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Blue hydrogen as an enabler of green hydrogen: the case of Germany

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Preface

As Europe starts to emerge from the COVID-19 crisis and the question of how to re-start ailing economies becomes more urgent, one solution that has been proposed has been investment in technology to encourage the energy transition. Within this context the gas industry faces an existential issue, as it needs to find a role within an energy economy that is set to decarbonise rapidly in order for the EU to meet its net zero emissions target by 2050. One solution that has been proposed both at an EU-level and also, as this paper describes, within some countries is the development of hydrogen as an alternative method for supplying gas.

However, this concept begs a further question – hydrogen generated from what? In an ideal world the answer would be from surplus electricity generated from renewable sources and used to electrolyse water to create hydrogen and oxygen with zero emissions. This "green" hydrogen could provide energy for industrial processes, for power generation (largely as a back-up to renewables when the wind is not blowing or the sun not shining) and even for residential and commercial use. Unfortunately, although this outcome would be perfect in theory, the practical reality is that it is highly unlikely to provide sufficient energy by 2050 to be a viable solution on its own.

This is the key argument discussed by Ralf Dickel in this paper on Germany's hydrogen strategy, which he uses as an excellent case study of the potential future role of hydrogen more broadly. He argues that although the production and consumption of green hydrogen should certainly be a long-term goal, there must be a role for "blue" hydrogen (produced by the reforming of methane into hydrogen plus CO_2) as an enabler of a future hydrogen economy. The technology is already available, CO_2 storage is becoming more viable and the gradual expansion of hydrogen use can allow new infrastructure to be built that can ultimately be used to enable the development of a green hydrogen business. However, without this interim step the aspirations for hydrogen could falter due to unrealistic expectations based on political, rather than commercial and technical, reality.

Ralf Dickel explores the logic behind this debate in a clear and logical fashion in this paper, and we would recommend it to policy-makers, energy companies and interested observers of the European energy market as a thorough and well-argued analysis of the key issues which need to be addressed if hydrogen is to play a major role in the decarbonisation of the European energy economy.

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The contents of this paper do not necessarily represent the views of the OIES or of its sponsors. Despite the contributions of so many people, responsibility for the views expressed and any errors is solely mine.

Ralf Dickel, May 2020

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Executive summary

The German government is pursuing phasing out lignite and hard coal-fired power by 2038 and a policy of strong support for renewables. At the same time, it is drafting a hydrogen strategy, questioning the role of blue hydrogen (from decarbonised natural gas) compared to that of green hydrogen (from renewable power and electrolysis).

Many papers compare blue and green hydrogen on a cost basis, concluding that blue hydrogen has the potential of large-scale CO_2 reduction.[1] This paper – using the case of Germany – argues that developing blue hydrogen is a must, as green hydrogen will not be available in substantial volumes until the power sector is fully decarbonised by renewable electricity, i.e., not before 2040, possibly 2050. Therefore, to decarbonise the non-electric sector expediently, a market switch to hydrogen must be developed based on blue hydrogen with the use of existing technology of steam methane reforming (SMR) and auto-thermal reforming (ATR), as well as CO_2 sequestration, the latter facing substantial opposition in Germany (less so in other littoral states of the North Sea). Starting with blue hydrogen will be essential for timely and deep decarbonisation and will pave the way for green hydrogen to enter the market as soon as it becomes possible.

Chapter 1 gives an overview of the most recent policy decisions and discussion in Germany regarding decarbonisation through phasing out coal and the strategy on hydrogen.

Chapter 2 argues that renewables are best used to decarbonise the power sector, where their decarbonisation effect is at least twice that of their transformation into green hydrogen. Absorbing all renewable power is the target of the German power grid design. Under the current policy, replacing lignite, hard coal and remaining nuclear with renewables for electricity generation will take until 2040. Using the substantial hydro potential of neighbouring countries, mainly Norway, should help fully decarbonise the German power sector by 2050. However, decarbonising the much larger non-electric energy sector by major recourse to renewable electricity does not seem possible ahead of 2050, either in Germany or in the EU (unless renewable electricity is rolled out at rates far in excess of current expectations). Producing significant volumes of green hydrogen would risk eating into the decarbonisation success of the electric sector as well as missing the Paris Agreement targets.

Chapter 3 shows that all elements exist for reducing CO_2 substantially by using blue hydrogen from SMR or ATR with CO_2 sequestration, complemented later by pyrolysis technology, which can cover areas out of reach for steam reforming. The expedient development of CO_2 sequestration capacity, as pioneered by Norway and the Northern Lights project, is critical, with substantial scaling up and replications required.

Chapter 4 discusses the development of H_2 demand and of the necessary supply infrastructure and the best place for conversion from methane to hydrogen. Blending H_2 and CH_4 for transportation is not a solution for the transition to a hydrogen market, it only results in transporting and delivering hydrogen-enriched natural gas.[2] However, this looks different at the distribution level: here the limits for blending should be higher than in the case of high-pressure transmission systems and blending could be adjusted in line with the customers' appliances and could be a step towards building acceptance by the household customer base.

The hydrogen market should therefore develop as insular pure hydrogen markets eventually growing together. Conversion from CH_4 to H_2 is generally best placed at the outlet of the high-pressure gas system feeding into local or regional pure hydrogen distribution systems for large customers and eventually blended systems for household customers. This approach keeps all functions of the high-pressure gas system, maintaining competition and security of supply by an integrated, resilient and diversified gas market and reliability of supply on demand by access to existing storage facilities. It

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[1] CE Delft (2018), "Feasibility study into blue hydrogen," July 2018, p. 43.

[2] Blending is limited at maximum 15-20 vol % of H_2, and separation of H_2 from the blended stream is not available at scale.

allows for the feed-in of intermittent green hydrogen later on and for imports of green hydrogen, which however are not expected on a significant scale before the 2040s.

Chapter 5 looks at the economics of blue hydrogen. The costs of decarbonising natural gas (in the overall order of 50-70 €/t CO_2, of which 10-20 €/t CO_2 is for transportation and sequestration) come on top of the market price for gas. Because decarbonisation is a public good, public institutions have to organise how these costs are to be borne. Germany was and still is supporting the development of renewable technology by amounts clearly exceeding the costs of decarbonisation via blue hydrogen, which is without alternatives for decarbonising the non-electric sector. As decarbonisation of natural gas is not based on essential facilities, it is not an issue of infrastructure regulation but rather of organising a public good (decarbonisation), inclusive of economic support mechanisms. Blue hydrogen mostly relies on developed technologies with a more limited cost-saving potential, and policy should not bet on the cost of blue hydrogen coming down further. Just as with renewable electricity in Germany or for CO_2 sequestration in the US, it should design support mechanisms, which give enough incentive to potential players for a quick rollout of known technology and the development of new technology.[3] Looking at the US might help: taxation rules (IRS 45Q) give a tax credit of 50/t CO_2 sequestered. Germany and the EU risk failing on their promises of decarbonisation but also letting their core industries fall behind the US industries regarding decarbonisation.

Finally, conclusions are drawn as to the hydrogen and decarbonisation policy of the non-electric sector for Germany and the EU.

[3] With technical and economic progress, such support could eventually be reduced.

Chapter 1: Germany's decarbonisation policy and discussion on hydrogen so far

Germany is discussing legislation for phasing out lignite and hard coal-fired power plants, and in parallel, a national hydrogen strategy (*Nationale Wasserstoffstrategie*). Both are in the context of Germany's decarbonisation policy as conceived by the *Energiewende* and later by the country's participation in the Paris Agreement (PA). However, these documents also have to cover other targets: social and regional acceptability of the coal phase-out, industrial and research policy on hydrogen and even foreign aspects of cooperation with developing countries. As fostering renewables in the electric sector was a major success, there is a tendency to project this also onto the potential of the non-electric sector. Proponents of this approach promote the use of additional power by BEVs (battery electric vehicles) and heat pumps at customer level, as well as power-to-X (dealt with in detail in section 2.3.3 a), mainly green hydrogen (produced from renewable electricity by electrolysis), to be fed into the existing gas infrastructure. The contrasting roles of green hydrogen and blue hydrogen (decarbonised natural gas) are a major and controversial point in the inter-ministerial discussion on national hydrogen strategy. The controversy seems to stem from the misapprehension of the real development potential for renewable power generation, as well as from a fear of strong opposition against any sequestration of CO_2, be it in Germany or abroad.

1.1 Implications of the Paris Agreement for Germany as a member of the EU

Germany is part of the Paris Agreement as an EU member, its obligations under the PA come from the European Union's commitments. Germany has a number of its own policy instruments to deal with decarbonisation, including nuclear, renewables and coal policy, as well as research on hydrogen.

In 2010, Germany decided on a policy to achieve an 80-95% reduction of GHG emissions by 2050 compared to 1990 (*Energiewende*). The *Energiewende* gives targets per decade (-40% by 2020; -55% by 2030; -70% by 2040),[4] but unlike the UK policies, it does not refer to GHG emission budgets. The *Energiewende* includes various instruments, amongst them a method of power grid design to integrate renewable power. After Fukushima, it was decided to phase out all nuclear power plants by end 2022, without any change to the targets or instruments of the *Energiewende*.

The backbone of Germany's decarbonisation legislation is the EEG (*Erneuerbare Energie Gesetz*, the law on renewable energy), enacted by the red-green government in 2000 and amended several times, last time in 2017. It addresses the development of financial support for (predominantly electric) renewable energy and its financing via a fee to be paid by power customers (*EEG Umlage*).

In the beginning, feed-in tariffs were a very effective instrument to get renewables going. The set feed-in tariffs – most prominently for PV – were reduced for new applications, reflecting the reduction in costs. Over time, more competition-driven instruments were introduced, such as auctions. To coordinate all elements of the power sector, (volume) corridors were introduced for the development of renewables. Targets valid today are a 65% share of renewables in electricity generation by 2030, and 80% by 2050.

1.2 *De facto* development

The share of renewables in power generation in Germany has reached a respectable 42.1% in 2019,[5] while the share of renewables in non-electric energy consumption in 2018 is only 10% (*see* Graph 4 in Chapter 2). The 22% share of electricity in today's final energy consumption will increase with more electric applications like BEVs and heat pumps. However, substantial parts of final energy consumption (large parts of industry, heavy and long-distance transport, heating in the existing building stock) do not lend themselves to electrification. Carbon-free H_2 is the obvious energy to decarbonise the non-electric energy sector.

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[4] For a full list of the targets of the *Energiewende*, *see* Dickel (2014).
[5] Umwelt Bundesamt (2020).

1.3 Phasing out lignite and hard coal power generation (*Kohleausstiegsgesetz*)

The draft laws related to phasing out lignite and coal-fired power are based on a consensus-driven report of the so-called Coal Commission,[6] presented in January 2019. The Coal Commission was established in 2018, representing the regions and social groups concerned. These draft laws are part of a larger package, which includes elements to mitigate regional and social impacts and gives incentives for new industrial activities based on the recommendation of the Coal Commission.

The phase-out path for lignite (*Stilllegungspfad*)[7] published on 15 January 2020 resulted in an agreement between the Federal Government and the heads of the local (lignite) states on 16 January 2020.[8] The Cabinet draft of 29 January 2020[9] on phasing out lignite and hard coal-fired power[10] (a detailed overview is given in Chapter 2.2) was presented to the parliament on 24 February 2020.[11] It is under discussion by both chambers of parliament (Bundestag and Bundesrat) in parallel via an expedited procedure.

Many detailed environmental, social, regional, as well as legal issues were raised by both chambers of parliament and in public by the associations concerned. It is anticipated that suitable detailed compromises will be found during the ongoing procedures, so that legislation in line with the proposed drafts can be expected by mid-2020.

1.4 Discussion on a national hydrogen strategy

The high level discussion of hydrogen policy in Germany started in mid-2019, following the gas strategy discussion. It was driven by concerns that the country would fall behind Asian states like China, Japan and Korea in a technology where, up until then, Germany considered itself to be the leader.

Germany's hydrogen strategy was announced on 5 November 2019[12] at a large conference aimed at collecting input from all stakeholders. There, Minister of Economic Affairs and Energy Peter Altmaier declared that hydrogen would be needed for decarbonising the non-electric sectors and that it would be blue hydrogen in the immediate future.

The first draft from the Ministry of Economic Affairs and Energy went into inter-ministerial coordination on 29 January 2020. This draft was driven mainly by technology, industrial and research considerations and did not relate to Germany's decarbonisation policy. It addressed both blue and green hydrogen, against the will of the Minister of Environment Svenja Schulze.[13] Shortly thereafter, the Minister of Research Anja Karlizek declared in an interview on 7 February 2020 that the future belonged to green hydrogen only ("*Die Zukunft gehört allein dem grünen Wasserstoff*").[14]

Comments by industry on 9 March 2020[15] encouraging a more ambitious strategy were followed by a summit at the Chancellor's office on 12 March 2020 without further progress. The Cabinet decision planned for 17 March 2020 was postponed *inter alia* due to the lack of agreement on the support for blue hydrogen. The subject was delegated to a task force to deliver results by Easter.[16] However, by the beginning of May 2020, no draft National Hydrogen Strategy had been published and the topic was sidelined by the ongoing COVID-19 crisis.

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6 German Coal Commission (2019).
7 Federal Ministry for Economic Affairs and Energy [Germany] (2020).
8 The Federal Government [Germany] (2020): "Federal/State Agreement on Phasing Out Coal".
9 The Federal Government [Germany] (2020): "Cabinet Passes Coal Phase-Out Law.
10 The Federal Government [Germany] (2020): Draft Law on Phasing Out Coal-Fired Power Generation and to Amend Other Laws (Coal Phase-Out Law.
11 German Parliament (2020).
12 The Federal Government [Germany] (2019).
13 Euractiv (2020.
14 Federal Ministry of Education and Research [Germany] (2020).
15 Energate Messenger (2020).
16 Stahl Business Association (2020).

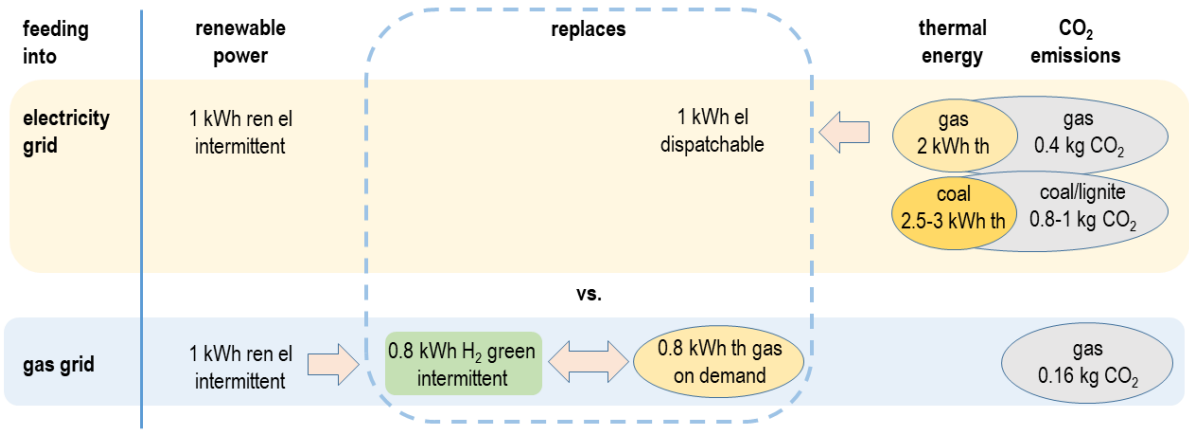
Chapter 2: Renewable electricity is best used to replace thermal power until the power sector is decarbonised

The law of conservation of energy[17] states that energy can neither be created nor destroyed; rather, it can only be transformed or transferred from one form to another. **One kWh renewable can only be used once, either as supply to meet power demand or alternatively to produce hydrogen via an electrolyser.** This chapter argues that the priority use of electric renewables is for decarbonising the power sector, and until that is achieved, little renewable electricity will be left for the production of green hydrogen. Therefore, blue hydrogen produced from natural gas has to be the pioneer in the decades to come, paving the way for the later use of green hydrogen. **A hydrogen strategy has to start with blue hydrogen for the inevitable lack of substantial volumes of green hydrogen in the near future.**

2.1 Any kWh of renewable power is best used in the power market as long as there is any fossil-powered generation remaining

A kWh of renewable power can either be used to replace fossil/thermal power generation or, alternatively, to produce green hydrogen from electrolysis. The GHG saving effect of replacing thermal power is much larger in the former case (*see* Graph 1 below). That is due to the inevitable losses of usable energy of 50% and more in thermal power generation. One kWh of renewable power can replace one kWh electric from thermal generation, where the thermal energy input is at least twice the electric output if produced in a CCGT, and up to 3 times more if produced in a lignite power plant, with the corresponding CO_2 emissions.

Graph 1: Renewable power has the largest CO_2 saving effect when replacing fossil power



Renewable power is best used to reduce fossil-fuel power generation as much as possible. There may be some occasions where surplus renewable power cannot be absorbed by the grid and could be used for green hydrogen, but this will not produce significant quantities of hydrogen. It would not make sense to create dedicated renewable capacity for hydrogen production while significant quantities of fossil fuels are still being used for power generation.

The faster electric renewable capacities are deployed, the earlier comes the point where renewable electricity is available for producing green hydrogen. Additionally, shrinking electricity demand would bring this point about more quickly, while consumption growth would push it back. This applies to all power systems with fossil power generation left, but also to nuclear plants when they reach the time limits of their operating permits.

[17] First proposed and tested by Émilie du Châtelet in 1749.

This would not matter, if time were not of the essence: Germany, like the EU,[18] wants to have a zero-carbon economy by 2050. It is committed to meeting the Paris Agreement target of keeping the temperature increase well below 2°C and undertaking efforts to keep it below 1.5°C, both targets corresponding to a given CO_2 budget.[19] Waiting for renewable power capacity to become available for the production of green hydrogen is not an option if you want to build up a hydrogen economy. Producing green hydrogen instead of using renewables to cover electricity demand would unnecessarily delay decarbonisation and unnecessarily eat into the carbon budget, although, being carbon-free and sustainable, green hydrogen would be the ideal decarbonisation solution. This applies to Germany as well as the EU with its integrated gas and electricity grids and markets. This rationale produces a feasible CO_2 reduction pathway by using decarbonised natural gas (blue hydrogen) instead of a visionary over-reliance on renewables with extreme risks of missing the decarbonisation target.

2.1.1 The German grid is designed to absorb all electric renewables, leaving little surplus for green hydrogen

By law, Germany's power grid has to be planned to absorb all renewable power generation,[20] as defined by government policy.[21] This approach matches the restricted choice of location and the intermittence of renewable power production to the locations and timing of power demand. It is the logical complement to the government policy, where the electricity sector is to be decarbonised by a maximum of renewable electricity generation.[22]

The German NEP 2019 (*Netzentwicklungsplan*, Network Development Plan) includes three scenarios for renewables deployment. The low and high NEP scenarios go to 2030, while the middle scenario B reaches 2035. For 2035, Graph 2 below shows the predominant use of renewables to supply "normal" electricity demand in Scenario B. The share of renewable electricity in gross electricity consumption in scenario B for 2035 is shown to be 74%.[23] This leaves 150 TWh to be generated by what remains of lignite and hard coal plants and a capacity based on natural gas of ca 40 GW.

These figures include some 20 TWh/a each for e-mobility and heat pumps, as well as power-to-X[24] with some flexible volumes for power-to-heat (13 TWh) and power-to-gas (9 TWh). The resulting grid design leaves 7 TWh/a to be regulated down due to demand-related curtailment and another 6 TWh/a to be regulated down due to grid-related curtailment. By 2035, a total of 22 TWh/a is available for power-to-gas (green hydrogen), the equivalent of 2 bcm/a of natural gas. Only small volumes of renewable electricity are left for transformation into green hydrogen until 2035 and beyond.

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[18] The share of renewables in 2019 in the EU as a whole was 36.6%. While EU countries had a higher share of renewables than Germany, even higher than 50%, this was linked to great availability of hydropower in Austria, Croatia, Portugal and Sweden, and for Denmark – a combination of wind and biomass. *See* Agora Energiewende (2020).

[19] A special report by the IPCC showed the severe risk of exceeding 1.5°C: IPCC (2018).

[20] This implies that the power generation is connected to the grid. Off-grid renewable generation so far would be a rare exception.

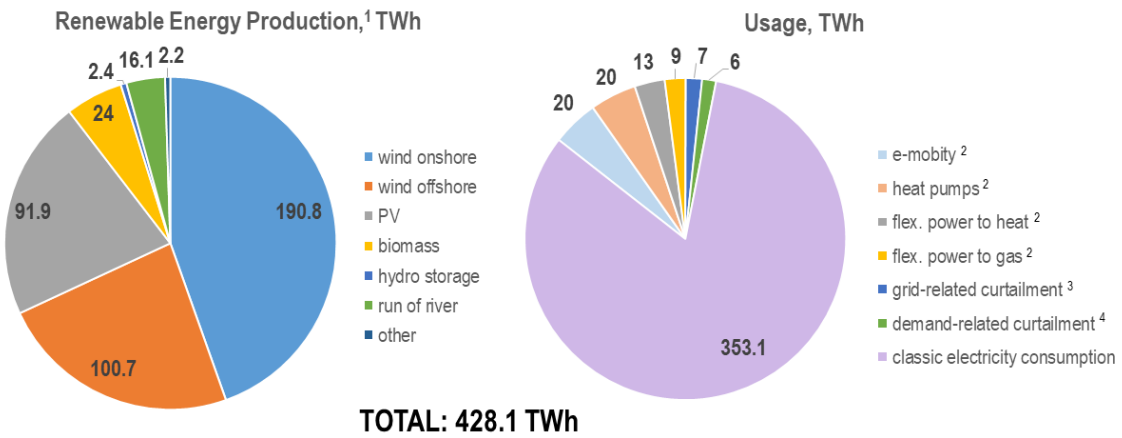
[21] Situations where renewable power generation could not be absorbed by demand in the integrated EU grid have been exceptional so far (*see* below).

[22] More recently, the building of onshore wind was restricted in places where it led to grid bottlenecks. *Außerdem haben wir mit dem neuen EEG geregelt, dass der Ausbau der Windkraft an Land in Gebieten mit Netzengpässen beschränkt wird*. *See* Federal Ministry for Economic Affairs and Energy [Germany]: "Questions and Answers over EEG 2017" (*in German*).

[23] BNetzA (2018).

[24] Corresponding to 4 years of renewable addition, *see below* Section "Build-up of renewables, in more detail".

Graph 2: Renewable power feed-in and usage in 2035



Source: Scenario B 2035 NEP 2030, Version 2019, 2. draft: [1] p. 111; [2] p. 42; [3] p. 113; [4] p. 112

2.1.2 Phasing out nuclear, lignite and hard coal-fired power generation in Germany

Phasing out nuclear

According to the law of 2011,[25] the six nuclear reactors with a total capacity of 8.5 GW remaining in operation today have to be phased out: three by end 2021 and three by end 2022.[26] There is no indication that this would be changed or softened.

Phasing out lignite and hard coal

The past policy of fostering renewables without ensuring the reduction of fossil power generation partially led to some undesirable side effects. Fossil fuel power production was not reduced in view of low marginal costs, but rather placed on the EU electricity market, so German CO_2 emissions from the power sector did not reflect the increase in renewable production. Based on the recommendations of the Coal Commission, on 19 January 2020[27] the German government presented a draft law to phase out lignite-fired power (17 GW) and hard coal-fired power (17 GW) completely by 2038, possibly earlier, by 2035.[28] In more detail:

- By 31 December 2022: 30 GW remaining in total, 15 GW lignite and 15 GW hard coal
- By 1 April 2030: 17 GW remaining in total, 9 GW lignite and 8 GW hard coal
- By 31 December 2038: no lignite nor coal-fired power left.

The reduction in capacity should be spread evenly over 2022-2030 and 2030-2038. There is a fixed scheme naming each lignite power plant to be closed,[29] which will be implemented by public-private agreements for compensation.

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[25] The Federal Government [Germany] (2011).

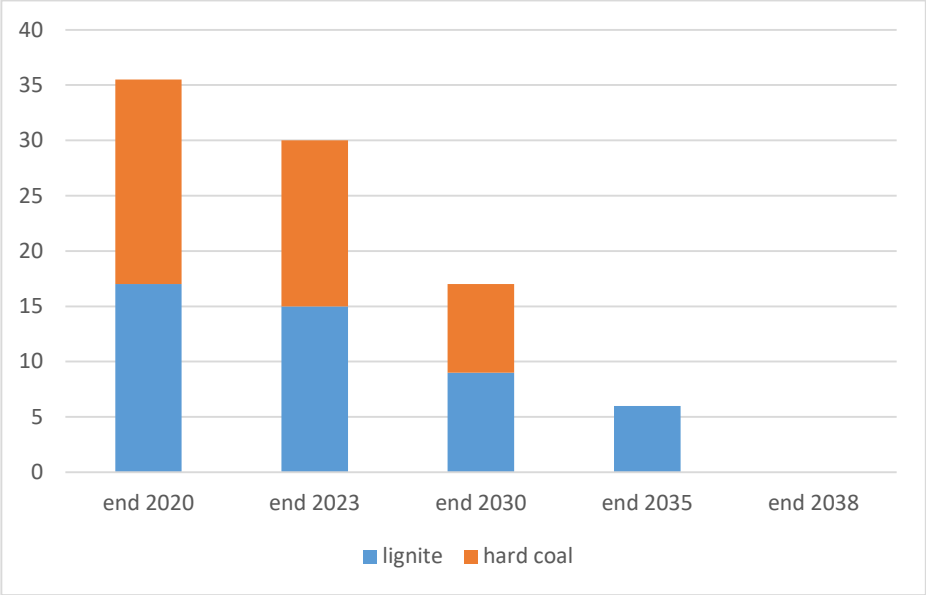
[26] Grohnde 1430 MW, Gundremmingen C 1344 MW and Brokdorf 1480 MW by end 2021; Isar 2 1485 MW, Emsland 1400 MW and Neckarwestheim 2 1400 MW by end 2022.

[27] The Federal Government [Germany] (2020): "Cabinet Passes Coal Phase-Out Law.

[28] The Federal Government [Germany] (2020): Draft Law on Phasing Out Coal-Fired Power Generation and to Amend Other Laws (Coal Phase-Out Law.

[29] The Federal Government [Germany] (2020): Draft Law on Phasing Out Coal-Fired Power Generation and to Amend Other Laws (Coal Phase-Out Law.: pp. 59-60.

Graph 3: Lignite and hard coal power phase-out (GW)



Source: own calculation based on draft law to phase out coal (Kohleausstiegsgestz)

The closure of hard coal-fired power capacity will be determined on an annual basis to achieve the overall closure objectives. The instrument to implement such closures is a bidding procedure until 2023, where operators may bid for compensation limited by a maximum set by law. Between 2024 and 2026, the closures and compensations will take place according to earlier bidding. Should the intended withdrawal capacity not be reached during that period (and after 2026 in any case), closures will be by regulatory order and without compensation.

This draft law and related legislation (mainly on regional and social compensation) is under parallel discussion in both chambers of the German parliament. The discussed modifications mainly concern compensation and the tightening of the phase-out scheme, no withdrawal or principal changes are expected. The intention is to finalise legislation by the beginning of June 2020, though in view of the ongoing COVID-19 crisis a postponement looks likely. In that case, the next possible date (according to parliamentary procedures) would be 18 September 2020.[30]

Replacing thermal power production by renewables

Nuclear was run as base load (with small exceptions) at about 8,000 h/a in the past. So was lignite, with more exceptions (during strong wind phases and low demand), more recently at about 6,000 h/a, while hard coal was run as load following (ca 2,800 h/a). The annual volumes of thermal production to be closed are estimated as follows:

8.5 GW nuclear	x	8000 h/a	=	68.0 TWh/a	(2019: 71 TWh)
17 GW lignite	x	6000 h/a	=	102 TWh/a	(2019: 102 TWh)
17 GW hard coal	x	2800 h/a	=	47.6 TWh/a	(2019: 49 TWh)
Total:				**217.6 TWh/a**	**(2019: 222 TWh)**

In order to replace the closed thermal power generation by renewables, two points need addressing:

(i) Reliable supply of capacity demanded at any time. Capacity available on demand has to manage load following of the difference between demand and intermittent renewable supply, especially during

[30] Energate Messenger (2020): "Corona shakes up coal phase-out schedule.

Dunkelflaute – times with low wind and low sun, typically in winter.[31] This is not discussed here, assuming that enough load following capacity is available from the remaining thermal power of lignite and coal and from gas-fired power, as well as from the flexibility mechanism from the EU electricity markets.

(ii) Providing the overall volumes. Year-on-year production of renewables can vary significantly.[32] The following considerations focus on the annual electricity volumes from renewables on the basis of an average year. Government policy stipulates a share of 65% of renewable power in gross electricity production by 2030, and 80% by 2050.[33] The Law on Renewable Energy (EEG, as amended in 2017) provides clearly defined (volume) corridors for new renewable power capacity.[34]

Build-up of renewables, in more detail

A new law of 2017 dealing especially with offshore wind[35] looks at a capacity increase from 7.5 GW in 2019 to 15 GW in 2030 under a bidding regime for the lowest feed-in fee.[36] Bids are to build offshore wind parks in a number of identified areas in the German EEZ of the North Sea and the Baltic Sea, outside of nature reserves and shipping routes. There is a commitment that all wind parks will be linked to an offshore cable system bringing the power to the grid onshore, which will be built to absorb all renewable energy. Offshore cables with a capacity of 600 MW are in operation in the Baltic Sea and in the North Sea with a capacity of 8000 MW, expansion is in the planning stage.[37]

All new capacity will be auctioned (exemption: citizen's energy companies [38] for wind and for PV under 750 kW):

- Offshore wind: 750 MW on average auctioned per year, to reach overall 15 GW in 2030
- Onshore wind: maximum 2900 MW auctioned per year as of 2020

PV: maximum 2500 MW/a to be built (600 MW with a size over 750 kW to be auctioned; the remainder with a size under 750 kW will be ruled under the old regime, with feed-in tariffs fixed for 20 years at the time of application, following monthly downward cost development).

§28 (3) of the EEG 2018 also foresees volumes of biomass plants to be auctioned: in 2019 – 150 MW, and from 2020 to 2022 – 200 MW annually, open thereafter. Because of the low volumes and the uncertainty after 2023, biomass is not considered here.

The resulting total annual production increase is:

Offshore wind:	750 MW	x	4000 h/a	=	3.0 TWh/a
Onshore wind:	2900 MW	x	2000 h/a	=	5.8 TWh/a
Photovoltaic:	2500 MW	x	800 h/a	=	2.0 TWh/a
Total:					**10.8 TWh/a**

The present government policy results in year-on-year additions of 10.8 TWh/a on average of renewable electricity generation, similar to the average year-on-year increase of 10 TWh/a in annual

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[31] There is no exact definition of *Dunkelflaute* (low sun, low wind); often the *Dunkelflaute* of January 2017 is used as a reference case: from 16 to 25 January 2017 power demand was between 72.8 and 76.0 GW, while supply by renewables (mainly hydro and biomass) was between 7.9 and 13.7 GW. *See* The Bundestag [German Parliament] (2019).

[32] Dickel (2018).

[33] Transmission System Operators (2020) p. 57.

[34] Federal Ministry for Economic Affairs and Energy [Germany] (2017).

[35] The Federal Government [Germany] (2017).

[36] Offshore wind is considered to have a vast potential worldwide. For installed capacity in 2018, Germany is second with 6.2 GW after UK with 8 GW. *See* IEA (2019).

[37] Federal Ministry for Economic Affairs and Energy [Germany]: "Overview of offshore grid connections".

[38] Under EEG § 36 g, special conditions apply to *Bürgerenergiegesellschaften* – citizens' energy companies, allowing associations of citizens to participate in the building of renewable electricity capacity close to their homes.

renewable electricity production from 2010 to 2019. Replacing all thermal power production of 217.6 TWh/a to be closed needs 20 years of adding 10.8 TWh/a annually at the presently envisaged rate.

Even with a year-on-year increase of 15 TWh/a, which was the average increase of renewable production during the last five years (2014-2019), it would take 15 years to replace the phased out nuclear, lignite and hard coal. During that time, only marginal volumes of renewable electricity (surplus power due to lack of demand or small bottlenecks in the grid) would be available for producing green hydrogen in Germany.

A special point is replacing the reduction of nuclear by about 34 TWh/a of alternative production by the end of 2021 and again by the end of 2022. With annual additions of renewables of 10.8 TWh/a, it will take 6 years to compensate for the phased-out nuclear. In the meantime, production has to be provided by extra gas-fired power leading to an increase in CO_2 emissions. At the same time, lignite and hard coal power production is also being phased out and replaced by additional gas-fired power production, leading to a reduction in CO_2 emissions. As a result, it will take about 4 years to come back to the level before the nuclear phase out (see table1).

Table 1: Phase -out of nuclear, lignite and hard coal-fired power by end 2038 and replacement by renewables and gas (schematic)

first full year *	Phasing out capacity			Volume phased out annually at h/a					Volumes covered by		CO_2 emiss. phased out			CO_2	CO_2
	nuclear	lignite	coal**	8000 nuclear	6000 lignite	2800 coal	*sum*	*cum.*	ren. *cum.* at 10.5 TWh/a	fill gap by gas	by lignite	by coal	*cum.*	extra by gas	annual diff.
	GW	GW	GW	TWh/a	TWh/a	TWh/a	TWh/a	TWh/a	TWh/a	TWh/a			Mln t CO_2/a		
2021		0.3			1.8	0.0	1.8	1.8	10.5	-8.7	1.8	0.0	1.8	-3.5	-5.3
2022	4.2	0.9		33.6	5.4	0.0	39.0	40.8	21.0	19.8	5.4	0.0	7.2	7.9	0.7
2023	4.3	1.5	3.2	34.4	9.0	9.0	52.4	93.2	31.5	61.7	9.0	7.2	23.4	24.7	1.3
2024			1.6		0.0	4.5	4.5	97.6	42.0	55.6	0.0	3.6	27.0	22.3	-4.7
2025			1.6		0.0	4.5	4.5	102.1	52.5	49.6	0.0	3.6	30.5	19.8	-10.7
2026		0.8	0.8		4.8	2.2	7.0	109.2	63.0	46.2	4.8	1.8	37.1	18.5	-18.7
2027			1.6		0.0	4.5	4.5	113.6	73.5	40.1	0.0	3.6	40.7	16.1	-24.7
2028		0.5	1.1		3.0	3.1	6.1	119.7	84.0	35.7	3.0	2.5	46.2	14.3	-31.9
2029		1.6			9.6	0.0	9.6	129.3	94.5	34.8	9.6	0.0	55.8	13.9	-41.8
2030		2.8			16.8	0.0	16.8	146.1	105.0	41.1	16.8	0.0	72.6	16.4	-56.1
2031			0.4		0.0	1.1	1.1	147.2	115.5	31.7	0.0	0.9	73.5	12.7	-60.8
2032			2.1		0.0	5.9	5.9	153.1	126.0	27.1	0.0	4.7	78.2	10.8	-67.3
2033			2.1		0.0	5.9	5.9	159.0	136.5	22.5	0.0	4.7	82.9	9.0	-73.9
2034			2.1		0.0	5.9	5.9	164.9	147.0	17.9	0.0	4.7	87.6	7.2	-80.4
2035		0.9	1.2		5.4	3.4	8.8	173.6	157.5	16.1	5.4	2.7	95.7	6.5	-89.2
2036		1.7	0.4		10.2	1.1	11.3	185.0	168.0	17.0	10.2	0.9	106.8	6.8	-100.0
2037			0.3		0.0	0.8	0.8	185.8	178.5	7.3	0.0	0.7	107.4	2.9	-104.5
2038					0.0	0.0	0.0	185.8	189.0	-3.2	0.0	0.0	107.4	-1.3	-108.7
2039		6.0			36.0	0.0	36.0	221.8	199.5	22.3	36.0	0.0	143.4	8.9	-134.5
Total	8.5	17.0	18.5												

* first full year where the power plant is closed in

** determined, resulting in an equal annual withdrawal of lignite and coal capacity

Source: own calculations

2.2 How to decarbonise the load-following power generation?

Even with replacing nuclear, lignite and hard coal, there are still substantial volumes of non-renewable power production left needed for load following based on GTs or CCGTs with natural gas.

The question is how to decarbonise this remaining fossil power generation. Assuming constant net power consumption of 513 TWh/a in 2018 (or a gross power production of 636 TWh in 2018, including exports of ca 10%), a substantial contribution of fossil-fired power of 35% in 2030 and of 20% of gas-fired power in 2050 would still be needed for load balancing.[39] That leaves room for CO_2 reduction. Two approaches seem possible:

i. Decarbonising the GT or CCGT power generation by either post-combustion with CO_2 sequestration, or by using a low-carbon fuel, such as blue or green hydrogen as input, assuming the use of hydrogen in gas turbines will be feasible. Post-combustion CCS is generally considered to be technically and economically difficult, especially with the low load factors resulting from load following. Using green hydrogen, if available, or blue hydrogen in a GT or CCGT would have a maximum efficiency of 50%, compared to higher use efficiency in other sectors, like industry.

ii. Looking for dispatchable renewable power and for storage of electricity. That suggests looking at the potential of using hydropower, if not in Germany, then across the EU plus Switzerland and Norway.

Already today, extensive power trade with neighbouring countries allows the intermittence of German renewable production to be smoothed by trading away power generation surpluses (at times even at negative prices). However, it cannot necessarily provide reliable power supply (e.g., in times of *Dunkelflaute*). There is an asymmetry between bringing surplus power to the EU power market on the one hand, and on the other – having access to enough reliable renewable supply when there is a shortfall in Germany.

Germany's potential for hydropower is limited due to its geography. However, by its integration into the EU power grid and power market, the country is directly or indirectly linked to the hydro potential of the Alps (*see* Table 2 below)[40] or other mountainous areas in the continental EU via its power system grid (UCTE). Of course, these volumes and capacities will be used by all EU countries having access to them via the EU power market to help manage the intermittence of their own renewable power.

Table 2: Hydropower in countries surrounding the Alps

	existing capacity		annual potential	
	without pump	pumped	existing	final
	GW	GW	TWh/a	TWh/a
France	18.2	7.1	54.44	120
Italy	14.6	7.6	45.54	65
Austria	8.1	5.2	37.06	56
Switzerland	11.8	1.8	36.00	41
Germany	4.6	6.8	18.98	25
Total	57.3	28.5	192.02	307

Source: own calculations based on Eurelectric, VGB

An even larger potential lies in Norway and Sweden, which are part of the NORDEL power system, comprising Norway, Sweden, Finland and the eastern islands of Denmark.

[39] 20% of 513 TWh = 102 TWh net, corresponding to ca 110 TWh gross or, if produced in a CCGT, to 20 bcm/a of natural gas.

[40] Eurelectric/VGB (June 2018).

Table 3: Hydropower in Norway and Sweden

	existing capacity		annual potential	
	without pump	pumped	existing	final
	GW	GW	TWh/a	TWh/a
Sweden	16.2	0.1	75.31	130
Norway	29.9	1.4	137.91	300
Total	46.1	1.5	213.22	430

Source: own calculations based on Eurelectric, VGB

So far, the power links between the EU's UCTE and Scandinavia's NORDEL are limited. Between Germany, which is part of UCTE, and the NORDEL system 4 HVDC cables are under construction with a total capacity of ca 3,500 MW.[41] Overall, there are 5 cables existing or under construction between the NORDEL and UCTE systems,[42] plus 3 from Scandinavia to the UK.[43]

A report by Prognos of October 2012 analysed the potential to combine the existing Norway and Sweden hydro system with German renewable power. German surplus power can be consumed in Scandinavia where it withholds hydropower production, and in times of low renewable power supply in Germany corresponding volumes can be released from Scandinavian hydro plants, on balance working like a large hydro storage.

"The cautious initial estimates of this work approach, however, show that the Scandinavian electricity system could contribute significantly to the absorption of surplus electricity and to cover the residual load in Germany."[44] "On the basis of the surpluses on the German electricity market […], there arises in the long term an economic potential for interconnectors between Germany and Scandinavia of at least about 4 GW in business interest requirements of about 18 GW at a macroeconomic analysis."[45]

For example, combining further additional offshore wind in Germany of up to 18 GW with Scandinavian hydro could transform intermittent offshore wind into 18 GW of dispatchable (renewable) power. That, in turn, could replace an annual volume of 18 GW x 4000 h/a = 72 TWh of gas-fired power, otherwise needed for load following. This presumes that overall at least 18 GW of connecting cables between Germany/the UCTE system and the NORDEL system are built.

In addition, Norway may offer a high potential for extra capacity and annual volumes exported to Germany, or more generally, to the UCTE area. Making use of the large additional hydro potential of Norway and Sweden[46] from 213 TWh/a at present to a prospective total of 430 TWh/a would certainly require a further substantial increase of the capacity of connecting cables. It would also have an impact on the inner Scandinavian connecting lines.

From the point of view of sustainable decarbonisation (maybe not from a purely economic viewpoint), it might be reasonable to use the hydropower potential of the EU, Switzerland and Norway to the maximum extent. This would provide additional dispatchable renewable power generation, which could absorb additional intermittent renewable power and thereby reduce the use of GTs and CCGTs after 2050 to a minimum.

Following that approach of further power market integration would absorb several more years of additional renewable power capacity, which then would not be available for green hydrogen. This is the

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41 Statnett, Fingrid, Energinet, Svenska Kraftnät: "Nordic Grid Development Plan 2019", pp. 16-17:

42 *Ibid*., pp. 10, 16, 17.

43 For list of high-voltage links, *see*: https://en.wikipedia.org/wiki/List_of_HVDC_projects#Maps.

44 Prognos (2012) pp. 50-51.

45 *Ibid*., p. 57.

46 Sweden will need some of the potential itself, phasing out its remaining nuclear fleet built in the 1980s. Part of it will be replaced by an ambitious programme for wind energy, but some recourse to hydro will likely be needed. By contrast, Norway is already almost 100% supplied by hydropower.

same underlying approach as for the replacement of lignite and coal-fired power, only that here the phasing in of additional renewable power needs the combination with reliable hydropower.

2.3 Ways to decarbonise the non-electric sector using renewable electricity

2.3.1 Decarbonisation of the power sector by renewables was a success story

Based on the EEG, building up renewable power in Germany with the predominant role of PV and wind has been very successful. In 2019, renewables reached an overall share of 43% in gross electricity generation, and during the first quarter of 2020, they exceeded 50% of gross electricity production due to exceptional weather. The political target of having a share of 65% of renewables in gross power generation by 2030 seems to be feasible even in the case of a larger power demand, so does the official target of 80% for 2050.[47]

2.3.2 Decarbonising the non-electric sector proved to be more difficult

While renewables are successfully decarbonising the power sector, this is not the case for the non-electric sector. Here renewables are mainly limited to firewood, biomass from waste, biodiesel and biogas (*see Dickel (2018).* Purpose-grown biocrops do not look promising: the biomass rate of harvesting the sun per m^2 (i.e., photosynthesis) is only about 10% of PV, though biomass can play a role as a waste product.

Improving energy efficiency and energy saving should be straightforward. In industry, it is a part of the permanent overall cost-minimising efforts. However, in such sectors as residential, commercial and traffic, achieving lasting results has proved problematic, e.g., improvements in house insulation were offset by a tendency to live in larger flats (more m^2 per person), almost negating the overall energy saving effect.[48]

2.3.3 Sector coupling

Sector coupling implies using electricity from renewables to meet the demand of the non-electric sector. Two constellations of sector coupling should be distinguished:

a) Power-to-X, which at the point of production transforms renewable electricity into hydrogen or other gas or liquid fuel, which is then delivered to the final customer. The most prominent example is the production of green hydrogen, which, as demonstrated above, would be a suboptimal contribution to decarbonisation, while renewable power can be used directly in the power market, replacing fossil-fuel power generation.

b) Creating additional power demand, replacing fossil fuels at final customer level, with a view to deliver renewable power later. The two major examples are heat pumps and battery electric vehicles (BEVs).

   Changing from fossil fuels to power appliances tends to imply major disruptions for the customer's everyday life, with practical inconveniences and financial burdens. This is different to the introduction of renewable power generation, which does not change the product delivered to the customer.

The government has many instruments for fostering electric renewables, mainly financially attractive offers for investors, which can be adjusted as necessary. The implementation of renewable projects is also relatively easy to supervise, e.g., through the regulator BNetzA. The case is different for consumer projects: consumer demand is not only a function of economic elements (even though costs, financing

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[47] "*Die für den Szenariorahmenentwurf maßgeblichen langfristigen Ausbauziele für erneuerbare Energien sind durch § 1 EEG 2017 und das aktuelle Klimaschutzprogramm 2030 definiert. Dabei gibt das EEG mit einem Anteil erneuerbarer Energien am Bruttostromverbrauch von mindestens 80 % das langfristige Ziel bis 2050 vor. Das Klimaschutzprogramm 2030 nennt einen Zielanteil von 65 % bis 2030 und geht damit über das aktuell im EEG für 2030 bzw. 2035 genannte Ziel hinaus*". *See* note 33 above.

[48] *See* Dickel (2018) p 11 ff.

and availability of craftsmen certainly play a crucial role), but also of life perspective (older people will be resistant to changes), social situations, like landlord-tenant relationships, etc.

With BEVs, there may be GHG benefits already before power consumption can be attributed to renewable electricity, due to a better ratio between needed primary energy and usable energy output. This comes from the better well-to-wheel efficiency of BEV *vs* ICE cars (e.g., shown at 11-22% for a CNGV as an example of an ICE car *vs* 22-35% for a BEV).[49] That is also true for the mobilisation of environmental heat by heat pumps, depending on ambient temperature resulting in a usage factor[50] of 4, down to 1 at temperatures of minus 15°C.

For BEVs, there is clearly a cost element for most people, but there are also inconveniences such as long loading times, limited reach or problems at low temperature. Installing heat pumps in existing building stock comes with major difficulties and initial financial investment. This is different for new buildings, where heat pumps are a common way to satisfy the zero-energy house requirement needed for a construction permit.

While in many cases BEVs and heat pumps will be better from an energy efficiency point of view, their use does not necessarily translate into better GHG performance, once the alternative is not fossil fuels but decarbonised hydrogen and renewable electricity. In the latter case, one would also have to look at the carbon footprint of each technology, which is still controversial.

Another element to consider is the build-up of new infrastructure. Heat pumps would need a reinforcement of the transmission and distribution electric grid and of available power generation capacity in winter. In comparison, decarbonised hydrogen used for heating would require some adaptation of the local gas grids from methane to hydrogen and changes to the burners or boilers. Similarly, loading stations need to be built for BEVs, also with repercussions for the electricity grid.

85,000 new heat pumps were installed in Germany in 2019, reaching 1 mln in total. This is modest compared to 42 mln dwellings in the country. Similarly, the number of registered BEVs at end 2019 was 239,000[51] compared to 47.7 mln registered ICE cars in Germany.[52]

At an average annual driven distance of 15,000 km/a and 20 kWh per 100 km, one mln BEVs would use 3 TWh/a, while one mln installed heat pumps have already been using about 5 TWh/a. There is a potential of significantly increasing demand for power from BEVs and heat pumps. NEP 2019 includes 20 TWh for each power-to-heat and power-to-BEV, roughly corresponding to 4 mln heat pumps in 2035 (three mln more to go) and some 7 mln BEVs, which appears rather ambitious.

2.4 Comparing the electric and non-electric sectors

Outside power generation, the share of renewables is low and stagnant, being based on firewood for residential and commercial sectors, biowaste in industry and biodiesel in transport, with little prospect for large increases (*see* Dickel, 2018).

In the end, non-electric final energy demand (possibly reduced by energy efficiency, compared to today) decreased by a surge in heat pumps and BEVs has to be provided for by decarbonised green or blue hydrogen. Germany's final energy demand today is split between 22% of electric energy and 78% of non-electric energy.

Even on very optimistic assumptions for energy saving and more power consumption for BEVs and heat pumps from renewable power, a vast amount of hydrogen is needed for the non-electric sector, which cannot be covered by green hydrogen anytime soon. Without decarbonising the non-electric sector, the carbon budget will continue to be used up at a high speed, jeopardising the 1.5°C target.

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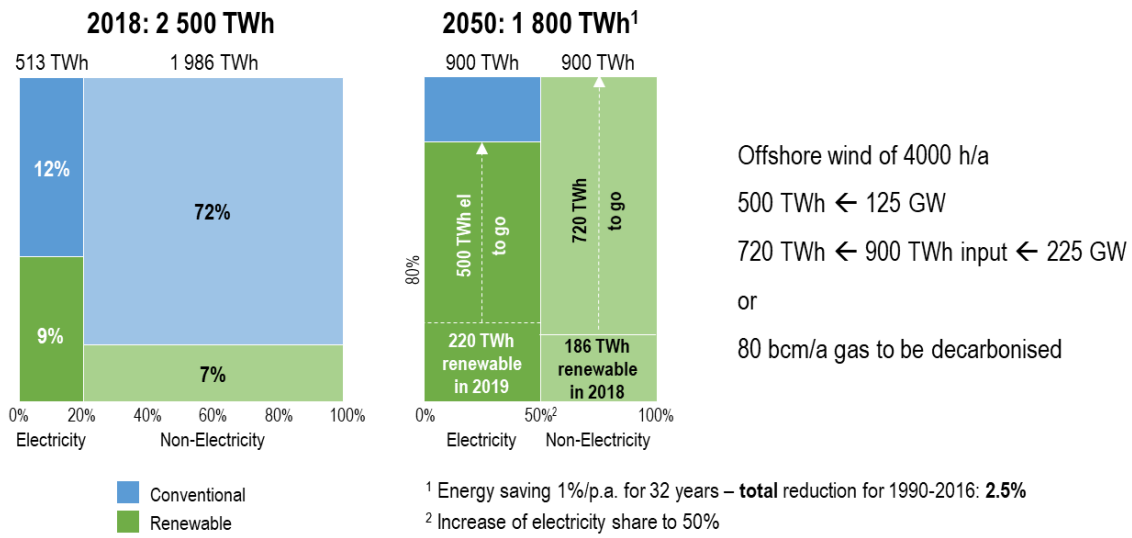
[49] Curran *et al* (2014)
[50] Ratio between consumed electricity and provided heat.
[51] VDA, Association of the Automotive Industry (2019.
[52] VDA, Association of the Automotive Industry (2020).

The left side of Graph 4 below[53] illustrates the share of renewables in Germany's electric and non-electric sectors in 2018 (but showing the 2019 renewables share of 42% in gross power production).

The right side of Graph 4 shows a hypothetical case with an ambitious reduction of final energy consumption by 1% per year until 2050, while in the past, only a 2.5% reduction in total was achieved between 1990 and 2016. The Graph also assumes an increase of the share of electricity in final energy consumption to 50%, corresponding to an increase in absolute numbers from 513 TWh in 2018 to ca 900 TWh in 2050, mainly due to BEVs and heat pumps. To cover 80% of power generation by renewables (still the official target for 2050), an increase of renewable electricity production of 500 TWh/a would be needed between 2018 and 2050. This is ambitious but realistic: the impressive average annual renewable production increase between 2014 and 2019 was 15 TWh/a. That looks feasible, even though it would clearly be beyond presently defined policy.

Graph 4: Share of renewables in final energy consumption in Germany (electric/non-electric): 2018 and vision for 2050



Source: own calculations, EWI

That still leaves 180 TWh el/a (or the input of about 360 TWh/a, or 33 bcm/a of natural gas) for gas-fired power or eventually for decarbonised gas/hydrogen. That would be for load following and as backup production in cases of *Dunkelflaute*. If that should be based on green hydrogen, that would mean 440 TWh/a as input of renewable electricity, given the 20% losses. This is very ambitious, though it might still be possible to achieve by 2050. Much of this gap could be covered through the integration of additional renewables from Germany with the Scandinavian power market.

However, providing green hydrogen for the supply of the non-electric market in addition does not look realistic in view of technical and political restrictions. Producing the missing 720 TWh/a in the non-electric sector from green hydrogen would require 900 TWh/a as input into electrolysers requiring 225 GW of additional wind power at 4000h/a, which is not realistic at all. At the same time, 720 TWh/a as blue hydrogen would require an input of 80 bcm/a (or about 900 TWh/a with conversion losses of about 20%) of natural gas, corresponding to today's gas consumption for conversion in 60 to 80 ATRs: demanding but possible. And without having to wait for the completion of the decarbonisation of the electric sector.

[53] The left-hand side is inspired by a presentation by EWI, on file with the author; the right-hand side by own calculation, presentation.

Chapter 3: Availability of technology for converting natural gas to hydrogen and for CO_2 transportation and sequestration

We have argued that green hydrogen will not be available in substantial volumes to support a hydrogen market any time soon. However, it makes sense to develop the hydrogen market and infrastructure and to test and deploy hydrogen applications based on known technologies, such as steam methane reforming (SMR) or auto-thermal reforming (ATR) – as long as there is no CO_2 disadvantage.

3.1 Two approaches to produce hydrogen from natural gas: steam reforming *vs* pyrolysis

3.1.1 Steam methane reforming or auto-thermal reforming

A hydrogen market could be kick-started by converting CH_4 into H_2 by steam methane reforming or auto-thermal reforming. However, it is necessary to dispose of the resulting volumes of CO_2 as soon as possible to have an early decarbonisation effect.[54]

Steam methane reforming or a similar process, auto-thermal reforming, results in four molecules of H_2 and one molecule of CO_2 from one molecule of CH_4 and two molecules of water, with energy needed for the conversion. In steam methane reformers the energy is added from an external source, while in an auto-thermal reformer the energy needed for the transformation is provided by additional gas input into the process. Both processes can achieve a CO_2 separation of 95% and more.[55] Recent developments focus on ATRs as they need less space and can be tuned to a chosen degree of CO_2 separation up to complete separation, at extra cost. Production from ATRs has good flexibility with a load gradient of 1% of capacity per minute.

Many world-scale SMR/ATR plant are successfully in operation, some units for up to 50 years already. Engineering companies delivering such plants include *inter alia* Thyssen Krupp Industrial Solutions, Linde, Air Liquide. Plant capacity ranges from 10,000 to 200,000 Nm^3/h inlet of natural gas, corresponding to 0.08-1.6 bcm/a. Given the mature status of this technology, it can be assumed that capacities are close to the maximum of economies of scale.

The resulting relatively pure CO_2 needs to be collected and transported to be safely sequestered in geological structures. However, some time will be needed to develop the CO_2 sequestration infrastructure, the necessary rules and regulations, and economic schemes (discussed further below).

3.1.2 Pyrolysis

Pyrolysis splits the CH_4 molecule into two H_2 molecules plus one C molecule with the addition of energy (e.g., in a liquid metal bed or by a plasma or by microwave). It produces carbon as a by-product, which may be used, for instance, for tyre or ink production and in any case can be transported by truck or rail and commercially used or easily deposited onshore without hazard or much cost.

Several pyrolysis technologies are being explored. In Canada, the Kvaerner process aimed at carbon production was applied on an industrial scale in the 1990s but was eventually shut down. Another commercial project driven by carbon production is the Olive Creek Plant in Nebraska, which is due for completion in 2020.[56] Processes targeting the production of hydrogen are at the small pilot stage or even at laboratory stage and involve, for example, a fluid tin bed approach by Wintershall-DEA and KIT[57] or several reactor designs, e.g. at BASF. A small-scale commercial hydrogen production pyrolysis project by Hazer in Australia is supposed to become operational in 2021.[58]

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[54] Based on its chemical composition, 1 bcm of methane (CH_4) = 0.676 mln t plus water, will result in 1 bcm of CO_2 (= 1.98 mln t CO_2) and 4 bcm of H_2. With each bcm of input into steam reforming, roughly 2 mln t CO_2 have to be disposed of.

[55] *See* Table 1 in The Chemical Engineer (2019).

[56] Monolith: https://monolithmaterials.com/olive-creek/project-update-details/.

[57] Karlsruhe Institute of Technology.

[58] Ammonia Energy Association (2020).

Unlike electrolysis, which produces hydrogen from water, or steam reforming, pyrolysis is a dry process, it does not require water. The resulting carbon can be transported by rail or truck, so it does not need a CO_2 pipeline or access to navigable inland waterways. The drawback is that the technology is in its early days and needs substantial scaling up. To get a hydrogen market going and achieve early decarbonisation, pyrolysis will only play a limited role. Once scaled up, it will have comparative advantages where CCUS (carbon capture, utilisation and storage/sequestration) is not applicable for political or geographic reasons.

3.2 CO_2 transportation

CO_2 can be transported as gas in pipelines or as liquid by ship.

3.2.1 CO_2 transportation by pipeline

CO_2 transportation by pipeline is a proven technology, mainly in the US, in the context of using CO_2 for enhanced oil recovery. "Currently, there are more than 6,500 km of CO_2 pipelines worldwide, most of them are linked to EOR operations in the US."[59] So far, there are several disjoint CO_2 transportation systems in the US bringing CO_2 from industrial processes to oilfields for EOR. A strategy for CO_2 reinjection was presented in December 2019 by the National Petroleum Council,[60] which recommended considering the building of 2-3 large trunk lines to collect CO_2 from industrial sources for EOR and sequestration.

In Germany, the construction of CO_2 pipelines is covered by a very restrictive 2012 law on CO_2 storage and transportation,[61] so CO_2 transportation by ship looks like the only realistic option.

3.2.2 CO_2 transportation by ship

"Ship transportation of CO_2 has been taking place for nearly 20 years, although only in small parcels for industrial and alimentary purposes. The existing fleet of four CO_2 carriers are around 1 000 m^3 each. […] The existing ships carry the cargo at 15-20 bara (absolute pressure) and around -30°C. For the larger volumes required for CCS purposes it is likely that the CO_2 will be carried at 7-9 bara and down to around -55°C. This is practically the same cargo condition as that of the significant fleet of Semi-Ref LPG carriers currently in operation. In fact, six such LPG/ethylene carriers of 8-10,000 m^3 in the ownership of IM Skaugen of Norway are approved for the carriage of CO_2. The fleet of Semi-Ref carriers presently engaged in the transportation of hydrocarbon gases number more than 300, with a service record totalling more than 5,000 ship years. This record not only provides a confirmation of operational performance, it means there exists a shipbuilding industry which has extensive experience in the building of such Semi-Ref ships."[62]

Tankers of 1,000 m^3 corresponding to ca 1,800 t CO_2 are within the limit of most navigable waterways in Germany, allowing for inland tanker transportation of liquefied CO_2 from most sites. A standard size ATR plant with an inlet capacity of 1 bcm/a of natural gas and an output of about 2 mln t CO_2/a would need 10 to 15 such ships depending on the roundtrip time to the probable point of sequestration in the North Sea (see chapter 3.2.2). Reloading in Rotterdam to larger tankers of 10,000 m^3 (*see* above) would reduce the number of ships on the Rhine and result in shorter roundtrip times to Rotterdam.

Ships are more flexible for building up the blue hydrogen market, compared to fixed CO_2 pipelines, and they have no principal problems with permitting. Shipping on the Rhine is covered by the Central Commission for Navigation on the Rhine (going back to the 1814 Vienna Congress),[63] which regulates transported goods.

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59 IEAGHG (2014): p. 4.
60 US National Petroleum Council (2019).
61 Federal Law Gazette [Germany] (2012).
62 ZEP, Zero Emissions Platform (2011): pp. 16-17.
63 *See*: https://en.wikipedia.org/wiki/Central_Commission_for_Navigation_on_the_Rhine.

Offshore transportation in the North Sea is regulated by the London Convention of 1972, which has been amended to cover CO_2. However, that amendment has not yet been ratified by all, including Germany.

3.3 CO_2 sequestration

While carbon capture technology is available at large capacities and there are no principal obstacles to building them, the core issue for decarbonising natural gas via SMR/ATR is sequestering large volumes of CO_2 produced as a by-product.

The 2019 Global Status of CCS report[64] gives an overview of all 23 CO_2 sequestration projects in operation worldwide: 19 of them are enhanced oil recovery projects, while Norway's Sleipner and Snoevhit, Algeria's In Salah and Australia's Gorgon are driven directly by CO_2 storage objectives. That suggests looking at EOR first, as the injection of CO_2 generates income, which contributes to covering the costs of CO_2 capture and transportation up to the point where it becomes commercially viable, as in the existing US cases.

3.3.1 Enhanced oil recovery

Principal application worldwide

The 2015 IEA report Storing CO_2 through Enhanced Oil Recovery [65] concludes: "With novel practices it is possible to turn today's EOR from a pure petroleum production tool to a means of storing CO_2 in large quantities – namely *EOR+*. Advancing to a business model in which long-term CO_2 storage is a revenue stream requires a fundamental shift in thinking and operations. It requires that operators re-consider reservoir management practices and operational choices that explicitly incorporate both increased oil production and storing of CO_2 as joint business objectives."

US and Canada

In the US and Canada CO_2 EOR has been in use for a long time in the declining phase of oil fields to enhance recovery by maintaining reservoir pressure and by lowering the viscosity of the oil (when mixed with CO_2). The CO_2 is then recycled from the oil produced. A substantial amount of CO_2 remains in the brine of the reservoir and/or is captured long-term by the formation of the reservoir. In the US and Canada CO_2 EOR is profitable enough to pay for the CO_2 used for injection into the oil reservoir.

According to the IEA, "The United States provides a good example of how policy incentives affect the growth of EOR projects. In the 1980s, faced with the prospect of declining domestic oil production, the Crude Oil Windfall Profit Tax 1980 kick-started the US EOR industry by significantly reducing its tax burden. More recently, the US section 45Q tax credit has been amended to provide a tax reduction of \$35/t CO_2 for 12 years for CO_2 stored in EOR operations."[66]

Potential for CO_2 EOR in the North Sea (UK, Norway)

The North Sea is an oil province in decline, and many fields stand to benefit from EOR. A project in the Gullfaks field needing CO_2 supplies of 5 mln t CO_2/a to yield an additional 18 mln t of oil (130 mln bbl) was investigated in the first decade of this century, but then abandoned *inter alia* for the lack of long-term reliable CO_2 supply.[67]

A report from SINTEF from 2007 on the potential of CO_2 EOR came to the following conclusion: "The storage potential for CO_2 in North Sea oil reservoirs is in the order of two billion tonnes. The EOR potential is estimated at 600 to 700 mln Sm3."[68]

When developing the fields in the Norwegian Continental Shelf (NCS), Norway chose to reinject gas into oil reservoirs for EOR. The North of England report of November 2018 translates gas injection into

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[64] Global CCS Institute (2019) page 23.
[65] IEA (2015).
[66] IEA (2018): "Whatever happened to enhanced oil recovery?".
[67] Researchgate (2019): pp. 7-8.
[68] SINTEF (2007): p. 31.

CO_2 injection: "The annual rate of natural gas injection in all Equinor operated oilfields in the NCS is around 35 Gsm³. Converted to an equivalent mass of CO_2 this would be nearly 65 Mt per year."[69]

For the UK, a 2015 investigation came to the following conclusion: "Oil reserves in the North Sea could potentially be increased by up to 10% by injecting carbon dioxide as part of a miscible gas injection enhanced oil recovery scheme (CO_2-EOR). CO_2-EOR also provides the opportunity to stimulate the development of CCS, reducing the cost of achieving the UK's energy and carbon targets. With some of the best and largest CO_2 storage assets in Europe, the transformation of the North Sea could provide opportunities to manage carbon emissions from neighbouring states over a long period."[70]

The final version of that same report concluded: "For CCS projects the priority is confirming the storage. **For CO_2-EOR it is about securing a CO_2 supply**. [emphasis added] Without sufficient CO_2 supply to enable the recovery of enough oil to cover the additional costs and risks of an EOR project, no projects will come forward. Suitable fields are expected to close by 2030, setting a timeframe for the delivery of CO_2, beyond which field redevelopment will raise costs."[71]

These reports were written before the Paris Agreement and the urgent need for core industries to come up with a CO_2-free strategy to stay in the EU.

In view thereof, the question is what framework is needed to combine 55 mln t CO_2 emitted by the German steel industry in 2017[72] with its potential use for EOR in the North Sea, e.g., 5 mln t CO_2/a for Gullfaks.

3.2.2 CO_2 storage in geological structures

Apart from enhanced oil recovery purposes, CO_2 is not usually injected into oil or gas fields nor into exhausted fields. Contrary to peoples' perception, CO_2 is not injected as a gas but rather as a supercritical fluid above the critical point of pressure and temperature; it is injected into saline aquifers, where it dissolves in salt water.

Sequestering CO_2 in geological structures can be organised similarly to oil and gas production, with a licensing regime for qualified companies under supervision of a public authority like the NPD in Norway. The difference is that so far there is no global price nor market for CO_2 as there is for oil or gas, and the income from engaging in CO_2 sequestration is derived from providing a public good and not from a global market like for oil or gas.

CO_2 sequestration in geological structures has been practised on a large scale in Sleipner (start 1996) and Snoevhit (start 2011) in Norway, in In Salah (start 2004) in Algeria and since 2019, in Gorgon offshore Australia. In each of these cases, carbon sequestration is part of gas production projects and is triggered by CO_2 content exceeding the spec for delivered gas and a standard or strong penalty to avoid venting CO_2. Therefore, CO_2 from CO_2-rich reservoirs is injected into geological structures to meet the gas spec.

The CO_2 Atlas for the Norwegian Shelf shows a potential of 70 Gt for CO_2 sequestration for the North Sea part.[73] The North Sea is not the only place with carbon sequestration potential in and around the EU, however, it is the best investigated area due to the pioneer roles of Norway and the UK. With the existing infrastructure and geological knowledge from 5 decades of oil and gas production, it is the obvious place to look at and to start with.

The Northern Lights project

The Northern Lights project currently under development in Norway is dedicated directly to CO_2 sequestration, with 1.5 and 5 mln t CO_2/a sequestration in its first and second phase, respectively. It is

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69 H21 North of England (2018): p. 345.
70 Energy Research Partnership (2015): "Prospects for CO_2-EOR in the UKCS – DRAFT".
71 Energy Research Partnership (2015).
72 Umwelt Bundesamt (2019).
73 Norwegian Petroleum Directorate (2019): "CO_2 storage Atlas Norwegian North Sea".

driven by the need to dispose of the CO_2 from all kinds of sources in order to have CO_2-free energy or dispose of the CO_2 from industrial processes.

The project has followed the procedures usual for licencing oil and gas projects in Norway: the NPD has stipulated the relevant regulation for CO_2 handling[74] and there was a licensing round in 2018, the first to license an area for CO_2 sequestration. The only participant was a consortium of Statoil, Shell and Total.[75] The first wildcat well was successfully completed in March 2020 to prove the suitability of the targeted formation for CO_2 disposal.[76]

The Northern Lights project of Equinor (formerly Statoil), Shell and Total uses technology similar to Sleipner's.[77] The difference is that it is based on injecting CO_2 coming from pre- or post-combustion of fossil fuels or from processes such as cement production. So the project's economic driver is not oil or gas production, but CO_2 sequestration. "The full-scale CCS Project in Norway is one of the first industrial CCS projects to develop an open-access infrastructure with the intent and the capacity to store significant volumes of CO_2 from across the European continent."[78]

3.4 Germany

According to Germany's Federal Institute for Geosciences and Natural Resources, the country has a CO_2 sequestration potential of 20 Gt +/- 8 Gt.[79]

The unfortunate public association of CO_2 disposal with the disposal of highly radioactive waste – an extremely contentious topic in Germany – has led to strong political resistance to carbon sequestration. All activities for the transportation and storage of CO_2 were *de facto* blocked by law as of 1 December 2016 (meaning today: no projects). Implementation is in the hands of the local states (*Länder*).

However, in 2019, Chancellor Merkel was pondering the necessity of CO_2 storage,[80] reopening the debate in view of the industry's need for decarbonisation lacking an electric solution (e.g., steel, cement). This would require a major political discussion, which would have to overcome the public's irrational apprehensive attitude towards CO_2 disposal, within or outside Germany. Such a discussion would have to cover decarbonisation issues together with approaches to future-proofing industry and its jobs.

Obviously, sequestration capacity exceeding that of the Northern Lights project would be needed, the sooner the better. While all technology elements are available, decarbonising natural gas at the scale of Germany's gas industry would be a substantial challenge. To illustrate, the German industry consumes 370 TWh/a, or 35 bcm/a of natural gas. That results in emitting roughly 70 mln t CO_2/a, exceeding by far the capacity envisaged for the Northern Lights project. At this same time, sequestering such volumes looks feasible within the overall potential of the Norwegian North Sea, estimated by the NPD at 70 Gt CO_2.[81] Upscaling and/or multiplying the Northern Lights scheme could be achieved by more licensing rounds for carbon sequestration projects (and CO_2 EOR projects). While other North Sea littoral states like the UK, the Netherlands and Denmark have a large potential for sequestration of CO_2 too and no strong resistance against using it, Norway is most advanced, having established a licensing regime for sequestering CO_2.

It is necessary to clarify Germany's legal framework to remove obstacles to exporting CO_2 to Norway and other North Sea littoral states. An economic framework is needed on the German/EU side, which

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74 Norwegian Petroleum Directorate (2019): "Regulations".
75 Norwegian Petroleum Directorate (2018).
76 Norwegian Petroleum Directorate (2020).
77 In Sleipner, CO_2 is a by-product specific to a single reservoir with a high CO_2 content, which should not be released into the atmosphere.
78 CCS Norway: "Full-scale: capture, transport and storage": https://ccsnorway.com/full-scale-capture-transport-and-storage.
79 German Federal Institute for Geosciences and Natural Resources (2010) p. 76 (*in German*).
80 Süddeutsche Zeitung (2019).
81 Norwegian Petroleum Directorate (2019): "CO_2 storage Atlas Norwegian North Sea".

would allow earning money on CO_2 handling and sequestration. Direct and indirect pricing of CO_2 emissions and some dedicated tax relief is needed to attract the right players, such as oil and gas companies, to become involved in the CO_2 removal chain.

For Germany, which wants to retain its steel and chemical industry as core competence clusters in a decarbonised world, CO_2 sequestration might work politically if it takes place initially in the North Sea. And if there is a public understanding that green hydrogen will not be able to come in time for the country to meet its decarbonisation targets and that blue hydrogen can provide a pathway for green hydrogen in the longer term.

Chapter 4: Development of demand, infrastructure and best place for conversion

The development of a hydrogen economy should be driven by demand. Many studies look at a cost-optimal model at a future point in time, especially for 2050, without analysing how to attain it. But how an effective and expedient transition to a hydrogen economy can be achieved in practice is important, particularly in view of the risks of not meeting the decarbonisation targets.[82]

4.1 Demand

The demand for hydrogen from decarbonised gas does not come from the market, but is a consequence of demand for the public good of decarbonisation. Clearly, the price for decarbonised hydrogen will be higher than the market price for gas, at least by the costs of converting CH_4 to H_2 plus the costs of disposing of the resulting CO_2. The demand could be either for hydrogen as feedstock, e.g., for ammonia, but also for the reduction of iron ore; or as energy from a carbon-free molecule replacing the existing demand for hydrocarbons.

4.1.1 What sequence?

A proven pattern for developing a market is to start with large-volume anchor customers with high load factors. That would justify investment into a basic hydrogen infrastructure, which would be expanded subsequently to smaller-volume customers and customers with lower load factors.

That would suggest starting with heavy industry (such as steel, refineries, chemicals) and then moving on to smaller industries, which could be reached by the basic infrastructure. Heavy-load and long-distance traffic by truck and rail with central distribution points could also be handled at this stage. Finally, municipalities with heating demand and high seasonality could be switched to hydrogen. Industry with high demand could trigger the construction of an SMR/ATR plant with some local H_2 systems (new or repurposed), tying in further industry demand. It should be noted that such systems require hydrogen storage for several days of production to back up the performance of the conversion plant (99%).

4.1.2 At what speed?

Demand for hydrogen is driven by individual local factors. However, decarbonisation – the reason for using hydrogen except as a feedstock – is a public good, for which there is no demand by individual market participants. Demand development for (decarbonised) hydrogen will strongly depend on the decarbonisation policy creating incentives and/or penalties, which would make carbon-free hydrogen economically viable. At the same time, investors must be attracted on the supply side, able and willing to organise the new blue hydrogen chain.

4.2 H_2 supply to meet demand?

Several industrial customers which can serve as anchor customers in the steel and chemical industry have an individual hydrogen demand in the order of up to 1 bcm/a of natural gas. Growing a hydrogen market requires building a corresponding SMR/ATR decarbonisation capacity based on natural gas supply from the integrated EU gas market. Gas supply should not be a volume issue, but rather a pricing and contracting issue to guarantee long-term supply for a heavy investment project.

SMR/ATR plants come at natural gas inlet capacity of 0.5-1.5 bcm/a. While it may start without CO_2 disposal, corresponding CO_2 transportation and disposal capacity (unless applying pyrolysis) should be organised as soon as possible. CO_2 transportation capacity by ship is flexible and the planned CO_2 sequestration of the Northern Lights project is 1.5 and 5 mln t CO_2 in the first and second phase, respectively.

The volume of gas input into an SMR/ATR plant (1 bcm/a) is small compared to the capacity of a gas import pipeline or a major domestic trunk line with 15-30 bcm/a. By comparison, the German industry throughout the whole country consumes 370 TWh/a, or 35 bcm/a of natural gas, with major industrial

[82] For such a risk assessment, *see* Pöyry (2019}, p. 2.

agglomerations along the Rhine river and its contributories (Rhine Ruhr area, Rhine Main area, area of Mannheim-Ludwigshafen , and the Saar region) , which could switch to hydrogen successively. The capacity steps of building SMR or ATR plants (1 bcm/a of natural gas input results in ca 1.9 mln t CO_2) are more in line with the stages of CO_2 sequestration of the Northern Lights project (1.5/5 mln t CO_2/a for the first/second phase). While SMR/ATR plants could be built in line with local demand development, the decarbonisation effect would only come with the creation of corresponding sequestration capacity.

4.3 Transition from CH_4 to H_2 by blending or by dedicated 100% hydrogen systems?

4.3.1 Blending does not deliver hydrogen but just a gas with a modest share of hydrogen

The idea of blending seems to be based on the wish to dispose of surplus renewable electricity transformed into hydrogen by electrolysis, possibly driven by a vision of building up a hydrogen market by gradually increasing the share of hydrogen. As the Wobbe index[83] of hydrogen is close to that of natural gas, the energy throughput capacity of a natural gas pipeline is reduced only by 10-20% when using hydrogen with the same pressure drop. However, this would not serve hydrogen demand as long as it is not possible to separate the hydrogen from the gas stream at the exit on an industrial scale. Downstream extraction of H_2 is not applied on any substantial scale and is expensive in any case.[84]

Limits of blending

Nor would blending contribute to decarbonisation in any meaningful way, since blending H_2 with CH_4 has narrow limits. It is generally accepted that natural gas-consuming devices and pipeline operation are safe with up to 5-15% of H_2 content.[85] These limitations also apply to pipeline compressors and gas storages, which are typically driven by gas turbines. Hydrogen blending increases the risks of embrittlement. It may require new certification, ending up with lower operating pressure and lower capacity of the pipeline.

Hydrogen needs different compressors than natural gas centrifugal compressors and a different drive: "hydrogen is a compressible gas, but because of the small molecular mass, centrifugal designs are not ideal, as they need to operate at tip speeds three times faster than those of natural gas compressors to achieve the same compression ratio."[86] With increasing amounts of hydrogen in the mix (the limit being also at about 20%), the capacity of using the existing centrifugal compression will decrease for reasons of hydrology to a point where replacing the compressors and their drives would become necessary.

Hydrogen concentration also has an effect on storage capacity, as the latter is proportionate to the calorific value of the gas stored, which for hydrogen is about a third of that of methane. It is worth noting that while using H_2 in salt caverns is not considered problematic, the possibility of storing natural gas blended with H_2 in porous storage is not yet clear. The first field test did not see problems with a mix of 10% hydrogen.[87]

Distribution in Germany is carried out via middle and low-pressure systems with less than 1 bar overpressure. Maintaining that pressure allows gas to be taken out at a variety of points, without

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[83] The (upper or lower) Wobbe Index is the upper or lower heating value of a gas divided by the square root of the relative density of that gas relative to ambient air. Everything else being equal, the energy transportation capacity by pipeline is proportionate to the Wobbe index of the gas transported. The index also characterises the combustion properties of gases in burners. In Europe, the Wobbe index is the leading parameter for gas system designs. The Wobbe index also reflects the speed at which the gas is flowing. As hydrogen has a flow speed of about 3 times that of methane, the lower calorific value of hydrogen compared to methane is almost compensated.

[84] NREL (2013), pp. Xi-Xii.

[85] *Ibid*., p. v: "If implemented with relatively low concentrations, less than 5-15% hydrogen by volume, this strategy of storing and delivering renewable energy to markets appears to be viable without significantly increasing risks associated with utilisation of the gas blend in end-use devices (such as household appliances), overall public safety, or the durability and integrity of the existing natural gas pipeline network. However, the appropriate blend concentration may vary significantly between pipeline network systems and natural gas compositions and must therefore be assessed on a case-by-case basis."

[86] The Chemical Engineer (2020).

[87] Underground Sun Storage project (2017) pp. 21-22.

dedicated gas flows, unlike in the transmission system. Therefore, the limits of blending at distribution level would not be affected by hydraulics considerations, only by embrittlement prevention and the specs of consumers' appliances.

All of these issues would have to be coordinated from the entry point and all the way to all exits/customers, and with all downstream countries in the case of transit.

Conclusion on blending

Blending would have merits at the distribution level, to gain experience and to win acceptance by the customer base. But it would not help to create a national hydrogen transportation system. Increasing the hydrogen content in the gas mix beyond 20% would run into major difficulties, meaning that the present high-pressure grid could not be operated without major changes. Coherent rules would be needed for all stages of the gas industry and its customers in Germany. Those rules would also need to be coordinated with Germany's upstream and downstream neighbouring countries. This appears to be overly complicated, expensive and highly inefficient, since the blend of, e.g., 15% of carbon-free hydrogen results in just a 5% carbon-free energy content – a very modest outcome for the effort required. And it would not open the door for any hydrogen sector development.

4.4 Location of conversion

As blending does not open the way to a hydrogen economy, systems with pure hydrogen have to be built. This raises the question about the location of the conversion and how much energy should be transported as natural gas or as hydrogen; and how to dispose of the CO_2 resulting from SMR/ATR (unless pyrolysis is used, which is still in the development stage).

Blue hydrogen must be produced by conversion somewhere along the chain, typically either: (i) close to the wellhead in view of geological structures available for CO_2 sequestration, or (ii) at the landing point, i.e., as far upstream as possible under the control of the importing country, or (iii) close to the customer at the exit point of the high-pressure system.

Methane is a very potent greenhouse gas, while hydrogen has no direct GHG effects. An argument could be made to convert natural gas as far upstream as possible, to avoid methane leakage along the gas chain. However, methane leakage is not a given, nor is it much of a cost issue, since the recouped methane has a value; rather, it is a management issue. It can be avoided by organising methane surveys on the ground and from the air, and taking adequate action where leakage is discovered. The income from the methane saved will often pay for the leakage prevention. Waiting for upstream conversion from methane to hydrogen instead of taking straightforward management measures would unnecessarily postpone the reduction of methane leakage.

The choice of location may be subject to specific circumstances (*see* cases of the Netherlands and the UK below), but in general, hydrogen market development favours having the conversion close to the customer, provided there is an associated CO_2 sequestration route or pyrolysis without CO_2 emissions can be applied.

4.4.1 Upstream of the EU vs inside the EU

The EU gas infrastructure works well as an integrated market, allowing for supply competition, demand-side responses, ensuring security of supply and reliability of supply on demand by having enough storage capacity and volume to cover seasonal variations and interruptions. Why give that up by locating the decarbonisation process in a country outside the EU? Until there is a global market for hydrogen, it appears unreasonable to hope for the producers to decarbonise their gas and not pass on the costs for a marked-up product.

Locating the conversion upstream of the EU has its advantages: the geological structures close to natural gas production would be available for the resulting CO_2 sequestration. Also, any political difficulties linked to CO_2 sequestration would be left to the gas producing countries. However, with decarbonisation upstream of the EU border, security of supply would not only depend on supply of natural gas but also on the reliability of the conversion process. The risk of technical performance of the conversion process is best managed inside the EU.

Natural gas can be used in almost any place in Germany due to the dense gas infrastructure. This would not necessarily be the case anytime soon with an H_2 transmission structure built on hydrogen imports. Dedicating a pipeline to hydrogen with an import capacity corresponding to 10-25 bcm/a of natural gas would require a large number of SMR/ATR plants upstream and long-distance transportation of large volumes of hydrogen. While the German hydrogen market is being developed, such an upstream pipeline would be underutilised. Therefore, conversion would be better placed inside the EU.

Imports of CO_2-free hydrogen not economically attractive any time soon

In general, for other EU countries the situation is similar to Germany's: most have a large share of fossil fuel-based power generation and/or nuclear, which will come to the end of its lifetime sooner or later. Apart from the power exchange happening via the EU power market, there is little reason why other countries should produce green hydrogen for export to Germany, as they would better use any additional renewable power for their own or the EU electricity market. A similar argument holds for countries with increasing power demand, such as emerging economies.

Pipeline imports of CO_2-free hydrogen into the EU would have to come from current natural gas exporters: Norway, Russia, North Africa and the Middle East. However, there is no clear reason why they should undermine the commercialisation of their gas exports, no matter how large their renewable production potential (wind in Norway and Russia, PV in North Africa and the Middle East).

Even if hydrogen production with renewable power becomes competitive, long-distance hydrogen imports may be possible in principle, but in practice this is unchartered territory. The main concern for pipelines is embrittlement, as well as hydrogen-induced cracking in welds and joints.[88] On the compression side, there are challenges as well: standard centrifugal compressors used for natural gas would not work for hydrogen, which would require piston compressors driven by reciprocating engines. Moreover, the capacity needed for the drive would be about three times that required for natural gas for the same energy flow, since compressors operate on the basis of volume rather than energy content.[89]

Transporting hydrogen by ship would not be any easier. There are three approaches: transporting H_2 in the form of ammonia, via an LOHC (liquefied organic hydrogen carrier) or by tanker as liquefied hydrogen (LH_2). Transportation of ammonia by ship is state of the art but the ammonia then has to be reconverted to hydrogen. The first cargo of hydrogen transported via an LOHC has been successfully unloaded just in April 2020, and the first LH_2 tanker is under construction to become operational in 2021.

The IEA in a projection for 2040 estimates the costs of H_2 transportation by ship alone for Australia-Japan (which is a shipping distance similar to that from Yanbu, Port Said or Lagos to Hamburg) at between 2.5 and 2.8 $(2017)/kg H_2. This compares with hydrogen production costs of 2.2 $(2017)/kg H_2 when using SMR with CCUS.[90] The H_2 shipping technology is still in the early stages of development, and cost projections for transportation alone do not look favourable for importing H_2 by ship, not to mention the political uncertainties for investors and customers. Still, there is a risk that H_2 imports could be used as a *deus ex machina* in the debate on Germany's decarbonisation options in order to avoid dealing with difficult or controversial political points.

4.4.2 Decarbonisation within the EU: place of conversion upstream in the high-pressure system vs exit of the high-pressure system

To cover the developing demand for hydrogen, SMR or ATR capacity has to be developed in step. Hydrogen systems must grow with the market development and not impede it. Time and effectiveness are of the essence, cost optimisation is secondary. H_2 supply has to be by new or repurposed dedicated H_2 pipelines from the conversion point to the customers. At the same time, the existing gas infrastructure

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[88] Argonne National Laboratory (2007): p. 4.
[89] *Ibid*., p. 5.
[90] IEA (2018): "World Energy Outlook 2018", OECD/IEA) p. 510.

needs to be maintained for supply to the conversion plants and to the not yet converted parts of the market.

As mentioned earlier, with SMR/ATR upstream, there are no economies of scale as this is a mature technology and the plants' maximum size is well below the capacity of export/import pipelines. The total waste heat could hardly be used at the input points. The main argument could be that conversion at the coastline gives direct access to sea transport and offshore sequestration. As far as transportation by CO_2 tankers is concerned, costs are not that much distance-dependent,[91] and smaller CO_2 tankers of up to 2,000 t could be built to operate both on sea and on the Rhine.

A centralised upstream approach would require a coordinated switch of large enough regions to absorb the energy stream from hydrogen corresponding to a large import pipeline or large national transmission lines (in the order of 15+ bcm/a). Conversion of supply in the area served by the converted pipeline must happen synchronously, otherwise major parts of the chain up to the wellhead would be underutilised. Maintaining the reliability of energy supply requires two pipelines with spare capacity during the transition, and the methane pipeline falling idle after the conversion is finalised.

The UK and the Netherlands have well advanced projects to introduce hydrogen. Neither is considering blending for the high-pressure grid, rather both intend to build new or rededicate existing transmission pipelines for hydrogen-only transportation.

The Netherlands: L-gas export lines falling idle

The Dutch L-gas export system is falling idle due to the closing of gas production from Groningen. That part of the system could be used to build up a hydrogen market in the area at low cost, with the decarbonisation process close to the point of CO_2 disposal (e.g., the North Sea coastline). Supply to the regions to be converted could be assured by the existing parallel H-gas pipelines without any loss of reliability. There are several obstacles to conversion, such as the flow speed of hydrogen exceeding the approved pipeline standard, new compression needed and hydrogen so far being classified as a chemical, with implications for its risk assessment.

A Dutch feasibility study[92] into blue hydrogen analyses conversion *vs* new-built infrastructure in the Netherlands and concludes *inter alia* that the costs of conversion are estimated to be between 5-30% of building new infrastructure. At the same time, the study recognises that a newly built hydrogen network would enable a smoother transition for industrial consumers. It also notes: "policy decisions have to be made on the characteristics of the grid, such as the design of the hydrogen grid including decision on the basis of the grid, and the hydrogen purity."[93]

However, for Germany the L-gas system is not an export system falling idle but rather a supply system, which has to be converted from L- to H-gas. The German NEP[94] is designed to leave as little as possible spare capacity in the system, i.e., even where there are parallel pipelines the capacity of both is needed.

Building a new hydrogen system in Northern England[95]

The H21 North of England project envisages switching to hydrogen for all gas customers in Northern England, including households. Conversion of natural gas to hydrogen is planned at the landing point, with offshore CO_2 disposal of up to 12.5 Mt CO_2/a nearby; new salt caverns are designated for seasonal H_2 storage onshore near the conversion location. A new relatively short high-pressure H_2 pipeline will link the conversion facilities to Leeds and the whole Northern England region. This step-by-step approach is driven by the progress of converting metering points over several years with modular building, adding one ATR each year between 2028 and 2034 with 1.25 GW (roughly 1 bcm/a input) and salt caverns as required by demand. This UK project is characterised by high density of demand along the (short) pipeline route, the proximity of well-suited salt structures for hydrogen storage and the

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[91] *Ibid*., the costs of CO_2 transportation, pp. 6, 53.
[92] CE Delft (2018), "Feasibility study into blue hydrogen," July 2018, p. 43.
[93] *Ibid*., p. 22.
[94] *NetzEntwicklungsplan*, grid development plan.
[95] H21 North of England (2018): p. 345.

proximity of large offshore structures for CO_2 sequestration. For the not yet converted regions, gas will be supplied from the existing pipeline system.

Advantages of decarbonisation at the exit of the high-pressure system in the case of Germany

In the case of Germany, conversion close to the customer looks most appropriate, provided a solution for safe CO_2 disposal is available or pyrolysis can be rolled out at scale: it would allow for flexible and individual following up of the development of large customer H_2 demand by building ATRs close to demand and maintaining the natural gas storage capacity. All high-pressure natural gas infrastructure including storage could be left as is with some local H_2 infrastructure added at the outlet of the high-pressure system.

In the longer run, decarbonising the compressors driven by gas turbines is necessary in any case, but there is no need for compression reconfiguration, which would be the case with the switch to pure hydrogen, where a simultaneous change of all compression configuration would be triggered. The high-pressure system from wellhead to city gate can continue to be used inclusive of full storage capacity without any change in regulation.

No coordination along the chain is needed for the transformation process, it can be done on a local basis in line with local circumstances and local policies. The concept aims at full immediate conversion to 100% hydrogen, with use growing with the increase in size and number of hydrogen areas.

Decarbonisation close to the city gate is also preferable for the integration of green hydrogen. Green hydrogen via electrolysis can be produced in Germany anywhere upstream of the electric grid bottlenecks (if any) and then fed into the local hydrogen grid. There is no need for blending limits as green hydrogen would simply replace the equivalent amount of blue hydrogen and the respective volumes of natural gas into SMR/ATR, a variation easily absorbed by the existing gas grid/market. SMRs and ATRs can change their output by 1% of capacity per minute.

An additional consideration is that with local, decentralised decarbonisation the inevitable process losses from conversion in the form of low-temperature heat have a higher chance of being used locally.

Once the pyrolysis technology becomes widely available in addition to SMR/ATR, it would be logical to place it close to the customer: it does not raise the issue of carbon disposal location or require access to water. It appears to be particularly suitable for places in southern and eastern Germany without access to navigable rivers (e.g., Munich, Dresden).

The issue of decentralised conversion was raised by Stefan Kohler, head of the supervisory board of Zukunft Erdgas, on 1 October 2019.[96] The issue of the place of conversion apparently is not addressed in the draft national hydrogen strategy, which is building on substantial imports of green hydrogen until 2030. The gas TSOs have published a vision for a regional hydrogen grid, which is also shortly described as a vision in the draft NEP 2020-2030[97] as a basis for further conceptual discussions, though so far it is not considered for grid planning.

[96] Energate Messenger (2019).
[97] FNB Gas, Transmission System Operators (2020): p. 158 ff.

Chapter 5: Policy implications: no need for new grid regulation; organisation of decarbonisation as a public good

5.1 Costs of decarbonising the non-electric sector

Most hydrogen today is used as feedstock for ammonia, ethanol and for refineries, which have no alternative; and SMR/ATR is the least-cost production method. For decarbonisation, the CO_2 resulting from the existing SMR/ATR process has to be disposed of, and the costs of decarbonisation are the costs of transportation and sequestration plus eventually the costs of adaptation of the SMRs/ATRs already in operation to collect CO_2 instead of venting it. The costs of producing hydrogen are incurred regardless of decarbonisation. In the future, a substantial proportion of hydrogen will not be used as feedstock but as a carbon-free energy carrier to replace natural gas or other hydrocarbons. Customers would not wish to use hydrogen *per se*, but rather would have to use it as a vehicle for carbon-free non-electric energy. Unlike with the use of hydrogen as feedstock, in this case the costs of conversion would come as extra costs, attributable to decarbonisation.

Until green hydrogen costs match those of blue hydrogen, the H_2 price will have to cover the (market) price of natural gas plus the costs of conversion from CH_4 to H_2 and of CO_2 disposal. In the case of pyrolysis (yet to be scaled up), there are no costs for CO_2 transportation and sequestration. Instead, there are relatively low costs of disposing of the resulting carbon, possibly even revenue from marketing that carbon in high volumes to such low-value markets as street and roadway construction or soil improvement. In any case, carbon disposal should not be a problem. To illustrate: decarbonisation of 30 bcm/a of natural gas (corresponding to Germany's annual industrial gas consumption) by pyrolysis would result in ca 22 mln t C/a. This compares with about 50 mln t/a of coal equivalent of lignite mined for power generation - any carbon from the pyrolysis process which could not be marketed could be stored in the existing open-pit lignite mines.

For a long time to come, the costs of producing carbon-free hydrogen will have to be added to the price of natural gas. There is no point in waiting for the cost mark-up to disappear. The analysis below focuses on the order of magnitude for the costs of gas decarbonisation via CCUS by looking at recent estimates.

The following reports from 2018 and 2019 deal with decarbonisation and its costs.

Giving a national overview of the status, costs and obstacles to decarbonisation:

- CE Delft in July 2018 published a "Feasibility study into blue hydrogen,"[98] with an assessment of the various components of introducing blue hydrogen in the Netherlands, including conversion costs by SMR and ATR, while discussing in a more qualitative way the potential and obstacles for H_2 transportation, CO_2 transportation and sequestration.
- In December 2019, The US National Petroleum Council delivered a report "Meeting the dual challenge"[99] to the Department of Energy. The report outlined a strategy for the next 20 years to increase the tax credits under IRS article 45Q for carbon sequestration from the present 50 \$/t CO_2 to 100 \$/t CO_2. This would foster decarbonisation by carbon capture and sequestration to 400 mln t CO_2/a, decarbonising major parts of the US industry. The report assesses the costs of CO_2 capture for a multitude of industries, as well as the costs for CO_2 transportation and sequestration in the US.

[98] CE Delft (2018), "Feasibility study into blue hydrogen".
[99] US National Petroleum Council (2019).

Project-related:

- The H21 North of England (NoE) project[100] is a large-scale blue hydrogen project serving an industrialised region with about 15 mln people and a present gas consumption of 85 TWh/a. The NoE report gives a detailed cost assessment of all the components, including the conversion from gas to hydrogen, transportation and sequestration of CO_2, hydrogen storage and transportation to the North of England customers, as well as of the costs of converting 3.7 mln customers.
- A recent project by Equinor/OGE "H2morrow"[101] looks at a blue hydrogen project producing hydrogen in an ATR plant *inter alia* for a new Thyssen Krupp hydrogen-operated furnace for the reduction or iron ore. It is planned to transport the resulting CO_2 by ship for sequestration in Norway.

Both projects are based on using ATR and require a similar order of investment. The NoE project foresees investing £8.52 bln in 9 ATR plants[102] with a total capacity of 12.15 GW, corresponding to £0.95 bln , or €1.09 bln, per plant, or €0.7 bln £/GW or €0.8 bln /GW. H2morrow plans for €1 bln for one ATR (inclusive of the CO_2 and H_2 logistics) for a capacity of 1 GW[103] – a comparable order of magnitude.

At the present exchange rate of £1 = €1.13[104] it appears that the costs of an ATR, the construction of which is subject to international competition, are in the order of €1.0-1.3 bln per 1 bcm/a gas input.

For the NoE project, the costs of transportation plus sequestration are shown to be about 20 £/t CO_2 at 1.5 mln t CO_2/a (corresponding to the size of the original H21 Leeds project) going down to 10 £/t CO_2 for 15 mln t CO_2/a,[105] corresponding to the size of the H21 North of England project (in €: 23 €/t CO_2 and 11.5 €/t CO_2, respectively). The NoE project benefits from being close to the UKCS for short-distance transportation and good geology for sequestration.

The H2morrow project has a longer transportation route for liquefied CO_2 by ship on the Rhine with reloading in Rotterdam to final sequestration in Norway. Overall, the cost sum for transportation and sequestration is similar to that of the NoE project

From the overview reports:

The Dutch report "Feasibility study into blue hydrogen" shows costs at 48 €/t CO_2 for an ATR with a CO_2 capture rate of over 90%; capture rates can be increased, at higher costs, but without technical limits.

The US report looks at the broad range of decarbonisation technologies required by different industries (not only ATR or steam reforming). The total costs of decarbonisation including transportation and sequestration are shown between 46 and 107 $/t CO_2 (corresponding to 42-97 €/t CO_2 at the exchange rate of 1.10 $/€).[106]

Table 4 compiles the information presented above, albeit fragmented and partly dependent on project or country-specific parameters. Nevertheless, it provides a reasonable order of magnitude for comparing the costs of gas decarbonisation with the costs of support for electric renewables and green hydrogen.

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[100] The H21 North of England Project is scaling up the original H21 Leeds project to the whole North of England region to make better use of economies of scale effects; *see* H21 North of England (2018).
[101] Equinor (2019).
[102] H21 North of England (2018), p. 386.
[103] Equinor (2019)., pp. 3 and 13.
[104] Exchange rates at 8 May 2020.
[105] H21 North of England (2018) p. 15.
[106] Exchange rates at 8 May 2020.

Table 4: Costs of natural gas decarbonisation/CCUS

	CO_2 capture by ATR investment		Transportation and sequestration	Overall CCUS costs
	per GW	per t CO_2		
the Netherlands		48€ /t CO_2		
H21 NoE	0.7 bln £/GW	ca 75-100 £/t CO_2*	7.5 £/t CO_2	
H2morrow	< 1 bln €/GW**			50-70 €/t CO_2
US (various processes)		29-93 $/t CO_2	14-23 $/t CO_2	46-107 $/t CO_2
* based on 8 500 h/a and an annuity of 0.15 - 0.2 /a ** inclusive of transportation and sequestration				

Source: compiled from the above

The largest part of the costs of decarbonising natural gas stems from the conversion stage, which is a well-known process subject to international competition. The share of transportation and sequestration in the costs is more case-specific and does not exceed 25%.

As decarbonisation is not demanded by the market, covering its costs has to be organised by the public authorities. Policy design has to start with costs as they are. Present costs of CO_2 avoidance may look high, but are lower than the implicit decarbonisation costs of most renewables (*see below*). But does that mean that we skip decarbonisation or we wait for a technological breakthrough, which may not come? There is no reason to wait based on the present avoidance costs if there are enough incentives to bring them down and a scheme exits that reduces public spending accordingly.

At the same time, as the US report shows, costs may increase over time, moving to higher decarbonisation rates: while the costs for conversion should come down due to learning-by-doing, the use of more difficult and more distant geological sites for sequestration would result in increasing specific costs. In that case, a public scheme should provide increased support over time while factoring in the learning-by-doing effects.

5.2 Organising the public good of decarbonisation is the issue, not gas grid regulation

Most reports raise the issue of new regulation for gas infrastructure for introducing hydrogen. Regulation outside of health, safety and environment usually means dealing with access to an essential facility[107] (from non-discriminatory, possibly open access up to public organisation of the essential facility inclusive of a regulated asset base). However, with a public good like decarbonisation, demand is indivisible and needs to be organised differently, by a public institution, which would also decide whether it is the taxpayer or consumer who would be dealing with the bill.

Hydrogen blending within the high-pressure system is a dead-end street (*see* Chapter 3). As the natural gas system in Germany/the EU is a well-functioning market by now, it can be used as it is for the next decades (including storage) without the need for new regulation for natural gas, with the introduction of hydrogen, if conversion is placed at the outlet of the high-pressure system.

5.2.1 Health safety and environment/technical regulation

Technical regulations become necessary with blending, but also with the total conversion of the existing gas infrastructure to hydrogen (embrittlement, flow speed, etc.). So far, hydrogen is not classified as an energy material or product, but rather as a chemical, subject to the respective technical regulation. For grid transmission and distribution, there is a need to set certain levels of hydrogen quality, or purity;

[107] Essential facility: a facility, which is needed to get access to customers, but cannot be easily duplicated by competitors; a crucial argument in the essential facility doctrine in the US is justifying intervention into private property by economic regulation. This concept was taken over by the EU: *See*: https://www.concurrences.com/en/glossary/Essential-facility.

energy production grade H_2 requires purity of over 95%, and industrial grade purity is 99.95% (while fuel-cell technology allows for no H_2 contamination). In a large grid, it would be difficult to maintain a high quality of hydrogen.

With the conversion of gas at the outlet of the high-pressure natural gas system, no additional regulation is needed for the gas grid. Downstream of conversion it is easier to design more individual distribution schemes for hydrogen with varying degrees of purity.

5.2.2 Economic regulation of infrastructure

Decarbonisation of gas to blue hydrogen is possible without using essential facilities. Conversion plants are NOT essential facilities: there is a large enough number of potential building sites, competing technologies (ATR, SMR, various methods of pyrolysis under development) and engineering firms delivering them. Gas supplies in Germany/the EU are based on a competitive market, and gas is available almost everywhere in Germany.

Disposing of CO_2 can be done by pipeline (regulated in the EU, *de facto* prohibited in Germany). It can also be done by ship or rail, which are not essential facilities. The use or disposal of carbon can be market-driven. CO_2 sequestration in geological structures can be organised by a licensing procedure, as it is done in Norway.

H_2 infrastructure may be regarded as essential facilities on a regional level, using public ground and having economies of scope. It is more like distribution networks, more suited for introducing TPA than for heavy-handed regulation. Furthermore, a local hydrogen grid could be contested[108] by smaller tailor-made local conversion schemes.

However, green hydrogen always requires some form of access regulation: it would need a grid to bring the small and intermittent volumes of locally bound renewable energy by wire to the electrolyser, or to the electrolyser and then by blending into a gas pipeline to the customer.

5.3 Support schemes for decarbonisation

Any support scheme should:

- effectively trigger and expedite the decarbonisation of the non-electric sector (building in a reasonable profit in the beginning helps)
- at the same time, it should be construed so as to minimise public expenditure, i.e., follow the learning curve
- allow all kinds of CO_2-free hydrogen production to develop based on merit within the given support framework.

In Germany, the support for electric renewables has been successful so far; there are good chances that the 2050 decarbonisation target for the electric sector will be reached. The question is whether that approach can be transposed onto the non-electric sector. The support scheme for electric renewables was to promote a technology break out of fossil fuel-driven technologies, with decarbonisation as an implied effect. Fostering blue hydrogen is about deploying known technologies to decarbonise the non-electric sector quickly, with some learning-by-doing effects, of course. As CO_2 sequestration depends on the availability of geological sites, there will be cost increases when moving to more difficult or more distant sites. In the following, we look at the German experience from fostering electric renewables and the proposed scheme for decarbonising the US industry by carbon capture and sequestration.

[108] Concept of a contestable market: instead of being subject to competition, the market is subject to the threat of competition.

5.3.1 Support for electric renewables in Germany to drive technology down the learning curve

The schemes to support renewable energy (which turned out to be predominantly electric renewables) were not primarily geared towards decarbonisation.[109] Promoting renewables was technology-specific support to drive costs down the learning curve to a level allowing competition with fossil-based energy, at least in power generation. This was achieved successfully, especially for PV.

The support was individually tailored to various technologies and project sizes. As a consequence, it was largely different for PV and onshore and, later, offshore wind, a situation which persist to this day.

Support for PV

The feed-in tariff for solar panels up to 10 kW had its peak with 55 cts/kWh in 2001. Since then, it has come down to 11 cts/kWh in 2015, and further to 10 cts/kWh at the beginning of 2020. Against the average power price at the wholesale level of 4 cts/kWh in the beginning of 2020, support was 6 cts/kWh.

Support for onshore wind

As of 2017, the value of support for onshore wind energy (in addition to the market price) was the result of auctions organised by the BNetzA for defined capacities. The average result of recent auctions increased by a factor of 1.08 sets the upper value for subsequent auctions. However, in 2019, most auctions did not exhaust the capacity on offer and the prices offered were very close to or equal to the upper limit of 6.2 cts/kWh. Therefore, by decision of 25 November 2019 the BNetzA within its mandate fixed the upper limit for auctions in 2020 to 6.2 cts/kWh,[110] which is to be paid on top of the market price.

Support for offshore wind

If operational in 2020, the feed-in fee for offshore wind was 13.9 cts/kWh for 12 years, then reduced to the basis feed in tariff of 3.9 cts/kWh. This corresponds to a support of 9.9 cts/kWh above market price.

This scheme was recently replaced by an auctioning regime, under which investors bid on the lowest extra support. The average result of the last auction on 1 April 2018 was 4.66 cts/kWh to be paid on top of the market price.[111]

Grid development in scenarios A and B of the NEP for 2030[112] envisages an €18 bln investment for an offshore grid for 6.4 GW.[113] Assuming amortisation over 20 years and 4,000 h/a as typical load results in 3.5 cts/kWh of support.[114]

Support related to reducing CO_2 emissions

As load following for renewables is managed by coal and gas, the avoided CO_2 emission is between 0.4 kg CO_2/kWh el for a CCGT and 0.8 kg CO_2/kWh el for a hard coal-fired power plant. The support for the resulting saving of 0.4 or 0.8 kg CO_2/kWh is shown in Table 5:

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[109] Otherwise, a price for carbon would have been enough to trigger renewables development.
[110] Federal Network Agency [Germany] (2019).
[111] BNetzA (2018): Results of the 2nd call from 1 April 2018, announcement 27 April 2018.
[112] Scenario A – moderate; Scenario B – guiding.
[113] Fraunhofer IEE Wind Monitor: "Grid expansion offshore"
[114] (18 bln € / 20) / (4000 * 6.4 GW) = 3.5 cts/kWh.

Table 5: Support for renewables and saved CO_2 emissions, examples

			PV <10 kW	Onshore wind auction	Offshore wind feed-in	Offshore wind auction	Plus tie-in to offshore grid
Support for renewables							
feed-in		cts/kWh	10	n.a.	13.9	n.a.	n.a.
less market price		*cts/kWh*	*4*	*n.a.*	*4*	*n.a.*	*n.a.*
support		cts/kWh	6	6.2	9.9	4.66	3.5
support for saved CO_2 emissions							
against CCGT	at 0.4 kg CO_2/kWh	€/t CO_2	150.0	155.0	247.5	116.5	87.5
against coal-fired power plant	at 0.8 kg CO_2/kWh	€/t CO_2	75.0	77.5	123.8	58.3	43.8

Source: own calculations

Even though support has reduced over time, it is still much higher than any carbon price and is above the costs for CCUS, as shown in the examples in Table 4 above; it is in the range of 50-70 €/t CO_2 and certainly does not exceed 100 €/t CO_2.

Additional support measures

These amounts do not yet include non-monetary support, such as the offtake obligation for intermittent power requiring upgrading the electricity grid to take in practically all renewable electricity or building offshore grids for feeding in offshore wind electricity.

Necessary re-enforcement of the electric grid for winter peaks of heat pumps and, to a lesser extent, for BEVs is rolled in into the grid fees, which in the end have to be paid by the non-exempted final customers. In addition, the social and regional hardships, as well as company losses due to phasing out lignite and hard coal power are mitigated by the Federal Government with a total of some €40 bln until 2038.[115]

There are other direct and indirect subsidies for electricity consumption, such as the financial support for BEVs, and indirect support for heat pumps, as a way to fulfil the zero energy rule for new houses.

It remains to be seen what support for electrolysis will be included in the new hydrogen strategy. It is certainly useful to support electrolysis as a necessary technology of the future but it does not make much sense to tie it to the availability of renewable electricity.

5.3.2 What technology neutrality?

Blue and green hydrogen can deliver the same hydrogen qualities, but their economic features are completely different. Blue hydrogen is derived from finite hydrocarbon fuels (still available for many decades), based on a well-working (gas) market, comes with decarbonisation costs for CCUS of a maximum of 100 €/t CO_2, and is technically available for expedient deployment with learning-by-doing effects.

[115] Tagesschau (2020).

For green hydrogen, there is no renewable electricity available in the next decades, actual support for renewable electricity is clearly above the costs for CCUS, and the present production of renewable electricity is based on almost 2 decades of generous technology support.

What could technology neutrality then look like, outside research support? As time goes by so fast, blue hydrogen has to do the job: it is the obvious way forward in view of the limited carbon budget, of energy resources and infrastructure availability, as well as non-disruption for customers. The support needed for decarbonisation via blue hydrogen is also lower than the support given to electric renewables, even without the costs of electrolysis. The Dutch "Feasibility study into blue hydrogen" concludes that "the price of green hydrogen is too high, especially to be used in the industry. Furthermore, it is not possible to produce via electrolysers at the scale required for industrial implementation."[116]

The German EEG scheme maybe did not pick renewables as winners, but they were invigorated by subsidies over the years to become able to enter the race with priority access to the power grid/market. Green hydrogen will not be available in large volumes before 2040, even if some political and environmental groups believe that this is just a question of political will. In view of the much higher decarbonisation effect of electric renewables in the electricity sector compared to converting it to green hydrogen, blue hydrogen is the only possible participant in the current drive to decarbonise the non-electric sector. Deployment and support for it should be based on merit derived from the contribution to reaching the decarbonisation target. Chapter 2 concluded that the acceleration of renewable power production should be fostered but blue hydrogen should be supported in the most effective way, while waiting for renewable electricity to become available for green hydrogen.

5.4 Tax credits in the US, IRS 45Q to support CCUS

The largest number of CCUS projects is in the US, also the largest CO_2 injection volumes. Incentives partly come from EOR by additional (daily) oil production and a better recovery factor of fields in decline. In addition, there are fiscal stimuli in the form of tax reductions by the amount of tax credits. In 2008, a tax credit for CO_2 injection was added to the US Tax Code under IRS number 45Q. Ten years later, the bipartisan Budget Act of 2018 expanded and extended the 45Q tax credit. *"The new 45Q provisions increased credits from $10/tonne for enhanced oil recovery (EOR) projects and $20/tonne for geological storage to $35/tonne and $50/tonne, respectively (plus inflation). The new law also eliminates the 75-million-ton cap and allows the developers to claim the tax credits for 12 years after the new equipment went into service."*[117]

At the time of writing, there were 26 known projects at different stages of development triggered by the amended IRS 45Q, 9 of which are known to be supported by DOE grants for front-end engineering design.[118] The decarbonisation of these projects would add up to more than 50 mln t CO_2/a.

On 12 December 2019, the National Petroleum Council submitted a comprehensive report to the Secretary of Energy,[119] analysing and suggesting a strategy to introduce additional decarbonisation incentives. The intention is to decarbonise the economy by an additional 350-400 mln t CO_2/a over the next 25 years by increasing the tax credits under IRS 45Q to the order of 90-110 $/t CO_2.[120] Graph 5 below[121] shows the different phases suggested for implementing this scheme over time.

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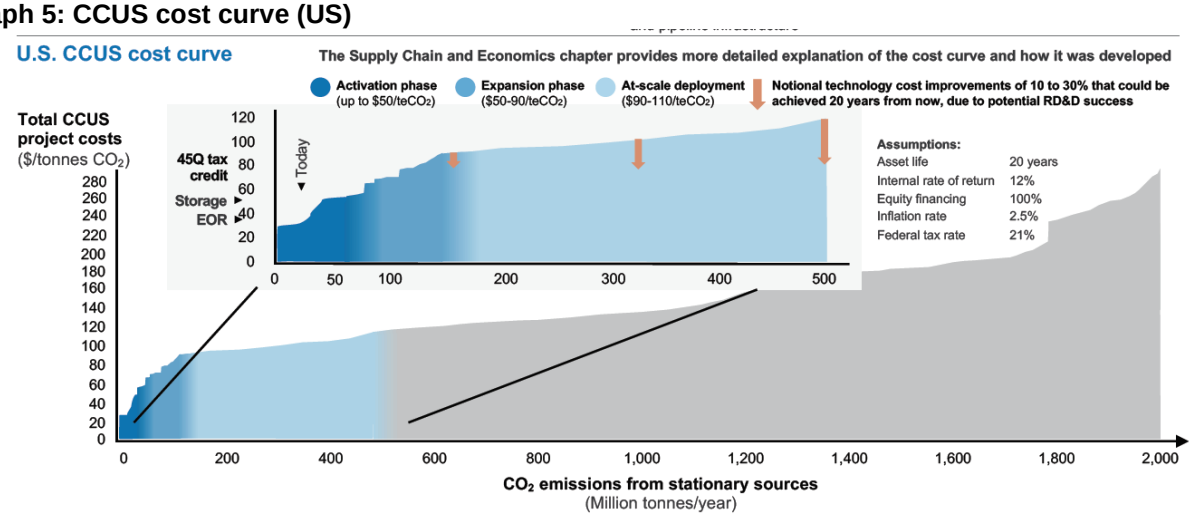
[116] CE Delft (2018), "Feasibility study into blue hydrogen," July 2018, p. 43.
[117] World Resources Institute (2019).
[118] Clean Air Task Force (2020).
[119] *See* US National Petroleum Council (2019).
[120] *Ibid*., p. 29.
[121] *Ibid*., Graph, p. 38.

Graph 5: CCUS cost curve (US)



Source: NPC: Meeting the Dual Challenge, report summary page 38

The Graph above also indicates potential of some 10-30% for bringing down costs by further research, development and demonstration, even though these are mature technologies. While this scheme is not directed at a blue hydrogen strategy for decarbonisation, it could become an effective decarbonisation scheme for the US industry by direct decarbonisation and by creating a CO_2 collection system.

If implemented, that would go a long way to decarbonise major parts of the US economy, making the US steel and other industries the first ones to become green, unless the EU/Germany find a way to decarbonise effectively their own core industry clusters.

5.5 Political aspects

Time pressure on Germany/the EU to act swiftly on decarbonising the non-electric sector comes from the carbon budget, which will be used up quickly if decarbonisation is not accelerated in both the power sector and in the non-power sector. A major political obstacle to developing an effective strategy is the paradigmatic corner into which some parts of the environmental movement have painted themselves by substituting the decarbonisation goals for the instrument of promoting renewables. Renewables are inadequate for the set goal in the given timeframe. Another political obstacle is the unjustified projection of objections to the problematic disposal of radioactive waste onto CO_2 sequestration, not only within but also outside Germany.

At the same time, parts of the green movement accept that solutions have to be found sooner rather than later to decarbonise and maintain core industries. Almost ironically, the pressure to act now also comes from the competition of core industries from the US, where the improved support scheme under IRS 45Q is attracting investors,[122] while further improvements are debated in Congress. The US example and discussion show that well-dosed state support can move things along.

To make its core industry/competence clusters future-proof by decarbonisation, Germany has to look for similar effective schemes to decarbonise its non-electric sector, starting with core industry. To make this happen, carbon sequestration in the North Sea is essential. The following seems necessary:

1. Cooperation between the main CO_2-exporting countries in northwest Europe (Germany, Belgium, the Netherlands, France) and the potential countries with CO_2 sequestration (Norway, the UK, Denmark, the Netherlands) to develop:
    - joint standards and certification on CO_2 handling and related devices

[122] *Ibid.*

- a joint strategy for using the North Sea as a CO_2 sink (with EOR and/or CO_2 sequestration)
- reliability of CO_2 supply and coordination of development, removing of any cross-border hindrance (ratifying the London Convention by Germany)
- handling of the remaining risks and long-term effects.

2. Payment for CO_2 to be abated: this must be paid in the end by the home country of the industry to be decarbonised. In the US, industry decarbonisation (point sources of CO_2 emissions) is *de facto* paid by tax credits. Germany should look for similar schemes, which would enable the decarbonisation and the cost covering for the respective chain from the conversion plant via CO_2 transportation to sequestration out of German territory, assuming that states like Norway will open their sector for decarbonisation under a license regime, which Norway seems to have already established.

Only such conditions would allow players to be found who would have the skills and assets to engage in parts or all of the new decarbonisation chain. Such a policy would help to make core industries in Germany future-proof and to maintain industrial sites and jobs. Not least, German and EU companies are already competitive in building the dozens of ATRs plus the CO_2 tankers needed to switch to blue hydrogen.

Such a policy should be coordinated with the EU, which would be best placed to take over the coordination on CO_2 policy for the North Sea with the EU littoral states, the UK and Norway. However, using taxes as the most effective instrument is not the EU competence, and ETS still does not look stable enough for investors to base their strategic decisions on.

Conclusions

Getting the relationship between decarbonisation and sustainable energy right is a crucial precondition for the success of decarbonisation.

The footnote on page one of the draft National Hydrogen Strategy is telling. It reads: "From the point of view of the German government, only hydrogen produced on the basis of renewable energy ("green" hydrogen) is sustainable in the long run."[123] This is a truism, which does not help reaching the decarbonisation targets nor designing a national hydrogen strategy. No doubt, **in the long run**, only renewable energy is sustainable energy, but the challenge is to decarbonise the energy sector by 2050, which in terms of energy infrastructure investment and use and switching to hydrogen is **in the short run**.

The inconvenient truth is: renewables and green hydrogen have no chance to come close to decarbonising the non-electric energy segment by 2050, which in Germany (and in the EU) today represents almost 80% of final energy consumption. Any renewable kWh is best used to replace fossil power generation, where it has at least twice the decarbonisation effect compared to transforming it to green hydrogen. For the next decades, large amounts of green hydrogen would come at the price of cannibalising the success of renewable electricity in the power sector and jeopardising a still possible success of meeting the PA targets. Contrary to the widespread perception, volumes of surplus power which cannot be used by the power market are very small as a result of the grid being designed to take in all renewable power and also in view of the much greater effect when used directly in the power market.

And for what? Blue hydrogen can do the job of decarbonising the non-electric sector starting now with a chance to decarbonise it by 2050 so that green hydrogen can come in to compete when ready.

However, blue hydrogen based on SMR/ATR (pyrolysis is still in an early stage of development) needs CO_2 sequestration at the scale of today's gas production. Denying the role of CO_2 capture and sequestration for the next decades, which the IPCC considers essential to meet climate goals,[124] puts a – maybe understandable – anti-fossil attitude ahead of a serious approach to reach climate targets.

Regarding Germany, decarbonising the electric sector by developing and deploying electric renewables has been successful so far and has good chances to achieve an almost complete decarbonisation of the electric sector by 2050.

However, the non-electric sector (about 80% of final energy demand) needs to be decarbonised by 2050 as well. Hydrogen is the obvious candidate to replace hydrocarbons, as its application is similar and switching to it does not cause too much disruption. Also, there are different ways to produce hydrogen in a CO_2-free way, either from renewable electricity and electrolysis (green hydrogen) or by decarbonised gas (blue hydrogen).

It is very unlikely that substantial amounts of green hydrogen will be available for the next two to three decades, as renewable electricity has a much higher decarbonisation effect when used in the power sector. Relying on imports of (green) hydrogen is not realistic: the EU and other industrialised countries are under similar pressure to decarbonise their power sector, just as Germany. Populated developing countries will need any additional power first for their own development; and importing hydrogen from remote renewable-rich countries mostly in desert areas has to overcome basic technological challenges both for pipeline and ship transportation, the latter likely being too expensive by 2040, according to the IEA.[125] Betting on carbon-free imports in the faraway future is denying the responsibility Germany has for its own decarbonisation. Betting on a substantial role of green hydrogen as the only or predominant

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[123] "*Aus Sicht der Bundesregierung ist nur Wasserstoff, der auf Basis erneuerbarer Energien hergestellt wurde („grüner" Wasserstoff) auf Dauer nachhaltig*."

[124] *See* note 19 above, p. 14. S. CHECK NOTE NUMBER

[125] *See* IPCC (2018).

route to decarbonisation before 2050 is a high-risk gamble against the odds, jeopardising the Paris Agreement targets.

Electric renewables in Germany were generously supported directly and indirectly under the EEG to take them through the learning curve. That support continues to be clearly above the costs of decarbonisation by blue hydrogen. Nurturing renewable technologies to become able to compete was and is a necessary element of decarbonisation and breaking out from a dominant fossil fuel-based technology. However, it does not achieve decarbonisation of the non-electric sector.

When it comes to the missing link of decarbonising the non-electric sector, this paper demonstrates:

1. Green hydrogen from domestic renewables as well as from imports will hardly play a role in deep decarbonisation by 2050. Deploying blue hydrogen on a large scale is the only realistic approach to achieve early and deep decarbonisation of the non-electric sector.
2. All elements of the blue hydrogen technology are ready for application on a large scale, while the additional technology of pyrolysis could be scaled up within the next 10 years. However, cross-border transportation of CO_2 and large-scale sequestration – matching CO_2 emissions from the non-electric sector – must be established as soon as possible to decarbonise the German non-electric sector.
3. This comes at the additional cost of converting CH_4 to H_2 and safely disposing of CO_2, which is not driven by market demand but by policy organising a public good (decarbonisation). These costs are known, and while there is room for reducing them, there is no reason to wait to establish ways to cover those costs as a public good (i.e., by the tax payer or by imposing them on the consumer).
4. Germany/the EU should find ways to organise the recovery of such costs with an attractive enough profit to bring in the investment and the players able to manage the decarbonisation part of blue hydrogen production. In addition to the oil and gas industry, which has the skills and assets and the interest to keep their business alive, large hydrogen customers and infrastructure industry also come to mind. Decarbonisation is a public good but does not involve essential facilities; there is no need for infrastructure regulation except a light-handed access regime for local or regional H_2 structures.
5. Placing the conversion at the outlet of the high-pressure gas system would allow it to be maintained as is with all the benefits of a well-functioning infrastructure and market, including competition, security of supply, diversification and reliable supply on demand using existing storages. Demand and a market for pure hydrogen can be developed in a tailored way by regional kernels, which can grow together over time and which can absorb green hydrogen when it becomes available. For Germany, this approach would allow an expedient conversion of the non-electric sector to hydrogen.

Despite its declared retreat from the Paris Agreement, in 2018 the US amended its tax legislation to foster CO_2 sequestration (IRS 45Q), to include an increased tax credit of \$50/t CO_2 sequestered. In December 2019, the National Petroleum Council submitted a paper to the DOE “Meeting the dual challenge” – a well-argued roadmap to at-scale development of carbon capture, use and storage. The report suggests increasing the tax credit from \$50/t CO_2 today to \$90-110/t CO_2 in the future, with a perspective to capture 350-400 mln t CO_2/a to support the production of carbon-free hydrogen for the US industry.

While the situation is more complicated in Germany and the EU, they should not fall behind the US and should implement similar effective schemes for supporting CCUS to ensure decarbonised hydrogen for their industry, in competition with the US and as an essential contribution to live up to their own ambitious decarbonisation targets.

Glossary

$	US dollar
£	UK pound
€	euro
ATR	auto-thermal reforming
bara	unit of absolute pressure
bcm	billion cubic meters
bcm/a	billion cubic meters per year
BEV	battery electric vehicle
bln	billion
BNetzA	Federal Network Agency, the German regulator for electricity, gas, telecommunications, post and railway markets (*Bundesnetzagentur*)
ca	*circa*
CCGT	combined-cycle gas turbine
CCS	carbon capture and storage/sequestration
CCUS	carbon capture, utilisaton and storage/sequestration
CH_4	methane
CNGV	compressed natural gas vehicle
CO_2	carbon dioxide
ct	Euro Cent
DOE	United States Department of Energy
Dunkelflaute	times with low wind and low sun, typically in winter
EEG Umlage	fee financing renewable energy, paid by power customers in Germany
EEG	German Law on Renewable Energy (*Erneuerbares Energie Gesetz*)
EEZ	exclusive economic zone
Energiewende	Germany's 2010 policy on achieving an 80-95% reduction of GHG emissions by 2050 compared to 1990
EOR	enhanced oil recovery
ETS	EU emissions trading system
EU	European Union
GHG	greenhouse gas
Gsm^3	billion standard cubic meters
GT	gas turbine

Gt	gigaton
GW	gigawatt
h/a	hours per year
H_2	hydrogen
H-gas	natural gas with a Wobbe index of 12.8 – 15.7 kWh/ m3 corresponding to ca. 87-99% methane content
HVDC	high-voltage direct current
ICE	internal combustion engine
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
IRS	United States Internal Revenue Service
KIT	Karlsruhe Institute of Technology
kW	kilowatt
kWh	kilowatt-hour
L-gas	natural gas with a Wobbe index of 8.4 – 13.1 kWh/m3 corresponding to ca. 80-87% methane content
LH_2	liquefied hydrogen
LOHC	liquid organic hydrogen carrier
LPG	liquefied petroleum gas, propane
m^3	cubic meter
mln	million
Mt	million tons
MW	megawatt
MW/a	megawatt per year
MWh	megawatt-hour
NCS	Norwegian continental shelf
NEP	the German Network Development Plan (*Netzentwicklungsplan*)
nm	nautical miles
Nm^3/h	normal cubic meters per hour
NoE	North of England (project)
NPD	Norwegian Petroleum Directorate, a governmental administrative organisation to manage petroleum resources on the Norwegian continental shelf
OGE	Open Grid Europe

OIES	Oxford Institute for Energy Studies
PA	Paris Agreement
PV	photovoltaic
Sm^3	standard cubic meter (at 15°C and 760 Torr)
SMR	steam methane reforming
Stilllegungspfad	German phase-out path for lignite, published on 15 January 2020
t	ton
TPA	third-party access
TSO	transmission system operator
TWh	terawatt-hour
TWh/a	terawatt-hours per year
UCTE	Union for the Coordination of Transmission of Electricity, the EU continental power system grid
UK	United Kingdom
UKCS	United Kingdom continental shelf
US	United States
WEO	World Energy Outlook

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