No-regret hydrogen

Charting early steps for
H_2 infrastructure in Europe

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Conclusions and the main section should be cited as indicated on page 7 and 27, respectively.

Preface

Dear reader,

The European Union has decided to increase its climate ambition for 2030 and to achieve climate neutrality by 2050. Creating a climate neutral economy will require the availability of large quantities of hydrogen, particularly in hard-to abate industrial sectors. Such hydrogen will increasingly be produced on the basis of renewable electricity, because only renewable-based hydrogen is fully carbon-free and its costs will continue falling.

Renewable hydrogen can be produced at a variety of sites in Europe. What is the best way to deliver hydrogen to the centres of industrial demand? To better understand the economic potential for pipeline transport, Agora Energiewende and AFRY Management Consulting have assessed the cost and infrastructure implications of a "no-regret" supply of industrial hydrogen at existing sites with off-grid renewable hydrogen production in Europe.

The results show how industrial clusters can be supplied with renewable hydrogen, thereby contributing to the greening, securing and strengthening of Europe's industry.

I hope you find this report informative and stimulating.

Yours sincerely,

Patrick Graichen,
Executive Director, Agora Energiewende

Key conclusions

1. **Hard-to-abate industrial sectors represent a major area of hydrogen demand in the future due to a lack of alternative decarbonization options.** Steel, ammonia, refineries and chemical plants are widely distributed across Europe. To reduce and eventually eliminate their process emissions, 300 TWh of low-carbon hydrogen are required. This number does not factor in the production of high-temperature heat, for which direct electrification should be considered first.

2. **The investment window for fossil-based hydrogen with carbon capture remains open, but in the long run renewable hydrogen will emerge as the most competitive option across Europe.** Given the current asset lifecycle and political commitments, fossil-based hydrogen with carbon capture will remain a viable investment until the 2030s, but strong policies for renewable hydrogen will shorten the investment window for fossil hydrogen, likely closing it by the end of the 2020s.

3. **We identify robust no-regret corridors for early hydrogen pipelines based on industrial demand.** Adding potential hydrogen demand from power, aviation and shipping sectors is likely to strengthen the case for an even more expansive network of hydrogen pipelines. However, even under the most optimistic scenarios, any future hydrogen network will be smaller than the current natural gas network. A no-regret vision for hydrogen infrastructure needs to reduce the risk of oversizing by focusing on indispensable demand, robust green hydrogen corridors and storage.

Content

No-regret hydrogen: Charting early steps for H_2 infrastructure in Europe.
Conclusions drawn by Agora Energiewende

1 Conclusions 9
2 References 21
3 Annex 25

No-regret hydrogen: Charting early steps for H_2 infrastructure in Europe.
Study conducted by AFRY Management Consulting

Executive summary 29

1 Introduction 33
1.1 Conventions 34
1.2 Structure of this report 34

2 Hydrogen demand 35
2.1 Assumptions and approach 35
2.1.1 Scope and approach to the estimation of the hydrogen demand 35
2.1.2 Estimation of demand in key sectors across Europe 35
2.1.3 Assignment of the geographic dimension to the sectoral demand 42
2.2 Results 46
2.2.1 Main results 46
2.2.2 Takeaways from the exercise 46

3 Hydrogen production 47
3.1 Assumptions and approach 47
3.1.1 Scope and approach to the estimation of the hydrogen supply 47
3.1.2 Calculation of the levelised cost of hydrogen production 49
3.2 Results 54
3.2.1 Main results – BLUE-GREEN scenario 54
3.2.2 Main results – FAST GREEN scenario 55
3.2.3 Takeaways from the analysis 55

4 Delivery systems 57
4.1 Discussion 57
4.1.1 Introduction 57
4.1.2 Storage 57
4.1.3 Transportation 59

4.2 Modelling 61
4.2.1 Introduction 61
4.2.2 Storage 62
4.2.3 Transportation 66
4.2.4 Cost optimisation – Hexamodel 67
4.2.5 Hexamodel results 67
4.2.6 Next steps in hydrogen ecosystem analysis 77
4.3 Conclusions and recommendations 77
4.3.1 Conclusions 77
4.3.2 Recommendations 77

5 References 79

Annex A – Additional Discussion and results 83
A.1 Maximum renewables energy potential 83
A.1.1 Estimation of the maximum practical solar PV energy potential 83
A.1.2 Estimation of the maximum practical wind energy potential 84
A.2 Further results 85
A.2.1 Seaborne transportation at European scale is limited 85
A.2.2 Retrofitting existing natural gas pipelines provides access to cheaper sources of hydrogen 86
A.2.3 Some routes provide common access to cheaper sources of hydrogen 86
A.2.4 Salt-caverns provide crucial storage services 88

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Conclusions drawn by Agora Energiewende

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1 Conclusions

1 Hard-to-abate industrial sectors represent a major area of hydrogen demand in the future due to a lack of alternative decarbonization options.

The race to climate neutrality is on. China, Japan, South Korea and the European Union have announced their intention to become climate-neutral and most of them want to achieve it by 2050.[1] In addition, the EU has raised its climate mitigation ambitions for 2030 to minus 55 percent greenhouse gas emissions relative to 1990.[2] In the wake of these developments, hydrogen from renewable energy has all but taken over as the darling of deep-decarbonisation. A broad spectrum of representatives from the industry, heat and transport sectors are racing to propose different ways of employing renewable hydrogen to decarbonise their operations.

For applications such as passenger cars and low-temperature building heat, conventional wisdom holds that there will be little room for hydrogen use, given its high energy efficiency losses,[3] but strong hydrogen advocates may see this differently. Where there is much more consensus is on the so-called "hard-to-decarbonise" or "hard-to-abate" applications.[4] What makes a sector hard to abate? Though the factors differ from sector to sector, the presumption is that direct electrification is difficult. In such cases, hydrogen or hydrogen-derived products may be needed because of their specific chemical properties, their high energy density and/or potential for long-term storage.

1 China wants to become carbon-neutral by 2060 (Murray 2020; European Council 2020).

2 European Council (2020)

3 See, e.g., Agora Verkehrswende, Agora Energiewende and Frontier Economics (2018); Fraunhofer-IEE (2020)

4 See e.g., IRENA (2020), Energy Transitions Commission (2020), McKinsey (2020)

Our analysis focuses on the least controversial hard-to-abate industrial sectors, which is why we consider the resulting hydrogen demand as "no-regret". The analysis maps no-regret hydrogen demand across Europe, connects it to low-carbon hydrogen generation[5] and elaborates on the need for transmission and storage infrastructure to connect demand with hydrogen supply – thereby contributing to ongoing discussions about future hydrogen networks in Europe.[6]

Steel, ammonia, refineries and chemical plants are widely distributed across Europe.

In our study, we focused on the industrial processes of ammonia production, methanol production, iron ore reduction, production of petrochemicals for plastics and fuels, and plastics recycling.

5 Nuclear power has not been investigated in this study. The long-term operation of existing nuclear may be a cost-effective option for hydrogen production in some European countries, but new plants do not seem to be a viable option at present, because most of the recent nuclear projects in Europe are already being outcompeted by wind and solar (Prognos 2014, IEA & NEA 2020).

6 European Commission (2020a), Guidehouse (2020)

300 TWh of low-carbon hydrogen will be required to reduce and eventually eliminate process emissions.

Figure 1 illustrates how aggregate hydrogen demand is projected to develop through 2050 by application. The underlying assumption is moderate growth in all sectors.[7] Given the climate neutrality target, we assume that hydrogen demand from refineries in Europe will vanish by 2050.[8] At the same time, we project that demand from steel plants and the chemical industry will increase over time. Overall, just under 300 TWh of low-carbon hydrogen will be required to reduce process emissions in the industrial sector.

Figure 2 shows the projected geographical distribution of the demand centres for 2050. The demand centres differ by more than an order of magnitude. Whereas smaller centres need less than 1 TWh hydrogen per year, the largest ones consume 10 to 30 TWh per year. Besides very high demand in the trilateral region of Belgium, the Netherlands and Germany due to the presence of a large cluster of chemical installations and steel plants, important demand centres can also be found in Eastern Europe and along the Mediterranean.

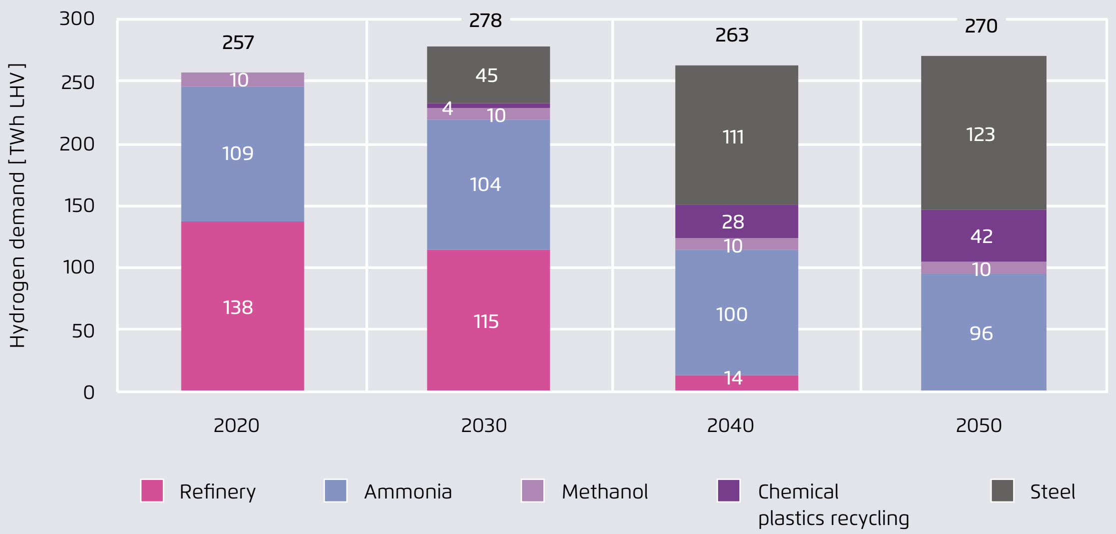
The exceptional growth in demand for low-carbon hydrogen by 2050 in the steel sector is supported by the plans of steel producers all over Europe to move to direct reduced iron (DRI) steel, as shown in Table 1. And as recent announcements from China and Korea show, EU companies are not the only ones.[9]

7 Here, we have mainly relied on Material Economics (2019) and the assumption that most demand will be met from within Europe, as it has been in the past. However, there is research to suggest that trade in hydrogen-derived electrofuels might eclipse trade in hydrogen. See Dena and LUT (2020).

8 Electricity-based synthetic liquid fuels (i.e. power-to-liquid) are expected to be imported to Europe in the future. See, e.g. Prognos, Öko-Institut, Wuppertal-Institut (2020).

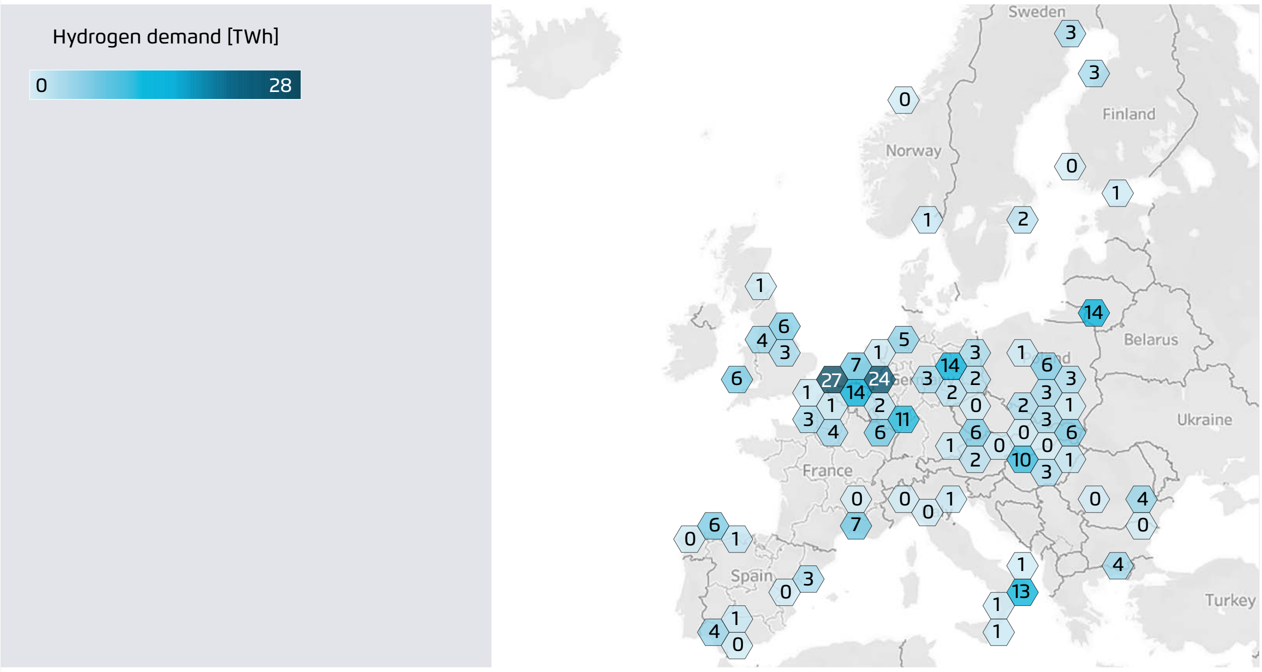
9 En24 (2020), Tenova (2020)

Industrial hydrogen demand from 2020 to 2050 within the specific demand sectors in TWh per year — Figure 1



AFRY (2021).

Distribution of industrial hydrogen demand projected for 2050 in TWh per year — Figure 2



AFRY (2021). Demand in 2050 is mainly driven by ammonia and steel production.

EU steel companies' plans for the deployment and commercialization of DRI plants before 2030 — Table 1

Project, Site	Country	Company	Status Quo	Fuel	Timeline
HYBRIT, Lulea		SSAB	Started pilot operation with clean hydrogen in 2020 (TRL 4-5)	Green H_2	2020: pilot plant 2026: commercia
DRI, Galati		Liberty Steel	MoU signed with Romanian government to build large-scale DRI plant within 3-5 years Capacity: 2.5 Mt/DRI/year	Natural gas, then clean H_2	2023-2025: commercial
tkH2Steel, Duisburg		Thyssen-krupp	Plan to produce 0.4 Mt green steel with green hydrogen by 2025, 3 Mt of green steel by 2030	Clean H_2	2025: commercial
H-DRI-Project, Hamburg		Arcelor Mittal	Planned construction of an H2-DRI demo plant to produce 0.1 Mt DRI/year (TRL 6-7)	Grey H_2 initially, then green H_2	2023: demo plant
SALCOS, Salzgitter		Salzgitter	Construction of DRI pilot plant in Salzgitter	Likely Clean H_2	n.a.: pilot plant
DRI, Donawitz		Voest-alpine	Construction of pilot with capacity of 0.25 Mt DRI/a	Green H_2	2021: pilot plant
DRI, Taranto		Arcelor Mittal	Plans to build DRI plant, ongoing negatiations with Italian government	n.a.	n.a.
IGAR DRI/BF, Dunkerque		Arcelor Mittal	Plans to start hybrid DRI/BF plant and scale up as H_2 becomes available	Natural gas then Clean H_2	2020s

Agora Energiewende analysis.

Our analysis of industrial demand does not factor in demand from process heat, however.

40% of today's industrial natural gas use in the EU goes to heat below 100°C and can be supplied with heat pumps

In 2017, total industrial final energy demand for natural gas in the EU-28 amounted to about 970 TWh.[10] Many energy scenarios in existing studies tacitly assume that much of the natural gas volume consumed by industrial applications today will need to be substituted with hydrogen or biomethane in the future.[11] But the brush used to paint this picture is too broad: in reality, different industrial processes require different grades of heat – which is why we need to reconsider the assumptions behind these scenarios.

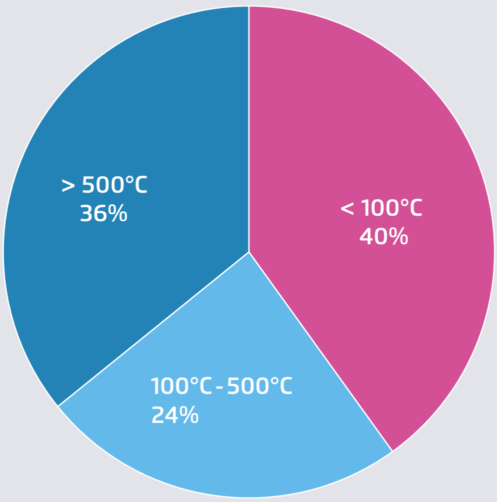
10 Final non-energy use of natural gas in industry amounted to about 180 TWh. (Both figures reflect the lower heating value.) Eurostat (2020)

11 See the scenario comparison in section 2.1.2 (AFRY 2021).

It turns out that gas technologies are not the only suitable candidates for providing industrial process heat. Figure 3 shows natural gas final consumption by European industry broken into three separate heat brackets: less than 100 degrees Celsius; between 100 and 500 degrees Celsius, and above 500 degrees Celsius. We note that 40% of industrial heat in Europe belongs to the sub 100 degrees Celsius bracket, which is well within the remit of heat pumps. These technologies are able to leverage ambient or recycled waste heat, allowing them to move around more heat energy than they consume in electrical energy, leading to performance factors exceeding 100%. Indeed, industrial heat pumps are already found in the food and beverage, packaging, textile and chemical industries. However, for temperatures exceeding 100 degrees Celsius, which account for the remaining 60% of natural gas used in industrial process heat, the commercially available heat pumps of today are not yet up to the task.[12]

12 The future holds even greater potential for heat pumps. Prototypes already exist today for up to 140°C and research indicates that they can achieve up to 200 °C (Arpagause et al. 2018).

Natural gas final energy consumption for 2017 in the EU industry sector by application temperature Figure 3



FFE (2020). See the appendix on page 25 for the distribution by EU member state.

Even for higher temperatures, a range of power-to-heat options can be more energy-efficient than hydrogen and should be considered first.

Electricity can be used directly to generate heat via physical mechanisms such as resistance, infrared, induction, microwave and plasma heating. A total of eight mechanisms for electric heating are commercially established, of which six can produce temperatures in excess of 1000 degrees Celsius (see Figure 4).[13] Electric systems appear to be more efficient than hydrogen systems because they require less energy conversion.[14]

Available power-to-heat technologies can cover all temperature levels needed in industrial production.[15] A well-known example is the electric arc furnace in steel production, which reaches temperatures of up to 3500°C.[16] Electric heating technologies appear to

13 Madeddu et al. (2020).

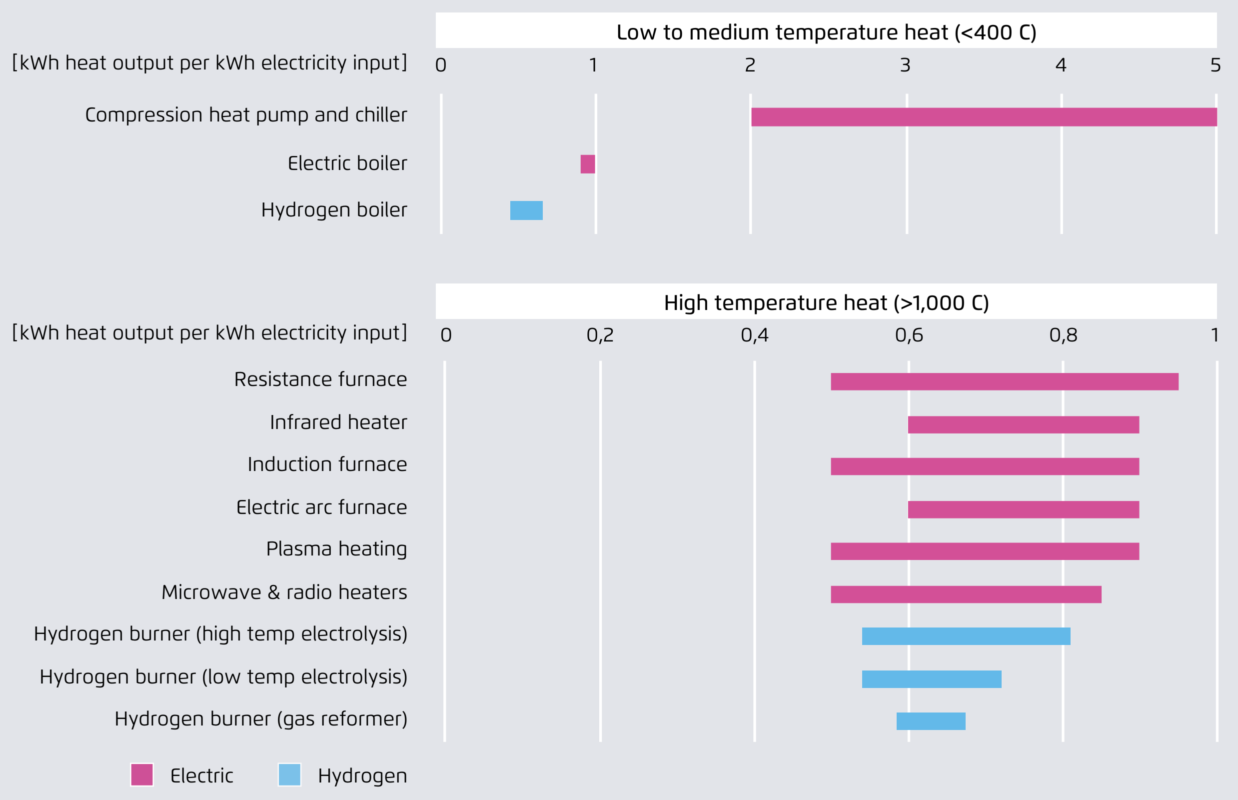
14 A more comprehensive comparison would need to also factor in the backup necessary for power generation from variable renewable energy sources. See, e.g., Prognos, Öko-Institut, Wuppertal-Institut (2020)

15 Madeddu et al. (2020).

16 Rentz et al (1997).

Performance factors of power-to-heat technologies vs. heat from burning hydrogen derived from electrolysis

Figure 4



Note: Values refer to lower heating value. Hydrogen burner efficiency of 90%. Efficiencies do not consider midstream losses. Hydrogen produced by gas reforming has gas as its energy input.
Madeddu et al. (2020), IEA (2019), Lowe et al (2011).

offer other benefits as well. They provide more flexibility than conventional convection heating technologies, greatly reducing preheating and treatment times and improving the strengths of materials during, say, aluminium hot forging.[17] Infrared-processed materials are stronger and more fatigue resistance than conventionally processed materials.

Given that the performance factor of electric heating is at the very least comparable to and at the very best – such as in the case of heat pumps – considerably better than burning hydrogen from electrolysis, power-to-heat technologies should be considered before thinking about producing heat from hydrogen. Accordingly, industrial heat demand should be re-assessed by application and heat range to determine its relevance from the point of view of hydrogen infrastructure.

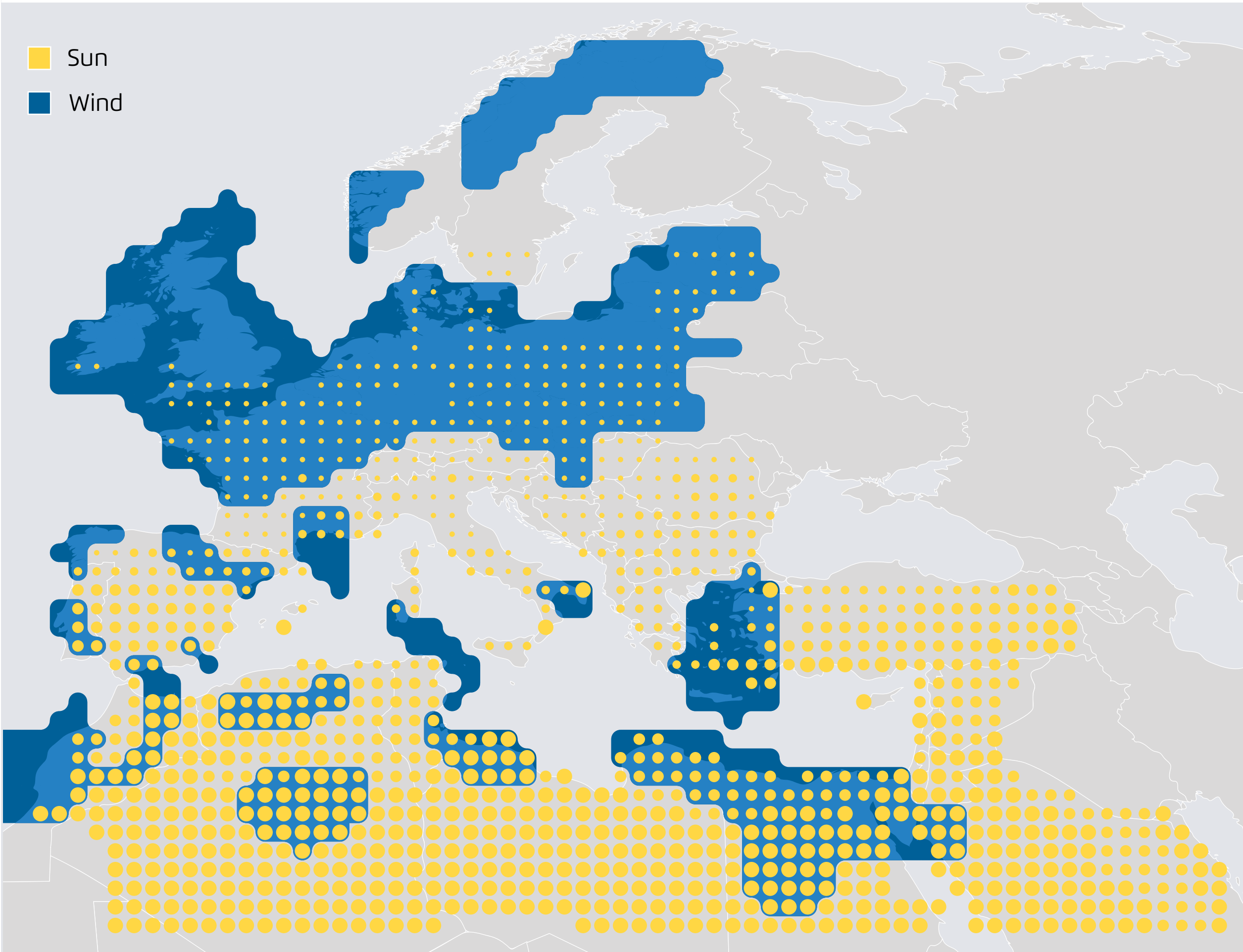
17 Arena (2019).

2 **The investment window for fossil-based hydrogen with carbon capture remains open, but in the long run renewable hydrogen will emerge as the most competitive option in Europe.**

For industrial processes that cannot be electrified, the most important question going forward is how to secure a supply of low-carbon hydrogen. We commissioned AFRY to explore the supply options from a cost-optimisation perspective, taking into account geospatial and political limitations as well as the possibility of imports from outside the EU.

Fundamentally, European and neighbouring countries have a high renewable energy potential that can be tapped for direct-electric applications and renewable hydrogen production (Figure 5). While the wind potential is stronger in Central-North Europe, solar PV will become increasingly important in the south. In parts of the MENA region, the best potential is reached by combining solar and wind.

Solar and wind potential in Europe and the MENA region — Figure 5



Dii & Fraunhofer-ISI (2012).

In addition to renewable hydrogen, AFRY considered fossil-based hydrogen from steam methane reforming with carbon capture and storage (SMRCCS) for three countries that are actively developing these technologies: Netherlands, Norway and the UK.

The analysis encompassed two scenarios:

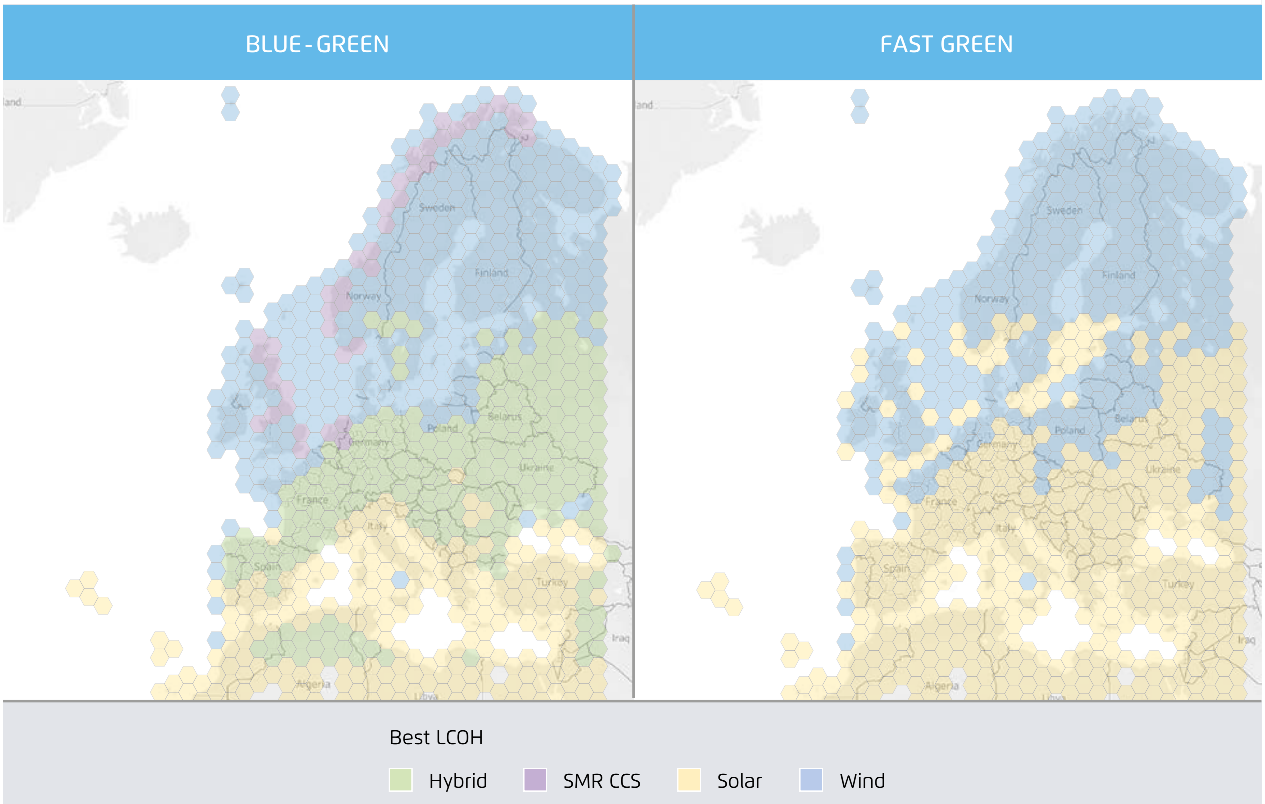
1) the BLUE-GREEN scenario, which, in addition to renewable hydrogen, considers hydrogen produced by SMRCCS in the three countries mentioned above.
2) the FAST GREEN scenario, which rules out SMRCCS and assumes an aggressive reduction in electrolyser costs over the period of the study in line with targets set by the EU hydrogen strategy.

Taking into account asset lifecycles and political commitments in the BLUE-GREEN scenario, fossil-based hydrogen with carbon capture will remain a viable investment until the 2030s.

Figure 6 shows the best levelised costs of hydrogen (LCOH) for both scenarios for 2030. In the BLUE-GREEN scenario, SMR CCS is confined to North Europe, where it competes with renewable hydrogen from offshore wind. In the south, solar PV has the lowest LCOH. Sandwiched in-between is a central European belt where the cheapest hydrogen would be achieved by a hybrid mix of wind and solar resources. While SMR CCS plays a role in BLUE GREEN in 2030, it becomes uncompetitive by 2050.[18]

18 See AFRY (2021), section 3.2.

Best levelised costs of hydrogen in the BLUE-GREEN and FAST GREEN scenarios for 2030 Figure 6



AFRY (2021). Hybrids use both solar PV and wind. In the BLUE-GREEN scenario, SMR CCS is restricted to the Netherlands, the UK and Norway.
© 2020 Mapbox © OpenStreetMap.

However, strong policies for renewable hydrogen will shorten the investment window for fossil hydrogen, likely closing it by the end of the 2020s.

Under the FAST GREEN scenario, investments in fossil-based hydrogen with carbon capture will become largely uncompetitive relative to renewable hydrogen from electrolysis before the 2030s.[19] Moreover, the hybrid business model will come under increasing pressure as cheaper electrolysers are able to break-even based on solar power alone in South and Central Europe.

Ambitious policy will be needed to drive down the cost of renewable hydrogen.

The European Commission and several member states have published their hydrogen strategies.[20] Those strategies encompass different policy support options for bridging the cost gap between unabated fossil-based technologies and renewable hydrogen, but they do not stipulate the implementation of actual instruments. If new policy instruments can deliver the 40 GW of electrolysis that Europe aims to achieve by 2030, the cost reductions in the FAST GREEN scenario could become a reality.[21]

19 This assessment is based on our own evaluation of the levelised cost of hydrogen provided in the public Tableau workbook: https://www.agora-energiewende.de/en/publications/data-appendix-no-regret-hydrogen

20 European Commission (2020b) and Hydrogen Europe (2020).

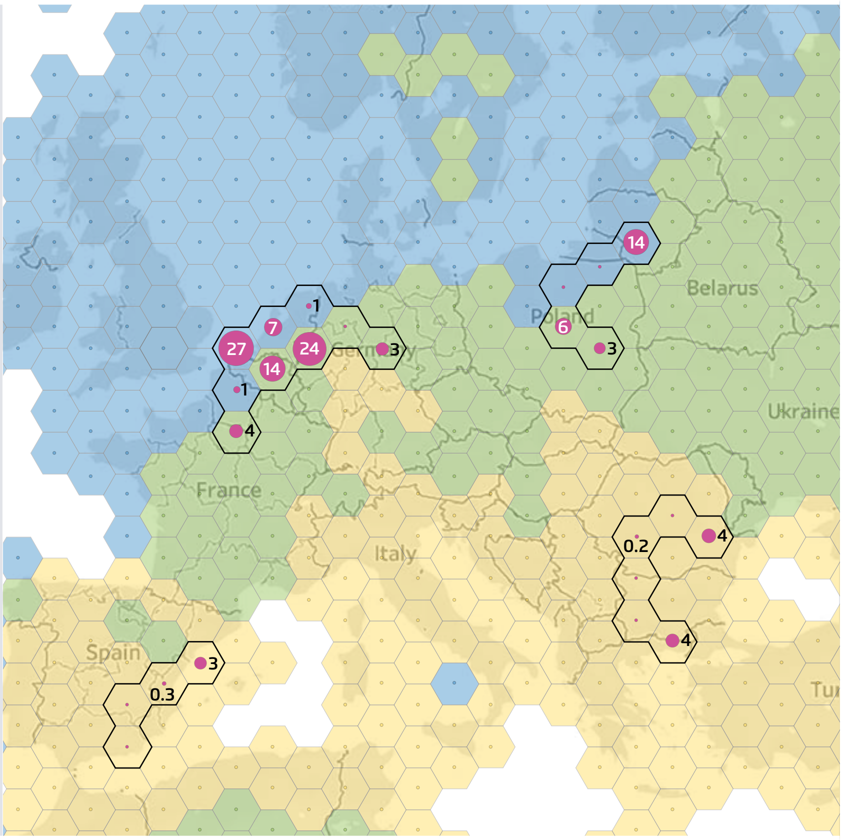
21 The cost curve would fall quicker still if the rest of the world pursued an equally ambitious hydrogen policy.

3 We identify robust no-regret corridors for early hydrogen pipelines based on industrial demand.

Based on the no-regret demand and the supply analysis decribed above, AFRY identified the optimal locations for hydrogen infrastructure across continental Europe. The resulting infrastructure delivers hydrogen to demand clusters at the lowest possible cost, and provides access to hydrogen storage to facilitate flexibility and seasonality.

Figure 7 shows pipelines that are resilient to both future levels of hydrogen demand and the technology assumptions considered here. They thus represent robust corridors for early investments in hydrogen delivery systems. Four such "no-regret" corridors were identified in total: in Central-West Europe, in East Europe, in Spain and in South-East Europe. Based solely on the industrial hydrogen demand and the technology and cost assumptions considered in this analysis, there is no justification for creating a larger, pan-European hydrogen backbone.

No-regret pipeline corridors with industrial hydrogen demand in TWh per year in 2050 — Figure 7



Note: Only those hydrogen pipelines that are resilient to the future levels of hydrogen demand and the technology assumptions used here have been considered to be "no-regret". See section 4.2.5.1 for more details and the annex for further results.

AFRY (2021).

Adding potential hydrogen demand from power, aviation and shipping sectors is likely to strengthen the case for a more expansive network of hydrogen pipelines.

Hydrogen is likely to become important as a back-up power supply for systems largely run on variable renewable energy sources,[22] for meeting the residual heat load in mostly decarbonised district heating systems and for providing energy-dense fuels for long-range aviation and shipping.[23] Adding those other hard-to-abate applications would increase the total demand for low-carbon hydrogen and amplify the need for connections between supply and demand clusters across Europe.

However, even under the most optimistic scenarios any future hydrogen network will be smaller than the current natural gas network.

In 2017, total gross inland natural gas consumption in the EU amounted to some 4600 TWh,[24] and the existing natural gas transmission network consisted of around 250 000 km[25] of pipelines. For 2050, most of the scenarios with 100% decarbonisation project a total demand of between 1000 and 2000 TWh of hydrogen, or between 20% and 40% of the natural gas energy consumed today.[26]

22 Possible alternatives for long-term storage also include pumped hydroelectricity, compressed air electricity storage and redox flow and sodium-sulfur batteries (IRENA 2017).

23 For the case of climate neutrality in Germany, see Prognos, Öko-Institut, Wuppertal-Institut (2020)

24 JRC (2020) .

25 GIE & Snam (2020).

26 JRC (2020).

A no-regret vision for hydrogen infrastructure reduces the risk of oversizing by focussing on inescapable demand, robust green hydrogen corridors and storage.

Assuming massive hydrogen use in not-so-hard-to-abate sectors runs the risk of oversizing hydrogen infrastructure. Because competition between electricity and hydrogen from electricity favors direct-electric technologies with fewer efficiency losses (as in the cases of passenger cars and building heat), a prudent approach would concentrate on demand from hard-to-abate sectors first.

While this study represents a step towards such a no-regret vision for hydrogen infrastructure, it is only the first piece of the puzzle. A more complete accounting would require expanded scenarios with additional hydrogen demand from power and district heating, and would perhaps have to factor in demand from long-range aviation and shipping. Moreover, a more detailed assessment of the midstream is needed on two levels. First, if the majority of final hydrogen demand ends as electrofuels, as a recent study projects,[27] will ship transport become competitive again in the backbone scenario? Second, what are the opportunity costs for ultra-high-voltage, direct-current electricity connections instead of a hydrogen backbone?

Until these issues are well understood, considerable uncertainties will remain regarding the robustness of further backbone infrastructure development within the EU.[28] It's because of these uncertainties that we propose focussing on the clear no-regret hydrogen corridors identified in this study. The corridors linking European industry can anchor hydrogen demand in the near term while retaining the flexibility to expand the network should more hydrogen demand materialise in the future.

27 Dena & LUT (2020).

28 See AFRY (2021) for further analytical refinements.

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3 Annex

Natural gas final energy consumption for 2017 in the industry sector by application temperature and member state

Table 2

	TWh per year				Distribution in percent			
	< 100°C	100°C-500°C	>500°C	Total	< 100°C	100°C-500°C	>500°C	Total
Austria	13	8	10	31	43%	24%	32%	100%
Belgium	16	11	20	46	34%	23%	43%	100%
Bulgaria	4	2	5	11	37%	20%	43%	100%
Croatia	2	1	2	4	44%	19%	38%	100%
Cyprus	0	0	0	0				
Czech Republic	13	5	7	25	52%	21%	27%	100%
Denmark	4	2	2	8	45%	28%	27%	100%
Estonia	1	0	0	1	53%	35%	12%	100%
Finland	4	3	0	7	57%	40%	3%	100%
France	51	25	32	109	47%	23%	30%	100%
Germany	81	67	95	243	33%	28%	39%	100%
Greece	2	1	1	4	52%	17%	31%	100%
Hungary	8	3	5	16	51%	17%	32%	100%
Iceland	0	0	0	0				
Ireland	3	3	3	9	38%	29%	33%	100%
Italy	42	24	37	103	41%	23%	36%	100%
Latvia	1	0	0	1	65%	16%	19%	100%
Lithuania	1	0	1	3	43%	14%	42%	100%
Luxembourg	1	1	2	3	17%	23%	59%	100%
Malta	0	0	0	0				
Netherlands	22	15	24	61	36%	25%	39%	100%
Norway	2	0	2	3	48%	8%	45%	100%
Poland	13	12	18	43	30%	28%	42%	100%
Portugal	6	3	5	14	39%	23%	38%	100%
Romania	11	3	12	26	41%	13%	46%	100%
Slovakia	7	1	3	10	69%	5%	26%	100%
Slovenia	1	2	2	5	28%	30%	42%	100%
Spain	32	23	33	88	36%	26%	38%	100%
Sweden	2	0	0	3	80%	7%	12%	100%
United Kingdom	48	19	26	93	51%	21%	28%	100%
Total	**389**	**234**	**348**	**971**	**40%**	**24%**	**36%**	**100%**

FFE (2020)

No-regret hydrogen: Charting early steps for H_2 infrastructure in Europe

Study conducted by
AFRY Management Consulting

Please cite as:
AFRY Management Consulting (2021): No-regret hydrogen: Charting early steps for H_2 infrastructure in Europe. Study conducted by AFRY Management Consulting.
In: Agora Energiewende and AFRY Management Consulting (2021): No-regret hydrogen: Charting early steps for H_2 infrastructure in Europe.

Executive Summary

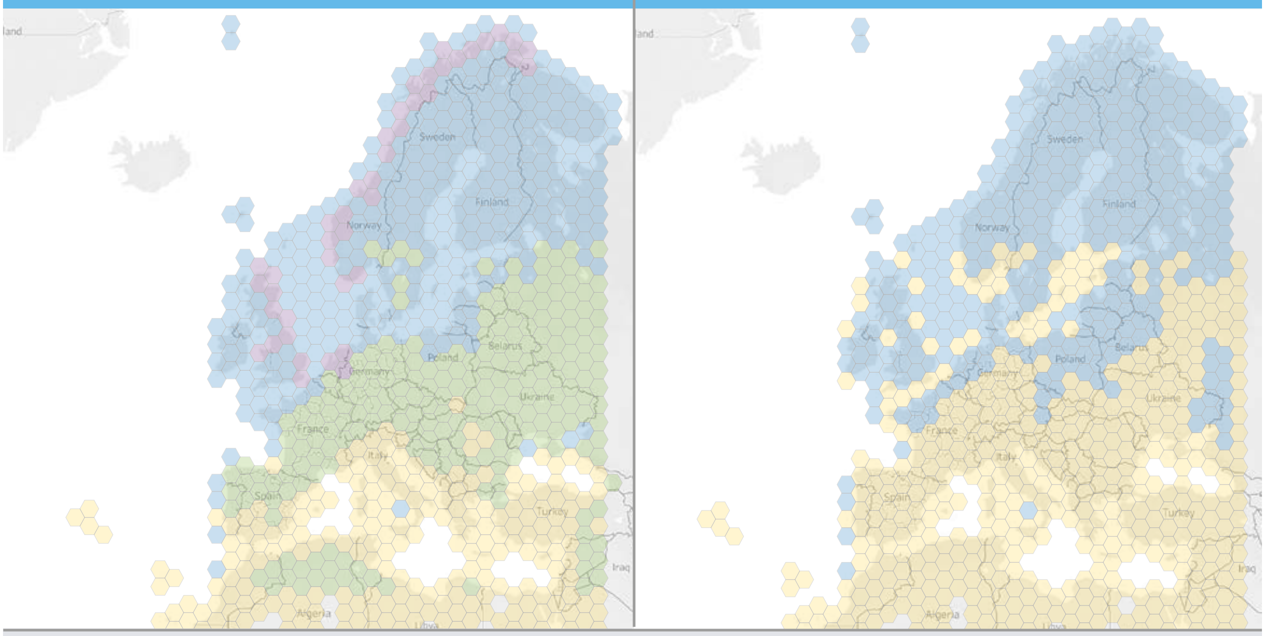
The challenge of decarbonising the European economy is widely acknowledged. Though significant progress since the first commitments to transitioning to a sustainable future were made, decarbonisation is becoming increasingly difficult, and there is an urgent need to focus on industry, process heat, space heating, and transport.

While there is no consensus that hydrogen will be the optimal solution in sectors where alternatives are widely available – particularly in transport and heating – there is a broader consensus on the role of hydrogen in certain hard-to-abate industrial sectors. With this comes the need to understand whether there is utility in establishing a "hydrogen backbone" across Europe that would allow the transportation and storage of hydrogen. Recent studies suggest that there might be an opportunity to lower the costs of serving future hydrogen demand through repurposing parts of the European gas pipeline network.

This paper indicates that hydrogen demand clusters will arise around large ammonia, steel, and petrochemical plants. However, the cheapest way to supply hydrogen to each location varies depending on technology cost assumptions. The technology outcomes used in this study are shown in Figure ES-1.

Best levelised cost of hydrogen in 2030 in the scenarios BLUE-GREEN and FAST GREEN | Figure ES-1

BLUE-GREEN	FAST GREEN



Best LCOH

Hybrid | SMR CCS | Solar | Wind

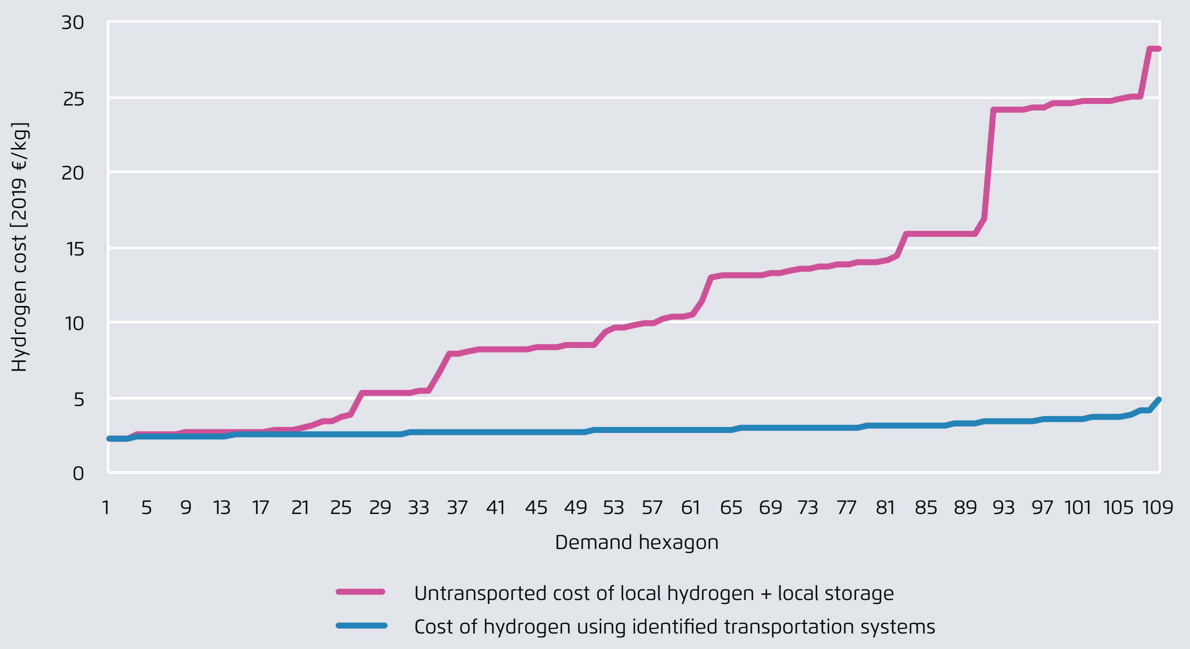
AFRY analysis. © 2020 Mapbox © OpenStreetMap.

We used our hydrogen delivery system model, "Hexamodel", to identify the optimal location of hydrogen infrastructure across continental Europe. The resulting infrastructure facilitates the most economic supply of hydrogen to meet demand clusters and provides access to hydrogen storage to facilitate flexibility and seasonality. The infrastructure lowers the geographical differences in the cost of hydrogen, as depicted in Figure ES-2.

Because the location of production varies depending on technology cost assumptions, the delivery system identified is sensitive to technology cost assumptions. Despite this sensitivity, we find that some delivery systems in Europe are common across the investigated scenarios, as shown in Figure ES-3. These delivery systems are resilient to both future hydrogen demand and the technology assumptions we have considered. The core European Hydrogen Backbone thus represents a "no-regret" investment for Europe.

Transportation impact

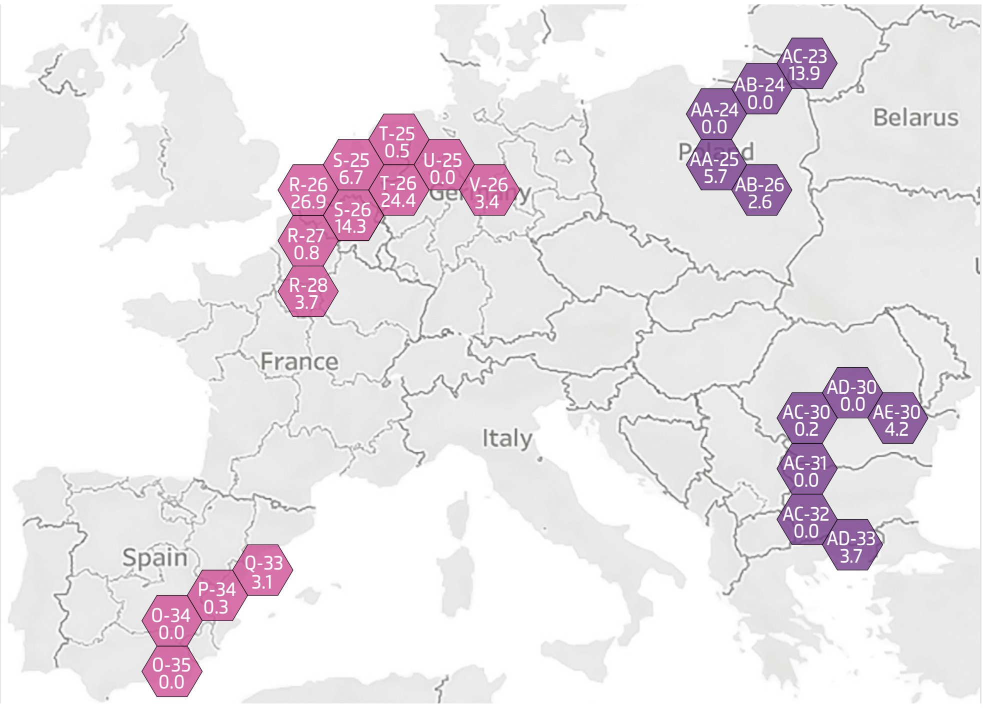
Figure ES-2



AFRY analysis. Results from the 2030 BLUE-GREEN analysis.

Clear "no-regret" routes (hexagons contain the ID and the demand in 2050 in TWh) Figure ES-3

- Clear "no-regret" (TSOs study – conversion)
- Clear "no-regret" (outside TSOs study – assumed new builds)



AFRY analysis. © 2020 Mapbox © OpenStreetMap.

1 Introduction

The challenge of decarbonising the European economy is widely acknowledged, and the EU's Green Deal[1] aims to achieve climate neutrality by 2050. There has been significant progress since the first commitments to a sustainable future were made and much of this progress has come without regret. However, the next phases of decarbonisation present increasing levels of challenge and risk, as the focus switches to decarbonising industry, process heat, space heating, and transportation.

The World Energy Outlook 2020[2] states that low-carbon hydrogen can have a variety of applications in tackling emissions in hard-to-abate sectors – iron, steel, and fertiliser production; transport and buildings – and in acting as a flexibility provider by storing electricity and helping to balance power systems.

While there is no consensus that hydrogen will be the optimal option in those sectors where alternatives are widely available – low-temperature heating and passenger cars, say – there is a broader consensus on the role of hydrogen in certain hard-to-abate sectors, chiefly in industry, aviation, and maritime transport. The EU Hydrogen Strategy[3] recognises it as a "solution to decarbonise industrial processes and economic sectors where reducing carbon emissions is both urgent and hard to achieve". These sectors have also been the object of recent interest from bodies such as IRENA[4] and the World Energy Council[5], which have highlighted the importance of hydrogen in the decarbonisation process.

Low-carbon and renewable hydrogen have a vital role to play in reducing the carbon footprint of specific industries that are essential to the ongoing competitiveness of the European economy. This study investigates the use of hydrogen in specific industries – the most likely sector to develop hydrogen demand in the short-term – in order to derive insights on the establishment of a hydrogen backbone and whether there may be any low-regret opportunities.

Unless hydrogen production is located near demand, hydrogen will need a dedicated delivery system. Given the policy reliance on wind- and solar-based renewable electricity for the production of hydrogen in Europe, the hydrogen delivery system will also need to include storage systems to absorb both short-term, weather-based variation and longer-term seasonality.

This paper examines:

→ The hydrogen demand required to decarbonise specific industrial sectors. This could be considered an expected minimum level of hydrogen demand.
→ The potential hydrogen production volumes needed to supply a minimum level of hydrogen demand and their associated costs.
→ The possibilities for establishing a hydrogen delivery system to support Europe's economy regardless of the actual path of decarbonisation while serving the minimum level of hydrogen demand.

For the sake of simplification, we consider the hydrogen system in isolation from the electricity system. In our model, for instance, the hydrogen produced from electrolysis is supplied by dedicated

1 European Commission (2020): A European Green Deal.

2 IEA (2020): World Energy Outlook 2020.

3 European Commission (2020): A hydrogen strategy for a climate-neutral Europe (COM/2020/301)

4 IRENA (2020): Reaching zero with renewables.

5 World Energy Council (2020): International hydrogen strategies.

RES generation. We acknowledge that both the electrolysers and RES generation may represent and achieve better value when connected to the electricity grid.

The conclusions of this paper present a vision of a "no-regret European Hydrogen Backbone" and propose a number of recommendations for further study and policy development.

The paper has been produced by AFRY Management Consulting (AFRY) working alongside Agora Energiewende. AFRY exerted final editorial control and the paper's conclusions represent AFRY's independent views.

1.1 Conventions

Unless otherwise stated, monetary values quoted in this report are in euros in real 2019 prices.

Unit costs and efficiencies identified in the report are defined at the Lower Heating Value (LHV) basis unless otherwise stated.

Unless otherwise noted, the source for all tables, figures, and charts is AFRY Management Consulting.

1.2 Structure

This report contains three main chapters – demand, supply, and delivery systems. Each is presented in a bottom-up style (methodology, results) in order to make the underlying assumptions transparent and to facilitate the discussion of assumptions and uncertainties. Various appendices are provided to illuminate the analysis. A Tableau Workbook has also been published containing detailed results for analysts to explore.

2 Hydrogen Demand

2.1 Assumptions and approach

2.1.1 Scope of hydrogen demand and its estimation

This study considers only large-scale industrial demand for feedstock and chemical reaction agents. This demand is difficult to fully decarbonise without using hydrogen, and Agora Energiewende believes hydrogen is the only workable low-carbon option. The study thus considers hydrogen to be a 'no-regret' solution.

The derivation of the demand points is conducted in two steps. The future industrial processes with the highest hydrogen demand potential are derived and quantified in section 2.1.2, while the geographical distribution of the processes within Europe are explained in section 2.1.3.

2.1.2 Estimation of demand in key sectors across Europe

Hydrogen in industrial applications can be used in three distinct categories:

1. chemical feedstocks for the synthesis of products in which it is a molecular constituent (e.g. ammonia, methanol);
2. chemical reaction agents in which it takes part in chemical reactions but is not a molecular constituent of the final product (e.g. the direct reduction of iron ore); and
3. combustion fuels for the supply of heat (e.g. heating cement kilns).

Today, hydrogen is primarily utilised within the first category. It is not extensively used for the other categories because cheaper options exist. Most hydrogen at industrial scale is currently produced from natural gas using either steam methane reforming (SMR) or auto-thermal reforming (ATR).[6] Both processes result in the emission of carbon dioxide. Emissions could be eliminated by switching to carbon-free hydrogen produced with electrolysis and renewable electricity. Other process emissions occur from using carbon-based materials as reaction agents. Here a switch to carbon-free hydrogen as a reaction agent (category 2) could also reduce carbon emissions.

For the purposes of this study, we focus only on the reduction of process emissions and thus on the utilisation of hydrogen as described in category 1 and 2. Those categories are 'no-regret' hydrogen demand points. While we acknowledge that hydrogen might have a valuable role as a combustion fuel – though electric arcs, biomass, heat pumps, and other zero-carbon technologies could potentially do the job as well – this study has not included category 3 as a 'no-regret' demand for hydrogen. The infobox below highlights some of these alternative technologies.

Over the period examined in this study, Agora Energiewende expects that chemical plastics recycling will grow, lowering the requirements for the production of new plastics. Chemical recycling will require hydrogen as a feedstock.

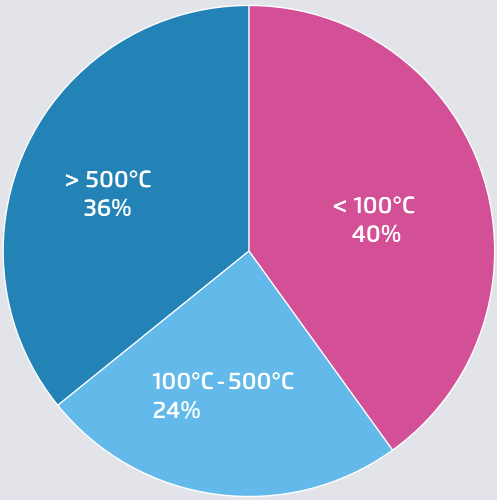
6 For simplicity's sake, we refer only to SMR.

INFOBOX

While it may seem natural to replace natural gas with hydrogen for industrial combustion processes, it is important to remember that low-carbon alternatives to natural gas are not limited to hydrogen. In addition to biomass- based thermal solutions there are several electricity-based technologies with varying degrees of maturity and efficiency. Heat pumps, one of the most efficient electricity-based mature technologies, is typically associated with low-temperature heat. As highlighted by Silvia Madeddu et al. (2020)[7], however, heat pumps are well-established in industry for temperatures of up to 100°C, and heat demand below 100°C makes up 40% of current industrial natural gas use, as illustrated in the figure below. The same paper also presents an overview of electric-based heating technologies that can reach temperatures above 100°C, such as electric arc furnaces and plasma technology, with efficiency levels that vary between 50% and 95%.

Other research suggests that heat pumps are currently able to reach 160°C[8], and that it would be technically and economically feasible to reach 280°C[9].

Natural gas final energy consumption in the EU industry sector by application temperature (2017) Figure 1



FfE mbH (2019)[10] and FfE e.V. (2020)[11]

7 Silvia Madeddu et al. (2020): Environ. Res. Lett. 15 124004.

8 Cordin Arpagaus et al. (2018): High temperature heat pumps: Market overview, state of the art, research status, refrigerants, and application potentials.

9 B. Zühlsdorf et al. (2019): Analysis of technologies and potentials for heat pump-based process heat supply above 150 °C.

10 FfE mbH (2019): Electrification decarbonization efficiency in Europe – a case study for the industry sector.

11 FfE e.V. (2020): eXtremOS - Ländersteckbriefe für 17 europäische Länder erstellt.

In the United Nations Climate Change inventory data, process emissions in Europe are classified into three main sectors, as shown in Figure 2. This allows us to establish the key focal points of the analysis:

1. The current use of hydrogen in the synthesis of ammonia and methanol and in hydrocracking and hydrotreating raw oil products takes up a large portion of process emissions in the chemical industry and in 'other' industries. This could be almost entirely abated by a switch to low- carbon and carbon-free hydrogen.
2. A large portion of process emissions in the metal industry sector is connected with the reduction of iron ore via coke, which releases carbon dioxide. These emissions could be abated by using hydrogen as a reducing agent.
3. In the minerals sector, most emissions cannot be abated because carbon dioxide is a molecular constituent of the raw minerals, which is released under high temperatures. The production of clinker, primarily used in cement, is responsible for 78Mt of the 112Mt emitted by the mineral industry.

In addition, we have assumed that chemical plastic recycling will be a crucial technology to achieve a sustainable future for waste management and to reduce the demand for raw oil products and emissions from refineries. Plastic recycling will also contribute to the demand for hydrogen.

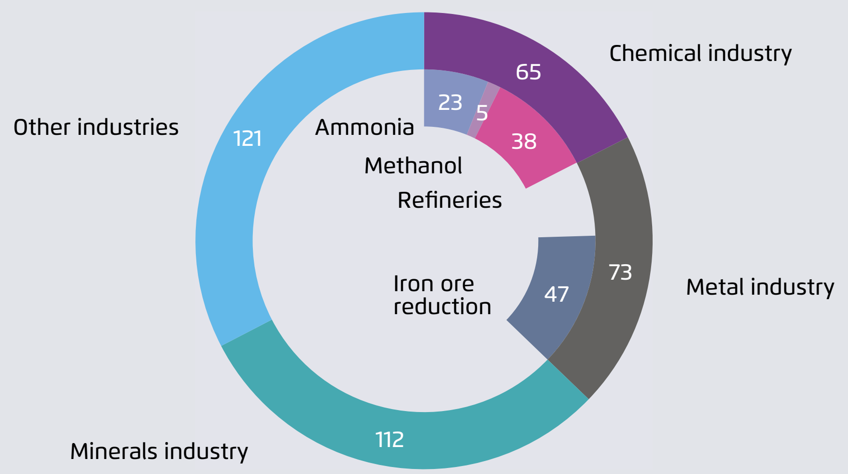
The scope of the study thus encompasses the following processes:

1. Ammonia production
2. Methanol production
3. Iron-ore reduction in the steel industry
4. Production of petrochemicals for plastics and fuels utilising hydrogen
5. Plastics recycling

For every process, we estimated the demand for hydrogen by examining the demand for the underlying commodity. In this report, AFRY has mainly relied on the underlying product demand projected in a study by Materials Economics[12] showing moderate growth in all sectors.

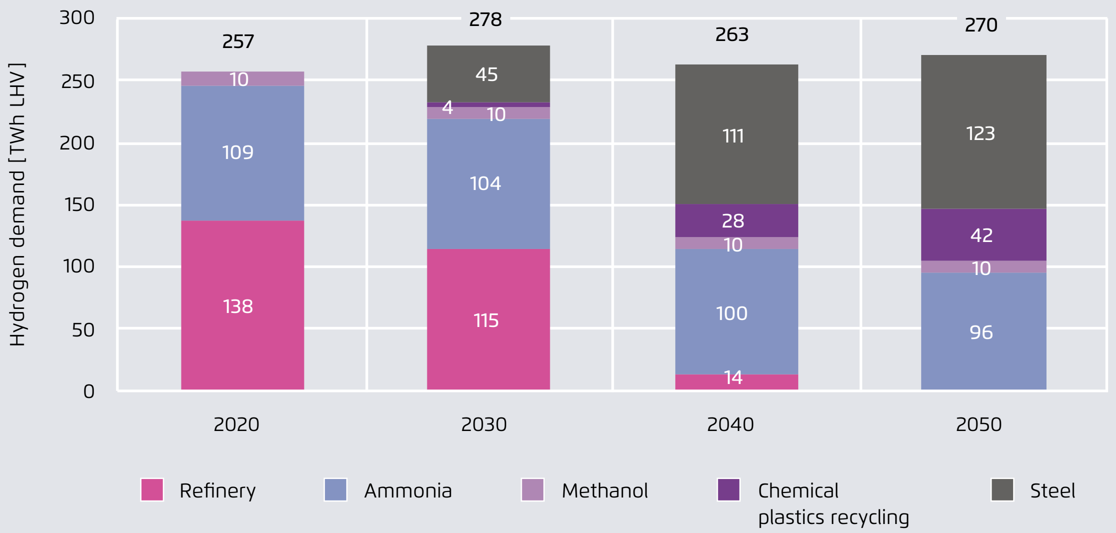
12 Material Economics (2019): Industrial transformation 2050- pathways to net-zero emissions from EU heavy industry.

Overview of process emissions (Mt) in Europe in 2018 and the specific emissions levels by source — Figure 2



AFRY analysis of the United Nations Climate Change inventory dataset.

Trajectory of industrial hydrogen demand from 2020 to 2050 within specific demand sectors — Figure 3



AFRY analysis.

The total 'no-regret' demand is presented in Figure 3. Starting with a demand for hydrogen totalling 257 TWh in 2020 (broadly consistent with the 2018 estimate of 8.3Mt by Hydrogen Europe[13]), total demand is projected to be slightly higher in 2030 at 278 TWh and then decline slightly to about 270 TWh by 2050. In 2050, the demand is projected to consist of 123 TWh for steel, 96 TWh for ammonia, 42 TWh for chemical recycling of plastics, and 10 TWh for methanol.

The overall trend shows a decline in demand from refineries, while demand from steel plants increases over time. The evolution of hydrogen demand over time in each process is explained below.

Figure 4 shows the 'no-regret' demand for 2050 compared with a selection of findings from other studies concerned with industrial hydrogen demands. As can be seen, most of the studies target a degree of decarbonisation in the range of 90–100% with a primary focus on the steel, chemicals, and cement sectors, thus indicating comparable approaches. Studies that project a much lower hydrogen demand foresee a significant decrease in commodity demand.[14] This marks the greatest difference between their estimations and our own. There are also studies projecting a much larger hydrogen demand. They either assume greater commodity demand or additionally cover the use of hydrogen in combustion processes.[15] These assumptions do not necessarily reflect the 'no-regret' approach that we have used in this study.

2.1.2.1 Ammonia & methanol

Ammonia is an important base chemical. Its synthesis relies on hydrogen as a feedstock chemical. Approximately 6.4 MWh of hydrogen is needed to

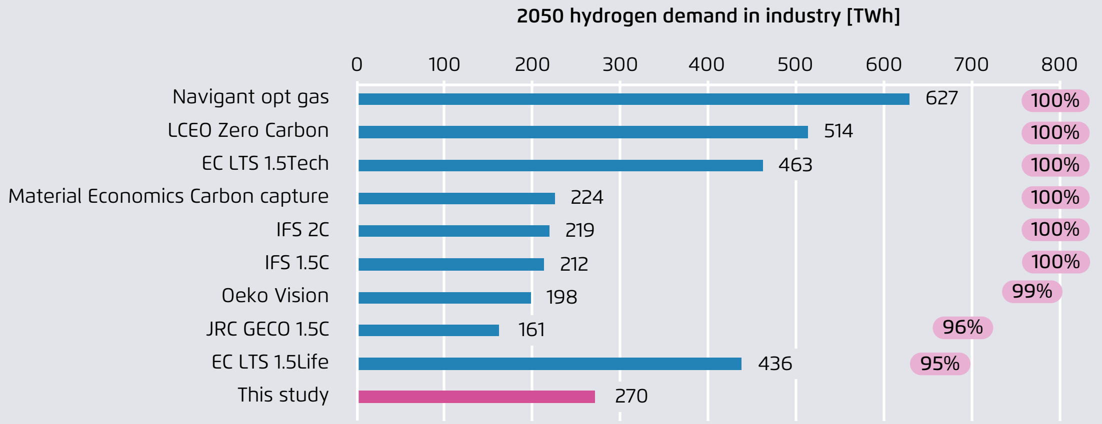
13 Hydrogen Europe (2020): Clean hydrogen monitor 2020.

14 See, for example, Joint Research Centre (2020): Towards net-zero emissions in the EU energy system by 2050

15 See, for example, European Commission (2018): A clean planet for all: A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy (COM/2018/773).

Literature review of industrial hydrogen demand in 2050 (bars) and the underlying decarbonisation targets (pills)

Figure 4



AFRY analysis.
Note: The scope of industrial hydrogen demand is not the same across scenarios. Some of the reviewed studies include the use of hydrogen in combustion processes.

produce one ton of ammonia.[16] The underlying demand is taken from the Materials Economics baseline scenario, with 15 Mt of ammonia demand by 2050. Thus, the final hydrogen demand for ammonia amounts to 95 TWh.

2.1.2.2 Steel

Around 47 Mt of CO_2e are emitted during the reduction of iron ore with coke in traditional blast furnaces[17] during steel production. This accounts for the majority of emissions in the entire steel production value chain. There are two emission reduction options, as described by IRENA[18]:

→ coke-based reduction replaced using hydrogen through direct reduced iron (DRI); and
→ emissions from existing coke-based processes captured using carbon capture, utilisation, and/or storage ("CCUS" or "CCS" as appropriate).

If the future process were to be conducted entirely with hydrogen, around 2 MWh of hydrogen per ton of hot briquetted iron (HBI), the compacted form of DRI, would be necessary.[19] This amounts roughly to 1.8 MWh of hydrogen per ton of final steel. However, high quality steels require a certain carbon-content within the material, so the direct reduction should be conducted in a 70%/30% mixture (by energy) of hydrogen and methane. This means that the steel sector would continue to emit some CO_2,which would need to be either captured with CCS or offset with

16 This assumes an electricity demand of 9.2 MWh/t and an electrolysis efficiency of 70%. The assumptions are based on Dechema (2017): Low carbon energy and feedstock for the European chemical industry.

17 UNFCC (2020): Greenhouse gas inventory data - Flexible Queries Annex I Parties

18 The paper also mentions that "a wider application of either of these emission reduction options will require large-scale infrastructure changes and investments". See IRENA (2020): Reaching zero with renewables. Also see Prognos, Öko-Institut, Wuppertal-Institut (2020): Towards a climate-neutral Germany. Conducted for Agora Energiewende, Agora Verkehrswende, and Stiftung Klimaneutralität.

19 This is based on a pilot project conducted by ArcelorMittal and described in Hölling et al. (2020): Bewertung der Herstellung von Eisenschwamm unter Verwendung von Wasserstoff.

negative emissions. This assumption reduces the hydrogen demand to 1.3 MWh/t hot metal.[20] This study assumes that the direct reduction approach will be adopted across Europe by converting existing blast furnaces plants once slated for reinvestment.[21] Based on this assumption, the share of plants using DRI will amount to 34% by 2030, to 87% by 2040, and to 100% by 2050. This assumption is supported by several pilot projects as reported in Table 1.

The future steel demand was derived from the Materials Economics baseline scenario, which foresees a growth from 169 Mt to 193 Mt in Europe by 2050. 40% of this demand is currently supplied by scrap metal sources which are recycled in an electric arc furnace. This trend is assumed to increase linearly to 50% by 2050, further decreasing the demand for direct reduction. Combining these assumptions, the overall hydrogen demand from the steel sector is estimated to be 123 TWh by 2050. This is the most significant sectoral increase in hydrogen demand considered in this study and the largest source of uncertainty within the 'no-regret' demand. Table 2 details the assumptions used to derive the total demand for hydrogen in steel plants.

20 This is based on Agora Energiewende's industry experts' view.

21 The 'no-regret' demand we have estimated would be lower if CCS were used instead of direct reduction.

Overview of EU steel companies' plans for the deployment and commercialization of DRI plants before 2030

Table 1

Project, Site	Country	Company	Status Quo	Fuel	Timeline
HYBRIT, Lulea		SSAB	Started pilot operation with clean hydrogen in 2020 (TRL 4-5)	Green H_2	2020: pilot plant 2026: commercia
DRI, Galati		Liberty Steel	MoU signed with Romanian government to build large-scale DRI plant within 3-5 years Capacity: 2.5 Mt/DRI/year	Natural gas, then clean H_2	2023-2025: commercial
tkH2Steel, Duisburg		Thyssen-krupp	Plan to produce 0.4 Mt green steel with green hydrogen by 2025, 3 Mt of green steel by 2030	Clean H_2	2025: commercial
H-DRI-Project, Hamburg		Arcelor Mittal	Planned construction of an H2-DRI demo plant to produce 0.1 Mt DRI/year (TRL 6-7)	Grey H_2 initially, then green H_2	2023: demo plant
SALCOS, Salzgitter		Salzgitter	Construction of DRI pilot plant in Salzgitter	Likely Clean H_2	n.a.: pilot plant
DRI, Donawitz		Voest-alpine	Construction of pilot with capacity of 0.25 Mt DRI/a	Green H_2	2021: pilot plant
DRI, Taranto		Arcelor Mittal	Plans to build DRI plant, ongoing negatiations with Italian government	n.a.	n.a.
IGAR DRI/BF, Dunkerque		Arcelor Mittal	Plans to start hybrid DRI/BF plant and scale up as H_2 becomes available	Natural gas then Clean H_2	2020s

Agora Energiewende analysis.

Assumptions used to derive the demand for hydrogen in steel making — Table 2

	Unit	2020	2030	2040	2050
Demand for steel[a)]	Mt	169.0	182.7	187.8	193.0
Share of production with primary route[b)]	%	60%	57%	53%	50%
Share of steel plants converted to DRI[b)]	%	0%	34%	87%	100%
Utilisation of H_2 in DRI in terms of energy[b)]	%	70%	70%	70%	70%
Hydrogen demand per ton steel via DRI-H_2 route[c)]	MWh/t	1.8	1.8	1.8	1.8
Overall hydrogen demand	**TWh**	**0.0**	**45.5**	**110.9**	**123.4**

a) Material Economics | b) Agora Energiewende assumption | c) AFRY analysis.

2.1.2.3 Mineral oil refinery

Less valuable heavier mineral oil products are partially hydrocracked or hydrotreated to produce more valuable/useful lighter products, setting the main demand point for hydrogen today. As reported by Fuels Europe[22], demand ranges across three product types: transport fuels (65%), naphtha for the petrochemical industry (25%), and other (such as tar) (10%). We assume that between 2020 and 2050 there will be a transition towards non-oil-based transport fuels (including synthetic fuels[23]) following an S-curve,[24] and that we will transition away from mineral naphtha to imported sustainable naphtha.[25, 26]

Based on these assumptions, hydrogen demand in refineries will decline very slowly between 2020 and 2030, accelerate between 2030 and 2040, and then slow down again after 2040 before reaching zero in 2050.

2.1.2.4 Plastics production

Based on the Materials Economics study and AFRY's own assumptions, the production of plastics by 2050 is estimated to split into the following production routes:

- → 35% chemical recycling with integrated pyrolysis, steam-cracker, and gasification[27];
- → 25% via the traditional production route using imported sustainable naphtha (Fischer-Tropsch synthesized hydrocarbons);
- → 25% bio-based plastics; and
- → 15% mechanical recycling.

In 2050 hydrogen will be required only for the chemical recycling route (to produce methanol from synthesis gas), because Agora Energiewende assumes that sustainable naphtha will be imported.

22 See FuelsEurope (2018): Vision 2050 – A pathway for the evolution of the refining industry and liquid fuels

23 This is consistent with Prognos, Öko-Institut, Wuppertal-Institut (2020): Towards a climate-neutral Germany. Agora Energiewende assumes that these will be imported from outside Europe.

24 This is a typical pattern of technology diffusion, as discussed for example in P.A. Geroski (2000): Models of technology diffusion.

25 See Prognos, Öko-Institut, Wuppertal-Institut (2020): Towards a climate-neutral Germany. Executive summary on behalf of Agora Energiewende, Agora Verkehrswende, and Stiftung Klimaneutralität.

26 It is not within the scope of this work to model the fuel mix in the transport sector or the appropriateness of importing sustainable naphtha. We assume that a transition towards zero demand for oil-based products constitutes a 'no-regret' option with regard to hydrogen demand in the oil refinery industry.

27 This assumption also draws on Agora Energiewende and Wuppertal Institute (2019): Climate-neutral industry: Key technologies and policy options for steel, chemicals and cement.

INFOBOX

Some residual GHG emissions in agriculture and industry cannot be eliminated by mitigation measures and need to be offset with negative emissions to reach climate-neutrality in the long run.

In the climate-neutral Germany scenario for 2050, total residual emissions will amount to 62Mt CO_2eq, which corresponds to 5% of emissions in 1990. The remaining emissions will be offset primarily by biomass CCS, direct air carbon capture and storage, and the absorption of CO_2 by green polymers.

Green naphtha / absorption of CO_2 with green polymers: Biomass or CO_2 absorbed from the air via direct air capture can be used in combination with renewables-based hydrogen in Fischer-Tropsch plants to create green naphtha and other bio-based hydrocarbons. These can then be processed into polymers and plastics. With an improved recycling system, the plastics can remain in the material cycle. Coupled with CCS for waste incineration, this technology can prevent the re-emission of captured carbon [and create negative emissions as a contribution to climate neutrality].

Methanol is an important base chemical and its synthesis is reliant on hydrogen as a feedstock chemical. Similar to ammonia, it requires approximately 6.4MWh per ton of commodity.[28] The underlying demand for methanol is taken from the Materials Economics baseline scenario (1.6Mt by 2050). Thus, the final hydrogen demand for methanol production is 9.6TWh.[29]

According to the Material Economics baseline scenario, plastics demand is expected to increase from 69Mt today to 72Mt by 2050. Overall hydrogen demand for plastics production using the chemical recycling route is therefore estimated to be 42TWh by 2050. The trajectory is assumed to follow a typical technology learning curve, meaning a slow pick-up of the new processes until 2030 (9%) and more rapid expansion starting in 2040 (68%).

Both the traditional production route as well as the chemical recycling route utilize steam-crackers, which are assumed to run partially on electricity (40%) and partially on sustainable naphtha or pyrolytic oil from chemical recycling. Both these routes will thus require CCS, which may lack public support. The latter route is discussed in the infobox below, which provides an extract from the study *Towards a Climate-Neutral Germany*.[30]

2.1.3 Determining the location of sectoral demand

After estimating the demand for hydrogen in different sectors at the European level, we developed an approach to break down such demand across different locations. This approach attributes demand to hexagons on a 'hexagrid', a graphical representation that visualises hydrogen demand and supply. Figure 5 illustrates the main part of the hexagrid.

28 This assumes an electricity demand of 9.1MWh/t and an electrolysis efficiency of 70%. The assumptions are based on Dechema (2017): Low carbon energy and feedstock for the European chemical industry.

29 This estimation does not account for future plastics production from the methanol-to-olefin route. It is Agora Energiewende's view that the production of plastics will be derived from chemical recycling of existing plastic waste, biological resources, and imported sustainable naphtha – sustainable options that it regards as more realistic.

30 Prognos, Öko-Institut, Wuppertal-Institut (2020): Towards a climate-neutral Germany. Executive summary on behalf of Agora Energiewende, Agora Verkehrswende, and Stiftung Klimaneutralität.

Hexagrid

Figure 5

AFRY analysis. © 2020 Mapbox © OpenStreetMap.

Using a hexagrid provides a convenient way of comparing potential production and demand across a large geographic space and of finding cost-optimal pathways for transportation. We defined the hexagons based on an approximate size[31] of 50,000km². The hexagrid covers the entirety of Europe and North Africa.

When establishing a new industry, the choice of location is based on a number of factors. The key considerations are proximity to resources (natural resources, labour) and proximity to demand. Choosing a location establishes commits to various communication channels, which may be difficult to relocate. The 'no-regret' demand for hydrogen in this paper is based on the conversion of existing industries with established channels of communication for their feedstocks and products. We assumed that the existing industry would be expensive to relocate, and position of the demand has thus remained fixed.

To identify total demand for each location, we make use of two separate techniques for demand in the steel industry and demand in the other sectors (i.e. for ammonia and methanol production and in the chemicals and petrochemicals industry).

2.3.1.1 Steel

First, we identified all large steel plants in Europe based on stationary installations indicated in the European Union Transaction Log (EUTL) and on the activities related to the production of coke, pig iron, or steel. We also cross-checked the EUTL data with information from Eurofer.[32]

31 The exact size varies due to the curvature of the earth.

32 This considers all plants on the Eurofer Map of EU steel production sites.

Second, we calculated the evolution of the hydrogen demand for iron ore reduction at each plant by making assumptions on when existing steel production sites that use blast furnaces and basic oxygen furnaces (BF-BOF) will need a reinvestment. We assume that all manufacturing plants that need a reinvestment after 2023 will convert from coke-based reduction to direct reduction using hydrogen.

Reinvestment needs for blast furnace installations were defined by first identifying the date of commissioning or the most recent date of relining for blast furnaces currently operating in Europe.[33] Relining blast furnaces is necessary approximately every 20 years. The projected date for relining at each site defines the latest point for substituting blast furnaces with a DRI reactor of equal capacity,[34] which can be operated with hydrogen instead of coke.

The resulting DRI production capacity, multiplied by the specific hydrogen demand per tonne of hot metal (assumed to be 1.3 MWh/t of hot metal, as described in paragraph 2.1.2) results in the total site-specific hydrogen demand at the projected date that new investment will be needed.

33 The dates were defined based on company or general media reports.

34 This is taken from the published Eurofer Map of EU steel production sites.

For instance, the largest steel plant in our study will have switched to hydrogen by 2030 and will provide 3.6 million tonnes of hot metal capacity, accounting for 4.7 TWh of hydrogen demand.

2.1.3.2 All other sectors

As capacity data is not available for installations in the remaining sectors (i.e. ammonia, mineral oil refining, and methanol & plastics production), we used emissions data to assign a geographic dimension to the demand for these sectors, which were previously estimated at the European level.

First, we gathered emissions data for the relevant stationary installations covered by the EU ETS. To do so, we made use of the 2019 emission data from the European Union Transaction Log (EUTL),[35] and filtered them by the relevant activities in the sectors that constitute hydrogen demand. These are described in Table 3.

Second, we break down the total hydrogen demand across Europe in each sector, assigning it to individual installations in proportion to 2019 emission levels.

35 EUTL comprises the data of stationary installations subject to the EU ETS. AFRY holds a database of such installations, which was built by compiling data for each installation. The main activity type appears among the information of individual installations.

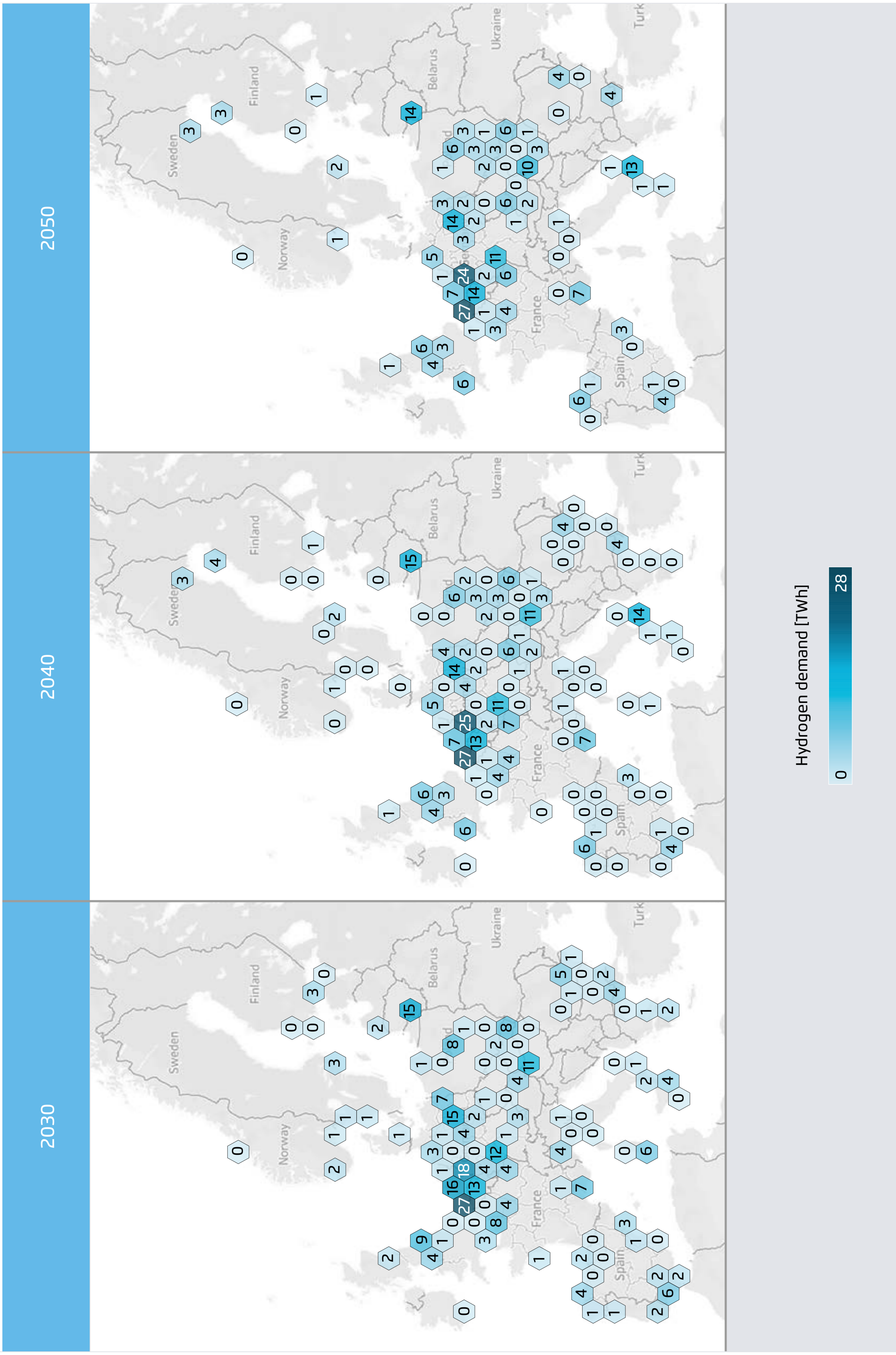
Mapping of industrial sectors covered in this study using EUTL emission categories — Table 3

Sector	EUTL main activity type
Ammonia	Ammonia
Mineral oil refining	Mineral oil refining
Plastics production	Adipic acid; bulk chemicals; glyoxal and glyoxylic acid; hydrogen and synthesis gas; manufacture of chemicals and chemical products; nitric acid; soda ash and sodium bicarbonate

European Union Transaction Log (EUTL)

Figure 6-7-8

Projected hydrogen demand [TWh LHV]



AFRY analysis. © 2020 Mapbox © OpenStreetMap.

2.2 Results

2.2.1 Main results

The resulting hydrogen demand in each hexagon is illustrated in Figure 6, Figure 7, and Figure 8 for 2030, 2040, and 2050, respectively.

Demand ranges from as little as 0.01 TWh per hexagon to as much as 27 TWh.

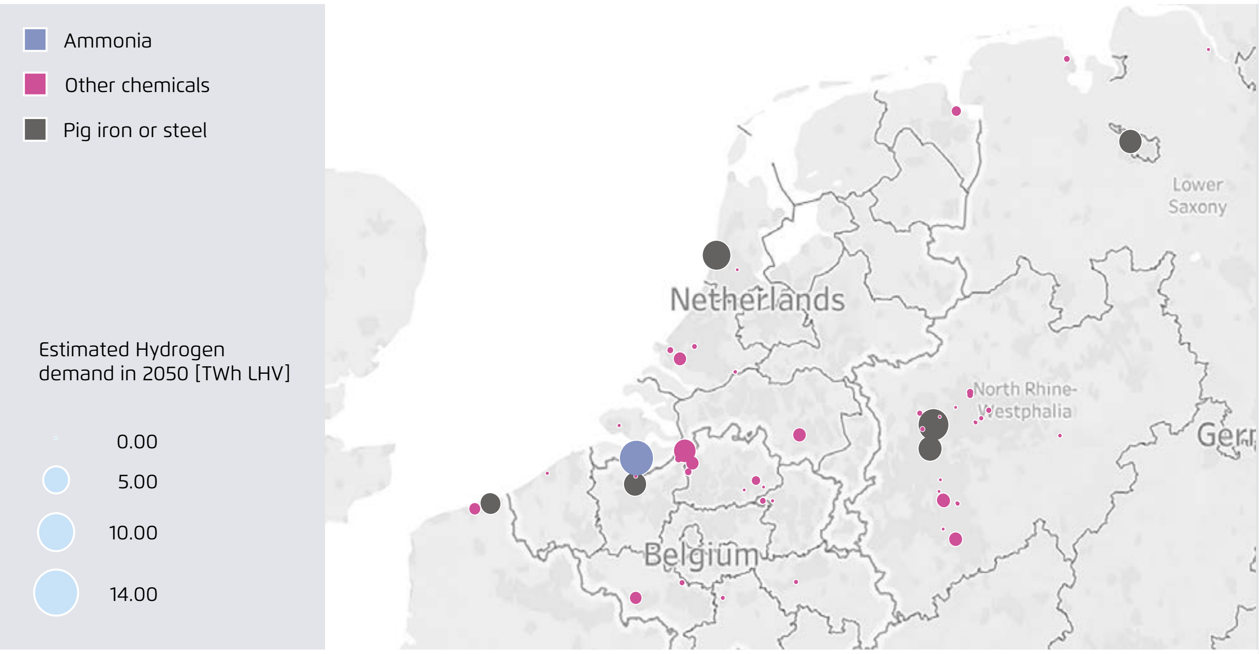
2.2.2 Takeaways from the exercise

The key demand hub emerging from the analysis is the trilateral region of North Rhine-Westphalia (Germany), Flanders (Belgium), and the Netherlands. The hub is the result of a large cluster of chemical and petrochemical installations and steel plants. The highest demand in a single hexagon is projected to be located between the Netherlands and Belgium in 2040. Demand will be driven by a large ammonia plant, a steel plant, and several large-scale chemical and petrochemical hydrogen consumers. This is shown in Figure 9.

Figure 6 to Figure 8 show other large demand hubs as well. These typically correspond to large ammonia or steel plants, and are often isolated. The most obvious hub is in Lithuania and is associated with the Achema ammonia plant, which according to our methodology is the single largest hydrogen demand installation in Europe.

Projected hydrogen demand in 2050 in the trilateral region by sector (size of bubble reflects demand volume)

Figure 9



AFRY analysis. © 2020 Mapbox © OpenStreetMap.

3 Hydrogen Production

This chapter reviews the economics of potential hydrogen production. It is divided into two main sections – a description of the methodology and assumptions we have used to assess production economics, and a presentation of the results of our analysis.

We introduce two scenarios: the 'BLUE-GREEN' scenario, which in addition to renewable hydrogen considers hydrogen produced by SMRCCS in specific locations; and the 'FAST GREEN' scenario, which rules out SMRCCS and assumes an aggressive reduction in electrolyser costs over the period of the study.

3.1 Assumptions and approach

3.1.1 Scope and approach to estimating the hydrogen supply

This section focuses on an analysis of potential hydrogen production. We consider dedicated renewable energy with electrolysis, SMR[36] with CCS ("SMRCCS"), and pyrolysis for specific geographical areas. For renewable hydrogen electrolysis, we consider dedicated hybrid PV/onshore wind as well as wind and solar photovoltaic (PV) generation.

For the purposes of this study, we have used technical and economic assumptions from a variety of sources provided by Agora Energiewende and supplemented by AFRY's own work. AFRY has not reviewed the credibility of Agora Energiewende's sources.

3.1.1.1 RES potential

An initial assessment of wind and solar resource potential based on physical and technical restrictions for each country (populated regions, built-up areas, natural reserves, terrain conditions) and on conversion losses estimated the hydrogen supply potential in Europe. Practical land availability factors were applied to decrease the theoretical potential to a more reasonable range, following the methodology described in annex A.1.

The renewables potential analysis showed that there is a high potential for solar in South Europe and a strong wind potential in Central and North, as expected. It is worth highlighting the co-existence of good solar and wind potential in the MENA region, which is in line with a study conducted by Dii Desert Energy and the Fraunhofer ISI Institute[37] (Figure 10).

The level of demand for hydrogen established in the previous chapter is intended to represent a reasonable minimum level. Factors such as public acceptance, grid proximity, grid capacity, and the amount of RES required to meet electricity demand make it difficult to identify the volume of RES-based zero-carbon hydrogen production that might be possible in Europe. Annex A.1 describes a calculation of maximum RES potential that disregards these factors, but it suggests a much higher hydrogen production potential than the identified 'no-regret' demand. This implies that Europe will not be resource-constrained and that it will not need a large-scale hydrogen delivery system because demand could be served by co-located production and storage facilities. While such a situation may be physically possible, it may not provide an economically efficient outcome.

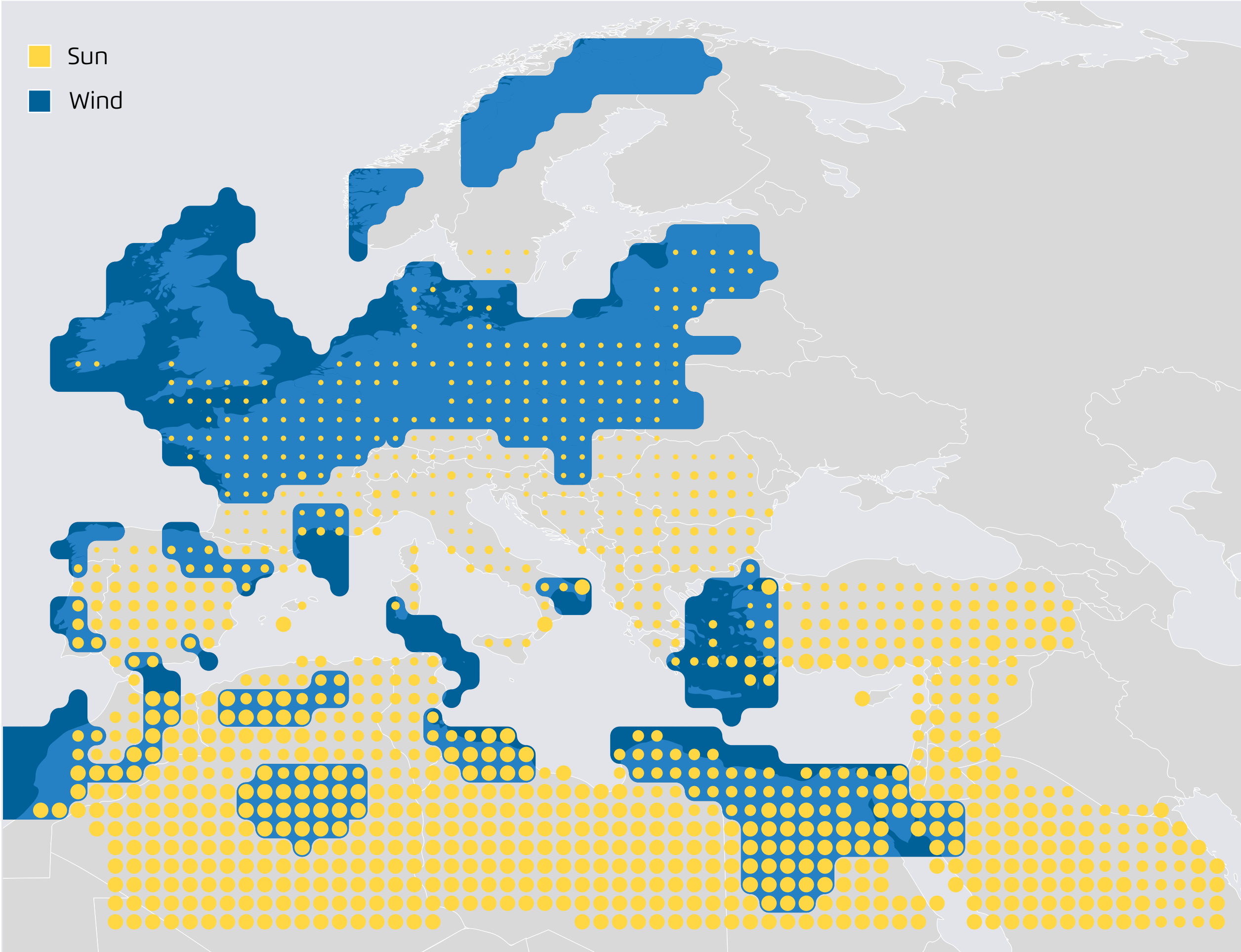
Since renewables potential does not provide reliable information on the 'no-regret' hydrogen supply potential, we considered the costs of hydrogen production and estimated the share of production that would most efficiently meet demand and ensure

36 This also includes alternative forms of methane reformation, as mentioned in 2.1.2.

37 Dii & Fraunhofer-ISI (2012): Desert Power 2050: Perspectives on a sustainable power system for EUMENA. Presented at SWP Berlin on May 22. s.l.:s.n.

Solar and wind potential in Europe and the MENA region

Figure 10



Dii & Fraunhofer-ISI (2012).

the ongoing competitiveness of the European economy. We identified a cost-optimal hydrogen supply based on a LCOH (levelized cost of hydrogen), using renewable-based electrolysis as well as SMRCCS processes (where applicable).

3.1.1.2 SMRCCS potential

When considering the likely costs of hydrogen production, it should be noted that SMRCCS is expected to be of significantly lower cost than RES-based zero-carbon hydrogen, especially in the short term. However, there is considerable opposition to the deployment of SMRCCS within many of the EU Member States for reasons of public acceptance and safety.[38] In addition, there is a high level of uncertainty as to the volume of fugitive methane emissions associated with the methane supply and whether the gas industry can eliminate them.

Nonetheless, some states (notably Netherlands, Norway, and the UK) are actively developing CSS technologies into a high level of readiness, as shown by a Trinomics study.[39] A low-carbon hydrogen

38 Because CO_2 is heavier than air, there are risks associated with suffocation in the event of leakage, although for offshore installations the risk is minimal.

39 Trinomics (2020): Opportunities for hydrogen energy

requirement (i.e. from SMRCCS) is also considered in the EU's Hydrogen Strategy, at least for an interim period.[40]

Finally, we note that CCS is required to decarbonise cement production and can enable negative emissions, which will be needed to create a carbon-neutral Europe.[41] The creation of a CCS infrastructure for hydrogen production through methane reforming could thus be an advantage, though this has not been explored in this study.

Even though Germany's readiness level for CCS technologies is characterized as high in the Trinomics study, the recently published national hydrogen strategy[42] does not expect Germany to deploy CCS. Accordingly, Agora has requested that low-carbon hydrogen supply from SMRCCS be considered realistic only for the UK, the Netherlands, and Norway. We have thus restricted the deployment of SMR-CCS to locations along the North Sea and the Liverpool Bay coastlines of UK and along the North Sea coastlines of the Netherlands and Norway.

3.1.1.3 Application to hexagrid

We have calculated hydrogen supply costs for over 950 hexagons, forming part of the 1755-hexagon 'hexagrid' introduced in section 2.1.3, stretching across Europe and parts of North Africa and the Middle East. A hexagrid approach is a good way of comparing production and demand potentials[43] across a large territory and of finding cost-optimal pathways for transportation.

Our study's two scenarios accommodate different assumptions regarding political feasibility and technology costs. Based on the scenario results, we identified the potential requirements for a hydrogen delivery system. These are discussed in the following section.

3.1.2 Calculation of the levelised cost of hydrogen production

3.1.2.1 BLUE-GREEN scenario

The BLUE-GREEN scenario comprises both low-carbon hydrogen from SMRCCS and zero-carbon hydrogen from dedicated RES production.

Renewable energy sources and electrolysis

In order to determine the most economic renewable energy source for hydrogen production in a given hexagon, hexagon specific LCOHs were calculated for three technologies: solar PV only, wind only[44] (onshore or offshore), and a hybrid solar PV/wind power plant. Consistent with previous Agora studies[45] we assumed a 15% coincidence factor, meaning that 15% of expected wind energy was not used because of an overlap with solar availability. This is illustrated in Table 4.

Tables 5 to 7 provide an overview of the assumptions used for the LCOH calculations.

Based on the costs of the respective RES technology and the alkaline electrolysers along with their availa-

technologies considering the national energy & climate plans.

40 European Commission (2020): A hydrogen strategy for a climate-neutral Europe.

41 Prognos, Öko-Institut, Wuppertal-Institut (2020): Towards a climate-neutral Germany. Executive summary conducted for Agora Energiewende, Agora Verkehrswende and Stiftung Klimaneutralität.

42 BMWi (2020): The national hydrogen strategy.

43 Competition between demand for hydrogen production and direct-electric applications was not considered in the analysis.

44 Full-load hours of wind production potential were capped at 3800 to reflect the removal of kinetic energy from the wind passing through large wind farms. This is explained further in the Annex (see A.1.2).

45 Agora Verkehrswende, Agora Energiewende and Frontier Economics (2018): The future cost of electricity-based synthetic fuels.

Resource utilisation in hydrogen production via electrolysis — Table 4

Technology	Available hours used from solar (%)	Available hours from wind (%)
Solar	100% [a]	0% [a]
Wind	0% [a]	100% [a]
Hybrid	100%	85% [b]

a) AFRY assumption, b) Frontier Economics (2018)

Cost levelisation assumptions — Table 5

		2030				2050			
Figure	Unit	Solar PV	Wind onshore	Wind offshore	Hybrid	Solar PV	Wind onshore	Wind offshore	Hybrid
Availability [a]	%	95%				95%			
Lifetime [a]	years	30				30			
Hurdle rate [b]	%	5.0%				5.0%			
Electrolyser efficiency [c]	% LHV	71%				80%			

a) AFRY assumption, b) Agora Energiewende assumption, c) IEA (2019): The future of hydrogen

CAPEX, upgrading, and OPEX for electrolysers — Table 6

		2030				2050			
Figure	Unit	Solar PV	Wind on-shore	Wind off-shore	Hybrid	Solar PV	Wind on-shore	Wind off-shore	Hybrid
CAPEX electrolyser [a]	€/kW (electricity)	435.5				259.5			
Upgrading electro-lysers at half of lifetime [b]	% of CAPEX	35				35			
OPEX electrolysers [a]	% of CAPEX	4.5				4.5			

a) AFRY Low Scenario assumption, b) Agora Energiewende assumption

CAPEX and OPEX per RES tech and results per RES tech — Table 7

		2030				2050			
Figure	Unit	Solar PV	Wind onshore	Wind offshore	Hybrid	Solar PV	Wind onshore	Wind offshore	Hybrid
CAPEX solar/wind	€/kW	330	800	1,179	1,130	250	686	811	936
OPEX solar/wind	€/kW/ year	8	36	95	44	6	33	79	39

AFRY Low Scenario assumption

bility, lifetime, efficiency and interest rate, we arrived at EUR/kW (H2 LHV) per year for hydrogen production. We then calculated the average LCOH (EUR/kg) per hexagon and scenario in view of the average load factor in kWh/kW and the lower heating value of hydrogen (33.3 kWh/kg). For hexagons that are partially offshore, we determined the hybrid LCOH by multiplying the hybrid hydrogen cost component with the onshore share of the hexagon and then adding the offshore share multiplied by the cost of offshore hydrogen.

SMRCCS & pyrolysis costs

A similar approach has been used to calculate the levelised costs of hydrogen production via SMRCCS. In the SMRCCS process, CCS technology is applied to capture and store 90% of the CO_2 emitted46 during the production process.

Methane pyrolysis produces a product known as carbon black, which currently has a limited number of industrial uses. There is ongoing research on expanding its applications, but for the purposes of this study we assumed that carbon black will need to be stored.

The input parameters for the analysis are shown in Table 8 and Table 9.

46 For simplicity, we have not considered the impact of free allocation of emission allowances in the calculation of the levelised cost of hydrogen of SMRCCS.

Cost levelisation assumptions (SMRCCS & pyrolysis) — Table 8

		2030		2050	
	Unit	SMR	Pyrolysis	SMR	Pyrolysis
Availability	%	91%			
Lifetime	years	30			
Hurdle rate	%	5%			
Natural gas price	€/MWh	22			
CO_2 price	€/tonne	40			

Agora Energiewende assumption

Technical characteristics (SMRCCS & pyrolysis) — Table 9

		2030		2050	
	Unit	SMR	Pyrolysis	SMR	Pyrolysis
Efficiency (LHV/LHV) [a)]	%	58%	43%	58%	43%
Efficiency (HHV/HHV) [a)]	%	62%	46%	62%	46%
CO_2 emission rate [a)]	%	10%	0%	10%	0%
CAPEX	€/kW H_2 production HHV	1125 [a)]	1880 [b)]	1125 [a)]	1428 [b)]
OPEX	€/kW/year H_2 production HHV	34 [a)]	156 [b)]	34 [a)]	119 [b)]
Fuel emission factor [b)]	t/MWh	0.181	0	0.181	0

a) Agora Energiewende assumption, b) AFRY Central Scenario assumption

The LCOH calculation results in 2.0 EUR/kg of hydrogen produced by SMR with CCS for both 2030 and 2050, with no cost reduction assumed for the period from 2030–2050.[47] Pyrolysis technology is expected to benefit from scaling and learning effects, however. The LCOH from methane pyrolysis amounts to 3.3 EUR/kg in 2030 and decreases to 2.9 EUR/kg in 2050. The carbon price was assumed to remain flat at 40 (€/tonne). However, in assuming a 90% CO_2 capture rate, the impact of carbon price is negligible and the levelized cost is less sensitive to carbon price assumptions. For instance, a carbon price of 160 (€/tonne) in 2050 would lead to a 2.1 (€/kg H2) LCOH for SMR with CCS.

47 The study assumes that costs for SMR remain level over time, as agreed with Agora Energiewende. Other sources have sets of numbers for the costs of SMR that decline over time.

3.1.2.2 FAST GREEN scenario

Our FAST GREEN scenario represents a 'what if' analysis. Its key underlying assumption is that there

Cost levelisation assumptions — Table 10

		2030				2050			
Figure	Unit	Solar PV	Wind onshore	Wind offshore	Hybrid	Solar PV	Wind onshore	Wind offshore	Hybrid
Availability [a)]	%	95%				95%			
Lifetime [a)]	years	30				30			
Hurdle rate [b)]	%	5.0%				5.0%			
Electrolyser efficiency [c)]	% LHV	71%				80%			

a) AFRY assumption, b) Agora Energiewende assumption, c) IEA (2019): The future of hydrogen

CAPEX, upgrading, and OPEX for electrolysers — Table 11

		2030				2050			
Figure	Unit	Solar PV	Wind on-shore	Wind off-shore	Hybrid	Solar PV	Wind on-shore	Wind off-shore	Hybrid
CAPEX electrolyser [a)]	€/kW (electricity)	96				67			
Upgrading electro-lysers at half of lifetime [b)]	% of CAPEX	35				35			
OPEX electrolysers [c)]	% of CAPEX	4.5				4.5			

a) BNEF (2019): Hydrogen's plunging price boosts role as climate solution, b) Agora Energiewende assumption, c) AFRY Low Scenario assumption

is sufficient policy support for renewable hydrogen via electrolysis, which leads to an accelerated learning curve and intensifies global electrolysis competition.

In FAST GREEN, the CAPEX for electrolysers falls sharply over the next decade, in line with the BNEF's projections.[48] While extreme cost decline may or may not happen, we have chosen to test how very low electrolyser cost could affect the need for hydrogen transportation infrastructures.

Tables 10 to 12 compare electrolyser costs and levelized hydrogen costs between the BLUE-GREEN scenario and the FAST GREEN scenario. In the FAST GREEN scenario, we did not assume the production of low-carbon hydrogen from SMRCCS.

48 BNEF (2019): Hydrogen's plunging price boosts role as climate solution.

CAPEX and OPEX per RES tech and results per RES tech — Table 12

		2030				2050			
Figure	Unit	Solar PV	Wind onshore	Wind offshore	Hybrid	Solar PV	Wind onshore	Wind offshore	Hybrid
CAPEX solar/wind	€/kW	330	800	1,179	1,130	250	686	811	936
OPEX solar/wind	€/kW/year	8	36	95	44	6	33	79	39

AFRY Low Scenario assumption

3.2 Results

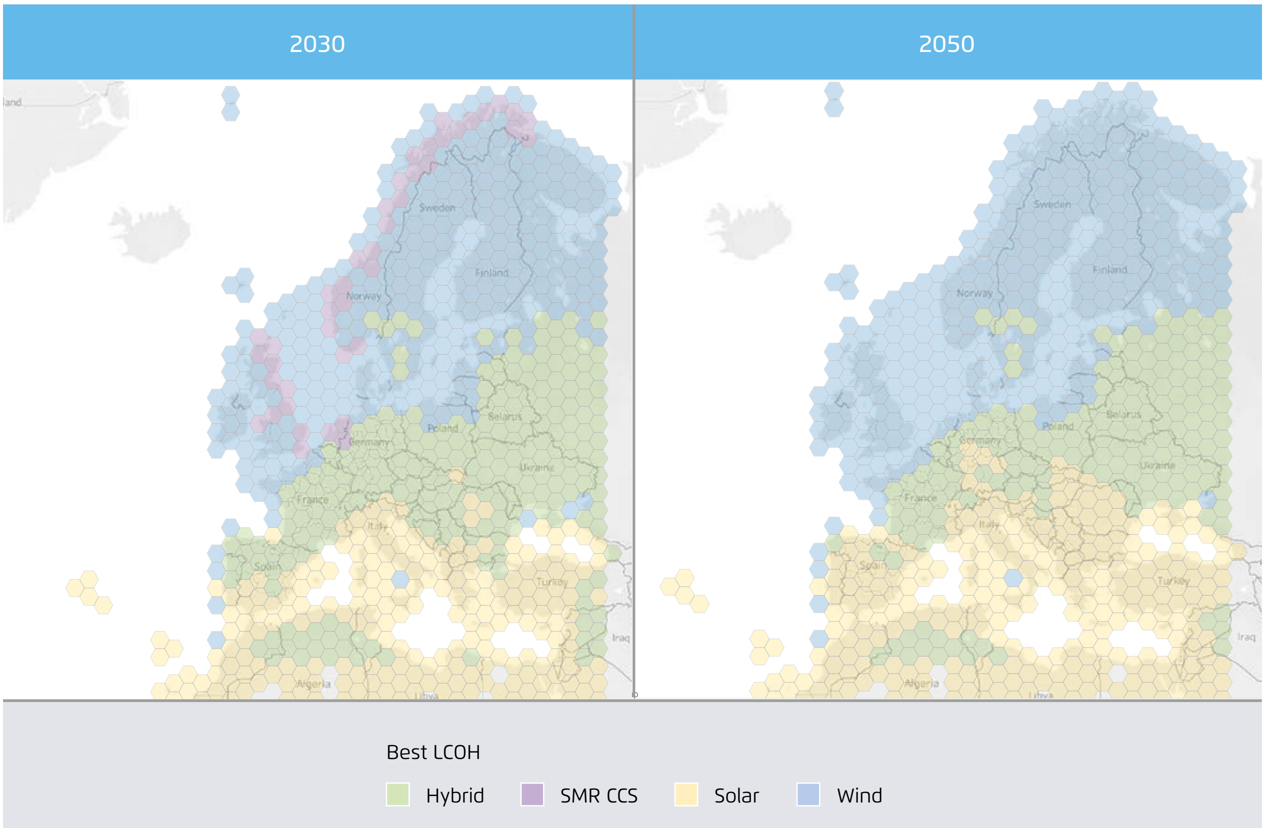
3.2.1 Main results – BLUE-GREEN scenario

The scenario showed SMRCCS in 2030 to be the most economical hydrogen production technology in countries with high technology readiness and political acceptance of CCS. Under the assumptions made, pyrolysis is competitive neither with SMRCCS nor dedicated, RES-based electrolysis. Figure 11 illustrates the most cost-efficient hydrogen production technology in each hexagon in the years 2030 and 2050, respectively. In some hexagons of countries that are ready to deploy SMRCCS, wind LCOH is lower and therefore preferable.

By 2050, SMRCCS appears to have been replaced by wind-based electrolysis in most hexagons, indicating a transition from fossil-based hydrogen production to electrolysis. By 2050, solar PV gains importance as electrolyser costs decrease significantly. Electrolysis becomes the dominant solution for renewable hydrogen production in South Europe. Higher shares of wind energy in the North while hybrid solutions in central Europe complete the picture.

Looking at only wind and solar PV as energy sources for hydrogen production, the LCOH assessment shows a three-way split along a North-South axis. In 2030, wind energy dominates the northern part of Europe, while hybrid solutions are cost-optimal in Central Europe and solar PV is the best solution in South Europe and Northern Africa. Minor changes can be observed when looking at 2050, with solar PV taking over some shares from hybrid electrolysis in

Best levelised cost of hydrogen incl. SMR with CCS in the BLUE-GREEN scenario | Figure 11



AFRY analysis. © 2020 Mapbox © OpenStreetMap.

various parts of Europe, based on the assumptions for cost development for these technologies. Notably, hybrid electrolysis remains cost-optimal for North Algeria and Libya, reflecting the great wind and solar potential in that region.

3.2.2 Main results – FAST GREEN scenario

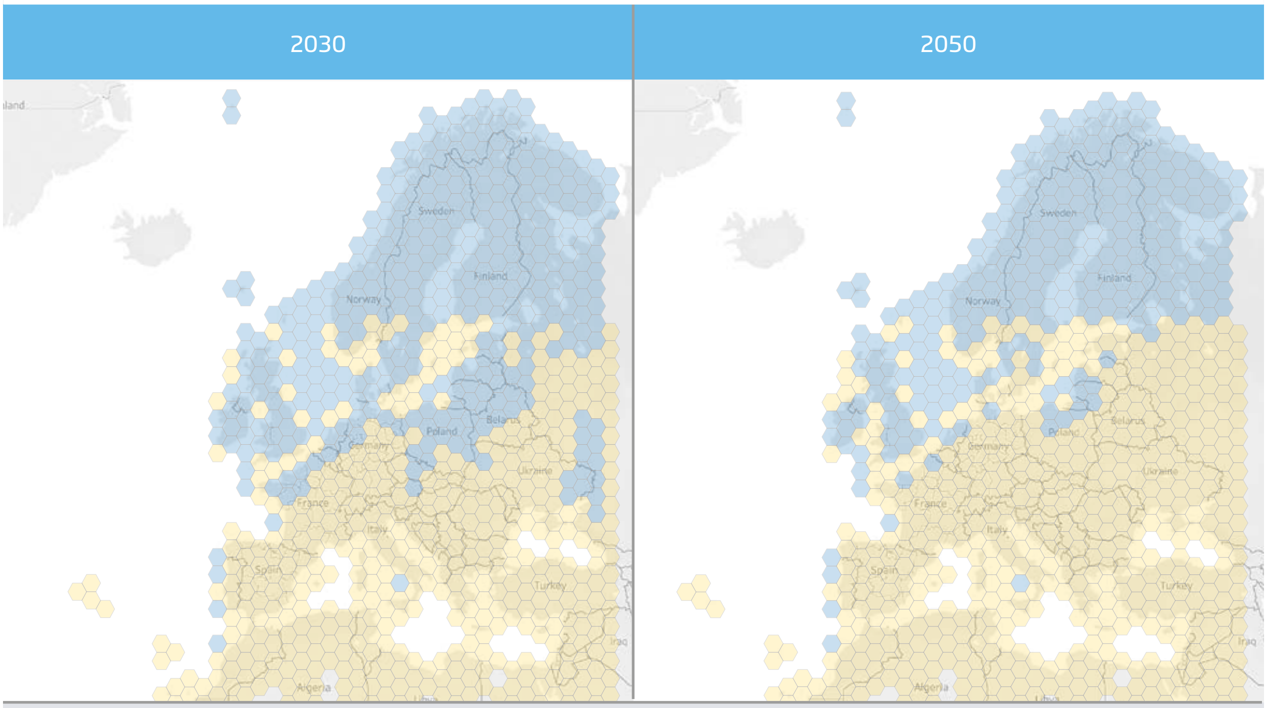
In the FAST GREEN scenario, more optimistic electrolyser costs lead to hybrid solutions being replaced by stand-alone configurations, as shown in Figure 12.

By 2050, a shift to solar-based hydrogen production can be seen in many hexagons. This is driven by lower electrolyser costs. Whilst electrolyser costs are common to both wind and solar, electrolyser costs are a more significant component in the levelised costs of solar-based hydrogen production. Solar-based production has a lower load factor (i.e. fewer full-load hours) than wind-based production, so the levelised costs of solar-based production are affected more by reduced electrolyser costs than by the levelised costs of wind-based production.

3.2.3 Takeaways from the analysis

- → Across the modelled geography, RES-based hydrogen production tends to be provided most cost effectively by wind at northern latitudes, solar PV at southern latitudes and hybrid technologies at central latitudes.
- → Hydrogen produced from SMRCCS is cost competitive in 2030 even when considering the relatively high costs for CCS infrastructure. Where geographically possible (i.e. the North Sea) it can serve

Best levelised cost of hydrogen in the FAST GREEN scenario — Figure 12



Best LCOH

Solar Wind

AFRY analysis. © 2020 Mapbox © OpenStreetMap.

local demand for hydrogen. By 2050, renewable hydrogen production becomes more economical.

→ Significantly reduced electrolyser costs will create a greater difference between dedicated solar-based hydrogen production and the alternatives. This is because electrolysers make up a larger share of costs for solar than for wind and hybrid.

4 Delivery Systems

4.1 Discussion

4.1.1 Introduction

Earlier, we established the 'no-regret' demand for hydrogen. We then identified that it can be served by different sources of production with varying degrees of efficiency/cost. In the following, we define a hydrogen delivery system that ensures that hydrogen can be delivered cost effectively to consumers when and where they need it. This chapter discusses the opportunities for establishing a 'no-regret' hydrogen delivery system.

Electrolysis will deliver hydrogen at a variable rate. Typically, industrial consumers require a constant flow of hydrogen. Therefore, an infrastructure is needed that can deliver hydrogen accordingly.

Electrolysis can be located almost anywhere, whereas industrial demand is fixed to existing sites. There may be cases where there is a close trade-off between the efficiency of production and the cost of transportation. Below we consider the potential requirements for both storage and transportation

4.1.2 Storage

Hydrogen produced from renewable electricity will vary because of diurnal solar patterns, wind speeds, cloud cover and seasonal effects. To absorb differences in supply and demand, hydrocarbon reformation relies on hydrocarbon storage (e.g. existing mineral natural gas storage facilities), whilst grid-connected electrolysis would rely on non-RES back-up systems, grid-connected storage or RES overbuild and curtailment. Though hydrocarbon storage (in particular natural gas storage) is economically viable across these scales, the economics of grid-connected storage solutions – especially inter-seasonal economics – are not so clear.

There is a range of existing and emerging literature on the subject of hydrogen storage. As of 2020, researchers were confident that hydrogen can be stored in salt caverns,[49] converted natural gas facilities or newly built facilities. It is less clear that other geological approaches (depleted hydrocarbon fields, aquifers, mines, and rock caverns) would be suitable for various reasons[50] (HYUNDER, 2014).

Above-ground storage techniques rely on very high pressure (up to 700 bar), very-low temperature liquefaction (c. -250 deg. C) or chemical conversion/reconversion – techniques that require substantially more energy/losses and impact on land use.

There are two temporal scales to consider:

- → in the short-term, hour-to-hour, day-to-day or week-to-week intermittency of RES production caused by diurnal solar patterns and weather variation, and
- → in the longer-term, a requirement driven by seasonality of demand.

These concepts dominate natural gas markets, where a range of gas storage facilities provide services across these temporalities.[51] The temporalities dictate

49 D. G. Caglayan et al. (2020): Technical potential of salt caverns for hydrogen storage in Europe. ELSEVIER, 45(11), pp. 6793–6805. Salt-cavern hydrogen storage systems in commercial operation also exist in the UK and the US.

50 HYUNDER (2014): Assessment of the potential, the actors and relevant business cases for large scale and seasonal storage of renewable electricity by hydrogen underground storage in Europe.

51 There are additional temporalities in the natural gas market. Shorter-term, within-day variation is typically absorbed by the pipeline networks and provided for through the use of line packing and within-gas-grid compression. Longer-term variation can also have an

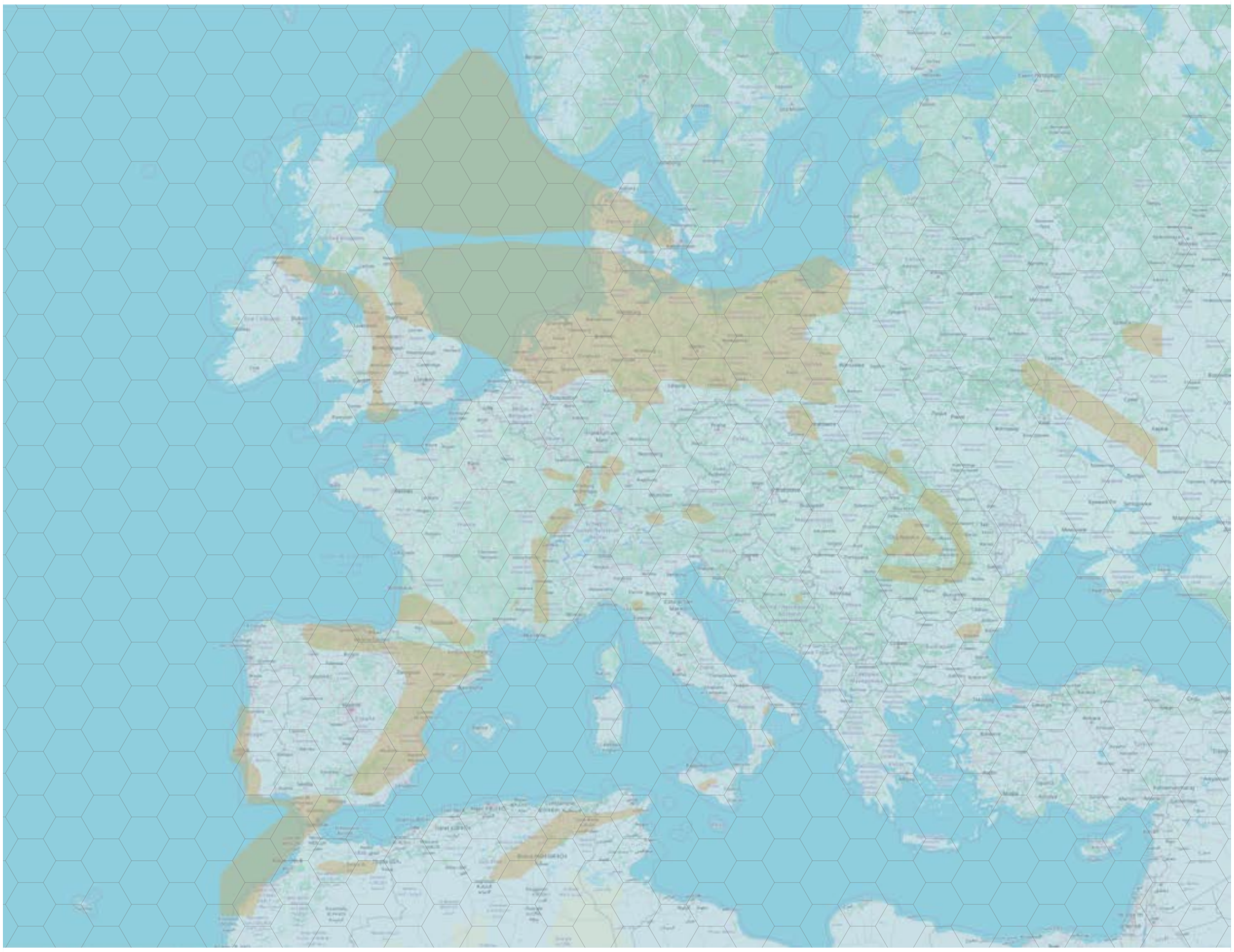
both the total amount of capacity required to get gas in and out of the storage facility (injection and withdrawal capacity) and the total amount of storage capacity (working gas volume). Together, these make up the cycle time (i.e. how quickly a facility can be taken from empty to full and back to empty). For underground storage, the geological characteristics of a facility can act as a constraint on the speed at which facilities can be cycled. However, salt caverns are generally able to provide reasonably fast cycle times. Above-ground storage is not constrained in this way, so equipment can be sized according to precise need.

impact on the requirements for working gas volume, although this is tempered by long-run decisions to invest in or delay additional production capacity. In addition, production and consumption patterns can be altered in response to price signals. We expect all of these features to appear in a hydrogen backbone.

4.1.2.1 Create new salt-cavern storage or repurpose natural gas storage?

Cost components for new salt-cavern storage facilities include: cavern leaching operation, cushion gas, and topside facilities including compression. There are ongoing costs associated with well inspection, topside maintenance and compression fuel/power costs.

Salt strata in Europe | Figure 13



AFRY after HYUNDER (2014)

The major cost component in establishing a new salt-cavern gas storage facility involves drilling to the salt strata, using water to dissolve the salt (leaching), disposing water/brine and constructing temporary water/brine pipelines. Returning water/brine can be disposed at sea (where the salt content will have a negligible effect on salinity), or in deep subsurface geologic formations (e.g. depleted oil fields). Figure 13 shows salt strata in Europe.

An alternative approach is to repurpose existing salt caverns that have been used for natural gas or other hydrocarbons. Repurposing avoids the costs of leaching, but introduces different costs associated with purging (to ensure there are minimal impurities introduced to the hydrogen stream) and the disposal/recycling of replaced equipment.[52] Nonetheless, various sources[53] believe that repurposing natural gas salt caverns may be less costly than creating new salt caverns. As the natural gas market is expected to contract and is already well-served by storage facilities, we would not expect the commercial or security consequences of removing storage capacity from the gas market to be a major barrier.

4.1.2.2 Conclusion – storage

It will be necessary to establish a hydrogen storage system that is capable of providing both weather-influenced and inter-seasonal storage capabilities. Salt caverns appear to be ideal for this application, and can be feasibly built new or repurposed from existing natural gas storage facilities. Alternative storage systems may also be possible but are either not proven to be feasible, or require significant land-use to provide bulk scale.

The re-purposing of existing natural gas salt caverns is particularly attractive if they are already connected to a natural gas pipeline system that can be converted to hydrogen. Before discussing the locations and interface between potential storage facilities and the pipeline system, we discuss the potential transportation system(s) that could be established.

4.1.3 Transportation

There are a number of physical mechanisms that could be used to transport hydrogen. These include:

- → a dedicated pipeline;
- → a pipeline co-mingled with other gasses, e.g. natural gas;
- → bottle or tanker-based transport systems on road, rail or sea, in gaseous, liquid or in chemical form.

4.1.3.1 Dedicated hydrogen pipelines

Dedicated hydrogen transportation pipelines already exist, but only for limited amounts of hydrogen.

Establishing a pipeline network has historically been achieved through vertical-integration, where the commodity being transported competes with other solutions/commodities at the point of consumption. Commodity producers establish delivery systems and recover the investment by way of long-term contracts with consumers. This has established the dedicated hydrogen transport system that exists today. This approach also established some of the existing European natural gas network, although as the industry has grown and with the 3rd EU Energy Package[54] requiring vertical separation to support cross-border competition, the pipeline infrastructure has now emerged as a series of regulated monopolies known as gas transmission system operators (TSOs).

One interesting potential that is being examined by TSOs is whether the existing natural gas transmission network[55] can be converted to the transportation

52 Compression equipment will likely need replacement to meet the pressure characteristics of hydrogen.

53 For example, see D. G. Caglayan et al. (2020) Technical potential of salt caverns for hydrogen storage in Europe.

54 Gas Directive 2009/73/EC, Gas Regulation EC/715/2009, inter alia.

55 High pressure steel pipelines are used for national and international bulk transportation. They are distinct from distribution pipelines, which are typically low-pressure and used for localised distribution.

of 100% hydrogen. 11 European TSOs[56] examined the potential timeline for the development of a European hydrogen network that included a mixture of both converted and new hydrogen pipelines. We draw two important observations from this study:

- → there are expected reductions in duties on gas transmission pipelines that enable some of the physical assets to be removed from the natural gas system and repurposed for hydrogen; and
- → technical requirements for conversion appear to be both feasible and relatively trivial, consisting of particular pressure cycling restrictions and/or internal pipeline coating.

It seems likely therefore that some form of dedicated hydrogen bulk-supply pipeline system could be established – either in conjunction with production via vertically-integrated commercial structures, or through the conversion of regulated assets. We believe there should be no problems with public support for the establishment of a dedicated hydrogen pipeline, because of their similarity to natural gas pipelines.

4.1.3.2 Co-mingling

Hydrogen can be blended with natural gas, and either consumed as the blended product, or separated (deblended) at the point of production. However, there are safety-related limits on the maximum proportion of hydrogen that can be included in the natural gas stream without requiring significant investment in natural gas consumers' equipment. Decarbonisation will drive the volume of natural gas being consumed to fall considerably, diminishing the capability for a natural-gas system to host it. Whilst a blending/deblending approach may afford some opportunity to transport hydrogen, it is unlikely to be a long-term component of a hydrogen delivery system.

4.1.3.3 Sea-borne transportation

There are various sea-borne transportation mechanisms. These include:

- → conversion to ammonia, transportation via marine tanker vessels, subsequent reconversion to (gaseous) hydrogen (NH_3);
- → liquefaction, transportation via dedicated cryogenic marine transport, with subsequent regasification prior to consumption (LH_2);
- → various liquid organic hydrogen carriers (LOHC); and
- → molecular lattice mechanisms.

As hydrogen is the primary input in current ammonia production (used primarily in fertiliser production), ammonia conversion technologies are fairly well advanced.[57] Whilst LH_2, LOHC and molecular lattice technologies are less well advanced, the LH_2 vector is remarkably similar to liquefied natural gas (LNG), though it requires a lower temperature.

We consider both LH_2 and NH_3-based sea-borne transportation within our modelling (see section 4.2). We note that the IEA[58] considers LOHC to be similar in cost to LH_2 and NH_3, so our modelling may also be representative of LOHC.

4.1.3.4 Bottle/tanker delivery systems

Tanker-based delivery systems, using established transportation infrastructure (road, rail, maritime) also present a mechanism for hydrogen delivery. They require local storage solutions at production and consumption sites to enable the transportation vehicle to be released. Bottle-based delivery systems transport the commodity in bottled form, with the bottles providing local storage at points of production and storage.

56 Guidehouse (2020): European hydrogen backbone. How a dedicated hydrogen infrastructure can be created.

57 M. Beckmann, C. Pieper (2019): Readiness level of technologies for the 'Energiewende': Results from VGB Scientific Advisory Board.

58 See IEA (2019): The future of hydrogen, fig. 32.

Both systems are very flexible, and allow for micro-scale incremental deployment. Tanker-based delivery systems provide for some efficiencies of scale compared to bottle-based systems, though at large scale both mechanisms are relatively expensive. For the demand volumes contemplated in this paper, it is unlikely that bottle/tanker delivery systems will be more economical than pipeline networks, especially when the pipeline networks include re-purposed natural gas pipelines.

These types of delivery systems also require hydrogen to be transported at very high pressure (to c.700 barg), in liquid form (c.-250 deg C) or contained in a molecular carrier (e.g. metal matrix) or chemical carrier (e.g. ammonia). Each of these states presents additional challenges when it comes to compression, cooling, containment and processing, with energy/ losses and impacts on land use.

4.1.3.5 Conclusion – transportation

There are a variety of transportation media that are technologically mature, but their costs vary significantly. The same is true of hydrogen production, which is why understanding the needs of a delivery system requires detailed modelling.

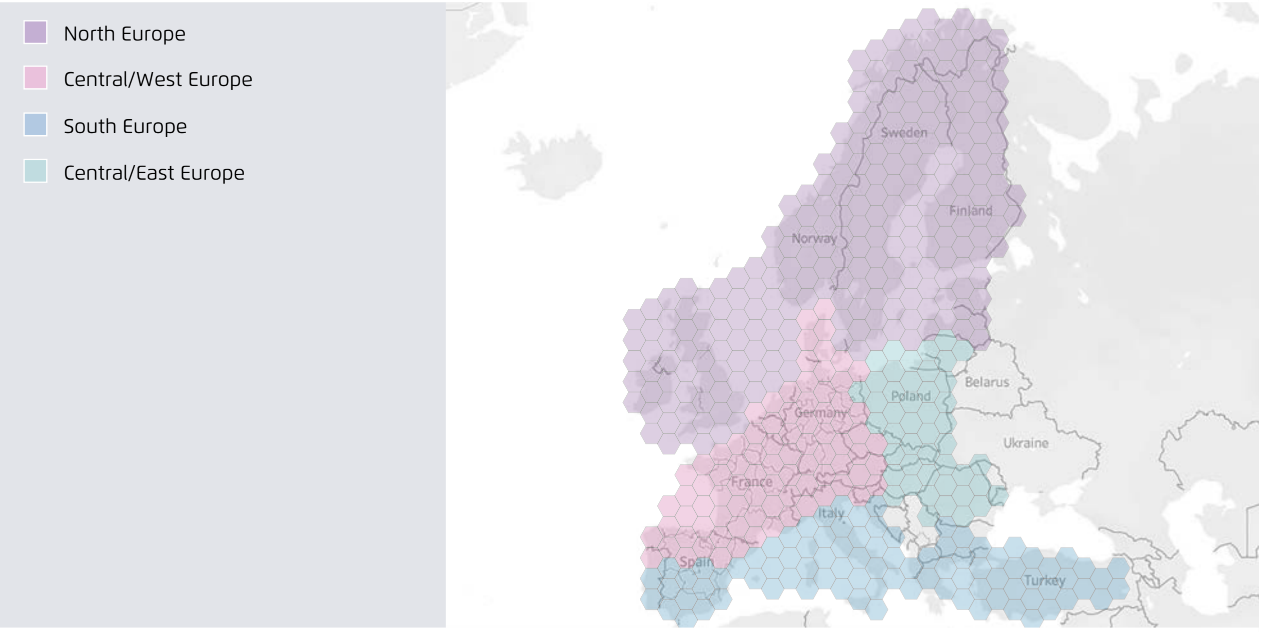
4.2 Modelling

4.2.1 Introduction

To understand the potential requirements for a hydrogen delivery system, we have constructed a model that determines the lowest cost for hydrogen for any given hexagon in the hexagrid. 'Flat' hydrogen is defined as hydrogen that has been stored so that it can be consumed by the flat-rate demand we consider in this study. There are two potential transportation routes: the transportation of 'flat' hydrogen from a point of storage to a point of demand, and the transportation of 'volatile' hydrogen from a point of production to a point of storage.

Regional split for hydrogen storage

Figure 14



AFRY analysis. © 2020 Mapbox © OpenStreetMap.

Our model is based on levelised cost calculations. In the subsequent sections, we describe the parameters and assumptions we make for:

→ the requirements of storage; and
→ the nature of transportation routes.

4.2.2 Storage

We assume that the 'no-regret' hydrogen demand from section 2 is consumed at a constant rate. Hydrogen produced will be supplied by a variety of sources, each with a different temporal variation, driven mostly by weather. Hydrogen produced in this way will require storage capacity.

4.2.2.1 Required duty

The actual storage requirement will be determined by the mix of hydrogen produced from wind, solar, hybrid and SMRCCS. The requirement will be location-specific and dictated by weather conditions. We have created regional supply profiles based on an assumed mix of wind, solar and hybrid for the purposes of illustrating different requirements for storage across Europe. The regional split is shown in Figure 14.

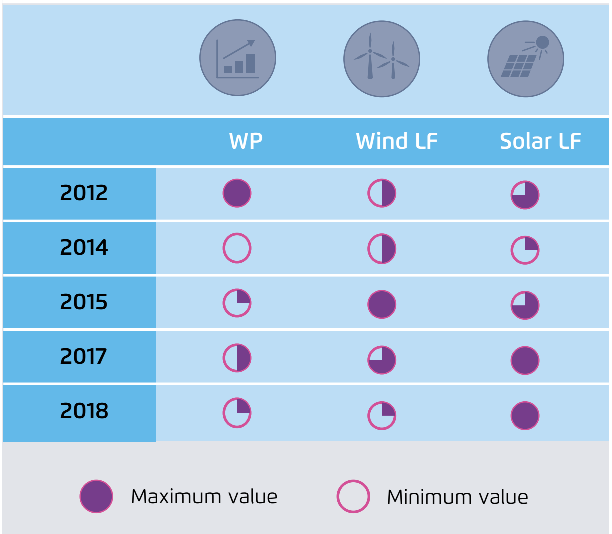
The definitions are provided in Table 13. We have examined the available historical weather data and have selected the weather patterns from 2017 because of the high output of wind and solar in that year,[59] as shown in Figure 15.

Figure 16 provides the requirements for injection (positive numbers) and withdrawal (negative numbers) for each region.

59 The choice of a historical weather year with high wind and solar output is independent of the levelised cost calculations, which assume average load factors.

60 As stated in section 3.1.2.1, this assumes a 15% coincidence with wind.

Historical weather data characteristics Figure 15



AFRY analysis.
WP = wholesale price (average annual); LF = load factor.

Supply scenarios for hydrogen storage analysis Table 13

	2030				2050			
	North Europe	Central/ West Europe	South Europe	Central/ East Europe	North Europe	Central/ West Europe	South Europe	Central/ East Europe
Wind	100%	27.8%	0%	16.7%	92.3%	25.0%	0%	11.1%
Solar	0%	13.9%	74.1%	11.1%	0%	31.3%	80%	44.4%
Hybrid[60]	0%	58.3%	25.9%	72.2%	7.7%	43.8%	20.0%	44.4%

AFRY analysis.

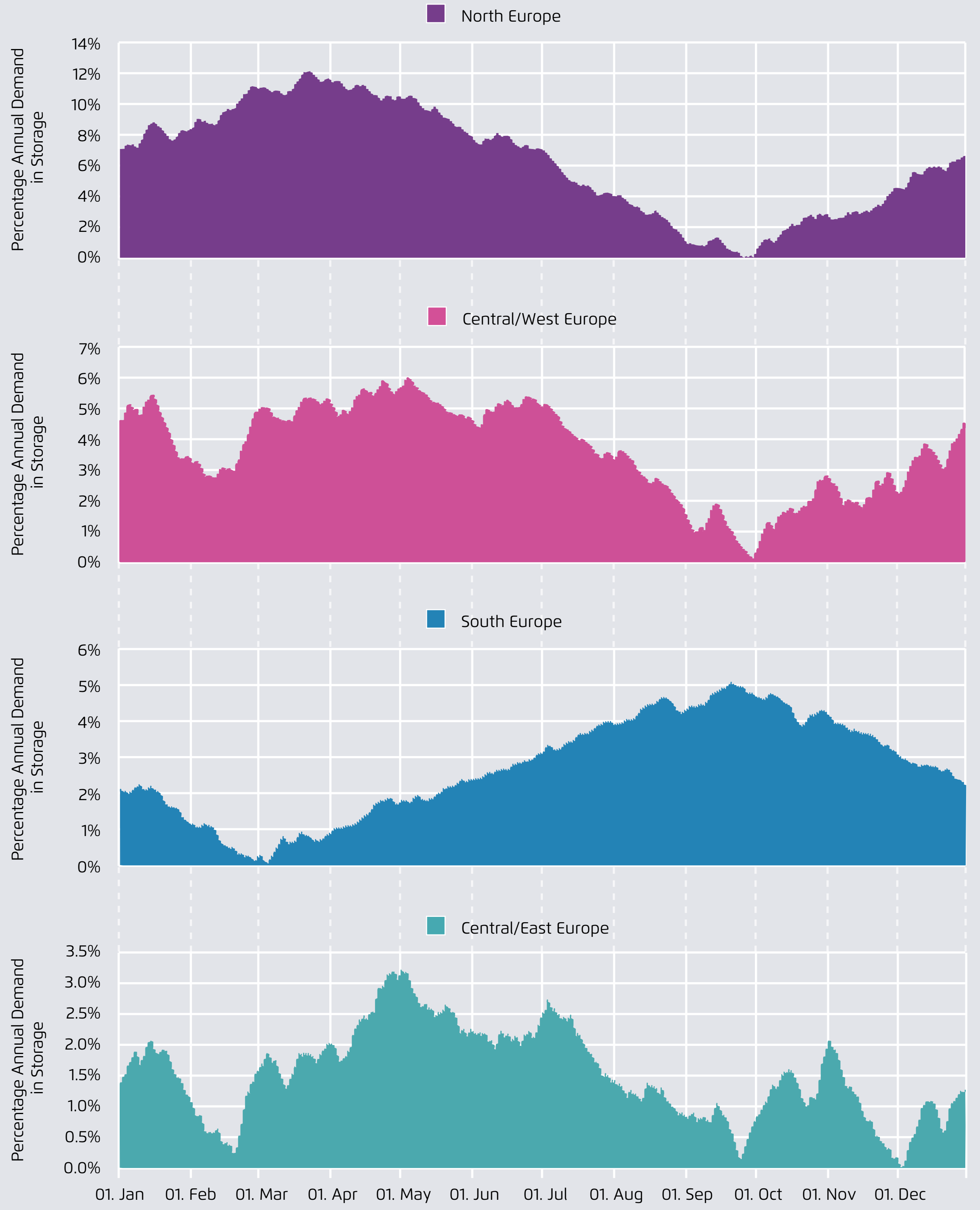
Injection and withdrawal requirements by region

Figure 16

AFRY analysis. Units indicate the % of daily annual average hydrogen demand. That is, -100% means there is no hydrogen production for that period; 0% means that production and demand are balanced for that period; +100% means that production is twice as large as demand for that period.

Cumulative storage requirements by region

Figure 17



AFRY analysis. Units indicate the % of annual hydrogen demand. In all cases, the minimum storage fill is 0%. The maximum figure implies the total volumetric size of the required storage facilities.

Storage analysis statistic outputs — Table 14

	North Europe	Central/West Europe	South Europe	Central/East Europe
Sum of injected volumes over the year (in % of annual demand) [A]	24.9%	25.2%	43.0%	20.6%
Total storage capacity requirement (i.e. maximum H_2 volume stored at any point within the year) (in % of annual demand) [B]	12.1%	6.0%	5.1%	3.2%
Number of full cycles per annum [B/A]	**2.06**	**4.22**	**8.45**	**6.38**

AFRY analysis.

From that we can construct the cumulative storage requirements for each region (assuming a minimum level of zero). The requirements are presented in Figure 17.

In addition to storage requirements independent of location, the above charts show:

1. a relatively high diurnal requirement in South Europe (associated with daylight);
2. a requirement for seasonal accumulation of hydrogen in North Europe (it is generally windier in winter than summer);
3. a requirement for counter-seasonal accumulation of hydrogen in South Europe (there is more sunlight in summer than winter).

From this analysis we obtained two metrics, which are presented in Table 14.

1. Cycles times – the number of full-duty cycles each region's storage requirements would need to provide. These statistics are used to derive levelised costs of hydrogen storage (discussed below).
2. The volume of annual production (from RES) that needs to be absorbed by storage. We assume a certain storage requirement for each unit of RES-based hydrogen production.

4.2.2.2 Levelised costs of storage

The metrics above informed our calculation of levelised costs of storage, shown in Table 15. The CAPEX figures that underlie our calculations have

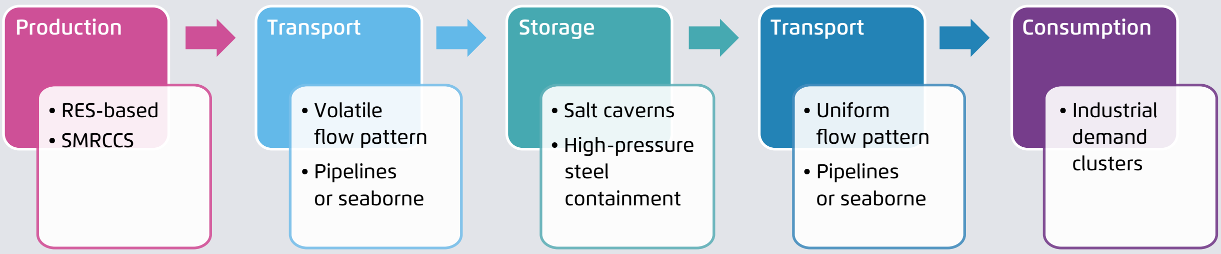
Regional levelised cost of storage — Table 15

	€/kg	€/kg	€/kg	€/kg
	North Europe	**Central/West Europe**	**South Europe**	**Central/East Europe**
LCOS pressurized tanks (max cycles)	22.24	10.84	5.42	7.17
LCOS salt caverns (max cycles)	0.67	0.33	0.16	0.22

Element Energy (2018): Hydrogen supply chain evidence base, b) European Commission (2020): Hydrogen Generation in Europe – Overview of Key Costs, c) Agora Energiewende assumption, d) AFRY assumption
Notes: Levelisation assumes a CAPEX of €334/MWh (LHV)[a] for salt caverns and of €11,036/MWh (LHV)[b] for pressurized tanks, an installation factor of 1.3[b], an OPEX of 4% of CAPEXa), a 5% discount rate[c] and a lifespan of 30 years.[d]

Conceptual hydrogen transportation route

Figure 18



AFRY analysis.

been taken from Element Energy[61] and the European Commission.[62] We have assumed 30-year asset lives and a discount factor of 5%. To account for the additional costs from engineering topsides in the marine environment, we have assumed that offshore salt cavern-based hydrogen storage costs twice as much as onshore salt cavern-based hydrogen.

It is interesting to note that the number of cycles per annum has a significant impact on the levelised cost of storage, which is expected because of higher load factors.

The levelised cost is scaled by the proportion of annual production that requires storage capacity. The model considers the levelised cost when optimising production and transportation costs.

4.2.3 Transportation

We expect hydrogen transportation to be required when it provides access to a source of 'flat' hydrogen that is cheaper than what can be locally produced. The transportation route must also accommodate storage. Hence, an end-to-end system must comprise production, transport, storage, transport and consumption, as shown in Figure 18.

We have considered two primary mechanisms for transporting hydrogen: transportation through pipelines (mostly land-based[63]), and sea-borne transportation in a liquid form. We have assumed that both liquid hydrogen (LH_2) and ammonia (NH_3) are viable forms of sea-borne transportation. Sea-borne transportation exhibits a fundamentally different economic model from land-based transportation because it has relatively high costs associated with liquefaction (for LH_2) or gasification (for NH_3) yet has relatively low marginal distance costs (the costs of shipping and fuel). But pipeline transportation has relatively high marginal distance costs,[64] except when existing natural gas infrastructure can be reused.

61 Element Energy (2018): Hydrogen supply chain evidence base.

62 European Commission (2020): Hydrogen generation in Europe – Overview of key costs.

63 However, there are existing offshore natural gas transportation systems that may be repurposed for hydrogen transportation.

64 There is a distance-based 'tipping point' at which sea-borne transportation is a cheaper transportation option than pipeline transportation.

For pipeline transportation we drew on both the ASSET report[65] and the 11 TSOs study[66] to generate levelised costs of land-based transportation.

We defined two levels of costs: a cost associated with repurposing existing natural gas pipeline and a cost associated with the construction of new pipeline capacity. For sea-borne transportation, we used the ASSET report to identify a single cost for transition from land to sea or from sea to land (also applied to offshore production[67]), and a cost for sea-borne transport.

The levelised costs we have assumed are indicated in Table 16.

We derived costs for each hexagon as entry/exit costs, i.e. the cost associated with transportation from the edge of a hexagon to/from its centre point, with additional costs for transition between land and sea.

4.2.4 Cost optimisation – Hexamodel

AFRY's Hexamodel was used to determine cost-optimal transportation systems for the delivery of hydrogen to centres of demand.

Hexamodel takes the volatile hydrogen production prices (as described in the supply section) for each hexagon and identifies the cost-optimal combination of transportation and supply. It factors in the local storage costs and the optimises the flat hydrogen prices, with additional transportation when optimal. The model is not subject to other constraints and is free to transport volatile hydrogen from any production node to any potential storage node and from any storage node to any demand node.

We have configured the Hexamodel to assess the cost-optimal supply to/from 1,755 hexagons via 10,196 individual routes. The input matrices comprise:

→ local volatile hydrogen costs for each hexagon;
→ hexagon-hexagon transportation costs for each route; and
→ local hydrogen storage costs for each hexagon.

The model constructs an intermediate matrix of cost-optimal volatile hydrogen for each hexagon. For each hexagon, the outputs comprise:

→ ultimate (volatile) supply hexagon;
→ volatile hydrogen transportation route;
→ storage hexagon;
→ flat hydrogen transportation route; and
→ the delivered price.

We filtered these results to focus only on the hexagons where we have identified 'no-regret' demands for hydrogen (as described in the demand chapter).

4.2.5 Hexamodel results

We visualised the results in Tableau for each of the two scenarios, FAST GREEN and BLUE-GREEN, for 2030 and 2050. We also created a publicly accessible Tableau Workbook to allow readers to explore the full set of results. Each scenario/year combination produced a unique set of results. We altered the model to reflect increased domestic German hydrogen production costs as a result of specific resource constraints in Germany.[68,69]

65 European Commission (2020): Hydrogen generation in Europe – Overview of key costs.

66 Guidehouse (2020): European hydrogen backbone. How a dedicated hydrogen infrastructure can be created.

67 Whilst we recognise that some offshore production (in the North Sea, say) may be able to make use of existing offshore pipeline infrastructure, we have not included this within our modelling because it has not been deemed available or suitable for hydrogen transportation.

68 The German production cost sensitivity drives the need for import infrastructure in North Rhine – Westphalia and the southern Lower Saxony/northern Thuringia regions.

69 See for example the scenario comparison in section 7.2 of Prognos, Öko-Institut, Wuppertal-Institut (2020):

Transportation model unit cost assumptions

Table 16

Item	Reference	Source	Cost	Units	Calculation	Cost Assumption	Units (1/2 hexagon)
New pipeline	ASSET [a)]	Guidehouse	4.60	€ / MWh / 600km	Median	9.168	€c / kg / half hexagon
		BNEF	9.60	€ / MWh / 600km			
		IEA	11.40	€ / MWh / 600km			
		DNV GL	45.00	€ / MWh / 600km			
		BNEF - min	16.10	€ / MWh / 600km			
		BNEF - max	49.80	€ / MWh / 600km			
Retrofitted pipeline	11 TSO [b)]	Upper	0.23	€ / kg / 1000km	Weighted average	2.024	€c / kg / half hexagon
		Lower	0.07	€ / kg / 1000km			
	ASSET [a)]	LCOT retrofit	3.70	€ / MWh / 600km			
Sea-land conversion	ASSET [a)]	H_2 to ammonia (IRENA)	27.00	€ / MWh	Simple Average	102.06	€c / kg / half hexagon
		Ammonia to H_2 (IEA)	34.00	€ / MWh			
		H_2 to LH_2 (DOE) (min)	38.00	€ / MWh			
		H_2 to LH_2 (DOE) (max)	74.00	€ / MWh			
		LH_2 to H_2 (AFRY assump-tion, 10%)	3.80	€ / MWh			
		LH_2 to H_2 (AFRY assump-tion, 10%)	7.40	€ / MWh			
Sea-borne cost	ASSET [a)]	LH_2 - Algeciras to Saudi Arabia	3.14	€ / MWh / 1000km	Simple Average	0.807	€c / kg / half hexagon
		LH_2 - Rotterdam to Saudi Arabia	3.07	€ / MWh / 1000km			
		NH_3 - Algeciras to Saudi Arabia	0.94	€ / MWh / 1000km			
		NH_3 - Rotterdam to Saudi Arabia	0.91	€ / MWh / 1000km			

a) European Commission (2020): Hydrogen generation in Europe – Overview of key costs, b) Guidehouse (2020): European hydrogen backbone. How a dedicated hydrogen infrastructure can be created.

Below we highlight some key findings consistent across each of the four sets of results.[70]

Many of the results show a requirement for cross-border transportation within Europe, sometime moving through more than one country to reach a demand centre. We do not provide a specific graphic to highlight this result, though it is visible in many of the results shown below.

4.2.5.1 Clear 'no-regret' routes

Our results show a clear and consistent need for transportation infrastructure for particular demands across time and scenarios. As such, we identified a number of routes that can be clearly considered 'no-regret'.

Under clear 'no-regret', we included routes that would make economic sense across the range of reasonable futures for the combination of demand and supply costs assessed in the study.

To identify the clear 'no-regret' routes we used four criteria:

1. Hydrogen is not self-produced and stored within the hexagon. This means that the identified hydrogen pipelines span at least two hexagons.
2. The annual demand served by a clear 'no-regret' route in 2050 should be at least 3TWh per year.
3. The demand served is sizeable in 2030 and 2040 as well. The parameter was not fixed to at least 3TWh in 2030 and 2040. Rather, it was assessed on a case by case basis.
4. A clear 'no-regret' route should be most economical in at least three of the following four combinations of years and scenarios: BLUE-GREEN in 2030, BLUE-GREEN in 2050, FAST GREEN in 2030 and FAST GREEN in 2050. The route in the fourth combination should be similar to the other three.

We also checked if the resulting routes were included within backbone segments, i.e. the retrofittable pipelines indicated in the study of the 11 TSOs.[71]

We found one demand hexagon that has a 2050 demand of at least 3TWh and is served by a consistent route across all four combinations of years and scenarios. This constitutes the 'tier one' clear 'no-regret' point. This is not among those covered in the TSOs study. It corresponds to AC-23 in Lithuania.

We identified nine additional hexagons that met all criteria and have similar supply hexagons, except that the route was consistent across only three of the four combinations of years and scenarios. These constitute the 'tier two' 'clear no-regret' points. Among the routes covered in the study of the 11 TSOs and available to be retrofitted we found:

→ Q-33 in Spain,
→ R-26 and S-26 in the Benelux region,
→ T-26 and V-26 in Germany, and
→ R-28 in the North of France

Among those outside the 11 TSOs study area we found:

→ AD-33 in Bulgaria,
→ AE-30 in Romania, and
→ Z-29 in Hungary.

Finally, we assessed the points that met the criteria for some of the four scenarios and we identified two additional points that can be considered 'tier three' clear 'no-regret' demand points. One condition for those is that they are located near a route already

Klimaneutrales Deutschland. Conducted for Agora Energiewende, Agora Verkehrswende and Stiftung Klimaneutralität

70 The model has not been optimised over time, so there might be instances where a temporally consistent 2050 cost optimisation would not build the routes identified for 2030.

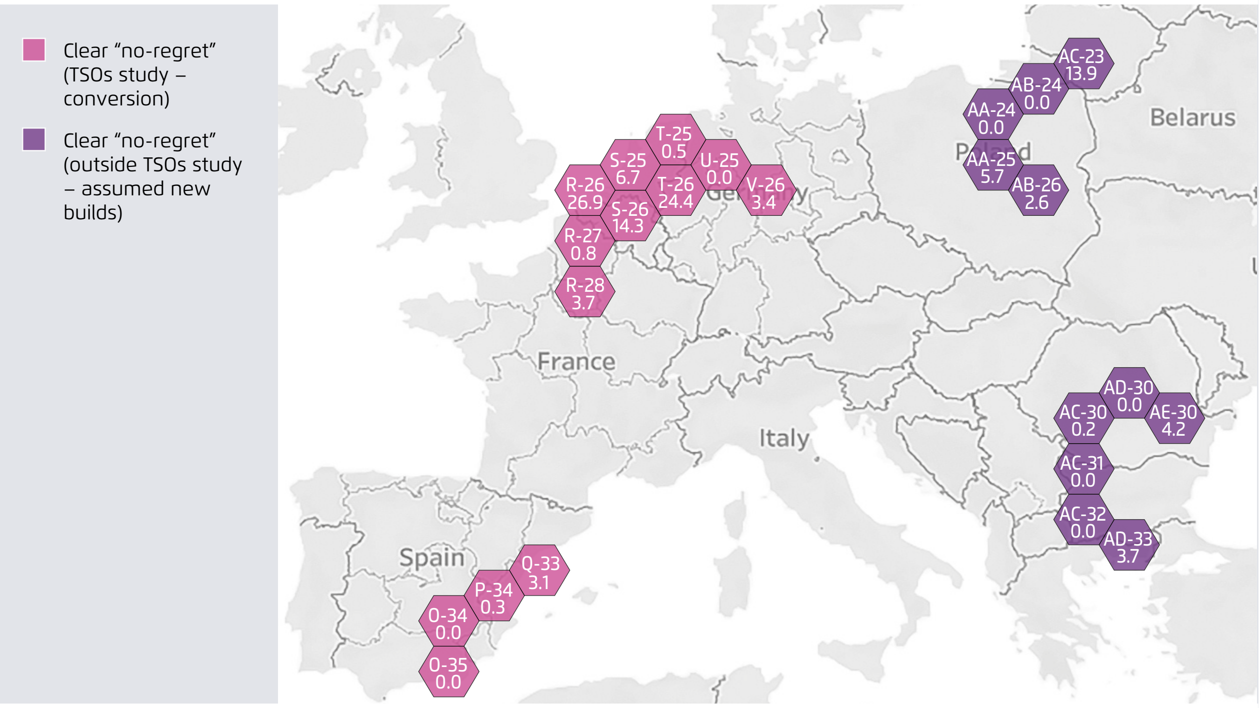
71 Guidehouse (2020): A European hydrogen backbone. How a dedicated hydrogen infrastructure can be created.

Clear 'no-regret' demand hexagons per tier and region — Table 17

Tier	Hexagon	Region	Included in the study of the 11 TSOs	Retrofitting assumed in modelling
1	AC-23	Lithuania	No	No
2	R-28	France	Yes	Yes
2	Q-33	Spain	Yes	Yes
2	R-26	Benelux	Yes	Yes
2	S-26	Benelux	Yes	Yes
2	T-26	Germany	Yes	Yes
2	V-26	Germany	Yes	Yes
2	AD-33	Bulgaria	No	No
2	Z-29	Hungary	No	No
2	AE-30	Romania	No	No
3	AA-27	Poland/Slovakia	No	No
3	AB-26	Poland	No	No

AFRY analysis.

Clear 'no-regret' routes (hexagons contain the ID and the demand in 2050 in TWh) — Figure 19



AFRY analysis. © 2020 Mapbox © OpenStreetMap.

identified for tier one or tier two points. The additional tier three points identified are outside the study area of the 11 TSOs. These are:

- → AA-27 between Poland and Slovakia, and
- → AB-26 in Poland.

Figure 19 provides a visual representation of the clear 'no-regret' backbone obtained and highlights in pink the part of the backbone within TSO study that could be developed by retrofitting existing natural gas pipelines.

The hexagons in purple are outside the 11 TSOs study and for the purpose of this project are assumed to be newly built hydrogen pipelines. Judging by an examination of the ENTSOG map,[72] there are no obvious existing natural gas pipelines in these locations that might be candidates for retrofitting, except perhaps for Romania.

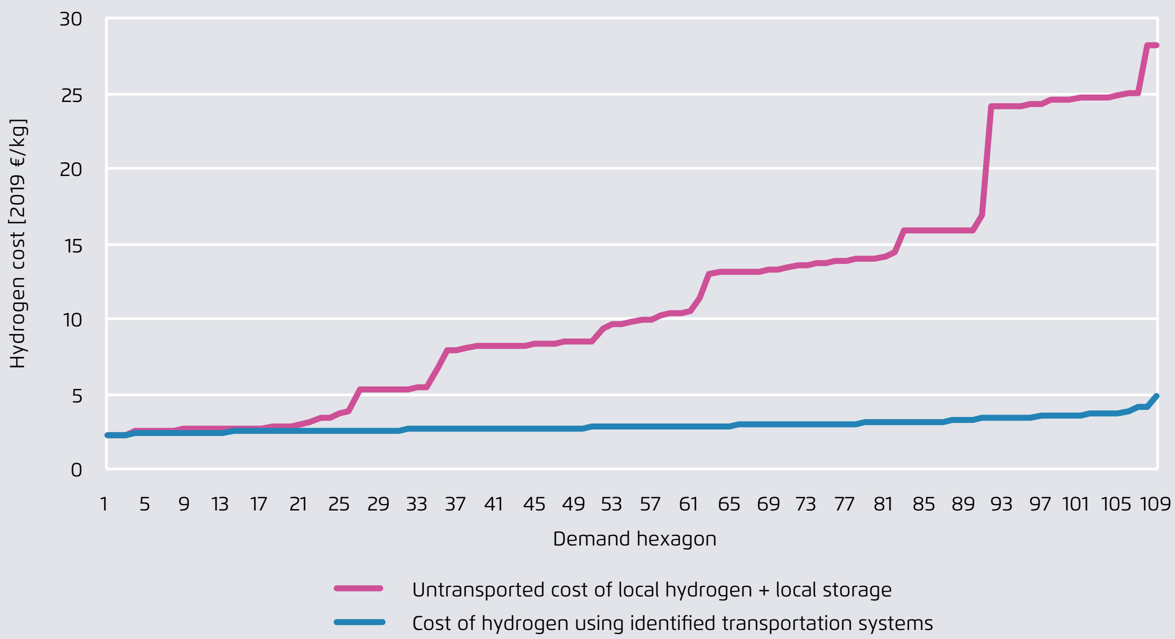
Based on this assessment, we identified the segments of the network where investments should be prioritised. These are shown in Table 17.

4.2.5.2 Delivered hydrogen costs

Figure 20 shows the impact of the modelled hydrogen transportation systems across the range of demand nodes. Figure 21 and Figure 22 present the levelised cost of smooth hydrogen in 2050 for each hexagon, for the BLUE-GREEN and FAST GREEN scenario, respectively.

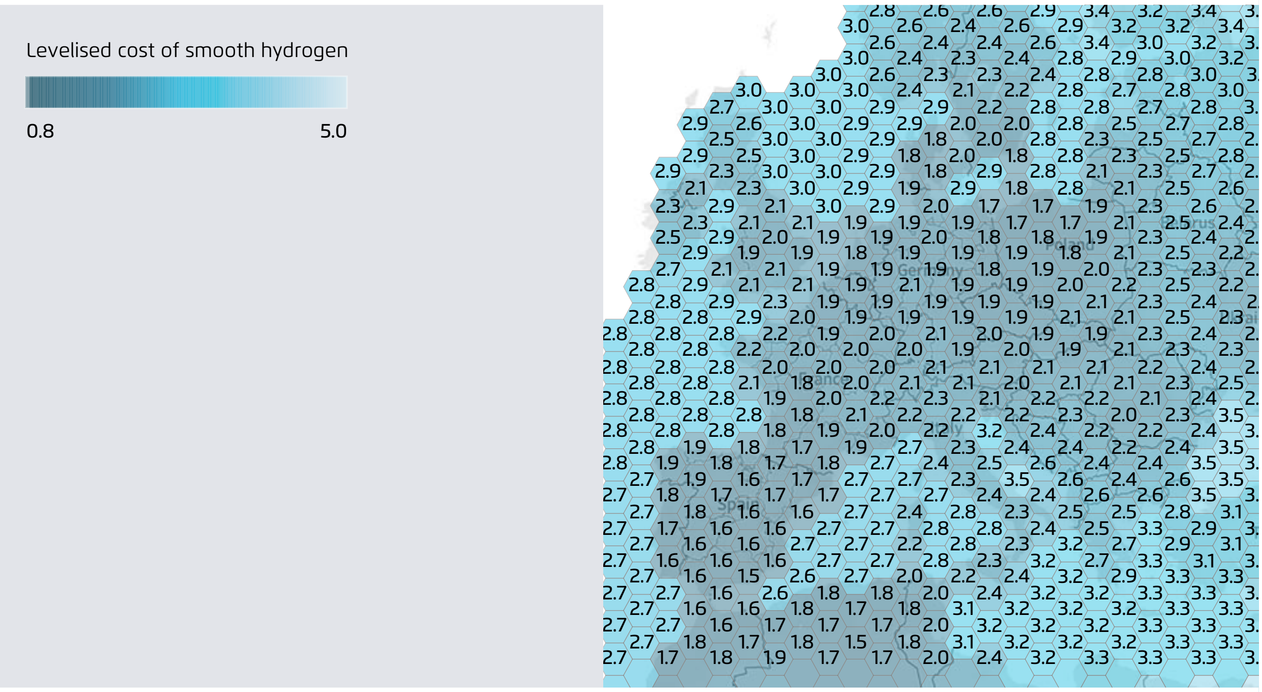
72 ENTSOG (2019): The European natural gas network 2019.

Impact of transportation — Figure 20



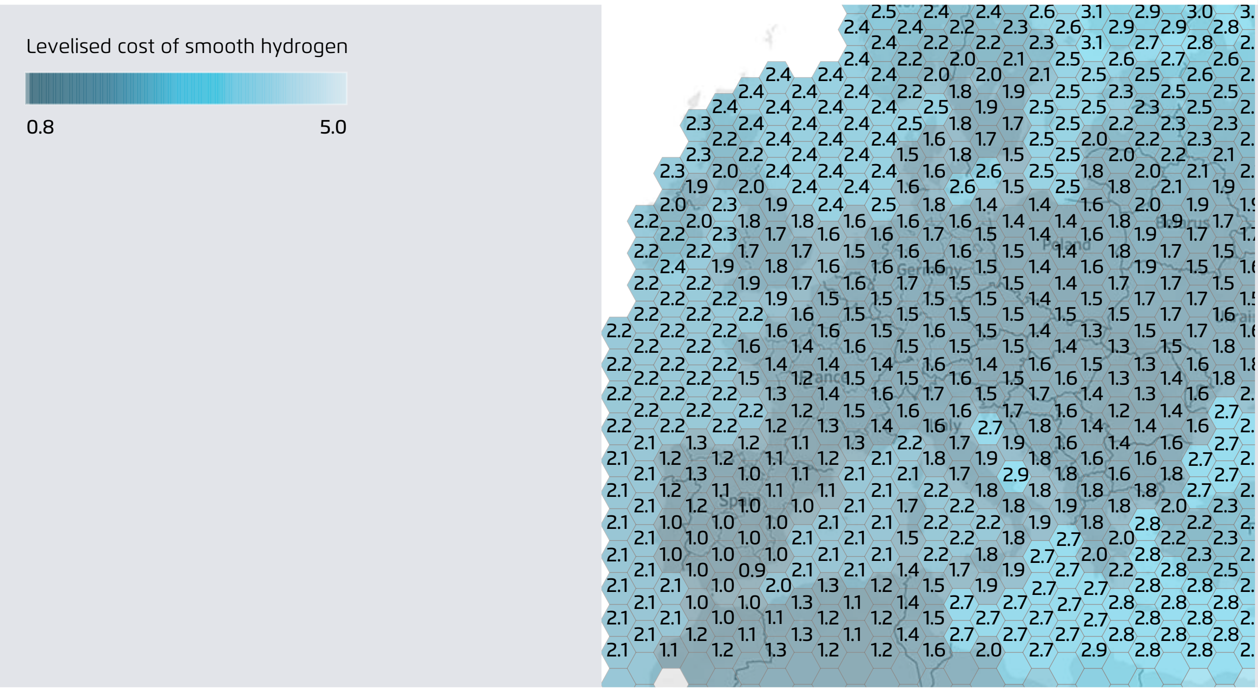
AFRY analysis. Results taken from the 2030 BLUE-GREEN analysis.

Levelised cost of smooth hydrogen in the BLUE-GREEN scenario in 2050 — Figure 21



AFRY analysis. © 2020 Mapbox © OpenStreetMap.

Levelised cost of smooth hydrogen in the FAST GREEN scenario in 2050 — Figure 22



AFRY analysis. © 2020 Mapbox © OpenStreetMap.

4.2.5.3 Selected case studies

As noted above, more results from the modelling work can be examined by the reader in the Tableau workbook.

The Hexamodel results, in addition to identifying the optimal hydrogen supply for each demand hexagon, can also be used to highlight alternative hydrogen supply routes that might play a role in the future hydrogen landscape. The infoboxes below present the hydrogen supply costs for a hexagon in the regions of Hesse, Germany and Tuscany, Italy. Both case studies investigate either local production or imports, for 2030 and 2050.

Infobox: Hesse, Germany.

This infobox considers a case study for a hexagon located in Hesse, Germany.

In the BLUE-GREEN scenario, shown in Figure 23 and Figure 25, imports from the hexagons containing the Netherlands (one of which also contains North-Rhine Westphalia) are the most economical source of supply, produced either from SMRCCS (in 2030) or RES (in 2050). In both years, transportation costs are low because of the ability to repurpose existing gas pipelines. By 2050, electrolyser costs have fallen sufficiently far so that RES-based production costs less than SMRCCS. Whilst production costs in Algeria and Spain are lower than in North-West Europe, the costs of transportation prevent it from being economic for consumption in Hesse, even when these costs are lowered through the repurposing of available gas pipelines.

In the FAST GREEN scenario, shown in Figure 24 and Figure 26, the story is similar: North-West European imports are more economical than Spanish and Algerian imports as the costs of transportation are substantial.

The case study finds that for both scenarios, the costs of production fall between 2030 and 2050. In both scenarios the identified costs compare favourably to imports from Saudi Arabia identified in the IGU's Global Gas Report[73] (2.9€/kg in 2050). Whilst IGU also identifies competitive costs for Russian imports, to be competitive this supply would need to be of comparable carbon content. Moreover, methane venting, leakage and flaring would also need to be addressed for Russian imports to be competitive.

73 IGU, BNEF, SNAM (2020): Global Gas Report 2020.

Hydrogen supply costs in Hesse, Germany

Figure 23-24-25-26

AFRY analysis.

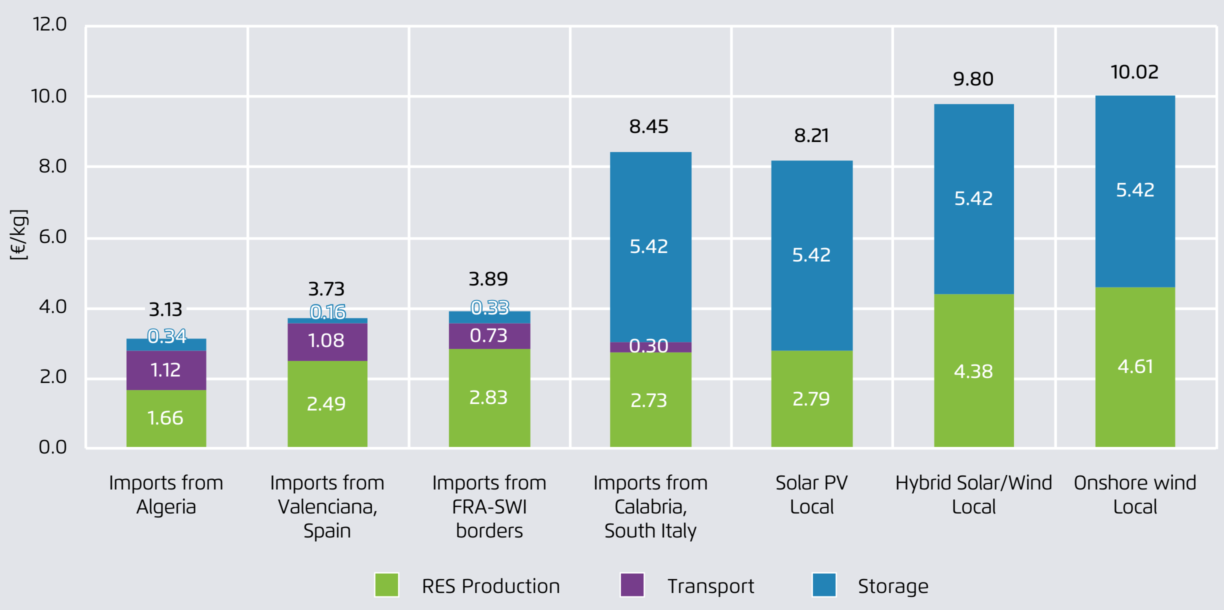
Infobox: TUSCANY 2030.

Another case study was developed for a hexagon located on the coastline of Tuscany, Italy.

This case study considered hydrogen flows within Italy (Calabria) and hydrogen imported from French-Swiss borders, Spain (Valenciana) and Algeria. The supply hexagon covering the France-Switzerland border was selected as the closest location for hydrogen storage, given the existence of salt strata that might be useful for storage. The analysis was based on the BLUE GREEN scenario developed in this project for 2030 and 2050.

In this case study, levelized costs for storage were considered for each of the suggested hydrogen supply methods. Since there is no storage infrastructure in place and no future potential for salt caverns in Tuscany, the only storage solution was assumed to be compressed hydrogen cylinders with a high CAPEX, as illustrated in Figure 27. Hydrogen supply from nearby regions such as Algeria, Spain and France is expected to be cheaper due to their low hydrogen storage costs (based on the presence of geological salt strata).

Hydrogen supply costs in Tuscany, Italy - BLUE-GREEN, 2030 — Figure 27



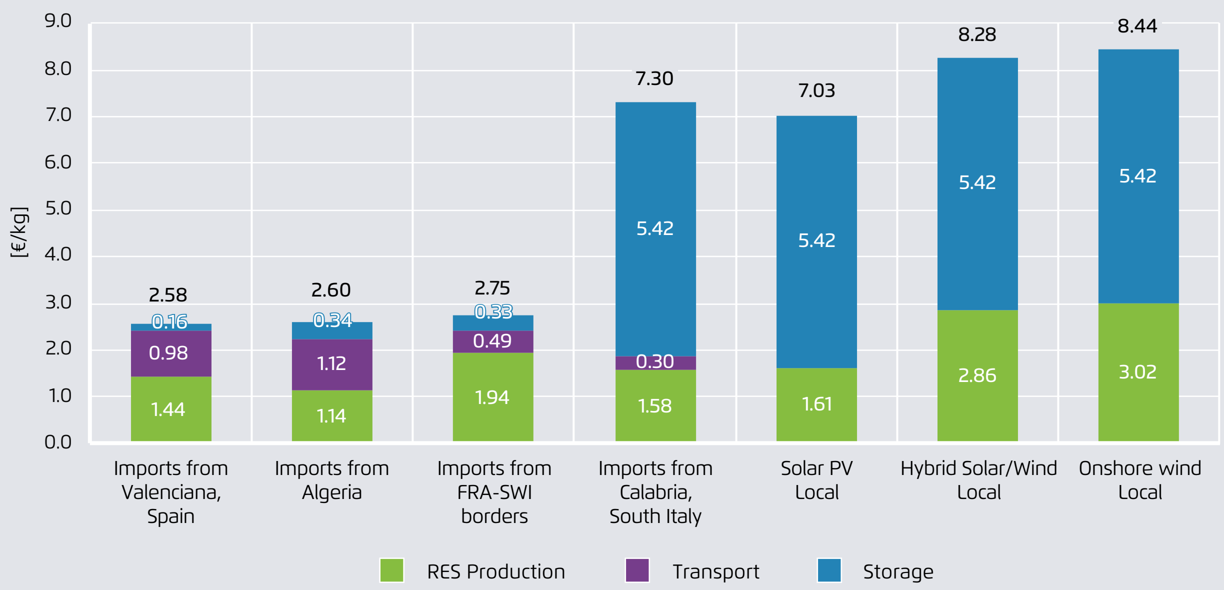
AFRY analysis, using BLUE-GREEN scenario assumptions and Hexamodel outputs for the other supplying regions. Pressurized tanks are used for local storage.

Infobox: TUSCANY 2050.

In 2050, hydrogen imports from Spain become less expensive, replacing imports from Algeria as the dominant supplier to Tuscany, as shown in Figure 28. As in the case of Hessen (Germany), this was driven by the expected repurposing of existing gas pipelines. Transport costs from Algeria include the construction of new pipelines and are therefore more expensive.

This indicates the ancillary benefits that an EU backbone can offer to hydrogen deployment in the future, since both Tuscany (Italy) and Hessen (Germany) are expected to profit jointly from the repurposing of existing gas pipelines located in-between them. This will lead to a low-cost renewable hydrogen supply and greater flexibility thanks to hydrogen storage.

Hydrogen supply costs in Tuscany, Italy - BLUE-GREEN, 2050 | Figure 28



AFRY analysis, using BLUE-GREEN scenario assumptions and hexamodel outputs for the other supplying regions. Pressurized tanks are used for local storage.

4.2.5.4 Additional results

Further results are discussed in the Annex. The results in the Annex demonstrate that:

- → sea-borne transportation at European scale is limited;
- → retrofitting existing natural gas pipelines provides access to cheaper sources of hydrogen;
- → some routes provide common access to cheaper sources of hydrogen; and
- → salt-caverns provide crucial storage services.

A publicly accessible Tableau Workbook has been created to allow readers to explore the full set of results.[74]

74 https://www.agora-energiewende.de/en/publications/data-appendix-no-regret-hydrogen

4.2.6 Next steps in hydrogen ecosystem analysis

Our modelling is a high-level representation of the potential for hydrogen transportation routes. The following list provides additional areas for analysis that should be considered for investigating the future hydrogen ecosystem:

→ The model considers locations of 'no-regret' demand only. Hydrogen demand for power system backup as well as heat and transport could change the requirements for storage – inducing, say, a greater need for hydrogen produced from SMRCCS.
→ Our analysis has considered dedicated hydrogen production only, and has not considered the opportunity for or additional complexities associated with grid-connected electrolysis.
→ Storage requirements should be examined at a more granular level – perhaps pegged to production – and considered across a range of weather patterns.
→ We assumed that salt caverns for hydrogen production can be created wherever there is an underlying salt layer within the hexagon. Technical feasibility studies should be conducted to identify suitable locations.
→ The model relies on the 11 TSOs study. A number of additional retrofittable natural gas pipelines may exist as well.
→ A detailed examination of transportation routes and cost differentiation (such as the costs of transportation in mountainous or populous areas) should be conducted.
→ Given the level of uncertainty in the cost estimates and the high-level nature of the study, our simplified approach assumed that the unit costs are the same across hexagons. An improvement to the methodology would entail the calculation of unit costs specific to each hexagon.
→ We assumed that offshore hydrogen production will require liquefaction and regasification. Alternatives to this set-up could be considered.
→ Forecasts of levelised costs could be used to make the model more dynamic. Modified in this way, our model could
  - take into account the impact of supply and demand volumes;
  - determine whether retrofitted pipelines will have sufficient capacity to to meet the needed requirements; and
  - optimise decisions over time.

4.3 Conclusions and recommendations

4.3.1 Conclusions

→ Hydrogen can be delivered more cost effectively to consumers if it is transported from cheaper production areas.
→ There are some clusters with clear opportunities for establishing hydrogen infrastructure to serve 'no-regret' hydrogen demand.
→ Most of these clusters are cross-border, and whilst there is very strong case associated with high hydrogen demand in the Benelux/NW Germany/NE France region, there are also clear cross-border opportunities between:
  - Poland and Lithuania; and;
  - Romania, Bulgaria and Greece.
→ Hydrogen storage is needed to balance supply and demand within any hydrogen network. This is particularly pronounced for RES-based hydrogen production and industrial demand. Our analysis indicates that salt cavern storage is significantly cheaper than alternative forms of storage.
→ There are clear cost advantages in redeploying natural gas transmission pipelines.
→ It is not clear that sea-borne hydrogen transportation will be required at a European scale.

4.3.2 Recommendations

On the basis of the above conclusions, we recommend the following:

→ EU policy makers should:
  - encourage all EU Member States and natural gas TSOs to determine which parts of their gas transmission network could be suitable for

redeploying as hydrogen pipelines, and to establish the physical requirements for doing so;
  - incentivise the early adoption of hydrogen in industrial demand centres; and
  - develop regulatory frameworks for hydrogen transportation including (where applicable) the principles for the transfer of regulated assets and any requirements for vertical separation and third-party access.
- → Member States should:
  - work with their neighbours to establish where cross-border hydrogen infrastructure will facilitate access to more cost-effective low- and no-carbon hydrogen production, especially when it comes to industrial demand; and
  - ensure that gas TSOs are incentivised to conduct studies to establish both the extent to which their networks can be repurposed/retrofitted for hydrogen transportation and the likely costs of doing so.

We also recommend a deeper analysis of the requirements for a European Hydrogen Backbone. Studies should address the opportunities for further investigation we identified in section 4.2.6. Whilst our analysis does not identify a completely interconnected backbone that spans Europe, this may be a feature of the input data (i.e. the retrofittable gas pipelines we identify[75] do not cover East Europe). And because we addressed only a 'no-regret' demand, it may be important to first establish whether a regional approach would be more appropriate.

75 Guidehouse (2020): European hydrogen backbone. How a dedicated hydrogen infrastructure can be created.

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Annex A – Additional Discussion And Results

A.1 Maximum renewables energy potential

A.1.1 Estimation of the maximum practical solar PV energy potential

Using a combination of GIS and visual-analytics software, we assessed the global photovoltaic power potential by country,[76] expressed as kWh per daily kW_p. (A map containing the power potential is available on the Global Solar Atlas website in tiff-format.) We considered the 'Level 2' practical potential calculated in the Global Photovoltaic Power Potential by Country study. Level 2 potential rules out land use types that prevent the installation of mounted PV solar panels, areas with physical or technical restrictions and areas with soft restrictions such as nature reserves. That study identified unsuitable areas by evaluating data on terrain elevation and slope, built-up areas, population clusters, land cover, water bodies and protected areas.

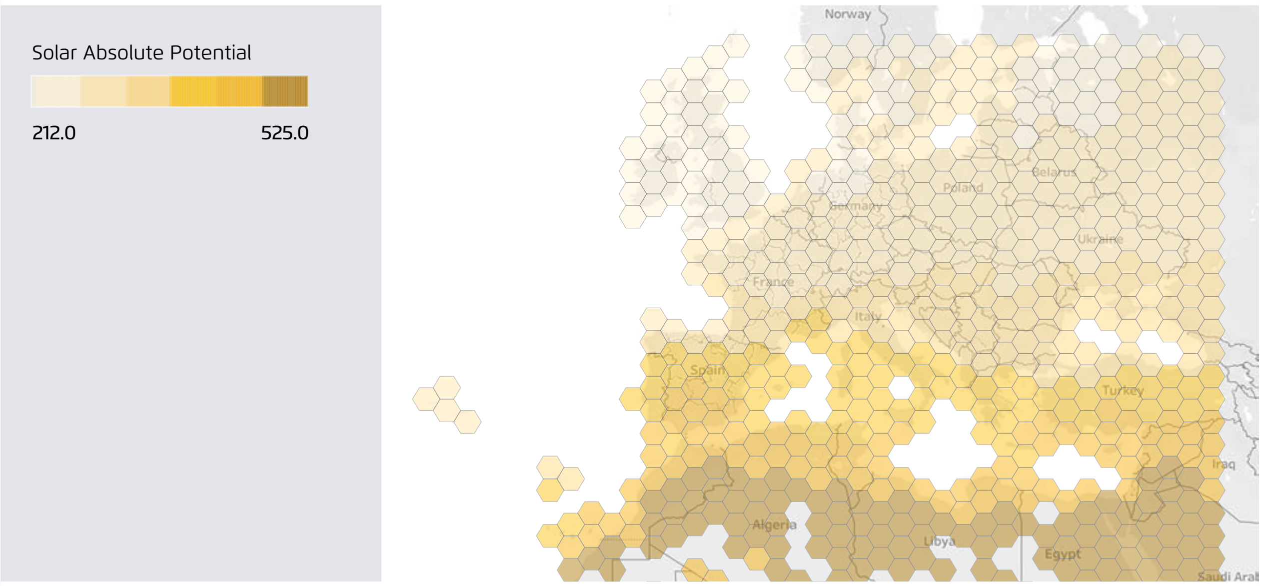
The aggregate annual solar PV potential within the hexagons was calculated by multiplying the average annual power potential per hexagon by a power density factor of 0,17 kW_p/m^2.This average annual power potential derives from the daily kWh/kW_p power potential multiplied by 3%,[77] a reasonable assumption given the available non-artificial areas. In a second step, the potential in kWh/m^2 was multiplied by the size of the hexagon to derive the hexagon-specific practical PV-potential. Missing data for North Africa were interpolated. The results of this analysis is shown in Figure 29. The annual

76 ESMAP (2020): Global photovoltaic power potential by country.

77 The assumption stems from a 3% use of the available non-artificial areas in one of the cases analysed by P.Ruiz et al (2019): ENSPRESO - an open, EU-28 wide, transparent and coherent database of wind, solar and biomass energy potentials.

Practical solar PV potential per hexagon in TWh/year

Figure 29



AFRY analysis and Global Solar Atlas dataset. © 2020 Mapbox © OpenStreetMap.

potential for electricity generation powered by solar radiation ranges from 212 TWh in the poorest areas to over 525 TWh in the most promising hexagons.

A.1.2 Estimation of the maximum practical wind energy potential

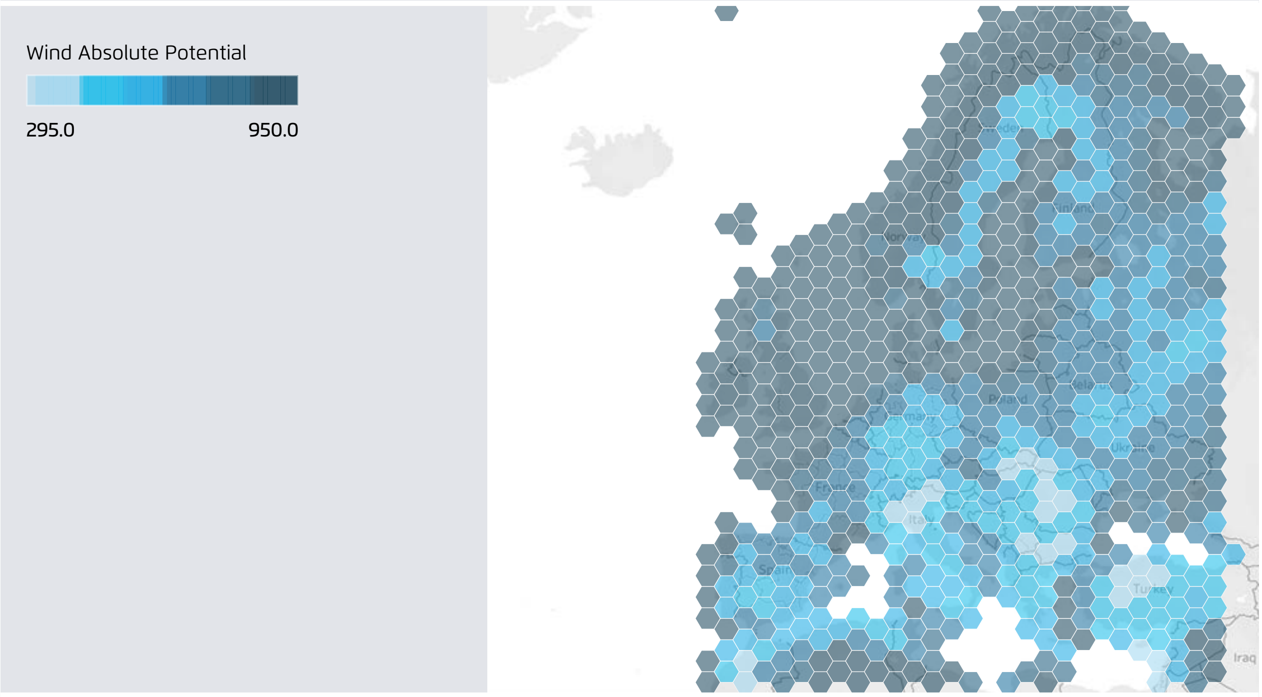
The assessment of the wind potential follows a similar approach. The starting point for the analysis of the European wind potential is the ENSPRESO database (ENergy System Potentials for Renewable Energy Sources),[78] established by the Joint Research Centre (JRC) of the European Commission. It provides data on the practical onshore and offshore wind potential of the EU-28. The theoretical wind potential derives from historical meteorological data in the MERRA reanalysis dataset (NASA) and geo-spatial data based on the Global Wind Atlas (Technical University of Denmark, World Bank Group).

The methodology used to derive the practical wind potential takes into account the availability of sea and land areas as well as national regulations on the offset distance between wind turbines. The authors of the ENSPRESO study developed three scenarios. This paper focuses on the High Wind Scenario, which has a general offset distance of 400 m (onshore wind). With respect to the offshore wind potential, exclusion zones were defined by factors such as shipping lanes and protected areas, where the ENSPRESO authors assumed wind turbines with a specific power of 300 W/m2 and a 100 m hub height.

The assessment of the achievable output was done by calculating the practical annual wind potential as the amount of electricity generated per unit of installed wind capacity (kWh/kW). The calculation took into

78 European Commission, Joint Research Centre (2019): ENSPRESO – WIND – ONSHORE and OFFSHORE. European Commission, Joint Research Centre (JRC).

Practical wind potential per hexagon in TWh/year — Figure 30



AFRY analysis and Joint Research Centre dataset. © 2020 Mapbox © OpenStreetMap.

account losses associated with the wind-to-power conversion process as well as land use constraints.

To integrate the potential data into the applied hexagon structure, the average power potential per hexagon was calculated with GIS software using an average power density factor of 0,005 kW/m^2.[79] The potential in kWh/m^2 was then multiplied by the size of the hexagon to find the hexagon-specific practical wind-potential. In cases where data on wind potential within a specific hexagon was missing, the potential was assumed to equal the average potential of neighbouring hexagons. A cap of 3800 full-load hours for wind (~43% of the capacity factor) was applied in all hexagons in order to reflect the kinetic energy removal effect that turbines have on each other in densely populated wind farm areas (Baltic/North sea). This resulted in lower wind speeds, with an aggregated impact on the energy production of the wind farms, as presented in the 'Making the most of offshore wind' study.[80] The results of this analysis are shown in Figure 30.

79 The power density factor was derived from WindEurope (2019): Our energy, our future: How offshore wind will help Europe go carbon-neutral.

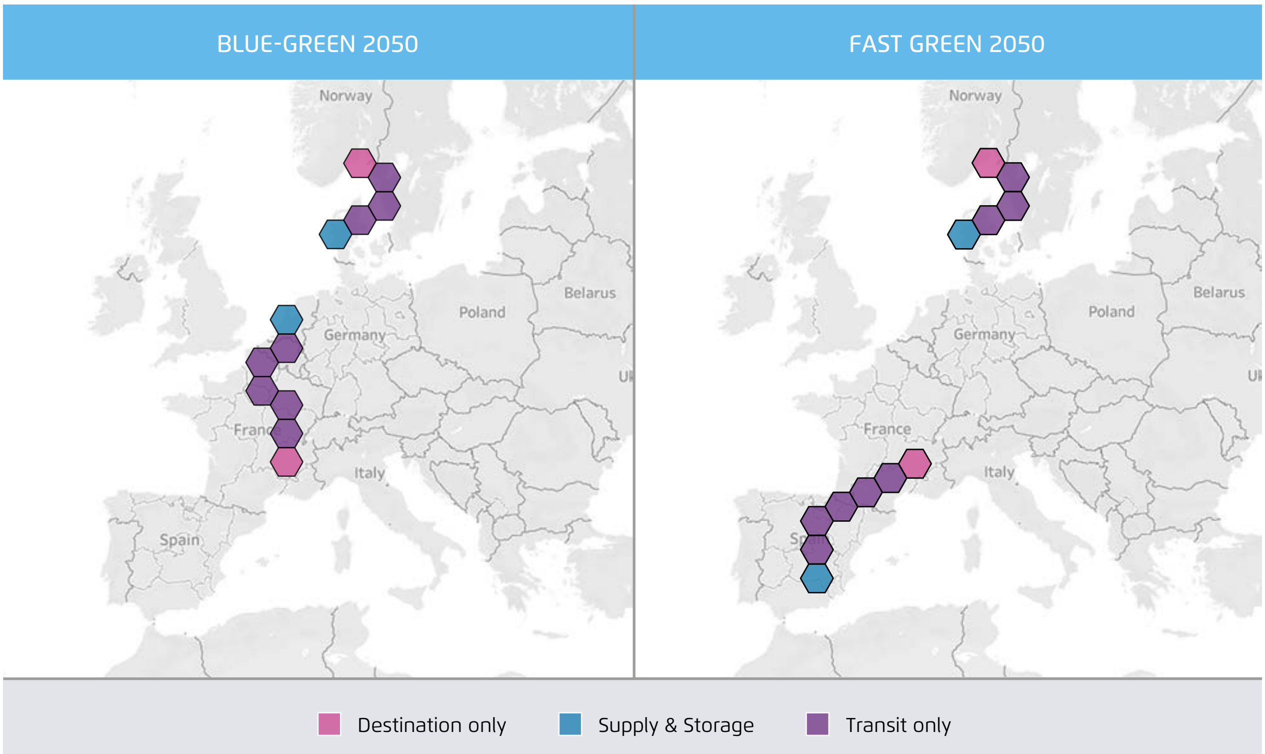
A.2 Further results

A.2.1 Sea-borne transportation at European scale is limited

The demand hexagon representing oil refinery demand in the Canary Islands is the only demand that

80 Agora Energiewende, Agora Verkehrswende, Technical University of Denmark and Max-Planck-Institute for Biogeochemistry (2020): Making the most of offshore wind: Re-evaluating the potential of offshore wind in the German North Sea.

Hexamodel results for hexagons in France and Norway — Figure 31



AFRY analysis. © 2020 Mapbox © OpenStreetMap.

makes use of sea-borne transportation. All other demands are provided by a combination of local or pipelined transportation. Because the model is restricted to Europe and North Africa, it does not consider the potential for global sea-borne flows.

A.2.2 Retrofitting existing natural gas pipelines provides access to cheaper sources of hydrogen

Figure 31 shows the results in 2050 for both scenarios for two selected demand points: S30 (France) and V20 (Norway). The French demand is served by hydrogen produced and stored in Spain (FAST GREEN scenario) or the Netherlands (BLUE-GREEN scenario). The Norwegian demand is served by hydrogen produced and stored in Denmark. All three make use of the pipelines identified in the 11 TSOs study.[81]

A.2.3 Some routes provide common access to cheaper sources of hydrogen

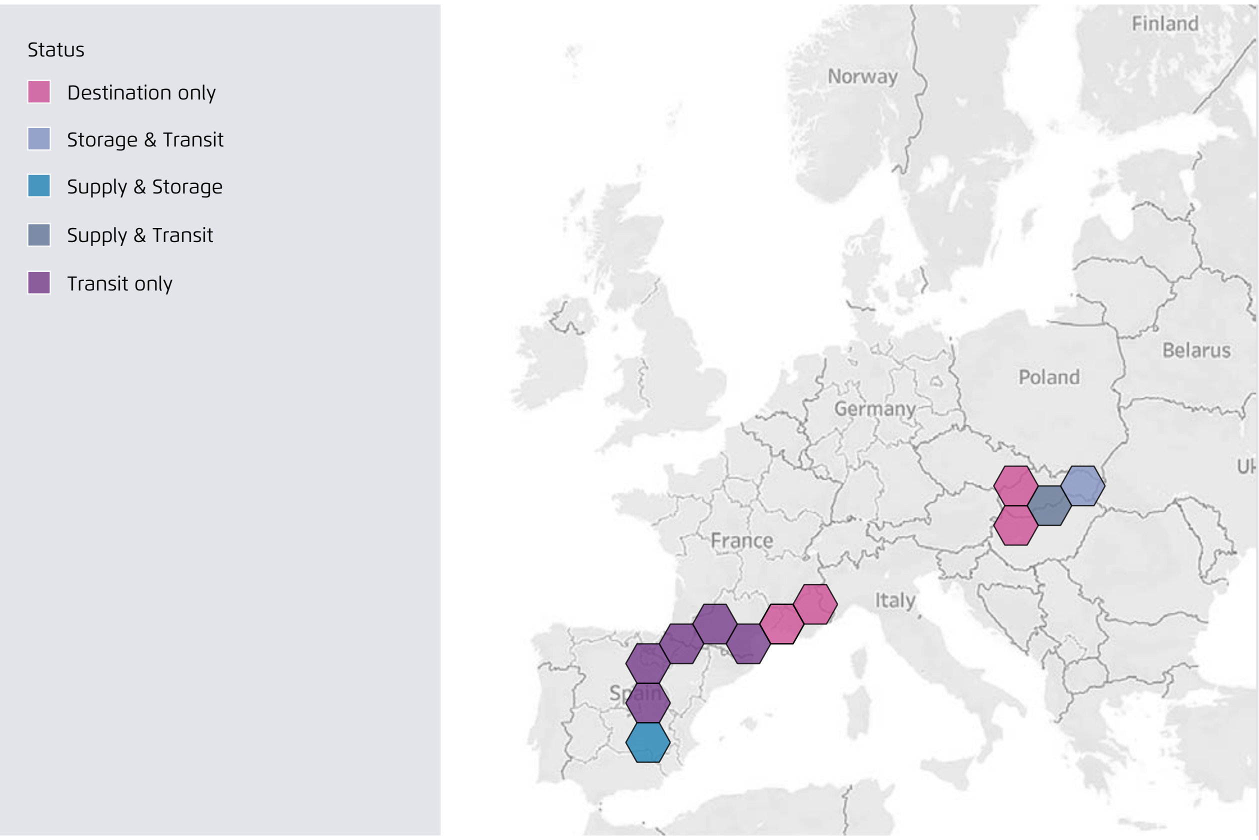
The graphic below shows the results for different demands served by the same sources of supply and along the same transportation routes.

Figure 32 shows two examples for the FAST GREEN scenario in 2050:

→ Demand in S31 & T31 (Southern France), supplied from Eastern Spain, makes use of a transportation

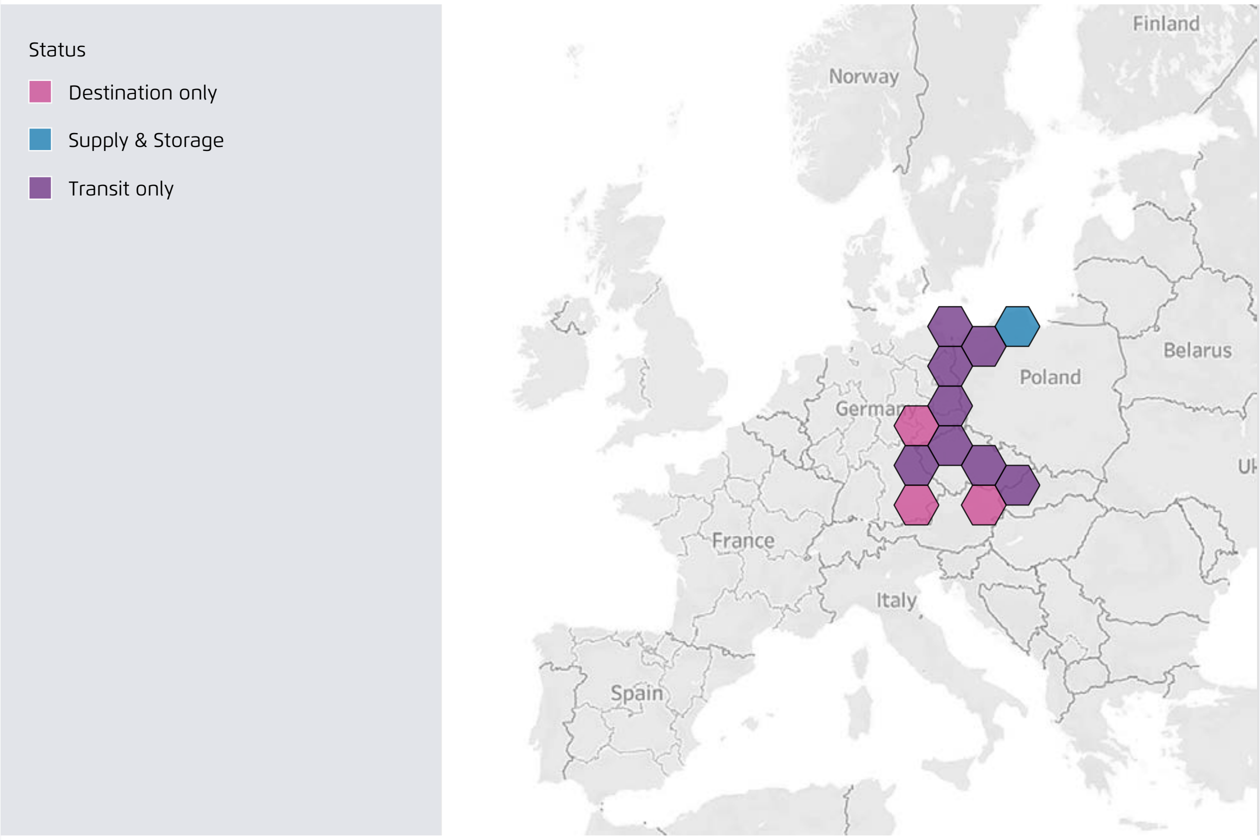
81 Guidehouse (2020): European hydrogen backbone. How a dedicated hydrogen infrastructure can be created.

The hexamodel case for hydrogen demand in Southern France and Slovakia/Czechia — Figure 32



AFRY analysis. © 2020 Mapbox © OpenStreetMap.

The hexamodel case for hydrogen demand in Central Europe | Figure 33



AFRY analysis. © 2020 Mapbox © OpenStreetMap.

route (retrofitted gas pipelines) that is also used by a demand in W31 (Central Italy).

→ Demand in Z28 (Slovakia/Czechia) and Z29 (Hungary) is supplied by hydrogen in the eastern neighbouring hexagon (central Slovakia/Hungary border region). The hydrogen is transported to storage facilities in Eastern Slovakia before being transported to the two demand nodes in the West.

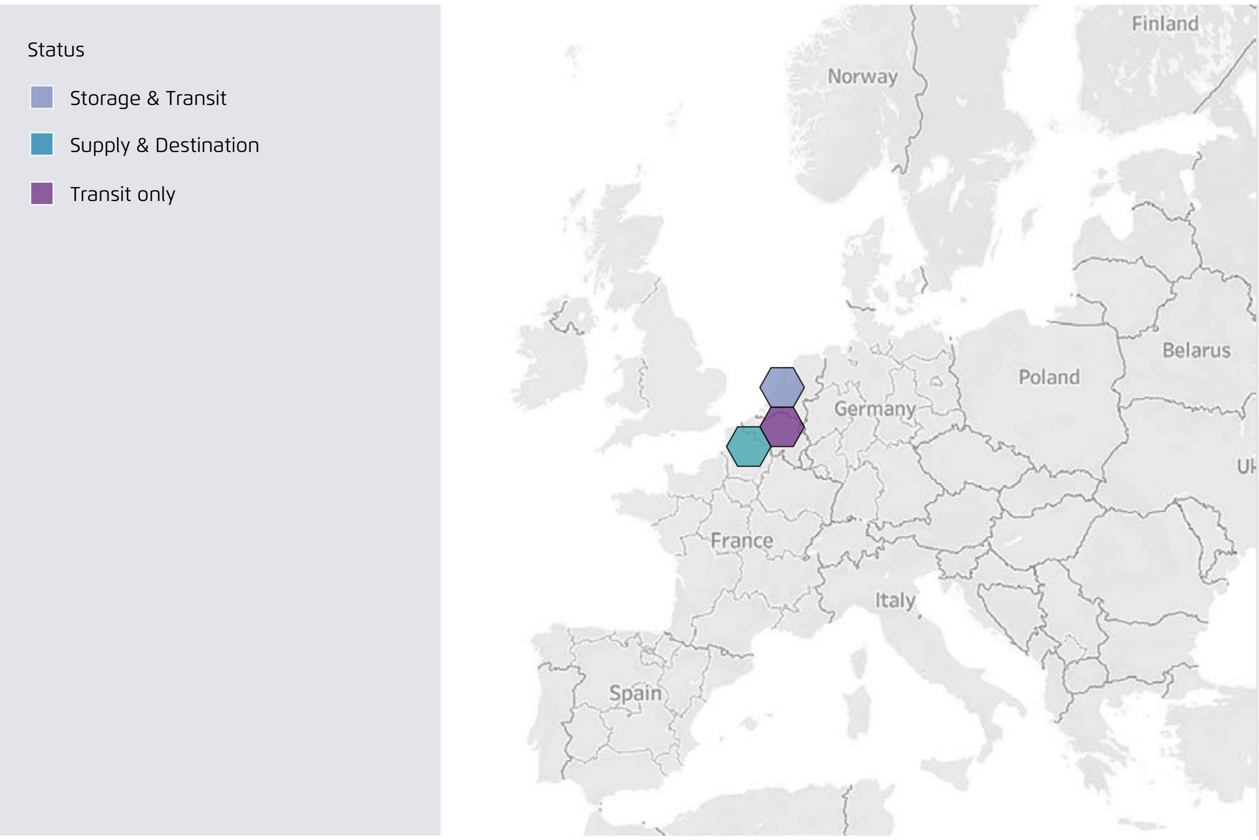
These routes are in addition to the 'no-regret' opportunities identified in our study.

Figure 33 also shows an example for the BLUE-GREEN scenario in 2050, in which hydrogen produced and stored in Poland and transported along retrofitted gas pipelines serves W26 (Eastern Germany), W28 (South Germany/Austria) and Y28 (East Austria).

A.2.4 Salt-caverns provide crucial storage services

The results also show instances where transportation is used specifically to access areas with salt deposits to make use of cheaper storage options. Figure 34 indicates hydrogen supplies produced and consumed in North France (R27) that are transported to and from the Netherlands for storage purposes (FAST GREEN 2030).

The hexamodel case for hydrogen demand in North France — Figure 34



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203/1-S-2021/EN

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