major part of the energy system given the goal of complete decarbonisation by 2050. Second, to reduce the cost of renewable and low-carbon hydrogen production.

There are parallels here to the EU's approach to renewable electricity in 2009. In order to drive down the cost of wind and PV the Commission focused to a certain extent on R&D activities ('technology push'). However, the EU dedicated a far greater share of available funding to providing massive subsidies supporting new RES-E capacity ('market pull') [49] in order to kick-start RES production. This had the explicit aim of catalysing renewable electricity installed capacity to provide a foundation for further later growth (*'it is impossible to wait until 2040 to start making the systemic change to ensure a decarbonised electricity system by 2050'*), but equally to lower RES-E costs by generating manufacturing economies of scale.

One could argue that the same approach should be followed with respect to low and zero-carbon hydrogen, providing immediate and massive subsidies for low-carbon and renewable hydrogen with the aim of reducing production cost. However, care should be taken before

[48] In the "A Hydrogen Strategy for a climate neutral Europe" (July 2020) COM(2020) 301 final, cumulative investments in renewable hydrogen in Europe by 2050 are estimated at EUR 180-470 billion, whereas only EUR 3-18 billion for low-carbon fossil-based hydrogen.

[49] - according to a Commission Report amounting to around €70 Bn per annum [11]

arguing that massive low and zero-carbon hydrogen production subsidies leading to manufacturing economies of scale are likely to lead to significantly lower hydrogen costs.

Whilst manufacturing economies of scale are important for low and renewable hydrogen, and plant costs can be expected to reduce significantly with standardisation and improved technology, it is reasonable to expect that a very significant part of these economies can be captured through ambitious R&D and demonstration funding. We will need hundreds of new hydrogen plants for the low and zero-carbon hydrogen market of the future, compared to the millions of PV panels and windmills required for the renewable electricity transition. Manufacturing economies of scale will therefore be less relevant than technology development in reducing future hydrogen costs, and it is questionable whether massive production subsidies are the right tool to catalyse them.

Furthermore, as mentioned above, renewable electricity is a high CAPEX/low OPEX energy vector. Lower CAPEX investment costs are determinative in the resultant electricity price. Hydrogen, on the other hand, is low CAPEX/high OPEX, meaning that reducing CAPEX will have a lesser effect in terms of cost reduction for hydrogen compared to renewable electricity. Massive production subsidies will not be likely to reduce OPEX costs for low and zero-carbon hydrogen.

In this light, it is important to consider carefully whether the use of massive public subsidies for low and zero-carbon hydrogen production at an early stage of market take-off can be a logical use of public funds if the objective is low and zero-carbon hydrogen cost reduction. Production subsidies during the early stages of market take-off may be justified for other reasons (preparing the market…), but the case for production subsidies as a cost-efficient tool for 'technology pull' appears questionable.

6. The Internal Energy Market, based on ETS prices and competition between green, blue and hydrogen turquoise hydrogen, ensuring that GHG content is reflected in pricing through objectively calculated lifecycle-based guarantees of origin, is likely to be the best manner to ensure the cost-effective development of the EU's future hydrogen market.

The principal legitimate objective of tenders/quotas would therefore appear to be to provide the foundations for the huge change needed by 2050, when zero-carbon hydrogen (and other zero-carbon molecules) will need to meet between 10 and 25% of the EU's energy requirements. As mentioned above, it is not reasonable to wait until the 'last-minute' to install the electrolysers/pyrolysis plants, to change end-user equipment (cement furnaces/steel smelters, HGVs, home heating systems…) and the transmission infrastructure required.

In determining how to do this however, a careful calculation needs to be undertaken regarding the speed with which the transformation is catalysed, particularly if one intends to use production subsidies (tenders/cfds) to bridge the gap between the ETS price and the 'strike price' to cause substitution.

On the assumption that the ETS is fully applied to the future low and zero-carbon hydrogen consuming industry (which is a significant assumption, see below), the later one waits to provide production subsides, the less subsidy required. This is because ETS prices will have increased, and the cost of producing the low and zero-carbon hydrogen will have reduced, due to successful R&D and demonstration investments. The numbers set out above illustrate that without significantly higher ETS prices than we see today, and the full application of the ETS to hydrogen consuming industry, the subsidies required to catalyse market entry and low and renewable hydrogen are likely to be very important.

Once again, we underline that given the large number of far from fully predictable variables that underpin such estimations, the predicted ETS prices required to catalyse substitution should be viewed as illustrative, rather than accurate predictions. What they do demonstrate however, is the need for a strongly fact-driven policy with respect to decisions on how quickly to move to hydrogen production subsidies, and the importance of enabling the use of the right 'colour' of hydrogen at the correct stage of the decarbonisation cycle.

Indeed, we would argue that these estimates, and their range and uncertainty, demonstrate that as far as possible the market should decide which form of hydrogen should be used at any given stage of the decarbonisation cycle, based on the ETS and where desired, 'color-blind' tenders for low and zero-carbon hydrogen production. Such an approach would be compatible with Internal Energy Market principles and the underlying objectives of energy sector integration. The market will decide more efficiently than regulatory decisions on how to balance the need to move towards zero-carbon options rather than low carbon options, as well as which is the best zero-carbon option (or combination of options) and wherever possible, this would appear to be the most cost-effective approach.

For example, the 2050 'cut-off point' when only zero-carbon hydrogen can be sold will have an effect on the green/blue/turquoise investment mix long before 2050 if the market is allowed to determine the hydrogen mix rather than regulatory quotas. No company will invest in CCS or other forms of hydrogen that is not zero-carbon in the mid to late decarbonisation cycle, unless offsetting can provide a zero-carbon product. As amortising such investments is likely to require a long time horizon, leaving this decision to the market will in any event lead to a *de facto* 'zero-carbon hydrogen only' investment requirement for example as early as 2035.

Discriminating at the start of the low and zero-carbon hydrogen market development against blue and turquoise hydrogen will effectively deprive the EU of cheap low carbon hydrogen between 2030-2050. This would lead to a more expensive energy transition than necessary, and reduce the penetration of low and zero-carbon hydrogen during the early phase of the market development. Such an approach may therefore have a net negative effect in terms of the speed of development of the low and zero-carbon hydrogen market and thus the speed and level of GHG reductions during the transition phase.

7. A key element to the development of a cost-effective future hydrogen system will be the existence of a hydrogen grid, which will be essential to lower the cost of hydrogen transportation, and prevent the emergence of entrenched monopoly positions.

The basic provisions of the Internal Gas Market (unbundling, TPA, tariff regulation) will need to apply to the future EU hydrogen grid.

Irrespective of the actual speed of the development of the future hydrogen market, it is absolutely clear that it will form a very significant part of the future EU energy system. Studies consistently find that the use of a network to transport hydrogen will be far cheaper than alternatives (road, rail..).

The Commission correctly identifies in its Hydrogen Strategy that the initial stages of the development of the EU's low and zero-carbon hydrogen market will be through industrial 'clusters', where demand for hydrogen as a feedstock, and then as an energy source for energy-intensive industry, are centred.

A hydrogen grid therefore needs to be developed 'just in time' to carry the huge increase in hydrogen compared to today. It is not possible to accurately predict the topography and scale of the hydrogen grid that will be needed in 2050. Much will depend on technological development and the relative competitiveness of the different forms of zero-carbon hydrogen, the competitiveness of zero-carbon hydrogen vs renewable electricity, and the ability to make the structural changes needed so that renewable electricity is able to meet all of the technically rational demand that it is capable of serving (e.g. installing heat pumps..).

However, it is clear for the hydrogen lobby that in the future we will need what is commonly referred to as a European Hydrogen Backbone, a network connecting the principal demand 'clusters', as well as any transport demand. Irrespective of the speed of development of the market, this will be required in the coming years. The Commission's Hydrogen Strategy points out that repurposing existing gas pipelines will be the most cost-effective basis of the future grid.

Thus, this development of the Hydrogen Backbone represents a 'no-risk' first step development of the network.

However, the planning challenges that will be faced, both grid (which pipelines to repurpose/new infrastructure needed), operational (ensuring efficient technical interaction between the new hydrogen network and the existing natural gas system), and environmental, should not be underestimated, nor should be the time needed to actually construct the new Backbone.

Thus, the process of planning the grid should start immediately, and its development and construction should be considered to be a priority. The grid will need to be built 'future-proofed', initial capacity will need to be greater than demand, inherent in a rapidly expanding market. The European Recovery Fund is an ideal instrument to isolate consumers from the immediate consequences of the future-proofing, but the Fund is time-limited as an instrument; another reason for urgency.

If a Backbone is not in place by the time that demand for low and zero-carbon emerges and accelerates, we can expect existing incumbents that currently operate local hydrogen supply networks to solidify and expand their local dominant or monopoly positions. The future EU hydrogen market must be characterised by effective competition and liquidity. Entrenched dominance and monopoly are very difficult to regulate under the competition rules and based on experience, impossible to break up. Thus, the aim must be to avoid such market structures from the outset. For this reason, the foundations of the Internal Energy Market for networks, unbundling, TPA and regulated prices will need to apply to the EU's future hydrogen network and will no doubt figure the Commission's legislative package scheduled for 2021.

8. Considerable care is required before imposing low or zero-carbon hydrogen quotas on actual/potential consuming hydrogen industry. It will be challenging to expose these industries to the ETS even with a carbon border tax.

Judging the speed of introduction of production subsidies (requiring high subsidies) and/or consumption quotas (strong problems of competitiveness and potential carbon leakage) will therefore require a careful balance between (i) ensuring that the EU's energy system evolves quickly enough to ensure that the necessary structural changes are in place by 2050 to guarantee a zero-carbon energy system by that date and (ii) increased ETS prices over time and the introduction of effective GHG policies by the EU's principal competitors.

Another important factor regarding the timing and pace of planned low and zero-carbon hydrogen penetration into the market results from the risk of carbon leakage. The principal industries where low and zero-carbon hydrogen will be used at scale are fertilizers, methanol and steel as a feedstock, and the high-heat energy-intensive industry as an energy source (cement, steel). These are all 'carbon leakage' sectors (and for good reason, energy costs typically represent 20-40% of the production costs of steel and cement), and are therefore completely or partially exempt from the ETS.

The Commission has announced its intention to expand the scope of the ETS and to combine this with a 'Carbon Border Adjustment Mechanism' or carbon border tax. It is far from obvious whether, at least initially, this will apply to, for example, steel. Given (i) the importance of energy costs for such industries, (ii) the political sensitivity of the issue, and (iii) the fact that such an approach inevitably has the consequence that EU consumers of the product (steel) pay more for the product than those situated abroad, this will have negative knock-on effects on the competitiveness of downstream EU customers(e.g. cars…), it will be difficult for the EU to bring the potential industrial customers of low and zero-carbon hydrogen into the ETS in the short to medium term.

Thus, any quotas requiring such companies to use low and zero-carbon hydrogen (one of the options identified in the Commission's Hydrogen Strategy) would inevitably challenge their international competitiveness, and thus be politically unlikely to find support. Indeed, it makes very little sense to adopt decarbonisation policies that will lead EU energy-intensive industry to relocate to countries that to not impose climate-related costs and export the finished product to the EU. Climate change is a global challenge, and the net effect would simply be to increase, not reduce, global GHG whilst losing jobs within the EU.

It may well be possible to bring these industries into the ETS in the future if our major competitors adopt equivalent measures. We certainly hope so, but this is currently unpredictable.

The EU therefore has a difficult balance to make when deciding when and how to adopt specific subsidies for the production of low and zero-carbon hydrogen, but implementing quotas on industry or, for example, minimum blending obligations into natural gas, appears unlikely to be a cost-effective approach for the EU that will protect the interests of citizens and its competitiveness.

Ambitious targets for low and zero-carbon hydrogen to be met through production subsidies fully compensating industrial hydrogen consumers for the cost of using low and zero-carbon hydrogen at an early stage of the decarbonisation cycle will be very expensive and require increased (transparent or hidden) taxes. Waiting further down the decarbonisation cycle will result in lower costs and a more cost-effective decarbonisation policy, but must be balanced with the need to ensure that the systemic changes needed to fully decarbonise the EU's energy system by 2050 remain practically achievable. This will therefore be a difficult balance to make, and will need to (i) reflect the imperative that the market is sufficiently developed to ensure full decarbonisation by 2050, and (ii) take into account the extent to which it proves possible to bring the future low and zero-carbon hydrogen consuming industry within the scope of the ETS in the short-to-medium term, combined with a carbon border adjustment mechanism.

This is a very difficult balance, and the purpose of this study is not to suggest a decisive answer, nor to propose a specific trajectory. It does aim, however, to illustrate the importance of taking an evidence-based and thoroughly considered approach to ensure a policy and trajectory that will balance the imperative of achieving the Green Deal decarbonisation target, and, at the same time protect the interest of EU citizens in terms of competitive energy prices, jobs and growth.

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1. The EU's energy policy objectives: a long and dynamic journey

The European Union has its origins in an energy-related treaty: the 1951 European Coal and Steel Community (ECSC). The ECSC had two main objectives: 1) to prevent future clashes among European countries by monitoring the production and trade of coal and steel; and 2) to organize the coal market, Europe's main fuel in the 1950s (Buchan and Keay, 2015)[50]. During the decades after the ECSC treaty, coal lost its dominance to oil and gas and consequently the treaty became less and less relevant to Europe's energy needs. The ECSC treaty finally expired in 2002, but it had marked the beginning of Europe's long experience of shared energy policies and objectives. This journey has also been a dynamic one as the establishment of different energy policies has mostly been an outcome of various concerns at a given moment in time. In the years after the ECSC treaty, coal production in Europe started to decline and foreign oil dependency increased. Simultaneously, nuclear power started to substitute coal and oil and in 1957, the European Atomic Energy Community (Euratom) was established to organize economic, operational and safety issues related to nuclear power in Europe. The Euratom treaty is still active today and provides services to Member States (note: only 14 Member States use nuclear power for generating electricity). Both the ECSC and Euratom were not energy strategies, *per se*, but, rather, political endeavours to ensure economic security across Europe. They were also specific to a single type of fuel rather than covering a wide range of energy vectors.

In the next two decades (the 1960s and 1970s) there were a few attempts, at the European-level, to establish a common energy strategy. But either they were ignored by Member States or they were overtaken by other issues. In 1968, in an attempt to improve competition in national gas and electricity markets, the Commission issued the "First guidelines for a Community energy policy", stressing the importance of moving away from the existing national markets and policies for having a fully-integrated energy sector in Europe, which could ensure supply security (Buchan and Keay, 2015). The idea of a more integrated energy market came up again in 1972 in the Commission's "Necessary progress in Community Energy". This document discussed, for the very first time, reducing energy consumption (to reduce high-price oil imports rather than for efficiency) and environmental protection.[51] However, with the oil crises of the 1970s, these topics were overlooked in energy policy objectives to make room for a more urgent issue: security of supply. In 1974 and after the first oil shock, the Commission issued another communication on the European Community's energy strategy focusing on energy security. Security of supply remained as the main energy policy concern through the 1970s and, for a time, after the second oil crisis of 1979-1980.

From the mid 1980s, oil price started to fall and previous concerns regarding energy security fell to some degree, too. This allowed the Commission and Member States to take other issues into account. During this time, debates started around establishing a single European market and, in 1986, the Single European Act was passed. Initially, the Act did not include the energy sector but in 1988, the Commission issued guidelines for the opening of cross-border trade and

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[50] David Buchan and Malcolm Keay, "Europe's long energy journey: towards and Energy Union?" published by the Oxford University Press for the Oxford Institute of Energy Studies, 2015.
[51] Environmental concerns which were introduced in the Commission's 1972 communication were mostly related to air pollution due to car emissions and water contamination from energy (Buchan and Keay, 2015), rather than climate change issues.

competition, as well as for freeing up energy infrastructures and for ending monopolies in the energy sector under a single European energy market. The liberalization and privatization process of the European energy sector continued through the 1990s with several import and export monopolies being abolished by 2000.

Meanwhile, establishing a single internal energy market has remained one of the main energy objectives in the EU. It has been reflected in three energy legislative packages published in 1996/8, 2003 and 2009. To accelerate cooperation among EU energy regulators, the third package also put down the foundations for the establishment of two EU entities: ACER and ENTSO-E.

With security of supply concerns vanishing from view in the late 1980s and during the 1990s, alongside the establishment of the internal market, it was climate change that captured the imagination of European policymakers. Climate change also started to become an international concern and, with strong support from the EU, two international agreements were signed during the 1990s: the UN Framework Convention on Climate Change in 1992; and the Kyoto Protocol in 1997. The core of these agreements and a number of later EU treaties, was climate change and associated efforts to reduce greenhouse gas emissions. However, though the energy sector has always been a major contributor of GHG emissions, it was only in 2007, when the Treaty of Lisbon was agreed upon by EU Member States, that the role of the energy sector in the fight against climate change was emphasized. Article 194 of this treaty addressed different aspects of the EU's energy sector and the necessity of setting specific energy policies and legislation. This set the stage for the introduction of a series of reforms including a third package of internal energy market legislation (the 2009 package mentioned above) and an overhaul of the European Emissions Trading System (EU ETS) (which began in 2005). In addition, for the first time a number of EU and national-level energy and climate targets, to be reached by 2020, were proposed, together with a set of tools and pieces of legislation to facilitate their realisation. These newly-established targets were designed to respond to the energy trilemma: sustainability, energy security and competitiveness. The Council and the European Parliament approved these targets and tools in, respectively, 2007 and 2008. The 2020 targets included:

- GHG emissions cut by 20% relative to 1990 levels;
- an increase in the share of renewable sources to 20% of final energy consumption;
- A 20% improvement in energy efficiency relative to projected energy use levels for 2020.

The EU has been successful in meeting its 2020 climate targets with a 23% reduction in GHG emissions in 2018, therefore fulfilling its sustainability goal. It is also close to reaching its 20% share of renewables and 20% energy efficiency targets.

By the mid 2010s, it was clear to EU policymakers that a new plan that included new energy and climate targets was required post 2020. This could be attributed to the fact that: a) a fully internal energy market had not been achieved by the mid 2010s; b) in the aftermath of the 2008-9 economic crisis, carbon prices under the EU ETS was continuingly decreasing; c) the cost of subsidizing renewable energy sources was increasing; and d) the investment levels in energy infrastructure were not satisfactory (Buchan and Keay, 2015). Furthermore, the Russia-Ukraine conflict of 2014 once again brought up energy security as a concern. Meanwhile, with strong support from EU Member States, the Paris Agreement was signed in 2015, adding to the EU's agenda an international commitment to contribute to keeping the global temperature rise below 2ºC for 2050. In response to these events, the Commission proposed a new energy strategy for the EU in 2015: the Energy Union. The Energy Union was considered to be the most comprehensive EU-wide energy strategy since the ECSC. The policy framework under the Energy Union expanded from tackling the three energy challenges, which was the aim of the 2020 strategy, to covering five energy and climate dimensions focusing on: internal energy market; security of supply; decarbonisation; competitiveness; and energy efficiency. As a result, taking into account both the objectives of the Energy Union and the ambitious goal of the Paris Agreement, a new set of targets to be reached by 2030, together with a set of legislative and non-legislative acts were proposed by the European Commission. This was termed the Clean Energy for all Europeans Package (CEP). The targets that were proposed in the package went through several trialogues between the Commission, the Council and the Parliament and, finally, in 2018, the European Council and the European Parliament approved the following targets:

- GHG emissions reduction by at least 40% relative to 1990;
- Increased share of renewable sources in final energy consumption to 32%;
- Improved energy efficiency by 32.5% relative to a business-as-usual scenario.

The binding level of GHG emissions and the share of RES targets for 2020 and 2030 differ: while the 2020 GHG emissions and share of RES targets were binding at member-state level, those of 2030 are only binding at the EU-level. This very important distinction raises the question of the commitment of Member States to implementing adequate individual policies which would result in the collective achievement of climate and energy goals by 2030. This led to the establishment of a new instrument for facilitating and organising the planning, reporting and monitoring progress of Member States: the Energy Union Governance Regulation.

The importance of climate objectives in EU policies was reflected in the EU's announcement of its intention to become a low carbon economy by 2050: first in "A Roadmap for Moving to a Competitive Low Carbon Economy" in 2011; and, finally, in "A Clean Planet for All" in 2018. To achieve this ambitious target a long-term and more comprehensive action plan was required. Besides the energy sector, the plan should also have covered other economic sectors and policy areas such as agriculture, the circular economy, forests and lands, etc. In December 2019, the newly elected Von der Leyen Commission presented the European Green Deal: a proposal of 50 action plans, to be implemented during the next five years, to facilitate the transition towards carbon neutrality. Decarbonisation, innovation and R&D in the energy sector will remain as critical as before and will be actively promoted under the Green Deal. However, the proposed policy framework under the Green Deal covers seven other policy areas as well, namely: biodiversity, food system, industry, buildings renovation, mobility, pollution elimination and climate action. While the proposed action plans under the Green Deal still need to be approved by EU legislatures (namely the European Council and the Parliament), their implementation might be affected by the Covid-19 pandemic.

As can be seen, the development of energy policies, from the ECSC to the Green Deal, has been a dynamic process. However, the relevant EU institutions (the Council and the

Parliament) have proved to have a forward-looking and consistent approach in their adoption of energy objectives and policies. What comes next in this journey will depend on many factors such as geopolitical conditions and how fast specific/new technologies can be developed to overcome climate change.

2. The first stage of the EU's Energy transformation: the 20-20-20 targets

2.1 Introduction

The EU's 2020 energy and climate strategy, known as "An Energy Policy for Europe", became functional in 2009. The main focus of the strategy was an energy trilemma: sustainability, the security of supply and competitiveness. Long-term policies were established to ensure the fulfilment of targets. At the time that the EU's 2020 energy strategy was established, 80% of all greenhouse gas emissions in Europe were linked to the energy sector, and the existing policies seemed insufficient for ensuring a more sustainable path towards the reduction of CO_2 emissions. Increasing energy demand, together with the growing dependency of the EU on imported gas and oil, brought the issue of security of energy supply to a head. The establishment of the Internal Energy Market still needed to be pushed to ensure competitive energy prices for EU citizens and further investments were required to secure the EU's global leadership in renewable technologies. All these challenges prompted EU's legislators to respond by setting, for the first time, specific targets to be reached by 2020 and to introduce a number of instruments to help reaching these targets. In this chapter, we review these targets and instruments. Moreover, we present the EU's and its Member States progress towards meeting the 2020 targets and we study whether some important concerns such as energy security have been affected by EU's 2020 energy and climate strategy.

2.2 Outline of the policy

2.2.1. Targets

In a nutshell, the 2020 energy and climate framework has three unilateral targets, known as the 202020 targets, and a set of instruments to help reach these targets by 2020. These targets include:

- A 20% reduction target in GHG emissions by 2020 compared to 1990;
- A 20% increase in renewables share in the EU's energy consumption and a 10% increase in renewables in the transport sector;
- A 20% energy consumption reduction goal to ensure energy efficiency is improved upon compared to 2007.

2.2.2. GHG emissions reduction under the EU ETS and the Effort Sharing Decision

The EU Emissions Trading System (EU ETS), in force since 2005, continued to be an important tool for reducing greenhouse gas emissions under the 2020 climate and energy framework. It covers 45% of GHG emissions in the EU with more than 12,000 installations in energy-intensive sectors and industries. Overall emissions by sectors which are covered by this scheme should be reduced by 21% in 2020 compared to 2005. In 2013, EU ETS was revised, and the third phase of the program started (from 2013 to 2020). In this phase, the previous national caps on emissions from ETS sectors were replaced by a single EU-level cap, and an auctioning method was used to allocate allowances. As for non-ETS sectors such as transport, agriculture and buildings, while an overall 10% reduction goal was set at the EU-level to be achieved by 2020, the binding annual sub-targets (known as annual emission allocations, AEAs) for different sectors were set nationally under the Effort Sharing Decision.

2.2.3 Energy efficiency actions

Improving energy efficiency is the most cost-effective way to reduce GHG emissions, while reducing energy dependency and ensuring security of supply. To reduce the overall energy consumption of the EU, the Energy Efficiency Action Plan (EEAP) was established in 2006 under the Energy Services Directive (2006/32/EC)[52], obliging Member States to set individual national targets and to present their plans to reach these targets. The EEAP planned to annually reduce 780 million tonnes of CO_2, while saving €100bn (EU DOC). In 2012, the Energy Efficiency Directive 2012/27/EU[53] was introduced by the EU replacing the Energy Services Directive. The new Directive, as before, required Member States to set their individual national targets but to provide three-year National Energy Efficiency Action Plans (NEEAPs). In addition, Member States were required to present their annual progress reports to the Commission. The 2012 Directive aimed at limiting final energy consumption to 1086 Mtoe and primary energy consumption to 1483 Mtoe in 2020. In both EEAP and NEEAP the national targets were not binding, but each Member State was required: to plan for more efficient heating and cooling systems; to improve the energy efficiency of existing buildings; to encourage the use of more efficient products through labelling; and to support production and the usage of more efficient means of transport.

2.2.4 Development of new infrastructures

Much of the EU's existing electricity and gas infrastructure will need extensive investments to ensure that they remain responsive to EU's energy needs. Developing new infrastructure such as new storage capacities, new transmission networks and new interconnection capacities, will strengthen the internal market by facilitating cross-border trade. It will also play a role in integrating an increased share of RES, which, in turn, will contribute to emissions reduction. At the same time, a well-connected energy network across the EU might reduce energy supply uncertainties. The 2020 framework, in fact, also includes a 10% interconnection target to be reached by 2020. In addition, the Priority Interconnection Plan was established to identify and to prioritize the most critical projects to be financed and implemented across the EU through the Trans-European Networks for Energy (TEN-E)[54].

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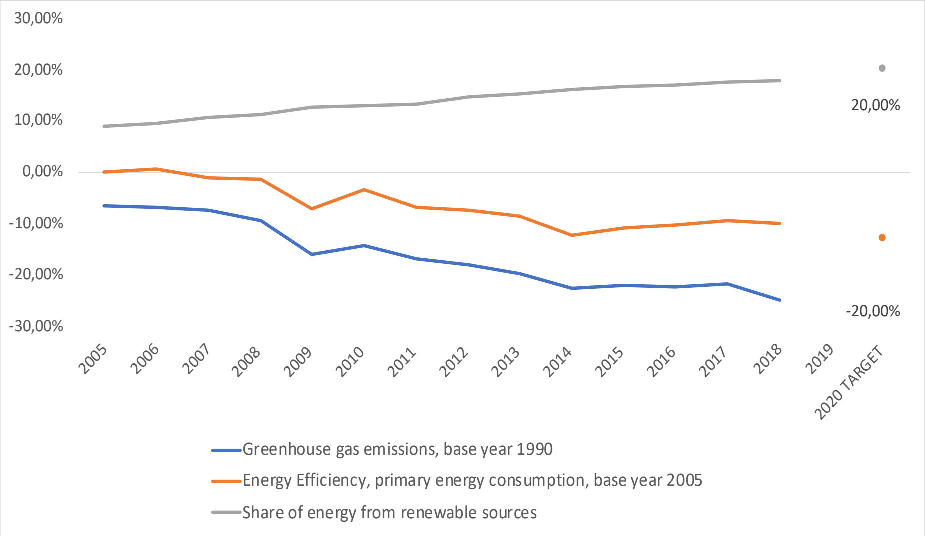
[52] Accessible at: https://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX:32006L0032
[53] Accessible at: https://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1399375464230&uri=CELEX:32012L0027
[54] More information at: https://ec.europa.eu/energy/topics/infrastructure/trans-european-networks-energy_en#:~:text=The%20Trans%2DEuropean%20Networks%20for,energy%20infrastructure%20of%20EU%20countries.&text=The%20EU%20helps%20countries%20in,funding%20for%20new%20energy%20infrastructure.

2.3 Results in terms of achieving targets

In this section, we provide a closer look at how the EU has progressed towards the 202020 targets and we explore whether the suggested/implemented policies have been successful in stimulating necessary actions in this regard.
A review of the current status of Europe's progress towards the 2020 targets shows that the EU is close to meeting these goals. The GHG emissions reduction target was already met in 2018, with emissions being 23% lower than 1990 (3% more than the 2020 target). However, RES share (2% behind in 2018) and energy efficiency targets (5% behind in 2018) have still not been met. Figure 2.1 shows how the EU has progressed, since 2005, towards 2020 targets.

Figure 2.1. Overall Progress at the EU level towards the 2020 targets from 2005 to 2018.



Data Source: European Environmental Agency (EEA) (2020).[55]

In early 2020, it seemed that Member States needed to intensify their efforts to meet these targets by end of the year 2020, especially for the energy efficiency target. However, with the emergence of the COVID-19 pandemic in the first quarter of 2020 and the suspension of most economic activities, these measures are probably affected as well. In particular, the GHG emissions measures will be much lower due to fewer emissions from the transport, aviation and carbon-intensive industries. But improved energy efficiency measure can also be expected. Nonetheless, even if the 2020 energy efficiency target is reached by the end of 2020, it will be due to these special circumstances and not to any special efforts made by Member States.

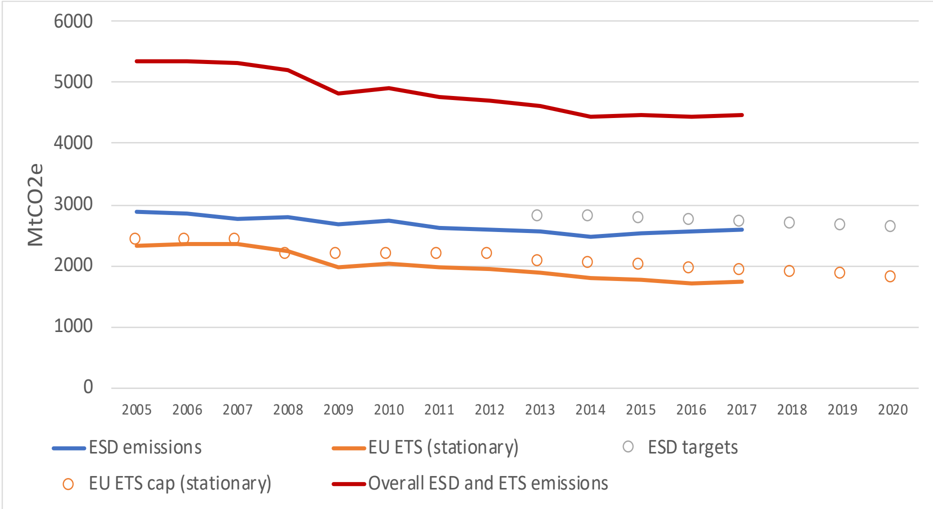
2.3.1 GHG emissions reduction

The greenhouse gas emissions reduction for 2020 can be explored under the European Emissions Trading System (EU ETS) (phases 1, 2 and 3 from 2005 to 2020) and the Effort Sharing Decision (ESD) (for the 2013-2020 period). Both at the EU and national levels, progress in reducing GHG emissions is considered to be on track for the EU's 2020 climate

[55] https://www.eea.europa.eu/themes/climate/trends-and-projections-in-europe/trends-and-projections-in-europe-2017/overall-progress-towards-the-european.

and energy targets. Figure 2.2 presents how greenhouse gas emissions has evolved under the EU ETS and the ESD at the EU level.

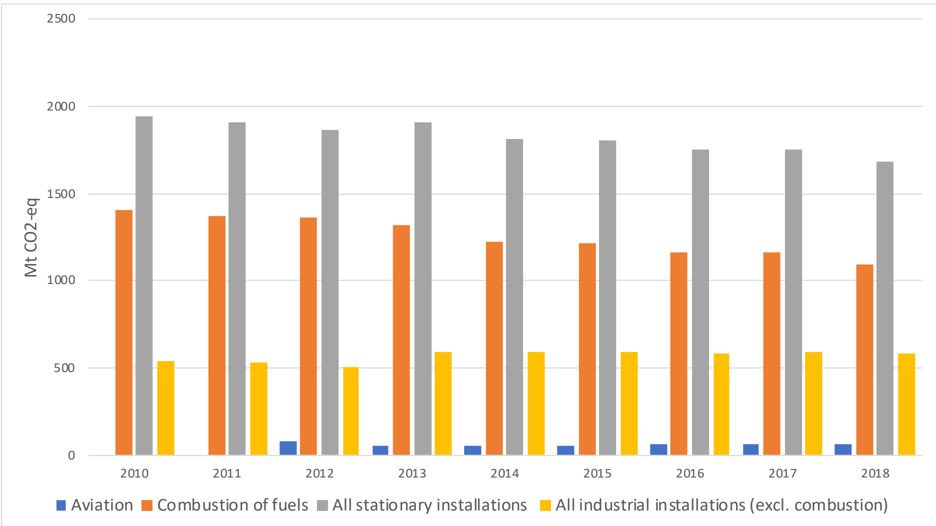
Figure 2.2. The overall GHG reduction under EU ETS and ESD.



Data Source: EEA and DG Energy (2020).

The sectors which are covered by the EU ETS are mostly energy and carbon-intensive such as the steel and glass industries and the power generation sector (combustion of fuels). The aviation sector was added to the EU ETS in 2012. Figure 2.3 shows the GHG emissions under the EU ETS for the 2010-2018 period. For all of the sectors covered, a decrease is observable during this period.

Figure 2.3. EU ETS by sector.

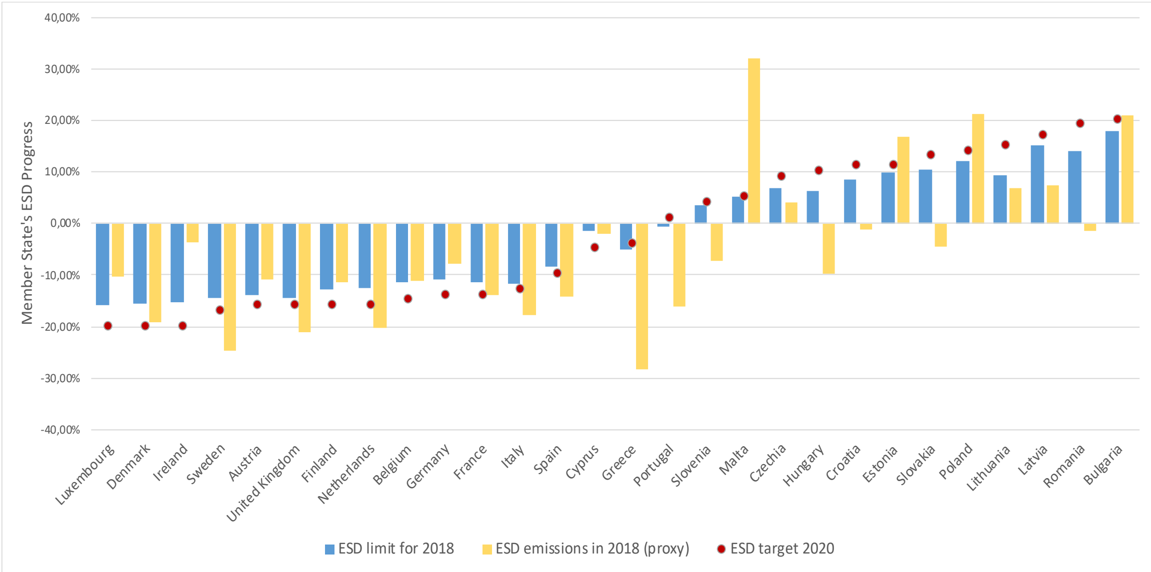


Data Source: EEA (2020).

Figure 2.4., on the other hand, compares Member States with respect to their progress towards reaching their GHG emissions reduction target in non-ETS sectors (covered by the ESD). In 2018, slightly more than half of Member States (17 Member States) had already achieved their

2020 ESD emissions reduction target. Except for a few countries including Malta, Poland and Estonia, all Member States are on track to meet their ESD commitments by the end of 2020.

Figure 2.4. GHG emissions under the ESD scheme by Member States.



Data Source: EEA (2020).

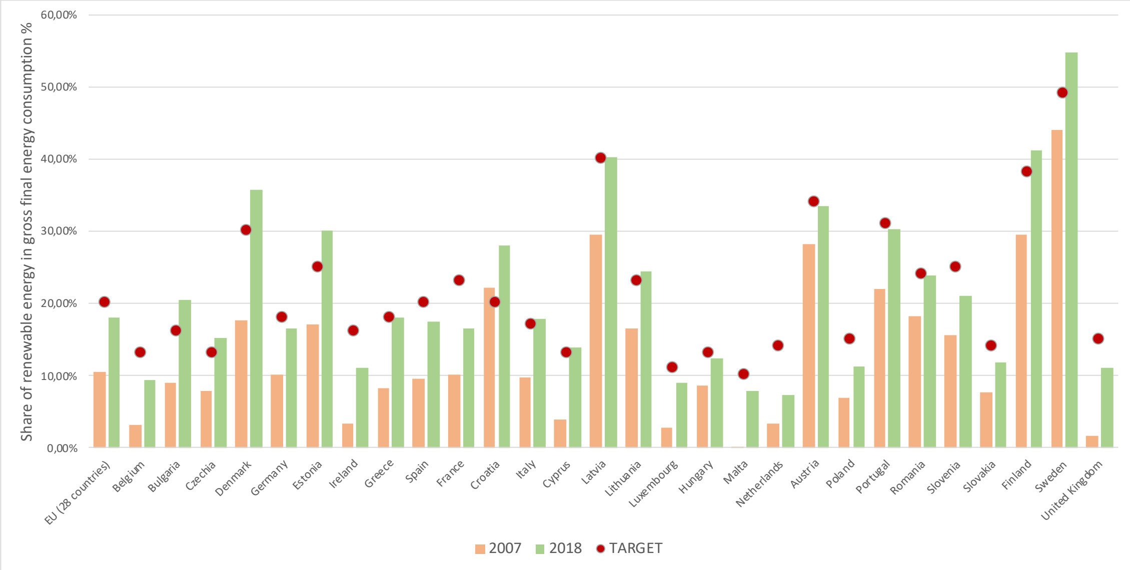
2.3.2 Renewable energy

The Renewable Energy Directive (2009/28/EC)[56] was established in 2009 as an overall policy to boost the adoption of renewable sources in the EU. To collectively reach the EU level a 20% target in RES share in total energy consumption, the Directive set individual national targets for the 28 Member States to be reached by 2020. In addition, it stated that at least 10% of transport fuels in all Member States should come from RES. To this end, the Renewable Directive also provided a set of provisions, for instance on guarantees of origin or RES grid access priority. It introduced and defined, too, support mechanisms which were to be adopted by Member States to promote energy production from renewable sources.

In this section we present the success levels of the EU and Member States in achieving their RES targets. Figure 2.5 illustrates RES share in gross final energy consumption of the EU and its 28 Member States (including the UK before it left the EU). It includes the starting measures in 2007 and the last available data in 2018 with a comparison to the 2020 target. In 2018, with an 18% share of RES, the EU is slightly falling short of its 2020 20% target. 16 Member States are either at or above their targets while other members should add to their efforts to integrate more renewables into their energy mix.

[56] Accessible at: https://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX%3A32009L0028

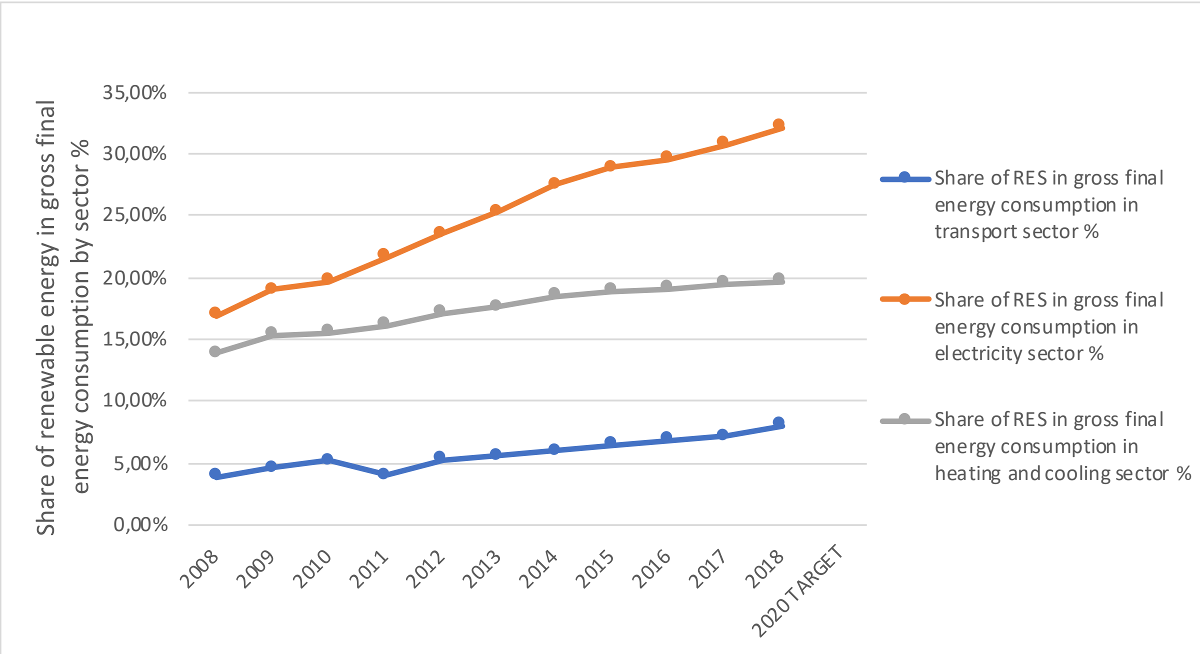
Figure 2.5. Share of renewable energy in gross final energy consumption %.



Data Source: Eurostat.

The EU has also committed to increasing the RES share in the transport sector by10%. Figure 2.6 presents how shares of renewables in gross final energy consumption has increased in the heating and cooling, the electricity and transport sectors. The available data until 2018 shows that, in the electricity sector, 31% of total energy consumption is supplied by renewable sources while this measure is 20% in the heating and cooling sector. Although these two sectors have performed well, the transport sector still falls behind its 10% RES integration, with 8% of final energy consumption being provided by renewables in 2018.

Figure 2.6. Share of renewable energy in gross final energy consumption by sector %.



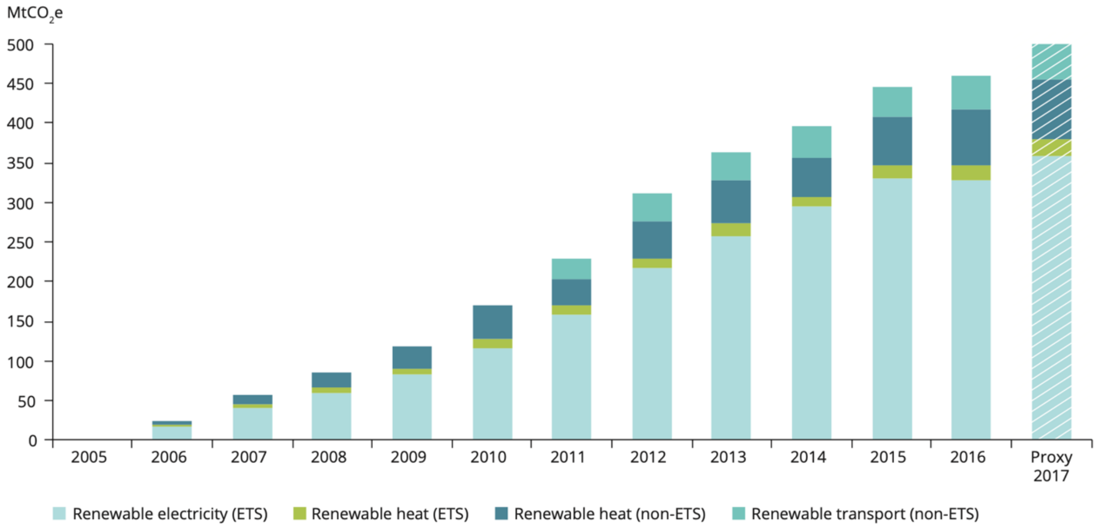
Data Source: Eurostat.

As mentioned above, a number of measures including the definition of support mechanisms which Member States could use to promote the adoption of RES were proposed in the 2009 Renewable Energy Directive. Trinomics (2018)[57] evaluates how the total of financial supports, allocated across the EU to promote electricity generation from renewable energy sources, has increased since 2008, jumping from €25bn in that year to €75bn in 2016. The increase in RES share in the electricity sector, from 17% in 2008 to 30% in 2016, which has been previously shown in Figure 2.6, can be attributed to this significant increase in support allocation.

Financial supports include subsidies in different forms, such as feed-in or premium tariffs, as well as supports with regards to RES integration, including network reinforcements and capacity mechanisms. While, the allocation of financial supports could, apparently, contribute to RES adoption, debates around the issues, suggest that these supports were costly. This was true especially in the first three years where they doubled after the introduction of subsidies, in particular the feed-in tariffs. These concerns eventually led to the replacement of feed-in tariffs with other mechanisms in many Member States. Nonetheless, it would be useful to understand whether these costly supports have also contributed to climate targets and to a reduction of GHG emissions. Figure 2.7, prepared by the European Environment Agency (EEA, 2018)[58], shows the estimated gross reduction in GHG emissions due to increased renewable energy consumption from 2006 to 2016. As seen in this figure, the annual reduction in GHG emissions at the EU level due to consumption of renewable energy has increased significantly. In fact, in 2006 it stood at 95 $MtCO_2$ and in 2016 at 464 $MtCO_2$. While, as mentioned above, financial supports to facilitate the integration of renewable electricity (RES-E) has increased substantially from €25bn in 2008 to €75bn in 2016. In the same period, GHG emissions which have been avoided due to integration of RES-E have also increased from 65 $MtCO_2$ in 2008 to 328 $MtCO_2$ in 2016 (71 % of all gross reduction in GHG emissions)[59]. Taking these measures into account, we estimate that the subsidy cost for avoided GHG emissions has decreased from approximately 385 €/tCO_2 in 2008 to 229 €/tCO_2 in 2016.

[57] "Study on Energy Prices, Costs and Subsidies and their Impact on Industry and Households" prepared by Trinomics for the European Commission – DG Energy, November 2018.
[58] "Renewable energy in Europe: Recent growth and knock-on effects" by European Environment Agency, 2018.
[59] According to EEA (2018), in the same period GHG emission reduction due to integration of RES-H&C and biofuels in transport account for 90 $MtCO_2$ (20% of all gross reduction in GHG emissions) and 42 $MtCO_2$ (9% of total gross reduction in GHG emissions) respectively. Thus, RES-E is a major contributor in reducing GHG emissions.

Figure 2.7. Estimated gross reduction in GHG emissions in the EU due to RES integration.

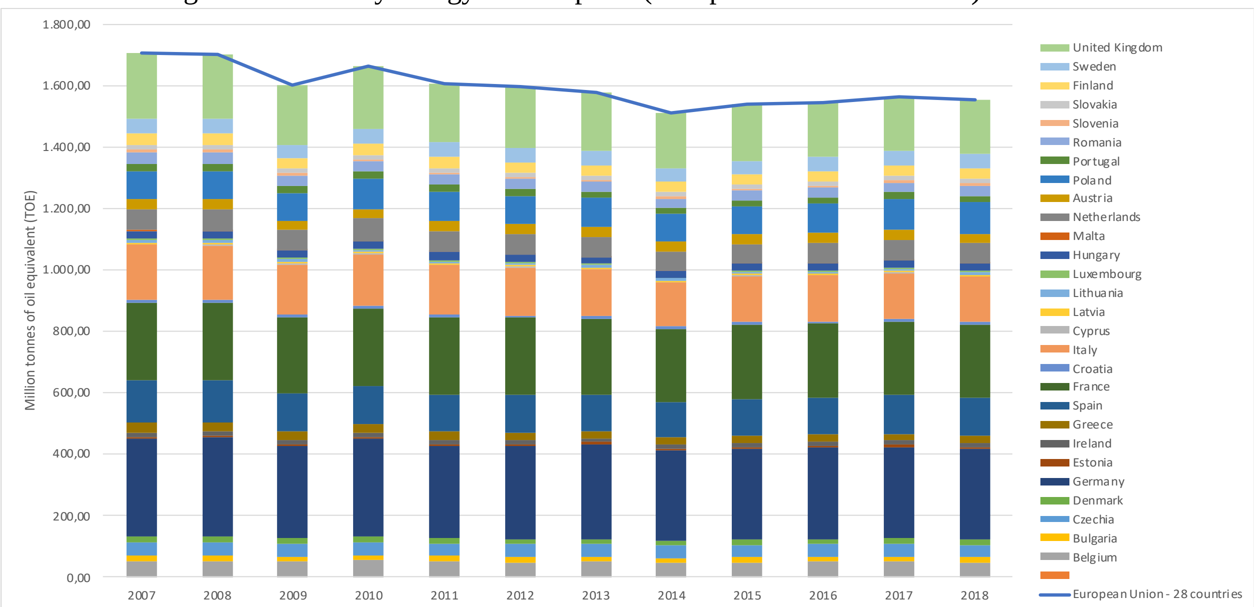


Source: EEA (2018).

2.3.3 Energy efficiency

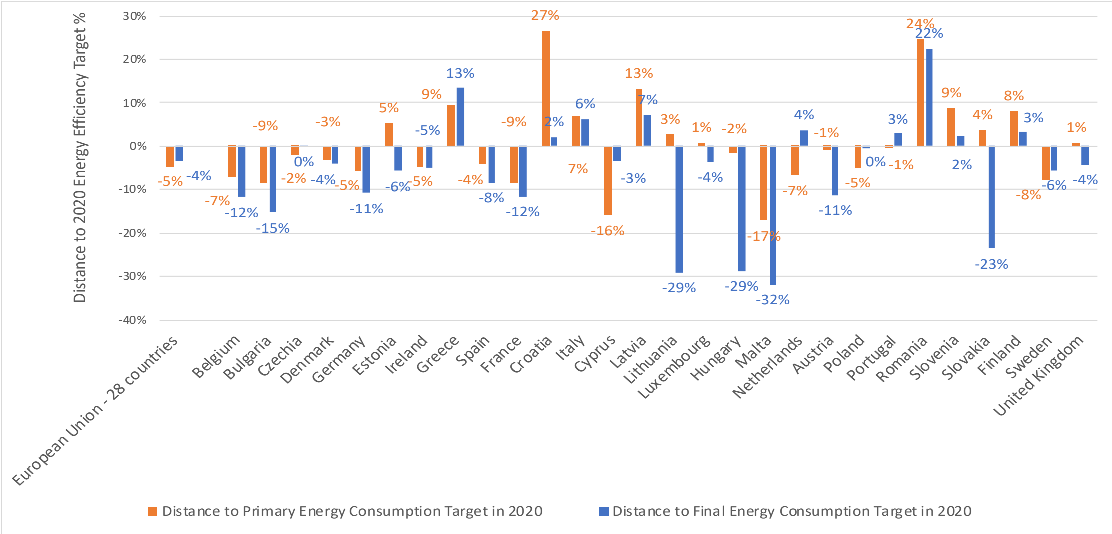
The 2020 target was to reduce energy consumption by 20% compared to 2007 levels. Figure 2.8 demonstrates how energy consumption has changed in the EU and Member States since 2007 and Figure 2.9 shows the progress of each member state in 2018 against the energy efficiency target that is indicated by their national energy efficiency action plan (NEEAP). As of 2018, the EU is 5% behind its efficiency goal in 2020 and only a few Member States have already reached their targets.

Figure 2.8. Primary energy consumption (Europe and Member States).



Data Source: Eurostat.

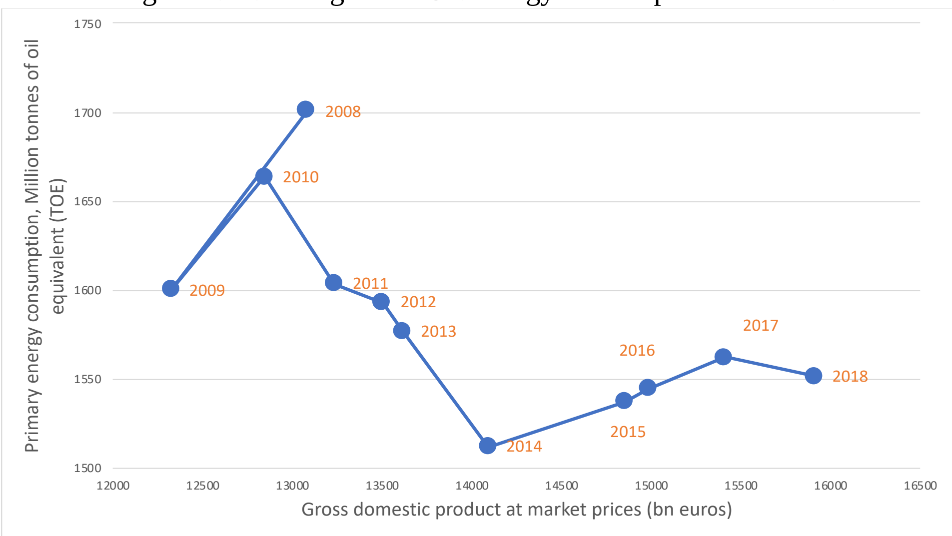
Figure 2.9. Distance to the 2020 Energy Efficiency Target %.



Data Source: Eurostat.

The 2008-2009 financial crisis significantly affected Gross Domestic Product (GDP) across the EU and as a result of declined economic activities, energy consumption declined as well. This, temporarily, led to improved energy efficiency measures and the EU seemed to be on track with respect to its energy consumption reduction targets from 2010 until 2014 (the aftermath of the economic crisis). However, from 2014 until 2017, energy consumption began to increase as the overall economic perspective improved. This highlights the importance of analysing energy efficiency in the light of changes in domestic production activities which affect energy consumption. Figure 2.10 illustrates how energy consumption has changed with changes in GDP.

Figure 2.10. Changes of EU's energy consumption and GDP.



Data Source: Eurostat.

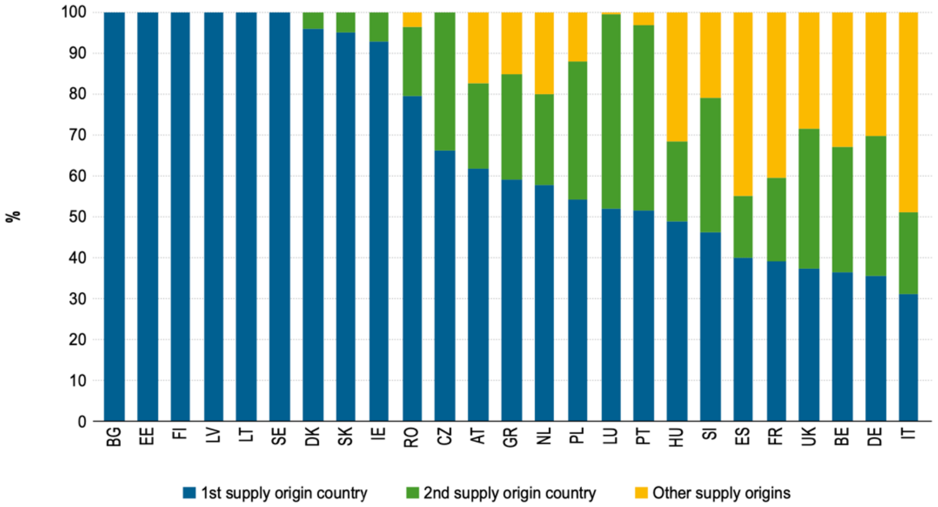
The last available data in 2018 shows that, although GDP has increased since 2017, once again the EU has been successful in reducing its energy consumption. Whether this trend continues is a matter for debate. In the COVID-19 pandemic, which led to a reduction of economic activities, even more severe than the 2008-2009 crisis, we can expect to see reduced energy consumption measures. Nonetheless, as in the financial crisis, these reductions cannot be attributed to energy saving efforts by Member States.

2.3.4 Energy security: Diversification of gas suppliers

Energy security is of particular importance to the EU. An imbalanced or unstable supply of energy in one member state can lead to difficult situations in other Member States, as well. The risk of disrupted energy supply is more likely with a limited number of suppliers. In the EU, the issue of a limited number of energy suppliers has been particularly true for natural gas. For instance, in 2012 several Member States, in the EU, had only one or only a few natural gas suppliers. This could be attributed to the fact that gas networks, specially across Eastern and South Eastern Europe, were not sufficiently developed to allow access to other sources (ACER, 2013).[60] The five main sources of gas supply for the EU are: natural gas pipelines from Russia, Norway and Algeria; LNG shipments from various suppliers; and domestic production. The number of sources for different Member States varies: with some having only a single supplier (e.g. Finland and Bulgaria); some depending mostly on their own domestic production (e.g. Romania and Denmark); and others standing in between these two extremes (ACER, 2019).[61]

Figures 4.11 and 4.12, taken from, respectively, ACER/CEER (2013) and ACER (2019), present natural gas suppliers (by geographical origin) for each member state in 2012 (Figure 2.11) and 2018 (Figure 2.12). Comparing these two figures reveals improvements in the diversification of gas suppliers, over six years.

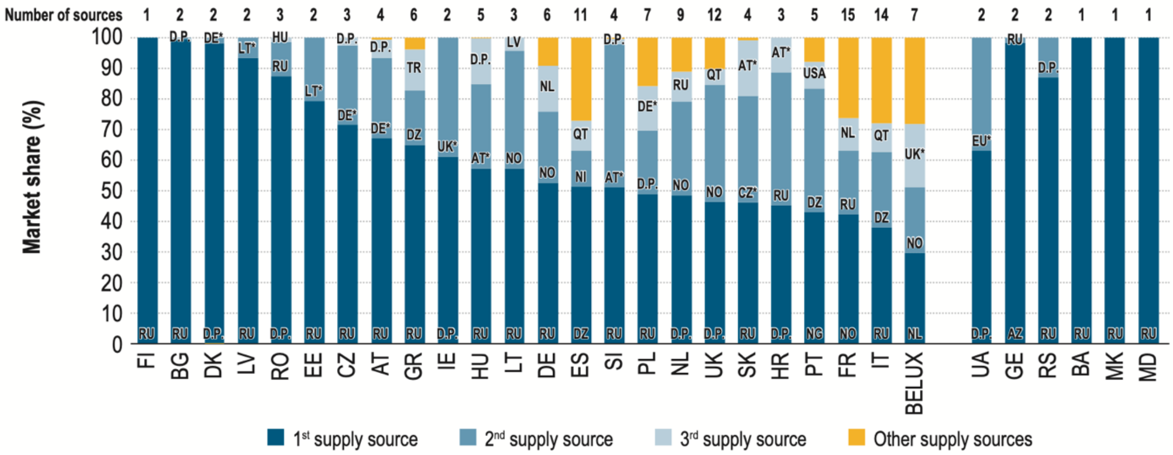
Figure 2.11. Estimated market share of the main natural gas supplier(s) – 2012



Source: ACER/CEER (2013).

[60] "Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2012", ACER, November 2013.
[61] "ACER Market Monitoring Report 2018 – Gas Wholesale Market Volume", ACER, October 2019.

Figure 2.12. Estimated number and diversity of supply sources in terms of the geographical origin of gas – 2018 - % of actual volumes purchased.



Source: ACER (2019).

"D.P stands for domestic production. For Denmark, the share of domestic production also includes the Norwegian offshore fields that are part of the Danish upstream network. Due to the merger of the Danish and Swedish market areas in 2019, metrics were not assessed for Sweden."

In 2012, five out of 25 Member States, were relying on only one supplier (Russia) , lacking, as they did, transmission connections to Western European countries and having no LNG import facilities (ACER, 2013). Denmark and Sweden were also heavily dependent on one supplier. Slovakia, the Czech Republic, Ireland and Luxemburg relied on two suppliers with one of the suppliers owning the majority of the market share: Russia for Slovakia and the Czech Republic and the UK for Ireland.

Six years later, in 2018, Russia remained the dominant gas supplier for 14 Member States, but as a result of commissioning a number of projects in previous years (including the Klaipeda terminal in the Baltic area, ACER, 2015[62]) and thanks to diversification of upstream gas producers, the market share for the primary supply source has shrunk.[63]

Infrastructure investments in EU regions which are more likely to face supply issues due to having only one natural gas supplier, together with the completion of the internal energy market, can be considered as remedies to energy security concerns. In both 2012 and 2018, those members states which are either well-interconnected or are equipped with facilities for importing LNG from various sources also have a higher level of supplier diversification (Member States including Italy, Germany, Belgium, the United Kingdom, France, Spain and the Netherlands). Table 2.1 presents how the number of connections and suppliers have changed during the same period for other Member States. In addition, the extent to which

[62] "Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2014", ACER, November 2015.
[63] For more information see ACER (2019) with an analysis of upstream market-health metrics: number of supply sources, RSI and HHI is provided.

changes have improved the volume of domestic demand that could be met from non-principle supplier is also set out in this table.

Table 2.1. Number of natural gas and LNG connections and suppliers and the percentage of domestic demand that could be met from non-principal supplier.

Country	Number of connections 2012	Potential number of gas supply sources 2012	% domestic demand that could be met from non-principal supplier 2012	Number of connections 2018	Potential number of gas supply sources 2018	% domestic demand that could be met from non-principal supplier 2018
Baltic States (Estonia, Latvia, Lithuania)	Estonia 2 Latvia 2 Lithuania 1	1	0	Estonia 2 Latvia 3 Lithuania 3	Estonia 2 Latvia 2 Lithuania 3	Estonia 22% Latvia 5% Lithuania 42%
Bulgaria	2	1	0	3	2 (including domestic production)	Almost 0
Croatia	1	Not yet a MS	Not yet a MS	2	3 (including domestic production)	58
Czech Republic	3	2	33	4	3	30
Hungary	3	3	51	5	5	43
Poland	4	3 NG/ 1 LNG	45	4	7 NG/ 6 LNG	52
Romania	2	3 (including domestic production)	82 (78% domestic production)	3	3 (including domestic production)	90 (88% domestic production)
Slovakia	3	2	5	3	4	50
Slovenia	3	3	54	2	4	49

Among the Baltic States, Lithuania has seen the highest improvement in the share of its domestic demand covered by a non-principle supplier: a 42% increase. This can be attributed to its increased number of connections, from one to three, and consequently the increased number of gas suppliers from one (Russia) to three (Russia, Norway, Latvia). For all the other listed Member States, excluding Hungary, the number of connections increased by 2018 compared to 2012, the number of gas suppliers has also increased and the volume of domestic demand has risen from non-principal suppliers. Therefore, it seems that the strategy to diversify natural gas and LNG suppliers through infrastructure investments and integration in the internal energy market has been successful in the last decade.

Since 2013, projects which help Member States to access more suppliers and facilitate market integration are identified under the Trans-European Networks for Energy (TEN-E) Regulation. Identified projects are then assessed with a number of criteria (such as a positive cost-benefit analysis and a relevant cross-border impact for market integration) to enter the list of Projects of Common Interest (PCIs) which are candidates for potential EU financial support. The

Connecting Europe Facility (CEF) is the main funding source for these infrastructure projects. Table 2.2 presents funding share for each member state from 2014 to 2018.[64]

Table 2.2. CEF Funds allocated to each MS.

EU Member States	FUNDING (€ million)	EU Member States	FUNDING (€ million)
Austria	0.01	Ireland	17
Bulgaria	122.5	Italy	0.2
Cyprus	116.9	Lithuania	237.7
Czech Republic	51.7	Latvia	230.5
Germany	119.8	Malta	4
Denmark	35.2	Netherlands	6.5
Estonia	306.7	Poland	518.3
Greece	41.5	Portugal	0.6
Spain	235	Romania	207.2
Finland	95.5	Sweden	2.8
France	368.1	Slovenia	77.3
Croatia	144.5	Slovakia	105.5
Hungary	1.7	United Kingdom	94.1

Gas security due to single supplier issues or lack of alternatives has dominated the EU's thinking over the last decade. However, thanks to an aggressive policy of diversification using the TEN-E Regulation and CEF, EU Member States have now, as can be seen from the tables above, a wide choice of gas suppliers, significantly reducing this threat. Thus, the EU's energy security should now focus on other potential aspects of energy security. With increasingly digitalized energy networks, cybersecurity is becoming the great new energy security concern, as both the security of energy flow and consumers' data become vulnerable. Therefore, a more forward-looking approach makes sense for the future with respect to energy security.

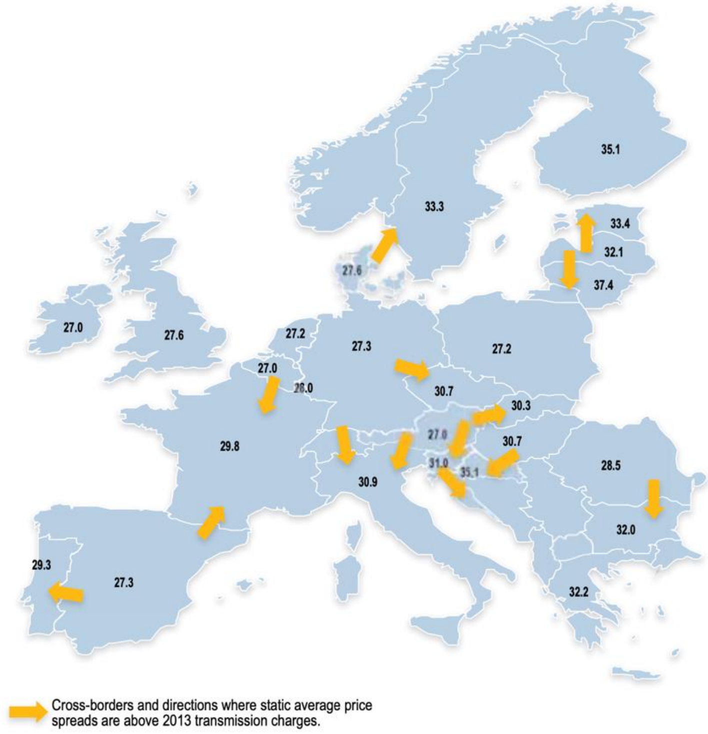
2.3.5 Effect on prices

In addition to a potential higher number of interruptions, relying on a single supplier can reduce the bargaining power of importing countries and will eventually affect the type of contract and the import price for them. Therefore, improving the diversification of suppliers can help maintain energy flows, while increasing competition at upstream supply markets and eventually lower import prices. Figures 4.13 and 4.14 show gas import prices for Member States in, respectively, 2013[65] and 2018. Prices are calculated using a basket of hub products, long-term supply contracts and domestic production prices (ACER, 2019).

[64] From "The Connecting Europe Facility: Five years supporting European infrastructure", European Commission, July 2019: https://ec.europa.eu/inea/sites/inea/files/cefpub/cef_implementation_brochure_2019.pdf

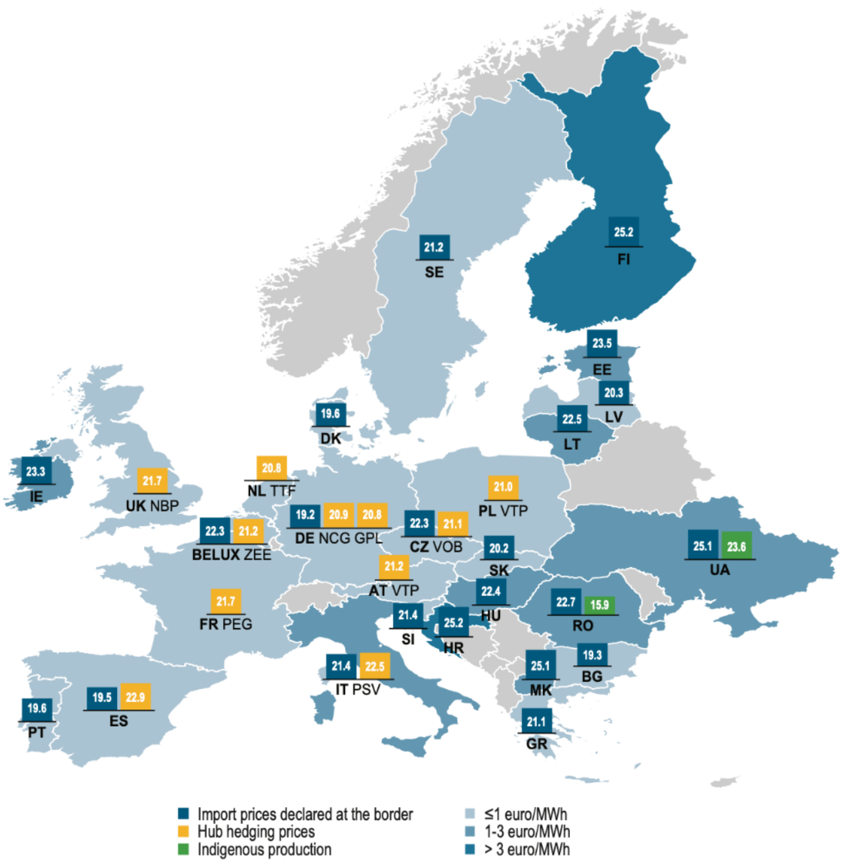
[65] "Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2013", ACER, October 2014.

Figure 2.13. EU-26 Average annual cross-border gas wholesale price spreads, 2013 (euro/MWh).



Source: ACER (2014).

Figure 2.14. 2018 estimated average suppliers' gas sourcing costs by EU MS (euros/MWh).



Source: ACER (2019)

In Table 2.3 we use the data on gas prices reported in Figures 4.13 and 4.14 to analyse whether prices in those regions which have single supplier issues (mostly Northern, Central and Southern Europe) have evolved to converge to import prices for other EU regions (Western Member States). The distance to minimum average import price is calculated for each MS in both 2013 and 2018 to show how prices have evolved with respect to the minimum value. The minimum average gas import price in 2013 was 27 euros/MWh while in 2018 it had been reduced to 19.2 euros/MWh.

Table 2.3. Gas import prices for Member States and their distance to minimum average import price in 2013 and 2018 (euros/MWh).

Member State	Average import price for each MS in 2013 (euros/MWh)	Distance to minimum average import price among Member States in 2013 (%)	Average import price for each MS in 2018 (euros/MWh)	Distance to minimum average import price among Member States in 2018 (%)
Northern, Central and Southern Europe Member States + Finland				
Finland	35.1	30%	25.2	31%
Estonia	33.4	24%	23.5	22%
Latvia	32.1	19%	20.3	6%
Lithuania	37.4	39%	22.5	17%
Bulgaria	32	19%	19.3	1%
Croatia	35.1	30%	25.2	31%
Czech Republic	30.7	14%	22.3	16%
Hungary	30.7	14%	22.4	17%
Poland	27.2	1%	21	9%
Romania	28.5	6%	22.7	18%
Slovakia	33	22%	20.2	5%
Slovenia	31	15%	21.4	11%
Average value	32.2	19%	22.2	15%
Western Europe Member States				
France	29.8	10%	21.7	13%
Germany	27.3	1%	19.2	0%
Italy	30.9	14%	21.4	11%
Spain	27.3	1%	19.5	2%
Greece	32.2	19%	21.1	10%
Portugal	29.3	9%	19.6	2%
Belgium	27	0%	22.3	16%
Luxemburg	28	4%	22.3	16%
Sweden	31.3	16%	21.2	10%
The Netherlands	27.2	1%	20.8	8%
Ireland	27	0%	23.3	21%
Austria	27	0%	21.2	10%
Denmark	27.6	2%	19.6	2%
The United Kingdom	27.6	2%	21.7	13%
Average value	28.5	6%	21.1	10%

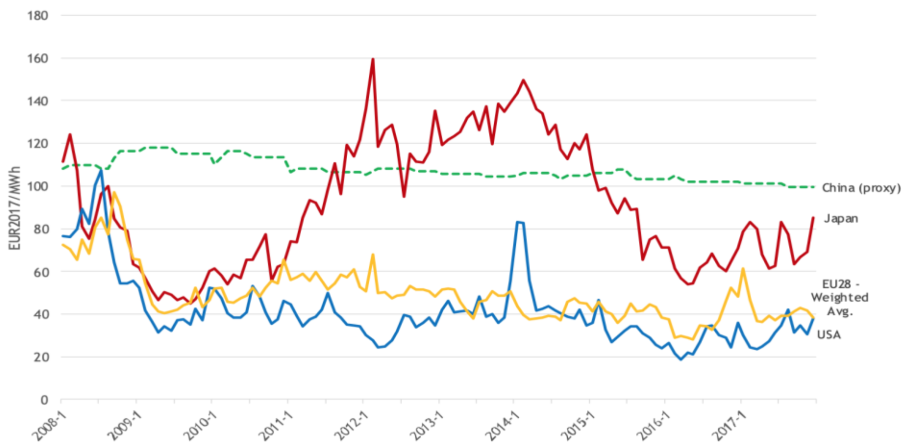
For all Member States the price decreased from 2013 to 2018. The average value for Finland, plus Member States located in Northern, Central and Southern Europe was 32.2euros/MWh in 2013 and 22.2euros/MWh in 2018. For Western European Member States the fall was from 28.5euros/MWh in 2013 to 21.1euros/MWh in 2018. From this simple calculation we can see a significant price differences between the two clusters in 2013, with the former having prices on average 13% higher than the latter. For 2018, instead, this difference shrinks to only 5%, which can be considered as a sign of success for diversification strategies.

Moreover, to understand the international position of the EU, with respect to electricity and gas prices, in Figures 4.15 and 4.16 the evolution of wholesale, household and industry retail prices for these sectors in the EU are compared with those of the EU's main partner countries including the USA, Japan and China since 2008 (Trinomics, 2018).

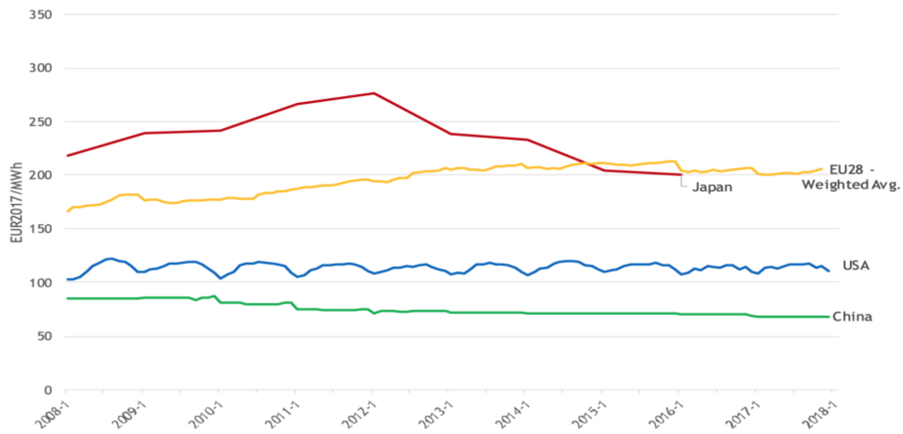
For electricity, Figure 2.15, EU wholesale prices have been relatively similar to the USA's and lower than China's and Japan's in the past decade. However, both household and industry retail prices for electricity are higher in the EU compared to the USA and China.

Figure 2.15. Electricity wholesale, residential and industrial prices.

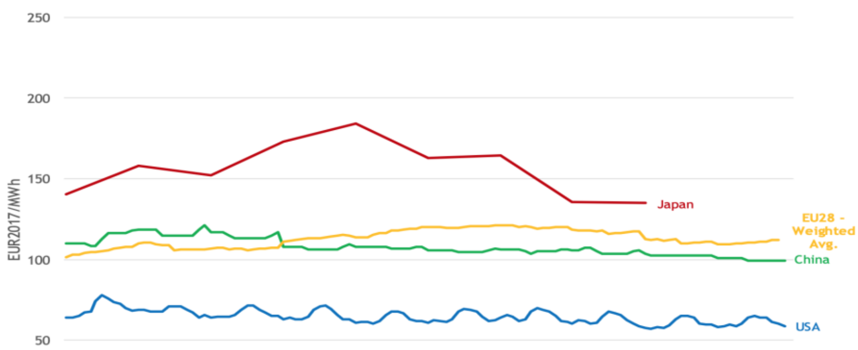
Electricity prices, wholesale, EU28, China, Japan and USA, 2000-2017, EUR$_{2017}$/MWh



Electricity prices, household retail, EU28, Japan, USA, China, 2008-2018, EUR$_{2017}$/MWh



Electricity prices, industry retail, EU28, USA, China, Japan, 2008-2018, EUR$_{2017}$/MWh

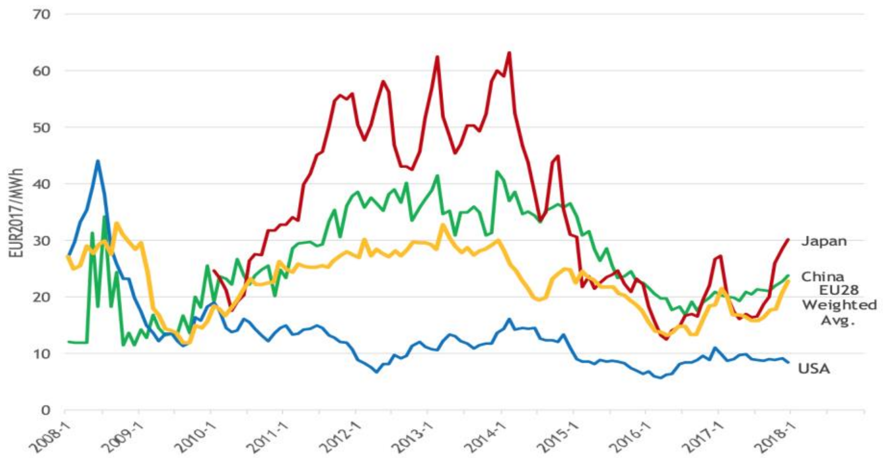


Source: Trinomics (2018).

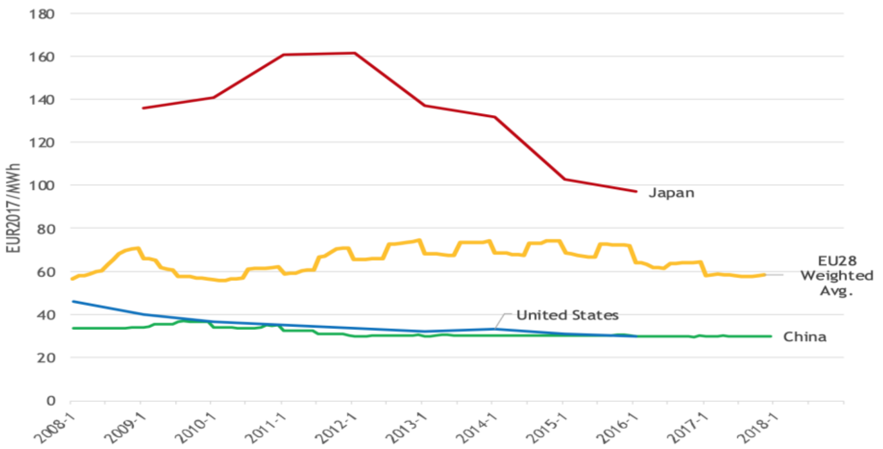
For gas, Figure 2.16, shows that prices in the USA are, in general, lower than any other partner countries and that the EU is in second place in terms of lower wholesale and industry retail prices. The household retail gas prices in the EU are, in general, higher than in the USA and China.

Figure 2.16. Natural gas wholesale, residential and industrial prices.

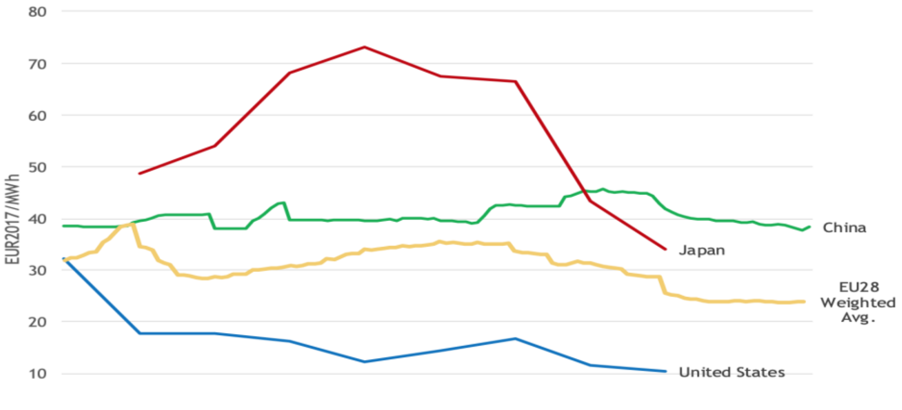
Natural gas: Wholesale prices, EU28, CN, JP, US, 2008-2018, EUR2017/MWh



Natural gas: household retail prices, EU, CN, JP, US, 2008-2018, EUR2017/MWh



Natural gas: industrial retail prices, EU, CN, JP, US, 2008-2018, EUR2017/MWh



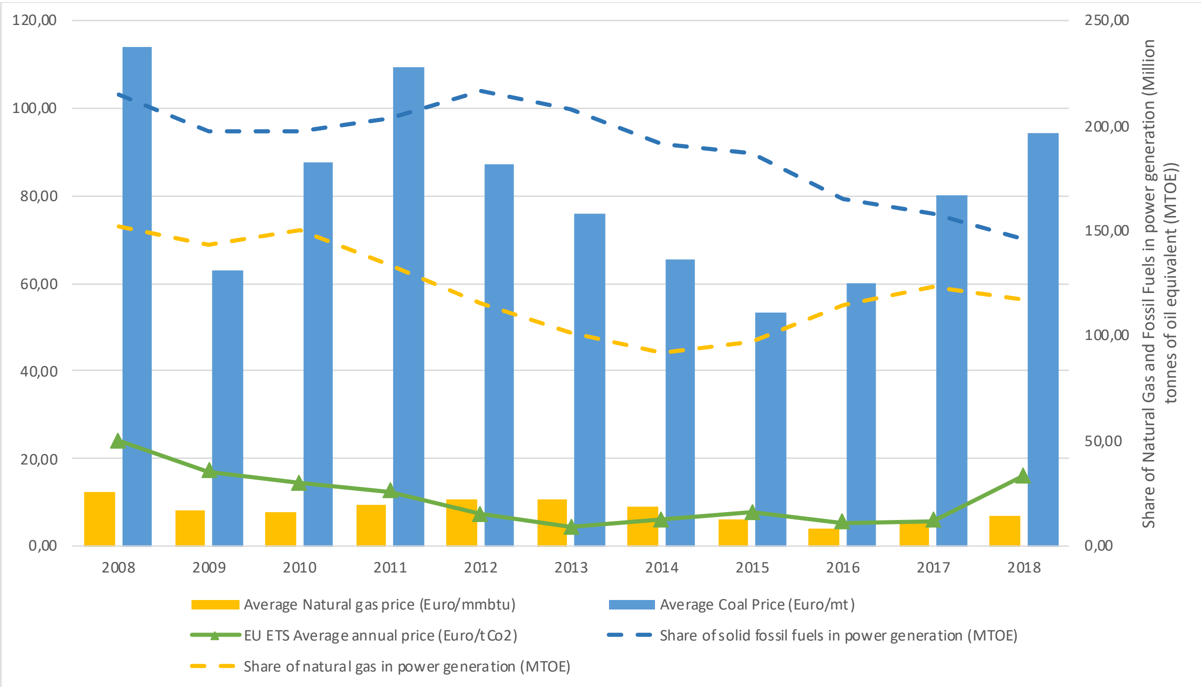
Source: Trinomics (2018).

2.3.6 From Coal to Natural Gas

Power generation is a major contributor to CO_2 emissions due to the use of fossil fuels (especially coal) in conventional power plants. Figure 2.17 presents share of natural gas and solid fossil fuels in EU power generation between 2008 and 2018. The evolution of gas and coal prices during this period and carbon prices based on the price of the European Trading Scheme Allowances (EUA) are also presented in the figure.

As can be seen, the use of solid fossil fuels as a transformation input in EU's energy sector has steadily declined from 2012 in spite of the falling price of coal up until 2016. Meanwhile, the share of natural gas in power generation has increased from 94 Mtoe in 2014 (the lowest in the period), to 124 Mtoe in 2017.

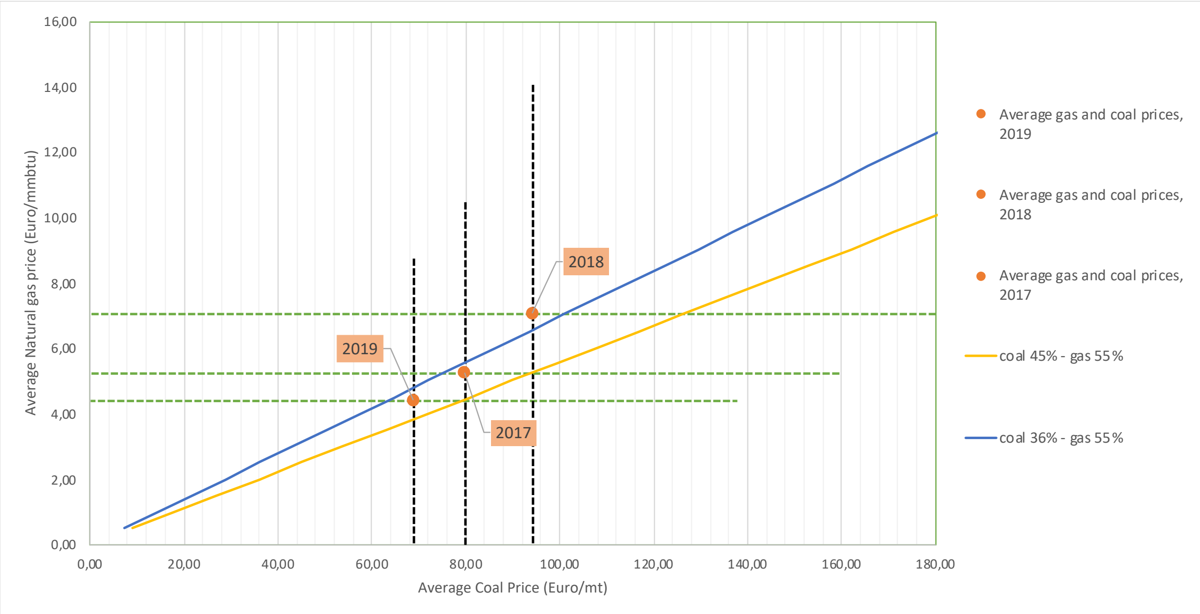
Figure 2.17. Average coal, gas and ETS prices and share of natural gas and coal in power generation.



Data Source: Eurostat, World Bank Commodity Price Data (The Pink Sheet) (2020), Markets Insider, Ember Carbon Price Viewer.

Figure 2.17 raises the question of whether carbon prices have been used properly as a tool to motivate the switch from coal to gas. The average efficiency of European coal and gas power plants has been improved significantly since the start of the 2020 climate and energy strategy and future improvements are expected (60% for gas and more than 50% for coal plants). The current average efficiency of coal-fired power plants in the EU is between 36% and 45% and for gas-fired power plants this measure reaches 55%. Based on these efficiency scores we have calculated the price for the substitution of coal to gas in 2017, 2018 and 2019 (Figure 2.18). The yellow line in Figure 2.18 represents the highly efficient coal-fired power plant and the blue line represents the less efficient one. In both 2017 and 2019, with less efficient coal-fired power plants, it proved cost-effective to switch from coal to gas, but with highly efficient coal plants the carbon price should be, respectively, 20 Euro/tCo2 (instead of 5,8 Euro/tCo2) and 35 Euro/tCo2 (instead of 25 Euro/tCo2).

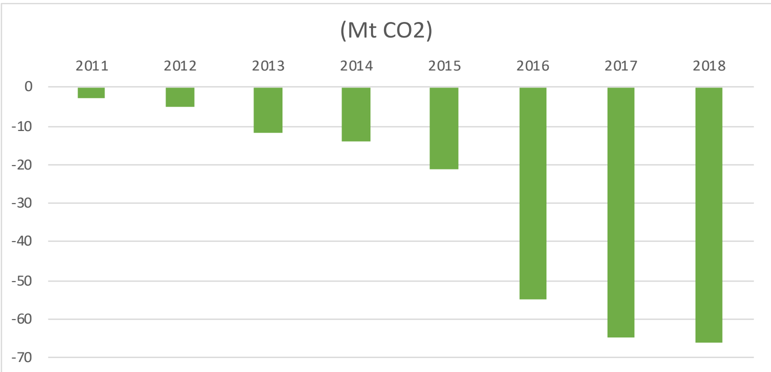
Figure 2.18. Switching prices from coal to gas, 2017, 2018, 2019.



Data Source: Own calculation, World Bank Commodity Price Data (The Pink Sheet) (2020).

The benefit of the switch from coal to gas in the European Union has been significant in terms of CO_2 savings. Figure 2.19 highlights CO_2 saving from 2011 to 2018 compared with 2010. The measure has increased from 3 ($MtCO_2$) in 2011 to 66 ($MtCO_2$) in 2018.

Figure 2.19. CO2 savings from coal-to-gas switching compared with 2010.



Source: IEA (2019).[66]

2.3.7 Job creation and competitiveness

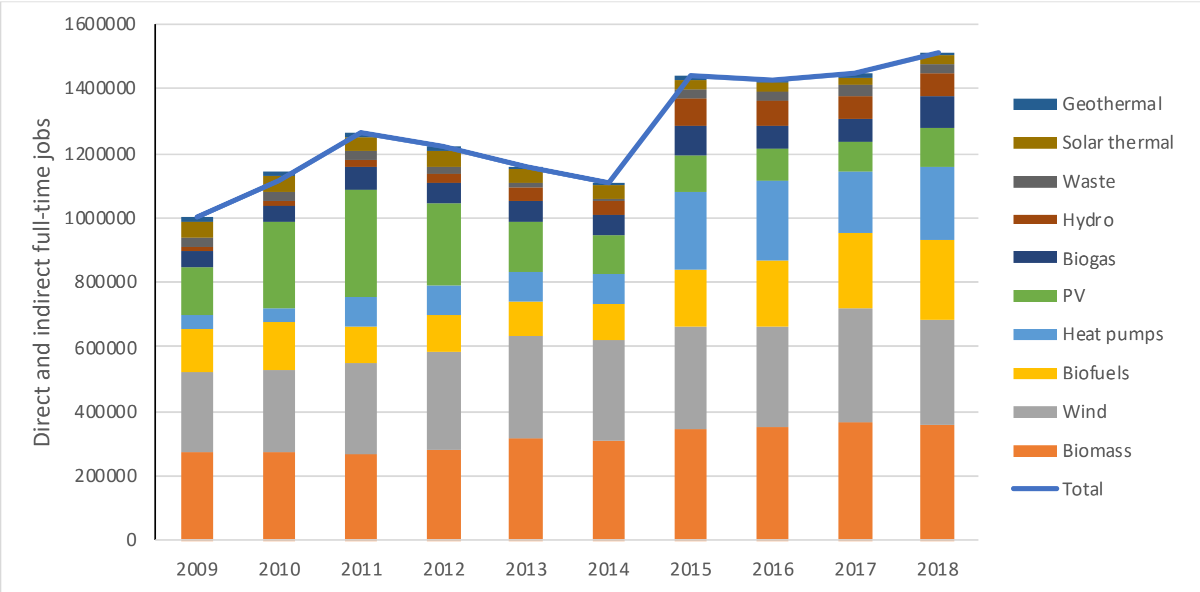
Any energy policy can have an impact on employment and job opportunities. The energy and climate policies can result in direct and indirect job creation in, especially, the RES and energy efficiency industries. However, they can also indirectly affect employment in energy-intensive sectors by affecting their competitiveness through carbon prices. Figure 2.20 illustrates the number of annual direct and indirect full-time jobs in the RES sector in the EU by technology

[66] "World Energy Outlook Special Report: The Role of Gas in Today's Energy Transitions", International Energy Agency, July 2019. All rights reserved.

type. The data for these measures has been collected from the EurObserv'ER[67] annual reports of 2009 to 2018. In its annual reports, the EurObserv'ER uses the data provided by the Eurostat and SHARES (Short Assessment of Renewable Energy Sources) tool to prepare analyses on "the energy dimension of the twelve renewable sectors now developed at an industrial scale within the European Union".

As reported in Figure 2.20, the number of annual direct and indirect full-time jobs in the RES sector in the EU has increased from 1 million jobs in 2009 to 1.5 million in 2018. Biomass, wind and biofuels are the renewables which create more than half of the jobs in the RES sector. While share of PVs declined during this period (perhaps due to the maturation of technology and the lower cost of PV production in China), the number of jobs in the heat pump industry has risen in recent years.

Figure 2.20. Annual direct and indirect full-time jobs in the RES sector.

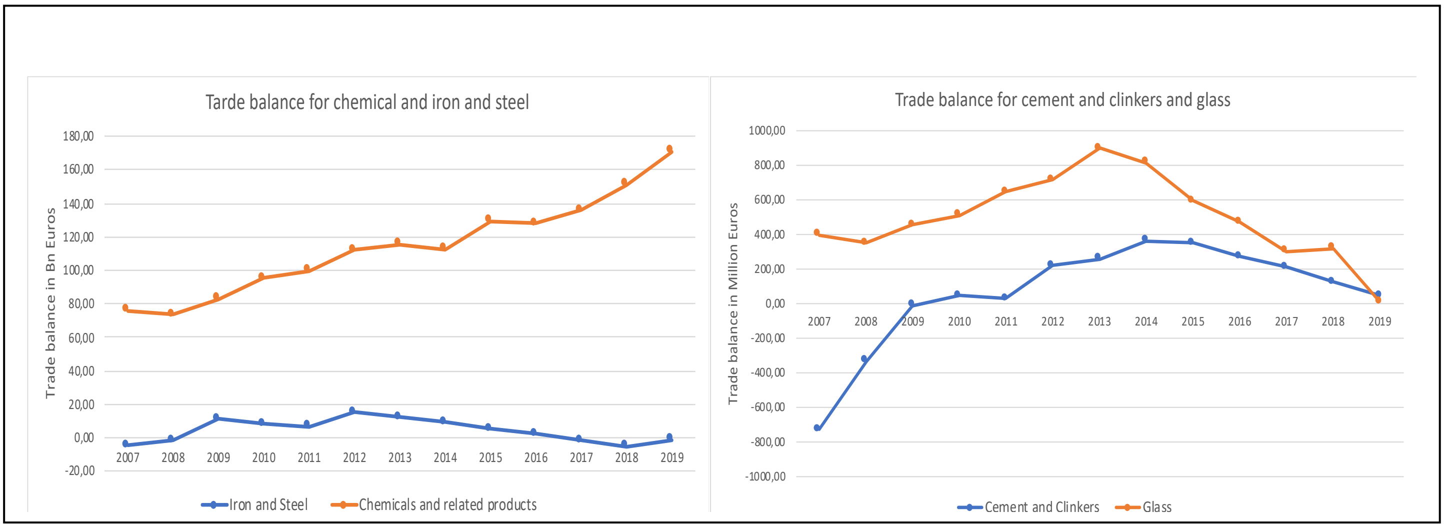


Data Source: EurObserv'ER Annual Reports (2011-2019).

The competitiveness of energy-intensive industries (such as chemicals, iron and steel, glass and cement) which are still dependent on less costly conventional fuels, can be significantly affected by increasing carbon prices. This has been the case in the EU for iron and steel, the glass and cement industry, especially after the introduction of the second phase of the EU ETS in 2013 and the increase in prices of the European Emissions Allowances. Figure 2.21 highlights the status of the trade balance for these industries before and after the 2013 carbon price reforms. It seems that, with the chemical products industry as an exception, the trade balance of energy-intensive sectors in the EU is significantly affected by carbon price policies, as it has followed a decreasing trend from 2013 for the iron and steel, glass and cement industries. This could be attributed to higher production costs due to the higher environmental costs imposed on those producers that are still using solid fossil fuels as their main energy input.

[67] The EurObserv'ER is a consortium supported by the European Commission that measures the progress made by renewable energies in each sector and in each member state of the EU. More info can be found at: https://www.eurobserv-er.org/

Figure 2.21. Trade balance of Europe's energy-intensive industries.



Data Source: Eurostat Comext.

2.3 Conclusion

In this chapter we reviewed the EU's 2020 climate and energy objectives and policies and looked at whether the EU has been successful in meeting its targets. The set of 2020 targets and actions to reach them were approved in 2009 by the European Council with the aim of tackling the energy trilemma by shaping and organizing EU and MS efforts. The beginning of this strategy coincided with the aftermath of the economic crisis of 2008-9, and to some extent, its implementation was affected by the financial limits set by that crisis. However, the latest available data shows that, despite economic constraints, the EU and its Member States have been relatively successful in meeting their primary targets. The EU achieved an overall 23% GHG emissions reduction in 2018 (compared to 1990): the 2020 reduction goal had been set at 20%. Both national and EU level targets have been met under the EU ETS and the ESD, covering, respectively, 45% and 55% of EU emissions. This is a significant success for the EU One may argue that this level of progress regarding emissions reduction is attributable to reduced production activities during the economic crisis. However, the stability of reductions highlight the EU's potential in achieving even more ambitious targets in the future.

Based on the latest available data, in 2018 (15% energy efficiency in 2018), the 20% reduction of energy consumption target could, most probably, not be met by the end of 2020. However, the COVID-19 pandemic and the consequential economic crisis in 2020 will affect energy efficiency measures as several economic activities have ceased. Nevertheless, such temporary target achievements should not be attributed to planned efforts. The current overall energy efficiency progress at the EU level stands at 15%, and only 11 Member States are already ahead of the national objectives set in their NEEAPs. In this chapter, we also analysed the progress of EU energy consumption and GDP measures together to understand whether energy consumption varies with economic changes. We showed that after the 2008-9 economic crisis, demand for energy decreased until 2013, allowing the EU to get back on track with respect to its efficiency goals. This trend was interrupted from 2014 to 2017, when energy consumption increased in the EU. The 2018 data shows that, once again, while energy efficiency has improved, we should still wait for the 2019 data to see whether this represents stable progress.

Concerning the 20% target share of renewable resources in final energy consumption, the EU has a relatively strong position with, respectively 18% and 8% shares of RES in 2018 in the energy and transport sector, lagging 2% behind the 2020 objectives. Share of RES in the electricity sector has reached an historical 32%, and the heating and cooling sector is behind with 20% of renewables integration. At the national level, more than half of Member States are on track to meet their goals by 2020, while the rest of Member States need to intensify their efforts to promote RES in both the energy and transport sectors. Indeed, the course of action to achieve the planned targets should take place under two different forms: expanding the necessary infrastructure to accommodate even more renewable energy in both the energy and transport sectors; and providing financial supports to promote the integration of different forms of RES.

We analysed whether the development of transmission infrastructure in regions with a single supplier has affected the diversification of gas suppliers and connections from 2012 to 2018. We found that, while the number of gas suppliers has increased for all Member States located in Southern, Central and Northern European regions, some Member States including Slovakia, Estonia and Lithuania have benefited more than other Member States from investments in critical gas infrastructures (such as transmission networks and LNG hubs). A significant share of gas demand in these countries was coming from non-principle suppliers in 2018 compared to 2013. This kind of diversification helps in improving the security of supply issues; dependence on a single supplier is clearly dangerous. According to our results, it seems that the EU’s 2020 energy strategy has successfully increased energy security.

Supplier diversification can affect the competition between upstream producers which, in turn, affects the bargaining power of Member States and import prices. Therefore, we also analysed how gas import prices have changed. We asked, too, whether price gaps between Southern, Central and Northern Member States, which were more exposed to import instability due to single supplier issues, and Western Member States, changed between 2013 and 2018. According to our analysis, the average import price for Southern, Central and Northern Member States, was 13% higher than Western Member States in 2013, while this measure changed to 5% in 2018. This result shows that the price gap is remarkably reduced and that prices in the two regions have converged in a significant fashion.

Overall, our analysis suggests that, though the 2020 energy and climate strategy has been costly in some respects (infrastructure investments and large RES subsidy payments), it has been successful in achieving most of its hoped for results. The GHG emission reduction target is already met and the EU is close to reaching its RES and energy efficiency targets. With respect to energy security the EU’s strategy was successful in improving it by helping Member States to diversify their gas and LNG suppliers through investments in connecting infrastructures. The number of jobs which has been created in the RES sector has increased from 1 million in 2009 to 1.5 million in 2018. However, there are some points which can be further improved upon including the EU ETS. Our analysis suggests that, up until 2019, carbon prices under the EU

ETS did not encourage the switch from coal to gas in power generation plants. For instance, the EU ETS price would have had to have been 20 Euro/t CO_2 (instead of 5.8 Euro/t CO_2) in 2017 and 35 Euro/t CO_2 (instead of 25 Euro/t CO_2) in 2019 to make the switch cost-effective.

3. The EU's 2030 climate and energy targets and the instruments to reach them

3.1 Clean Energy for All Europeans: new targets, new instruments, new governance

The 2020 Climate and Energy strategy was the first comprehensive European policy framework to set specific energy and climate goals to be achieved within a certain period. The 2020 climate target was a 20% GHG emissions reduction with binding national targets for non-ETS sectors under the Effort Sharing Decision. In addition to GHG emissions reduction, a binding national target of a 20% share of renewables and a 20% reduction in total primary energy consumption were set for 2020. Together with these targets, the Package also included instruments for helping Member States achieve them. By 2018, the GHG emissions reduction was 23% compared to the 1990 level, the RES share in final energy consumption amounted to 18% and energy efficiency was as high as 15%. The GHG emissions reduction measure had already been met in 2018 and the EU is on track to meet the other two targets on RES and energy efficiency in 2020. Since 2007, when the 2020 Climate and Energy strategy was first proposed, higher climate and energy targets after and beyond 2020, has been part of the political debates at the EU level. The first steps in introducing a new energy and climate package for the EU after 2020 were taken in February 2015 when the Energy Union was launched. The Energy Union represents a forward-looking framework and includes five dimensions covering the future actions of the European Union regarding climate and energy targets. It calls for future EU energy policies to focus on:

a) Energy Security;

b) A Fully Integrated Energy Market;

c) Energy Efficiency;

d) Decarbonisation;

e) Research, Innovation and Competitiveness.

Based on this framework, in 2016 the Commission proposed the establishment of a new rulebook on European energy and climate policies[68] including new targets for 2030 and new instruments to help reach these targets by 2030. The EU rules included in this new energy rulebook, known as "the Clean Energy for all Europeans Package", were agreed upon by the Council and the European Parliament between May 2018 and May 2019. The Clean Energy for all Europeans Package (known also as the Clean Energy Package – CEP) provides a legislative framework for achieving Energy Union objectives. However, in addition to internal drivers of the shift towards a low-carbon future, the EU also aims at responding to its international commitments, including the Paris Agreement and the UNFCCC in the CEP.

Through the CEP, the EU intends to move further ahead in responding to environmental concerns, while prioritising competitiveness and energy security. Thus, even more ambitious targets have been set for 2030 compared to the 2020 targets. In a nutshell, the 2030 targets are a 40% GHG emissions reduction (subject to an increase to 55% following the EC

[68] COM/2016/0860 by the European Commission on Clean Energy for All Europeans, accessible at: https://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1582103368596&uri=CELEX:52016DC0860.

communication of September 2020)[69], a 32% share for renewables, at least 32.5% energy efficiency and a 15% interconnection target. Based on the CEP, these targets can be revised upwards in 2023. The binding level of the 2030 GHG emissions reduction and RES targets differ from the equivalents for 2020 as they are set at the Union- rather than the Member-State level.

More ambitious targets called for revised or novel instruments to be included in the Package for stimulating the move towards achieving 2030 targets. Moreover, setting Union-wide targets that are not binding at national-level, required the establishment of a governance mechanism to ensure that independent efforts by Member States will lead to EU-level targets being met collectively. The revised and new instruments are included in the Clean Energy Package as eight pieces of legislation: four Regulations and four Directives. In addition, CEP introduces a number of non-legislative initiatives focusing on coal regions, EU islands and energy poverty to establish a fair energy transition across the EU.

In this chapter, we discuss the 2030 targets as included in the CEP and the instruments which are established to help reach these targets by 2030.

3.2 EU climate and energy targets for 2030

Following the Paris Agreement, in the CEP the EU set a 40% GHG emissions reduction target compared to the 1990 measures to be achieved in the 2021-2030 period. To meet this goal, emissions coming from the industries included in the ETS were to be reduced by 43% compared to 2005. This reduction should be equal to 30% for non-ETS sectors. While the overall emissions reduction target and the ETS target are binding at the EU level, the target on emissions from non-ETS sectors is binding at the Member State level. Under the Effort-Sharing Regulation[70] which replaces the Effort-Sharing Decision for the 2021-2030 period and covers emissions from the non-ETS sectors, Member States are required to deliver binding annual GHG emissions reduction targets. Table 3.1 presents these targets.

Table 3.1. Member States non-ETS Greenhouse Gas Emission Limits by 2020 and 2030.

Member State	GHG limits in 2020 compared to 2005 levels	GHG reductions in 2030 compared to 2005 levels
Belgium	–15 %	–35 %
Bulgaria	20 %	–0 %
Czech Republic	9 %	–14 %
Denmark	–20 %	–39 %
Germany	–14 %	–38 %
Estonia	11 %	–13 %
Ireland	–20 %	–30 %
Greece	–4 %	–16 %

[69] COM(2020) 562 final by European Commission, accessible at: https://ec.europa.eu/clima/sites/clima/files/eu-climate-action/docs/com_2030_ctp_en.pdf
[70] Accessible at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2018.156.01.0026.01.ENG

Spain	–10 %	–26 %
France	–14 %	–37 %
Croatia	-	–7 %
Italy	–13 %	–33 %
Cyprus	–5 %	–24 %
Latvia	17 %	–6 %
Lithuania	15 %	–9 %
Luxembourg	–20 %	–40 %
Hungary	10 %	–7 %
Malta	5 %	–19 %
Netherlands	–16 %	–36 %
Austria	–16 %	–36 %
Poland	14 %	–7 %
Portugal	1 %	–17 %
Romania	19 %	–2 %
Slovenia	4 %	–15 %
Slovakia	13 %	–12 %
Finland	–16 %	–39 %
Sweden	–17 %	–40 %
United Kingdom	–16 %	–37 %

Source: European Commission (2020).

As in the 2020 climate and energy framework, an increasing share of renewables in the final energy mix is one of the main CEP priorities. The Package sets a 32% target share for renewables by 2030 which, contrary to the 2020 target, is binding at the EU level. To ensure that adequate support is being provided to increase RES uptake, the Renewables Energy Directive II, has been in force since 2018 replacing the 2009 Renewables Energy Directive. Looking into the measures from the past decade, share of renewables from 2010 to 2018 (the last available data) has increased roughly 5% (from 13.1% to 18%). Therefore, it might seem that the 32% share for renewables by 2030 is an ambitious target and that it will only be met by the EU with some difficulties. Achieving an even more ambitious target within a similar time frame will be still more challenging in particular with less emphasis on RES subsidies, as is in the new Renewable Energy Directive. However, the study by IRENA[71] and assessments by the Commission[72] show that with continuous technological developments, this target can be reached by 2030.

Energy efficiency is a focal point for the CEP and a target of at least 32.5% has been set for 2030 with the possibility of an upward revision in 2023. This target is non-binding at Member State level and Member States can decide upon their specific national contributions. In the CEP, less energy consumption in the buildings sector is assumed to play an important role in

[71] Renewable Energy Prospects for the European Union by IRENA, accessible at: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2018/Feb/IRENA_REmap_EU_2018.pdf

[72] https://ec.europa.eu/energy/data-analysis/energy-modelling/euco-scenarios_en and https://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1600339518571&uri=COM:2020:564:FIN

achieving this goal.[73] In particular, one of the eight pieces of legislation in the CEP is the Energy Performance in Buildings Directive with building renovation as its main focus.

Meeting the new energy efficiency target by 2030 is even more challenging that the renewables target. A 20% increase in energy efficiency was one of the three main targets of the 2020 energy and climate policies. As noted in Chapter 4, by 2018, primary energy consumption reduction at the EU level reached 15%, falling 5% behind the 2020 target. Compared to the 2020 policies, emphasis on energy efficiency is stronger in the CEP than in the 2020 policies – indeed, two different Directives target it. However, growing energy demand[74] might hinder progress towards the minimum 32.5% goal.

A 15% electricity interconnections target by 2030 (a 5% increase with respect to the 2020 target) is also included in the CEP. TEN-E Regulation and PCIs[75] will remain the key frameworks for providing financial support to interconnection projects, while the focus will be mostly on electricity networks, as opposed to gas corridors, due to the increasing importance of RES integration. The Clean Energy Package also promotes stronger cross-border cooperation by introducing the Risk Preparedness Regulation (EU) 2019/941 and updating the functioning of ACER through the ACER Regulation recast.

3.3 EU instruments for achieving 2030 targets

3.3.1 Revised ETS

As in the previous period, the EU ETS will play an important role in reducing GHG emissions from 2021 to 2030. According to the CEP, emissions coming from the ETS sectors should be reduced by 43% by 2030. Since the start of the EU ETS in 2005, three phases have been implemented with the last one starting from 2013 and ending in 2020. To take the 40% GHG emissions reduction target of the Clean Energy Package into account, the EU ETS has been revised for phase four covering the 2021-2030 period.[76]

As discussed in chapter 4, demand for ETS Allowances decreased from 2008 until the beginning of phase three of the EU ETS in 2013. With a fixed number of available allowances, this resulted in surpluses and decreasing carbon prices. Such outcomes were not predicted in phase three and, therefore, correcting measures were adopted. Between 2014 and 2016, prices were pushed up slightly with the Backloading measure, but this was considered to be a short-term solution. Later in 2019, Market Stability Reserve (MSR) became functional as a long-term solution to help adjust the number of allowances further in case the market faced demand drops. This lack of ability to create a balanced and resilient market that could respond to shocks in a sustainable manner was considered to be a major shortcoming of phase three of the EU

[73] The buildings sector is responsible for 40% of final energy consumption in the EU and, therefore, energy savings from this sector can contribute largely to energy efficiency objectives.
[74] IEA's 2019 World Energy Outlook estimates that global energy demand will increase with an average annual growth rate of 1% until 2040.
[75] To comply with the EU's long-term climate neutrality goal and the European Green Deal, the TEN-E Regulation will be subject of revisions in upcoming years and criteria for fund allocations could be modified accordingly.
[76] The Commission proposed the revised EU ETS for the period after 2020 in 2015. It went through several amendments by the Council and the European Parliament and finally the revised EU ETS Directive (Directive (EU) 2018/410) entered into force from April 2018(EC website on EU ETS).

ETS[77]. Therefore, phase four revisions have been made to address market imbalance and functionality and for improving resilience to shocks. In particular, to reduce the surplus of allowances, the rate of annual reductions in allowances has increased from 1.74% in phase 3 to 2.2% in phase 4. In addition, until 2023, 24% of all allowances in circulation will be transferred to the MSR if a threshold of 833 million allowances is surpassed. The rate will be 12% from 2024 until the end of phase 4. These measures could significantly affect carbon prices by cutting surpluses, especially until 2023 when the number of stored allowances in reserve is doubled. A higher carbon price could also encourage industries to switch from fossil fuels and adopt green energy sources more quickly.

To ensure that European energy-intensive sectors will maintain a competitive global position and to avoid carbon leakage, in phase four of the EU ETS a new definition of exposure to carbon leakage is provided. Sectors identified as being at high risk will receive 100% free allowances until 2030, while the free allowances will gradually decline up to 0% in 2030 for less exposed sectors.

Measures and differences for Phase three and four are presented in Table 3.2.

Table 3.2. Summary of Phase 3 and Phase 4 of EU ETS.

	Phase 3 (2013-2020)	**Phase 4 (2021-2030)**
EU-wide emissions reduction target	21%	43%
Rate of annual reductions in allowances	1.74%	2.2%
Market Stability Reserve (MSR)	None: Back-loading	Until 2023: 24% of allowances in circulation As of 2024: 12% of allowances in circulation
Free allocations to sectors exposed to carbon leakage (% of their required allowances)	Gradual reduction from 80% in 2013 to 30% in 2020.	Highest risk sectors: 100% Less exposed sectors: from 2026 gradual reduction from 30% in 2026 to 0% in 2030.
New Entrance Reserve (NER300 Program)	300 million emission allowances	450 million emission allowances

[77] The Oxford Energy Institute for Energy Studies: "The EU ETS phase IV reform: implications for system functioning and for the carbon price signal".

3.3.2 New RES Directive

The recast Renewable Energy Directive 2018/2001/EU[78], known as RED II, entered into force from December 2018 as a part of the Clean Energy for all Europeans package. It sets a minimum 32% target (up until 2023 the target may be increased relative to potential cost reductions in RES productions) on the share of renewables in the final energy consumption to be achieved by 2030; 12% more than the 2020 target which was set in the 2009 Directive. The target is at the EU-level rather than the binding national-level targets of the 2009 Directive. By setting a collective EU-level target, the Directive aims at granting the flexibility that Member States require to set their individual targets considering their energy mixes.[79] As for the renewables share in the transport sector, the recast Directive set a 14% goal to be met by 2030 of which 3.5% (1% by 2025) should come from advanced biofuels and biogas.[80] Member States are required to transpose the provisions of RED II into national law by 30 June 2021.

Both 2009 and 2018 Renewables Energy Directives share common grounds in providing guidance to Member States for the deployment of RES. Mechanisms such as support schemes, guarantees of origin, joint projects, cooperation between Member States and third countries (from the European Parliament Factsheet) are recommended in both Directives. But there are some differences. For instance, the 2009 Directive encouraged the adoption of renewables support schemes and provided a wide range of definitions for potential supporting mechanisms and each Member State had the freedom to choose their preferred set of tools including feed-in tariffs, feed-in premiums, etc. In 2013, in an attempt to provide financial support to RES in a more cost-effective manner, the Commission announced the abolition of feed-in tariffs (from the European Parliament Factsheet) and preference was given, instead, to premiums.[81] In RED II, while it is not compulsory for Member States to provide any supporting schemes for RES integration, one further step has been taken to allocate RES supports in a more competitive and cost-effective way by requiring Member States to introduce market-based support mechanisms. In particular, support mechanisms should be, as much as possible, technology neutral and should not distort the electricity markets. Moreover, to encourage cross-border cooperation, Member States should allow renewable energy that is produced in other countries to compete for a share of their support schemes. In 2023, the Commission will assess whether a minimum share of support schemes (5% by 2025 and 10% by 2030) should open mandatorily by each MS to foreign RES productions. Among other changes in the recast Directive, including the abolition of grid access and dispatching privileges for renewables[82], there are a few new legislative concepts:

- *Renewables self-consumers*: to encourage and facilitate the deployment of renewables by consumers. Prosumers or self-consumers will have the ability to generate, consume,

[78] The RED II is accessible at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2018.328.01.0082.01.ENG&toc=OJ:L:2018:328:TOC.
[79] Recital 9 in the Directive.
[80] Fact Sheets on the European Union by The European Parliament: https://www.europarl.europa.eu/factsheets/en/sheet/70/renewable-energy.
[81] Feed-in tariffs have the potential to extensively increase the number of new installations and to result in an increasing support cost (ECOFYS, 2014).
https://ec.europa.eu/energy/sites/ener/files/documents/2014_design_features_of_support_schemes.pdf.
[82] The electricity that is generated by renewable resources is now treated as electricity generated by non-RES and falls under the same corresponding rules that are defined in Electricity Regulation and Electricity Directive.

store or sell their renewable energy without being subject to discriminatory procedures and/or charges. They will be able to participate in markets and to use support schemes.

- *Renewables energy communities*: the same rights as in the case of renewables self-consumers, are defined for the renewable energy communities. This means that they can participate in energy markets and compete for relevant supporting mechanisms and that they will not be subject to discriminatory procedures.

- *Sustainability and GHG emissions saving criteria for biomass*: introducing revised sustainability and GHG emissions saving criteria for biofuels and bioliquids and, for the first time, extending these criteria to forest biomass that are used for heating and cooling and power generation. According to this new extension, for installations starting operation between 2021 and 2025 the GHG emissions savings threshold should be 70%; 80% for installations starting up from 2026 onwards.[83]

3.3.3 Energy Efficiency Directives

The EU considers energy efficiency to be the most cost-efficient way of reducing GHG emissions. However, the progress towards meeting its 2020 target of 20% energy efficiency has been slow with only 15% by 2018. It seems that more effort is needed to achieve the new ambitious target of at least 32.5% lower energy consumption by 2030. The 'energy efficiency first' principle is promoted in the Clean Energy for all Europeans package by including two Directives on energy efficiency and energy performance in buildings. A summary of the two Directives and the key amendments for the 2021-2030 period are presented in this section.

Energy Performance in Buildings Directive (EU) 2018/844[84]:

Improving performance for buildings is considered to be a very important step in reducing final energy consumption at the Union level since buildings are responsible for 80% of energy used for heating and cooling across Europe. In addition, 40% of total energy consumption and 36% of CO2 emissions in the EU are also associated with buildings.[85] To meet its efficiency target in a cost-effective manner, the EU will need to increase its renovation rate from 1% to 3% per year.[86] To promote the construction of energy efficient and decarbonised buildings and also to facilitate the renovation of existing buildings, the Energy Performance in Buildings Directive is introduced in the CEP. This includes several provisions from the Energy Performance of Buildings Directive 2010/31/EU (EPBD) and the Energy Efficiency Directive 2012/27/EU together with new elements covering the following key topics:

- Long-term building renovation strategies and targets;

- Roll-out of the infrastructure for electro-mobility (electrical recharging points);

[83] Article 29 of recast RED.
[84] The EPBD is accessible at: https://eur-lex.europa.eu/legal-content/EN/TXT/?toc=OJ%3AL%3A2018%3A156%3ATOC&uri=uriserv%3AOJ.L_.2018.156.01.0075.01.ENG.
[85] Factsheet: Energy Performance in Buildings Directive: https://ec.europa.eu/energy/sites/ener/files/documents/buildings_performance_factsheet.pdf.
[86] Commission's impact assessment on the energy performance of buildings accessible at: https://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX%3A52016SC0414.

- Inspection, monitoring and control of energy use (new provisions on self-regulating devices);
- Energy performance certificates.

Member States were required to establish the new and revised provisions into national laws by March 2020.

Energy Efficiency Directive (EU) 2018/2002[87]*:*

The amending Directive on Energy Efficiency (EU) 2018/2002 is in force from December 2018 replacing the Energy Efficiency Directive (2012/27/EU). Main changes in the amending Directive are as follows:

- The new energy consumption reduction target by 2030 equals a minimum of 32.5% which can be increased up to 2023. This entails a 1128 Mtoe cap on primary energy consumption and a 846 Mtoe cap on final energy consumption (Commission website).[88] There are no national binding targets and the 32.5% goal should be met collectively at the EU-level.
- Member States are obliged to achieve 0.8% annual energy savings in final energy consumption for the 2021-2030 period. This requirement is extended to beyond 2030 and Member States need to follow this obligation as long as it is necessary to meet the 2050 energy and climate targets.
- To empower district heating, cooling and domestic hot water consumers and to extend their rights, clearer rules are set with respect to billing and metering. For instance, billing and consumption information should be freely provided to consumers. Only remotely readable meters and heat cost allocators should be installed as of October 2020 and the old ones should be replaced by remotely readable ones by January 2027.

3.3.4 New Electricity Market Design

Establishing a new electricity market design with a forward-looking approach to include what could come next in the electricity market is one of the main objectives of the Clean Energy for All Europeans Package. In this context, four legislative acts (one directive and three regulations) are included in the CEP. The aim of these pieces of legislation is to establish a modernized electricity market by focusing on two main points: increasing cross-border cooperation and coordination; and empowering consumers. The four pieces of legislation are briefly discussed below.

[87] The Directive is accessible at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2018.328.01.0210.01.ENG&toc=OJ:L:2018:328:TOC.

[88] These are after-Brexit targets corresponding to Commission's decision to redefine the target for after the UK no longer applies EU law. The initial targets (before Brexit) were equal to 1273 Mtoe of primary energy consumption and/or 956 Mtoe of final energy consumption.

Replacing the Electricity Regulation (EC/714/2009) as of January 1 2020, Electricity Regelation (EU) 2019/943[89] focuses on the establishment of the future electricity market. The main trajectories of the Regulation are:

- Setting core future electricity market principles;
- Setting rules on wholesale trading, capacity mechanisms and network access charges;
- Defining principles of balancing markets and balancing responsibilities;
- Defining rules on dispatching, re-dispatching and congestion solutions based on market-based approaches;
- Setting principles on activities of TSOs and DSOs as well as Regional Coordination Centers (RCCs) with a focus on interconnectors, bidding zones and network codes;
- Establishment of the EU DSO entity and defining its core tasks.

The measures included in the Electricity Regulation aim at facilitating cross-border trade and at increasing system flexibility and security. With respect to costs, it seems that such measures could result in a more coordinated electricity market, which in turn could lead to overall system cost efficiency. The new provisions will also contribute to further RES integration through better harmonized cross-border trade and cooperation, together with the clearly defined task of the new EU DSO to integrate RES.

There is also the recast Directive on common rules for the internal market for electricity (EU) 2019/944[90] which replaces Directive 2009/72/EC and which should be transposed into national law by 31 December 2020. The Electricity Directive focuses on consumers participation in the electricity market. It asks Member States to try establishing a non-discriminatory and consumer-based electricity market. Member States are encouraged to provide opportunities for consumers to participate in such market through demand-side response, storage, self-generation/consumption, energy communities and smart metering. The main provisions introduced by the Electricity Directive concerning consumers empowerment are as following:

- *Extended consumer rights*: to move away from passive consumer roles a series of measures are introduced to allow consumers to choose the most suitable solution for them. Measures such as clearer rules regarding dynamic electricity price contracts, more simplified switching processes and the ability to enter into aggregation contracts without the supplier's consent.
- *Active consumers*: the Directive now clearly states the rights of consumers to become active and to generate, sell or store their generated electricity. Active consumers should always have the right to access a grid connection.
- *Citizen energy communities*: this concept is introduced for the first time in the Electricity Directive. Citizen energy communities have the right to generate, consume, sell or store electricity (same rights as active consumers) and can access all electricity

[89] The Regulation is accessible at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2019.158.01.0054.01.ENG&toc=OJ:L:2019:158:TOC.
[90] The Directive is accessible at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2019.158.01.0125.01.ENG&toc=OJ:L:2019:158:TOC.

markets. They can also decide to own and/or operate distribution grids and participate in cross-border trade.

- *Electricity price setting*: to support low-income and vulnerable consumers, until 2025, Member States can relax the "No price regulation" rule and intervene in electricity price settings.

Overall, it seems that these measures together with those set in the RED II regarding renewables consumers, can simplify consumer participation in the electricity market and also increase RES uptake. These provisions can also encourage consumers to take a more active role. If this happens, consumers, especially higher-income consumers who can afford to install their own electricity generation or storage devices, would be able to choose the most cost-effective solution. But the question remains whether such an outcome can be extended to all consumers. Could such measures be considered as fair if, as a result of increased participation of a group of consumers, those who remain passive pay more for the service? The provision on electricity price setting intends to support the low-income consumers. But will this provision be enough to fully support vulnerable consumers or will additional measures be required to ensure fairness? These will remain as open questions until the Directive is implemented and the results are out.

Risk Preparedness Regulation[91] is another legislative act regarding electricity market design. As mentioned before**,** one of the objectives of the Clean Energy for all Europeans package is to ensure security of supply by encouraging and strengthening regional cooperation and coordination. In this context, the new Regulation (EU) 2019/941 on risk-preparedness in the electricity sector has been introduced to accelerate efforts at both national and regional levels to identify potential future electricity crises scenarios by each Member State. The new initiative, in force since 4 July 2019, requires Member States to cooperate and coordinate with neighbouring countries in preparing risk preparedness plans against these scenarios. It will help Member States to be able to prevent crises situations and, if necessary, to effectively manage them, which will in turn maximize the security of electricity provision.

The new electricity market design will need a more robust cross-border coordination among not only system operators but also among national regulators. The Agency for the Cooperation of Energy Regulators (ACER) was first established as a part of the Third Energy Package by Regulation (EC) 713/2009 to support and to enhance regional cooperation. In the Clean Energy Package, the ACER Regulation (EU) 2019/942[92] is established to recast the (EC) 713/2009 and to update the functioning of ACER. Accordingly, additional competences have been allocated to ACER to monitor activities of the regional coordination centres and system operators. This will allow a more simplified interplay among national regulators to manage cross-border interactions. In addition, ACER should supervise ENTSO-E in setting up technical parameters while ensuring that both ENTSO-E and ENTSO-G execute their tasks. Monitoring regional cooperation among electricity and gas transmission operators and the adequate implementation of energy exchanges is another responsibility of ACER.

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[91] The Regulation is accessible at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2019.158.01.0001.01.ENG&toc=OJ:L:2019:158:TOC.
[92] The Regulation is accessible at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2019.158.01.0022.01.ENG&toc=OJ:L:2019:158:TOC.

3.4 The governance mechanism of the Energy Union

As mentioned before, the Clean Energy for All Europeans Package sets Union-wide targets for GHG emissions reduction by 2030, excluding the non-ETS reduction target which is set at Member States level. Union targets are also set for, on the same time-scale, share of renewables and energy efficiency. The binding level of emissions reduction and share of RES targets is the main novelty of the CEP which provides Member states the freedom to set their individual climate and energy targets. However, it can also create some challenges with respect to ensuring that Member States will set adequate energy targets and establish and implement adequate policies so that the Union-wide targets of the CEP are collectively reached by 2030 (Vandendriessche et al., 2017)[93]. Moreover, the EU has international climate and energy commitments to deliver, including the Paris Agreement objectives, which will also need a monitoring framework to ensure that these objectives can be achieved. Therefore, to ensure that the EU will comply with its 2030 targets and international commitments, a governance mechanism with a bottom-up approach that sets binding obligations on planning, reporting, and monitoring, instead of binding energy and climate targets was required.

The Council and the European Parliament approved the Governance of the Energy Union and Climate Action Regulation (EU) 2018/1999[94] in December 2018 as one of the eight legislative acts of CEP. It sets a legislative foundation for the governance of the Energy Union and for the EU's long-term energy and climate strategies. Being a part of the CEP, for the 2021-2030 period the focus of the Regulation will be on reaching the 2030 climate and energy targets and fulfilling EU's international commitments. It aligns with the objectives of the other seven legislative pieces of CEP, especially the Renewable Energy Directive and the recast Energy Efficiency Directive.

The stated aims of the Governance Regulation are to streamline various existing planning and reporting obligations and to stimulate cross-national cooperation and coordination among Member States with respect to energy policies (European Commission, 2016). The objectives of the Governance Regulation can be summarized as following (Vandendriessche et al., 2017):

- Coordinated implementation of 2030 targets;
- Providing certainty and predictability for investors, consumers and citizens through long-term policy coherence and stability;
- Reducing administrative burdens though an integrated system of planning, reporting and monitoring;
- Ensuring compliance with the EU's international commitments (UNFCCC and the Paris agreement).

A set of provisions are used to ensure that these stated objectives are met. The key provisions are:

[93] EUI Working Papers: "The Governance of the EU's Energy Union: Bridging the Gap?" at: https://cadmus.eui.eu/bitstream/handle/1814/48325/RSCAS_2017_51.pdf?sequence=1&isAllowed=y.

[94] The Regulation is accessible at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2018.328.01.0001.01.ENG&toc=OJ:L:2018:328:TOC.

- Preparing and presenting the ten-year National Energy and Climate Plans (NECPs) by Member States;
- Providing annual and biennial progress reports by Member States;
- Monitoring progress of Member States by the Commission and providing recommendations to individual or to all Member States when necessary.

The National Energy and Climate Plan is the main instrument embedded in the Governance Regulation to ensure that the objectives of the Energy Union are considered by Member States when designing their energy and climate objectives. NECPs are ten-year plans containing the national targets and objectives of Member States covering the five dimensions of the Energy Union together with their corresponding policies and measures to meet these targets. In addition, Member States should include in their NECPs, their planned contributions and long-term strategies towards the collective achievement of Union-level climate and energy targets. A similar fixed template should be used by all Member States when preparing their NECPs which simplifies comparing them with each other and can help Member States to better collaborate over their plans when needed. The first round of NECPs should cover the 2021-2030 period and final plans should have been submitted to the Commission for evaluation by December 2019. Future NECPs should be submitted every ten years thereafter. Targets and objectives of the NECPs may be updated, but only if an upward revision of the targets is intended, and the final updated plans should be submitted to the Commission by June 2024.

As mentioned above, the national targets stated in the NECPs should be aligned with the five dimensions of the Energy Union, namely energy security, internal energy market, energy efficiency, decarbonising and research, innovation and competitiveness. In particular Member States should outline the following in their NECPs:

- Their objectives regarding increasing energy security by increasing the diversification of energy sources and supply;
- Their plans to improve gas and electricity infrastructure and interconnection points as well as cooperation with other Member States.
- Their plans and objectives regarding financing research and innovation projects.

In setting energy efficiency and share-of-renewable national targets, Member States should take into account the provisions that are established in the recast Energy Efficiency and Renewable Energy Directives. In addition, targets should be set on the basis of the achievements of the 2020 nationally-binding targets. For both energy efficiency and share of renewables targets, an indicative trajectory defining contributions from 2021 onwards should be provided. These trajectories will be collectively compared to the Union reference points in 2022, 2025, 2027 and 2030 to assess whether Union-level targets can be reached.

An iterative reporting process is a key tool in the Governance Regulation to avoid delivery gaps and to check if the plans are implemented properly. Various annual and biennial progress reports should be provided by Member States, outlining their progress towards meeting their indicative objectives as well as their progress regarding any plans covering the five dimensions of the Energy Union. Updates regarding the implementation of policies and measures on energy efficiency and renewables should be provided in more details. Frequent reporting is a strong point in Governance Regulation. It provides the Commission, as well as Member States, with the ability to monitor the progress and to assess whether the Union is on track to meet its targets. The Commission will be responsible for monitoring how plans are implemented and for assessing whether the measures that are taken by Member States are sufficient for meeting the EU-level targets, especially the collective RES and energy efficiency targets. Should the Commission decides that the contribution, ambition or progress of a Member State is not sufficient for meeting the collective Union-level targets, it is to issue adequate recommendations to the individual member state (or if needed to all Member States) to correct its (their) measures. Although these recommendations are not legally binding, Member States should explain these insufficient outcomes and should comply accordingly. For instance, in covering the gaps with respect to energy efficiency targets, Member States can consider improving the efficiency of buildings or transport sectors. With respect to covering the gaps in the share of renewables targets, Member States can adjust the share of renewables in transport and heating and cooling sectors or they can use the cooperation mechanism, all according to what is set in the Renewable Energy Directive. They could also make a voluntary financial payment to the Union renewable energy financing mechanism or contribute to renewable energy projects, managed directly or indirectly by the Commission.

The Governance mechanism seems to be strong in terms of obligations on planning and reporting. The frequent reporting mechanism can help identifying early stage ambition, delivery and trajectory gaps. Reporting with a similar template can simplify coordination among Member States. Plus, the Union-wide climate and energy targets provide extra flexibility to Member States in deciding on their national targets with respect to their socio-economic state. They will have the freedom to select their energy mix in a way that they consider to be most cost-effective for them. All of these will result in a more cost-effective decarbonisation process. However, the more serious debate is about whether the ambition level of national targets is enough for reaching Union-level targets or whether the Governance mechanism is strong enough to stimulate full implementation of national policies. The Governance Regulation requires the Commission to provide recommendations to Member States when there is insufficient progress or ambition. However, no further detail is provided as to what measures might be used by the Commission or what punitive powers might be available, should this be the outcome. In addition, the governance mechanism does not provide any strong or clear guidelines on what should be done if the recommendations are not implemented. In many senses, the governance mechanism with its suggested tools for closing the gaps is considered to be soft (Vandendriessche et al., 2017). With this respect, only time (and full implementation) will tell whether there is a need for stronger governance.

3.5 National targets contained in National Energy and Climate Plans

Under the Governance Regulation, Member States are required to prepare National Energy and Climate Plans (NECPs). NECPs should provide an overview of national energy and climate objectives and the corresponding policies to achieve these objectives over ten-year periods. These national plans should, in particular, take the 2030 targets of GHG emission reductions, renewable energy, energy efficiency and electricity interconnection into consideration when setting the 2030 targets.

The first drafts of NECPs for the first period covering 2021-2030 were required to be submitted by Member States to the Commission by 31 December 2018. After primary evaluations, a first set of recommendations was provided by the Commission in June 2019, to help Member States align their national objectives with EU level targets. The plans were required to be finalised by the end of 2019 and currently they are under evaluation by the Commission. Each member state should submit the first progress report to the Commission by 15 March 2023 and a new one every two years afterwards. The first updated integrated plans, which can only reflect an increased overall ambition and not a reduced target, should be submitted to the Commission by 30 June 2023 and be finalized by 30 June 2024.

A summary of the proposed targets in the NECPs (as in the final revised plans) [95] for renewable energy, sector-specific RES share and primary and final energy consumptions are presented in Tables 3.3, 3.4, 3.5 and 3.6.

Table 3.3. RES 2020 and 2030 targets.

Member State	2020 Framework		2030 Framework	
	2017	2020 target	RES Formula contribution	Draft NECP
Belgium	9.06%	13%	25%	17.5%
Bulgaria	18.73%	16%	27%	27.09%
Czech Republic	14.76%	13%	23%	22%
Denmark	35.77%	30%	46%	55%
Germany	15.45%	18%	30%	30.0%
Estonia	29.21%	25%	37%	42%
Ireland	10.65%	16%	31%	Between 15.8% and 27.7%
Greece	16.32%	18%	31%	35%
Spain	17.51%	20%	32%	42%
France	16.3%	23%	33%	33%
Croatia	27.29%	20%	32%	36.4%
Italy	18.27%	17%	29%	30%
Cyprus	9.85%	13%	23%	23%
Latvia	39.01%	40%	50%	50%
Lithuania	25.84%	23%	34%	45%
Luxembourg	7.5%	11%	22%	25%
Hungary	13.33%	13%	23%	21%
Malta	7.17%	10%	21%	11.5
Netherlands	6.6%	14%	26%	27-35%
Austria	32.56%	34%	46%	46-50%
Poland	10.9%	15%	25%	21%-23%
Portugal	28.12%	31%	42%	47%
Romania	24.47%	24%	34%	30.7%

[95] The finalized plans are accessible at: https://ec.europa.eu/energy/topics/energy-strategy/national-energy-climate-plans_en.

Slovenia	21.55%	25%	37%	27%
Slovakia	11.49%	14%	24%	19.2%
Finland	41.01%	38%	51%	51%
Sweden	54.5%	49%	64%	65%
United Kingdom	10.21%	15%	27%	-

Source: European Commission (2020).

Table 3.4. 2030 sector-specific share of RES in gross final consumption of energy as stated in NECPs.

Member State	**Share of RES by 2030 in:**		
	Electricity sector	**Transport sector**	**Heating and cooling sector**
Belgium	40%	25%	17.5%
Bulgaria	30.33%	14.2%	42.6%
Czech Republic	16.9%	14%	30.7%
Denmark	100%	19%	60%
Germany	65%	27%	27%
Estonia	11.4%	2%	29%
Ireland	16%	31%	Between 15.8% and 27.7%
Greece	60%	14%	40%
Spain	74%	28%	-
France	40%	15%	38%
Croatia	63.8%	13.2%	36.6%
Italy	55%	22%	33.9%
Cyprus	30.3%	14.1%	39.4%
Latvia	60%	7%	57.6%
Lithuania	45%	15%	67.2%
Luxembourg	33.6%	25.6%	30.5%
Hungary	21.3%	16.9%	28.7%
Malta	11%	15%	26%
Netherlands	49-55%	-	-
Austria	23%	3%	20%
Poland	32%	14%	28.4%
Portugal	80%	20%	38%
Romania	49.4%	14.2%	33%
Slovenia	43%	21%	41%
Slovakia	27.3%	14%	19%
Finland	53%	45%	61%
Sweden	82.6%	47.7%	72.2%
United Kingdom	-	-	-

Table 3.5. National contributions for primary energy consumption and 2020 and 2030 targets.

Member State	**2017 data (Mtoe)**	**Target for 2020 (Mtoe)**	**Contribution for 2030 (Mtoe)**	**Compared to 2020 (%)**	**Compared to 2017 (%)**
Belgium	49.1	43.7	42.7	-2.3%	-13%
Bulgaria	18.3	16.9	17.5	3.6%	-4.3%
Czech Republic	40.1	44.3	41.3	-6.9%	2.9%
Denmark	17.7	16.9	18.3	8.3%	3.4%
Germany	298.3	276.6	240	-13.2%	-19.5%
Estonia	5.6	6.5	5.5	-15.4%	-2.7%
Ireland	14.4	13.9	15.9	14.6%	10.5%
Greece	23.1	24.7	25.0	1.2%	8.1%
Spain	125.6	122.6	98.5	-19.6%	-21.5%
France	239.5	226.6	202.2	-10.7%	-15.5%
Croatia	8.3	10.7	8.2	-23.1%	-1.2%
Italy	148.9	158.0	125.0	-20.9%	-16.1%
Cyprus	2.5	2.2	2.4	9.9%	-4%
Latvia	4.5	5.4	4	-26%	-11%
Lithuania	6.2	6.5	5.46	-16%	-12%
Luxembourg	4.3	4.5	3.5	-23.0%	-19.7%
Hungary	24.5	24.1	27.0	12.0%	10.3%
Malta	0.8	0.8	1	25%	25%
Netherlands	64.5	60.7	46.6	-23.3%	-27.8%
Austria	32.5	31.5	29.0-31.0	-1.6% to -7.9%	-10.8% to -4.6%
Poland	99.1	96.4	91.3	-5.2%	-7.8%
Portugal	22.8	22.5	18.5	-17.8%	-18.9%
Romania	32.4	43.0	32.3	-25%	-1%
Slovenia	6.6	7.1	6.3	-11%	-4.5%
Slovakia	16.1	16.4	16.2	-1.3%	0.1%
Finland	31.7	35.9	34.8	-3%	9.8%
Sweden	46.1	43.4	39.6	-8.7%	-14%
United Kingdom	177.0	177.6	-	-	-

Source: European Commission (2020).

Table 3.6. National contributions for final energy consumption and 2020 and 2030 targets.

Member State	**2017 data (Mtoe)**	**Target for 2020 (Mtoe)**	**Contribution for 2030 (Mtoe)**	**Compared to 2020 (%)**	**Compared to 2017 (%)**
Belgium	36.0	32.5	35.2	8.3%	-2.2%
Bulgaria	9.9	8.6	10.32	0.4%	-12.3%
Czech Republic	25.5	25.3	23.7	-6.6%	-7.2%
Denmark	14.6	14.7	15.78	7.3%	8.1%
Germany	218.7	194.3	185	- 4.8%	- 15.4%
Estonia	2.9	2.8	2.7	-1.9%	-4.2%
Ireland	11.8	11.7	13.0	11.5%	10.9%
Greece	16.8	18.4	16.5	-10.3%	-1.7%
Spain	84.2	87.2	73.6	-15.6%	-12.5%
France	148.9	138.1	120.9	-12.4%	-18.8%
Croatia	6.9	7.0	6.9	-1.6%	-1.1%
Italy	115.2	124.0	103.8	-16.3%	-9.9%
Cyprus	1.85	1.9	2.0	5.2%	8.1%
Latvia	4.0	4.5	3.5	-22%	-12.5%
Lithuania	5.3	4.3	4.52	5.1%	-14.7%
Luxembourg	4.23	4.2	3.05	-27.3%	-27.8%
Hungary	18.5	14.4	18.6	29.0%	0.4%
Malta	0.6	0.6	0.78	30%	30%
Netherlands	50.3	52.2	43.9	-15.9%	-12.7%
Austria	28.4	26.5	24.0 – 26.0	-1.8% to -4.4%	-8.5% to -15.5%
Poland	71.0	71.6	67	-6.4%	-5.6%
Portugal	16.6	17.4	14.6	-16%	-12%
Romania	23.2	30.3	25.7	-15%	10.7%
Slovenia	4.9	5.1	4.7	-7.8%	- 4%
Slovakia	11.1	9.2	10.8	16.7%	-3.1%
Finland	25.2	26.7	24.9	-6.7%	-1.1%
Sweden	32.6	30.3	29.1	-4%	-10.7%
United Kingdom	133.3	129.2	-	-	-

Source: European Commission (2020).

In its communication on assessment of the first drafts of the NECPs[96], the Commission stated that the collective EU-level RES and energy efficiency targets for 2030 could not be met. Based

[96] The communication on assessment of 28 NECP drafts is accessible at: https://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1565713062913&uri=CELEX%3A52019DC0285.

on draft NECPs, the collective measure for renewable shares at the EU-level will be between 30.4% and 31.9% in 2030 instead of 32%. The gap was even wider for energy efficiency measures. The Commission evaluated that, with draft NECPs, the decline for primary energy consumption would be between 26.3% and 30.2 % and for final energy consumption between 26.5% and 30.7 %.

After the first assessment of the NECPs, the Commission concluded that they lack ambition, targeting only the minimum possible achievable outcomes rather than the maximum ones. The EC recommended that if the level of efforts at the national level remains insufficient for Energy Union targets, additional measures should be implemented to ensure suitable progress.[97]

It seems that Member States have considered the recommendations of the Commission, as in ten of finalised NECPs which were submitted by December 2019, the national RES targets have been increased. The Commission released its assessment if the final NECPs on 17 September 2020.The assessment states that if the plans are fully implemented, the EU can reach a range of 33.1 to 33.7% share of renewables by 2030.[98] For energy efficiency targets, however, the gap, though less than in draft NECPs, still remains.[99] The assessment shows that with the final NECPs, aggregative energy efficiency would amount to 29.7% reduction for primary energy consumption and 29.4% for final energy consumption which are both below the 32.5% target. In the same document, the Commission emphasises on prioritizing building renovation and announces its plan to revise the Energy Efficiency Directive and specific targeted provisions of the Energy Performance of Buildings Directive to stimulate energy efficiency.

3.6 Conclusion

In this chapter, we presented the Clean Energy for All Europeans Package. Following the establishment of the Energy Union, the CEP was proposed in 2016 and came into force in 2018. It includes new targets to be met by 2030, accompanied by new instruments to make this happen. In a period of ten years, the EU: should reach a 40% GHG emissions reduction compared to the 1990 levels (10% more than 2020 target and it might further increase this to 50-55% under the Green Deal); should increase share of RES to 32% of final energy consumed (12% more); and should reduce energy consumption by 32.5% (12.5% more). The 2030 targets are *per se* more ambitious than the 2020 ones considering what has been achieved over, almost, the same period. However, by providing new instruments and also by revising a number of existing ones, the Clean Energy Package tries to facilitate the achievement of these ambitious goals.

The new and revised instruments in form of eight pieces of legislation, including four Regulations and four Directives, were presented and discussed throughout the chapter. These pieces of legislation include: a Directive on Energy Performance of buildings; the recast

[97] Communication assessing the 28 draft NECPS, 18 June 2019: https://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1565713062913&uri=CELEX:52019DC0285.

[98] COM(2020) 564, "An EU-wide assessment of National Energy and Climate Plans", European Commission, 17 September 2020. Accessible at: https://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1600339518571&uri=COM:2020:564:FIN

[99] In final NECPs, the collective 2030 measure for primary energy consumption is 1176 Mtoe and for final energy consumption is 885 Mtoe. The 2030 target for PEC is 1128 Mtoe and for FEC is 846 Mtoe.

Renewable Energy and Energy Efficiency Directives; the Governance Regulation; and four legislative acts for establishing a modern electricity market (consisting of an amending electricity directive, a new electricity regulation, a risk preparedness regulation and a regulation outlining a stronger role for ACER).

The 2030 targets on GHG emissions and RES integration are set at the EU-level, unlike those of 2020 which were nationally binding targets. This raised concerns regarding whether the individual efforts of Member States would be sufficient for reaching Union-wide targets. This led to the establishment of a new governance mechanism under the Regulation for Energy Union Governance. The aim of this Regulation is to set a coordinated planning and reporting mechanism which can also facilitate progress monitoring at the member-state level. Based on the governance mechanism, Member States are required to present their individual national energy and climate targets and their policies to reach these targets by 2030 under their National Climate and Energy Plans (NECPs). Then, subsequently, they need to report their progress towards the achievement of their goals periodically. The Commission will, then, be responsible for monitoring the progress of Member States and for providing recommendation where needed. The final version of NECPs submitted by Member States show that based on these plans, the Union-wide targets for 2030 can be achieved. Although in terms of both RES share and energy efficiency targets, the targets look as if they will only just be achieved, if at all.

4. The European New Green Deal: European carbon neutrality by 2050

4.1 Commitment to carbon neutrality in 2050

The EU's journey towards emissions reduction led to the setting of specific climate and energy targets for 2030. Several measures and policies were established to stimulate the move towards meeting two different sets of targets by 2020 and 2030. The EU was successful in reaching its 2020 climate target with 23% of GHG reductions by 2018 compared to the 1990 level; the initial target had been 20% by 2020. For 2030, an initial 40% Union-level reduction target compared to 1990 was included in the CEP. The ultimate goal of the EU, however, is to become the first climate-neutral economy by 2050.

In October 2018 the IPCC Special Report on the necessity of limiting global warming to 1.5°C rather than 2°C was published. The report set out the social and economic costs of global warming and, as such, the absolute urgency of climate neutrality by 2050. Shortly after, in November 2018, the European Commission proposed an objective of carbon neutrality by 2050 in its "A Clean Planet for All" communication. After troubled negotiations among Member States (which highlighted the difficulty of achieving this target due to different socio-economic characteristics of Member States) the EU level objective of carbon neutrality by 2050 was approved by the European Council in December 2019. "A Clean Planet for All" also included proposals for various scenarios and pathways for taking the EU towards this goal and discussed the need for drastic efforts going well beyond present measures for reaching this goal. Accordingly, in December 2019, the European Commission proposed a series of initiatives, including 50 actions over the next five years, as a roadmap for reaching climate-neutrality by 2050. This strategic roadmap, called the European Green Deal (EGD), alongside reducing GHG emissions, aims at decoupling economic growth from resource use through a just and inclusive transition. The Green Deal addresses different environmental/sustainability aspects. It covers a wide spectrum of measures within eight policy areas: clean energy; biodiversity; agriculture and food; sustainable industry; buildings renovation; transport; eliminating pollution; and actions against climate change. The Green Deal is also a growth strategy that aims at boosting innovation and job creation by providing support for small and medium-sized enterprises across the EU in a sustainable manner through the adoption of a new EU industrial strategy.[100] Additionally, the Green Deal aims at tackling the social aspects of the transition by adopting a just transition mechanism for funds allocation. From the international point of view, with the Green Deal, the EU is trying to lead by example: it is using all the instruments at its disposal (including multilateral/bilateral trade and development policies) to show how climate objectives can be achieved, while growth and fairness are secured.

4.2 Financing the transition

Achieving net zero emissions by 2050 will require extensive investments. These investments should come not only from the public sector, such as the EU and national funds, but also from the private sector. In this context, 14 January 2020 the Commission released a communication,

[100] On 10 March 2020 the Commission proposed a new European Industrial Strategy with the establishment of green transition, global competitiveness and digital transition as its core values for supporting small and medium-sized enterprises across the EU. In addition, the Commission will support a new circular economy action plan to ensure that sustainable products will be available to consumers.

addressing the European Green Deal Investment Plan, also known as the Sustainable Europe Investment Plan. The plan has three dimensions:

a) Financing: mobilising investments through various financial tools;

b) Enabling: unlocking public and private investments in green projects by reducing risks and providing incentives;

c) Practical support: supporting public authorities and project promoters in planning, designing and executing sustainable projects.

The initial European Green Deal Investment Plan aimed at mobilizing at least €1 trillion in investments from both the private and public sectors through several financial instruments including the InvestEU Program, the Just Transition Mechanism, national structural funds and the Innovation and Modernisation funds under the EU ETS.

With the emergence of Covid-19, on 27 May the European Commission proposed a major recovery plan[101] with the fight against climate change and the Green Deal as a growth strategy, at its heart. On 21 July, after going through several rounds of negotiations among the 27 Member States, the European Council agreed on a recovery budget encompassing a Multiannual Financial Framework (MFF) equal to €1074bn, which will cover seven years, 2021-2027. There was also a recovery instrument called the Next Generation EU (NGEU) of some €750bn which will cover the 2021-2024 period.[102]

21 July, the Council announced that to comply with the EU's commitment to the objectives of the Paris Agreement and the United Nations Sustainable Development Goals *"programmes and instruments should contribute to mainstream climate actions and to the achievement of an overall target of at least 30% of the total amount of Union budget and NGEU expenditures supporting climate objectives. EU expenditure should be consistent with Paris Agreement objectives and the "do no harm" principle of the European Green Deal."* This means that approximately €550bn of MFF+NGEU funds should be allocated to climate and environmental measures for the next seven years.

The InvestEU Fund will be the EU's internal investment support mechanism for mobilising public and private investment through an EU budget guarantee of €75bn, which will back the investment projects of implementing partners. The European Investment Bank (EIB) will play an important role in implementing Union policies and in contributing to digitalising Europe's economy, as well as by taking part in the fight against climate change. The EIB will become the privileged implementing partner for InvestEU.

In the 2021-2030 period, the EU will need to increase its annual investments by € 350 billion compared to the 2011-2020 period in order to achieve its 2030 climate and energy targets.[103]

[101] COM (2020) 456 final: 'Europe's moment: Repair and Prepare for the Next Generation', European Commission, 27 May 2020. Accessible at: https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:52020DC0456&from=IT

[102] Conclusions of the Special meeting of the European Council, 17-21 July 2020, Accessible at: https://www.consilium.europa.eu/media/45109/210720-euco-final-conclusions-en.pdf

[103] COM (2020) 562 final: 'Stepping up Europe's 2030 climate ambition Investing in a climate-neutral future for the benefit of our people', Communication by the European Commission, 17 September 2020. Accessible at: https://ec.europa.eu/clima/sites/clima/files/eu-climate-action/docs/com_2030_ctp_en.pdf

As mentioned above, investments for the transition to a climate-neutral, climate-resilient, resource-efficient and just economy should also come from the private sector as the public sector alone does not have the necessary resources. To this end, the Sustainable Finance initiative will play an important role in mobilising the necessary investments from the private sector by *"re-orienting private investments towards more sustainable technologies and businesses"*.

One of the key points of the Green Deal is the achievement of net-zero emissions while leaving no one behind. A just transition can, indeed, be an important aspect of the shift towards climate neutrality by 2050, as Member States will face the challenge in different ways. To provide both budgetary and practical support to those regions which will be affected by the transition more than others, the Just Transition Mechanism (JTM) has been introduced. Over the 2021-2027 period, funds will be available for most affected regions under the JTM to alleviate the distributional effects of the transition including the loss of fossil-fuel related jobs and increasing employment in sustainable facilities, instead. To this end, a Just Transition Fund (JTF) will be established receiving some €17.5 billion of EU funds (adjusted under the Green Recovery plan and the Council's conclusions of July 2020). In cooperation with the Commission, Member States will need to identify regions which are eligible for JTF funding.

4.3 A 55% GHG emissions cut by 2030

The ambitious target of becoming the first climate-neutral economy, will require more ambitious EU-level binding targets and a roadmap of long-term strategies and policies, until and beyond 2030. This translates into the need for raising previously agreed targets. In this regard, in March 2020, the Commission proposed the first European Climate Law[104] aiming at making the main objective of the European Green Deal (i.e. net-zero GHG emissions by 2050) an EU-wide binding target. To ensure that existing policies will be consistent with climate-neutrality, a number of amendments are suggested in the proposal. These include an increase in the 2030 GHG emissions reduction target from 40% to 50-55%, as well as the adjustment of national climate targets stated in the NECPs under the Governance Regulation to better reflect EU-wide climate-neutrality objective.

The first step addressed in Climate Law was to propose the new 2030 GHG emissions target by the Commission based on a comprehensive impact assessment, by September 2020. On 17 September 2020, as the Impact Assessment of the social, economic and environmental impacts of increasing the GHG emissions reduction target of 2030 demonstrated that it is, in fact, a realistic and feasible goal, the Commission presented its plan[105] for increasing this target from 40% to 55%. The same assessment by the Commission suggest that in order to reach the 55% reduction measure in 2030, the share of RES target should increase to 38-40% by 2030 while final and primary energy consumption would have to decrease to around 39-41% and 36-37%, respectively. This entails that not only current NECPs should be updated to include more ambitious national energy and climate targets for 2030 but also several of current legislations should be revised to enable/enforce the efforts to achieve these more ambitious targets.

[104] 'Proposal for a European Climate Law' at: https://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1588581905912&uri=CELEX:52020PC0080

[105] COM (2020) 562 final: 'Stepping up Europe's 2030 climate ambition Investing in a climate-neutral future for the benefit of our people', Communication by the European Commission, 17 September 2020. Accessible at: https://ec.europa.eu/clima/sites/clima/files/eu-climate-action/docs/com_2030_ctp_en.pdf

Accordingly and based on the proposed Climate Law, the next steps will be as follows:

- Proposing, by June 2021, necessary revisions to existing policy instruments in order to comply with the new 2030 target. It is most likely that, among other things, the revision of related pieces of horizontal legislation including the Emissions Trading System Directive and the Effort Sharing Regulation, and energy-specific legislation such as the Renewable Energy Directive, the Energy Efficiency Directive, the Energy Taxation Directive and the TEN-E Regulation will be required. Furthermore, as mentioned above, Member States will need to take additional measures and to increase their 2030 RES and Energy Efficiency targets, in their NECPs. In addition, the introduction of new development strategies can be expected in order to deliver the EU's strategic long-term goal including an action plan for fostering the building renovation (the Renovation Wave), a strategy for facilitating the integration of offshore renewable energy and a strategy to tackle methane leakage.

- The adoption of an EU-wide 2030-2050 trajectory for GHG emissions to measure progress after 2030. Based on the exiting reporting and monitoring mechanism that is included in the Governance Regulation, the Climate Law also proposes measures for tracking progress towards the net-zero objective and for adjusting actions when necessary. The governance mechanism presented in the Climate Law is considered to be complementing the existing mechanism, namely the Governance Regulation. By September 2023, and every five years thereafter, progress at the EU and the national levels will be assessed to make sure that they are consistent with the 2030-2050 EU-wide trajectory and the climate-neutrality objectives. The Commission will then have the authority to issue recommendations to Member States to fill any gaps. As in the Governance Regulation, Member States should take account of these recommendations.

4.4 The new agenda of the Commission for implementing the Green Deal

4.4.1 Proposal for ETS Revision

The Commission proposed to increase the 2030 GHG emission reduction target from 40% to 55% in September 2020. To reach this ambitious target, more efforts will be required in the 2021-2030 period and current EU legislation and instruments will be reviewed by 30 June 2021 to make sure that they comply with this target. EU ETS is one of these instruments and the EU will review its fourth phase, which covers the 2021-2030 period, while tightening the cap on GHG emission reductions, as well as extending the EU ETS to include some sectors which are not currently regulated under this system. The Commission will also consider an extension of the EU ETS to the maritime and shipping sectors. Another change will be an increase in the annual Linear Reduction Factor and the phasing out of free allowances. The aviation sector, in particular the intra-EU aviation emissions, will see the reduction of free allowances. The Green Deal also proposes carbon pricing for both the transport and the building sectors to complement GHG emission reduction measures in these sectors with additional EU ETS provisions by 2030.

After the phase-out of free allowances, as an alternative and to prevent carbon leakage, the Commission will propose the adoption of a carbon border adjustment mechanism for certain sectors, in parallel with the EU ETS revision; this is also known as a carbon border tax, reflecting carbon emissions attributed to imported goods. This mechanism will enable the ETS to cover sectors such as steel and cement and will be necessary for helping these industries, maintaining their competitive status if the gap between the EU's and global-climate ambition widens. The carbon border adjustment mechanism will be compatible with the World Trade Organisation (WTO) rules and will be negotiated with trade partners accordingly.

4.4.2 Proposal for the revision of existing energy policies and for the introduction of new energy strategies

Increasing the 2030 emissions reduction target to 55% is an ambitious goal, not only in terms of the scale of emissions reduction over just ten years, but also due to other challenges that it would create. For instance, the energy sector is the main GHG emitting sector and inevitably a great deal of attention will be given over to decarbonizing here through fossil fuels abatement and an increased integration of renewable resources for both electricity generation[106] and mobility purposes. This will require extensive infrastructure investments and the rapid development of innovative technologies, which can be challenging.

The Green Deal intends to address these challenges and to propose potential solutions for them through the introduction of new instruments; it also proposes reforms to existing legislation. Here we present the most important reforms and initiatives proposed under the Green Deal for the energy sector to date.

Revising the Energy Taxation Directive

The EU ETS is an important tool for addressing the problems with emissions, but this covers less than half of the emissions in the EU (the largest polluters in power generation and industry). Energy taxation as a tool for sending the right price signals can be complementary to the EU ETS (and Effort Sharing). The first Energy Taxation Directive (ETD), Directive 2003/96[107], was approved, 27 October 2003, by the Council. Its purpose was to establish a harmonized energy taxation framework across the EU and to ensure the functionality of the internal market. It defined EU rules on the minimum taxation of energy products as motor or heating fuels and for electricity. To also include climate objectives in the Directive, the Commission proposed a revision in 2011, which was withdrawn in 2015. On 12 September 2019, the Commission published its evaluation of the ETD,[108] stating clearly that the Directive is no longer contributing to the EU's policy objectives. This is due both to several technological developments which have changed the energy market since 2003 and to advancing EU climate and energy objectives, which will require a timely energy taxation mechanism. The evaluation also points out that the current mix of energy products in the EU markets are not reflected in the ETD and that the Directive lacks the ability to link minimum tax rates for fuels and their energy content and CO_2 emissions.[109] It concludes that these deficiencies make the current ETD incompatible with other EU energy and climate policies (such as the EU ETS, Renewable

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[106] The 40% GHG emission reduction required 53% of electricity to come from renewables by 2030. With the 55% GHG emission target, the share of RES-E should now increase to 67% ('Contribution of the Florence School of Regulation to the European Commission consultations on Energy Sector Integration & Hydrogen Strategy'. Florence School of Regulation, EUI, June 2020, by Conti et al.).

[107] Accessible at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=celex%3A32003L0096.

[108] Accessible at: https://ec.europa.eu/taxation_customs/sites/taxation/files/energy-tax-report-2019.pdf

[109] Evaluation of the Energy Taxation Directive (ETD) by the European Commission, September 2019: https://ec.europa.eu/taxation_customs/sites/taxation/files/energy-tax-report-2019.pdf

Energy Directive and Energy Efficiency Directive) and that they might hinder the achievement of the EU's climate and energy objectives, especially its climate neutrality target.

In this context, in the Green Deal the Commission proposed to revise the Energy Taxation Directive to:

> *"a) align taxation of energy products and electricity with EU energy and climate policies, to contribute to the EU 2030 energy targets and climate neutrality by 2050;*
>
> *b) preserve the EU single market by updating the scope and the structure of tax rates and rationalising the use of optional tax exemptions and reductions."* [110]

Policy options which could be included in the ETD revision are:

a) Better alignment of maximum tax rates to the EU's climate and energy policies by taking into account what affects excise rates such as inflation, energy content and linkage to GHG emissions;

b) Implementation of sectoral tax differentiation by differentiating motor fuel and heating fuel in different sectors such as maritime and aviation;

c) Considering different tax mechanisms for different energy products based on their contribution to climate objectives.

A revision of the Energy Taxation Directive is currently under preparation and should be presented for public consultation in Q2 2020. A Commission proposal is expected in Q2 2021.

EU Strategy on Energy System Integration and Hydrogen

Energy system integration is defined as *"the coordinated planning and operation of the energy system 'as a whole', across multiple energy carriers, infrastructures, and consumption sectors"*.[111] This kind of holistic view of the energy system, using existing synergies among different infrastructures through different technologies could lead to significant cost savings on the path towards climate neutrality. The three pillars of the European Commission's view on how energy system integration will contribute to fulfilling its climate neutrality objective include:

1. *The creation of a more 'circular' energy system, with energy efficiency at its core.*
2. *The achievement of greater direct electrification of the end-use sector.*
3. *The use of renewable and low-carbon fuels, including hydrogen, for end-use applications where direct heating or electrification are not feasible.*

The Commission states that implementing energy system integration can: lead to decarbonisation of those sectors which are hard to decarbonise (such as the transport sector or certain industrial processes); strengthen EU competitiveness, empower consumers and provide

[110] Retrieved from: https://ec.europa.eu/info/law/better-regulation/have-your-say/initiatives/12227-Revision-of-the-Energy-Tax-Directive

[111] 'Powering a climate-neutral economy: An EU Strategy for Energy System Integration', Communication by the European Commission, July 2020.

additional flexibility for energy systems through various technologies such as storage systems; and. These outcomes would be achieved by linking electricity, gas, transport, buildings and industry sectors. Indeed, as this is a whole system approach, several barriers can be raised towards its implementation. Examples of possible barriers include: infrastructure development, providing financial supports to new technologies, regulatory barriers, information sharing and consumer rights. To establish a whole system approach that encompasses different sectors and different energy carriers and to overcome some of the aforementioned barriers, the revision of several existing pieces of legislation will be necessary.

The Commission published its communication on the "EU Strategy for Energy System Integration"[112], 8 July 2020, setting out six major pathways and 38 actions within these pathways to create an integrated energy system across the EU. The proposed actions by the Commission include the notion of necessary revisions of several pieces of legislation including the Renewable Energy, Energy Efficiency and the Energy Performance of Buildings Directives, TEN-E and TEN-T Regulations, EU ETS and the Energy Taxation Directive. Table 4.1 presents the six pathways and the 38 key actions proposed in the "EU Strategy for Energy System Integration".

Table 4.1. EU Strategy for Energy System Integration.

Major Pathways	**Key Actions**	**Legislations to be Revised**
A more circular energy system, with the energy-efficiency-first principle at its core	*To better apply the energy-efficiency-first principle:* • Issue guidance to Member States on how to make the energy-efficiency-first principle operational; • Promote the energy-efficiency-first principle in all upcoming relevant legislative revisions; • Review the Primary Energy Factor. *To build a more circular energy system:* • Facilitate the reuse of waste heat from industrial sites and data centres; • Incentivize the mobilization of biological waste and residues from agriculture, food and forestry sectors.	• TEN-E Regulation; • Energy Efficiency Directive; • Renewable Energy Directive.
Accelerating the electrification of energy demand, building on a largely renewables-based power system	*To ensure continued growth in the supply of renewable electricity:* • Ensure the cost-effective planning and deployment of offshore renewable electricity; • Establishing minimum mandatory green public procurement (GPP) criteria; • Tackle remaining barriers to a high level of renewable electricity supply. *To further accelerate the electrification of energy consumption:* • As part of the Renovation Wave initiative, promote the further electrification of buildings' heating; • Develop more specific measures for the use of renewable electricity in transport, as well as for heating and cooling in buildings and industry;	• Renewable Energy Directive; • Alternative Fuels Infrastructure Directive; • Industrial Emissions Directive; • TEN-E Regulation.

[112] Accessible at: https://ec.europa.eu/energy/sites/ener/files/energy_system_integration_strategy_.pdf.

	• Finance pilot projects for the electrification of low-temperature process heat in industrial sectors; • Assess options for supporting the further decarbonisation of industrial processes; • Propose to revise CO_2 emission standards for cars and vans. *To accelerate the roll-out of electric vehicle infrastructure and ensure the integration of new loads:* • Support the roll-out of 1 million charging points by 2025; • Accelerate the roll-out of the alternative fuels infrastructure; • Take up corresponding requirements for charging and refuelling infrastructure; • Develop a Network Code on Demand Side Flexibility for unlocking the potential of electricity consumption to contribute to the flexibility of the energy system.	
Promoting renewable and low-carbon fuels, incl. hydrogen, for hard-to-decarbonise sectors	• Propose a comprehensive terminology for all renewable and low-carbon fuels and a European system of certification of such fuels; • Consider additional measures for supporting renewable and low-carbon fuels, possibly through minimum shares or quotas in specific end-use sectors (aviation and maritime); • Promote the financing of flagship projects of integrated, carbon-neutral industrial clusters; • Stimulate the production of fertilisers from renewable hydrogen through Horizon Europe; • Demonstrate and scale-up the capture of carbon for its use in the production of synthetic fuels, possibly through the Innovation Fund; • Develop a regulatory framework for the certification of carbon removals.	• Renewable Energy Directive.
Making energy markets fit for decarbonisation and distributed resources	*To promote a level-playing field across all energy carriers:* • Issue guidance to Member States for addressing the high charges and levies borne by electricity and for ensuring the consistency of non-energy price components across energy carriers; • Align the taxation of energy products and electricity with EU environment and climate policies; • Provide more consistent carbon price signals through a possible proposal for the extension of the ETS to new sectors; • Phasing out direct fossil fuel subsidies; • Revision of the State aid framework. *To adapt the gas regulatory framework:* • Review the legislative framework to design a competitive decarbonised gas market. *To improve customer information:* • In the context of the Climate Pact, launch a consumer information campaign on energy customer rights; • Improve information for customers on the sustainability of industrial products.	• Energy Taxation Directive; • EU ETS; • State aid framework.
A more integrated	• Revisions of the TEN-E and TEN-T regulations to fully support a more integrated energy system;	• TEN-E Regulation;

energy infrastructure	• Review the scope and governance of the TYNDP; • Accelerate investment in smart, highly-efficient, renewables-based district heating and cooling networks.	• TEN-T Regulation; • Renewable Energy Directive; • Energy Efficiency Directive.
A digitalized energy system and a supportive innovation framework	• Adopt a Digitalisation of Energy Action plan to develop a competitive market for digital energy services; • Develop a Network Code on cybersecurity in electricity with sector-specific rules; • Adopt the implementing acts on interoperability requirements and transparent procedures for access to data within the EU; • Publish a new impact-oriented clean energy research and innovation outlook for the EU.	

Source: EC (2020).

Role of Hydrogen

In the recovery plan proposal by the Commission[113] the need to unlock investment in key clean technologies and value chains has been emphasised on and clean hydrogen has been pointed to as one of the essential areas to address in the context of energy transition

Hydrogen has various applications in several sectors. It can be used as an industrial feedstock (to produce ammonia, steel, aluminium, etc), as fuel or storage and it can be used to decarbonise hard to electrify sectors. In addition, when used as an energy source, hydrogen emits no CO_2. Therefore, the development of hydrogen technologies is considered, in the Green Deal, to be an essential solution for delivering carbon neutrality and for playing an important role in establishing sector integration.

As mentioned before, hydrogen is a clean energy source, but CO_2 might be produced during its manufacture. Based on levels of the emitted CO_2, the hydrogen produced might be labelled as "clean" (produced using renewable energy), "grey" (produced using fossil-fuels) or "low-carbon" (produced using either non-renewable electricity or fossil-fuels but with carbon capture technology). Although renewable hydrogen has several merits and could contribute significantly to the EU's journey towards net zero emissions by 2050, it is not yet a cost-efficient technology. The large-scale adoption of renewable hydrogen (produced using wind and solar energy) is still far from being a reality due to its high cost. Meanwhile, low-carbon hydrogen is gradually taking on its role as an alternative; however, as with renewable hydrogen, it is not cost-competitive against fossil-based hydrogen.

The share of hydrogen in the EU's energy mix is projected to grow from less than 2% (now) to 13-14% by 2050.[114] However, several challenges remain for all hydrogen types. These

[113] COM (2020) 456.
[114] 'A Clean Planet for All. A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy', COM(2018) 773.

include a lack of infrastructure investments[115], regulatory barriers and holes in research and development. In this regard, the European Commission presented "A hydrogen strategy for a climate-neutral Europe" on 8 July 2020[116], addressing the challenges of developing hydrogen technologies across the EU and proposing the steps necessary for overcoming them. In the Strategy, the following timeline is proposed by the Commission for the large-scale development of the technology across the EU:

- From 2020 to 2024, the installation of at least six gigawatts of renewable hydrogen electrolysers in the EU, and the production of up to one million tonnes of renewable hydrogen.

- From 2025 to 2030, hydrogen becomes an intrinsic part of the integrated energy system, with at least 40 gigawatts of renewable hydrogen electrolysers and the production of up to ten million tonnes of renewable hydrogen in the EU.

- From 2030 to 2050, renewable hydrogen technologies should reach maturity and be deployed on a large scale across all hard-to-decarbonise sectors.

The implementation of this plan and the scaling of hydrogen requires a number of complementary actions including the revision of some existing legislation and the establishment of adequate support mechanisms. In particular, the Hydrogen Strategy proposes the revision of the TEN-E regulation to include hydrogen-friendly infrastructure planning and TYNDPs and for stimulating private investments in electrolysers. In addition, revisions of the Alternative Fuels Infrastructure Directive (AFID) and regulation around the Internal Gas Market are proposed to accelerate infrastructure development and the establishment of enabling market rules for the deployment of hydrogen. The Strategy also proposes the allocation of funds through a number of schemes including: the Strategic European Investment Window of InvestEU; the ETS Innovation Fund to support demonstration of innovative hydrogen-based technologies; and market-based support mechanisms for renewable hydrogen. The Commission has also launched the European Clean Hydrogen Alliance as a complement for the Energy System Integration Strategy and for developing an investment agenda and a pipeline of concrete projects. The Alliance will be a point of cooperation between public authorities, industry leaders, civil society and the European Investment Bank.

4.5 Covid19: the Next-Generation EU Plan

The Green Deal is challenging per se: it is very broad and ambitious and its success will depend on its effective implementation both at the EU and at the MS level. The Deal, as, a new growth strategy for the EU, still needs to be approved by EU legislators. Following the proposed action plan117 by the Commission many initiatives announced in the Green Deal have to be formulated by the Commission and where they are of a legislative nature, they will require not

[115] Cumulative investments in the EU could be up to €180-470 billion for renewable and €3-18 billion for low-carbon hydrogen by 2050 (as stated in the proposed Hydrogen Strategy).
[116] Accessible at: https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf
[117] Available at: https://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1596443911913&uri=CELEX:52019DC0640#document2

only adoption EU legislators but also effective application in the Member States. Meanwhile, the Covid-19 outbreak and its socio-economic consequences have raised additional concerns regarding the effective implementation of the Green Deal.

As the coronavirus outbreak rapidly developed, several sectors of the economy were affected due to heavy restrictions put in place by governments to fight the outbreak; this was particularly true of the energy sector. For instance, electricity consumption declined notably in many EU countries (between 10 to 28% in three major EU economies: Germany, France and Italy). As demand declined, fossil-based electricity generation declined as well (following the generation merit order) and wholesale electricity markets experienced many episodes of negative prices. In addition, lockdown measures had a heavy impact on the carbon-intensive aviation industry. These events resulted in a reduction of demand for the EU ETS and consequently carbon price collapsed, for a short period, from €25/ton to €15/ton[118], removing the pressure from carbon-intensive industries to invest in clean technologies.

Thus, the fear was that turning the attention of policymakers to new economic challenges and the need for a post-COVID economic recovery, would also push aside climate change concerns and would hinder investments in low-carbon industries and technologies. Accordingly, when debates started up around providing financial support for affected Member States and when, in May, France and Germany supported a potential €500bn recovery plan, voices were heard in support of a 'green' post-COVID recovery plan. The argument was that the Green Deal is also a 'growth strategy' that could contribute to the recovery. It is true, the argument went, that the pandemic is an urgent issue which needs immediate attention, but climate change is, and will remain a priority that requires our best efforts. The huge funds needed for recovery are both a risk (the money could no longer be spent on greening the economy and some spending might lead to stranded costs) and, if used properly, an opportunity to re-orient activities towards a greener economy. This was a lesson learned from the aftermath of the 2008 economic crisis. Between 2008 and 2009 GHG emission declined rapidly in the EU but they bounced back in 2013 as the recovery kicked in. This turn of events was not predicted in the EU's €200bn Economic Recovery Program. Energy efficiency and emissions reduction were pushed aside and only 2% of the budget was reserved for climate change.

On 27 May the Commission proposed a new recovery instrument called Next Generation EU within a revamped EU budget.[119] The Next Generation EU, €750bn for the 2021-2023 period, was said to complement the EU budget of €1100bn for the 2021-2027 period. The Green Deal and digitalization were placed at the heart of the proposed package and 25% of spending was, it was decided, to be devoted to climate action. This was a message to show that the EU was committed to its carbon neutrality goal and to maintaining its long-term vision. In the words of Commission President Ursula von der Leyen:

"The recovery plan turns the immense challenge we face into an opportunity, not only by supporting the recovery but also by investing in our future: the European Green Deal and digitalization will boost jobs and growth, the resilience of our societies and the health of our environment. This is Europe's moment. Our willingness to act must live up to the challenges we are all facing. With Next Generation EU we are providing an ambitious answer."

[118] Carbon prices bounced back and in September 2020 the average price stood at €28/ton.
[119] COM 456 (2020).

On 21 July, the European Council agreed upon a deal supporting the Commission's proposals. The deal, which still needs consent from the European Parliament, agrees on: 1) a Multiannual Financial Framework for the 2021-2027 period with €1074bn; and 2) the NGEU for the 2021-2023 period with €750bn. As with the Commission's proposal, on 27 May, climate action is mainstreamed in all policies with 30% of the total amount from both MFF and NGEU to be allocated to climate change objectives. In addition, the conclusions published by the Council also emphasize the importance of sticking to the "do no harm" principle as proposed in the Green Deal. However, some points are open to criticisms. For instance, the budgets for some key climate programs which are part of the Green Deal, such as InvestEU and Horizon Europe, were cut. The Just Transition Fund received half of the budget which had been previously suggested (€17.5bn). In addition, no clear rules were introduced in the deal to make sure that the 30% budget for climate action is invested in low-carbon schemes.

The July agreement still requires approval by the European Parliament. Its implementation, meanwhile, will be challenging both in term of the social and industrial aspects of the 'green recovery'. From a social and political point of view, protecting jobs and incomes will be a post-pandemic priority. Prioritizing sectors for financial support could be specially challenging: Member States should decide whether to protect jobs in carbon-intensive industries; or whether to support jobs in other sectors. From a policy-making point of view and focusing specifically on the energy sector, the treatment of natural gas is a challenge. Natural gas has been considered as a transition fuel for replacing coal and oil and for ensuring the flexibility of electricity networks but it is increasingly challenged by technologies such as Demand Response and storage whose costs are becoming more and more competitive. Thus, how policies regarding investments in natural gas projects (particularly PCIs) should evolve remain as an open debate. From a technological point of view, again in the energy sector, the challenge could be that of developing and adding immense RES to energy networks and also with the development of hydrogen technologies. Glachant (2020),[120] discusses these two aspects raising several questions regarding technical and policy issues:

1) Market design: with the 55% GHG emissions reduction target by 2030, will the electricity market design be up to the job of facilitating the integration of a large amount of RES (more than 63% of RES share in the electricity mix)?
2) Is the physical infrastructure, including the distribution grids, well-planned for accommodating a massive amount of RES? How should network planning, network investments and grid tariffs evolve? What would be the role of grid users?
3) Hydrogen is rising to become a promising substitute for fossil fuels especially in carbon-intensive industries. The Commission recognized this trend and has published its communication on a new Strategy on Hydrogen. However, with various hydrogen production technologies (green, blue and grey), the question is which will become the

[120] 'Greening the covid-19 recovery: feasibility and implementation issues in the European Union', Jean-Michel Glachant, The Oxford Institute for Energy Studies, July 2020: https://www.oxfordenergy.org/wpcms/wp-content/uploads/2020/07/GREENING-THE-COVID-19-RECOVERY-FEASIBILITY-AND-IMPLEMENTATION-ISSUES-IN-THE-EUROPEAN-UNION.pdf

main focus of the EU policy framework. What proportion of R&D budgets should go to each of those technologies? Cost-effectiveness will prove decisive.

Overall, the EU's Green Recovery plan seems to be feasible and is a step forward for the EU. It shows how 27 countries can unite in solidarity to overcome challenges. Questions remain and these must be resolved, but the first steps have been taken and we will see how successful this recovery plan proves.

5. Visions of the energy sector in a carbon neutral society

In this chapter, we will analyse the role of technological assumptions within different future visions of the energy sector in a carbon neutral society. In particular, we will analyse the role of technological assumptions for seven "energy scenarios" [121] (future energy visions or narratives supported by detailed quantitative modelling) based on the following criteria: 1) world level or EU-region level focus; 2) developed by organisations recognised for their "energy scenarios" modelling; 3) a time horizon until 2050 or even beyond; and 4) compatibility with the Paris agreement targets.[122] We analyse the role of technological assumptions within and across these different future visions based on two metrics (namely, annual CO_2 emissions reduction potential *per* technology portfolio and cumulative technological investments); and with two time horizons (2030 and 2050). We analyse these metrics both at an aggregated-level and at a disaggregated-level (i.e. nine different technology sets). These nine technologies sets are formulated: 1) based on a common logic in how they contribute to energy sector decarbonization; and 2) based on availability of data for technological investments and annual CO_2 emissions reduction potential.

Taking into the account the long-term nature of technological investments and the political sensitivity around them, we are interested in answers to the following questions:

1. Are the visions on the decarbonisation of the energy system diverse or similar?
2. What are the key common technological assumptions across these studies? Is there any consensus that the increasing penetration of renewable electricity in the power sector holds has the best potential for reducing CO_2 emissions, as often suggested by policy-makers? Is there also a common phase-out of fossil fuel investments?
3. On which technologies do these studies diverge? Is there any consensus regarding the potential of other, less frequently mentioned technological solutions? In particular, are immature breakthrough technologies assumed to have potential or are they neglected? What about the role of decarbonised gases (e.g. hydrogen)?
4. Are the additional infrastructure costs and balancing technologies costs expected to enable energy system decarbonisation accounted for in these energy scenarios? How much do they contribute to the overall cost?
5. For the EU, are the technological trends pinpointed in the European Green deal[123] Communication confirmed?

[121] The following example reports more details on energy scenarios storylines and how these are designed: https://www.iea.org/commentaries/understanding-the-world-energy-outlook-scenarios.

[122] Note: the Paris Agreement on Climate Change entered into force 4 November 2016 and the parties which ratified this convention have to communicate, by early 2020, to the United Nations Framework Convention on Climate Change, their own nationally-determined contributions (NDCs) towards the global greenhouse gas emissions reduction target.

[123] "Further decarbonising the energy system is critical to reach climate objectives in 2030 and 2050. The production and use of energy across economic sectors account for more than 75% of the EU's greenhouse gas emissions. Energy efficiency must be prioritised, A power sector must be developed that is based largely on renewable sources, complemented by the rapid phasing out of coal and decarbonising gas ….". Source: https://ec.europa.eu/info/sites/info/files/european-green-deal-communication_en.pdf.

The seven energy scenarios [124] are the following:

1) World Energy Outlook (WEO) 2019 "Sustainable Development goals" scenario (IEA, 13 November 2019) (*World Energy Outlook 2019*, 2019)[125]
2) Global Renewables Outlook – Energy Transformation 2050 "Transforming Energy Scenario" (TES) scenario (IRENA, 1 April 2020) (*Global Renewables Outlook – Energy Transformation 2050 (2020 Edition)*, 2020)
3) "Low Energy Demand - LED" scenario (IIASA researchers, 4 June 2018) (Grubler et al., 2018)
4) "Sky" scenario (Shell, 26 March 2018) (*Shell scenarios Sky—Meeting the goals of the Paris Agreement*, 2018)
5) Global Energy and Climate Outlook - GECO 2018 "1.5°C" scenario (EU EC – JRC, 12 December 2018) (Després et al., 2018)
6) A Clean Planet for all —A European long-term strategic vision for a prosperous, modern, competitive and climate neutral economy – "1.5 LIFE" scenario (EU EC, 28 November 2018) (*A Clean Planet for all — In-depth analysis in support of the commission communication COM(2018) 773*, 2018)
7) A Clean Planet for all —A European long-term strategic vision for a prosperous, modern, competitive and climate neutral economy – "1.5 TECH" scenario (EU EC, 28 November 2018) (*A Clean Planet for all—In-depth analysis in support of the commission communication COM(2018) 773*, 2018)

The most recent IEA WEO 2020 Sustainable Development scenario and IEA WEO 2020 Net Zero Emissions 2050 scenario were not included because relevant technological data is only partially disclosed.[126] This justifies the choice of including IEA WEO 2019 "Sustainable Development goals" scenario in order to perform a consistent analysis.

The last two energy scenarios refer to the EU-region and for those we will only analyse the aggregated metrics of annual CO_2 emissions reduction potential and cumulative investments.

The two metrics we will use to study technological pathways across different energy scenarios studies are:

1) *Annual CO_2 emissions reductions by technology sets - the main priority of these energy scenarios is decarbonisation*
   It is important to note that, although IPCC clearly states that global warming is caused by seven main types of Greenhouse gas (GHG) emissions, CO_2 emissions being only one, some studies do not include results relative to the reduction of other GHGs in their energy

[124] These energy scenarios include global energy visions before the COVID crisis by European organisations, intergovernmental energy institutions and international research centres; very few scenarios by these organisations have been published since the COVID crisis began. Additionally, no relevant global energy vision focused on decarbonisation and developed by an American-based institution was found or mentioned in reports and academic articles on the topic.

[125] All rights reserved. Although it is debated whether this scenario is indeed credible towards achieving Paris Agreement targets, we included it on the basis of the statement of its authors: "This means that the Sustainable Development Scenario is "likely" (with 66% probability) to limit the rise in the average global temperature to 1.8 °C, which is broadly equivalent to a 50% probability of 1.65 °C stabilisation" https://www.iea.org/commentaries/understanding-the-world-energy-outlook-scenarios. The authors show that the global CO2 emisssions from energy sector and industrial processes of this scenario are aligned with those of other IPCC scenarios in order to give it credibility.

[126] Cumulative investments data in technology sets is reported only until 2040, instead of the 2050 time horizon of this scenario. Additionally, energy and industrial processes CO2 emissions reduction data by technology sets is reported only for 2 broad categories ("power" and "end-use") and only until 2030.

visions. Additionally, some scenarios also consider non-energy emissions (e.g. oil refining and industrial feedstock production), [127] while others do not. Finally, we exclude LULUCF and AFOLU contributions to CO_2 emissions reduction since some studies exclude those and since it is not clear that they should be classified as a technology, with an associated investment. [128] The reference for CO2 emissions, based on which emissions reduction are calculated, is 36.8 GtCO2/yr in 2016 according to IEA statistics.

2) *Expected cumulative investments in technologies sets – the means to deploy these technologies*
We harmonised these two metrics in order to allow for a proper comparison, by using, respectively, the 2018 global annual CO_2 emissions data reported by EU EC [129] for the annual emissions reduction metric and 2018 US$ for the cumulative investments metric. We cross-analyse the two metrics identified, both at an aggregate level and also at a disaggregated technological level. In this way, we identified the decarbonization potential and costs of nine sets of technologies. However, we must distinguish here between scenarios which report results on decarbonization potential referring only to energy emissions reduction (i.e. IEA WEO 2019) or to both energy and non-energy emissions reduction (i.e. other scenarios). For the scenarios reporting technological emissions reduction data without further distinguishing between technological energy and non-energy emissions, we did not make further changes. We did the same for scenarios reporting technological emissions reduction data in terms of GHG emissions.[130] Finally, some scenarios only include technological emissions reduction data for 2050. In cases where 2030 technological data was not available (e.g. "de-fossilizing the mix" and "energy efficiency" for JRC Poles), we extrapolated the 2030 data in a linear fashion.

We consider the following technology sets, groupings of technologies with a similar "decarbonization logic" and for which investments data was found:

- Some of these sets contain technologies which have "positive" decarbonization potential, leading to the phasing out of fossil fuel technologies. For instance, an onshore wind farm within "de-fossilizing the mix" set could substitute a coal power plant. Another example is that of energy efficiency appliances, which lead to a reduced use of energy vectors. In cases where fossil fuel technologies are included in the mix of technologies producing those energy vectors, then the reduced use of those energy vectors will ultimately lead to a reduced demand for fossil fuel technologies. CCS technologies lead to reduced emissions of existing fossil fuel technologies. Negative Emission Technologies absorb GHG emissions from the atmosphere. Finally, gas-

[127] These scenarios are 1) World Energy Outlook (WEO) 2019 "Sustainable Development goals" scenario (IEA, 13 November 2019). All rights reserved. (World Energy Outlook 2019, 2019), 2) Global Renewables Outlook – Energy Transformation 2050 "Transforming Energy Scenario" (IRENA, 1 April 2020) (Global Renewables Outlook – Energy Transformation 2050 (2020 Edition), 2020) and 3) A. Grubler et al. "A low energy demand scenario for meeting the 1.5°C target and sustainable development goals without negative emission technologies" (Nature Energy, June 2018).
[128] For the Shell – Sky scenario it was not possible to distinguish the CO2 emissions reduction from "de-fossilizing the mix", "energy efficiency" and "fossil fuels".
[129] Global fossil CO_2 emissions are estimated at a total of 36.8 Gt CO_2/yr by 2016 according to "Fossil CO_2 and GHG emissions of all world countries – 2019 Report" (2019) by JRC.
[130] In absence of further data, we assume that the GHG emissions reduction potential of energy technologies consists mostly of CO2 emissions reduction potential.

switching technologies substitute other fossil fuel technologies, which are more GHG emissions-intensive, leading to a reduction in GHG emissions at parity of output.

- Others have "neutral" decarbonization potential, as they do not contribute directly to the phasing out of fossil fuel technologies. This is the case with power grids or gas grids.

- Finally, fossil fuel technologies have "negative" decarbonization potential as these investments lead to increased CO_2 emissions.

Finally, an extra category was added for investments or emissions not clearly belonging to one of these technologies sets.

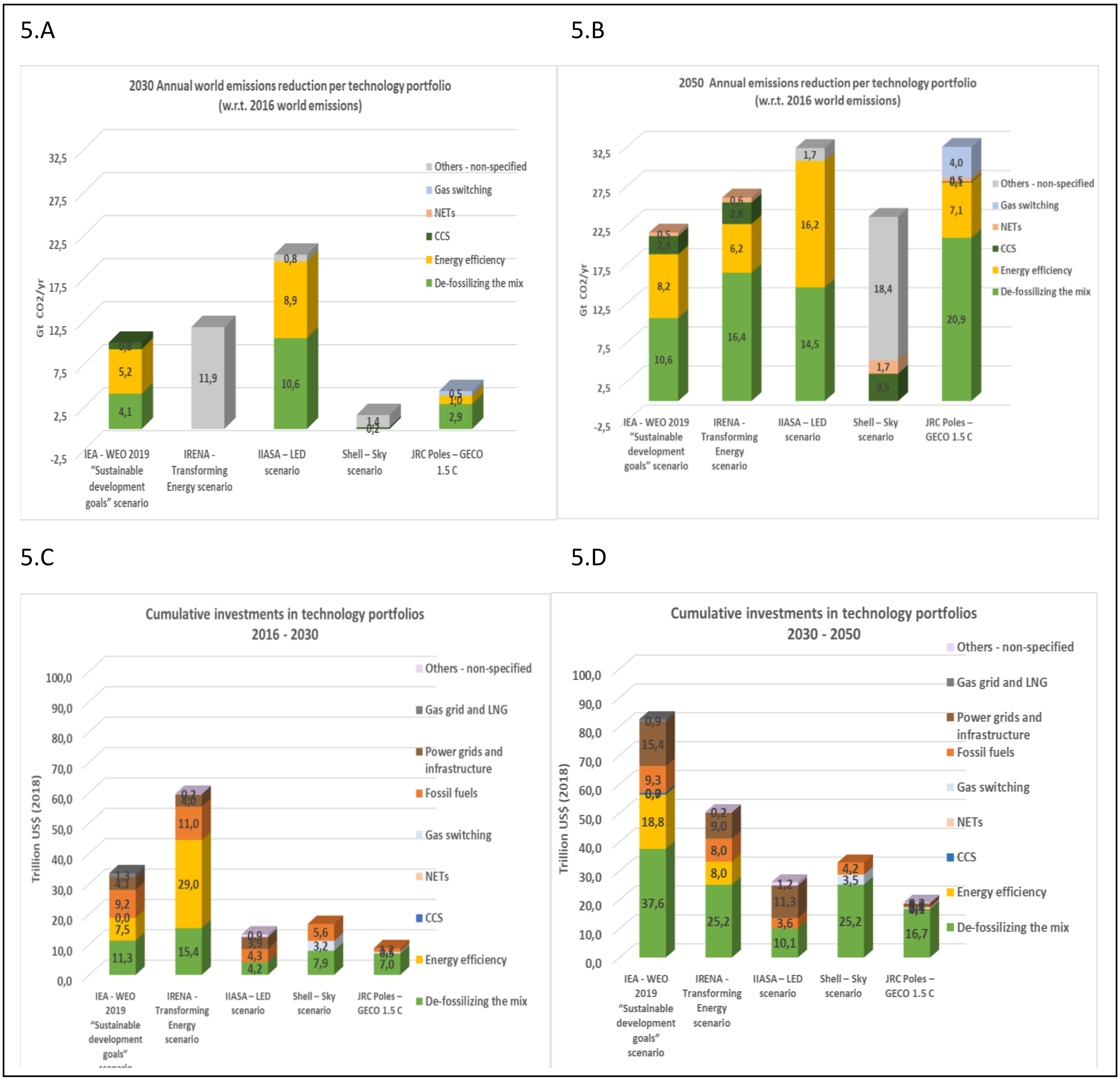
Table 5.1: Technologies sets considered

Nr.	Name of technologies set	Technologies included	Decarbonisation logic	Contribution towards decarbonization
1	De-fossilizing the mix	Renewable energy technologies, demand-side electrification technologies, renewable gases technologies and other non-fossil fuel technologies (e.g. nuclear)	Technologies driven by the same demand used as a "Fossil fuels" set but requiring non-fossil fuel inputs (e.g. electricity, hydrogen, wind, sun irradiation….)	"Positive" decarbonization potential
2	Energy efficiency	Building efficiency, industry efficiency, transport efficiency and power sector efficiency	New technologies underlying demand uses which reduce the need for input energy vectors. Therefore, in the presence of a technological portfolio including "fossil fuel" technologies, these technologies partly reduce the demand for the energy vectors generated by fossil fuel technologies and associated GHG emissions	"Positive" decarbonization potential
3	CCS	Carbon capture and storage technologies applied to fossil-fuel based power plants, to industrial & chemical processes and to synthetic fuel production (e.g. blue hydrogen)	Technologies which, if coupled to fossil fuel technologies, lead to less GHG emissions compared to pre-existing fossil fuel technologies.	"Positive" decarbonization potential
4	NETs – Negative emissions technologies	Direct air carbon capture and storage, and bioenergy with carbon capture and storage	Technologies which have as an input GHGs, therefore leading to negative emissions	"Positive" decarbonization potential

Nr.	Name of technologies set	Technologies included	Decarbonisation logic	Contribution towards decarbonization
5	Gas switching	Gas power plants and gas boilers	Natural gas technologies are less GHG emissions-intensive compared to other fossil fuel technologies (i.e. oil and coal). Therefore, if these other fossil fuel technologies are substituted by natural gas technologies at parity of output, there is an associated decrease in GHG emissions. Natural gas technologies accounted for 22.9% in terms of world total primary energy demand by 2018 according to IEA,	"Positive" decarbonization potential
6	Power grid and infrastructure	Transmission and distribution power grid investments, storage system and smart meters	Technologies for transporting and storing renewable electricity over time, needed as a consequence of the further presence of electricity-based "de-fossilizing the mix" technologies	"Neutral" decarbonization potential
7	Gas grid and LNG	Hydrogen network investments, investments in retrofitting gas infrastructure for hydrogen penetration, LNG	Technologies for transporting and storing low-carbon gases or decarbonized gases over time, needed as a consequence of the further presence of gas-based "de-fossilizing the mix" technologies	"Neutral" decarbonization potential
8	Non-gas fossil fuel	Oil and Coal based power plants without CCS, fossil fuel supply investments	Technologies with fossil fuels as input which are more GHGs emissions-intensive than natural gas technologies (i.e. oil and coal). They are present in large quantities (58.1% in terms of world total primary energy demand by 2018 according to IEA) and they, therefore, need to be phased out	"Negative" decarbonization potential
9	Other non-specified technologies	Undefined	Buffer category, explicating emissions reduction/investments which were not explicitly reported for other categories (e.g. Industrial processes)	?

These nine technology sets are not exhaustive, as they do not include currently unforeseen technologies or currently known technologies whose emissions reduction potential and investments are null or are not reported.

Figures 5.A,B,C,D: Annual world emissions reduction per technology portfolio and cumulative investments in technology portfolios across the five global energy scenarios examined by two future time horizons (2030 and 2050)



Across these different energy scenarios, we observe the divergence of modelled emissions reduction targets and of needed cumulative technological investments for both the 2030 and 2050 time horizons. For the first metric (global annual energy emissions reduction), there is no clear consistency even for the 2030 time horizon. For 2030 the IEA scenario calculates a decrease in emissions of 10.0 $GtCO_2$/yr, while IIASA's LED scenario calculates a decrease of 20.3 $GtCO_2$/yr and Shell's Sky scenario a decrease of 1.6 $GtCO_2$/yr. Finally, IRENA – Transforming Energy Scenario calculates a decrease of 11.9 GtCO2/yr and JRC Poles 1.5°C scenario a decrease of 4.4 GtCO2/yr. For 2050, the discrepancies narrow though some scenarios calculate larger emissions reduction (e.g. IIIASA's LED scenario and JRC's GECO

1.5 scenario calculate a reduction in CO2 emissions of respectively 32.4 $GtCO_2$/yr and 32.5 $GtCO_2$/yr), and others smaller (e.g. IRENA's Transforming Energy Scenario 27.3 $GtCO_2$/yr).

For the second metric (cumulative technological investments), there is a large discrepancy. By 2030 the IEA scenario calculates for example, cumulative investments in technology portfolios of circa 30 Trillion US$ (2018), while IRENA reports circa 60 Trillion US$ and IIASA's LED scenario 17 Trillion US$. This discrepancy continues for 2050. For the period 2030-2050, the IEA WEO 2019 SDS scenario calculates 83 Trillion US$ of cumulative investments, while IRENA 50.4 Trillion US$ and IIASA's LED scenario calculates 33 Trillion US$.

The more ambitious energy scenarios ambitious in terms of annual CO_2 emissions reduction by 2030 and 2050, (i.e. LED scenario & GECO 1.5°C scenario), report relatively small investment needs, partly due to a lack of common understanding on how to report investments in certain technologies (e.g. energy efficiency). Conversely, energy scenarios calculating the largest cumulative energy investments by 2030 and 2050 (IEA WEO 2019 SDS and IRENA Transforming Energy scenario) are not the most ambitious in terms of CO_2 emissions reduction.

We will now proceed to analyse the main outputs by technology set:

1) in terms of potential CO_2 emissions reduction, the *"de-fossilizing the mix" technological set* ("category" or "technological set" or "technology portfolio") was the most significant for three scenarios out of five by 2030 and for four scenarios by 2050. It is curious though that the technological investments in "de-fossilizing the mix" are not equally proportionate across the studies to the effective CO_2 emissions reduction potential. In the 2030-2050 period, some studies include a non-negligible decarbonisation potential and the amounts of investments relative to specific technologies, such as electric vehicles (EVs) technologies (IEA WEO 2019), nuclear technologies (IEA WEO 2019), hydrogen technologies (IEA WEO 2019 and JRC GECO 1.5 scenario), biomass (JRC GECO 1.5 scenario) and biofuels (e.g. IEA WEO 2019). Some studies thus see the maturation and increasing competitiveness of certain new technologies, such as "hydrogen" and "EVs", while other studies do not explicitly consider them.

2) The second most significant technological set in terms of decarbonisation potential, present across all studies, was *energy efficiency*: some studies allocated a larger share in emissions reduction (e.g. IEA WEO 2019 and IIASA's LED scenario) compared to others (e.g. IRENA Transforming Energy scenario and JRC GECO 1.5 SCENARIO). Regarding investments in energy efficiency, it must be noted that there is no consensus on how to report its investments. Three studies out of five do not report cumulative investments in energy efficiency and the two scenarios reporting these investments attribute a large share of investments to said technologies. However, this implies that there is no clarity on the actual investment costs for reaching the decarbonisation potential of energy efficiency modelled in all studies. However, given the available results in "energy efficiency" technological investments which are superior to those on "de-fossilizing the mix" investments for the same scenarios, it should be assumed that energy efficiency will play a key role, together with increasing renewable electricity.

3-4) One of the reasons which explain the large discrepancy across the previously described results is the absence of certain technologies from some studies. All studies assume *"CCS"* *and "NETs" technologies* to be commercially immature by 2030 or to be non-significant. However, the picture by 2050 is rather different. Regarding assumptions on "CCS" technologies by 2050, some studies assume commercial availability and a certain decarbonisation potential (IEA WEO 2019 SDS, IRENA Transforming Energy scenario and the Shell Sky scenario), while others (IIASA's LED scenario and JRC Poles GECO 1.5 C) assume that "CCS" technologies will not be commercially available by 2050. The same applies for assumptions on "NETs" technologies: while "NETs" are assumed to be commercially available by 2050 in some scenarios (IEA WEO 2019 SDS, the Shell Sky scenario, IRENA Transforming Energy scenario and JRC Poles – GECO 1.5 C), these same technologies are assumed not to be commercially available in the LED scenario.

5) *Gas switching* is treated fairly unequally across the different studies. Only the JRC Poles – GECO 1.5 C scenario specifies emissions reduction due to gas switching. Instead the IEA WEO 2019 SDS scenario[131], the IRENA Transforming Energy scenario, the IIASA LED scenario and the Shell Sky scenario do not specify emissions reduction specifically due to gas switching. Surprisingly, the picture for "gas switching investments" is discrepant: the IEA WEO 2019 SDS scenario, the IRENA Transforming Energy scenario and the IIASA LED scenario do not differentiate natural gas investments from those for other fossil fuels. While "gas switching" investments in the JRC GECO 1.5 scenario are less relevant across both time horizons (2-6% of total cumulative investments), this same investments category in the Shell Sky scenario is more significant (11-19%).

6) *"Power grid and infrastructure" investments* are reported across all studies except the Sky scenario (where these investments are bundled together with those in "de-fossilizing the mix"). However, the reported values vary for the period 2030-2050, most likely due to the fact that the technologies included in this "box" are not the same across all studies and because different modelling assumptions are used.

7) *Investments in "Gas grid and LNG" technologies* are only modelled in the IEA WEO SDS scenario and represent a small share of cumulative investments.

8) It is interesting to observe that *fossil fuel investments* are still included for both time horizons (2030 and 2050) across all studies included. For those scenarios which do not specify "gas switching" investments (i.e. the IEA, IRENA and IIASA's scenarios), the fossil fuel investments calculated also include natural gas investments.

9) The *"others – non-specified" category* includes both technological emissions reduction potential and investments not accounted for in these previous categories. For example, IIASA LED scenario also calculates the emissions reduction potential from industrial processes technologies, which are not energy technologies and therefore not included in the previous categories. Instead, in the Shell Sky scenario it is not possible to distinguish between the emissions reduction potential of fossil fuel technologies, energy efficiency technologies and "defossilizing the mix" technologies.

[131] IEA does not distinguish the emissions reduction due to gas switching from that due to other fuels switching (e.g. hydrogen).

We additionally compare the overall annual technological emissions reduction with respect to 1990 [132] and overall cumulative technological investments relative to the European Green Deal text. Of course, a like-for-like comparison between the EU's decarbonisation visions and global decarbonisation visions is not possible. However, it is still interesting to observe how the calculated annual emissions reduction rate and, in particular, cumulative technological investment figures in "A Clean Planet for All" compare to those at world-level according to global scenarios.

Table 5.2: Overall annual technological emissions reduction and cumulative technological investments across the seven energy scenarios considered, in addition to the European Green Deal text, by two future time horizons (2030 and 2050)

Energy scenario	WEO 2019 SDS (**IEA**)	Global Renewables Outlook "Transforming Energy Scenario" (**IRENA**)	LED (**IIASA**)	Sky (**Shell**)	1.5°C (**JRC**)	"A clean planet for all" – 1.5TECH (**EU EC**)	"A clean planet for all" – 1.5LIFE (**EU EC**)	EU EC targets – updated to European Green Deal
Publication date	13th November 2018	9th April 2019	4th June 2018	26th March 2018	12th December 2018	28th November 2018	28th November 2018	11th December 2019
Prior or after the release of "A clean planet for all" ?	After	After	Before	Before	After	-	-	After
Annual emissions reduction at global level by 2030 w.r.t. 1990 [106] For *, please look at footnote [133]	-11% * -2,6 * $GtCO_2/yr$	-10% * -2,3 * $GtCO_2/yr$	28% 6,1 $GtCO_2/yr$	-57% * -12,8 * $GtCO_2/yr$	-43% * -9,8 * $GtCO_2/yr$	37,9% 1,5 $GtCO_2/yr$ (relative to EU only) [134]	37,9% 1.5 $GtCO_2/yr$ (relative to EU only) [134]	50-55% 2.0-2.2 $GtCO_2/yr$ (relative to EU only)
Annual emissions reduction at global level by 2050 w.r.t. 1990	56% 12,7 $GtCO_2/yr$	58% 13,1 $GtCO_2/yr$	88% 18,2 $GtCO_2/yr$	18% 4,2 $GtCO_2/yr$	81% 18,3 $GtCO_2/yr$	100% 4.0 $GtCO_2/yr$ (relative to EU only) [106]	92,5% 3.7 $GtCO_2/yr$ (relative to EU only) [106]	100% 4.0 $GtCO_2/yr$ (relative to EU only)

[132] 1990 was taken as the reference year in agreement with the reference year for the EU GHG emissions reduction targets, as reported in the European Green Deal document.

[133] * The negative values reported here for annual emissions reduction values refers to an actual increase in global CO_2 emissions with respect to 1990. This value is estimated at 22.6 Gt CO_2/yr by 1990 according to "Fossil CO_2 and GHG emissions of all world countries – 2019 Report" (2019) by JRC.

[134] The values reported by the "A Clean Planet for all" also include "non-energy" industrial emissions. The contribution of LULUCF to emissions reduction was excluded, explaining both part of the difference between the two scenarios and the gap with respect to the EU EC targets, which instead account for LULUCF.

Energy scenario	WEO 2019 SDS (**IEA**)	Global Renewables Outlook "Transforming Energy Scenario" (**IRENA**)	LED (**IIASA**)	Sky (**Shell**)	1.5°C (**JRC**)	"A clean planet for all" – 1.5 TECH (**EU EC**)	"A clean planet for all" – 1.5 LIFE (**EU EC**)	EU EC targets – updated to European Green Deal
Cumulative technological investments at global level in 2016 – 2030	33,5 Trillion $2018	59,6 Trillion $2018	13,7 Trillion $2018	16,8 Trillion $2018	8,8 Trillion $2018	15,7 Trillion EUR2018 (relative to EU only)	15,7 Trillion EUR2018 (relative to EU only)	2,6 Trillion EUR2018 over 10 years (2021 - 2030) (relative to EU only)
Cumulative technological investments at global level in 2030-2050	82,6 Trillion $2018	50,4 Trillion $2018	26,1 Trillion $2018	32,9 Trillion $2018	19,1 Trillion $2018	30,7 Trillion EUR2018 (relative to EU only)	28,3 Trillion EUR2018 (relative to EU only)	-

Policy outcomes

- Having analysed the future role of technological assumptions across the five "energy scenarios" at world level, no clear consistency across these studies was found. The energy scenarios at the global-level are discrepant regarding both their results on future CO_2 emissions reduction and on necessary cumulative technological investments, by both 2030 and 2050. Additionally, energy scenarios with more ambitious results on future CO_2 emissions reduction potential do not report an equally high need for cumulative technological investments and *vice-versa*. The reviewed energy scenarios are not consistent in their means (cumulative technological investments) and ends (annual CO_2 emissions reduction). Policy-making, therefore, should not be blindly based on specific energy scenarios without checking for consistency between their means (cumulative technological investments) and ends (annual emissions reduction at global scope).
- The "De-fossilizing the mix" technologies set (i.e. renewable energy technologies, electrification technologies, decarbonised gases ….) results as the most relevant in terms of CO2 emissions reduction potential at the world-level. However, the identified cumulative technological investments at the world-level are not consistent across the studies. Additionally, there is no consistency across the different energy scenarios for the role of specific technologies within this set (e.g. "hydrogen" and "EVs"). The same applies for the "energy efficiency" technologies at world-level, the second most significant technological set in terms of decarbonisation potential, for which there is also a lack of common understanding on how to model technological investments. Independently of these discrepancies, the two key trends pinpointed by the European Green Deal towards EU decarbonisation (i.e. energy-efficiency and renewables-based power sector) are also confirmed as potential major decarbonisation drivers at the world-level. Regarding the role of other technology sets (e.g. "CCS",

"NETs", "gas switching" ….), there is greater discrepancy across energy scenarios at the world-level and more specific affirmations are not possible.

- The values at EU-level of cumulative technological investments from the European Green Deal and from two "A Clean Planet for All" scenarios by the EU EC have the same order of magnitude as those resulting at world-level from the other energy scenarios (i.e. Trillions or tens of Trillions of US$). Given the size of the EU-level results on annual emissions reduction by 2050 (i.e. 3.7 – 4.0 $GtCO_2$/yr with respect to 1990) compared to world-level results by 2050 (i.e. 4.2 – 19.9 $GtCO_2$/yr with respect to 1990), EU-level decarbonisation goals will mean significant technological investments compared to those needed at the world-level.

In the next chapters, we will examine in detail assumptions on the future costs of some technologies which we find interesting and which we would mark down as critical within the "de-fossilizing the mix" technological set. These are: renewable electricity (i.e. wind and solar); and hydrogen.

6. Assumptions on the future costs of solar PV and wind technologies

In this chapter, we will focus on the future costs of renewable electricity technologies. In particular, we will focus on Solar PV and wind technologies. Additionally, we will break these renewable technologies down further, given their different costs: A-1) utility-scale solar (including utility-scale solar PV farms); A-2) rooftop solar; B-1) onshore wind farm; and B-2) offshore wind farms. We will limit ourselves to the following time horizon: today (and in cases where data is not available, we take estimates from 2018 or 2019), 2030 and 2050. It must be said that the numbers for 2030 (10 years from now) are hypotheses, but they still are more reliable than our numbers for 2050 (30 years from now). For these technologies, we will cross-analyse future cost assumptions made by international organisations who are reputed for their future energy system studies (e.g. IEA and IRENA) and by EU EC. In particular, we select as critical future cost assumptions the following three metrics: 1) the technology-specific levelised cost of electricity (for which the variable costs are low, so CAPEX and relative interest rates play a key role); 2) the technical potential of renewable electricity in moving towards EU decarbonisation (the size of the portfolio of renewable electricity generation needed to supply demand according to energy scenarios including EU decarbonisation); and 3) system-costs (the costs needed to deliver electricity from solar and wind technologies to the consumer, such as grid costs[135] and balancing costs). For each of these critical future cost assumptions, we identify the relevant sub-assumptions and cross-analyse these as well. As we will see, the cost assumptions used by different organisations are not always made clear and there is room for speculation about which assumptions are used and how they were constructed.

For example, investment figures on grids are mentioned in the "A Clean Planet for All" scenarios: e.g. cumulative power grid investments of 2414 Billion EUR over 2021 – 2050 in EU according to the H2 scenario. But the respective levelised grid technologies costs are not reported. Grid costs are essential for linking 1 kWh of renewable electricity produced by offshore wind farms to potential onshore clients, especially since an offshore grid is only being gradually built now in the UK and Germany. The same can be said for storage costs, linking 1 kWh of renewable electricity produced by solar farms to an EV charged late at night.

Therefore, we split this chapter into four sections: 1) definition of renewable electricity; 2) assumptions on the future levelised costs of electricity; 3) assumptions on future technical potential; and 4) assumptions on future system-costs.

6.1. Definition of renewable electricity

Renewable electricity (RE) refers to electricity derived from renewable sources. In particular, we will focus in this chapter on electricity from solar and wind energy, which are also called variable renewable energy sources. Variable renewable energy (VRE) sources have the following properties: 1) they are location-specific, 2) they are "variable" in terms of time with different time scales (yearly, seasonal, monthly, daily, hourly and sub-hourly), and 3) they are uncertain, as it is difficult to predict beforehand the quantity of "variable" energy flowing at this or that moment. Renewable electricity production from solar and wind energy will carry on these three properties.

[135] Another characteristic of renewable electricity is its voltage. None of the scenarios considered models transformer costs separately and, therefore, we can assume transformer costs to be included within grid costs.

6.2. Assumptions on future levelised costs

Levelised costs are the technology-specific costs necessary for producing 1 kWh of renewable electricity from renewable electricity production technologies. Levelised costs can also be interpreted as total production costs divided by total renewable electricity output. We will consider the levelised costs of: A-1) utility-scale solar; A-2) rooftop-scale solar; B-1) onshore wind farm; and B-2) offshore wind farms technologies. We examine the most recent credible estimates for levelised costs and we look at how well renowned organisations assume the future levelised costs of these technologies.

In particular, we consulted these sources: IRENA "Global Renewables Outlook: Energy Transformation 2050" (April 2020) [136]; IRENA "Renewable Power Generation Costs in 2019" (June 2020); IEA "World Energy Outlook 2020 – Sustainable Development Scenario" (October 2020) [137]; data employed in the "A Clean Planet for all" scenarios by EU EC [138]; Lazard "Levelized Cost of Energy" (October 2020); 2020 global LCOE benchmark data by BloombergNEF [139]; and BloombergNEF, Snam & IGU "Global gas report 2020" (August 2020) [140]. Values in USD were converted into EUR at an 0.85 exchange rate.[141] We filtered out outdated future estimates in favour of other, more recent sources.

The levelised costs of these technologies depend on several assumptions: 1) capital expenditure (CAPEX); 2) interest rates; 3) capacity factor; 4) operation and maintenance costs; and 5) plant lifetime. The fuel costs of these technologies are null. We consider the first three factors to be critical. CAPEX is a key levelised cost component, as variable costs of renewable generators are low due to the zero fuel costs. For example, the wind turbines of a wind farm go to make up a significant share of total costs for delivering 1 kWh and are CAPEX. Interest rate dictates what output investors want from their capital and this changes levelised costs significantly.[142] Finally, capacity factor determines the number of hours a renewable generator can operate at full capacity in one year, and therefore, the kWhs it can produce in that year. The higher the capacity factor, the higher the number of kWhs produced, and the lower the levelised costs of one kWh of renewable electricity at total costs parity. Utility-scale solar PV has a capacity

[136] Future levelised costs assumptions by IRENA for renewable electricity were taken from the electricity cost assumptions relative to green hydrogen costs, since the worldwide average assumptions reported for future levelised costs of renewable power generation resulted higher and conflicting. This same issue was noticed for the levelised costs assumptions reported in the following two older reports by IRENA and cited in "Global Renewables Outlook: Energy Transformation 2050": IRENA "Future of Solar Photovoltaic" (Nov. 2019) and IRENA "Future of Wind" (Oct. 2019).

[137] All rights reserved.

[138] This data was found in the supplementary material for the paper "Energy-system modelling of the EU strategy towards climate-neutrality" (Energy Policy, Nov. 2019).

[139] https://www.smart-energy.com/renewable-energy/solar-and-wind-are-the-cheapest-new-sources-of-energy-says-bnef/.

[140] Future levelised costs assumptions by BNEF for renewable electricity were taken from the electricity cost assumptions relative to green hydrogen costs.

[141] Relative to 23 August 2020 and taken from https://www.exchangerates.org.uk/EUR-USD-exchange-rate-history.html.

[142] For example, evidence is brought by the following study: Steffen, B. (2020). Estimating the cost of capital for renewable energy projects. Energy Economics, 88, 104783.

factor[143] that is significantly different from that of offshore wind [144]. No further specifications regarding the impact of the technology location on these critical factors of levelised costs are found in the sources consulted: e.g. floating offshore wind farms located in sea zones with seabed depth deeper than 50-60 m vs. fixed-foundation offshore wind farms located in zones with a seabed depth of less than 50 m.

1) in terms of technological maturity, all of these technologies are ranked at least 9 [145] on the technology readiness levels scale of the IEA ETP Clean Energy Technologies guide. In other words, all of these technologies are commercial. However, some sub-technologies now at concept or prototype level could emerge and bring costs down still further (e.g. the perovskite solar cell).

Table 6.1: Levelised costs, CAPEX and capacity factor by 2019/2020, by 2030 and by 2050 of renewable electricity technologies, according to future costs studies

Technology	Dimension	2019/2020	2030	2050
A-1) utility-scale solar	Levelised costs	45 – 58 - 160 EUR/MWh (worldwide 5th percentile, average and 95th percentile by IRENA, 2019) 29.75 – 42.5 EUR/MWh (range derived from averages for EU, USA, China and India by IEA, 2019) [146] 33.15 – 42.5 EUR/MWh [147] CAPEX - * Capacity factors - * (worldwide weighted-average by BloombergNEF, H1 2020) 11.2 EUR/MWh (world record low bid, Portugal, August 2020) [148] 26.35 – 31.45 – 35.7 EUR/MWh (worldwide low end, average and high end for utility-scale crystalline and utility-scale thin film by Lazard, 2020)	14.9 EUR/MWh (worldwide “PV best” values, IRENA) 21 – 38.5 EUR/MWh (range derived from regional averages for EU, USA, China and India, extracted through linear interpolation of 2040 IEA values) [149] 14.4 – 33.15 EUR/MWh (worldwide estimates, BloombergNEF) 17.85 EUR/MWh (estimate for Australia, BloombergNEF) 10 EUR/MWh (authors’ estimate for “very low cost” conditions) [150]	3.825 EUR/MWh (worldwide “PV best” values, IRENA) 18.7 EUR/MWh (worldwide “PV average” values, IRENA) 13.6 EUR/MWh (estimates for Algeria, Spain and an unspecified location, BloombergNEF) 10.2 EUR/MWh (estimate for Australia, BloombergNEF)

[143] Around 18%, equivalent to 1577 hours of full-load operation, according to IRENA’s worldwide central estimate in 2019.
[144] Around 49%, equivalent to 4290 hours of full-load operation, according to IRENA’s worldwide central estimate in 2019.
[145] TRL 9 = commercial operation in relevant environment.
[146] In particular, the average levelised costs estimate for EU by IEA is 42.5 EUR/MWh.
[147] Based on whether it is fixed axis PV or a tracking PV.
[148] Source: https://www.pv-magazine.com/2020/08/24/portugals-second-pv-auction-draws-world-record-low-bid-of-0-0132-kwh/ (24th August 2020, accessed on 17th October 2020).
[149] This range of levelised cost is derived through linear interpolation from the 2019 and 2040 LCOE values reported by IEA for the Sustainable Development Scenario (SDS) and for Stated Policies Scenario (STEPS). In particular, IEA SDS reports a range of average 2040 solar PV LCOE of 17 – 25.5 EUR/MWh and IEA STEPS of 29.75 – 42.5 EUR/MWh. In particular, the average estimate for EU in SDS and STEPs scenarios by IEA are respectively 35.7 – 37.8 EUR/MWh.
[150] This estimate is justified based on the recent world record low bids of 11.2 EUR/MWh in Portugal.

Technology	Dimension	2019/2020	2030	2050
A-1) utility-scale solar	CAPEX	590 – 1252 - 2315 EUR/kW (worldwide 5th percentile, average and 95th percentile by IRENA, 2019) CAPEX 518.5 - 1037 EUR/kW (range derived from averages for EU, USA, China and India by IEA, 2019) [151] CAPEX 892.5 – 1232.5 EUR/kW (worldwide low end and high end for utility-scale crystalline and utility-scale thin film by Lazard, 2020)	690 EUR/kW (assumption for EU, "A Clean Planet for All")	495 EUR/kW (assumption for EU, "A Clean Planet for All")
	Capacity factor	10.5% - 18% - 24% (worldwide 5th percentile, average and 95th percentile by IRENA, 2019) Capacity factor 13-21% (range derived from averages for EU, USA, China and India by IEA, 2019) [152] Capacity factor 23% - 36% (worldwide low end and high end for utility-scale crystalline and utility-scale thin film by Lazard, 2020)	Capacity factor 23% (worldwide "PV best" values, IRENA)	Capacity factor 27% (worldwide "PV best" values, IRENA) Capacity factor 18% (worldwide "PV average" values, IRENA)
A-2) rooftop-scale solar	Levelised costs	55.3 – 140.3 EUR/MWh (LCOE range for Germany by IEA, 2018/2019) 80.75 – 157.3 EUR/MWh (LCOE range for France by IEA, 2018/2019) 93.5 – 191.3 EUR/MWh (LCOE range for Japan by IEA, 2018/2019) 62.9 – 193.0 EUR/MWh (LCOE range for rooftop residential, rooftop C&I and community solar by Lazard, 2020)		
	CAPEX	701.25 – 2401.25 EUR/kW (LCOE range for rooftop residential, rooftop C&I and community solar by Lazard, 2020)	CAPEX 930 EUR/kW (assumption for EU, "A Clean Planet for All")	CAPEX 610 EUR/kW (assumption for EU, "A Clean Planet for All")

[151] In particular, the average CAPEX estimate for EU by IEA is CAPEX 714 EUR/kW.
[152] In particular, the average capacity factor estimate for EU by IEA is capacity factor 13%.

Technology	Dimension	2019/2020	2030	2050
A-2) rooftop-scale solar	Capacity factor	Capacity factor 13% - 23% (LCOE range for rooftop residential, rooftop C&I and community solar by Lazard, 2020)		
B-1) onshore wind farm	Levelised costs	32 - 45 – 92 EUR/MWh (worldwide 5th percentile, average and 95th percentile by IRENA, 2019) 29.75 – 46.75 EUR/MWh (range derived from averages for EU, USA, China and India by IEA, 2019) [153] 37.4 EUR/MWh (worldwide weighted-average by BloombergNEF, H1 2020) 22.1 - 34 – 45.9 EUR/MWh (worldwide low end, average and high end by Lazard, 2020) 16.9 EUR/MWh (world record price, Saudi Arabia's Dumat Al Jandal, 2019) [154]	17 EUR/MWh (worldwide "wind best" values, IRENA) 29.75 – 44.5 EUR/MWh (range derived from regional averages for EU, USA, China and India, extracted through linear interpolation of 2040 IEA values) [155] 23.8 – 40 EUR/MWh (estimates for China and Japan, BloombergNEF)	9.35 EUR/MWh (worldwide "wind best" values, IRENA) 22.1 EUR/MWh (estimate for Germany, BloombergNEF) 14.45 – 28.05 EUR/MWh (estimates for China and Japan, BloombergNEF) 19.55 EUR/MWh (worldwide "wind average" values, IRENA)
	CAPEX	940 – 1250 – 2095 EUR/kW (worldwide 5th percentile, average and 95th percentile by IRENA, 2019) CAPEX 901 - 1326 EUR/kW (range derived from averages for EU, USA, China and India by IEA, 2019) [156] CAPEX 892.5 – 1232.5 EUR/kW (worldwide low end, average and high end by Lazard, 2020)	CAPEX 690 EUR/kW (assumption for EU, "A Clean Planet for All")	CAPEX 848 EUR/kW (Assumption for EU, "A Clean Planet for All")

[153] In particular, the average estimate for EU by IEA is 46.75 EUR/MWh (CAPEX 1326 EUR/kW and Capacity factor 28%).

[154] Source: https://www.powersaudiarabia.com.sa/web/attach/news/Dumat-Al-Jandal-Lowest-LCOE.pdf (8th August 2019, accessed on 17th October 2020).

[155] This range of levelised cost is derived through linear interpolation from the 2019 and 2040 LCOE values reported by IEA for the sustainable development scenario and for STEP scenario. In particular, IEA Sustainable Development Scenario reports a range of average 2040 onshore wind farm LCOE of 29.75 – 38.25 EUR/MWh and IEA STEP scenario of 34 – 42.5 EUR/MWh. In particular, the average estimate for EU by IEA in SDS and STEPs scenarios are respectively is 42.3 – 44.5 EUR/MWh. The levelised costs assumptions by 2050 for IEA WEO 2020 scenarios are not reported.

[156] In particular, the average estimate for EU by IEA is 46.75 EUR/MWh (CAPEX 1326 EUR/kW and Capacity factor 28%).

Technology	Dimension	2019/2020	2030	2050
B-1) onshore wind farm	Capacity factor	25% - 35.6% - 51% (worldwide 5th percentile, average and 95th percentile by IRENA, 2019) Capacity factor 25-42% (range derived from averages for EU, USA, China and India by IEA, 2019) [157] Capacity factor 38% - 55% (worldwide low end, average and high end by Lazard, 2020)	46% (worldwide "wind best" values, IRENA)	63% (worldwide "wind best" values, IRENA) 45% (worldwide "wind average" values, IRENA)
B-2) offshore wind farm	Levelised costs	76 – 97.8 – 133 EUR/MWh (worldwide 5th percentile, average and 95th percentile by IRENA, 2019) [158] 63.75 – 110.5 EUR/MWh (range derived from averages for EU, USA, China and India, extracted through linear interpolation of 2040 IEA values) [159] 78 EUR/MWh (worldwide weighted-average by BloombergNEF, H1 2020) 58.7 - 73.1 – 88.4 EUR/MWh (low case, midpoint and high case by Lazard, 2020) 42.5 EUR/MWh (lowest price awarded to UK offshore wind auction, 2019[160])	45.9 – 81.6 EUR/MWh (range derived from regional averages for EU, USA, China and India, extracted through linear interpolation of 2040 IEA values) [161] 36 – 46 - 96 EUR/MWh (G20 country values, min-average-max, IRENA)	34.85 EUR/MWh (estimate for Germany, BloombergNEF) - * [162] (IRENA)

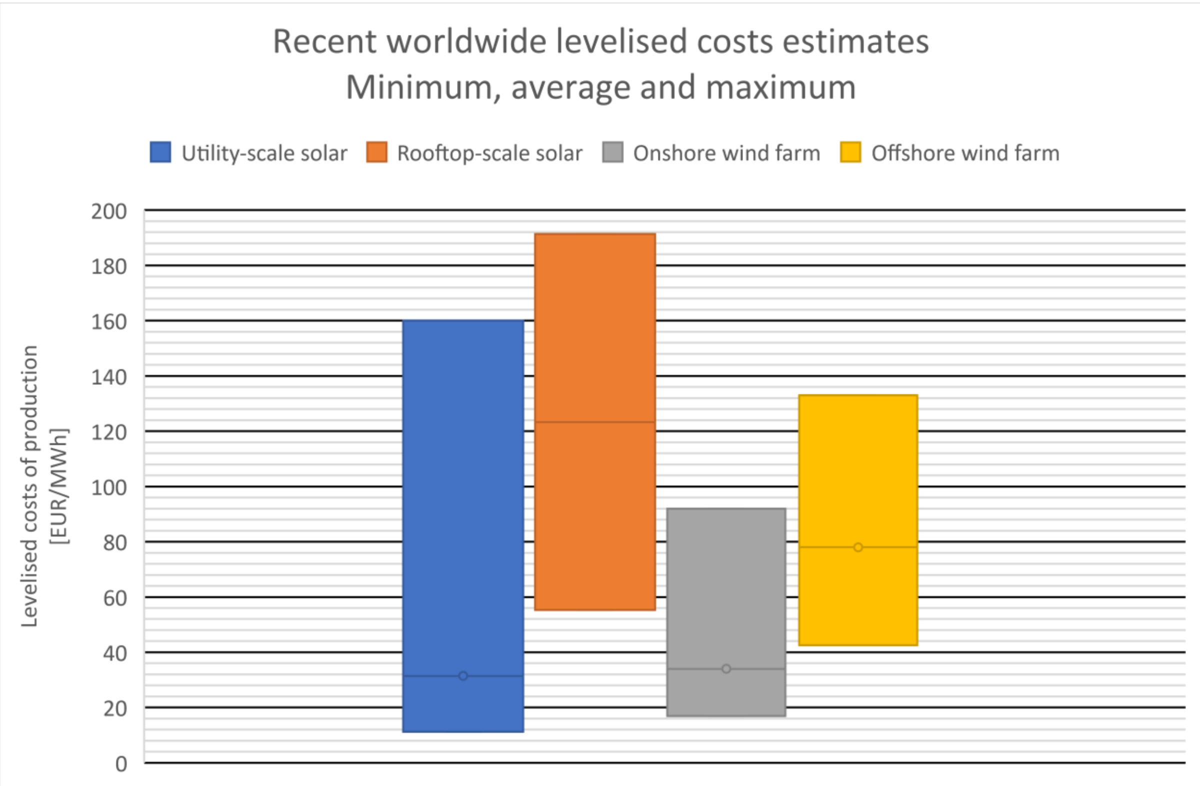
[157] In particular, the average estimate for EU by IEA is 46.75 EUR/MWh (CAPEX 1326 EUR/kW and Capacity factor 28%).
[158] This levelised cost estimated is a global estimate.
[159] In particular, the average estimate for EU by IEA is 63.75 EUR/MWh (CAPEX 3230 EUR/kW and Capacity factor 49%).
[160] Source: https://cleantechnica.com/2019/09/23/uk-offshore-wind-prices-reach-new-record-low-in-latest-cfd-auction/ (23th September 2019, accessed on 17th October 2020).
[161] This range of levelised cost is derived through linear interpolation from the 2019 and 2040 LCOE values reported by IEA for the sustainable development scenario and for STEP scenario. In particular, IEA Sustainable Development Scenario reports a range of average 2040 offshore wind farm LCOE of 29.75 – 46.75 EUR/MWh and IEA STEP scenario of 34 – 55.25 EUR/MWh. In particular, the average estimate for EU by IEA in SDS and STEPs scenarios are respectively 45.9 – 48.2 EUR/MWh.
[162] The levelised costs values for offshore wind used in IRENA "Global Renewables Outlook: Energy Transformation 2050" (2020) are not explicitly reported.

Technology	Dimension	2019/2020	2030	2050
B-2) offshore wind farm	CAPEX	2450 – 3230 – 5080 EUR/kW (worldwide 5th percentile, average and 95th percentile by IRENA, 2019) CAPEX 2210 - 3123.75 EUR/kW (low case, midpoint and high case by Lazard, 2020)	CAPEX 2048 EUR/kW (Assumption for EU, "A Clean Planet for All")	CAPEX 1929 EUR/kW (Assumption for EU, "A Clean Planet for All")
	Capacity factor	30% – 43,5% – 54% (worldwide 5th percentile, average and 95th percentile by IRENA, 2019) [163] 48% - 52% (low case, midpoint and high case by Lazard, 2020)		

Notes: We remind the reader once again that, except for the "A Clean Planet for all" documentation (2018), the other sources cited are all dated to 2020.

Levelised costs

Figure 6.1: Recent worldwide levelised costs estimates according to table 6.1



Recent central estimates for 2020 levelised costs by Lazard and by BloombergNEF are already significantly lower than IRENA's central estimates in 2019: 27%–46% for utility-scale solar

[163] This levelised cost estimated is a global estimate.

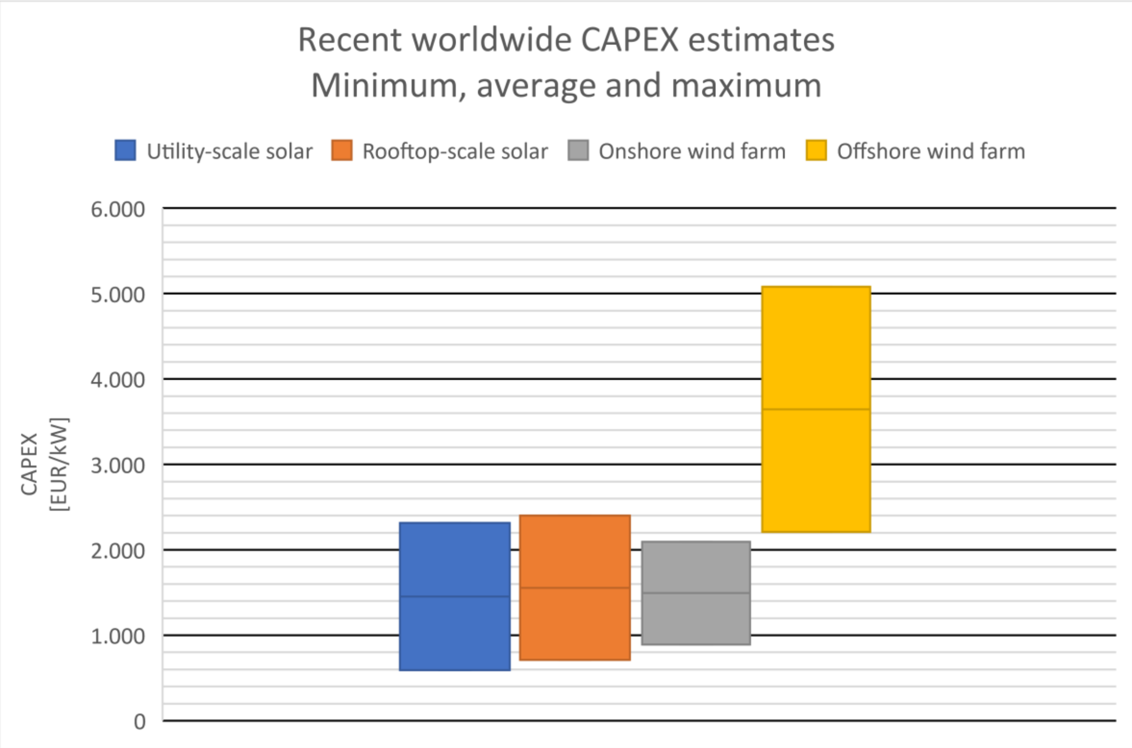
PV; 17%-24% for onshore wind; and 20% for offshore wind. Additionally, recent world record prices for renewable auctions are significantly lower than the recent worldwide average for levelised cost by Lazard and BloombergNEF: 64-74% for utility-scale solar PV (11.2 EUR/MWh for the lowest known bid in Portugal); 50-55% for onshore wind (16.9 EUR/MWh for the lowest known bid in Saudi Arabia) and 46% for offshore wind (42.5 EUR/MWh for the lowest price in a recent UK auction). If we look at BloombergNEF and Lazard's estimates, then both onshore wind and solar PV result competitive at levelised costs of 30– 40 EUR/MWh, while offshore wind is estimated to have a higher levelised costs of 78 EUR/MWh. According to IRENA's central estimates, onshore wind and solar PV are also competitive, though at different values (circa 45 and 58 EUR/MWh). Offshore wind's estimate is, meanwhile, set at 97.8 EUR/MWh. Instead, IEA estimated, in 2018/2019, the rooftop-scale levelised costs at 53.3–191.3 EUR/MWh and Lazard in 2020 at 62.9 – 192.95 EUR/MWh. Finally, IRENA provides not only a central estimate, but also the 5th and 95th percentile worldwide estimates. For utility-scale solar PV the ratio between the 95th percentile and the 5th percentile is a significant 4:1; for onshore wind the ratio is also significant at 3.5:1; and for offshore wind farms the ratio is 1.8:1. The ratios between the high end and the low end estimates reported by Lazard are, instead, smaller (1.35:1 for utility-scale solar and 2.1:1 for onshore wind). Additionally, the central estimates for the levelised costs of utility-scale solar, onshore wind and offshore wind technologies are heavily skewed towards the lower-end of the estimated range (world-record bids).

By 2030, for IEA, we extrapolated linearly levelised cost assumptions based on estimates for 2018 and assumptions for 2040 and these assumptions by 2030 result compatible with the range of values assumed by IRENA. We observe a significant decrease in levelised cost assumptions by both IEA and IRENA for both utility-scale solar and onshore wind. If we take the central estimate of the levelised costs range assumed by IRENA for 2030 offshore wind, levelised costs are assumed to decrease by, respectively, 22% and 53%. Regarding the range of levelised costs suggested by IRENA, they are significant for offshore wind farms (2.7:1). Additionally, BloombergNEF's estimates result lower and closer to recent world record lowest bids.

By 2050, there are both IRENA assumptions and BloombergNEF assumptions. IRENA assumes that worldwide best values for PV and onshore wind are respectively 1/5th and 1/2 of reported worldwide average values. Additionally, IRENA assumes a significant decrease in worldwide average values between 2030 and 2050: 43% for solar PV and 44% for onshore wind. BloombergNEF's reported estimates fit within the range of values given by IRENA. For offshore wind only one estimate datapoint by BloombergNEF is available at 34.85 EUR/MWh and this results close to the minimum value identified by 2030.

CAPEX

Figure 6.2: Recent worldwide CAPEX estimates according to table 6.1



Recent estimates on CAPEX are available from IEA, IRENA and Lazard. The estimates by Lazard and IEA are similar in range to those by IRENA. The range estimates for CAPEX across all sources results wide for solar (3.9:1 for utility-scale solar; 3.4:1 for rooftop-scale solar) and modest for wind (2.3:1 for onshore wind, 2.3:1 for offshore wind). This is an interesting trend, as the breadth of these ranges is different compared to those of levelised costs.

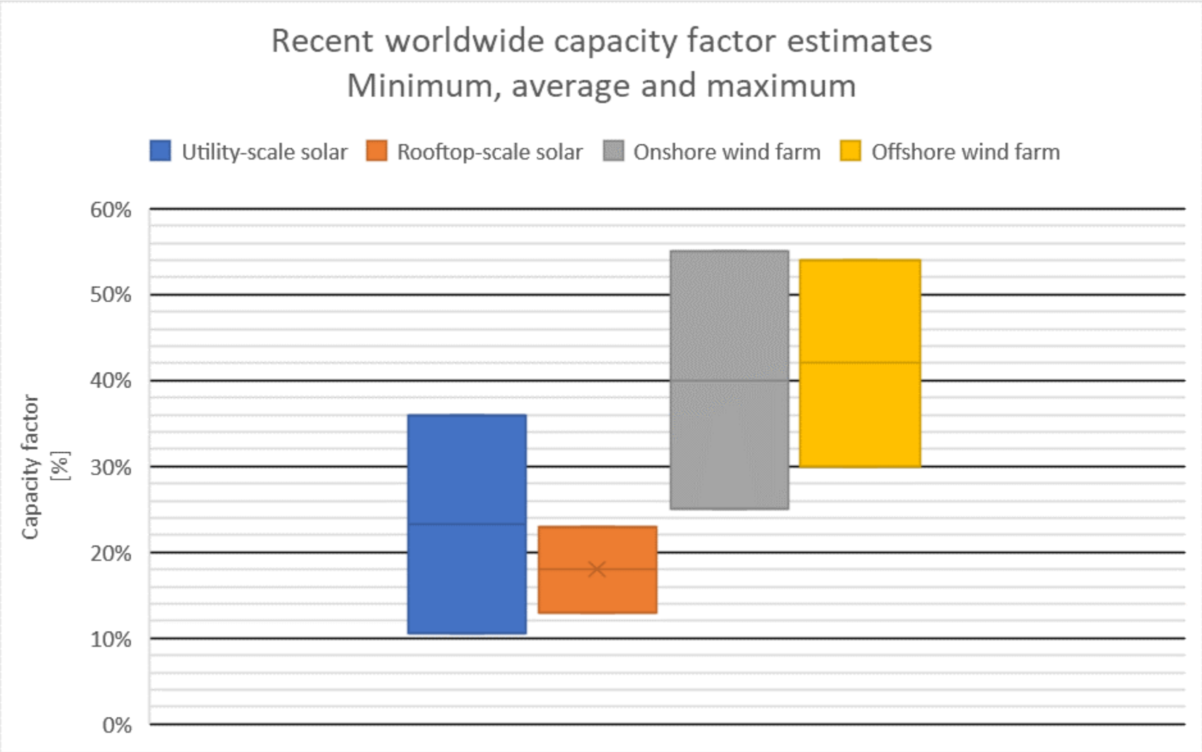
By 2030 and 2050 no CAPEX assumptions are disclosed in publicly-accessible documentation relative to the latest estimates available, except for assumptions in “A Clean Planet for All” scenarios. Therefore, we refer to the CAPEX assumptions included in previous documentation (IRENA “Future of Wind” (Oct. 2019) and IRENA “Future of Solar Photovoltaic” (Nov. 2019)). According to these sources, CAPEX assumptions by 2030 are: 289-709 EUR/kW (utility-scale solar), 680—1148 EUR/kW (onshore wind) and 1445-2720 EUR/kW (offshore wind). Instead, CAPEX assumptions by 2050 are: 140-409 EUR/kW (utility-scale solar), 552.5-850 EUR/kW (onshore wind) and 1190-2380 EUR/kW (offshore wind).

By 2030, both CAPEX assumptions employed “A Clean Planet for All” scenarios and IEA’s CAPEX assumptions fit within the range of assumptions by IRENA (with the exception of IEA’s assumption for onshore wind CAPEX). The range of assumptions by IRENA decreases with respect to recent estimates, although these ranges result equally wide.

By 2050, CAPEX assumptions by IRENA and by EU EC decrease modestly with respect to 2030 (by circa 1.5 times) and the range of CAPEX assumptions remains significant.

Capacity factor

Figure 6.3: Recent worldwide capacity factor estimates according to table 6.1



Recent IEA estimates of capacity factors seem to converge with IRENA's estimates. However, Lazard reports slightly higher capacity factor estimates. The range of estimates reported across all sources is modest in terms of capacity factor: 2.9:1 for utility-scale solar; 0.6 for rooftop-scale solar, 2.2.:1 for onshore wind farms; and 1.8:1 for offshore wind farms.

Like for CAPEX assumptions, by 2030 and 2050 no capacity factor assumptions are disclosed in publicly-accessible documentation relative to the latest estimates available (except for a couple of IRENA datapoints by 2030). Therefore, we refer to the capacity factor assumptions included in previous documentation (IRENA "Future of Wind" (Oct. 2019) and IRENA "Future of Solar Photovoltaic" (Nov. 2019)). By 2030, capacity factor assumptions by IRENA for onshore and offshore wind increase slightly compared to recent estimates (respectively 30-55% and 36-58%). For utility-scale solar IRENA has no assumptions on capacity factors. The ranges are as wide as those regarding recent estimates. By 2050, capacity factor assumptions continue to increase slightly with respect to 2030, to 32-58% for onshore wind and 43-60% for offshore wind.

Capacity factor [164] depends on: i) renewable resources at the location of the production technology; and on ii) technology-specific assumptions. For example, a wind turbine will operate at full capacity more hours *per* year if it is located in a windier spot. Additionally, higher wind turbines with larger blades are able to capture more energy from wind flows in the same location. It might be expected that the location with the best renewable resources will be occupied first by renewable electricity technologies and that additional capacity will occupy

[164] This should not be confused with the utilisation rate, which takes into account the amount of curtailed electricity.

locations with poorer resources. However, the trend of increasing capacity factors shows that technological improvements drive the slight increase in capacity factor.

Interest rate

The real interest rate considered in the CAPEX methodology is the following:

- In the IRENA “Global Renewables Outlook: Energy Transformation 2050” report, no mention is made of assumed interest rates. Instead, in the estimates of “levelised costs today” in the report “Renewable Power generation 2019”, the real weighted average cost of capital is assumed to stand at 7.5% in the OECD.
- In the IEA WEO 2020 report, a standard real pre-tax weighted average cost of capital (WACC) is assumed between 2.4% and 4.0% for solar PV and onshore wind. A real 4% weighted-average cost of capital is assumed to offshore wind projects in the European Union.
- “Clean Planet for All” scenarios documentation reports “overnight investment costs in a green field site” at 0% interest rate; there are no assumed interest rates. According to PRIMES model documentation (which is the model used in the “A Clean Planet for All” scenarios), “capital decisions use weighted average cost of capital (WACC) and subjective discount rates to annualise (levelised) costs so as to compare with variable-running costs which by definition are annual”.
- Lazard assumes an after-tax WACC of 7.7% for global levelised costs estimates.

6.3. Assumptions on the technical potential for EU decarbonisation

We will highlight relevant assumptions on the technical potential of renewable solar and wind electricity in moving towards EU decarbonisation. We cross-assess the assumptions in various energy scenarios, whose key technological assumptions are:

- IEA WEO 2020 SDS scenario (time horizon up to 2050, although data is reported only until 2040).
  - Main technological assumptions: variety of low-carbon technologies, including diffusion of “small size” technologies for energy end-uses (e.g. EVs, heat pumps, electrolysers) and energy-efficiency technologies. Increased penetration of solar and wind in the power sector.
- IRENA Global Renewables Outlook: Energy Transformation 2050 “TES” scenario (time horizon up to 2050).
  - Main technological assumptions: 1) renewable power generation and solar thermal in buildings; 2) electrification of heat and transport, biodiesel and renewable heat; and 3) biomass.
- EU EC “A Clean Planet for All” ELEC scenario (time horizon up to 2050).
  - Main technological assumptions: electrification in all sectors.
- EU EC “A Clean Planet for All” H2 scenario (time horizon up to 2050).

- Main technological assumptions: hydrogen in industry, transport and buildings sectors.

In particular, we report the following assumptions on technical potential (in terms of electricity generation from solar and wind in TWh) relative to the EU-region across different energy scenarios. Electricity generation from solar and wind was chosen as the metric for technical potential because, multiplied by the technological levelised costs, it gives us a main cost component of renewable electricity technologies.

- In 2019, the IEA WEO 2020 SDS scenario estimates the electricity generation from solar and wind at 480 TWh (16.8% of total generation): of which 362 TWh from wind and 118 TWh from solar.
- By 2030, different assumptions on solar and wind electricity generation are made:
    - 1361 TWh according to IEA WEO 2020 SDS scenario (43.1% of total electricity generation): of which 917 TWh from wind and 444 TWh from solar,
    - The electricity generation assumptions for EU are not reported explicitly in the documentation of the IRENA Global Renewables Outlook: Energy Transformation 2050 "TES" scenario.
    - 1367 TWh according to the ELEC and H2 "A Clean Planet for All" scenarios (38%): of which 955 TWh from wind and 412 TWh from solar.

Both wind and solar are assumed to play a significant role, though wind is still assumed to hold the largest technical potential.

- By 2050, different assumptions on electricity generation from solar and wind are carried out by the same institution:
    - 1548 TWh according to the "A Clean Planet for All" ELEC scenario: (36.2%), of which 865 TWh from wind and 683 TWh from solar.
    - 1802 TWh according to the "A Clean Planet for All" H2 scenario: (39.0%), of which 998 TWh from wind and 804 TWh from solar.
    - The electricity generation assumptions for the EU are not reported explicitly in the documentation of the IRENA Global Renewables Outlook: Energy Transformation 2050 "TES" scenario.

Solar is assumed to play a more balanced role with respect to wind.

According to these numbers electricity generation from solar and wind are set to increase significantly by 2030, and to rise even further by 2050.

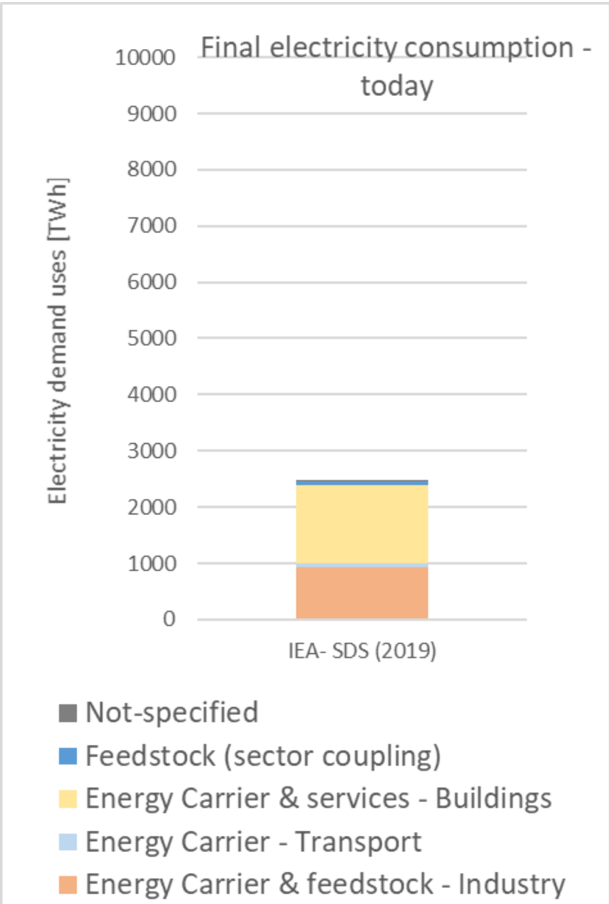
We identify the two following key assumptions for technical potential): I) potential electricity uses; and II) renewable electricity capacity. Understanding potential electricity uses implies mapping how many kWhs of electricity consumers will need and whether they will use electricity for an EV or for space heating. If potential electricity uses amount to little or if we do not know the uses, then we cannot justify the assumed costs of renewable electricity generation from solar PV and wind. In the case of the potential electricity uses for the heating and services of a small off-grid house in the mountains (let's assume 0.4 kWh per day), then there is little need for a massive onshore wind farm for supply. In the case of the EU power system, knowing potential electricity uses means knowing how much electricity generation comes from other sources or indicatively how much imported electricity would be needed. The second question is how much electricity capacity from solar and wind will satisfy these requirements. Electricity generation from solar and wind depends on the available electricity capacity, through the capacity factor. Additionally, electricity capacity leads to CAPEX costs. For the aforementioned off-grid small house, we might assume that an electricity capacity from solar of 2.7 kW (at an arbitrary 15% capacity factor) would produce the necessary 0.4 kWh per day of electricity.

Let us now compare how these assumptions are made across scenarios by international institutions focused on the EU.

Potential electricity uses

In 2019, the IEA WEO 2020 SDS scenario estimate, electricity demand stands at about 2454 TWh (20.9% of total final energy consumption).

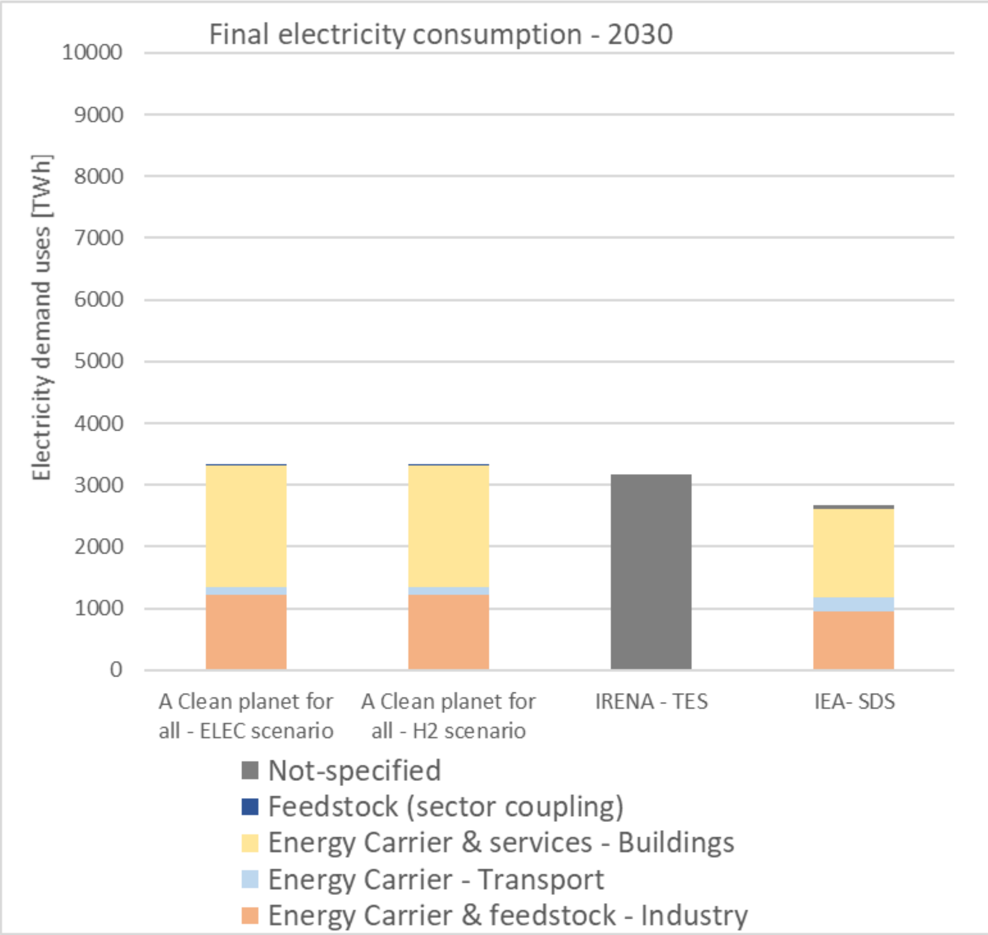
Figure 6.4: Estimates for potential electricity uses in 2019



By 2019, the IEA WEO 2020 SDS scenario identifies three electricity uses:

- Energy carrier and services demand in buildings: demand of electricity as an energy carrier for space heating or water heating or demand for services (e.g. cooking, lighting, PC, building appliances). By 2019 this amounted to 1407.2 TWh (59% of total electricity demand).
- Energy carrier demand in transport: demand of electricity as an energy carrier for mobility (e.g. freight mobility, passenger mobility). By 2019 this amounted to 58.2 TWh (2%)
- Energy carrier and feedstock demand in industry : demand of electricity as an energy carrier for heat or demand for feedstock for process demands (e.g. electrorefining in the metals industry). By 2019 this amounted to 930.4 TWh (39%).

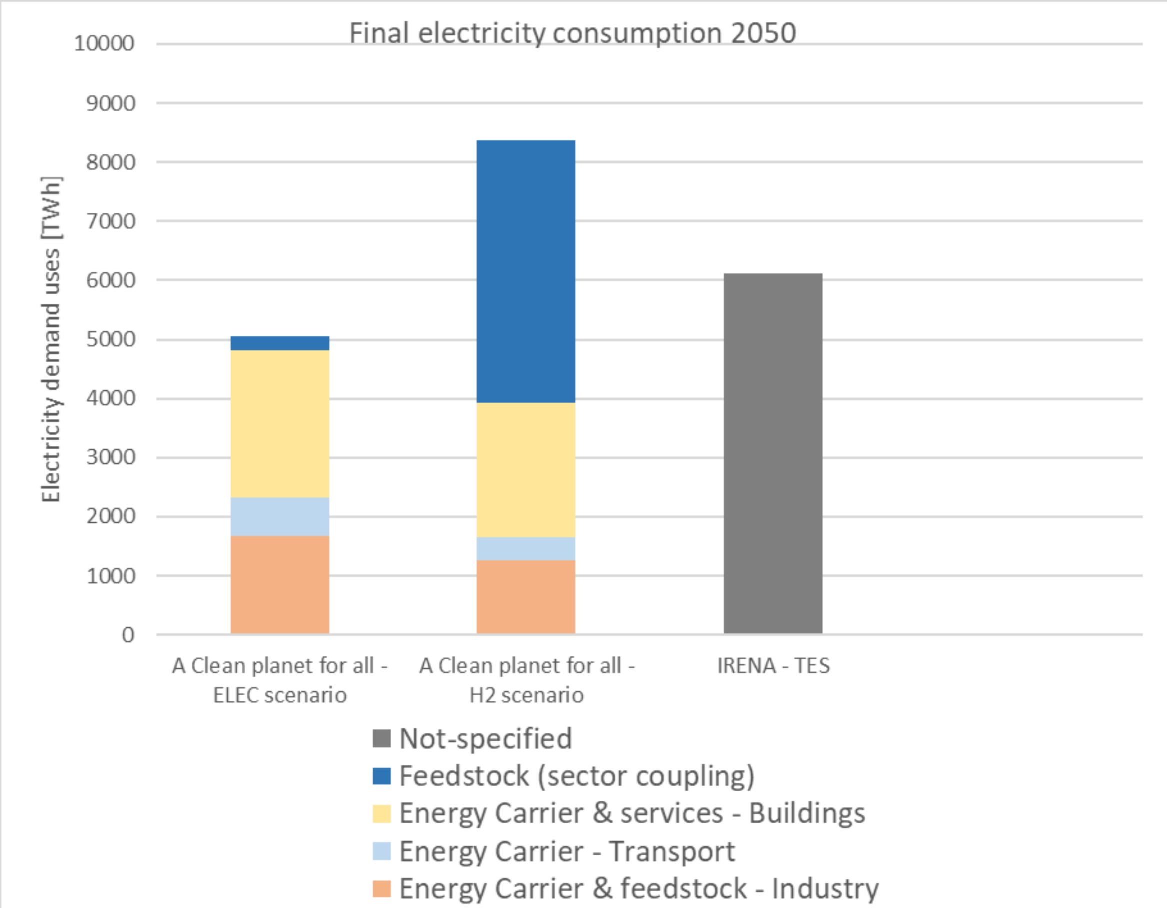
Figure 6.5: Potential electricity uses in 2030 according to four energy scenarios



By 2030, electricity potential demand was assumed to lie within a similar range by the different institutions: 2453.9 TWh (20.9%) according to the IEA WEO 2020 SDS scenario; at 3316.5 TWh (29%) according to the "A Clean Planet for All" scenarios ELEC and H2; and at circa 2790 TWh (23%) according to the IRENA REMAP EU scenario.

In terms of demand, there is now a fourth category: feedstock for synthetic fuel conversion (Sector Coupling) to create hydrogen, synthetic methane and other synthetic fuels. This amounts, however, only to six TWh (almost 0%) in both of the EU EC scenarios. A fifth category ("not-specified") was needed as IRENA TES scenario does not specify the type of potential uses.

Figure 6.6: Potential electricity uses in 2050 according to two energy scenarios



By 2050, electricity demand was assumed quite differently according to two scenarios by the same institution: either 5046 TWh (ELEC scenario) or 8362 TWh (H2 scenario). IRENA TES scenario assumes instead 6125 TWh.

In terms of demand use, the same four categories appear again. However, it is interesting to see that: 1) assumptions about an increase in feedstock uses for synthetic fuel conversion diverge according to the same instutition (the EU EC ELEC scenario and the H2 scenario); and 2) a slight increase in energy carrier demand in transport can be seen. However, we must always keep in mind that we are speaking of assumptions by 2050.

Renewable electricity capacity from solar and wind

The following assumptions on renewable electricity capacity from solar and wind are reported in the four scenarios examined previously for "potential electricity uses":

By 2019,

- The IEA WEO 2020 SDS scenario estimates 285 GW of variable renewable electricity capacity (29.6% of total generation capacity): of which circa 168 GW from wind and 117 GW from solar PV.

By 2030,

- IEA assumes 727 GW of variable renewable electricity (54.9%): of which 336 GW from wind; and 391 GW from solar PV.
- Instead, the IRENA "Global Renewables Outlook: Energy Transformation 2050" TES scenario assumes 603 GW of variable renewable electricity: of which 319 GW from wind; and 284 GW from solar PV.
- Finally, the "A Clean Planet for All" ELEC and H2 scenarios each assume 671.8 GW (53.0%): of which 262.9 GW from onshore wind; 88.4 GW from offshore wind; and 320.5 GW from solar PV.

  It is clear that (variable) renewable electricity capacity is set to almost double. However, the assumptions for renewable electricity capacity and, the relative increase with respect to 2018 estimates, are not the same. Renewable electricity capacity for onshore wind is assumed to almost double, while the renewable electricity capacity for offshore wind is assumed to grow by a factor of three to four and that of utility-scale PV by a factor of two to three.

By 2050,

- We only have assumptions relative to the two "A Clean Planet for All" scenarios. The ELEC scenario assumes a renewable electricity capacity of 1547.8 GW (72.4%): 560.2 GW from onshore wind; 304.6 GW from offshore wind; and 683 GW from solar PV.
- Instead, the H2 scenario assumes a renewable electricity capacity of 1801.4 GW: 78.0%, 635.3 GW of onshore wind; 362.2 GW from offshore wind; and 803.9 GW from solar.
- Finally, the IRENA "Global Renewables Outlook: Energy Transformation 2050" TES scenario assumes 1405 GW of variable renewable electricity: of which 621 GW from wind; and 784 GW from solar PV.

Here we see a circa 2.5 increase in renewable electricity capacity with respect to 2030. While the renewable electricity capacity of onshore wind and solar PV are assumed to increase by a factor of just over two, the renewable electricity capacity of offshore wind is assumed to grow impressively from 88.4 GW to either 362.2 GW or 304.6 GW (by a factor of almost four). Once more, we should stress that assumptions about 2050 are far less reliable than those for 2030.

Renewable electricity capacity from solar and wind also depend on other critical sub-assumptions. Critical sub-assumptions include: i) surface availability (be it land or sea), ii) renewable resource potential (which is site-specific), iii) efficiency and iv) the logic regulating investment decisions. Surface availability is a particularly critical sub-assumption for solar PV and onshore wind, since the land surface required for solar PV and onshore wind capacity might not be available (for example, due to the presence of buildings or crops). Secondly, renewable energy potential determines the maximum amount of (physical) renewable energy which is available over a given available surface for a given time horizon, without accounting for technical considerations. Thirdly, efficiency determines the amount of renewable electricity which can be extracted from a unit of (physical) renewable energy, with a given technology at a specific stage of technological maturity. Fourth and finally, the logic regulating investment decisions is a critical sub-assumption because it determines whether renewable electricity production plants are built and in what quantities: e.g. target policies or due to favourable economics or due to the deployment of demonstration projects.

It must be noted that: i) EU surface availability can be expected to be significantly lower than those of, for example, Australia or Saudi Arabia (in particular for utility-scale solar PV). However, we will not examine these critical sub-assumptions in detail with all possible metrics, because it would go far beyond our own research capabilities.

6.4. Assumptions on future system costs

In addition to technology-specific levelised costs, future costs for solar and wind technologies include system costs. We are limiting ourselves here to the EU power system. We can identify: 1) assumptions on future grid costs; and 2) assumptions on future balancing costs. In fact, the 1 kWh of renewable electricity which goes from the renewable generator to the potential use might lead to: 1) grid costs from building new grids or upgrading an existing one; and to 2) balancing costs since renewable electricity from wind and solar is: i) variable, ii) uncertain and iii) non-dispatchable.

IRENA "Global Renewables Outlook: Energy Transformation 2050– TES scenario" assumes 47.6 EUR billion/year [165] in "power grids and flexibility" investments for EU through 2050. Instead, "A Clean Planet for All" ELEC and H2 scenarios assume each an average annual investment in power grid of 59.2 EUR billion/year over 2021-2031. Over the period 2031-2050 the ELEC scenario assumes 110.3 billion EUR/year while the H2 scenario 91.1 billion EUR/year.

Assumptions on future grid costs

Future grid costs depend on certain factors: I) the existing grid; II) the spatial distribution of solar and wind electricity generation technologies; III) the technical potential of electricity generation technologies (or "size"); and IV) grid technology costs.

Grid costs are particularly technology-specific. Let us take two extreme cases: rooftop-scale PV and offshore wind. In the first case, for rooftop-scale PV, the spatial distribution of rooftop-scale PV technologies is on homes, where a grid already exists, and the size of a rooftop-scale PV generator is quite small; typically 1-10 kW. Therefore, until a significantly higher share of rooftop-scale PV is installed, and grid reinforcements are needed, future grid costs can be assumed to be insignificant. In the second case, for offshore wind farms,

[165] 56 USD billion/year in the original source.

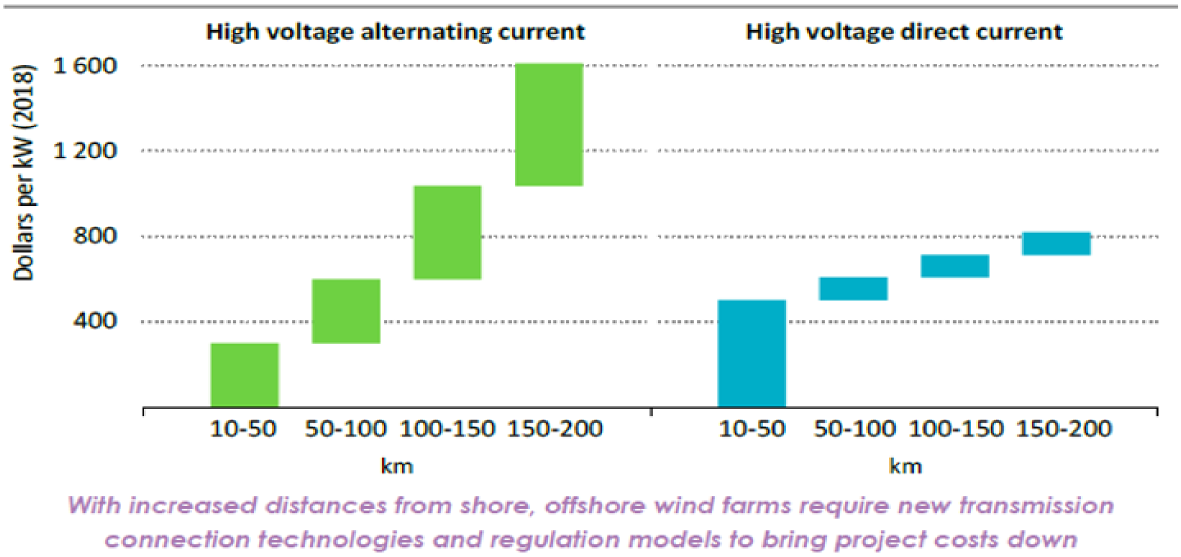
electricity generation from offshore wind farms takes place on the sea, where there is no grid, and the typical size of offshore wind farms is from 100 MW to 2 GW according to BloombergNEF. Utility-scale PV and onshore wind stand somewhere in the middle and assumptions vary: e.g. think of the differences between a utility-scale PV farm floating on a lake, or in the middle of a desert, or potentially close to a city with an existing grid.

We analyse how future grid costs assumptions vary across the different scenarios. In particular, only IEA makes a distinction between the electricity generation of onshore wind and offshore wind. IEA WEO 2020 STEP scenario [166] estimates that around "30% of the increase in transmission lines and 20% of the increase in the distribution network lines (to 2030) is attributable to the increase of renewables". According to the World Energy Model 2020 documentation, "transmission network costs are derived based on specific renewable grid integration costs, derived from a literature review... Regional differences due to geography and labour costs are taken into account". However, only the example of wind is mentioned ($100/kW - $250/kW of installed wind capacity). Instead, regarding distribution grid extension costs, it is assumed that "additional network investment is required only if the electricity generated from distributed generation, such as solar PV in buildings and bioenergy in industry, exceeds local demand and is fed back to the system". However, no references to specific costs are done.

Differently from the recent IEA WEO 2020 SDS, the older IEA WEO 2019 SDS scenario examines some of the sub-assumptions underlying grid costs from offshore wind in EU-region. For example, the average distance from offshore wind farms to mainland grid, for offshore wind farms that are under construction or commissioned or in the pipeline, is reported. This average distance for commissioned farms is *circa* 16 km for the UK, 44 km for Germany, 25 km for Netherlands and 20 km for Denmark. Instead, the average distance for farms under construction or in the pipeline is, respectively, circa 78 km, 62 km, 32 km and 25 km. These numbers are both variable and non-negligible. In terms of technical potential, commissioned project sizes are circa 100 – 350 MW. Grid technologies mentioned are either AC or HVDC and the following is reported regarding their costs: "even without considering the cost of substations, AC transmission has a cost advantage over shorter distances (10-100 km), but over longer distances high-voltage DC (HVDC) transmission can offer significant cost savings". This following IEA figures confirms this: [167]

[166] The IEA WEO 2020 STEPs scenario sees a smaller deployment of renewable electricity technologies compared to IEA WEO 2020 SDS.
[167] IEA "World Energy Outlook 2019" (Nov. 2019). All rights reserved.

Figure 6.7: Indicative upfront capital cost for high-voltage transmission cables by type and distance from shore, IEA (2019)



Note: Installation costs for transmission cables vary based on site conditions.

Sources: IEA analysis; Xiang et al. (2016); DIW ECON (2019).

The same logic can be applied to the EU-level in considering RE electricity imports from abroad. In this case, the technical potential corresponds to electricity generation from solar and wind at the EU-level. Grid technology costs would then enable electricity generation from solar and wind abroad to be imported; but whether technologies would depend on undersea or underground or overhead lines has significant cost implications. [168]

As will soon become clear, increased interconnection is also a balancing option. However, it is not easy to identify whether it is, indeed, a future cost of renewable electricity or not.

Assumptions about future balancing costs

Assumptions about future balancing costs depend on the following sub-assumptions: I) the amount of electricity generation from solar and wind energy; II) the uncertainty of electricity generation from solar and wind; III) the variability in electricity generation from solar and wind; IV) the non-dispatchability of solar and wind; V) load profile; and VI) balancing options' costs. Some balancing options identified include demand-side response, storage, dispatchable generation (ramp-up/ramp-down capacity), curtailment and increased interconnection.

[168] In absence of further data from these scenarios studies, we bring evidence from a third source (external costs source "e-Highway 2050 Modular Development Plan of the Pan-European Transmission System 2050" (2013) – Annex D3.1). In particular, this study estimates current AC overhead technology costs at 1200 kEUR/km, HVAC overhead at 7500-1650 kEUR/km (depending on whether the system is rural or urban), HVDC overhead at 1200-1599 kEUR/km, HVDC underground at 1600 kEUR/km and HVDC subsea cables at 1900 kEUR/km. Instead, this same study assumed 2050 AC overhead technology costs at 1077-1615 kEUR/km, HVAC overhead costs at 1200 kEUR/km, HVDC overhead at 1269 – 1903 kEUR/km, HVDC overhead at 1269 – 1903 kEUR/km, HVDC underground 1600 kEUR/km and HVDC subsea at 1595 kEUR/km for three cables. No reference is made to interest rates.

IRENA “Global Renewables Outlook: Energy Transformation 2050– TES scenario” identifies the stationary storage size and EVs storage size towards the “need for power system flexibility” due to VRE. Regarding stationary storage size, departing from the recently estimated 30 GWh of stationary storage capacity in 2019, IRENA assumes 3400 GWh by 2030 and 9000 GWh by 2050. Instead regarding EVs storage size, departing from the recently estimated 200 GWh of EVs storage in 2019, IRENA assumes a need for 7546 GWh by 2030 and 14145 GWh by 2050. Finally, IEA World Energy Outlook 2020 scenarios identify a “(power system) flexibility need”, having defined flexibility as “a variety of services spanning time scales measured in seconds to hours, days and across seasons” (e.g. hour-to-hour ramping requirements). For EU a power system flexibility need of circa 37-40 GW is estimated between 2020 and 2030. In particular, it is mentioned that “in the European Union, strengthening interconnections is fast becoming the central pillar of flexibility”.

However, the assumptions presented in the scenarios we have considered are derived from a least-cost system minimisation model. It is not, therefore, possible to identify the specific balancing costs from renewable electricity generation in the absence of counter-factual scenarios or further evidence. Nevertheless, we map whether these different scenarios model the drivers for future balancing costs and we look at the balancing options that they consider. A red cell means that this driver or balancing option is not modelled. Instead a green cell means that this driver or balancing option is modelled. Yellow means that the modelling of the driver or balancing option is not mentioned.

The following documents were consulted:

- E3MLab “PRIMES Model 2013-2014 - Detailed model description” (2014)
- IEA “World Energy Model Documentation – 2020 version” (2020)
- IRENA “Global Renewables Outlook: Energy Transformation 2050” (April 2020) and IRENA “Renewable Energy Prospects for the European Union” (Febr. 2018)[169]

[169] The choice of also examining IRENA “Renewable Energy Prospect for the European Union” (Febr. 2018) was because this scenario includes additional analysis, focused specifically on the consequences of increased renewable electricity penetration in the power system.

Table 6.2: Modelling of drivers for future balancing costs and of balancing options across four energy scenarios

Scenarios	Drivers Variable renewable electricity properties		Balancing options				
	Uncertainty	Variability	Demand-side response	Storage	Curtail-ment	Dispatchable generation	Increased interconnection
IEA WEO 2020 SDS scenario							
IRENA TES scenario & REMAP EU scenario							
"A Clean Planet for All" H2 scenario							
"A Clean Planet for All" ELEC scenario							

As it can be observed, except for IRENA not modelling uncertainty of variable renewable electricity, all other drivers are modelled. Additionally, the balancing options mentioned are all taken into account across these documents. This makes any assessment of balancing costs assumptions and sub-assumptions more difficult.

Policy outcomes

- According to sources recognised for their future costs studies, both onshore wind and solar PV currently result competitive in terms of worldwide estimates for levelised costs, while offshore wind and rooftop PV have significantly higher levelised costs. However, there is large variability between recent world record lowest bids and average values reported by BloombergNEF and by Lazard for 2020. By 2030, a significant decrease in the assumed average levelised costs for utility-scale solar, onshore wind and offshore wind can be expected. By 2050, the assumed range of levelised costs is expected to further decrease and average values will be similar to those reported in recent world record lowest bids. Out of the three critical sub-assumptions of levelised costs identified (i.e. CAPEX, interest rates and capacity factor), CAPEX sub-assumptions are assumed to decrease while capacity factors are assumed to slightly increase. The assumed real interest rates do not change through time and differ between the different organisations. These renewable electricity technologies are already cost-competitive with other electricity generation technologies (e.g. fossil-fuel based) and they can be assumed to become increasingly cheaper.

- The technical potential of renewable electricity from solar and wind towards EU decarbonisation (in terms of total capacity of technologies portfolio - GW) is set to more than double by 2030 and to have a circa 5 - 6 increase by 2050 with respect to 2030. Two critical sub-assumptions for technical potential can be identified: I) potential electricity uses (TWh); and II) electricity generation from solar and wind over 1 year (TWh). Potential electricity uses are assumed not to change drastically by 2030 compared to today. However, by 2050 potential electricity uses could either almost double or triple, because of increasing electrification and potentially also because of the increasing use of electricity as feedstock for synthetic fuel conversion (e.g. hydrogen, ….). Electricity generation from solar and wind is set to more than double by 2030, reaching a 38%-43% share in total generation, and to further increase by c. 3 – 3.5 by 2050 (36%-39%). Therefore, renewable electricity from solar and wind, relative to the EU-region, can be assumed to play a more significant role in terms of the total capacity and the total generation of the technologies portfolio towards EU decarbonisation, in order to comply with the potential increasing need for electricity.

- System-costs for the EU power system of renewable electricity technologies can be analysed in terms of two main assumptions: I) grid costs; and II) balancing costs. The assumptions on grid costs are mostly not set out in the energy scenarios studies, with the exception of the IEA scenario, with some data relative to the critical sub-assumptions of additional network lines due to renewables, grid costs due to offshore wind farms in the EU and to renewable integration costs due to onshore wind. Assumptions on balancing costs are not evident since they cannot be identified without counter-factual scenarios and further evidence. Energy scenarios model different drivers for balancing cost of renewable electricity technologies (i.e. variability and uncertainty) and different balancing options (e.g. demand-side response, storage, curtailment, interconnection). This is true of all scenarios with the exception of the IRENA REMAP EU scenario which did not model the uncertainty driver. Therefore, this opens the way for modelling exercises that transparently and methodically investigate the system-costs of renewable electricity technologies.

7. Assumptions on the future costs of hydrogen technologies [170]

In this chapter, we will focus on future hydrogen technology costs. We break our analysis down into two parts: 1) potential hydrogen uses in moving towards an EU carbon neutral industry and energy system; and 2) the assumptions on future hydrogen supply costs, which underlie potential future hydrogen uses. In particular, we will focus on the following time horizon: today (for which we take 2019-2020 as a proxy), 2030 and 2050. Yet again it is worth noting that assumptions about 2030 (ten years from now) are hypothetical, but that these assumptions are far more reliable than those about 2050 (30 years from now).

In the first section, we will analyse potential hydrogen uses across four different technological scenarios, which model the transition towards an EU carbon neutral industry and energy system by 2050. Additionally, we focus on three critical sub-assumptions that we identified in these studies: i) types of potential hydrogen uses; ii) the inclusion of potential synthetic fuel uses, derived from hydrogen within the EU-region, and iii) the inclusion of potential uses of hydrogen blended with natural gas.[171] Some examples of potential hydrogen uses include the following: i) residential cooking and water heating; ii) production of chemicals, such as ammonia or methanol, by industrial consumer; and, iii) the production of synthetic liquid fuels for aviation by a domestic Fisher-Tropsch plant.

In the second section, we focus on assumptions on future hydrogen costs in delivering potential hydrogen use in the EU-region. In fact, potential hydrogen uses will depend on some assumptions, including the cost-competitiveness of hydrogen supply to the energy consumer with respect to other energy fuels. Instead, the potential industrial feedstock uses of hydrogen [172] are not substitutable by other fuels. In order to do this, we cross-assessed the assumptions and the relative sub-assumptions on future hydrogen costs according to three international organisations, known for their future cost studies, namely, IEA, IRENA and BloombergNEF. In this second section, we will try to answer four main questions:

i. Will domestic or foreign future hydrogen supply be cheapest?
ii. What hydrogen production technologies will be the cheapest? Green hydrogen[173], blue hydrogen [174] or turquoise hydrogen [175]? How can we best quantify their cost-competitiveness (e.g. ETS prices)?
iii. What are the critical sub-assumptions for each combination of location and hydrogen production technologies? Regarding domestic green hydrogen costs, what are the critical sub-assumptions (e.g. CAPEX, full load hours and cost of electricity) for scenarios in which levelised costs [176] are minimal? Are those assumptions relative to a renewable electricity-based electrolyser or to a grid-based electrolyser?

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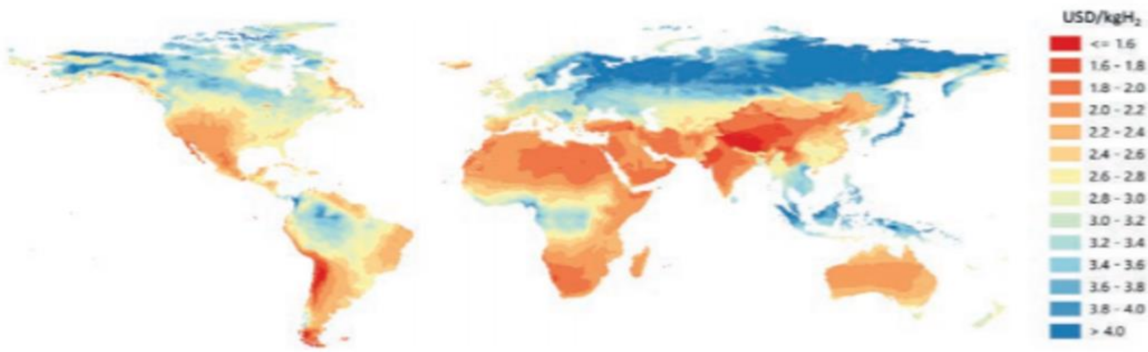
[170] We would like to specially thank Prof. Ronnie Belmans (KU Leuven) and Director Alberto Pototschnig (FSR) for their precious time and feedback. Any mistakes remain those of the authors.
[171] Instead, we did not find any mention of the modelling of the time profile of hydrogen uses or of the location of hydrogen use within EU-region.
[172] As we will see in the first section, industrial feedstock uses are related to the production of chemicals, steel and refined oil.
[173] By green hydrogen, we mean hydrogen produced by an electrolyser either directly coupled to a renewable electricity generator, or coupled to the grid (if low-carbon electricity is sourced).
[174] By blue hydrogen, we mean hydrogen produced by a Steam Methane Reforming plant with CCS.
[175] By turquoise hydrogen, we mean hydrogen produced by a Methane pyrolysis plant with CCU.
[176] Levelised costs are the technology-specific costs for producing one kg of hydrogen from hydrogen production technologies.

iv. What assumptions can be made on transport and storage costs within EU-territories? [177]

The first question (i.e. "Will domestic or foreign future hydrogen supply be cheapest ?") is necessary because, as the reader can see in the map below [178], IEA assumes that in the "long term" (2050?), hydrogen produced from renewable electricity generators will be available and at significantly different levelised costs depending on location. In particular, we observe that the levelised costs of production relative to EU-regions are not the most favourable ones for this technology. However, the costs of importing hydrogen into the EU-region involve additional sub-assumptions (i.e. storage and location costs), additional to production costs. IRENA and BloombergNEF also assume that hydrogen costs will vary based on location.

Figure 7.1 Hydrogen costs from hybrid solar PV and onshore wind systems in the long term, IEA (2019)



Notes: This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area. Electrolyser CAPEX = USD 450/kWe, efficiency (LHV) = 74%; solar PV CAPEX and onshore wind CAPEX = between USD 400–1 000/kW and USD 900–2 500/kW depending on the region; discount rate = 8%.

Source: IEA analysis based on wind data from Rife et al. (2014), *NCAR Global Climate Four-Dimensional Data Assimilation (CFDDA) Hourly 40 km Reanalysis* and solar data from renewables.ninja (2019).

The declining costs of solar PV and wind could make them a low-cost source for hydrogen production in regions with favourable resource conditions.

The second question (i.e. "What hydrogen production technologies will be the cheapest ?") is necessary because there are multiple hydrogen production technologies for which future hydrogen supply might be possible. In particular, we focus on three hydrogen production technologies: those for green hydrogen; those for blue hydrogen; and those for turquoise hydrogen.

Regarding the third question (i.e. "What are the critical sub-assumptions for each combination of location and hydrogen-production technologies?"), we focus on each specific type of hydrogen production technology (e.g. green hydrogen) and on the critical sub-assumptions underlying its levelised costs assumptions (e.g. the levelised costs assumptions of green hydrogen: CAPEX, interest rates, full-load hours and costs of electricity). In particular, we

177 We included the assumptions about compression costs within those about domestic transport costs.

178 The figure was taken from the IEA report "The future of Hydrogen" (June 2019). All rights reserved.

investigate the sensitivity of levelised costs assumptions with respect to some of these critical sub-assumptions.

Finally, the fourth question (i.e. "Which assumptions on transport and storage costs within EU-territories can be made?"), is also necessary because, just like production costs, domestic transport and storage costs are also critical assumptions of hydrogen supply costs.

To answer the first three questions, we will consider five scenarios (one including two sub-scenarios) for assumptions on future hydrogen (supply) costs for an EU consumer: 7.2.1) domestic green hydrogen costs scenario – utility-scale solar PV sub-scenario and offshore wind farm sub-scenario; 7.2.2) domestic blue hydrogen costs scenario; 7.2.3) domestic turquoise hydrogen costs scenario; 7.2.4) imported green hydrogen costs scenario; and 7.2.5) imported blue hydrogen costs scenario. One example of scenario 7.2.1) would be that of a fuel cell plant close to a domestic electrolyser, which buys green hydrogen produced by an electrolyser connected to a utility-scale solar PV facility. Another example, relative instead to scenario 7.2.4), would be that of an industrial client in Spain who buys green hydrogen produced in North Africa by an electrolyser coupled to a Solar PV farm and shipped as liquid hydrogen. A final example relative to scenario 7.2.5 would be that of an fuel cell electric vehicle station in the EU that buys blue hydrogen produced in Russia in a Steam Methane Reforming plant with CCS which is then transported through pipelines. For each of these five scenarios, we compare both recent estimates of hydrogen costs and assumptions around future hydrogen costs according to the different organisations examined. We analyse also: i) technical potential [179]; ii) levelised costs [180]; and iii) "critical" sub-assumptions about levelised costs. We will analyse the fourth question (i.e. "What assumptions can be made on domestic transport and storage costs?") successively.

7.1. Potential hydrogen uses in moving towards an EU carbon neutral industry and energy system

In this first section, we present recent estimates on hydrogen use and cross-assess future potential hydrogen use towards an EU carbon neutral industry and energy system according to five scenarios. Two of these scenarios were carried out by the European Commission, the other two by the industry and research community (FCH JU [181] and Guidehouse & Gas for climate [182]) and the fifth one by an intergovernmental organisation (IEA). Compared to the scenarios offered up in chapter 6 "assumptions on future costs of solar PV and wind technologies", we do not include the IRENA TES scenario as it does not disclose its EU-specific results for future

[179] By technical potential, we mean the amount of hydrogen which can be potentially produced by a portfolio of technologies in a certain time frame, e.g. in one year.

[180] The definition of levelised costs is intuitive when the system is one hydrogen production plant (e.g. an electrolyser). In this scenario, levelised costs correspond to the total costs of that production plant, divided by the technical potential of the plant (i.e. the amount of hydrogen produced in a certain time frame, e.g. one year). However, this concept can also be extended when the system is the entire EU or an import option.

[181] The Fuel Cells and Hydrogen Joint Undertaking is a public-private partnership of three members: the European Commission; Hydrogen Europe (representing the fuel cell and hydrogen industries); and Hydrogen Europe Research (representing the research community).

[182] Gas for Climate is a group of ten leading European gas transport companies and two renewable gas industry associations, whereas Guidehouse is an international consultancy.

potential hydrogen use. We consider the following scenarios studies and we qualify them based on the responsible institution, decarbonisation goals and main technological assumptions:

1. *"A Clean Planet for all – H2 scenario" (November 2018) by European Commission.* This scenario achieves just above 85% Greenhouse gas emission reduction by 2050 compared to 1990, reaching by 2050 net emissions of 0.806 GtCO2eq including land use and forestry sectors sink. This scenario starts from a baseline scenario which finishes with a 2030 horizon.
   Main technological assumptions: this scenario assumes that hydrogen technologies will be available and cost-competitive, leading to a high penetration of hydrogen in industry, transport and buildings sectors.

2. *"A Clean Planet for all – ELEC scenario" (November 2018) by the European Commission.* This scenario achieves just above 85% Greenhouse gas emission reduction by 2050 compared to 1990, reaching net emissions of 0.816 GtCO2eq, by 2050, including land use and forestry sectors sink. This scenario starts from a baseline scenario which finishes with a 2030 horizon.
   Main technological assumptions: this scenario assumes that electrification technologies will be available and cost-competitive, leading to a high penetration of electricity in all sectors.

3. *"Hydrogen Roadmap Europe – ambitious scenario" (January 2019) by Fuel Cells and Hydrogen Joint Undertaking.* This scenario is based on an EU decarbonisation pathway towards the two-degree target set by the Paris Agreement, reaching, by 2050, carbon emissions of 0.771 GtCO2. The starting point of this scenario is 2015.
   Main technological assumptions: this scenario focuses specifically on future potential hydrogen demand and on relative technological assumptions. This scenario assumes that hydrogen technologies will be widely available and that there will be high hydrogen penetration in hard-to-abate sectors (i.e. transport, industry and buildings) and in Sector coupling areas.[183]

4. *"Gas Decarbonisation Pathways 2020-2050 – Accelerated Decarbonisation Pathway" (April 2020) by Gas for Climate and Guidehouse.* This pathway achieves net-zero emissions by 2050 and is based on the EU Green Deal. The starting point of this scenario is 2020.
   Main technological assumptions: this scenario focuses specifically on potential renewable gases demand (including biomethane and hydrogen) and on relative technological assumptions. The production of biomethane, green hydrogen and blue hydrogen will be scaled up to 10% of total gas demand by 2030 and to 100% total gas demand by 2050.

5. *"World Energy Outlook 2020 - Sustainable Development Scenario (SDS)" (Oct. 2020) by IEA.* This scenario is "fully aligned with the Paris Agreement" [184]. Global CO2

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[183] It is not reported, in this document, whether energy values in HHV or LHV are considered for the hydrogen demand assumptions in exhibit 2. In line with the Commission Staff Working Document "Clean Energy Transition – Technologies and Innovations" SWD(2020) 953 final which interpretates these energy values as expressed in LHV, we reconverted these energy values from a LHV-basis to a HHV-basis.
[184] Source: https://www.iea.org/reports/world-energy-model/sustainable-development-scenario.

emissions from the energy sector and industrial processes fall to circa 10 GtCO2 by 2050 and are on track to net zero emissions by 2070.
Main technological assumptions: variety of low-carbon technologies, including diffusion of “small size” technologies for energy end-uses (e.g. EVs, heat pumps, electrolysers) and energy-efficiency technologies. Increased penetration of solar and wind in the power sector.

It should be noted that, except for IEA World Energy Outlook 2020 SDS, these scenarios are based on technological assumptions, which are founded either on electrification technologies or hydrogen technologies. Therefore, cross assessing these different scenarios to display range of potential hydrogen uses would be more informative than presenting the values of a single scenario.

As previously mentioned, we will also focus on three critical assumptions underlying the results on future potential hydrogen use: i) types of hydrogen uses; ii) the inclusion of synthetic fuels uses, derived from hydrogen within the EU-region, and iii) the inclusion of potential uses of hydrogen blended with the gas grid. All scenarios include, within their results on potential hydrogen uses, not only the hydrogen uses of hydrogen molecules (also blended with natural gas), but also the hydrogen uses of domestically derived synthetic fuels molecules. Therefore, keeping in mind that we are limiting ourselves to the EU, we identify the following four scenarios of potential future hydrogen uses:

1) hydrogen produced domestically and consumed by domestic consumers;

2) hydrogen produced domestically, converted to synthetic fuels domestically (e.g. synthetic liquid fuels or methanol) and consumed by domestic consumers;

3) hydrogen produced abroad, transported either as hydrogen or through an intermediate hydrogen carrier (e.g. LOHC [185], ammonia) and consumed as hydrogen by domestic consumers;

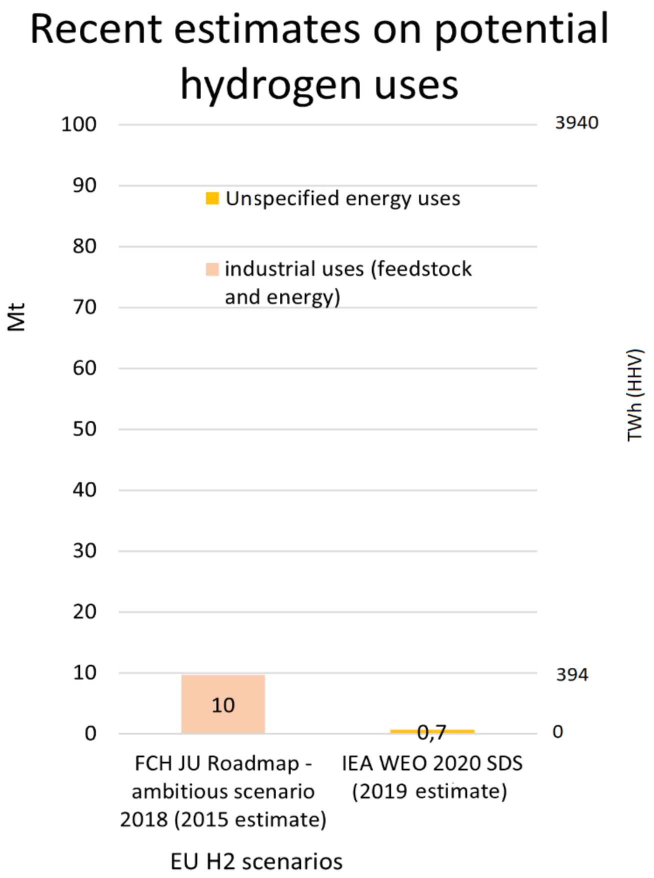
4) hydrogen produced abroad, transported either as hydrogen or through an intermediate hydrogen carrier (e.g. LOHC [185], ammonia), converted domestically into a synthetic fuel and consumed by domestic consumers.

However, we do not include hydrogen produced abroad (e.g. in Oman), converted there into a synthetic fuel (e.g. methanol), transported into EU as fuel and delivered to the consumer as synthetic fuel. [186] In order to fill this gap, it would be necessary to know the import levels of synthetic fuels, consumed as such by consumers.

[185] Liquid Organic Hydrogen Carrier.
[186] There is a substitution effect between importing hydrogen to convert it domestically into synthetic fuels and importing directly synthetic fuels. This effect will depend on the trade-off of: i) assumptions on hydrogen import costs and on synthetic fuels conversion costs domestically; and ii) assumptions on synthetic fuels import costs. According to the IEA and BloombergNEF, the transport costs of synthetic fuels are much lower than those of hydrogen and, therefore, synthetic fuel import costs could result cheaper than hydrogen import costs.

Regarding the following plots, we would like to note that 10 Mtons of H2 correspond to 394 TWh (HHV) [187], to 336 TWh (LHV) [188] and to 119 bcm (@ 1 atm & 15.5°C).

Figure 7.2 Recent estimates of potential hydrogen uses

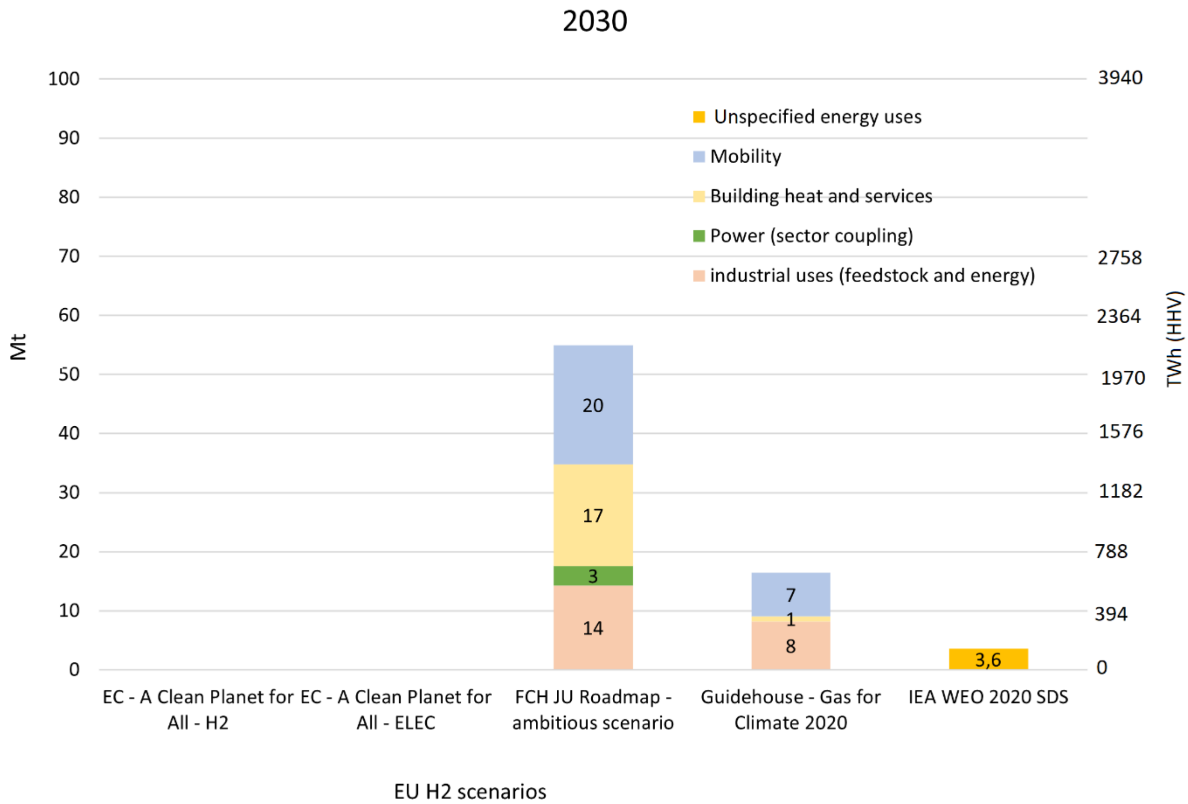


In 2015 estimates, only hydrogen industrial uses (feedstock & energy) could be identified in estimates, which potentially can be assumed to have stayed at a similar level until recently. In particular, 10 Mt of hydrogen industrial feedstock use were included, for which hydrogen is consumed as a raw input material (i.e. industrial feedstock) for producing industrial goods. Examples of those industrial goods are: Chemicals (e.g. Ammonia, Methanol…), “Crude steel” – DRI and Refined oil. More recently, IEA WEO 2020 SDS scenario identified a small amount of unspecified energy uses (0,7 Mt).

[187] Higher heating value (0.03939 MWh/kg for hydrogen). Values expressed in HHV include all the potential chemical energy of hydrogen molecules. Therefore, values in HHV are more appropriate for feedstock uses and some energy carrier uses, which condense the water product to recover energy.

[188] Lower heating value (0.03361 MWh/kg for hydrogen). Water is produced from the energy uses of hydrogen (combustion process). Compared to values in HHV, values expressed in LHV include energy losses from water vaporization. Therefore, values in LHV are more appropriate for certain energy carrier uses, which do not recover these energy losses through condensation.

Figure 7.3 Potential hydrogen uses by 2030



By 2030, these scenarios are clearly divergent regarding potential hydrogen uses. For example, the two "A Clean Planet for All" scenarios by EU EC and IEA WEO 2020 SDS do not take future hydrogen industrial feedstock use into account. Instead, these scenarios only report future hydrogen energy uses, which result null by 2030 for the scenarios by EU EC and 3.6 Mt for IEA WEO 2020 SDS. Instead, the "FCH JU Roadmap – ambitious scenario" and the "Guidehouse – Gas for Climate 2020 Accelerated Decarbonisation Pathway" scenario give a total value for potential hydrogen uses ranging between 16 and 54 Mt. For these last two scenarios, future potential hydrogen energy uses are assumed, in addition to pre-existing hydrogen industrial feedstock uses:

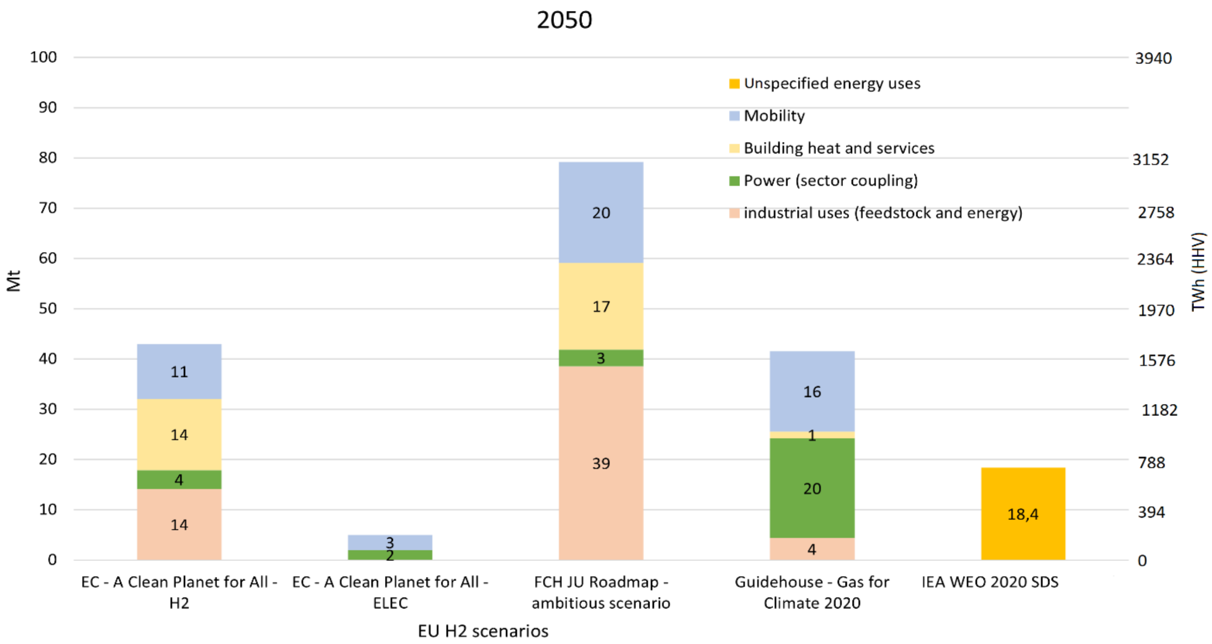
- Building heat and services uses: e.g. buildings space heating, water heating, cooking and other end-uses;
- Industrial energy uses [189]: e.g. hydrogen combustion for steam and hot water production;
- Power (i.e. Sector coupling) uses: hydrogen is converted to electricity, e.g. for seasonal electricity storage or for generation at peak load (including potential uses of synthetic fuels);
- Mobility uses: e.g. refuelling stations for passenger transport and freight transport (including potential uses of synthetic fuels)

[189] The industry energy carrier uses were included within "industrial uses (feedstock and energy)". Additionally, within this last category we arbitrarily included "other (hydrogen)" demand, explained within "Gas Decarbonisation Pathways 2020-2050 – Accelerated Decarbonisation Pathway" (April 2020) by Gas for Climate and Guidehouse.

These future potential hydrogen energy uses amount to between 3.6 Mt (i.e. IEA WEO SDS), 8 Mt (i.e. Gas for Climate scenario) and 40 Mt (i.e. FCH JU Roadmap – ambitious scenario). In the last two scenarios, mobility use plays a significant role. Instead, the relative shares of building heat and services uses and power (Sector coupling) uses diverge across these two scenarios. Finally, as mentioned, IEA WEO 2020 SDS does not disclose the types of energy uses considered.

Overall, the share of hydrogen energy uses within total final energy consumption could, in these scenarios, increase modestly to 2 - 6% [190].

Figure 7.4 Potential hydrogen uses by 2050



Finally, by 2050, the resulting total amount of future potential hydrogen uses diverges significantly across these future scenario studies. For example, the "A Clean Planet for All" scenario ELEC by EU EC reports only 5 Mt of hydrogen, while the scenario H2 reports 43 Mt of hydrogen due to the (different) technological assumptions founded on hydrogen technologies. The FCH JU Roadmap scenario and the Gas for Climate 2020 scenario report, respectively, 79 Mt and 41 Mt of hydrogen demand. Finally, IEA WEO 2020 SDS scenario reports 18.4 Mt. Except for mobility uses, the relative share of the other three types of uses differs significantly across these scenarios: some point to a larger share of industrial uses (the FCH JU Roadmap ambitious scenario and the "A Clean Planet for All" H2 scenario), others point to a larger share of power (Sector coupling) uses (the Gas for Climate's scenario and the "A Clean Planet for All" ELEC scenario). The share of future hydrogen energy uses within total final energy consumption varies between 10% and 24% for these first four scenarios. [191]

[190] Total final energy consumption is assumed to range between 10853 – 11500 TWh by 2030 in these four scenarios.
[191] Total final energy consumption is assumed to range between 7995 and 9404 TWh for 2050 in these two scenarios.

7.2. Assumptions on future hydrogen costs

As previously noted, there are different assumptions underlying the results on potential hydrogen uses. We will focus here on future hydrogen costs. As mentioned in the introduction, assumptions on future hydrogen supply costs have four critical assumption (and associated sub-assumption) "pillars" which interest us: 1) location (i.e. domestic or abroad); 2) hydrogen production technologies (i.e. green hydrogen, blue hydrogen or turquoise hydrogen); 3) critical sub-assumptions for each combination of location and hydrogen production technology in which we are interested (i.e. technical potential, levelised costs and sub-assumptions of levelised costs); and 4) transport and storage costs. Few of the scenarios included in 7.1 set out assumptions regarding future hydrogen costs:

- The two "A Clean Planet for All" scenarios by EU EC include hydrogen production technologies for both green hydrogen and for blue hydrogen and do not make any reference to hydrogen imports. Additionally, these scenarios also report the critical sub-assumptions (i.e. technical potential and levelised costs) of both hydrogen and synthetic fuels. Additionally, in chapter six on the future costs of renewable electricity, we estimated that "A Clean Planet for All" ELEC and H2 scenarios both assume 6TWh of potential electricity uses for sector coupling by 2030. Instead, these scenarios assume, respectively, circa 233 and 4431 TWh of potential electricity uses for sector coupling by 2050. If we assume an efficiency for electrolysers of 0.69% by 2030 and 0.74% by 2050 [192], the resulting technical potential of green hydrogen would correspond, by 2030, to circa 0.105 Mt H2/yr and, by 2050, to circa 4.4 Mt H2/yr (ELEC) and 83.2 Mt of H2/yr (H2).

- In the Gas for Climate 2020 Accelerated Pathway scenario, reference is made to the possibility of imports of green hydrogen from North Africa and of imports of blue hydrogen from regions like Russia. However, no numbers are provided. Hydrogen production technologies for both green hydrogen and blue hydrogen are included. The relative critical sub-assumptions, i.e. levelised costs and technical potential, are provided for 2030 and 2050, leaving calculations to the reader.[193]

- Finally, FCH JU provides the future 2018-2030 costs of hydrogen in its Hydrogen Roadmap EU Ambitious scenario[194], disaggregated into three categories: 1) hydrogen production costs (i.e. 26.5 billion EUR); 2) hydrogen storage costs (i.e. 8.4 billion EUR); and 3) hydrogen transport costs (i.e. 10.6 billion EUR). References to both green hydrogen and blue hydrogen are included, but there are no references to imports. Further information on the sub-assumptions (e.g. levelised costs) are undisclosed.

[192] These values were taken from IEA "The Future of Hydrogen" (June 2019) – assumptions annexed for water electrolysis, in absence of such data in the IEA World Energy Outlook 2020 documentation.
[193] For example, the "Accelerated Decarbonisation Pathway" assumes a technical potential of "clean" hydrogen production of 135 TWh (63% green hydrogen, 37% blue hydrogen) by 2030 and of 2210 TWh (72% green hydrogen, 28% blue hydrogen) by 2050. Additionally, levelised costs are provided. Regarding green hydrogen in 2050 about 200 TWh of green hydrogen from curtailed electricity can be supplied at 29 EUR/MWh and more than 2000 TWh from dedicated renewable electricity generation at 52 EUR/MWh.
[194] Labelled as "cumulative investments in infrastructure".

Given the lack of data for these scenarios, we will investigate future hydrogen costs assumptions for EU consumers by cross-assessing the studies of three international organisations recognised for their future cost studies: the IEA [195], IRENA [196] and BloombergNEF [197]. In particular, we will focus on five scenarios (one including two sub-scenarios) resulting from combinations of: 1) location assumptions and 2) hydrogen production technologies assumptions. These are 7.2.1) domestic green hydrogen costs – utility-scale solar PV sub-scenario and offshore wind farm sub-scenario; 7.2.2) domestic blue hydrogen costs; 7.2.3) domestic turquoise hydrogen costs; 7.2.4) imported green hydrogen costs; and 7.2.5) imported blue hydrogen costs. For each of these five scenarios for future hydrogen cost assumptions and for each organisation, we also look at their critical sub-assumptions: i) technical potential; ii) levelised costs; and iii) critical sub-assumptions around levelised costs. Successively, we will compare future assumptions on hydrogen production costs across these five scenarios (including the two sub-scenarios of the domestic green hydrogen scenario) (7.2.6) and we will present equivalent ETS prices as a cost-competitiveness metric for the domestic scenarios with respect to grey hydrogen (7.2.7). Finally, in 7.2.8 we will focus on assumptions on domestic transport and storage costs.

Today, according to Gas for Climate 2020 “Gas decarbonization pathways”, hydrogen in the EU is currently grey hydrogen and there is no production of green (except for small pilots) or of blue hydrogen. Therefore, these five scenarios are of interest for understanding the potential for green, blue and turquoise hydrogen supply.

As mentioned below, in 7.2.4, for domestic turquoise hydrogen costs, the reader must remember that the credibility of these scenarios and relative assumptions are conditioned by the technological maturity of the technologies underlying each. These technologies are respectively: 7.2.1 - 7.2.2) electrolysers, 7.2.3) steam methane reforming with CCUS, 7.2.4.) methane pyrolysis with CCU, 7.2.5.) electrolysers + hydrogen transport and storage technologies and 7.2.6.) steam methane reforming with CCUS + hydrogen transport and storage technologies. The technological maturity of each technology can be qualified through the “technology readiness level” (TRL) metric. According to IEA ETP Clean Energy Technology Guide (https://www.iea.org/articles/etp-clean-energy-technology-guide), methane pyrolysis currently stands at technology readiness level (TRL) 6 (i.e. “full prototype at scale”). Instead, electrolysers [198] and steam methane reforming with CCUS [199] stand, respectively, at TRL 9 (“commercial operation in relevant environment”) and TRL 8-9 (i.e.“first of a kind commercial” – “commercial operation in relevant environment”) according to the same source. Finally, hydrogen transport technologies have a varying technology readiness level (TRL 5-7 for hydrogen tankers to TRL 11 for hydrogen pipelines) and the same applies for hydrogen storage technologies (TRL 2-4 for depleted oil & gas fields, TRL 9-10 for salt cavern storage

[195] IEA “World Energy Outlook 2020” (Oct 2020), which, however, reports publicly only a few hydrogen cost estimates. Therefore, we complement these missing references with those available in IEA “The Future of Hydrogen” (June 2019).

[196] IRENA « Global Renewables Outlook: Energy Transformation 2050» (April 2020), which refers to data included in IRENA “Hydrogen: A renewable energy perspective” (Sept. 2019).

[197] BloombergNEF “Hydrogen Economy Outlook” (March 2020), BloombergNEF “Global Gas Report 2020” (Aug. 2020) and BloombergNEF “Sector Coupling in Europe: Powering Decarbonization” (Febr. 2020).

[198] On the basis of the domestic and imported green hydrogen scenarios.

[199] On the basis of the domestic and imported blue hydrogen scenarios.

and TRL 11 for storage tank). Therefore, the credibility of these scenarios and associated assumptions is lower in the 7.2.4.) scenario, domestic turquoise hydrogen costs, than for the other four scenarios.

The definition of levelised costs is intuitive when the system is one hydrogen production plant (e.g. an electrolyser). In this scenario, levelised costs correspond to the total costs of that production plant, divided by the technical potential of the plant (i.e. the amount of hydrogen produced in a certain time frame, e.g. one year). However, this definition can also be extended to the case when the system is the entire EU. For example, the levelised costs of green hydrogen imports from North Africa into EU will depend on total supply costs (i.e. transport costs, storage costs, production costs), divided by the relative imports technical potential (dependent, for example, on the maximum import capacity of transport technologies and on the technical production potential abroad dedicated to exports).

An exchange rate of 0.85 EUR/US$ was applied for converting the numbers into EUR[200]. The numbers presented must be taken indicatively as they were estimated from the charts and plots of the cost studies. All the estimates used in the following analysis are reported in annex A. Additionally, when converting from EUR/kgH2 to EUR/MWh (HHV), we considered the following HHV value: 0.03939 MWh/kg. [201]

7.2.1 Future domestic green hydrogen costs according to two sub-scenarios: the utility-scale solar PV sub-scenario and the offshore wind farm sub-scenario

i) Technical potential

By the technical potential for domestic green hydrogen, we mean the amount of hydrogen produced by a portfolio of electrolyser plants sourced with renewable electricity over a year. This depends on the following critical sub-assumptions: I) the availability of renewable electricity; II) the efficiency of the portfolio of electrolysers; III) the availability of water; IV) the water consumption per portfolio of electrolyser plants; and V) the logic regulating investment decisions. We identify sub-assumptions I, II, III and IV as being critical because both renewable electricity and water are input fuels for green hydrogen production. Instead, we identify sub-assumption V) logic regulating investment decisions as critical because it determines whether a portfolio of electrolyser plants is built and in what quantities (e.g. due to target policies or due to favourable economics).

It must be noted that: I) the availability of renewable electricity is linked to assumptions on the technical potential of EU decarbonisation (examined in chapter 6.3). As mentioned previously, the technical potential of EU decarbonisation has two main sub-assumptions: potential electricity uses; and renewable electricity capacity. Therefore, concerns regarding the sub-assumption on renewable electricity capacity need to be remembered when making assumptions about the technical potential of domestic green hydrogen. These concerns relate mainly to surface availability in the EU, a sub-assumption judged critical for renewable electricity capacity assumptions. The concern is that EU surface availability will be

[200] Source: https://www.exchangerates.org.uk/EUR-USD-exchange-rate-history.html (relative to 23 August 2020).
[201] Source: Belmans Ronnie, Vingerhoets Pieter, "Molecules: Indispensable in the decarbonized energy chain" https://fsr.eui.eu/publications/?handle=1814/66205.

significantly lower from that, say, of Australia or Saudi Arabia (in particular for utility-scale solar PV). This question would have to be carefully examined. There are, in any case, significant implications for the technical potential assumptions of the domestic green hydrogen scenario vs the imported green hydrogen scenario.

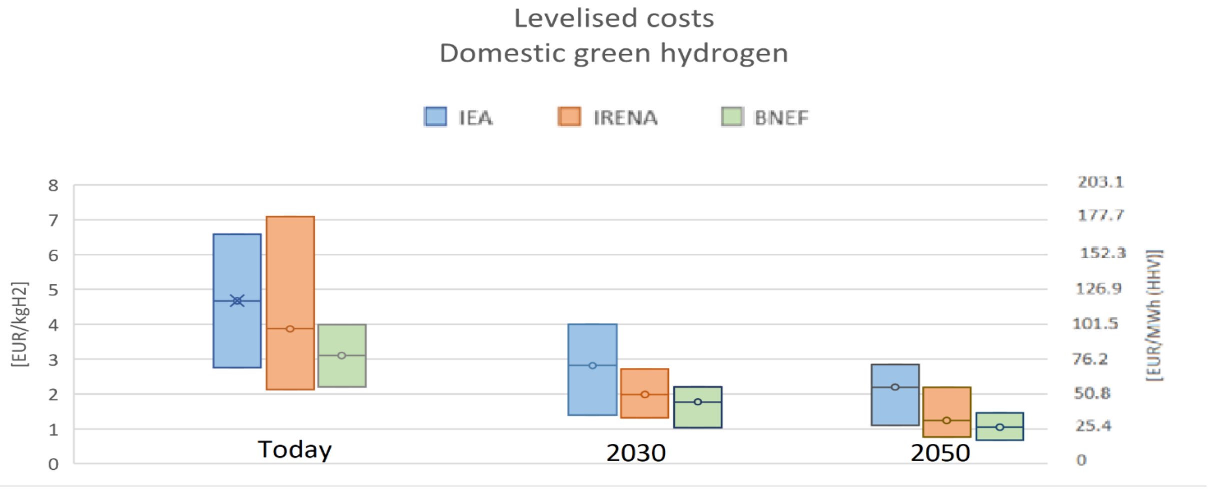
Also, the III) availability of water has to be thought of as a constraint given increasing weather shocks [202] and other future concerns (e.g. alternative water needs, for instance in agriculture). Therefore, IV) water consumption per portfolio of electrolyser plants has also to be carefully evaluated. However, we will not examine these critical sub-assumptions in detail with all possible metrics, because that would go far beyond our research capabilities.

IEA, IRENA and BloombergNEF do not provide an explicit assessment of the future technical potential of domestic green hydrogen production in the EU within the documents examined. Instead, BloombergNEF provides an assessment, for 2050, of "potential resource" hydrogen for German consumers. In particular, the following assumptions are provided:

1) hundreds of TWh of "potential resource" domestic green hydrogen from onshore wind in Germany (order of magnitude of 0.25 Mt H2/yr)
2) hundreds of TWh of "potential resource" domestic green hydrogen from solar PV in Germany (order of magnitude of 0.25 Mt H2/yr)
3) thousands of TWh of "potential resource" domestic green hydrogen from offshore wind in Germany (order of magnitude of 2.5 Mt H2/yr)

ii) Levelised costs

Figure 7.5 Assumptions on levelised costs for domestic green hydrogen scenario across future costs studies examined



[202] In absence of evidence in the literature employed here, it is not possible to draw conclusions regarding the relationship between the availability of water (as an input fuel) and the technical potential of domestic green hydrogen. Among some of the possible sub-assumptions which could result critical for the availability of water, we identify the following: access to water resources at the requested chemical composition; environmental impact regulation relative to water use; and standards for the chemical composition of water used for green hydrogen production.

Estimates on the levelised costs of the domestic green hydrogen across the sources examined range, today, between 2.1 and 7.1 EUR/kgH2 (respectively, 33 and 180 EUR/MWh). However, it should be remembered that: 1) with few exceptions only worldwide estimates are available; and 2) depending on the organisation, the number of estimates and ranges vary. In addition to the specific assumptions of each organisation, lower levelised costs are also related to more favourable "boundary conditions" (i.e. lower electricity costs, higher full load hours), which, as can be seen in the map at the beginning of this chapter, are not located in the EU for green hydrogen.

The average levelised costs of domestic green hydrogen are assumed to decrease by 2030 according to IEA, BloombergNEF and IRENA assumptions, and even further for 2050. The breadth of the range of levelised cost assumptions depends on the organisation and on the number of data points available for each time horizon.

iii) Sub-assumptions of levelised costs

For the assumptions on the levelised costs of domestic green hydrogen, we identify the four following critical sub-assumptions: I) CAPEX [203]; II) interest rates; III) cost of electricity; and IV) full load hour. [204] Based in particular on III) cost of electricity and IV) full load hour, we can map the levelised costs of green hydrogen both for the electrolysers connected to renewable generators (be it from an utility-scale solar PV farm or onshore wind farm or offshore wind farm) and for that of grid-connected electrolyser hydrogen [205]. Although water is another input fuel for green hydrogen production, we do not assume water costs as a main sub-assumption for levelised costs. This assumption, note, is in line with the literature examined (e.g. according to IEA "The Future of Hydrogen" assumptions annex, "Water costs are not considered").

We start by looking into a sensitivity analysis of the assumptions on the levelised costs of domestic green hydrogen with respect to the four sub-assumptions that we identified as being critical. We do so in order to understand which are the most important. Additionally, based on these results we will later update our average and minimum assumptions on the levelised costs of two sub-scenarios for domestic green hydrogen (one for utility-scale solar PV and another for offshore wind) with respect to new sub-assumptions on electricity costs and full load hour factors.

[203] In this chapter, the CAPEX of domestic green hydrogen refers uniquely to the CAPEX of the electrolyser. E.g. in the case of electrolysers coupled to renewable electricity generators, the CAPEX does not include the CAPEX of the renewable electricity generator.

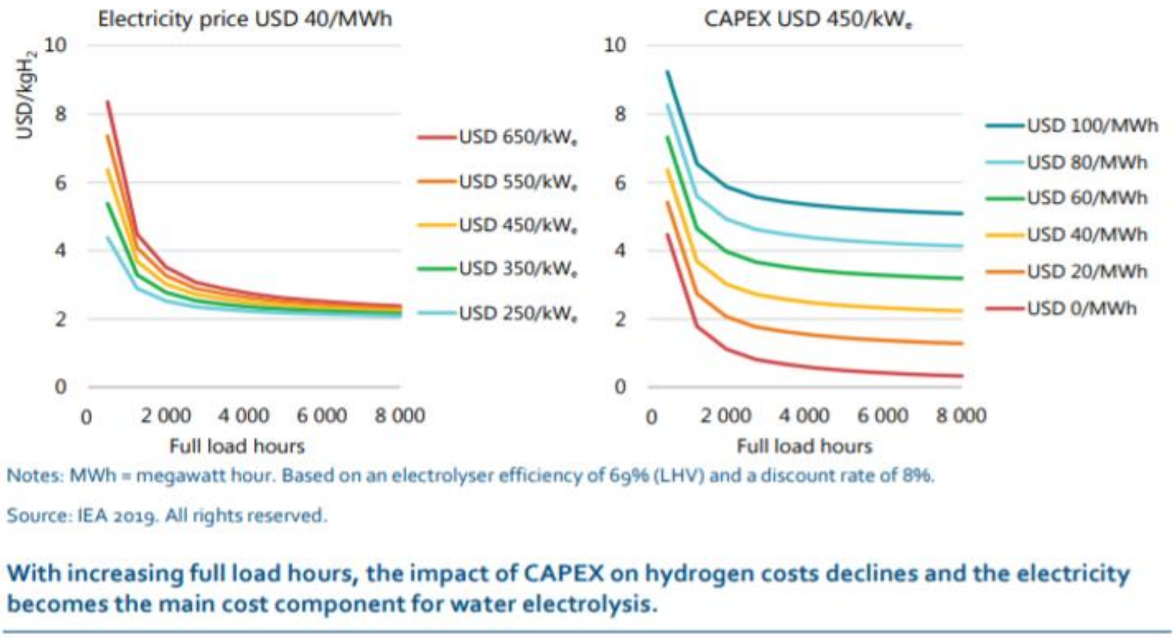
[204] Other assumptions for the levelised costs of domestic green hydrogen are efficiency, transport costs and storage costs. But we do not find them to be as critical as the four mentioned above.

[205] This is possible because it is always the same technology, but with different "boundary conditions". These different "boundary conditions" influence both the cost of electricity and full load hour, and ultimately, the levelised costs.

Sensitivity analysis

We will start by drawing some preliminary conclusions from the following IEA sensitivity analysis [178]:

Figure 7.6 Future levelised cost of hydrogen production by operating hour for different electrolyser investment costs (left) and electricity costs (right), IEA (2019)



What is interesting here is that, except for extremely low full load hours (< 1500 hrs/year circa), electricity costs (i.e. electricity prices) are a more critical sub-assumption of the future levelised costs of green hydrogen than full load hours and CAPEX. We quantify this through the following sensitivities derived from these two plots and reported in the table below:

Table 7.1 Sensitivity analysis of future levelised costs of green hydrogen with respect to other parameters

Sensitivity	CAPEX sensitivity (i.e. from 250 USD/kWe to 650 USD/kWe)	Cost of electricity sensitivity (i.e. from 0 USD/MWh to 100 USD/MWh)	Full load hour sensitivity (i.e. from 2000 hours to 8000 hours * From 2250 hours to 4400 hours **)
At parity of full load hour (i.e. 2000 hours) & at parity of CAPEX (i.e. 450 USD/kWe)	-	0.465 EUR/kgH2 / 10 EUR/MWh-el [206]	-
At parity of full load hour (i.e. 6000 hours) & at parity of CAPEX (i.e. 450 USD/kWe)	-	0.475 EUR/kgH2 / 10 EUR/MWh-el [207]	-

[206] Or 12.7 EUR/MWhH2 / 10 EUR/MWh-el (HHV) or also 4.65 USD/kgH2 / 100 USD/MWh - el.
[207] Or 1.2 EUR/MWhH2 / 10 EUR/MWh-el (HHV) or also 4.75 USD/kgH2 / 100 USD/MWh - el.

Sensitivity	CAPEX sensitivity (i.e. from 250 USD/kWe to 650 USD/kWe)	Cost of electricity sensitivity (i.e. from 0 USD/MWh to 100 USD/MWh)	Full load hour sensitivity (i.e. from 2000 hours to 8000 hours * From 2250 hours to 4400 hours **)
At parity of cost of electricity (i.e. 40 USD/MWh) & at parity of CAPEX (i.e. 450 USD/kWe)	-	-	- 0.663 EUR/kgH2 / 6000 (full load) hours/ year * [208] - 0.455 EUR/kgH2 / 2150 (full load) hours/ year ** [209]
At parity of cost of electricity (i.e. 40 USD/MWh) & at parity of full load hour (i.e. 2000 hours)	- 0.96 EUR/kgH2 / 400 EUR/kWe [210]	-	-
At parity of cost of electricity (i.e. 40 USD/MWh) & at parity of full load hour (i.e. 6000 hours)	- 0.44 EUR/kgH2 / 400 EUR/kWe [211]	-	-

We learn from this sensitivity analysis that electricity costs (i.e. electricity prices) are the most critical assumption for the levelised costs of green hydrogen. In fact, levelised costs change significantly by 4.65 /4.75 EUR/kgH2 for a variation of 100 EUR/MWh in electricity prices (i.e. a change of 0.93 / 0.95 EUR/kgH2 per 20 EUR/MWh). Instead, except for very low full load hours, the sensitivity of the levelised costs with respect to the full load hours factor is more modest. In fact, levelised costs change modestly by -0.663 EUR/kgH2 for a significant variation of 6000 (full load) hours /year in full load hours factor (i.e. a change of - 0.26 / – 0.27 EUR/kgH2 per 2000 (full load) hours/year) or by – 0.455 EUR/kgH2 /2150 (full load) hours/year. Also, sensitivity with respect to CAPEX is rather low and levelised costs change by 0.44 – 0.96 EUR/kgH2 for a significant variation of 400 EUR/kWe in CAPEX costs: i.e. a change of 0.11 – 0.24 EUR/kgH2 for a variation of 100 EUR/kWe in CAPEX costs.

Unfortunately, no sensitivity analysis on interest rates is given.

CAPEX & interest rate

Today IRENA estimates CAPEX costs [212] at 714 EUR/kW (except for one estimate at 170 EUR/kW), while IEA estimates CAPEX costs varying between 425 and 1190 EUR/kW based on the specific sub-technology (in particular, 1116.5 EUR/kW by 2020 according to IEA World Energy Outlook (WEO) 2020 Sustainable Development Scenario (SDS)). Instead,

[208] Or 16.8 EUR/MWhH2 / 6000 full load hours (HHV) or also 0.78 USD/kgH2 / 6000 full load hours.
[209] Or 11.5 EUR/MWhH2 / 2150 full load hours (HHV) or also 0.45 USD/kgH2 / 2150 full load hours.
[210] Or 24.4 EUR/MWh / 400 EUR/kWe or also 0.96 USD/kgH2 / 400 USD/kWe.
[211] Or 11.2 EUR/MWh / 400 EUR/kWe or also 0.44 USD/kgH2 / 400 USD/kWe
[212] CAPEX values of domestic green hydrogen are expressed in EUR/kW (relative to input electricity).

BloombergNEF's CAPEX estimate relative to China (191 EUR/kW) results significantly lower than those by IRENA and IEA. [213]

By 2030 CAPEX assumptions diverge: IEA assumed CAPEX at 595 EUR/kWe in "The Future of Hydrogen" report (June 2019), but updated its forecast to 326.4 EUR/kW in IEA WEO 2020 SDS and 544.85 EUR/kW in IEA WEO 2020 Stated Policies Scenario (STEPS). Instead, BloombergNEF assumes that CAPEX varies between 374 EUR/kWe and 114.75 EUR/kWe. Finally, IRENA assumes a CAPEX costs at 460 EUR/kW.

By 2050, CAPEX assumptions vary between 314.5 EUR/kWe, 170 EUR/kWe and even 83 EUR/kWe. Independently from the different assumptions across these organisations, the decreasing CAPEX trend stands out.

Except for IEA who provides a value of 8% for real interest rate across the different time horizons according to its report "Future of Hydrogen" (June 2019), the other organisations do not disclose their interest rate assumptions. [214]

Cost of electricity & Full load hour

We map for each time horizon and across available data the range of electricity costs and full load hours factor corresponding to the following levelised cost ranges:

I. Levelised costs < 2 EUR/kgH2
II. Levelised costs between 2 and 4 EUR/kgH2
III. Levelised costs between 4 and 6 EUR/kgH2
IV. Levelised costs > 6 EUR/kgH2

Today no estimate fits in zone I. Instead, eight estimates fit in zone II, corresponding to electricity costs ranging between 14.9 EUR/MWh and 46.75 EUR/MWh and full load hours ranging between 26% and 48% (i.e. 2280 hrs/year and 4200 hrs/year). Finally, two estimates fit in zone III at electricity costs of 72.25 EUR/MWh and full load hours factor of 26 to 27% (i.e. 2280 – 2370 hrs/year) and one estimate fit in zone IV at an electricity cost of 124 EUR/MWh and full load hours factor of 29% (i.e. 2540 hrs/year). The average electricity cost is 47 EUR/MWh, whereas the electricity cost relative to the cheapest levelised cost estimate is 14.9 EUR/MWh. The average full load hours factor is 38% (i.e. 3330 hrs/year), whereas the full load hours factor for the cheapest levelised cost is 48% (i.e. 4200 hrs/year).

By 2030, two assumption data point fits in zone I at an electricity cost varying from 16.95 EUR/MWh to 44.2 EUR/MWh and full load hours factor of 46%. The assumption data point relative to "very low cost" solar at an electricity cost of 10 EUR/MWh would also fit in zone I. Five assumption points fit in zone II at an electricity cost of between 34 EUR/MWh and 67.8 EUR/MWh and full load hours factor of 23 to 57% (i.e. 2015 – 5000 hrs/year). Finally, zones III and IV result empty. The average electricity cost is 34.5 EUR/MWh, whereas the electricity

[213] Source: https://www.cleanenergywire.org/news/eu-plans-completely-change-outlook-global-hydrogen-economy-bloombergnef (23 July 2020, accessed on 17 October 2020).
[214] Interest rate assumptions can be expected to change as the technology matures through time: i.e. the interest rate of a demonstration project is expected to be higher than the interest rate for a commercially mature project. This will also be true between different projects (based on public financing versus private financing and other assumptions).

cost relative to the cheapest levelised cost estimate is 16.95 EUR/MWh. The average full load hours factor is 39% (i.e. 3415 hrs/year), whereas the full load hours factor for the cheapest levelised cost is 46% (i.e. 4030 hrs/year).

By 2050, 5 assumption points fit in zone I at an electricity cost of between 3.8 and 19.55 EUR/MWh and full load hours factor of 18% to 63% (i.e. 1580 – 5520 hrs/year). One assumption point fit in zone II at an electricity cost of 51 EUR/MWh and a full load hours factor of 34%. Finally, zones III and IV result empty. Additionally, the levelised costs of two data points in zone I result lower than 1 EUR/kgH2 at an electricity cost lower than 10 EUR/MWh. The average electricity cost is 20.7 EUR/MWh, whereas the electricity cost relative to the cheapest levelised cost estimate is 9.35 EUR/MWh, according to IRENA for "worldwide best" onshore wind farm costs by 2050. The average full load hours factor is 37% (i.e. 3240 hrs/year), whereas the full load hours factor for the cheapest levelised cost is 30% (i.e. 2635 hrs/year).

It is interesting to note that the full load hours factor is a less critical assumption compared to the cost of electricity. Additionally, zones III and IV (i.e. > 4 EUR/kgH2) are only populated by data points today and are empty in 2030 and 2050. Finally, zones I and II are populated by data points across all time horizons, but the number of data points in zone II decreases over time.

From one scenario of domestic green hydrogen costs to two sub-scenarios: utility-scale solar PV and offshore wind

According to the previous sensitivity analysis the costs of electricity sub-assumptions result more critical than the full load hours sub-assumptions, and even more critical than the CAPEX sub-assumptions. Based on Table 6.1 of section 6.2, both the costs of electricity sub-assumptions and capacity factor sub-assumptions differ significantly depending on whether we have utility-scale solar, onshore wind farm or offshore wind farm. We will ignore the differences in the CAPEX sub-assumptions.

The renewable electricity levelised costs assumptions and the capacity factor assumptions from studies written more than six months ago have proven to be outdated. We would, therefore, like to split the domestic green hydrogen scenario into two sub-scenarios, each based on a different renewable electricity technology: specifically utility-scale solar PV and offshore wind farm. We need also to accordingly update the levelised cost assumptions of the domestic green hydrogen scenario (be it minimum or average) to each sub-scenario. It must be noted that this original scenario was built through a literature review which did not differentiate between green hydrogen from onshore wind, offshore wind or solar PV. Whereas, for the EU, the sub-scenario for utility-scale solar PV could well be true for southern EU countries (e.g. Italy, Spain, Portugal), the sub-scenario for offshore wind farm would be more dominant in northern EU countries (e.g. the Netherlands, Germany or Denmark). In order to update the levelised cost assumptions, we need to identify two different sets of "updated" assumptions about electricity costs and capacity factor for these two renewable electricity technologies. (1) Then we apply the results of the sensitivity analysis to both the original and to the two new sets of assumptions about costs of electricity and the capacity factor, in order to derive the levelised cost assumptions for the two sub-scenarios.

In particular, the results of the sensitivity analysis used are:

- a variation in levelised costs asssumptions with respect to electricity costs sub-assumption of + 0.47 EUR/kgH2 per each additional 10 EUR/MWhel of costs of electricity
- a variation in full load hours sub-assumptions of - 0.455 EUR/kgH2 per each additional 2150 full load hours/year. It must be noted that this variation was calculated over a range of full load hours from 2250 hours/year to 440 hours/year, comparable to the range of capacity factor assumptions between utility-scale solar PV and offshore wind farms.

We present, in the following tables, the original set and the two new sets of electricity costs and full load hours sub-assumptions, in order to derive the two sub-scenarios for domestic green hydrogen costs. The new sets of assumptions were either taken from the updated literature in Table 6.1. of section 6.2 or, in the absence of sufficient data, estimated arbitrarily by the authors. Depending on whether we update minimum or average levelised cost assumptions, we take into account different sub-assumptions about electricity costs and full load hours.

Table 7.2 Table with costs of electricity sub-assumptions for domestic green hydrogen scenario and for the two sub-scenarios (utility-scale solar PV and offshore wind farm)

Costs of electricity sub-assumption	Domestic green hydrogen scenario		Utility-scale solar PV sub-scenario		Offshore wind farm sub-scenario	
Time horizon	Relative to minimum levelised costs assumptions	Relative to average levelised costs assumptions	Relative to minimum levelised costs assumptions	Relative to average levelised costs assumptions	Relative to minimum levelised costs assumptions	Relative to average levelised costs assumptions
Today	14.9 EUR/MWh	47 EUR/MWh	11.2 EUR/MWh ※	31.5 EUR/MWh ⁑	42.5 EUR/MWh †	73.1 EUR/MWh ◊
2030	16.95 EUR/MWh	34.5 EUR/MWh	10 EUR/MWh [215]	25 EUR/MWh [216]	36 EUR/MWh [217]	46 EUR/MWh [218]
2050	3.825 EUR/MWh	20.7 EUR/MWh	3.825 EUR/MWh [219]	18.7 EUR/MWh [220]	30 EUR/MWh [221]	34.85 EUR/MWh [222]

Notes: ※ Worldwide record bid for utility-scale solar PV in Portugal. ⁑ Average cost of electricity for utility-scale solar PV in 2020 according to Lazard. † Lowest price awarded to UK offshore wind

[215] This value was assumed arbitrarily for the “very low cost” conditions of utility-scale solar PV in 2030.
[216] This value was assumed arbitrarily and fits with the ranges of estimates by IEA and BloombergNEF for utility-scale solar PV in 2030.
[217] G20 country values, minimum, forthcoming report according to IRENA “Global Renewables Outlook: Energy Transformation 2050” (2020).
[218] G20 country values, average, forthcoming report according to IRENA “Global Renewables Outlook: Energy Transformation 2050” (2020).
[219] Worldwide “PV best” values, IRENA.
[220] Worldwide “PV average” values, IRENA.
[221] Authors’ own arbitrary estimate in absence of more data.
[222] Estimate for offshore wind LCOE for Germany according to BloombergNEF.

auction, 2019. ◊ Midpoint average cost of electricity for offshore wind farms in 2020 according to Lazard.

Table 7.3 Table with capacity factors sub-assumption for domestic green hydrogen scenario and for the two sub-scenarios (utility-scale solar PV and offshore wind farm)

Full load hours sub-assumption	Domestic green hydrogen scenario		Utility-scale solar PV sub-scenario		Offshore wind farm sub-scenario	
Time horizon	Relative to minimum levelised costs assumptions	Relative to average levelised costs assumptions	Relative to minimum levelised costs assumptions	Relative to average levelised costs assumptions	Relative to minimum levelised costs assumptions	Relative to average levelised costs assumptions
Today	48% 4200 hrs/year	38% 3330 hrs/year	36% [223] 3155 hrs/year	23% [224] 2015 hrs/yr	54% [225] 4730 hrs/year	50% [226] 4380 hrs/year
2030	46% 4030 hrs/year	39% 3415 hrs/year	38% + 3330 hrs/year	24% + 2100 hrs/yr	57% + 4990 hrs/year	52% + 4555 hrs/year
2050	27% 2365 hrs/year	37% 3240 hrs/year	40% + 3500 hrs/year	26% + 2230 hrs/year	60% + 5260 hrs/year	54% + 4730 hrs/year

Notes: + Authors'own arbitrary estimation

We also recall the average and minimum levelised costs assumptions of the (original) domestic green hydrogen scenario

- 3.9 EUR/kgH2 average levelised cost for domestic green hydrogen today;
- 2.1 EUR/kgH2 minimum levelised cost for domestic green hydrogen today;
- 2.2 EUR/kgH2 average levelised cost for domestic green hydrogen by 2030;
- 1.8 EUR/kgH2 average levelised cost for domestic green hydrogen by 2030;
- 1.3 EUR/kgH2 average levelised cost for domestic green hydrogen by 2050; and
- 0.8 EUR/kgH2 minimum levelised cost for domestic green hydrogen by 2050.

We report two examples of the procedure we followed for updating "average" and "minimum" levelised costs for the utility-scale solar PV sub-scenario in 2050:

"Average" levelised costs for Utility-scale solar PV sub-scenario in 2050:

1.3 EUR/kgH2 + (18.7 EUR/MWh – 20.7 EUR/MWh) * 0.047 EUR/kgH2 / EUR/MWh - (2230 hrs/year – 3240 hrs/year) * 0.455 EUR/kgH2 / 2150 full load hours/year = 1.4 EUR/kgH2.

[223] Highest recent capacity factor estimate by Lazard and IEA for utility-scale solar PV.
[224] Arbitrary choice of a recent capacity factor value fitting with the ranges proposed by IRENA and Lazard.
[225] Highest recent capacity factor estimate by Lazard and IEA for offshore wind farm.
[226] Arbitrary choice of a recent capacity factor value fitting with the ranges proposed by IRENA and Lazard.

“Minimum” levelised costs for Utility-scale solar PV sub-scenario in 2050:

0.8 EUR/kgH2 + (3.825 EUR/MWh – 3.825 EUR/MWh) * 0.047 EUR/kgH2 / EUR/MWh – (3500 hrs/year - 2365 hrs/year) * 0.455 EUR/kgH2 / 2150 full load hours/year = 0.6 EUR/kgH2

We report, in the following table, the minimum and average levelised costs of domestic green hydrogen scenario, which had been identified across all estimates points available in literature, and the “updated” assumption on minimum and average levelised costs for the two sub-scenarios of utility-scale solar PV and offshore wind farms.

Table 7.4 Minimum and average levelised costs assumptions for domestic green hydrogen scenario and for the two sub-scenarios (utility-scale solar PV and offshore wind farm)

Time horizon	Type of levelised cost assumption	Domestic green hydrogen scenario	Utility-scale solar PV sub-scenario	Offshore wind farm sub-scenario
Today	Average levelised cost assumption	3.9 EUR/kgH2 99.1 EUR/MWh	3.45 EUR/kgH2 87.6 EUR/MWh	4.9 EUR/kgH2 124.5 EUR/MWh
	Minimum levelised cost assumption	2.1 EUR/kgH2 53.3 EUR/MWh	2.15 EUR/kgH2 54.5 EUR/MWh	3.3 EUR/kgH2 83.4 EUR/MWh
2030	Average levelised cost assumption	2.3 EUR/kgH2 58.3 EUR/MWh	2.1 EUR/kgH2 53.3 EUR/MWh	2.6 EUR/kgH2 66.0 EUR/MWh
	Minimum levelised cost assumption	1.8 EUR/kgH2 45.7 EUR/MWh	0.9 EUR/kgH2 22.8 EUR/MWh	1.7 EUR/kgH2 43.1 EUR/MWh
2050	Average levelised cost assumption	1.3 EUR/kgH2 33.0 EUR/MWh	1.4 EUR/kgH2 35.8 EUR/MWh	1.65 EUR/kgH2 41.9 EUR/MWh
	Minimum levelised cost assumption	0.8 EUR/kgH2 20.3 EUR/MWh	0.5 EUR/kgH2 12.7 EUR/MWh	1.3 EUR/kgH2 33.0 EUR/MWh

The resulting levelised costs values are reported in the following figures:

Figure 7.7 Minimum and average levelised costs assumptions for the two sub-scenarios of domestic green hydrogen (solar utility-scale PV and offshore wind farm)

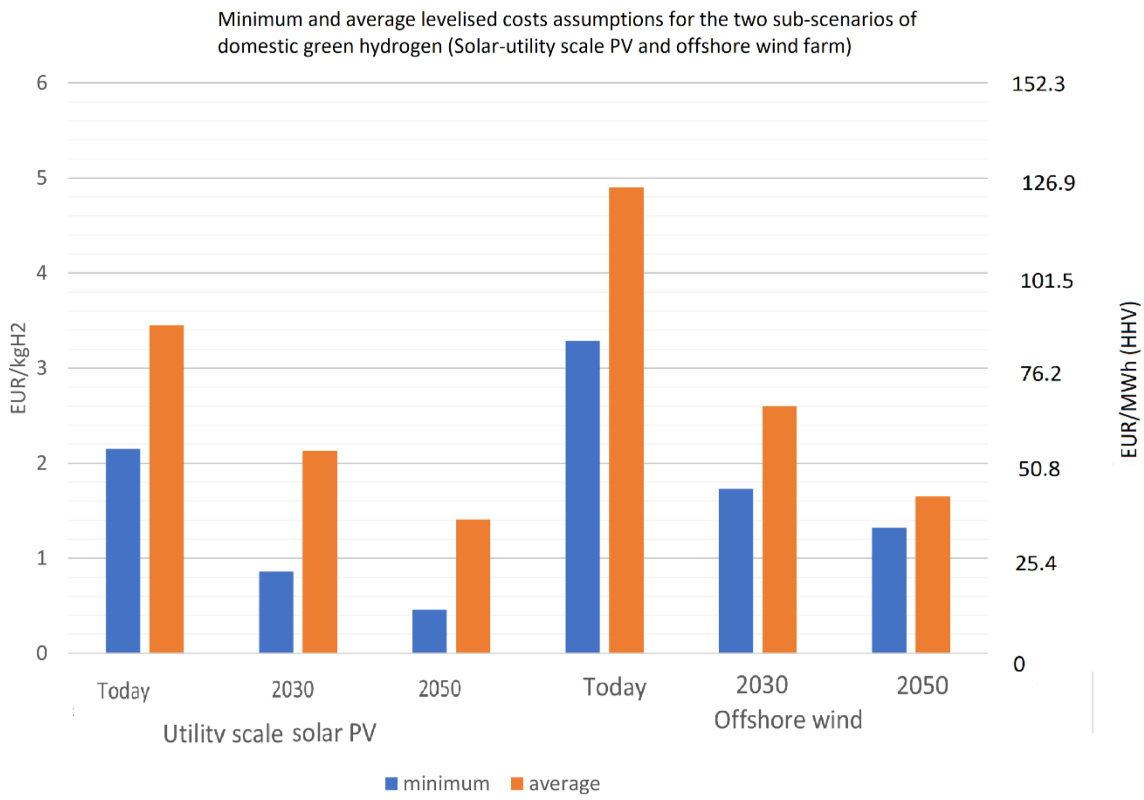
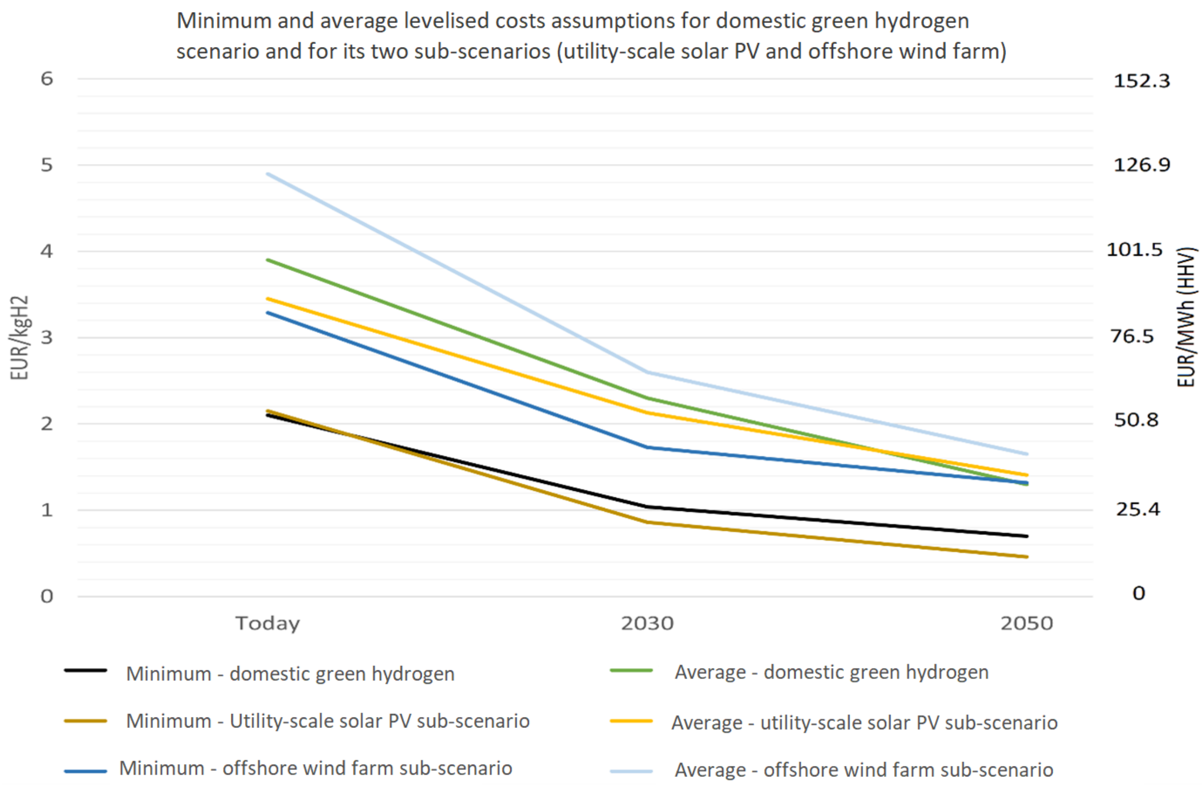


Figure 7.8 Minimum and average levelised costs assumptions for domestic green hydrogen scenario and for its two sub-scenarios (utility-scale solar PV and offshore wind farm)



We can make the following observations based on this data:

- By updating the average and minimum assumptions on hydrogen levelised costs for domestic green hydrogen scenario, we see that levelised costs assumptions for utility-scale solar PV sub-scenario are generally lower. Instead, the levelised costs assumptions for offshore wind farm sub-scenario are generally higher. This is mainly due to the quite different sub-assumptions for levelised renewable electricity costs between these two sub-scenarios and the (original) domestic green hydrogen scenario. Although it is true that the full load hours factor sub-asssumption are higher for the offshore wind farm sub-scenario than for the utility-scale solar PV sub-scenario, the opposite is true for the costs of electricity sub-assumptions. These prove more critical sub-assumptions than the full load hours factor sub-assumptions.

- Both the average and minimum assumptions on levelised hydrogen costs for the utility-scale solar PV sub-scenario and for the offshore wind farms sub-scenario are expected to significantly decrease over time. For example, the average assumptions on levelised costs for the utility-scale solar PV sub-scenario decreased from today's 3.45 EUR/kgH2 to 2.1 EUR/kgH2 by 2030, and then to 1.4 EUR/kgH2 by 2050. The same can be said for the average assumptions on levelised costs for the offshore wind farm sub-scenario: levelised costs are expected to decrease from today's 4.9 EUR/kgH2 to 2.6 EUR/kgH2 by 2030, and then to 1.65 EUR/kgH2 by 2050. Minimum costs could well reach 0.9 EUR/kgH2 for utility-scale solar PV by 2030 and 0.5 EUR/kgH2 by 2050. Instead, minimum costs for the offshore wind farm sub-scenario could stand at 1.7 EUR/kgH2 by 2030 and 1.3 EUR/kgH2 by 2050.

7.2.2 Assumptions on future domestic blue hydrogen costs

By blue hydrogen, we mean hydrogen produced by a Steam Methane Reforming plant with CCS. This scenario assumes the technological availability of blue hydrogen.

i) Technical potential

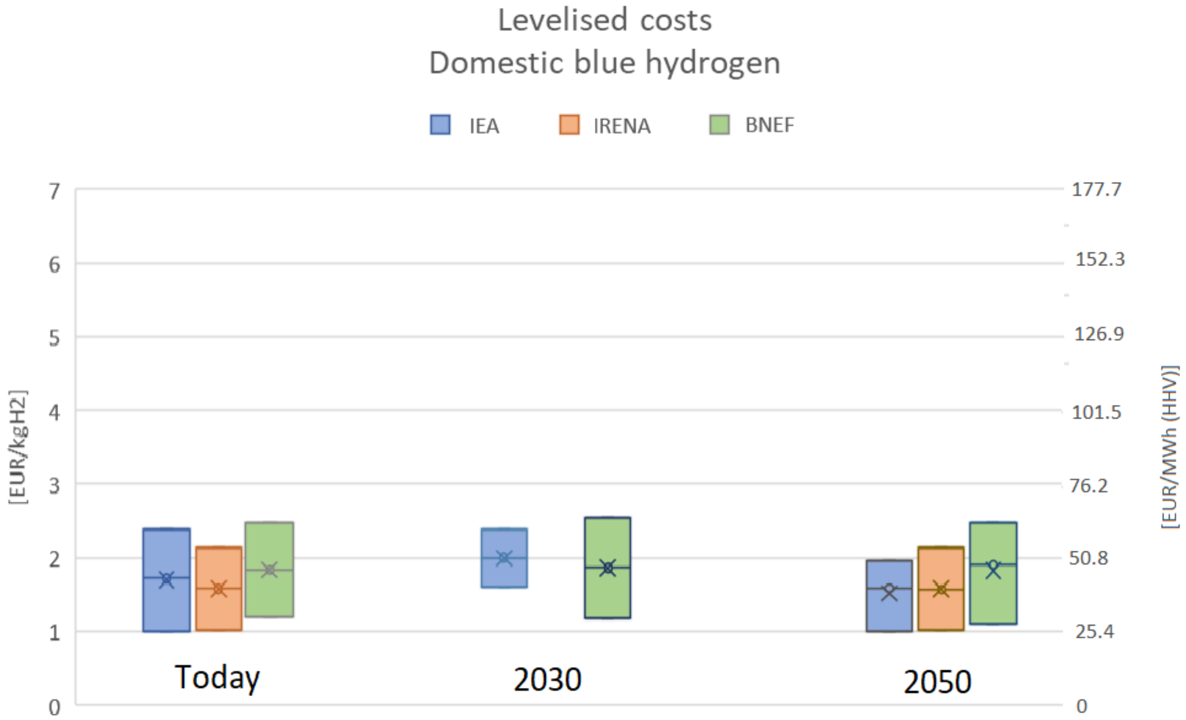
By the technical potential for blue hydrogen, we mean the amount of hydrogen produced by a portfolio of Steam Methane Reforming plants with CCS over a year. This depends on the following assumptions: I) demand; II) the availability of natural gas fuel; and III) the availability of a CO2 sink (be it an industrial client or a CO2 storage and transport grid).

The only project in the EU referred to across these studies is the H-vision project in Rotterdam harbour. This project will be able to produce 15-20 tonnes of hydrogen per hour (0.13 – 0.175 Mtons of hydrogen per year) and its target is to capture and store at the same time 8 Mt CO2/year.

Additionally, BloombergNEF provides an assessment by 2050 of "potential resource" hydrogen for German consumers. In particular, "potential resource" blue hydrogen is assumed at tens of TWh (order of magnitude of 0.025 Mt H2/yr).

ii) Levelised costs

Figure 7.9 Assumptions on levelised costs for domestic blue hydrogen scenario across future costs studies examined



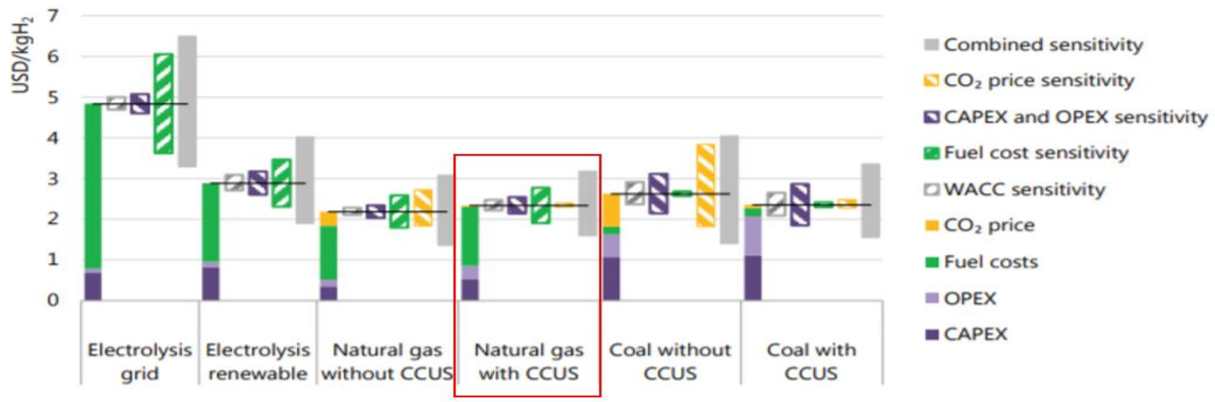
The levelised costs of domestic blue hydrogen are assumed to remain in a similar range over time across the different studies. However, IRENA does not provide assumptions for 2030.

iii) Sub-assumptions of levelised costs

For domestic blue hydrogen, we identify the following four main assumptions: I) CAPEX; II) interest rates; III) natural gas prices; and IV) the additional cost of CO2 storage and transport. Costs due to CO2 prices and efficiency are other levelised cost assumptions, but we identify their influence as being less critical. There is also no clear “value of CO2” given in the scenario of domestic blue hydrogen connected directly to an industrial client which consumes CO2. [227] What we do see in the following sensitivity analysis by IEA is that the levelised costs of blue hydrogen (i.e. “Natural gas with CCUS”) are much more sensitive to natural gas prices (i.e. fuel costs) than to CAPEX.

[227] One might wonder what would be the “value of CO2” and for which potential industrial clients.

Figure 7.10 Hydrogen production costs for different technology options, 2030, IEA(2019)



Notes: WACC = weighted average cost of capital. Assumptions refer to Europe in 2030. Renewable electricity price = USD 40/MWh at 4 000 full load hours at best locations; sensitivity analysis based on +/-30% variation in CAPEX, OPEX and fuel costs; +/-3% change in default WACC of 8% and a variation in default CO_2 price of USD 40/tCO_2 to USD 0/tCO_2 and USD 100/tCO_2. More information on the underlying assumptions is available at www.iea.org/hydrogen2019.

Source: IEA 2019. All rights reserved.

In the near term, hydrogen production from fossil fuels will remain the most cost-competitive option

CAPEX & Interest rate

Capex assumptions are mostly not made explicit. Only IEA reports a CAPEX estimate by 2018 of 1428 EUR/kW H2 [228] and assumes a CAPEX for 2030 and 2050 of, respectively, 1156 EUR/kW H2 and 1088 EUR/kW H2. IEA is the only organisation to spell out the real interest rate assumptions (8%). [214]

Natural gas prices

Different assumptions on natural gas prices are reported across these studies (i.e. from 0.89 EUR/GJ [229] to 8.86 EUR/GJ [230]). It is evident that assumptions on natural gas prices significantly influence the levelised costs of blue hydrogen: for example, IEA assumes, by 2030, levelised costs ranging from 1.6 to 2.4 EUR/kgH2 for natural gas price assumptions varying from 4.5 EUR/GJ [231] to 8.4 EUR/GJ [232]. The same thing is assumed by BloombergNEF and IRENA.

The assumptions on average natural gas prices across all studies varies according to the time horizon: 4.6 EUR/GJ [233] today, 5.8 EUR/GJ [234] by 2030 and 4.9 EUR/GJ [235] by 2050.

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[228] CAPEX values are reported in EUR/kW H2. One kW H2 refers to the "technical potential" of the plant, expressed as the amount of hydrogen produced (in Lower Heating Value energy) over a certain time horizon (i.e. seconds).
[229] 3.2 EUR/MWh.
[230] 31.9 EUR/MWh.
[231] 16.2 EUR/MWh.
[232] 30.2 EUR/MWh.
[233] 16.6 EUR/MWh.
[234] 20.9 EUR/MWh.
[235] 17.6 EUR/MWh.

Additional costs of CO_2 storage & transport

Only IEA makes explicit the assumption on the additional costs of CO_2 storage & transport (17 EUR/tCO_2) for all time horizons.

7.2.3 Assumptions on future domestic turquoise hydrogen costs

By turquoise hydrogen, we mean hydrogen produced by a methane pyrolysis plant with CCU.

The costs studies previously examined do not include costs data on turquoise hydrogen [236]. Therefore, in order to draw up some considerations , we develop a scenario which assumes the technological availability of turquoise hydrogen by 2030. [237] Costs assumptions are based on the analysis of a different set of studies, which however we do not judge to be as authoritative as those previously considered (IEA, IRENA and BloombergNEF).

Additionally, as already noted, it must be remembered that methane pyrolysis currently stands at technology readiness level (TRL) 6 (i.e."full prototype at scale") according to the IEA ETP Clean Energy Technology Guide (https://www.iea.org/articles/etp-clean-energy-technology-guide). Instead, electrolysers [238] and steam methane reforming with CCUS [239] stand, respectively, at TRL 9 ("commercial operation in relevant environment") and TRL 8-9 (i.e. "first of a kind commercial" – "commercial operation in relevant environment") according to the same source. Therefore, it is important to bear in mind that, these cost assumptions are less credible than those in other scenarios as the technology readiness level of methane pyrolysis is lower than those for electrolysers and steam methane reforming with CCS,

Instead, this scenario assumes the technological availability of turquoise hydrogen. We, therefore, analysed a different set of studies in order, specifically, to get conclusions on turquoise hydrogen:

- ThinkStep "GHG Emissions in the EU Energy market today and in 2050" (presentation by Dr. Michael Faltenbacher, 29th Oct. 2018)
- "Levelised cost of CO_2 mitigation from hydrogen" by Parkinson et al. (Energy & Environmental Science, Nov. 2018) + supporting information

[236] This was one of the outcomes of an online workshop "very-low / decarbonised hydrogen from natural gas" https://fsr.eui.eu/event/very-low-decarbonised-hydrogen-from-natural-gas/ .
[237] Since methane pyrolysis is assumed to be commercial from 2035 onwards in the "Gas Decarbonisation Pathways 2020-2050" Global Action Pathway scenarios, we took the liberty of assigning, to the 2030 time horizon, the assumption on 2035 levelised costs of methane pyrolysis by this source. Additionally, the paper by B. Parkinson does not specify the time horizon for its assumptions on the levelised costs of methane pyrolysis. Here too we took the liberty of assigning a time horizon of 2030 for his assumptions. However, the reader must be aware that these assumptions are less credible than those in other scenarios, due to the lower technology readiness of methane pyrolysis as compared to those of electrolysers and steam methane reforming with CCUS. Additionally, feedback from industry experts referred to a possible commercialisation year of 2035 for methane pyrolysis technology. Therefore, the scenario presented in this work can be considered ambitious in terms of the commercialisation year and would require due policy support.
[238] On the basis of the domestic and imported green hydrogen scenarios.
[239] On the basis of the domestic and imported blue hydrogen scenarios.

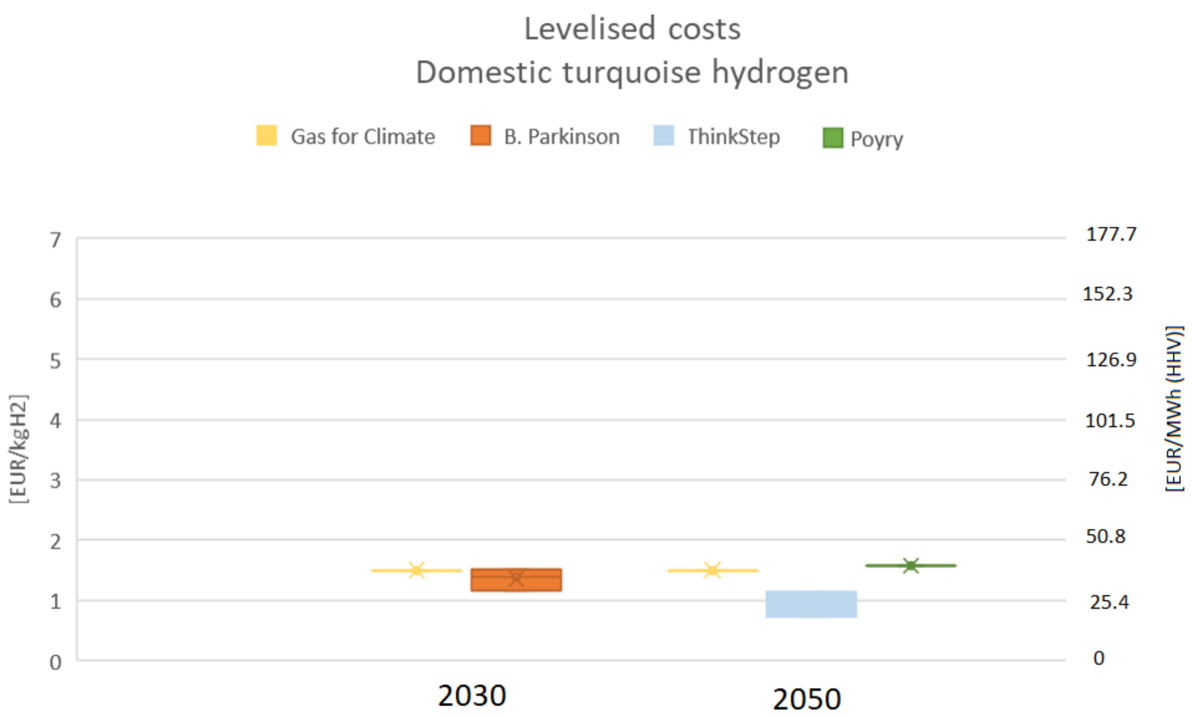
- Gas for Climate & Guidehouse, “Gas Decarbonisation Pathways 2020-2050” (April 2020)
- Zukunft Erdgas & Poyry, “Hydrogen from natural gas – the key to deep decarbonisation” (July 2019)

i) Technical potential

No reference to the technical potential of turquoise hydrogen has been made in these studies.

ii) Levelised cost

Figure 7.11 Assumptions on levelised costs for domestic turquoise hydrogen scenario across future costs studies examined



For 2030 (understood rather loosely in one source), assumptions on levelised costs range from 1.16 EUR/kgH2 to 1.52 EUR/kgH2. For 2050 instead, assumptions on levelised costs range between 0.72 EUR/kgH2 and 1.57 EUR/kgH2 according to three sources.

iii) Sub-assumptions of levelised costs

For the levelised net costs of turquoise hydrogen, we identify the following four critical assumptions: I) CAPEX; II) interest rates; III) natural gas prices; and IV) revenues from solid carbon sales [240].

[240] Although there is evidence that electricity costs include assumptions about turquoise hydrogen costs for some technological pathways (L. Fulcheri and Y. Schwob “From Methane to Hydrogen, Carbon Black and Water” (Int.

CAPEX and interest rate

CAPEX assumptions are not provided, save in one study (i.e. 1261 EUR/kW H2 by 2050 according to Poyry). Additionally, only the "Gas decarbonization pathways" study by Gas for Climate & Guidehouse makes explicit the real interest-rate assumption (5%). [214]

Natural gas prices

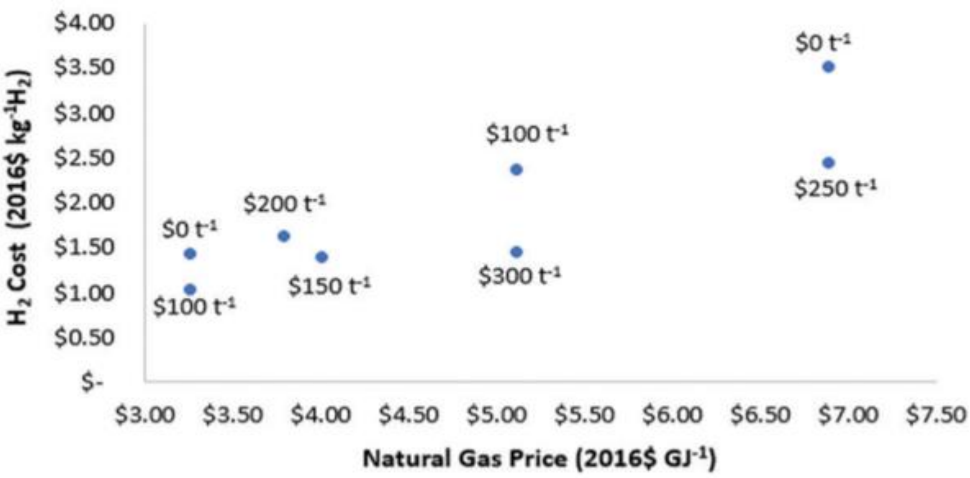
Natural gas prices assumptions are provided and vary between 3.4 EUR/GJ [241] and 8.3 EUR/GJ [242]. The sub-assumptions on average natural gas prices for turquoise hydrogen costs assumptions varies according to the time horizon: 4.6 EUR/GJ [243] by 2030 and 5.6 EUR/GJ [244] by 2050.

Revenues from solid carbon sales

The revenues from solid carbon sales lead to a decrease in levelised (net) costs of turquoise hydrogen. While the study by Poyry assumes zero value for solid carbon byproducts of methane pyrolysis and therefore no revenues, only the paper by B. Parkinson assumes revenues from the sale of solid carbon by-product at prices varying between -8.5 and 127.5 EUR/GJ [245].

We report the following sensitivity analysis from this same paper by Parkinson on the levelised (net) costs of turquoise hydrogen with respect to natural gas prices and to solid carbon sale prices. It will be seen that both natural gas prices and solid carbon sales play an important role.

Figure 7.12 Summary of the LCOH form pyrolysis processes available in the literature. Labelled values represent the carbon sale price ($ t^{-1} carbon) assumed in the study.



J. Hydrogen Energy, 1995), we do not assume electricity costs as a critical assumption in alignment with the examined literature on turquoise hydrogen costs where electricity assumption costs are not disclosed.

[241] 12.2 EUR/MWh.

[242] 29.9 EUR/MWh.

[243] 16.6 EUR/MWh.

[244] 20.2 EUR/MWh.

[245] "Negative value reflects a no value product with a small disposal cost".

7.2.4 Assumptions on future imported green hydrogen costs

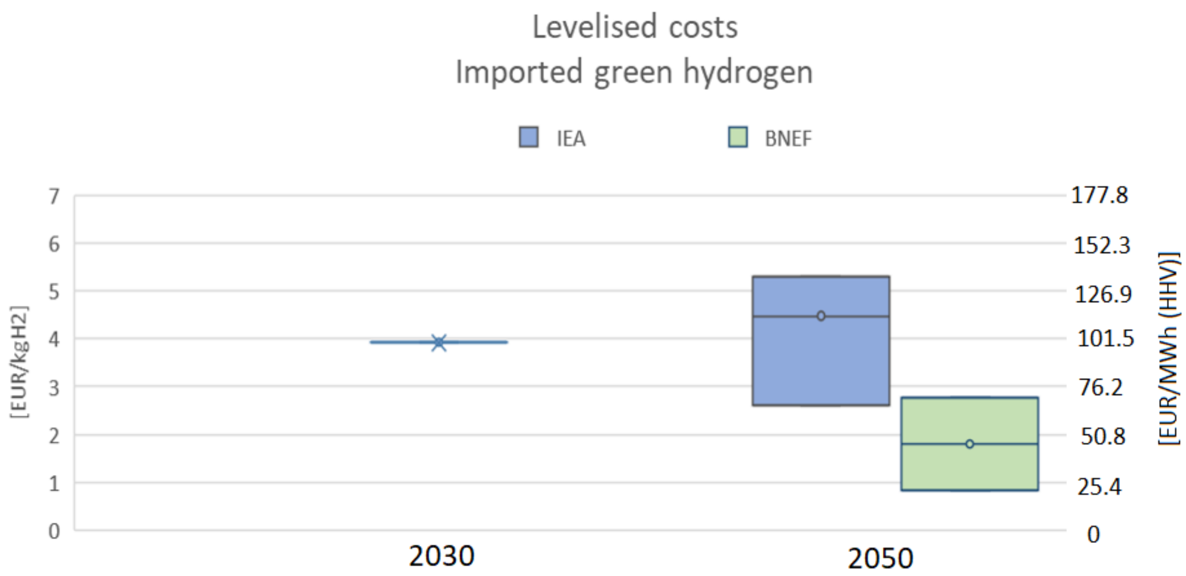
i) Technical potential

BloombergNEF provides an assessment up to 2050 of the "potential resource" hydrogen for German consumers. In particular, the following assumptions are made:

1) thousands of TWhs of green hydrogen imports from Algeria through a pipeline (order of magnitude of 2.5 Mt H2/yr)
2) tens of TWhs of green hydrogen imports from Spain through a pipeline (order of magnitude of 0.025 Mt H2/yr)
3) Thousands of TWhs of green hydrogen imports from Saudi Arabia through the shipping of liquified hydrogen (order of magnitude of 2.5 Mt H2/yr)

ii) Levelised costs

Figure 7.13 Assumptions on levelised costs for imported green hydrogen scenario across future costs studies examined



By 2030, there is only one assumption for the levelised costs of imported green hydrogen in these studies (in particular, of green hydrogen imported from North Africa).

By 2050, instead, more assumptions on levelised costs are reported in these studies (e.g. of green hydrogen imports from North Africa, from Algeria or Saudi Arabia). The ranges of levelised costs of green hydrogen imports assumed by IEA and BloombergNEF do not overlap. The green hydrogen import option with the lowest costs corresponds to imports from Algeria (i.e. 0.8 EUR/kgH2 imported through pipelines, according to BloombergNEF). Instead, the other import options including from North Africa and Saudi Arabia are more expensive.

iii) Sub-assumptions of levelised costs

Relative to the levelised cost of imported green hydrogen, we identify, as critical, the following two sub-assumptions: I) transport costs; [246] and II) storage costs. Both depend on a sub-assumption on III) the type of intermediate hydrogen carrier (e.g. ammonia, LOHC, liquid hydrogen).

Other assumptions for levelised costs are CAPEX, interest rates, efficiency, electricity costs and full load hour. But we do not analyse these as they are more relevant for the exporting country [247], than for the importing country.

Transport costs, storage costs and intermediate hydrogen carrier

By 2030, the only assumption reported has a relative sub-assumption on transport costs of only 0.7 EUR/kgH2[248] (i.e. 18% of total costs) and considers pipeline transport through ammonia.

By 2050, assumed transport costs vary between 0.19 and 2.6 EUR/kgH2. In particular, these costs are: 0.19 EUR/kgH2 (i.e. pipeline transport from Algeria, 23% of total costs from only one assumption); 2.2 – 2.6 EUR/kgH2 [249] (liquid hydrogen transport for imports from North Africa, 45-49% of total cost); 1.15-1.7 EUR/kgH2 [249] (ammonia ship transport from North Africa, 27-39% of total cost); 1.9–2.6 EUR/kgH2 [249] (LOHC ship transport from North Africa, 41-49% of total cost); and 2.05 EUR/kg H2 (liquid hydrogen ship transport for imports from Saudi Arabia, 74%). Therefore, the share of transport costs within total costs can be quite variable, ranging from 23% to 74%.

Instead, no references are found to storage costs across these assumptions. This could potentially be either because storage costs are included as part of transport costs, or because they are not made explicit, or because they are assumed to be less relevant for the specific applications for which these assumptions were provided (e.g. mobility uses compared to power uses).

7.2.5 Assumptions on future imported blue hydrogen costs

i) Technical potential

IEA, IRENA and BloombergNEF do not provide an assessment of the technical potential of imported blue hydrogen for the EU.

[246] Within hydrogen transport costs, we also include compression costs: compression raises the pressure of hydrogen to the requested value by the consumer. Additionally, it must be noted that hydrogen is transported at a finite speed, much slower than the speed of electricity (i.e. the speed of light). Therefore, within the sub-assumption on the levelised cost of transport, the assumption on the intermediate hydrogen carrier includes the levelised cost of storage.

[247] No reference was found to assumptions on imported green hydrogen costs from Australia or from Chile in the EU.

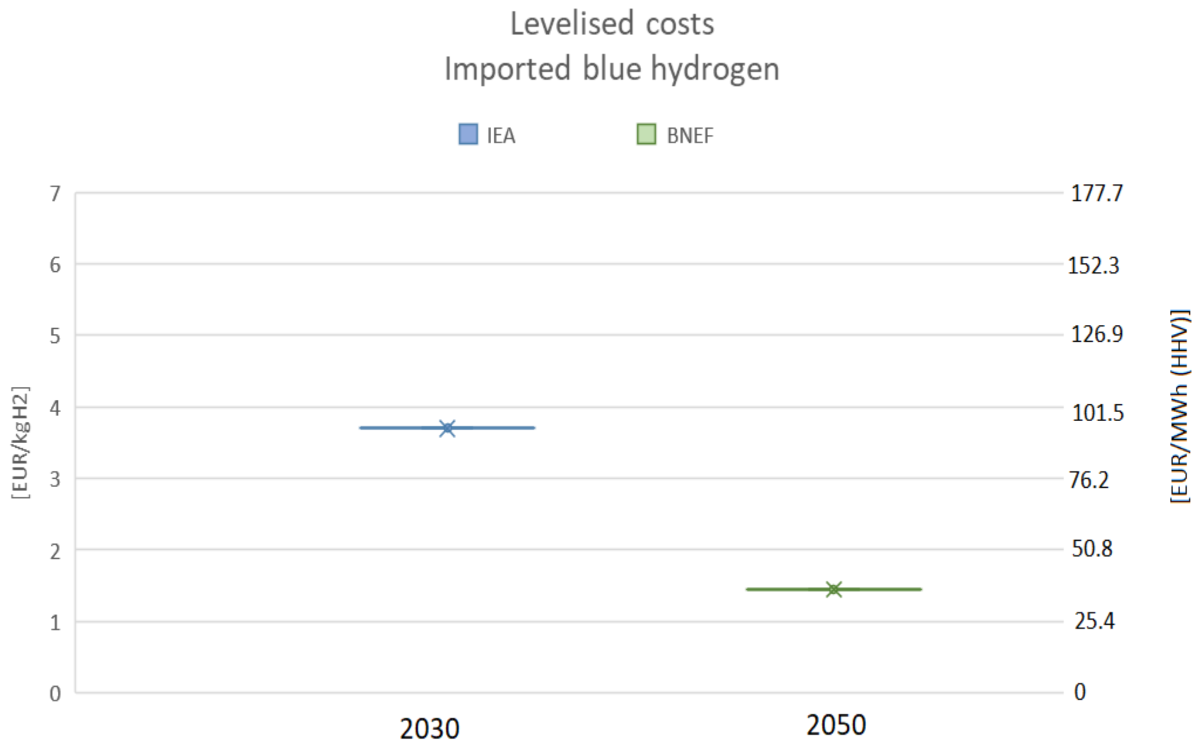
[248] The transport costs identified are associated to the reconversion costs from ammonia to hydrogen.

[249] Within these transport costs, the following categories of costs were included from the original source: “conversion”, “import/export terminals”, “transmission”, “distribution” and “reconversion”.

However, BloombergNEF provides an assessment by 2050 of "potential resource" hydrogen for German consumers. In particular, BloombergNEF assumes that thousands of TWhs of blue hydrogen imports from Russia, through pipelines, and tens of TWh of domestic German blue hydrogen would reach German consumers. In terms of Mton of H2, this would correspond, respectively, to an order of magnitude of 25 Mton H2/yr and 0.25 Mton H2/yr.

ii) Levelised costs

Figure 7.14 Assumptions on levelised costs for imported blue hydrogen scenario across future costs studies examined



By 2030, there is only one assumption for the levelised costs of imported blue hydrogen (from Russia) at 3.92 EUR/kgH2.

By 2050, there is also only one assumption (also of imported blue hydrogen from Russia) at 1.45 EUR/kgH2.

For the levelised cost of imported blue hydrogen, we identify the following two main assumptions: I) transport cost; and II) storage cost. In particular, both depend on III) the type of intermediate hydrogen carrier (e.g. ammonia, LOHC, liquid hydrogen).

Other assumptions for levelised costs are CAPEX, interest rate, efficiency, natural gas prices and full load hour. But these are not particularly critical for the importing country; mattering more for exporters.

Transport costs, storage costs and intermediate hydrogen carriers

By 2030, only one transport cost assumption is available at 0.8 EUR/kgH2 (i.e. 22% of total costs, in particular related to reconversion from ammonia).

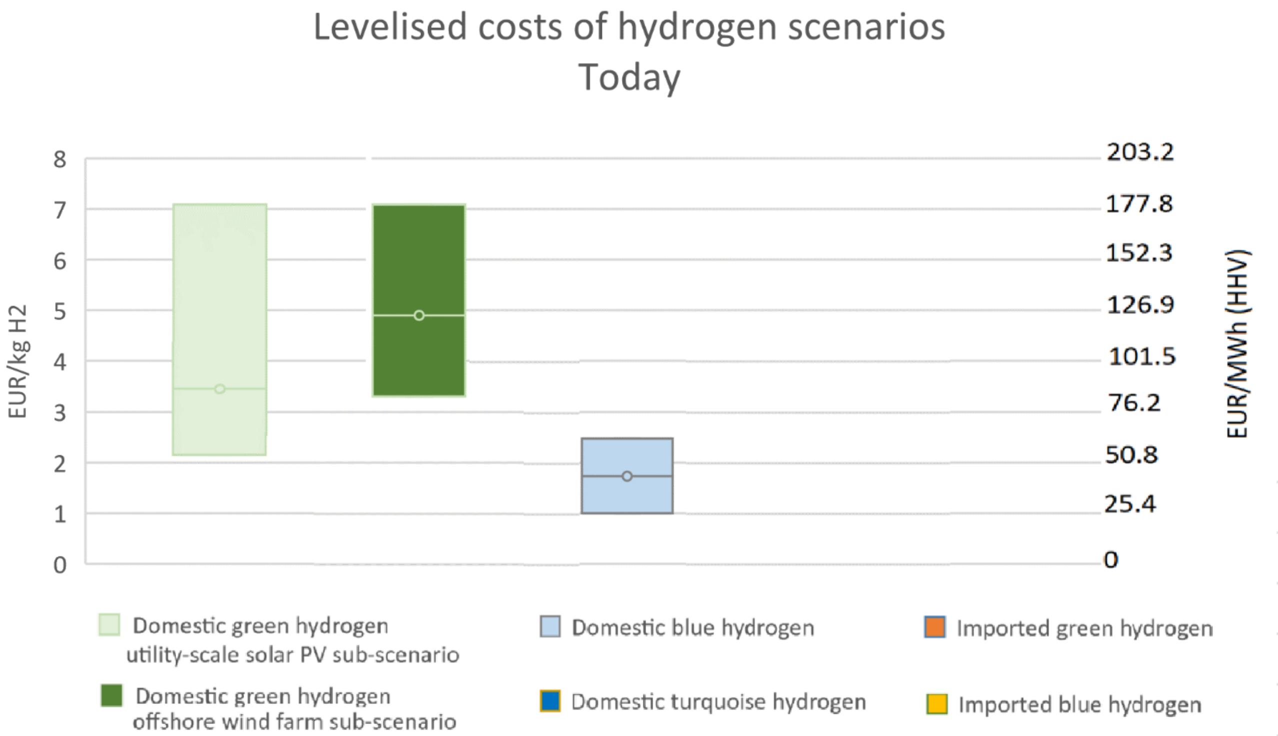
By 2050, only one transport cost assumption is available at 0.3 EUR/kgH2 (i.e. 21%, in particular related to pipeline transport).

Instead, no references are found for storage costs across these assumptions. Either storage costs are included as part of transport costs, or they are not explained, or they are assumed to be less relevant.

7.2.6 Comparison of future assumptions on levelised hydrogen production costs across the five scenarios (including the two sub-scenarios)

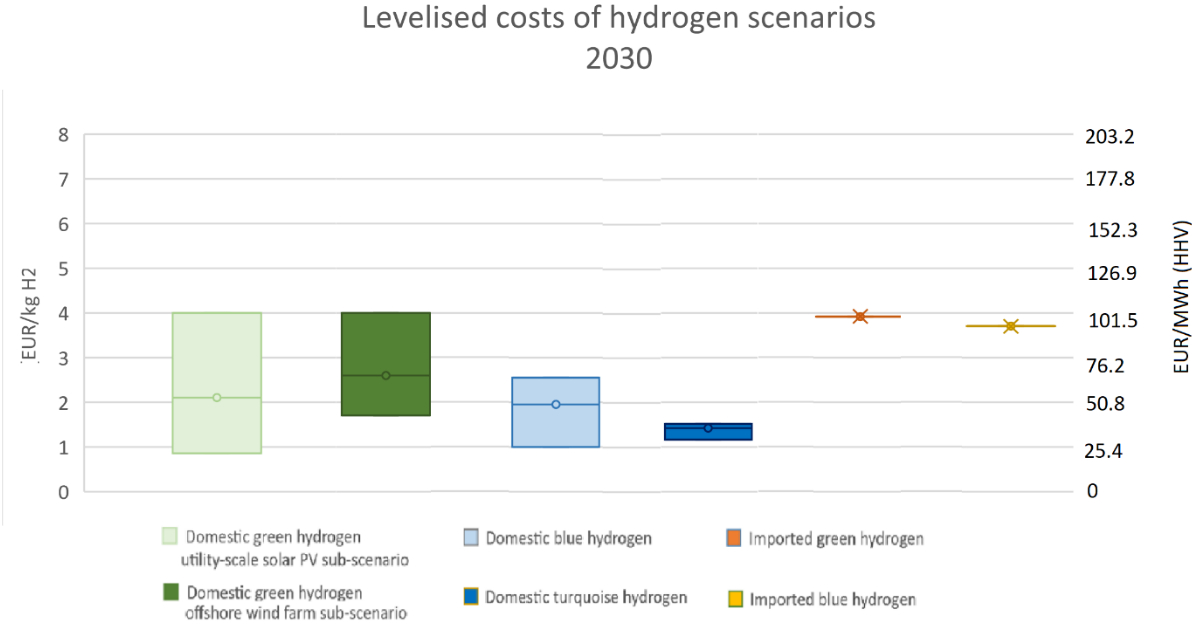
Let's now compare the levelised costs of hydrogen across the the five scenarios previously presented (including the two sub-scenarios) for the three time-horizons:

Figure 7.15 Comparison of assumptions on levelised hydrogen production costs today across the five scenarios (one including two sub-scenarios)



The estimates available today refer only to the domestic green hydrogen costs (including the two sub-scenarios) and for domestic blue hydrogen costs. The range of cost estimates for domestic green hydrogen – utility-scale solar PV and offshore wind farm sub-scenarios is much wider than that for domestic blue hydrogen costs. Additionally, it is clear that the average levelised costs for both sub-scenarios of domestic green hydrogen are higher. In fact, they are slightly less than twice as high as domestic blue hydrogen.

Figure 7.16 Comparison of future assumptions on levelised hydrogen production costs by 2030 across the five scenarios (including the two sub-scenarios)



By 2030, only a few assumptions on the levelised costs of imported hydrogen are available. The assumed levelised costs of imported hydrogen are circa 3.9 EUR/kgH2 [250] for imported green hydrogen and 3.7 EUR/kgH2 [251] for imported blue hydrogen. These are clearly higher than the average levelised costs of the two domestic hydrogen scenarios and of the two sub-scenarios: i.e. 2.1 EUR/kgH2 for the utility-scale solar PV sub-scenario [252]; 2.6 EUR/kgH2 for offshore wind farm sub-scenario [253]; circa 1.95 EUR/kgH2 [254] for domestic blue hydrogen scenario and circa 1.4 EUR/kgH2 [255] for the domestic turquoise hydrogen scenario. However, it must be noted that the ranges of these two sub-scenarios and two scenarios partly overlap. Additionally, levelised cost values for utility-scale solar PV sub-scenario could reach even 0.9 EUR/kgH2 [256] at very low costs of electricity (e.g. circa ten EUR/MWh, relative to "very low" cost solar [257]).

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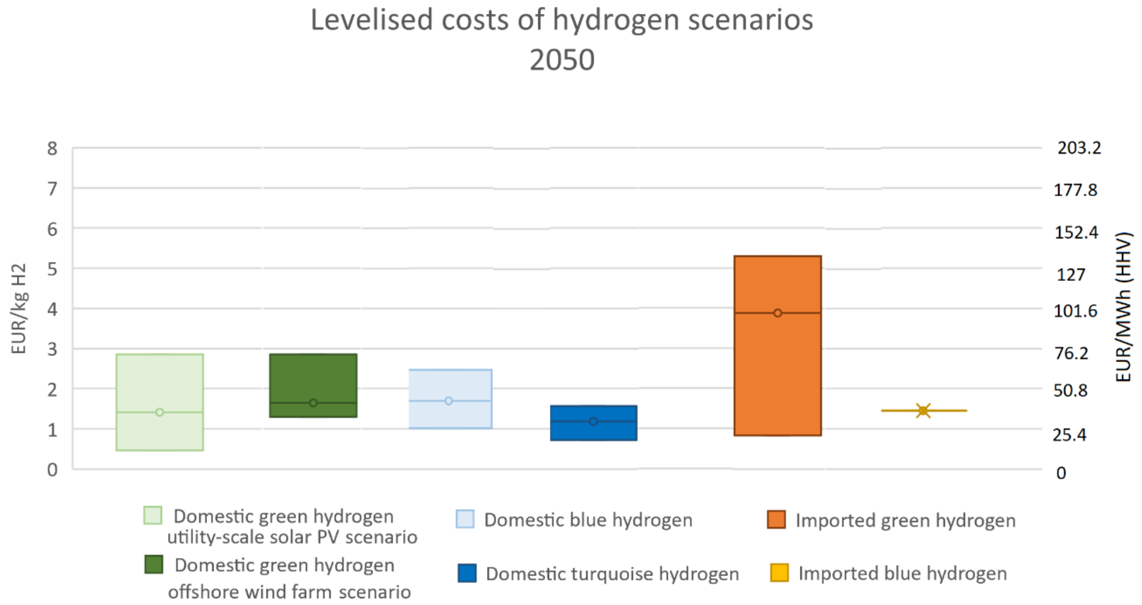
[250] 99.0 EUR/MWh (HHV).
[251] 93.9 EUR/MWh (HHV).
[252] 53.3 EUR/MWh (HHV).
[253] 66.0 EUR/MWh (HHV).
[254] 49.5 EUR/MWh (HHV). This average levelised cost is higher, by 2030, than the average of recent estimates, due to a smaller number of estimates points available and a higher average natural gas price assumption. We cannot, of course, say whether such average natural gas price assumptions will be achieved. Therefore, the reader is advised to consider the resulting range of levelised costs rather than the punctual average estimate.
[255] 35.5 EUR/MWh (HHV).
[256] 22.8 EUR/MWh (HHV).
[257] An example of "very low" cost solar is the recent world-record low bid, which was recorded in the solar PV auctions held in Portugal in August 2020 (11.2 EUR/MWh). https://www.pv-magazine.com/2020/08/24/portugals-second-pv-auction-draws-world-record-low-bid-of-0-0132-kwh.

Figure 7.17 Comparison of future assumptions on hydrogen production levelised costs by 2050 across the five scenarios (one including two sub-scenarios)



If we rank the two five scenarios (including the two sub-scenarios of domestic green hydrogen scenario), for 2050, by their increasing average levelised costs, then the order is as follows: 1) the domestic turquoise hydrogen scenario (circa 1.2 EUR/kgH2 [258]); 2) the domestic green hydrogen scenario - utility-scale solar PV sub-scenario (circa 1.4 EUR/kgH2 [259]); 3) the imported blue hydrogen scenario (circa 1.45 EUR/kgH2 [260]); 4) the domestic green hydrogen scenario - offshore wind farm sub-scenario (circa 1.65 EUR/kgH2 [261]); 5) the domestic blue hydrogen scenario (circa 1.7 EUR/kgH2 [262]) and 6) the imported green hydrogen scenario (circa 3.9 EUR/kgH2 [263]). However, it must be noted that the ranges of these five scenarios (including the two sub-scenarios of domestic green hydrogen) overlap. Additionally, the levelised costs of one of the sub-scenarios could stand as low as 0.8 EUR/kgH2 [264] depending on the cost of electricity. The domestic turquoise hydrogen scenario remains the cheapest option in terms of average levelised costs in both 2030 and 2050. although note that assumptions on domestic turquoise hydrogen are not as credible as for the other two domestic technologies (i.e. green hydrogen and blue hydrogen), given that methane pyrolysis technology is currently in its pilot stage and given that it is less technologically mature. Instead, imported green hydrogen remains the most expensive option for both 2030 and 2050.

[258] 30.5 EUR/MWh (HHV).
[259] 29.2 EUR/MWh (HHV).
[260] 36.8 EUR/MWh (HHV).
[261] 41.9 EUR/MWh (HHV).
[262] 43.2 EUR/MWh (HHV).
[263] 99.0 EUR/MWh (HHV).
[264] 20.3 EUR/MWh (HHV).

7.2.8 Equivalent ETS prices as a cost-competitiveness metric for the domestic scenarios with respect to grey hydrogen

We will now proceed to an analysis which incorporates both: 1) cost-competitiveness with respect to grey hydrogen in terms of average levelised costs; and 2) the GHG emissions reduction potential with respect to grey hydrogen. The benchmark technology considered here is grey hydrogen. We will use, for this analysis, a single virtual cost metric built by summing the levelised costs to an additional virtual ETS cost-component, directly proportional to the direct GHG emissions of these technologies [kg CO2eq/kWh] and to an "equivalent ETS prices" [EUR/tCO2]. In the scenario of technologies with zero direct GHG emissions, this virtual cost-component is zero independently of the "equivalent ETS prices". In particular, we are interested in the value of "equivalent ETS prices" which would enable cost-parity in terms of this virtual metric for two different technologies.

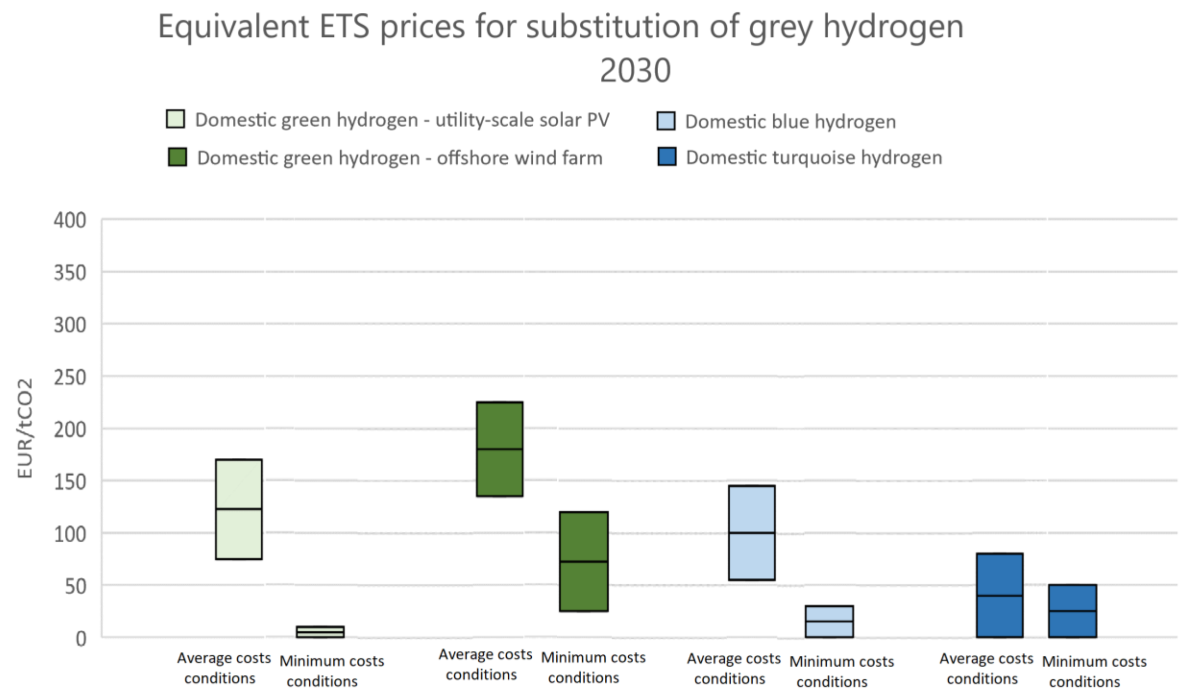
In practice, this additional ETS virtual cost-component would correspond to the cost component from carbon prices. Negative "equivalent ETS prices" would imply that the relevant technology is cost-competitive without any additional carbon price. Instead, high "equivalent ETS prices" would imply a need for high carbon prices to make said technology cost-competitive.

We consider three scenarios for the levelised costs of grey hydrogen, in order to account for the variability of the levelised costs of grey hydrogen, partly due to natural gas prices assumptions: scenario 1) grey hydrogen levelised costs of 1.5 EUR/kgH2 [265]; scenario 2) grey hydrogen levelised costs of circa 1 EUR/kgH2 [266]; scenario 3) grey hydrogen levelised costs of circa 0.8 EUR/kgH2 [267]. The CO2 prices assumptions are equal to zero for these three scenarios. Since steam methane reforming technology for grey hydrogen production is a mature technology, these levelised costs estimates can be assumed not to change from today to 2050. For each of the three scenarios of domestic hydrogen costs analysed in this chapter, we consider the average levelised costs across the different organisations.[268] Instead, we do not include the two import scenarios because: 1) a proper analysis would require the GHG emissions factor of transport and storage technologies, whose data was not found; and 2) we noted previously how imports costs are more expensive than domestic supply costs for 2030. We consider the following GHG emissions factor: 9 kgCO2/kgH2 for steam methane reforming without CCS; 1.0 kgCO2/kgH2 for blue hydrogen [269]; 0 kgCO2/kgH2 for green hydrogen;[270] and 1.35

[265] 38.1 EUR/MWh (HHV). This value is assumed by the EU in the "A hydrogen strategy for a climate-neutral Europe" COM (2020) 301 final, disregarding the cost of CO2. Additionally, IEA "Future of hydrogen" (2019) assumes a similar levelised cost value relative to Europe in 2030, at zero carbon prices and at a natural gas price of 6.4 EUR/GJ. The references by IEA "World Energy Outlook 2020" to the costs of grey hydrogen include the costs from CO2 prices and these, therefore, were excluded.
[266] 25.4 EUR/MWh (HHV). This levelised cost value was assumed by Gas for Climate & Guidehouse in "Gas Decarbonization Pathways 2020 – 2050".
[267] 20.3 EUR/MWh (HHV). This levelised cost value was assumed by ThinkStep "GHG Emissions in the EU Energy market today and in 2050" (presentation by Dr. Michael Faltenbacher, 29th Oct. 2018).
[268] By doing so, we simplify the analysis as we do not assess the common interdependency on natural gas prices between the average levelised costs of grey hydrogen, on the one hand, and, on the other, blue and turquoise hydrogen. Therefore, the range of equivalent ETS prices resulting from the three scenarios is meant to correct this simplification.
[269] Taken from IEA "Future of hydrogen" (2019), assumptions annex document.
[270] Regarding the electrolysers emissions factor, we do not account for the GHG emissions-intensity of electricity consumed. However, the European Environmental Agency highlighted, in its 2018 statistics, that the emissions-

kgCO2/kgH2 for turquoise hydrogen [271]. By accounting for three different scenarios of grey hydrogen levelised costs, each dependent on a different natural gas sub-assumption, we try to correct for this bias.

Figure 7.18 Comparison of ETS equivalent prices calculated for substitution of grey hydrogen with domestic green, blue and turquoise hydrogen by 2030 (incl. two sub-scenarios for domestic green hydrogen)



Regarding domestic green hydrogen from the utility-scale solar PV sub-scenario, today a rather high equivalent ETS price of 215 – 300 EUR/tCO2 would be required for cost-parity with grey hydrogen at average cost conditions. However, this value significantly decreases to 70 – 150 EUR/tCO2 at minimum cost conditions. For 2030, the equivalent ETS prices for domestic green hydrogen stand at around 75 – 175 EUR/tCO2 for average cost conditions; and at 0 – 10 EUR/tCO2 for minimum cost conditions (a null value implies cost-competitiveness in absence of carbon pricing). Finally, for 2050, the equivalent ETS prices range between 0 and 80 EUR/tCO2, implying that carbon prices comparable to today's carbon prices (i.e. 27.1 EUR/tCO2 [272]) would be needed for cost-parity between green hydrogen and grey hydrogen at the assumed average levelised costs. Needless to say, equivalent ETS prices also result negative by 2050 at minimum cost conditions.

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intensity of EU electricity was 294.2 gCO2/kWh. According to the EU EC "A Clean Planet for All" scenarios ELEC and H2, the electricity emissions-intensity could decrease to 172.8 gCO2/kWh by 2030 in both scenarios and to, respectively, 12.0 and 15.1 gCO2/kWh by 2050.

[271] According to the "Levelised Cost of CO2 Mitigation from Hydrogen Production Routes" reference, which was the only reference found with emissions factor for turquoise hydrogen, the direct emissions of a pyrolysis facility range between 0.2-2.5 kg CO2/kg H2. Therefore, we assumed a GHG emissions factor of 1.35 kgCO2/kgH2, which is the average in this range. However, a fair point is stated in Gas for Climate "Gas Decarbonisation Pathways 2020-2050": "Other options, most notably carbon capture and utilisation (e.g. via methane cracking and methane pyrolysis) need to be further technically developed and evaluated for their real greenhouse gas emission reduction potential (i.e. long-term carbon sequestration potential)."

[272] Source: https://ember-climate.org/data/carbon-price-viewer/ (relative to September 21 2020).

Regarding domestic green hydrogen from the offshore wind farm sub-scenario, today a rather high equivalent ETS price of 375 – 460 EUR/tCO2 would be required for cost-parity with grey hydrogen at average cost conditions. However, this value significantly decreases to 195 – 280 EUR/tCO2 at minimum cost conditions. For 2030, the equivalent ETS prices for domestic green hydrogen stand at around 135 – 225 EUR/tCO2 for average cost conditions; and at 25 – 120 EUR/tCO2 for minimum cost conditions. Finally, for 2050, the equivalent ETS prices range between 20 and 115 EUR/tCO2, implying that carbon prices comparable to today's carbon prices (i.e. 27.1 EUR/tCO2 [273]) would be needed for cost-parity between green hydrogen and grey hydrogen at the assumed average levelised costs. Instead, equivalent ETS prices vary between negative values and 70 by 2050 at minimum cost conditions.

Regarding domestic blue hydrogen, a modest equivalent ETS price range of 25–105 EUR/tCO2 would be required for cost-parity with grey hydrogen at average levelised costs conditions. By 2030 the equivalent ETS prices for domestic blue hydrogen results slightly higher (i.e. 55–145 EUR/tCO2) due to the differences in the availability of assumptions data for 2030 and a higher average natural gas price assumption. For 2050, the equivalent ETS prices for domestic blue hydrogen result around 25-105 EUR/tCO2. This trend in constant equivalent ETS prices is justified by assumptions of negligible CAPEX increase, whereas average natural gas prices assumptions slightly differ within the considered time horizon.

Regarding domestic turquoise hydrogen, by 2030 we determined the equivalent ETS prices range to be between 0 and 80 EUR/tCO2. By 2050 the equivalent ETS prices range between 0 EUR/tCO2 and 50 EUR/tCO2. This implies that, at the assumed levelised costs, turquoise hydrogen results cheaper with respect to grey hydrogen in 2050.

If we were to totally phase out the current 10 Mt of grey hydrogen industrial feedstock uses by 2030, based on the range of equivalent ETS prices for average levelised costs conditions calculated for each scenario, then the required subsidies would be approximately the following [274]:

- 7.1 – 15.0 Billion EUR (in the scenario of total substitution of grey hydrogen with green hydrogen of utility-scale solar PV sub-scenario at an ETS price of 75 – 170 EUR/tCO2);
- 12.4 – 20.3 Billion EUR (in the scenario of total substitution of grey hydrogen with green hydrogen of offshore wind farm sub-scenario at an ETS price of 135 – 225 EUR/tCO2);
- 4.5 – 11.5 Billion EUR (in the scenario of the total substitution of grey hydrogen with blue hydrogen at an ETS price of 55 - 145 EUR/tCO2);
- 0 – 5.9 Billion EUR (in the scenario of total substitution of grey hydrogen with turquoise hydrogen at an ETS price ranging from negative values to 80 EUR/tCO2. However, we need again to remember that future assumptions on methane pyrolysis are not as credible as assumptions for the other two domestic technologies. Methane

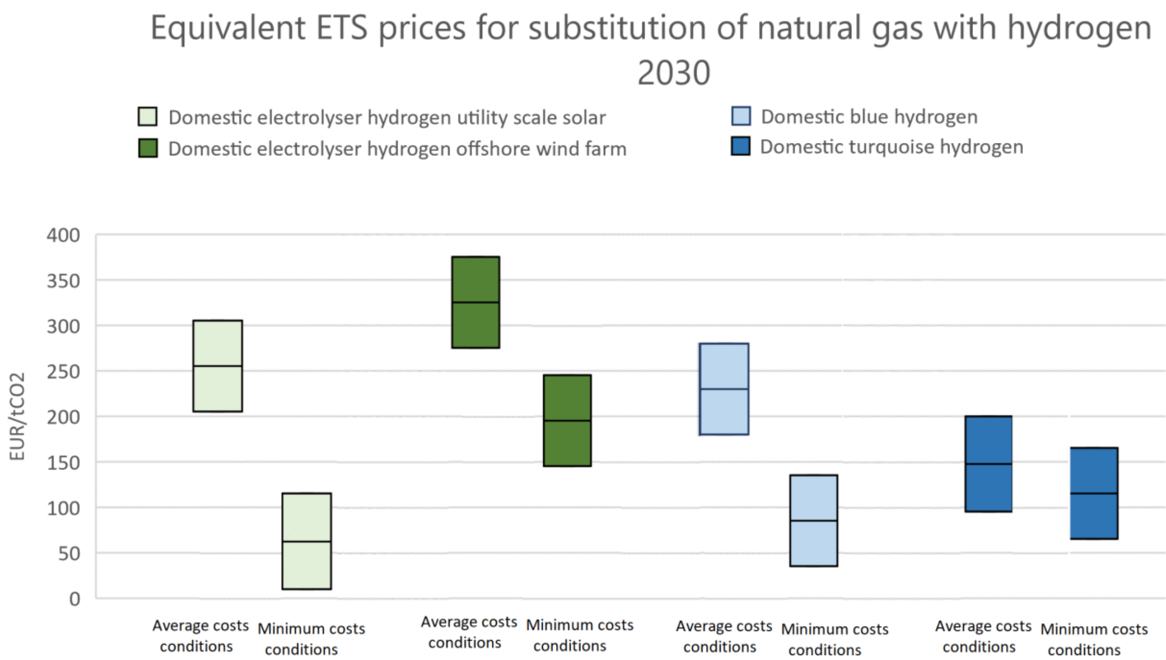
[273] Source: https://ember-climate.org/data/carbon-price-viewer/ (relative to September 21 2020).
[274] These values were derived by multiplying ten Mt of hydrogen, by the emissions reduction potential of that specific hydrogen production technology with respect to grey hydrogen, by the equivalent ETS price by 2030 for that specific hydrogen production technology.

pyrolysis is currently at the pilot stage and is less technologically mature than the other two hydrogen technologies.)

If we consider the range of required subsidies for each of these scenarios, the order of magnitude of the expected subsidies would be quite significant. In the case of green hydrogen at minimum cost conditions (0.9 EUR/kgH2 for utility-scale solar PV sub-scenario and 1.7 EUR/kgH2 for offshore wind farm sub-scenario), then potentially only, respectively, 0 – 0.7 Billion EUR and 2.6 – 10.5 Billion EUR subsidies would be needed. The reader should remember that there is no guarantee that these minimum levelised costs conditions will be achieved by 2030, nor that there will be a considerable amount of technical potential available at these costs.

Additionally, we also calculated the equivalent ETS prices for substitution of natural gas combustion with hydrogen combustion. In order to do so, we calculated these equivalent ETS prices as the different between average levelised production costs of the considered hydrogen scenario and the assumed natural gas fuel costs, divided by the difference in combustion emissions factor. We consider two scenarios for natural gas fuel costs: 1) 3.24 EUR/MWh (or 0,9 EUR/GJ) and 2) 23 EUR/MWh (or 6,4 EUR/GJ). Secondly, we consider a hydrogen combustion emissions factor of 0 kgeCO2/kWh and a natural gas combustion emissions factor of 0.20 kgeCO2/kWh [275]. We do not include the direct GHG emissions of the future hydrogen costs scenarios, as a like-for-like comparison between hydrogen combustion and natural gas combustion would require data on GHG emissions due to natural gas extraction. Finally, we convert the hydrogen average levelised costs from EUR/kgH2 to EUR/MWh by considering a hydrogen Lower Heating Value of 0.03331 MWh/kgH2.

Figure 7.19 Comparison of ETS equivalent prices calculated for substitution of natural gas prices with domestic green, blue and turquoise hydrogen by 2030 (incl. two sub-scenarios for domestic green hydrogen)



[275] Source: emissions factor for stationary combustion of natural gas according to IPCC.

Next, we have domestic green hydrogen from the utility-scale solar PV sub-scenario. Today significantly high equivalent ETS prices of 400– 505 EUR/tCO2 at average levelised costs conditions would be needed to enable cost-parity of natural gas combustion with hydrogen combustion, and 205– 310 EUR/tCO2 at minimum levelised costs conditions. By 2030, lower equivalent ETS prices for natural gas substitution are needed (145 – 250 EUR/tCO2). However, always at minimum levelised costs conditions, by 2030 equivalent ETS prices result significantly lower (10 – 115 EUR/tCO2). Instead, by 2050 a modest range of equivalent ETS prices (95 – 195 EUR/tCO2) in the case of .average levelised costs conditions, and a lower range (0 – 55 EUR/tCO2) in the case of minimum levelised costs conditions.

Regarding domestic green hydrogen from offshore wind farm sub-scenario, today significantly higher equivalent ETS prices of 620 – 720 EUR/tCO2 at average levelised costs conditions would be needed to enable cost-parity of natural gas combustion with hydrogen combustion, and 375 – 480 EUR/tCO2 at minimum levelised costs. By 2030, lower equivalent ETS prices for natural gas substitution would be needed but they are still significant (275 – 375 EUR/tCO2). However, for minimum levelised costs conditions, by 2030 equivalent ETS prices result significantly smaller (145 – 245 EUR/tCO2). Instead, by 2050 we have a modest range of equivalent ETS prices (130 – 235 EUR/tCO2) in the case of average levelised costs, and a lower range (80 – 185 EUR/tCO2) in the case of minimum levelised costs.

Regarding domestic blue hydrogen, lower but still significant range of equivalent ETS prices (145 – 280 EUR/tCO2) would be needed by today, 2030 and 2050. However, in the case of minimum levelised costs conditions these values reduce to 35 – 135 EUR/tCO2. Instead, regarding domestic turquoise hydrogen, a modest range of equivalent ETS prices (95 – 200 EUR/tCO2) at average levelised costs conditions by 2030, and a smaller one (65 – 165 EUR/tCO2) at minimum costs conditions. Finally, by 2050 this range is significantly smaller (65 – 165 EUR/tCO2) although these levelised costs assumptions remain highly uncertain. From these illustrative figures we can conclude that substitution of natural gas combustion with hydrogen combustion will not occur unless significantly high future ETS prices are assumed or the assumptions on significantly low average levelised costs of domestic turquoise are verified.

We also calculated the subsidies needed if we were to substitute 10% of the 2018 final energy demand in EU satisfied by natural gas with “clean” hydrogen (i.e. 1343 TWh, out of 2942 TWh). To do so, we multiplied the CO2 emissions associated to the 2018 final energy demand (268.6 Mton CO2 [276]) by the equivalent ETS prices for the substitution of natural gas combustion with hydrogen combustion by 2030 at average levelised costs conditions. Then the required subsidies would be approximately the following:

- 38.9 – 67.2 Billion EUR (in the case of substitution of natural gas combustion with domestic green hydrogen sourced with electricity from utility-scale solar PV plants at an ETS price of 145 – 250 EUR/tCO2);
- 73.9 – 100.5 Billion EUR (in the case of substitution of natural gas combustion with domestic green hydrogen sourced with electricity from offshore wind farms at an ETS price of 275 – 375 EUR/tCO2);

[276] We multiplied the 10% of the 2018 final energy demand in EU (i.e. 1343 TWh) by the CO2 emissions factor of natural gas combustion (i.e. 0.20 kgeCO2/kWh).

- 48.3 – 75.2 Billion EUR (in the case of the total substitution of natural gas combustion with blue hydrogen at an ETS price of 180 - 280 EUR/tCO2);
- 25.5 – 53.7 Billion EUR (in the case of the total substitution of natural gas combustion with turquoise hydrogen at an ETS price of 95 – 200 EUR/tCO2). However, we need again to remember that future assumptions on methane pyrolysis are not as credible as assumptions for the other three domestic technologies. Methane pyrolysis is currently at the pilot stage and is less technologically mature than the other two hydrogen technologies.

Instead, the required subsidies by considering equivalent ETS prices for the substitution of natural gas combustion with hydrogen combustion by 2030 at minimum levelised costs conditions.

- 10.7 – 38.9 Billion EUR (in the case of substitution of natural gas combustion with domestic green hydrogen sourced with electricity from utility-scale solar PV plants at an ETS price of 40 – 145 EUR/tCO2);
- 38.9 – 65.4 Billion EUR (in the case of substitution of natural gas combustion with domestic green hydrogen sourced with electricity from offshore wind farms at an ETS price of 145 – 245 EUR/tCO2);
- 9.4 – 36.3 Billion EUR (in the scenario of the total substitution of natural gas combustion with blue hydrogen at an ETS price of 35 - 135 EUR/tCO2);
- 17.5 – 44.3 Billion EUR (in the scenario of total substitution of natural gas combustion with turquoise hydrogen at an ETS price of 65 – 165 EUR/tCO2).

Finally, the required subsidies by considering equivalent ETS prices for the substitution of natural gas combustion with hydrogen combustion by 2050 at average levelised costs conditions.

- 14.8 – 43.0 Billion EUR (in the case of substitution of natural gas combustion with domestic green hydrogen sourced with electricity from utility-scale solar PV plants at an ETS price of 55 – 160 EUR/tCO2);
- 35.6 – 62.2 Billion EUR (in the case of substitution of natural gas combustion with domestic green hydrogen sourced with electricity from offshore wind farms at an ETS price of 130 – 235 EUR/tCO2);
- 38.9 – 65.8 Billion EUR (in the scenario of the total substitution of natural gas combustion with blue hydrogen at an ETS price of 145 - 245 EUR/tCO2);
- 17.5 – 44.3 Billion EUR (in the scenario of total substitution of natural gas combustion with turquoise hydrogen at an ETS price of 65 – 165 EUR/tCO2).

If we consider the range of required subsidies for each of these scenarios, the order of magnitude of the expected subsidies for substitution of 10% of the 2018 final energy demand in EU satisfied by natural gas could result ten times larger compared to those for substitution of current 10 Mt of grey hydrogen industrial feedstock uses by 2030.

The following table summarises this information:

Table 7.5 Summary of average and minimum levelised costs and equivalent ETS prices for the substitution of grey hydrogen across scenarios of domestic hydrogen production costs

Scenario	Levelised cost assumptions across all sources Today [EUR/kgH2*] [EUR/MWh**]	Levelised cost assumptions across all sources 2030 [EUR/kgH2*] [EUR/MWh**]	Levelised cost assumptions across all sources 2050 [EUR/kgH2*] [EUR/MWh**]	Equivalent ETS prices for substitution of grey hydrogen Today [EUR/tCO_2]	Equivalent ETS prices for substitution of grey hydrogen 2030 [EUR/tCO_2]	Equivalent ETS prices for substitution of grey hydrogen 2050 [EUR/tCO_2]
Domestic green hydrogen – utility-scale solar PV	€3.45/kg H2 €87.6/MWh (Average)	€2.1/kg H2 €53.3/MWh (Average)	€1.4/kg H2 €35.8/MWh (Average)	215 – 300	75 - 170	0 – 80 **
	€2.15/kg H2 €54.6/MWh (Minimum)	€0.9/kg H2 €21.8/MWh (Minimum)	€0.5/kg H2 €11.7/MWh (Minimum)	70 - 150	0 – 10 **	0 **
Domestic green hydrogen – offshore wind farm	€4.9/kg H2 €124.4/MWh (Average)	€2.6/kg H2 €66.0/MWh (Average)	€1.65/kg H2 €41.9/MWh (Average)	375 - 460	135 - 225	20 - 115
	€3.3/kg H2 €83.8/MWh (Minimum)	€1.7/kg H2 €43.2/MWh (Minimum)	€1.3/kg H2 €33.5/MWh (Minimum)	195 - 280	25 - 120	0 – 70 **

Scenario	Levelised cost assumptions across all sources Today [EUR/kgH2*] [EUR/MWh**]	Levelised cost assumptions across all sources 2030 [EUR/kgH2*] [EUR/MWh**]	Levelised cost assumptions across all sources 2050 [EUR/kgH2*] [EUR/MWh**]	Equivalent ETS prices for substitution of grey hydrogen Today [EUR/tCO_2]	Equivalent ETS prices for substitution of grey hydrogen 2030 [EUR/tCO_2]	Equivalent ETS prices for substitution of grey hydrogen 2050 [EUR/tCO_2]
Domestic blue hydrogen	€1.7/kg H2 €43.2/MWh (Average)	€1.95/kg H2 €49.5/MWh (Average) [277]	€1.7/kg H2 €43.2/MWh (Average)	25 - 105	55 - 145	25 - 105
	€1.0/kg H2 €25.4/MWh (Minimum)	€1.0/kg H2 [278] €25.4/MWh (Minimum)	€1.0/kg H2 €25.4/MWh (Minimum)	0 – 30 **	0 – 30 **	0 – 30 **
Domestic turquoise hydrogen	- (Average)	€1.4/kg H2 €35.5/MWh (Average)	€1.2/kg H2 €30.5/MWh (Average)	-	0 – 80 **	0 – 50 **
	- (Minimum)	€1.2/kg H2 €30.5/MWh (Minimum)	€0.7/kg H2 €17.8/MWh (Minimum)	-	0 - 50 **	0 **

Notes: ** competitiveness conditions without additional carbon pricing. Whereas the technologies underlying domestic green hydrogen (electroysers) and domestic blue hydrogen (Steam Methane Reforming with CCS) are currently commercial, the technology underlying domestic turquoise hydrogen (methane pyrolysis with CCU) is still at demonstration stage.

[277] This average levelised cost by 2030 is higher than the average of recent estimates, due to a smaller number of estimate points available and higher average natural gas price assumption. We cannot say whether such average natural gas price assumptions will indeed be achieved. Therefore, the reader is advised to consider the resulting range of levelised costs rather than the punctual average estimate.

[278] This minimum levelised cost assumption for domestic blue hydrogen has been assumed based on the discretion of the authors not as the minimum across estimates available by 2030 (1.2 EUR/kgH2), but as the minimum for recent estimates (1.0 EUR/kgH2). This is justified because a higher minimum value by 2030 than that for today would not fit with an expected CAPEX decrease at parity of possible natural gas prices and interest rates.

Table 7.6 Summary of equivalent ETS prices for the substitution of grey hydrogen combustion with natural gas combustion across scenarios and sub-scenarios of domestic hydrogen production costs

Scenario	Levelised cost assumption	Equivalent ETS prices for the substitution of natural gas combustion * Today [EUR/tCO2]	Equivalent ETS prices for the substitution of natural gas combustion* 2030 [EUR/tCO2]	Equivalent ETS prices for the substitution of natural gas combustion* 2050 [EUR/tCO2]
Domestic green hydrogen – utility-scale solar PV	Average	400 – 505	205 - 305	95 - 195
	Minimum	205 - 310	10 - 115	0 – 55 **
Domestic green hydrogen – offshore wind farm	Average	620 - 720	275 - 375	130 – 235
	Minimum	375 - 480	145 - 245	80 - 185
Domestic blue hydrogen	Average	145 - 245	180 - 280	145 - 245
	Minimum	35 – 135	35 – 135	35 – 135
Domestic turquoise hydrogen	Average	-	95 – 200	65 – 165
	Minimum	-	65 – 165	0 – 90 **

Notes: ** competitiveness conditions without additional carbon pricing

7.2.9 Assumptions on transport and storage costs within EU-territories

The assumptions on transport costs and storage costs within EU-territories are also critical assumptions for future hydrogen supply costs. We will start by examining the critical sub-assumptions of assumptions on domestic transport costs and, then, those on storage costs. Data is sourced from IEA "The future of hydrogen" (June 2019) [279] and BloombergNEF "Global Gas Report" (April 2020).

Assumptions on Transport costs

Assumptions on transport costs will depend mainly on: i) the potential need for transport technologies; and ii) assumptions on transport technologies costs.

[279] All rights reserved. Instead, IEA WEO 2020 does not report assumptions on domestic hydrogen transport and storage costs.

The potential need for transport technologies will depend on: i) the location of domestic production technologies or import hubs; and ii) the location of potential hydrogen uses. This will surely depend on the type of potential hydrogen uses considered: some types (e.g. industrial feedstock uses and industrial energy uses) can be assumed to be typically concentrated in "hubs" where the need for transport technologies amount to a few tens of kms. Instead, other types of potential hydrogen uses (e.g. mobility uses, building heat and services uses) can be assumed to be typically dispersed over a wider region, where the need for transport technologies will surely be much higher. Across the scenarios examined in 7.1, no mention was made on the modelling of the location of hydrogen uses within the EU-region and, given the relative uncertainty with potential hydrogen uses, there is also much uncertainty on the potential need for transport technologies by 2030 and 2050.

Assumptions on transport technology costs depend on four critical assumptions: i) distances; ii) transport means (e.g. pipeline, shipping or trucks) [280]; iii) the state of the hydrogen transported (e.g. gaseous hydrogen, liquid hydrogen or through an intermediate hydrogen carrier); and iv) the volume of hydrogen transported (e.g. few tons/day or hundreds tons/day). [281] In particular, depending on iii) the state of hydrogen transported, assumptions on transport technologies costs include sub-assumptions on compression costs (for gaseous hydrogen), conversion and reconversion costs (for liquid hydrogen, ammonia and LOHC [282]) and storage costs. We will cross-analyse assumptions on transport technologies costs by BloombergNEF for 2019 and by IEA over an undefined time horizon.

For "short distances" below or equal to some few hundreds of kilometres, both BloombergNEF and IEA assume as potential transport means both pipelines and trucks:

- Assumptions on transport costs for pipeline transport vary between 0.026 EUR/kgH2 [283] and 0.75 EUR/kgH2 [284] according to the IEA, and between 0.04 EUR/kgH2 [285] and 1.55 EUR/kgH2 [286] according to BloombergNEF. For pipeline transport, assumptions on transport costs are reported only for gaseous hydrogen transport and for different volumes (hundreds of tons/day by the IEA and tens to thousands of tons/day by BloombergNEF).

- Instead, assumptions on transport costs for truck transport vary between 0.58 EUR/kgH2 [287] and 3.29 EUR/kgH2 [288], and between 0.40 EUR/kgH2 [289] and 3.33 EUR/kgH2 [290]. [291] For truck transport, assumptions on transport costs are reported for different states of hydrogen (gaseous hydrogen and LOHC by IEA; and gaseous hydrogen, LOHC, liquid hydrogen and ammonia by BloombergNEF) and only BloombergNEF reports the dependency of these assumptions on volume (zero to tens of tons/day).

Therefore, for "short distances" assumptions on transport costs for pipeline transport result potentially cheaper than those for truck transport.

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[280] Safety issues dependent on the state of the hydrogen transported (e.g. gaseous hydrogen and ammonia) can have an impact on the availability of specific means of transport.
[281] We will not investigate assumptions on the transport costs of hydrogen blended with natural gas.
[282] Liquid organic hydrogen carrier.
[283] 0.8 EUR/MWh (HHV).
[284] 22.3 EUR/MWh (HHV).
[285] 1.3 EUR/MWh (HHV).
[286] 46.2 EUR/MWh (HHV).
[287] 17.3 EUR/MWh (HHV).
[288] 98.2 EUR/MWh (HHV).
[289] 11.9 EUR/MWh (HHV).
[290] 99.5 EUR/MWh (HHV).
[291] The assumptions on transport costs reported also include, when relevant, conversion and reconversion costs.

For “longer distances” between some hundreds and thousands of kilometres, the IEA assumes as potential transport means both pipeline and ships, whereas BloombergNEF also assumes the availability of trucks:

- Assumptions on transport costs for pipeline transport vary between 0.27 EUR/kgH2 [292] and 2.73 EUR/kgH2 [293] according to the IEA, and between 0.09 EUR/kgH2 [294] and 2.55 EUR/kgH2 [295] according to BloombergNEF. For pipeline transport, assumptions on transport costs are reported for different states of hydrogen transported (gaseous hydrogen and Ammonia by IEA, gaseous hydrogen by BloombergNEF) and only BloombergNEF reports the dependency of these assumptions on volume (tens to thousands of tons/day).
- Instead, assumptions on transport costs for ship transport vary between 1.33 [296] and 2.35 EUR/kgH2 [297] according to IEA, and stand at more than 2.55 EUR/kgH2 [298] according to BloombergNEF. For ship transport, assumptions on transport costs are reported for different states of hydrogen transported (ammonia by both the IEA and BloombergNEF, liquid hydrogen by IEA and LOHC by IEA) and only BloombergNEF reports the dependency of these assumption on volume (tens to thousands of tons/day).
- Finally, assumptions on transport costs for trucks vary between 0.82 EUR/kgH2 [299] and 5.70 EUR/kgH2 [300]. For truck transport, assumptions on transport costs are reported for different states of hydrogen transported (gaseous hydrogen and LOHC by BloombergNEF) and BloombergNEF reports the dependency of these assumption on volume (zero to tens of tons/day).

Therefore, also for “longer distances” assumptions on transport costs for pipeline transport result potentially cheaper than those for truck and ship transport. [301]

Assumptions on storage costs

Assumptions on storage costs will depend mainly on: i) the potential need for storage technologies; and ii) assumptions on storage technologies costs.

The potential need for storage technologies will depend on: i) the temporal profile of domestic production or imports; and ii) the temporal profile of potential hydrogen uses. This will naturally depend on the type of potential hydrogen uses considered: for example, power uses might have a more significant seasonal variability and a larger need for storage, whereas mobility uses might be assumed to have more variability at a daily-level and a smaller need for storage. Across the scenarios examined in 7.1, no modelling was found for the temporal profile of potential hydrogen uses within EU-region. Given the relative uncertainty on potential hydrogen uses, there is also great uncertainty on the potential need for storage technologies by 2030 and 2050.

[292] 8.1 EUR/MWh (HHV).
[293] 81.7 EUR/MWh (HHV).
[294] 2.5 EUR/MWh (HHV).
[295] 76.2 EUR/MWh (HHV).
[296] 39.6 EUR/MWh (HHV).
[297] 70.3 EUR/MWh (HHV).
[298] 76.2 EUR/MWh (HHV).
[299] 24.4 EUR/MWh (HHV).
[300] 170 EUR/MWh (HHV).
[301] This consideration applies whenever pipeline transport is technically feasible, which might not be the case for long undersea distances.

Assumptions on storage technology costs depend on four critical assumptions: i) duration of storage and cycling rate (how often the volume of hydrogen is stored, charged and discharged, e.g. weekly or seasonally); ii) storage means (e.g. tanks, salt cavern or depleted natural gas reservoirs); [302] iii) state of the hydrogen stored (e.g. gaseous hydrogen, liquid hydrogen or through an intermediate hydrogen carrier or in solid state through metal hybrids); and iv) volume of hydrogen stored (e.g. few tons/day or hundreds tons/day). In particular, depending on iii) the state of hydrogen store, assumptions on storage technologies costs include sub-assumptions on conversion and reconversion costs (for liquid hydrogen, ammonia and LOHC [303]). We report below the current and future assumptions on levelised costs of storage (LCOS) by BloombergNEF. [304] The cheapest assumptions on levelised storage costs are those relative to salt caverns (0.20 EUR/kgH2 [305]) and pressurized containers (0.16 EUR/kgH2 [306]).

Figure 7.20 Assumptions on storage technologies costs according to BloombergNEF

	Gaseous state				Liquid state			Solid state
	Salt caverns	Depleted gas fields	Rock caverns	Pressurized containers	Liquid hydrogen	Ammonia	LOHCs	Metal hydrides
Main usage (volume and cycling)	Large volumes, months-weeks	Large volumes, seasonal	Medium volumes, months-weeks	Small volumes, daily	Small - medium volumes, days-weeks	Large volumes, months-weeks	Large volumes, months-weeks	Small volumes, days-weeks
Benchmark LCOS ($/kg)[1]	$0.23	$1.90	$0.71	$0.19	$4.57	$2.83	$4.50	Not evaluated
Possible future LCOS[1]	$0.11	$1.07	$0.23	$0.17	$0.95	$0.87	$1.86	Not evaluated

Source: BloombergNEF. Note: [1] Benchmark levelized cost of storage (LCOS) at the highest reasonable cycling rate (see detailed research for details). LOHC – liquid organic hydrogen carrier.

Policy outcomes

- In terms of potential hydrogen uses, two critical sub-assumptions are identified: i) types of potential hydrogen uses; and ii) inclusion of potential synthetic fuel uses, derived domestically from hydrogen. In 2015 hydrogen demand was estimated at 10 Mt of industrial feedstock uses and in 2019 only 0.7 Mt of unspecified energy uses were estimated. By 2030, the scenarios are divergent regarding the total amount of future potential hydrogen use (varying between 0 Mt and 47 Mt of hydrogen). Additionally, by 2030 future potential hydrogen energy uses (e.g. mobility, power…) are assumed, including synthetic fuel use, together with industrial feedstock use. By 2050, these technological scenarios are still divergent, regarding the total

[302] Safety issues dependent on the state of the hydrogen transported (e.g. gaseous hydrogen and ammonia) can have an impact on the availability of specific transport means.
[303] Liquid organic hydrogen carrier.
[304] Taken from BloombergNEF "Hydrogen Economy Outlook – Key messages" (March 30, 2020).
[305] 5.8 EUR/MWh (HHV).
[306] 4.8 EUR/MWh (HHV).

amount of future potential hydrogen uses (varying between 5 Mt and 79 Mt of hydrogen, including synthetic fuel applications).

➢ No data on technical potential is available across these studies. In terms of levelised costs, recent estimates are available only for domestic green hydrogen from utility-scale solar PV electricity (with an average levelised cost of circa 3.45 EUR/kgH2 and a minimum levelised cost of circa 2.15 EUR/kgH2), domestic green hydrogen from offshore wind farm electricity (with an average levelised cost of circa 4.9 EUR/kgH2 and a minimum levelised cost of circa 3.3 EUR/kgH2), and domestic blue hydrogen (with an average levelised cost of circa 1.7 EUR/kgH2 and a minimum levelised cost of circa 1.0 EUR/kgH2). By 2030, the average levelised costs of imported hydrogen (i.e. circa 3.9 EUR/kgH2 for imported green hydrogen and 3.7 EUR/kgH2 for imported blue hydrogen) are clearly higher than the average levelised costs of domestic hydrogen (i.e. 2.1 EUR/kgH2 for domestic green hydrogen from utility-scale solar PV electricity, 2.6 EUR/kgH2 for domestic green hydrogen from offshore wind farm electricity, circa 1.95 EUR/kgH2 for domestic blue hydrogen and circa 1.4 EUR/kgH2 for domestic turquoise hydrogen). By 2030, the range of the levelised costs overlap for the three domestic scenarios, given the significantly small assumptions for minimum levelised costs by 2030: 0.9 EUR/kgH2 for domestic green hydrogen from utility-scale solar PV electricity; 1.7 EUR/kgH2 for domestic green hydrogen from offshore wind farm electricity; 1.0 EUR/kgH2 for domestic blue hydrogen and 1.2 EUR/kgH2 for domestic turquoise hydrogen. By 2050 domestic turquoise hydrogen proved a cheaper option at an average levelised cost of circa 1.2 EUR/kgH2, followed by domestic green hydrogen from utility-scale solar PV electricity (1.4 EUR/kgH2) and domestic green hydrogen from offshore wind farm electricity (1.65 EUR/kgH2). Instead, the average levelised cost of domestic blue hydrogen stood at 1.7 EUR/kgH2. Imported green hydrogen results the most expensive option at an average levelised cost of circa 3.9 EUR/kgH2. But there is great variability in its range of levelised costs estimates. Based on available evidence, importing hydrogen would prove a more expensive option for EU decarbonisation compared to domestic hydrogen production. However, more evidence relative to imports of green hydrogen from countries with very cheap renewable generation would be needed to draw solid conclusions. Additionally, the cheap scenario for domestic turquoise hydrogen assumes the availability of this pilot-stage technology by 2030, though whether this scenario will be achieved, and if not by when, remains to be seen.

➢ By analysing, for each case, the critical sub-assumptions of levelised costs, one outcome is that domestic green hydrogen costs depend mainly on electricity costs, while CAPEX and full load hours are less critical sub-assumptions. Therefore, the future high penetration of renewable electricity generation at low levelised costs, as seen in chapter 6, will also lead to lower levelised costs of domestic green hydrogen. Similarly, for blue hydrogen costs, natural gas prices assumptions result more critical than CAPEX assumptions. For turquoise hydrogen, no particular statements can be made, except that both assumptions about natural gas prices and about revenues from solid carbon sales are critical. For imported hydrogen costs, assumptions on storage costs are not available and the share of transport costs within total import hydrogen costs vary greatly, ranging from 21% to 74%.

➢ “Equivalent ETS prices” needed for cost-parity between grey hydrogen and each of the three cases of domestic hydrogen production technologies were calculated by 2030 for average levelised costs conditions: 75 – 170 EUR/tCO2 for domestic green hydrogen from utility-scale solar PV electricity; 135– 225 EUR/tCO2 for domestic green hydrogen from offshore wind farm electricity; 55 – 145 EUR/tCO_2 for domestic blue hydrogen and 0 – 80 EUR/tCO_2 for domestic turquoise hydrogen. Taking into account current EU ETS prices (i.e. 26.5 EUR/tCO_2), domestic turquoise hydrogen, domestic green hydrogen from utility-scale solar PV electricity and domestic blue hydrogen would be more likely to result cost-competitive with grey hydrogen, by 2030, always assuming that they are available by then. Instead, the "equivalent ETS prices" for minimum levelised costs conditions result significantly smaller: 0 - 10 EUR/tCO_2 for green hydrogen from utility-scale solar PV electricity; 25 – 125 EUR/Tco2 for green hydrogen from offshore wind farm electricity; and 0-30 EUR/tCO_2 for blue hydrogen and 0-50 EUR/tCO_2 for turquoise hydrogen. By using these "equivalent ETS prices" as a proxy for the policy subsidies needed to phase out the 10 Mt of grey hydrogen, then the order of magnitude of the subsidies needed turns out to be billions or tens of Billions EUR. In the case of minimum levelised costs for green hydrogen by 2030 (e.g. 0.9 EUR/kgH_2 for utility-scale solar PV sub-scenario and 1.7 EUR/kgH_2 for offshore wind farm sub-scenario), then, respectively, only 0 – 0.7 Billion EUR and 2.6 – 10.5 billion EUR subsidies would be needed. Instead the equivalent ETS prices for the substitution of natural gas combustion reveal, under simplifying assumptions which do not include additional CAPEX costs, that "clean" hydrogen is currently not cost-competitive compared to natural gas and will most likely not be so by 2030.

- Regarding hydrogen transport costs, there is a large uncertainty on the potential need for hydrogen transport technologies within EU-territories by 2030 and 2050. For both "short distances" (below or equal to some few hundreds of kilometers) and "long distances" (between some hundreds and thousands of kilometers), pipeline transport of gaseous hydrogen (at undefined volumes) result the cheapest transport means (0.03 – 1.55 EUR/kgH_2 [307] for "short distances" & 0.40 – 3.33 EUR/kgH_2 [308] for "long distances"). Regarding hydrogen storage costs, there is also large uncertainty on the potential need for hydrogen storage technologies. Storage in salt caverns (0.20 EUR/kg H_2[309]) and in pressurized containers of gaseous hydrogen (0.16 EUR/kg H_2[310]) result currently the cheapest storage options.

[307] 0.8 EUR/MWh (HHV) – 43.2 EUR/MWh (HHV).
[308] 8.1 EUR/MWh (HHV) – 81.7 EUR/MWh (HHV).
[309] 5.8 EUR/MWh.
[310] 4.8 EUR/MWh.

8. Societal Response

8.1 General Response

There is no doubt that Europeans are in favour of actions to limit global warming. In 2019 Eurobarometer recorded that 93% of citizens consider climate change to be a serious problem[311]. Opinion polls since 2008 indicate, meanwhile, that there is growing concern about the impact of climate change and that Europeans are increasingly likely to take personal actions in response. The personalisation of actions is an important trend, because it considerably strengthens support for government policies. There is a clear support for more public financial support for clean energy, energy efficiency measures, renewable energy targets, for innovation and for active climate diplomacy. And this sentiment is found not only in Europe. A CBC News poll has demonstrated that opinion in the oil-rich province of Alberta (Canada) favour the push towards renewable energy and away from oil and gas. US public opinion supports renewable energy technology promotion and environmental protection over fossil energy extraction[312]. Interestingly support for policies declines when their costs are made explicit.

Climate change has put energy policy and the need for deep decarbonisation at the very centre of the political agenda. Energy policy is a political issue rather than a strictly scientific or economic one. A comprehensive move from fossil fuels to renewable energy sources implies significant structural changes and social consequences in relation to employment, mobility and consumption. Public acceptance is needed not only for the general direction of energy policy, but also for its design, implementation and impact. The 2019 Eurobarometer poll demonstrates that in the shift away from fossil fuels towards renewable energy sources public opinion expects more competitive energy prices for consumers[313]. And this dual trend could be found through the whole survey. The highest priority should be that the EU addresses energy poverty and ensures fair energy transition, and that no citizen or region should be left behind. For the next ten years investment in and the development of clean-energy technologies ought to be prioritized; steps should also to be taken to ensure that energy costs are kept as low as possible. Support for change does not mean that costs do not matter. The transition needs to be cost-efficient. But that is not the only concern of citizens. A recent Norwegian study has found that people feel distant from the energy transition[314]. The concept of energy transition tends to be restricted to the expert level, and for Norwegians there are many negative associations.

Current support for energy transition should not be taken for granted. Citizens should better understand the policies and the challenges related to their implementation. They should better understand the costs related and benefits from implementation. They should feel the ownership of this change.

8.2 Fair transition

The depth and scale of the energy transition will affect each and every household. There are serious arguments in favour of the statement that households with low incomes are affected

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[311] Special Eurobarometer 490, Report Climate Change, April 2019.

[312] Parrish Bergquist et al. Energy policy and public opinion : patterns, trends and future directions, 2020 Prog. Energy 2

[313] Special Eurobarometer 492, Europeans'attitudes on EU energy policy, May 2019

[314] Endre Tvinnreim et al, Who cares about Norway's energy transition?, 2020, Energy Research & Social Science 62(2020)

differently by individual climate policies compared to high-income households[315]. Households have different consumption baskets, different sources and different levels of income, and different borrowing constraints. The policies basically use carbon taxation and standards for fewer GHG emissions and promote new climate friendly products. Both directions are more favourable to households with high-income levels, and distributional levels depending on detailed policy design. Each policy measure should try to minimise any adverse distributional effect. In some cases this will prove difficult and complicate the administration of proposed measures.

The active promotion and use of energy efficiency policies can bring substantial benefits to low-income households. The insulation of house at no cost or very reduced costs will reduce energy usage, say. Lower bills will allow the consumers to pay without any assistance. Special schemes that support low-income households in buying energy efficient energy equipment by giving away their old equipment might also be considered. A one-time investment should allow consumers to receive benefits over several years. Energy efficiency is a best low-cost near-term strategy for GHG mitigation and for fair transition.

The Clean Energy Package (CEP) put a lot of emphasis on empowering consumers. The support for low-income households to participate in demand response schemes or by installing small-scale solar installations could also prove interesting avenues to explore.

Clean, efficient and cheap public transport is another policy that makes low-income households better off relative to high-income households.

Compensating low-income households for any adverse effects of climate policies should seriously be considered. Lump-sum transfers seem better compared with other possible measures like fuel-rate discount or lifeline rates.

Whatever scheme is being used to make the transition fairer, there are criteria to be fulfilled. Benefits should accrue only to low-income households. They should provide for maximum benefits for money spent. The education of eligible households should make them aware how to best use the scheme for their benefit. The schemes should have reasonable administrative and implementation costs. The schemes should not provide incorrect price signals.

Transition should also be fair towards the regions. Some regions will face particularly strong challenges. One of the most affected will be so-called European lignite triangle. Recent study had found out that lignite could be phased out as early as 2032[316]. And the study recognizes that "funding from the Just Transition Fund is key to the success of the lignite exit strategy". The "guided transition" of the most affected regions does not solve all the challenges, but it could provide a good basis for the future prosperity of these areas.

And the same should also be true of the efforts of different Member States. A -55% target for GHG reduction by 2030 compared to the 1990 levels would mean that "Member States with below-average GDP will need to make greater contributions than is currently the case, otherwise there will be no credible pathway to climate neutrality by 2050. These additional efforts should be supported by dedicated solidarity mechanisms" recognises Agora Energiewende[317].

8.3 Consumer protection

Protecting consumers should continue to be high on the European energy agenda. It is estimated that more than 50 million households in the EU experience energy poverty. With increasing

[315] G.Zachmann, G.Fredriksson, G.Clayes, The distributional effects of climate policies, Bruegel, Blueprint series 28, 2018

[316] Forum Energii (2020) Modernising the European lignite triangle.

[317] Agora Energiewende (2020) How to raise Europe's climate ambition for 2030.

electricity use in terms of final consumption the support for energy transition will strongly correlate with the vigorous implementation of consumer protection in the electricity sector.

EU retail markets are governed by national regulatory systems. There is still a high level of concentration in some markets. This means that wholesale price decreases are not necessarily reflected in retail prices. The second electricity directive already required it to be possible for industrial and commercial consumers to freely choose their suppliers from 1 July 2004; while household electricity consumers had to be able to choose their supplier three years later. The third liberalisation package emphasised the provision of electricity as a universal service to households and small enterprises. It allowed the adoption of public-service obligations, not least through a supplier of last resort. The new electricity directive recognizes the possible distortion of regulated prices and requires their gradual removal. Prices should be above costs. The EU is clearly moving towards market-based prices. There is a good reason for thinking that, by the end of the 2020s, there will only be market-based electricity retail pricing in the EU. These developments require active consumers to be better protected by EU legislation.

Each consumer has the right to be connected to the electricity network and to be supplied with electricity. Terms, conditions and tariffs for connections are supervised by the national regulatory authorities.

Each consumer has the right to choose his or her electricity supplier, including suppliers registered in another Member State. Consumers must receive clear information on their energy contracts.

Each consumer has the right to change supplier without extra charges. The network operator must make the change within a maximum of three weeks. By 2026, switching should be carried out within 24 hours.

Each consumer has the right to accurate information on his or her electricity consumption at no additional cost and to billing based on actual consumption.

Each consumer has the right to file a complaint to the supplier and in the event that the complaint is not managed to the customer’s satisfaction the complaint will be sent to an independent body for a prompt, inexpensive and fair out-of-court settlement.

Member States have to define the concept of vulnerable customers in their national legislation. EU legislation provides full flexibility in this respect. The legislation in question suggests that criteria might include: income level; the share of energy expenditure out of disposal income; the energy efficiency of the house; and dependence on electrical equipment for health reasons or age. There should be adequate measures in place to protect consumers. Member States can even prohibit the disconnection from the mains of vulnerable customers. States can also decide to provide benefits from their social security systems to ensure that vulnerable consumers have the necessary levels of electricity supply.

Disconnection from the mains is a last resort which is best avoided. Self-disconnection and self-rationing of energy remains an area of concern. To avoid this phenomenon, improved identification and consistent support for consumers is needed.

National regulatory authorities have identified new challenges. The number of smart meters remotely switched by suppliers from credit to prepayment mode to repay a debt is increasing.

Suppliers should use the remote switching facility fairly in line with their obligations and national regulatory authorities should closely monitor this.

Energy efficiency advice can be very helpful when consumers are trying to reduce their bills. In recent years, more consumers, including consumers in debt, have contacted supplier energy advice lines staffed by qualified energy efficiency advisers. Suppliers should be encouraged to do more to ensure that customers in debt or in arrears benefit from appropriate advice.

Regulation on the Governance of the Energy Union and Climate Action (EU) 2018/1999 requires Member States to assess the number of households in energy poverty when preparing their integrated national energy and climate plans. To make this assessment they need to establish and publish a set of criteria. Member States are free to choose these criteria. The criteria suggested are: low income; expenditure of a large proportion of disposable income on energy; and poor energy efficiency. In principle, Member States need to find to guarantee basic standards of living in relation to energy services. A decent standard of living requires adequate warmth, cooling, lighting and energy to power appliances.

In cases where the assessment indicates a serious problem, Member States must outline, in their plans, policies and measures for addressing energy poverty and a national indicative objective to reduce it.

Encouraging active consumer participation in the electricity market should go hand-in-hand with customer protection. This approach is not new but Member States need to be more ambitious. The Member States or their regulatory authorities must establish relevant indicators to allow for the effective monitoring of developments and for additional steps (when needed).

8.4 How to deal with Nimby

Energy transition requires a great deal of new energy infrastructure. In many cases there is strong opposition from people living in close proximity to planned projects. For instance, wind energy projects and overground power lines are often met by local hostility. The unwillingness of individuals or communities to accept the large-scale projects are mostly related to the conviction that these projects might affect life quality and the value of their property. To describe this phenomenon a negative colloquialism 'Nimby' (Not in my backyard) was coined in the 1970s. At the same time it should be recognised that people need to care about their neighbourhoods.

Without any doubt, infrastructure projects affect people and their assent is needed. Technical and economic arguments are not enough. A more comprehensive approach is required. More education and awareness about the project is helpful, but that will not be enough to guarantee consent from the local community. The only way to achieve that is through stakeholder dialogue, where the grievances of individuals or communities receive proper attention. Information should be relevant to the interests and concerns of those affected by the project. Public consultation quality not quantity is what matters. People are well educated and well connected today. A properly -designed structured dialogue proactively addressing risk and benefit perceptions, the understanding of the situation from the stakeholders perspective is crucial in promoting projects. Increasingly there are high public expectations and these need to be addressed.

Some EU countries are trying to create a general legal framework to get better levels of public support. Germany anticipates stronger financial interests from communities and affected individuals in wind energy projects, also making the distance rules for wind turbines from dwellings more stringent. At the same time measures are being implemented to get more legal certainty in the development of renewable energy projects and in the synchronisation of RES developments with the creation of networks.

The technological approach used in projects could also make a difference. In a many cases the use of cables instead of overground power lines makes a substantial difference for public opinion. It is true that underground cables are more expensive and even then some stakeholder groups are dissatisfied, but the costs of not having the project developed are in, many cases, much higher. Also, cable technology development is advancing and costs are falling.

One of the best strategies for increasing public support is to use the existing infrastructure in the best possible way. The full use of interconnection capacity in the European electricity market will be strongly facilitated by the requirements of the new Electricity Regulation adopted as apart of CEP. But the most important advantages could be achieved by the full use in the energy transition of the existing European gas network, where necessary retrofitting it. Gas for Climate study has found out that in an Optimal Gas scenario, compared to Minimal Gas scenarios, the social cost savings are over EUR 200 billion annually by 2050[318]. Increased use of clean hydrogen and biomethane should be one of the pillars of energy transition.

8.5 Climate diplomacy

Climate change is a global problem and a global response is also needed. Achieving the Paris Agreement has been a major success. Later developments have been less spectacular, but still the process is continuing. Globally synchronised decarbonisation efforts are definitively in the best interests of humanity. That means that the EU and its diplomacy should make massive efforts in achieving new breakthroughs. This is expected not only by Europeans but also by many citizens in other countries. Achieving the goals of the European Green Deal could provide guidance and aspirations for others to follow.

Global public opinion, technological development and sustainable financing are all useful tailwinds for EU climate diplomacy. Global public opinion supports more sustainability in general and stronger mitigation measures against climate change. The growing competitiveness of renewable energy sources provides for their broad use. Most additions to global power generation capacity comes from RES. The financial sector sees huge advantages in sustainability portfolios. A good example is the position of BlackRock, the world's largest investment firm. BlackRock is on record as saying that it will put sustainability at the centre of its investment strategy going forward. Climate risk, according to this logic, is also investment risk.

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[318] Gas for Climate (2020), Gas decarbonisation Pathways 2020-2050

The negative factors influencing climate diplomacy include: populism; the vested interests of fossil fuel producers; and transition costs. Answers to populism should be honest, precise and based on strong information. Populism feeds on negligence and old stereotypes. Social networking today could provide the best tool in limiting populism. For countries and companies depending on fossil fuel extraction and sales diversification is the answer. Some big oil and gas producers are already changing their strategies moving towards cleaner energy supplies: e.g. Shell, BP and ENI. At the country level the UAE stands as a positive example. The reasons for change are not only societal pressures for the "social licence to operate sustainably," but also competition coming from RES. To stay in the growing business of energy supply without structural change is impossible. Similar arguments could also be used about transition costs. Long-term scenarios fail to capture the value of transition in terms of risk mitigation, improved societal satisfaction and increases in competitiveness. Still transformation in the industrial, agricultural and transport sector is challenging. The European Green Deal includes some avenues for how to make the change. Many hopes rest on the production and use of renewable and low-carbon hydrogen. Being ambitious on hydrogen could definitely accelerate the understanding that transition costs are reasonable.

Climate diplomacy has been strongly affected by the COVID-19 pandemic. COP26 is postponed until 2021. Online negotiations are less productive. Slowdowns in economies are delivering a reduction in GHG emissions without structural changes. The risk is that with the restart of the economies GHG emissions will grow strongly. With stimulus packets used in many parts of the world there is a good opportunity for facilitating structural change of all the sectors towards sustainability. The main lesson from COVID-19 is that you cannot isolate yourself from risks. Shutting borders is not enough to stop a virus. Economic slowdowns in one part of the world affect other economies. Climate change is clearly a worse risk: the closure of borders will not work at all there. The only way forward is to master this challenge together. Changes in global health actually gives more chances for climate diplomacy for breakthroughs and more ambitious mitigation frameworks and transparency in monitoring GHG emissions.

Diplomacy always requires allies. Strong allies for climate diplomacy are civil society, and many cities and regions. Other strong allies include small island development states (SIDS). Then, perhaps most important of all there is Africa. This is a continent with 17% of the world population, but only 3% of installed global power generation capacity. A strong partnership in climate change diplomacy and support for the sustainable development of the energy sector in Africa – perhaps under the aegis of the African Union – might make for a global success story.

Annex A: Data collected on hydrogen production levelised costs from the sources examined

Annex A – Table 1: Data on hydrogen production levelised costs for domestic green hydrogen

Domestic green hydrogen	Hydrogen production levelised costs
Today	2.2 – 4.0 EUR/kgH2 *optimistic CAPEX estimates (BloombergNEF, worldwide estimate) 3.0 EUR/kgH2 CAPEX 714 EUR/kW Cost of electricity 34 EUR/MWh Full load hour 48% (IRENA, 2018, worldwide estimate) 2.1 EUR/kgH2 CAPEX 714 EUR/kW Cost of electricity 17 EUR/MWh Full load hour 48% (IRENA, 2018, worldwide estimate) 2.25 EUR/kgH2 CAPEX 714 EUR/kW Cost of electricity 19.6 EUR/MWh Full load hour 48% (IRENA, 2018, worldwide estimate) 2.9 EUR/kgH2 CAPEX 714 EUR/kW Cost of electricity 14.9 EUR/MWh Full load hour 26% (IRENA, 2018, worldwide estimate) 3.7 EUR/kgH2 CAPEX 714 EUR/kW Cost of electricity 46.75 EUR/MWh Full load hour 48% (IRENA, 2018, worldwide estimate) 5.8 EUR/kgH2 CAPEX 714 EUR/kW Cost of electricity 72.25 EUR/MWh Full load hour 26% (IRENA, 2018, worldwide estimate) 2.2 EUR/kgH2 CAPEX 714 EUR/kW Cost of electricity 19.55 EUR/MWh Full load hour 47% (IRENA, 2018, green hydrogen from wind, worldwide lowest estimate) 3.7 EUR/kgH2 CAPEX 714 EUR/kW Cost of electricity 46.75 EUR/MWh Full load hour 34% (IRENA, 2018, green hydrogen from wind, worldwide central estimate)

	4.25 EUR/kgH2 CAPEX 714 EUR/kW (IRENA, 2018, green hydrogen from wind, worldwide upper estimate) 2.8 EUR/kgH2 CAPEX 714 EUR/kW Cost of electricity 15.3 EUR/MWh Full load hour 27% (IRENA, 2018, green hydrogen from solar PV, worldwide lower estimate) 5,1 EUR/kgH2 CAPEX 714 EUR/kW Cost of electricity 72.25 EUR/MWh Full load hour 27% (IRENA, 2018, green hydrogen from solar PV, worldwide central estimate) 5,4 EUR/kgH2 CAPEX 714 EUR/kW (IRENA, 2018, green hydrogen from solar PV, worldwide upper estimate) 2,8 EUR/kgH2 CAPEX 741.2 EUR/kW Real interest rate 8% Cost of electricity 30.6 EUR/MWh Full load hour 34% (IEA, 2019, electrolyser hydrogen, Sustainable Development Scenario) 6,6 EUR/kgH2 CAPEX 741.2 EUR/kW Real interest rate 8% Cost of electricity 98.6 EUR/MWh Full load hour 46% (IEA, 2019, electrolyser hydrogen, Sustainable Development Scenario) CAPEX 425 – 1190 EUR/kW (IEA, worldwide estimate)
2030	1.0 – 2.4 EUR/kgH2 *optimistic CAPEX projection (BloombergNEF, worldwide estimate) 3.6 EUR/kgH2 CAPEX 595 EUR/kW Real interest rate 8% Cost of electricity 40.0 EUR/MWh Full load hour 24% (IEA, green hydrogen, Europe estimate) 3.0 EUR/kgH2 CAPEX 595 EUR/kW Real interest rate 8% Cost of electricity 23.8 EUR/MWh Full load hour 46% (IEA, green hydrogen, Europe estimate) 4.0 EUR/kgH2 CAPEX 595 EUR/kW Real interest rate 8% Cost of electricity 39.95 EUR/MWh Full load hour 23.4%

	(IEA, renewable electricity hydrogen, “near term” estimate for Europe) 2.5 EUR/kgH2 CAPEX 595 EUR/kW Real interest rate 8% Cost of electricity 34 EUR/MWh Full load hour 46% (IEA, green hydrogen, Europe estimate) 2.0 EUR/kgH2 CAPEX 595 EUR/kW Real interest rate 8% Cost of electricity 44.2 EUR/MWh Full load hour 46% (IEA, green hydrogen, Europe estimate) 2.2 EUR/kgH2 CAPEX 374 EUR/kW Cost of electricity 33.15 EUR/MWh (BloombergNEF, green hydrogen from solar PV, worldwide estimate) 1.9 EUR/kgH2 CAPEX 114.75 EUR/kW Cost of electricity 14.4 EUR/MWh (BloombergNEF, green hydrogen from solar PV, worldwide estimate) 1.4 EUR/kgH2 CAPEX 114.75 EUR/kW Cost of electricity 14.4 EUR/MWh (BloombergNEF, green hydrogen from solar PV, worldwide estimate) 1.5 EUR/kgH2 (IRENA, worldwide estimate) 2.7 EUR/kgH2 CAPEX 460 EUR/kW Cost of electricity 72.25 EUR/MWh Full load hour 23% (IRENA, worldwide estimate) 1.55 EUR/kgH2 CAPEX 460 EUR/kW Cost of electricity 17.0 EUR/MWh Full load hour 46% (IRENA, worldwide estimate) 2.4 EUR/kgH2 CAPEX 460 EUR/kW Cost of electricity 46.8 EUR/MWh Full load hour 46% (IRENA, worldwide estimate)
2050	1.2 EUR/kgH2 CAPEX 170 EUR/kW Cost of electricity 17 EUR/MMWh Full load hour 48% (IRENA, 2018, worldwide estimate)

	0.8 EUR/kgH2 CAPEX 314.5 EUR/kW Cost of electricity 9.35 EUR/MWh Full load hour 63% (IRENA, green hydrogen from wind, worldwide lowest estimate) 0.9 EUR/kgH2 CAPEX 314.5 EUR/kW Cost of electricity 19.55 EUR/MWh Full load hour 45% (IRENA, green hydrogen from wind, worldwide central estimate) 1.1 EUR/kgH2 CAPEX 314.5 EUR/kW (IRENA, green hydrogen from wind, worldwide upper estimate) 1.0 EUR/kgH2 CAPEX 314.5 EUR/kW Cost of electricity 3.83 EUR/MWh Full load hour 27% (IRENA, green hydrogen from solar PV, worldwide lowest estimate) 1.7 EUR/kgH2 CAPEX 314.5 EUR/kW Cost of electricity 18.7 EUR/MWh Full load hour 18% (IRENA, green hydrogen from solar PV, worldwide central estimate) 2.2 EUR/kgH2 CAPEX 314.5 EUR/kW (IRENA, green hydrogen from solar PV, worldwide upper estimate) 0.7 - 1.5 EUR/kgH2 *optimistic CAPEX projection (BloombergNEF, worldwide estimate) 0.9 EUR/kgH2 CAPEX 374 EUR/kW Cost of electricity 33.15 EUR/MWh (BloombergNEF, green hydrogen from solar PV, worldwide estimate) 1.3 EUR/kgH2 CAPEX 83 EUR/kW Cost of electricity 14.4 EUR/MWh Cost of storage 0.55 EUR/kgH2 Cost of transport 0.1 EUR/kgH2 (BloombergNEF, green hydrogen from solar PV, worldwide estimate) 0.8 EUR/kgH2 CAPEX 83 EUR/kW Cost of electricity 14.4 EUR/MWh Cost of storage 0.05 EUR/kgH2 Cost of transport 0.1 EUR/kgH2 (BloombergNEF, green hydrogen from solar PV, worldwide estimate) 1.3 EUR/kgH2 CAPEX ? Cost of electricity 34.85 EUR/MWh (BloombergNEF, estimate for green hydrogen from offshore wind in Germany)

	1.1 EUR/kgH2 CAPEX ? Cost of electricity 13.6 EUR/MWh (BloombergNEF, estimate for green hydrogen from solar PV in Germany) 0.8 EUR/kgH2 CAPEX ? Cost of electricity 22.1 EUR/MWh (BloombergNEF, estimate for green hydrogen from onshore wind in Germany) 2.6 EUR/kgH2 CAPEX 382.5 EUR/kW Real interest rate 8% (IEA, long-term green hydrogen estimate for Europe) 1,1 EUR/kgH2 CAPEX 228,7 EUR/kW Real interest rate 8% Cost of electricity 17 EUR/MWh Full load hour 23% (IEA, electrolyser hydrogen, Sustainable Development Scenario) 2,85 EUR/kgH2 CAPEX 228,7 EUR/kW Real interest rate 8% Cost of electricity 51 EUR/MWh Full load hour 34% (IEA, electrolyser hydrogen, Sustainable Development Scenario)

Annex A – Table 2: Data on hydrogen production levelised costs for blue hydrogen from Steam Methane Reforming with CCS

Blue hydrogen from Steam Methane Reforming with CCS	Hydrogen production levelised costs
Today	1.3 EUR/kgH2 CAPEX ? NG price 2.42 EUR/GJ (IRENA, 2018, worldwide estimate) 1.9 EUR/kgH2 CAPEX ? NG price 6.44 EUR/GJ (IRENA, 2018, worldwide estimate) 1.2 EUR/kgH2 CAPEX ? NG price 0.89 EUR/GJ (BloombergNEF, worldwide estimate) 2.5 EUR/kgH2 CAPEX ? NG price 8.30 EUR/GJ (BloombergNEF, worldwide estimate) 1,0 EUR/kgH2 (estimate excluded from average and minimum calculations on the basis of predicted unlikelihood) CAPEX 1345,6 EUR/kW Real interest rate 8% NG price 1,2 EUR/GJ Additional CO2 transport and storage cost 17 EUR/tCO2 (IEA, 2019, SMR + CCS, Sustainable Development Scenario) 1,7 EUR/kgH2 CAPEX 1345,6 EUR/kW Real interest rate 8% NG price 5,4 EUR/GJ Additional CO2 transport and storage cost 17 EUR/tCO2 (IEA, 2019, SMR + CCS, Sustainable Development Scenario)
2030	2.4 EUR/kgH2 CAPEX 1428 EUR/kW Real interest rate 8% NG price 8.86 EUR/GJ Additional CO2 transport and storage cost 17 EUR/tCO2 (IEA, worldwide estimate in the near-term) 1.2 EUR/kgH2 CAPEX 1428 EUR/kW Real interest rate 8% NG price 2.42 EUR/GJ Additional CO2 transport and storage cost 17 EUR/tCO2 (IEA, near-term worldwide estimate) 1.6 EUR/kgH2

	CAPEX ? Real interest rate 8% NG price 4.5 EUR/GJ additional cost of CO2 storage & transport 17 EUR/tCO2 (IEA, Europe estimate) 2.0 EUR/kgH2 CAPEX ? Real interest rate 8% NG price 6.4 EUR/GJ additional cost of CO2 storage & transport 17 EUR/tCO2 (IEA, Europe estimate) 2.4 EUR/kgH2 CAPEX ? Real interest rate 8% NG price 8.4 EUR/GJ additional cost of CO2 storage & transport 17 EUR/tCO2 (IEA, Europe estimate) 2.55 EUR/kgH2 CAPEX ? NG price 8.7 EUR/GJ (BloombergNEF) 1.2 EUR/kgH2 CAPEX ? NG price 0.9 EUR/GJ (BloombergNEF) 1.1 EUR/kgH2 (authors' estimation on the basis of recent and 2050 data)
2050	2.0 EUR/kgH2 *optimistic CAPEX projection(?) NG price 6.4 EUR/GJ Additional CO2 transport and storage cost 17 EUR/tCO2 (IEA, worldwide long-term estimate for import to Europe) 1.0 EUR/kgH2 CAPEX ? Real interest rate 8% NG price 1.62 EUR/GJ (IRENA, worldwide estimate) 2.1 EUR/kgH2 CAPEX ? Real interest rate 8% NG price 4.85 EUR/GJ (IRENA, worldwide estimate) 2.5 EUR/kgH2 CAPEX ? NG price 8.7 EUR/GJ (BloombergNEF) 1.1 EUR/kgH2 CAPEX ? NG price 0.9 EUR/GJ (BloombergNEF)

	2.2 EUR/kgH2 CAPEX ? NG price 7.0 EUR/GJ (bloombergNEF, blue hydrogen production in Germany) 1,0 EUR/kgH2 CAPEX 1089,7 EUR/kW Real interest rate 8% NG price 1,4 EUR/GJ Additional CO2 transport and storage cost 17 EUR/tCO2 (IEA, SMR + CCS, Sustainable Development Scenario) 1,8 EUR/kgH2 CAPEX 1089,7 EUR/kW Real interest rate 8% NG price 5,95 EUR/GJ Additional CO2 transport and storage cost 17 EUR/tCO2 (IEA, SMR + CCS, Sustainable Development Scenario)

Annex A – Table 3: Data on hydrogen production levelised costs for domestic turquoise hydrogen

Domestic turquoise hydrogen	Levelised costs of domestic turquoise hydrogen
Today	
2030	1.26 - 1.50 – 1.52 EUR/kgH2 [319] CAPEX ? NG price 3.4 EUR/GJ Carbon sale price –8.5 : 127.5 EUR/ton (B. Parkinson et al.) 1.5 EUR/kg H2 CAPEX ? Real interest rate 5% [320] NG prices 8.3 EUR/GJ (Gas for Climate) [321]
2050	1.6 EUR/kgH2 CAPEX 1261 EUR/Kw NG prices 5.56 EUR/GJ Carbon sale price 0 EUR/GJ (Poyry) 1.5 EUR/kg H2 CAPEX ? Real interest rate 5% [322] NG prices 8.3 EUR/GJ (Gas for Climate) [321] 0.7 – 1.0 – 1.15 EUR/kgH2 [323] CAPEX ? NG price ? (ThinkStep) [324]

[319] These estimates also account for the value of by-product solid carbon sales.
[320] Additionally, a thirty-year economic lifetime is assumed.
[321] An interesting comment within this report is: “For the economic competitiveness of the technology it is even crucial to find industrial end uses for the carbon, since without income from this by-product, the hydrogen produced is more costly than via SMR or ATR”. In this chapter, we do not consider the value of by-product solid carbon as it affects market value more than costs. “Industry players like Gazprom” predict that they will be able to produce hydrogen at costs of 1.14 EUR/kgH2, “with the upside potential depending on the price received for the carbon”.
[322] Additionally, a thirty-year economic lifetime is assumed.
[323] Min, average and max.
[324] In particular, reference is made to TDM (“thermal decomposition of Methane”) technology.

Annex A – Table 4: Data on hydrogen production levelised costs for imported green hydrogen

Imported green hydrogen	Levelised costs of imported hydrogen
Today	
2030	3.9 EUR/kgH2 transport cost 0.7 EUR/kgH2 (reconversion) (IEA, estimate for import in EU from North Africa through ammonia pipelines)
2050	2.6 EUR/kgH2 (IEA, estimate for import in Europe in long-term) 0.83 EUR/kgH2 Transport costs 0.19 EUR/kgH2 (BloombergNEF, Imports from Algeria through pipeline) 2.76 EUR/kgH2 Transport costs 2.05 EUR/kgH2 (BloombergNEF, Imports from Saudi Arabia through liquified H2 shipping) 5.3 EUR/kgH2 Transport cost 2.6 EUR/kgH2 (liquid hydrogen) (IEA, estimate for import from North Africa into Europe, centralised reconversion) [249] 4.6 EUR/kgH2 Transport cost 1.9 EUR/kgH2 (LOHC) (IEA, estimate for import from North Africa into Europe, centralised reconversion, excluding refuelling station costs) [249] 4.4 EUR/kgH2 Transport cost 1.7 EUR/kgH2 (Ammonia) (IEA, estimate for import from North Africa into Europe, centralised reconversion, excluding refuelling station costs) [249] 4.9 EUR/kgH2 Transport cost 2.2 EUR/kgH2 (liquid hydrogen) (IEA, estimate for import from North Africa into Europe, decentralised reconversion, excluding refuelling station costs) [249] 5.3 EUR/kgH2 Transport cost 2.6 EUR/kgH2 (LOHC) (IEA, estimate for import from North Africa into Europe, decentralised reconversion, excluding refuelling station costs) [249] 4.2 EUR/kgH2 Transport cost 1.15 EUR/kgH2 (Ammonia) (IEA, estimate for import from North Africa into Europe, decentralised reconversion, excluding refuelling station costs) [249]

Annex A – Table 5: Data on hydrogen production levelised costs for imported blue hydrogen

Imported blue hydrogen	Levelised costs of imported blue hydrogen
Today	
2030	3.7 EUR/kgH2 Transport cost 0.8 EUR/kgH2 (ammonia, reconversion costs) (IEA, assumption for import from Russia through ammonia pipelines)
2050	1.45 EUR/kgH2 Transport cost 0.3 EUR/kgH2 (pipeline) (BloombergNEF, assumption for import to Germany from Russia)

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