Hydrogen Infrastructure Report
The Recipe for a Hydrogen Grid Action Plan

October 2024

Contents

List of abbreviations

CCGTs	Combined Cycle Gas Turbines
CCUS	Carbon Capture, Utilisation and Storage
CEF	Connecting Europe Facility
CHP	Combined Heat and Power
DA	Delegated Act
DSO	Distribution System Operator
EHB	European Hydrogen Backbone initiative (as driven by the TSO)
EIA	Environmental Impact Assessment
EHB	European Hydrogen backbone refers to concept of the EU hydrogen network
EMD	Electricity Market Design
HVAC	High Voltage Alternative Current
HVDC	High Voltage Distribution Cable
LC	Low Carbon
LHC	Liquid hydrogen carriers
LNG	Liquified Natural Gas
LOHC	Liquid Organic H2 Carrier
PCI	Projects of Common Interest
TSO	Transmission system operator
VRES	Variable Renewable Energy Sources
RCF	Renewable Carbon Fuel
RED III	Renewable Energy Directive
RES	Renewable Energy Sources
RFNBO	Renewable Fuels of Non-Biological Origin
UHS	Underground Hydrogen Storage

Rationale of the paper

The European Commission has highlighted the need to expand hydrogen as one of the building blocks to reach 2040 greenhouse gases (GHG) reduction objectives. And regardless of whether we are aiming to reach the 10 million tonnes (Mt) objective set by the 2020 European Union (EU) Hydrogen Strategy[1], the 20 Mt of imported and domestically produced renewable hydrogen by 2030 targeted by REPowerEU, or the 3 Mt modelled in the 2040 climate targets impact assessment, the deployment of hydrogen in the EU will be dependent on building out a large-scale domestic and international infrastructure network.

A profound decarbonization of the industrial processes and feedstocks, and a massive roll out of distributed and remote Variable Renewable Energy Sources (VRES) - all of it in the context of heightened need for energy security and international competitiveness - will require hydrogen to satisfy the need for clean gas, but also to complement electrification and accelerate VRES integration in the system.

A multi modal energy system will complement an electricity grid revamp and expansion – and the electrification process at large - and maximize energy transport efficiency. It will also be more cost-effective for end customers and will optimize the roll-out and assimilation of VRES in the European landscape. However, many regulatory, financial, and technical challenges lie ahead. This analysis examines the distinct characteristics of various types of hydrogen infrastructure but does not seek to foster competition amongst them. Hence, it establishes hydrogen infrastructure as a viable energy transport solution within policy environments that are increasingly turning to electrification.

Our paper serves a triple purpose:

- Provide the reader with the most comprehensive overview of what hydrogen infrastructure means (including dispelling myths about it), outline the types of infrastructure we will need to roll out the hydrogen economy and why it is important given the role hydrogen infrastructure plays in the decarbonisation of the European energy ecosystem.
- Outline the challenges that lie ahead for it to materialize.
- Formulate concrete policy recommendations for policy makers.

[1] For 2040, the European Commission also estimates 33 Mt of H2 demand in Europe (scenario 3). We take into account here the result modelled in the impact assessment for the 2040 climate targets, however, the modelling does not take into account the national NECPs nor the REPowerEU objectives.

Executive Summary

The lack of adequate hydrogen infrastructure is a critical challenge impairing the development of the hydrogen market across Europe. To unlock the potential of hydrogen and ensure European decarbonization targets are fulfilled, infrastructure will have to be developed throughout the continent to connect production to demand centres, enable imports of cheap hydrogen and provide a resilient system through storage capacities.

1. **Hydrogen infrastructure is the best solution to accelerate a cross-sectorial decarbonisation at a lower cost.** A report based on METIS, a modelling software used by the European commission to model the various energy systems, demonstrate that, at European level, two infrastructures (combination of power grid and hydrogen grid) are cheaper than one; in concrete, it concludes that the development of a pan European hydrogen network in a multi-energy model over the 2030-2050 timeframe could save as much as 330 billion EUR compared with a more isolated approach. This has been also demonstrated by the French electricity and gas TSOs in a dedicated joint-study for France.
2. **Hydrogen will provide the flexibility needed to a power system dominated by electrification and variable renewables**. The European Commission expects electricity to satisfy about half of the final energy demand in 2050 (from 23% today)**.** To accommodate the new demand and the massive installation of renewables, the electricity grid capacity must increase 47% by 2030 and 144% by 2040 in Europe. And even considering this aggressive expansion plans, ACER expects flexibility needs to double already by 2030 with important seasonal flexibility needs. JRC estimates that even with high levels of grid expansion, total redispatch volume increases almost six-fold by 2040. In 2022 Europe incurred 5 Bn EUR remedial actions; and those will increase to at least 30bn EUR by 2040, potentially increasing to 103 Bn EUR if the grid would not expand as fast as anticipated.
3. **Investment in hydrogen infrastructure remain relatively modest compared to power grids.** The Grids Action Plan estimates the need for 584 bn EUR in electricity grid investments for 2030. In comparison, for the hydrogen grid network buildout the European Commission expects investment needs of 28-38 bn EUR for EU-internal pipelines and 6-11 bn EUR for storage to transport about 20 Mt of renewable hydrogen.
4. **Producing hydrogen near the generation source makes more economic sense than converting electricity to hydrogen at the demand site.** Research done by the Department of Energy in USA indicates that ‘’the cost of electrical transmission per delivered MWh can be up to eight times higher than for hydrogen pipelines’’, in particular when compared with HVDC networks and for a distance of 1000 km. This comparison is relevant when the energy transported is meant to be transformed into hydrogen.
5. **An integrated hydrogen backbone (network of hydrogen pipelines and storage sites) is a key enabler for cost optimisation – thus protecting the competitiveness of European energy intensive industries.** Abundant renewables are not distributed evenly throughout Europe. And the energy intensive industries are concentrated in clusters where the possibility of sourcing cheap renewable energy locally are limited. With transportation costs via high-capacity pipelines as low as 0.3 EUR/kg per 1,000 km, the European economy would benefit from an **integrated hydrogen backbone.**
6. **The hydrogen backbone is expected to grow to over 50,000 km by 2040**, consisting of about 60% repurposed infrastructure and 40% new pipelines according to some stakeholders. However, this will depend in the end on the intrinsic traits of each country. Retrofitting existing natural gas grid present many advantages, such as reduced environmental impact, faster permitting times and lower costs. According to TSO data, repurposing 20” pipelines incur only 30% of the expenses associated with deploying new pipelines. Additionality, CO2 infrastructure needs to be urgently

developed to transport, and store captured carbon from low carbon hydrogen production locations. A coherent planning of this overall transformation remains a key challenge.

7. **Importing hydrogen and its derivatives is a necessity for the near-term competitiveness of the European industry and long-term system decarbonisation.** The EU will not produce enough clean hydrogen to fulfil its 2050 demand and will need to complement its production via imports. Some global regions enjoy abundant clean energy resources and limited demand. Leveraging the hydrogen potential in those regions will not only be essential in the global effort to reduce emissions and dependency on fossil fuels but will also boost the local economy, providing income and jobs. These benefits won't need to be generated by fossil fuels anymore.
8. **Shipping hydrogen derivates becomes an attractive option for distances above 3,000 km**. On general terms, pipelines should be mainly used for the import of pure hydrogen covering most of the demand – complementing with domestic production –, whereas shipping is the best option for derivatives. The main cost driver for imported hydrogen is the reconversion process. For this reason, for industrial applications that require hydrogen in the form of hydrogen carriers (such as ammonia, methanol, e-fuels, or synthetic methane) and do not require dehydrogenation/cracking, the economics of imports could become more attractive than domestic production. However, there are certain factors such as pipeline availability, end-use purpose and location, purity levels, and security of supply and cost that may tilt the balance to one method or another. Investments in ports will need to grow significantly to expand and adapt the necessary infrastructure (e.g., reception facilities, storage facilities, ammonia crackers, distribution pipelines).
9. **Underground Hydrogen Storage is critical for energy intensive industry and the best partner for variable renewable energies.** Hydrogen storage in salt caverns is emerging as the most economical solution to substitute fossil thermal flexibility as it can provide energy in a "high-capacity high-volume" basis. However, due to long investment lead times, lack of a clear regulatory framework and missing investment incentives, investments are lagging. About 9 TWh of storage in salt caverns is under project development, far behind some of the first estimates of its needs (36TWh to meet a demand of 20Mton of hydrogen). A delay of investments jeopardises EU's decarbonisation goals, as energy storage in the form of hydrogen will be key not only for managing misaligned supply and demand on the hydrogen market itself but also providing multiple benefits for the electricity system – from flexible power generation and demand response, through seasonal storage and ensuring security of supply of energy for European citizens.
10. **Planning and cooperation remain key.** The development of the hydrogen infrastructure does face several challenges. First, regulators and the energy sector need to move from a silo-planning to a cross-sectorial energy network approach, adapting the way the energy system needs are identified and improving the way the cost-benefit analysis of projects are done. Second, it is important that planning is carried out thoroughly, from the bottom up and top-down levels, to ensure hydrogen infrastructure fits regional specificities and its build out, when based on retrofitting, is coordinated for securing supply to existing natural gas users. Third, building out the hydrogen grid will require anticipatory investments and a smart investment framework with initial state support, considering that the hydrogen grid is not up and running at the moment, and first customers should not carry out the total cost of grid development through connection tariffs.

Below a summary of the policy recommendations presented in this paper (detailed list available in chapter 5).

POLICY RECOMMENDATIONS FOR ROLLING OUT HYDROGEN INFRASTRUCTURE

The European Commission should, as soon as possible:

- Develop an EU wide storage strategy that translates into concrete legislative measures.
- Develop a Union strategy for imported and domestic hydrogen as mandated under RED3
- Develop a European hydrogen grid strategy based on the European hydrogen backbone initiative.
- Develop an EU strategy on flexibility with a system integration approach across different timeframes.
- Develop the Union Data Base for imports efficiently, lifting any obstacles to importing renewables gases from third countries, of which grids are not part of the single logistical facility.
- Revise the EU Taxonomy to facilitate a smooth repurposing of the natural gas grid.
- Modify the TEN-E regulation to include much stronger provisions on hydrogen projects.
- Ensure financial support for hydrogen infrastructure through the Projects of Common Interest scheme via increased CEF Energy funds, adapted selection criteria, and maximum support rates for hydrogen projects.

Member states should:

- Rapidly implement the Hydrogen and Decarbonised Gas Package, designating a hydrogen network operator, clarifying the framework for third party access to infrastructure and other provisions
- Support anticipatory investments in hydrogen infrastructure.
- Rapidly implement RED targets at national level to accelerate investments.
- Transpose RED III accelerated permitting process to hydrogen infrastructure.
- Address investment signals across different timeframes for storage.

Network operators should:

- Incorporate energy storage into network development.
- Strengthen cross-sectoral system planning via better scenarios and improved modelling tools.
- Include offshore Hydrogen production and transmission infrastructure in the Offshore Network Development Plan (ONDP) elaborated by ENTSO-E, involve ENNOH when it is implemented.

1. A new framework for energy: making sector integration come true

1.1. What do we understand by sector integration and sector coupling?

The goal of the energy transition is to decarbonise all economic activities, and this is best done by maximising the production and integration of Variable Renewable Energy Sources (VRES) across all sectors of society, from transport to industry, agriculture, power, and buildings. It should aim to achieve cost-efficiency at a cross-sectorial level, and the lowest environmental and social impacts, and with the highest security of supply. Achieving this requires a re-thinking of energy system planning and operation, moving from a silo-approach to a new systemic approach that integrates the intrinsic constraints of VRES and of an increasing electrified demand.

Focusing only on the "energy efficiency first" principle fails to fully consider the temporal, physical, and geographical constraints of VRES production, transport, and consumption. In the opposite, sector integration and sector coupling aim for a system-wide optimization. To better understand this process, it is important to define sector coupling and system integration:

- **Sector coupling** can be understood as the principle of linking the electricity and gas sectors, both in terms of their markets and infrastructure[2]. Sector coupling is focused on the **production/supply side of VRES** and aims at maximizing VRES output by leveraging the benefits of both electrification and Power-to-Gas. It also supports the better utilisation of the electricity system with the use of renewable-based molecules (gas-to-power).
- **Sector Integration refers to the notion of maximizing VRES integration on the end-uses.** The European Commission's system integration Strategy[3] describes sector integration as the **interlinkage of various energy carriers** — not just electricity and gas but also heat, cold, and solid and liquid fuels — **across end-use sectors including heating, transport, and industrial production.**

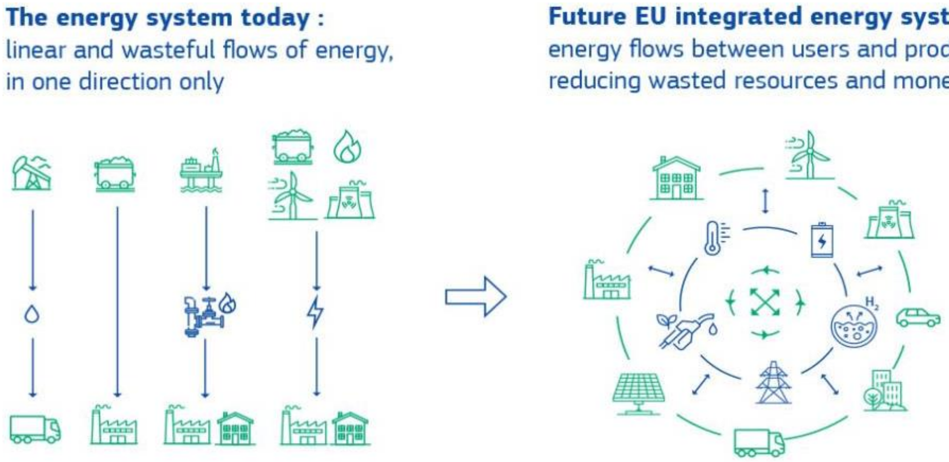


Figure 1: EU Strategy for energy system integration.

System planning needs to tackle on the supply side how to couple clean electricity and gas to maximize VRES production through sector coupling, and on the end-use side to link them to the consumption sectors so that they can be decarbonized as quickly and as efficiently as possible.

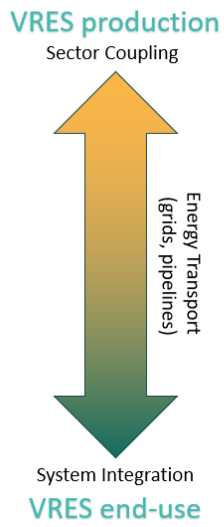
However, the boundaries between sector coupling and sector integration are not clear. They both influence each other bi-directionally and are intrinsically interconnected through energy transport infrastructure that also adds technical, geographical, and economical constraints to the system.

The benefits achieved through Sector Coupling and Sector Integration can be summarized in the following manner:

[2] BMWK, "What exactly is meant by "sector coupling"?, accessible here.

[3] European Commission, "Communication on Powering a climate-neutral economy: An EU Strategy for Energy System Integration", accessible here.

- **Maximisation of energy production:** Renewable energy production should be prioritized where and when is most efficient, and not through grid constrains due to physical limitations and lack of grid capacity availability. It is necessary to store energy across different timeframes in order to decouple VRES production from demand and tackle security of supply.
- **Derisking and diversifying investments:** a multi-infrastructure approach derisks investments and also maximizes VRES integration in the wide EU energy and industry ecosystem. Following the "*not placing all your eggs in one basket"* approach, the energy transitions will be more efficient than mono-vector approach, as it will be explained in the upcoming sections.
- **Maximisation of VRES used across sectors**: hydrogen will maximise RES consumption as hydrogen allows access to consumers for which electrification is impossible, impractical, unreasonably expensive, difficult due to scale-up or simply undesired.



All these benefits lead to **cost-efficiency across all sectors**, and hydrogen, as a clean energy vector, is a major lever of this system-efficiency, as it can bridge the gap between VRES production and demand beyond the limitations of electricity grids and wired solutions.

The very first step to achieve a clean transition will require re-thinking the current energy supply system into a multi-modal system and a change of paradigm in energy network planning.

1.2. The role of hydrogen in sector integration

Sector integration will allow future energy systems to **seamlessly shift among various clean energy carriers**: electricity, heat, biogas, and hydrogen (LCH2 + RFNBOs), thereby enhancing flexibility and storage across sectors, time, and place. Being a versatile, clean, and flexible energy vector**, hydrogen will play a crucial role in enabling this interconnectivity**: hydrogen can be used as a feedstock for industry and as a carbon-neutral fuel for transport (land-use, maritime and aviation), an energy carrier in the power sector as well as for heating in buildings and heavy industry[4].

Markets are likely to form in hubs with significant and stable hydrogen or clean carrier's demand, where synergistical infrastructure planning would be carried out (see below). This approach will be especially reflected in hydrogen valleys.

[4] Hydrogen Europe, "Response to EC Public Consultation: Strategy for energy system integration", accessible here.

Hydrogen Europe

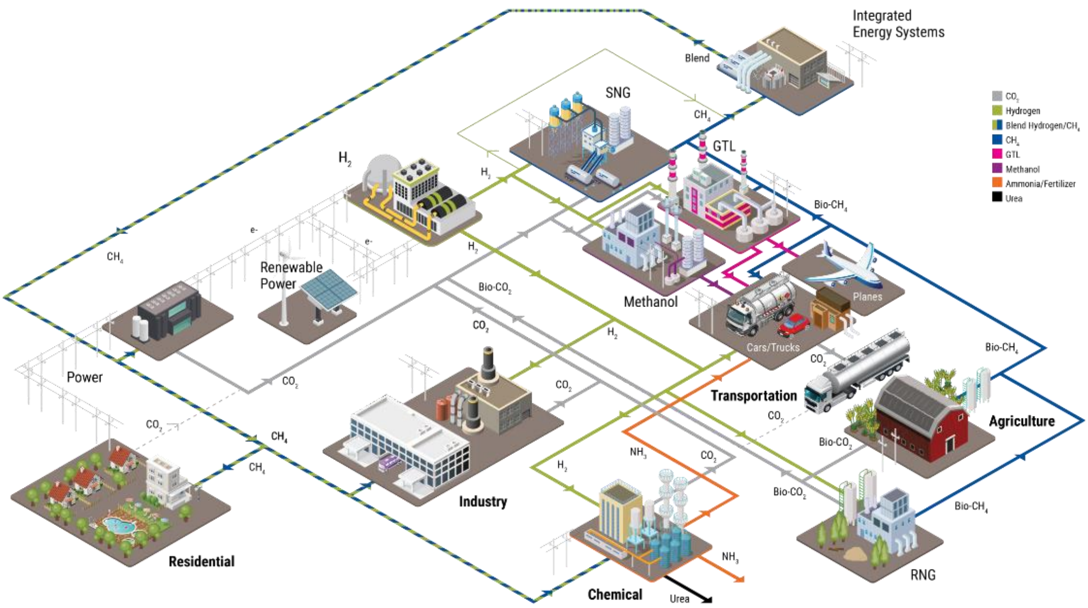


Figure 2: Integrated Energy System. Source: Department of Energy of the USA[5].

This cross-sectorial planning – embedding molecules and electrons – will allow for massive cost savings for the system, as two systems are cheaper than one. A recent study from the Gas for Climate consortium estimated that the cost savings from the development of a pan European hydrogen network in a multi-energy model over the 2030-2050 timeframe could be as high as **330 billion EUR** compared with a more isolated approach[6].

Focus: The benefits of a pan-European H2 network: METIS 3[7]

To evaluate the hydrogen infrastructure needs to fulfil the REPowerEU 2030 plan and the dynamics of hydrogen operations and sector integration, a multi-energy model was used in METIS. Key findings include:

- A cost-efficient pan-European hydrogen network enables production in optimal regions and redistribution to main consumers.
- Flexible operational management of the hydrogen system is cost-optimal, providing power system flexibility despite higher operational costs.
- Flexible electrolyser operation supports VRES integration by producing hydrogen during low electricity price and carbon intensity periods.
- Large hydrogen storage capacities are essential for system flexibility, with underground storage for seasonal needs and above-ground for short-term flexibility.
- Electrolysers can also furnish ancillaries (balancing) and capacity services (for system adequacy mechanisms) via demand side response.

There are practical examples of sectors where hydrogen contributes directly towards sector integration.

[5] GTI, "Hydrogen storage: drivers and near term solutions", accessible here.
[6] Gas for Climate Consortium, "Assessing the benefits of a pan European hydrogen transmission network", accessible here.
[7] EC, METIS 3:S8, "Assessing hydrogen infrastructure needs in a scenario with hydrogen imports and EU production", accessible here.

1) Hydrogen, CCS and CO2 infrastructure to produce carbon-based RFNBOs.

Hydrogen can be a main enabler of carbon capture as it can help find a second use for biogenic carbon and CO2 from industrial sites covered by the ETS[8] to produce carbon based RFNBOs, thereby enabling a business case for captured CO2, and further incentivise emissions reduction.

Indeed, **production feasibility of carbon-based RFNBOs can be improved if hydrogen and CO2 infrastructure for transporting biogenic CO2 are tied together**: according to the EC, a yearly quantity of 50 Mt of CO2 could be captured and stored by 2030, which is modelled to rise to 280 Mt by 2040 and 450 Mt by 2050[9], and harnessing that CO2 potential could reduce the cost and make the business case for synthetic fuel production in Europe.

Hydrogen can be chemically bounded with CO2 to produce hydrocarbons, which is a precursor for a range of products: transport fuels (diesel, jet fuel), fuel additives (methanol) or platform chemicals. Those, in turn, can be converted into a wide range of chemicals and materials (e.g., polymers, BTX...)[10]. Also, using excess CO2 from industrial sites where those synthetic fuels are consumed, potentially opens the possibility for closed-loop circular CO2 utilization.

As a result, **it is of utmost importance to consider the hydrogen backbone when designing CO2 infrastructure** – and vice versa, to capitalize on system integration, the synergies and uses that both infrastructures bring to the system.

It is also important to consider methane pipeline's repurposing when planning for CO2 infrastructure. Finally, the infrastructure planning process should avoid ending up with stranded assets (CO2 infrastructure) in the very long term, as we move into a truly carbon-free economy (e.g. pure hydrogen airplanes rather than e-fuels).

2) Hydrogen for industrial and domestic heat infrastructure

Another significant example for sector integration is **the use of hydrogen in the heating sector**. **While there is a significant case for heating electrification, practical challenges persist**[11].

- Electrifying industrial process heat is widely acknowledged as a pivotal step in decarbonizing industry. Despite this, 83% of Europe's industrial process heat is still derived from fossil fuel combustion, with only a mere 3% sourced from electricity[12]. **Clean hydrogen can provide heating services to medium and high heat industries to speed up the decarbonization of these industries**.
- The main issue with **domestic heating** is that while electrification (by prioritizing the installation of heat pumps) can be extremely effective, **a single-technology approach to a system so diverse and complex as domestic heating may not be the most cost-effective solution in all cases:** Each city district has a different configuration, and different resources at hand: it may have district heating and/or an established distribution gas network. Hence, **to tackle this problem, a bottom-up approach should be adopted and would requires a case-by-case analysis.** It is worth mentioning that there is a growing role of district heating infrastructure in off taking excess heat from electrolysis.

In this context, the repurposing of the gas infrastructure to be used for hydrogen in the heating sector will be a planning challenge. Additionally, the role of heating infrastructure will be especially relevant

[8] Until 2041, and from power plants until 2036.

[9] Communication from the European Commission, "Towards an ambitious Industrial Carbon Management for the EU", accessible here.

[10] Hydrogen Europe, "Response to EC Public Consultation: Strategy for Energy System Integration", accessible here.

[11] These include the high costs involved, inadequate grid capacity, low technology readiness — particularly for medium and high heat applications — and unfavourable electricity-to-fossil-fuel price ratio.

[12] DTU, Strengthening Industrial Heat Pump Innovation: Decarbonizing Industrial Heat, accessible here.

at DSO level, which is further explored in Annex A.1. The importance of heating infrastructure at distribution level.

3) Hydrogen as a flexibility asset in the Power Sector

From the point of view of the whole value chain, it cannot be disregarded that the conversion of electricity to hydrogen entails 20-30% of efficiency loss[13]. However, these efficiency losses are counterbalanced by the flexibility services that hydrogen brings to the Power System. With the massive roll-out of new variable and distributed RES combined with an underdeveloped grid the system needs flexibility sources to tackle and avoid electricity losses, for instance Germany experienced 10 bn EUR in congestion management costs in 2023[14]. And even in the most advanced grid development scenarios, the EC show that redispatch volumes in 2040 are in the order of magnitude as today's electricity demand in France or Germany[15]. In this sense, **electrolysers can provide the much-needed flexibility to the system by ramping up production to reduce and avoid congestions**, even before they happen. This, in turn, reduces the needs for investments in new power lines and reduces congestion and curtailments payments[16]. The flexible operation of electrolysers is further explained in Annex A.2. Flexibility provided by electrolysers to the power system.

1.3. How to include System Integration in infrastructure planning?

System integration implies a change of paradigm in network planning, where **energy and infrastructure providers factor in alternative options and the impact of their investment and operation decisions beyond their sector**. If this approach is taken, **investment in any energy network cannot be based solely on the supply and demand scenarios for that sector alone**. Instead, it also needs to be coordinated with the production, consumption, and infrastructure developments in other sectors and be optimized to deliver on the energy trilemma (sustainability, competitiveness, and security of supply).

Focus: A Future System Operator in the UK. Source: Ofgem[17].

A very illustrative example of a cross-sector planning approach is the ongoing discussions in the UK regarding the establishment of an unbiased Future System Operator (FSO). This FSO would oversee both electricity and gas system and would adopt a holistic approach in planning and operating energy networks. In fulfilling its duties, the FSO must account for the interplay among electricity networks, gas networks (comprising natural gas, biomethane, and hydrogen), heat networks, transport networks, and potentially CO2 networks as they evolve.

Not only the FSO would be unbundled from the ownership of the networks (hence being unbiased on the choice of building more "grids"), but it would also be "unbundled" from the sector and adopt a planning that would maximize the systemic welfare of the energy network.

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[13] Flux Power, "Hydrogen Fuel Cell Efficiency: How does it compare to lithium-ion", accessible here.

[14] Bundesrechnungshof, Energy transition not on track: urgent need for readjustment, accessible here.

[15] Thomassen, G., Fuhrmanek, A., Cadenovic, R., Pozo Camara, D. and Vitiello, S., Redispatch and Congestion Management, Publications Office of the European Union, Luxembourg, 2024, doi:10.2760/853898, JRC137685, accessible here.

[16] By using power grids more efficiently, we can reduce the need to reinforce them. Grid congestion indicates that the current capacity of the power lines is insufficient to transport the required electricity. When we reduce congestion, the need to increase the capacity of these lines decreases, minimizing the necessity for costly upgrades and expansions.

[17] Ofgem, "Future System Operator", accessible here.

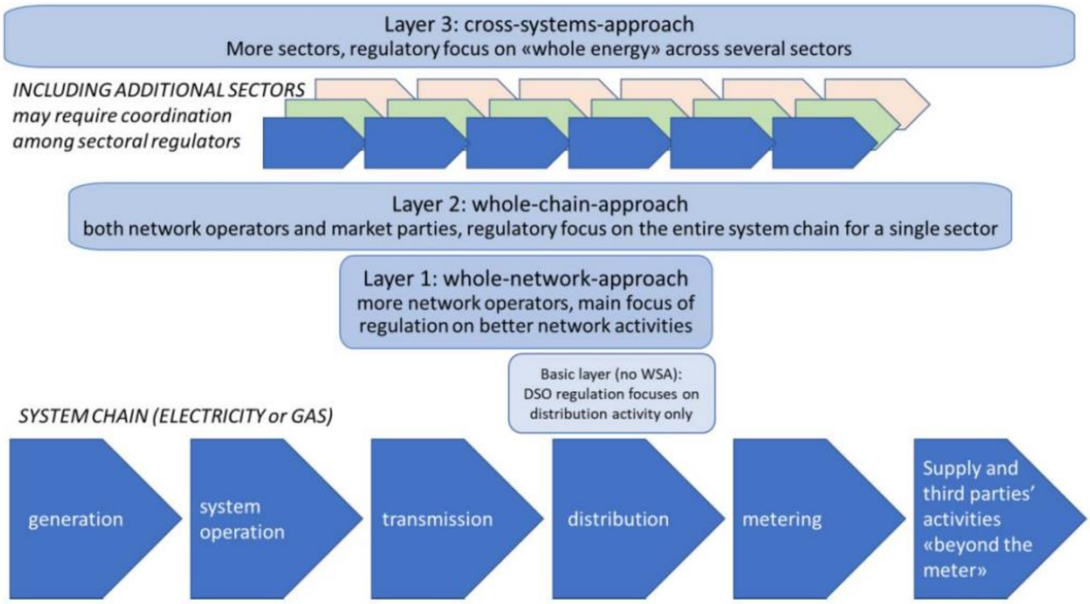


Figure 3: Three layers of an integrated approach to network planning and operation. Source: CEER[18].

Given the interdependencies between electricity, molecules, and heat among a wide array of value chains, enhanced coordination and planning among diverse energy networks is vital to achieve decarbonization goals.

An integrated energy system will help achieve carbon neutrality goals by **leveraging a synergy between existing and future infrastructure to lower the cost of decarbonization**. In this vein, the **four infrastructure pillars and prerequisites of sector integration** are: expand, modify, repurpose, & leverage existing infrastructure.

The following sections will explore how hydrogen infrastructure can optimize system integration by reducing overall costs, interlinking supply, and demand, and increasing flexibility.

[18] CEER, "Paper on Whole System Approaches", accessible here.

2. The need for a European Hydrogen Transport Infrastructure

2.1. What constitutes the hydrogen backbone?

Hydrogen transport infrastructure is a prerequisite to large-scale adoption of any form of hydrogen. A pan-European hydrogen infrastructure network – the so-called **hydrogen backbone** - is necessary to **enable matching supply and demand across different regions and maximize the use of renewable energy resources**.

The transportation of hydrogen primarily involves pipelines, and is divided into transmission and distribution levels, similarly to methane infrastructure:

- In the **transmission system**, hydrogen is carried through long-distance pipelines, connecting production facilities to major consumption areas. They include hydrogen interconnectors, networks directly connected to hydrogen storage facilities, hydrogen terminals, as well as hydrogen interconnectors which primarily serve the purpose of transporting hydrogen to other hydrogen networks, hydrogen storages or hydrogen terminals[19]. In some cases, big industrial consumers can be directly connected to the transmission system.
- In the **distribution system**[20], the focus shifts to more local networks, where hydrogen is delivered to end-users like small and medium industries, refuelling stations, or residential and non-residential buildings. These pipelines are used for the local or regional transport of hydrogen, and primarily serve the purpose of supplying directly connected customers.

Focus: The importance of natural gas distribution systems in Europe

Currently, in the EU, there are approximately 1.8 million kilometres of gas pipelines at the distribution level, managed by 1,280 Distribution System Operators (DSOs). Non-EU countries operate an additional 623,000 kilometres of gas pipelines, overseen by 96 DSOs. Within the EU, roughly 93 million customers are connected to these distribution grids. To put this number into perspective, transmission pipelines account for approximately 200,000 km in Europe[21].

This two-tiered system of high-pressure transmission pipelines and lower-pressure distribution networks is essential for the effective and safe delivery of hydrogen, pipelines also offer line pack storage[22], which offers further flexibility in system operation. Building the hydrogen pipeline system at the transmission and distribution level can take two forms: greenfield – building completely new pipelines – or repurposing of existing gas infrastructure to transport hydrogen.

Additionally, gaseous fuels can be transported between pipelines by rail, sea or road and injected into pipelines, unlike wires which must be continuous, which strengthens the overall flexibility in operation and security of supply of the system.

2.2. Why do we need a European Hydrogen backbone?

2.2.1. To connect demand and supply

As of today, most of the hydrogen used in Europe today is 'grey hydrogen', produced by reforming methane**.** This process typically occurs on-site at industrial facilities, with direct access to natural gas.

[19] Definition as provided by Art 2(23) of Recast directive on common rules for the internal markets in renewable and natural gases and in hydrogen, accessible here.
[20] Definition as provided by Art 2(24) Recast directive on common rules for the internal markets in renewable and natural gases and in hydrogen, accessible here.
[21] ACER, Gas Factsheet, accessible here.
[22] Line pack storage will grow in importance as the European hydrogen backbone develops, and it is a competitive advantage that hydrogen pipelines present vs. electric lines, as it brings to the table additional flexibility. However, it still needs to be further complimented with significant and reliable hydrogen storage volumes, to be studied on Section 4.

However, this same model will be difficult to replicate as Europe moves away from grey hydrogen towards RFNBOs, Europe shall connect those areas with high VRES availability to demand centres.

Figure 4: Conventional H2 production sites in Europe. Source: Clean H2 Monitor (Hydrogen Europe)[3]

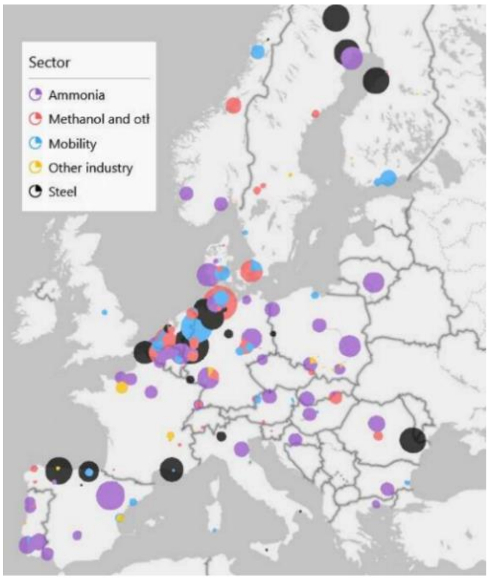
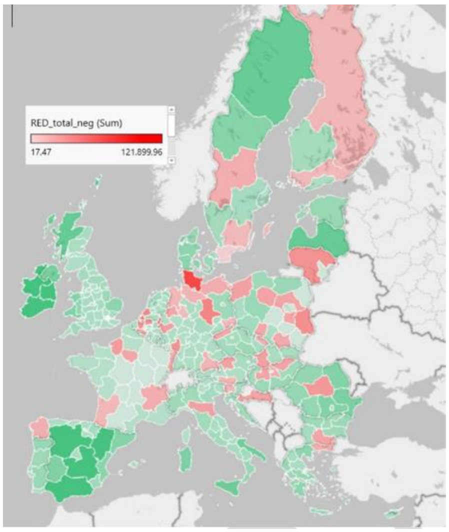


Figure 5. Announced clean H2 consumption in industry per country by 2030 in Europe (Mt/year). Source: Clean H2 Monitor (Hydrogen Europe)[23]

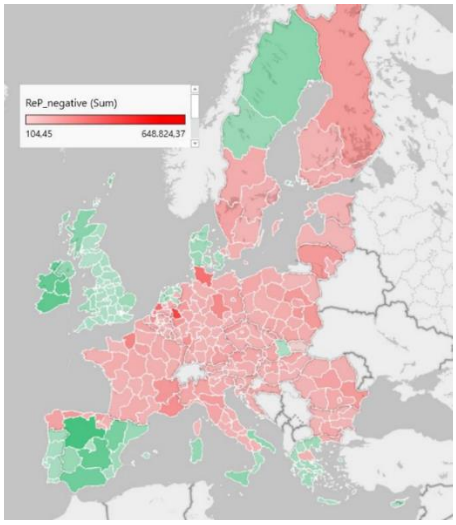
In Europe, **there is a geographical and temporal mismatch between areas with a high potential for renewable energy generation and hydrogen demand hotspots**. This mismatch calls for the development of a safe, reliable, and interconnected infrastructure to guarantee enough decarbonised hydrogen flows across the continent and enables a transition towards a carbon-neutral economy.

Regional differences, even within countries, will give competitive advantages to some areas to produce and export hydrogen, while others will not meet their existing and future demand with local potential production capacity. As a result, to satisfy the increase of hydrogen demand, industrial **off takers and producers will have to rely on infrastructure to store and transport hydrogen across regions**.

[23] Hydrogen Europe, "Clean Hydrogen Monitor 2023", accessible here.



Regional (NUTS-2) supply/demand balance in 2030: RED III demand scenario



Regional (NUTS-2) supply/demand balance in 2030: REPowerEU demand scenario

Figure 6: Balance of renewable generation potential and demand with electricity for H2 in Europe, 2030. Source: Hydrogen Europe[24]

Germany, Belgium, and the Netherlands, which currently have very high demand for hydrogen produced from fossil fuels, **are at the forefront of transitioning to clean hydrogen consumption**. Their efforts are expected to influence and drive similar transformations in other countries with renewable and low-carbon energy resources, such as Spain, France, Portugal, Finland, Denmark, and Sweden.

Focus: Carbon capture and storage as an enabler for blue hydrogen

Carbon capture and storage could potentially be a kick-starter for providing low cost, low-carbon hydrogen to large energy consumers while green hydrogen and RFNBOs become more affordable and available at larger scale. It would be a first step to decarbonize those centres with high consumption of grey hydrogen and avoid further emissions of CO2.

CO2 transport infrastructure – as seen in Section 1.2 – will be necessary in transporting the Captured CO2 in the process of low carbon hydrogen production to storage sites, many of which will be offshore, as seen in the Delta Rhine Corridor[25] *project.*

2.2.2. To alleviate the cost of network tariffs and grid development

1) The mismatch between VRES and transport capacity will not be solved by electricity grid development alone.

The shift towards a renewable based power grid requires upgrading the electricity grid to integrate 1,292 GW of variable renewable sources by 2040[26]. This will bring massive challenges that will entail a spike in system and infrastructure costs. Challenges include connecting remote renewable sources (offshore wind farms), and distributed renewables (solar PV and onshore wind turbines) as well as connecting millions of solar panels on rooftops at distribution level. All this on top of providing electricity access to millions of new users (electric vehicles, heat pumps, new electrical industrial activities, datacentres, etc.)

[24] Hydrogen Europe, "Clean Hydrogen Monitor 2023", accessible here.
[25] Delta Rhine Corridor, BASF, Gasunie, OGE and Shell, accessible here.
[26] European Commission, Commission Staff Working Document Impact Assessment Report, "Europe's 2040 climate target and path to climate neutrality by 2050 building a sustainable, just and prosperous society", accessible here.

To accommodate this new electricity demand and the massive installation of VRES capacities, electricity grid capacity must increase 47% by 2030 and 144% by 2040 in Europe[27]. Moreover, in the EU, more than 50% of the grid has been in operation for over 20 years, approximately half of its average lifespan, so the future grid's investments must also foresee the revamping of old grids to modernise them and make them more efficient[28].

This is a tangible problem that the EU electricity grid needs to tackle right now: **in 2023, negative prices increased 12-fold[29].** These negative prices drive up the congestion management costs and lead to curtailments in renewable energy, as the grid cannot host more capacity. This issue is further aggravated by repowering prospects, which will drive the need to reinforce the capacity in those nodes to host the new increased VRES capacities.

Focus: The Repowering challenge – a future challenge that requires immediate consideration.

The grid will need to ***be adapted to absorb more capacity stemming from repowered wind farms****. As wind farms are repowered, the capacity of the new turbines will be increased with the new available technology. To match the production of these sites, increasing connection to those repowered plants will be needed. To alleviate the pressure on the development of electricity grids, relieving capacity through a hydrogen pipeline could increase capacity of those sites without needing to reinforce the grid. As seen in the graph below, repowering needs will increase dramatically in the mid-2030s:*

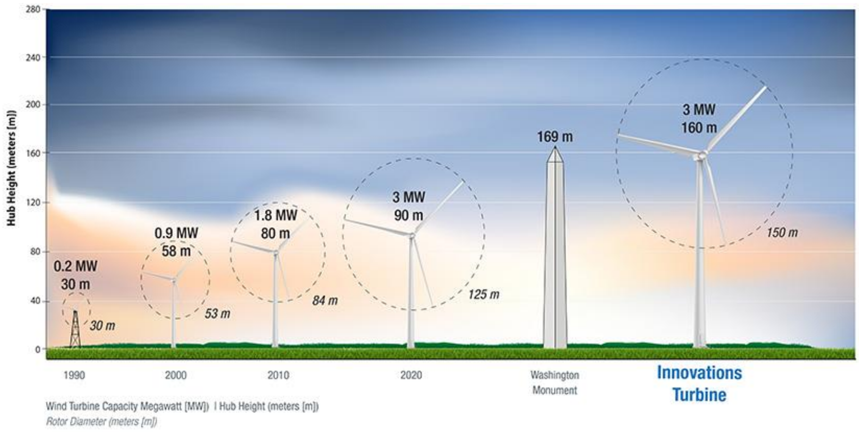


Figure 7: Wind Turbine Capacity Evolution. Source: Josh Bauer, NREL[30].

The best locations for repowered wind turbines will always be the same sites as the ones where the oldest wind turbines are located. *By repowering those sites (after the typical 20 years life span of a turbine), we not only significantly increase VRES production, but also reduce pressure on land and maximize resources.*

2) Deploying the electricity grid will require unprecedented investment

The Grids Action Plan[31] estimates the need for **584 bn EUR in electricity grid investments for 2030**. In comparison, for the hydrogen grid network buildout **the European Commission expects investment needs of 28-38 bn EUR for EU-internal pipelines** and 6-11 bn EUR for storage to transport 20.6 Mt of renewable hydrogen by 2030**[32].**

[27] Climate Action Europe, Wired for Climate Neutrality – A Paris Agreement Compatible (PAC) roadmap for power grids, accessible here.
[28] IEA, Electricity Grids and Secure Energy Transitions, accessible here.
[29] ACER, Key developments in EU electricity wholesale markets 2024 Market Monitoring Report, accessible here.
[30] NREL, Technology Advancements Could Unlock 80% More Wind Energy Potential During This Decade, accessible here.
[31] European Commission, "Grids, the missing link – An EU action plan for grids" , accessible here.
[32] European Scientific Advisory Board on Climate Change, Towards EU climate neutrality Progress, policy gaps and opportunities, accessible here.

Some **studies point out that the modelling on the investment needs for grids may even be underestimated**: according to a study from EMBER[33], REPowerEU underestimates annual grids spending by at least 5 bn EUR[34]. Other reports such as one from the European Roundtable of Industrialists, have identified **a gap of 800 bn EUR investment needs by 2030, scaling up to 2.5 tn EUR by 2050**[35]. This report further found that **spending on grid investments must more than double on an annual basis** compared to historical trends if the EU is to reach its climate targets.

Focus: The costs of the new German Electricity Network Development Plan and the case for offshore grids.

The German regulator Bundesnetzagentur approved in March 2024 a new Electricity Network Development Plan (NDP) with an updated cost projection of €320 billion, earmarking an additional €270 billion over the initial €50 billion estimate. This NDP forecasts 20 years ahead, and includes 4,800km of new transmission lines and 2,500km of grid reinforcement to link the windy North to the South & West. Moreover, the regulator confirmed that its plan is delayed by 6 years, so electrical connections are unlikely to materialize on time.

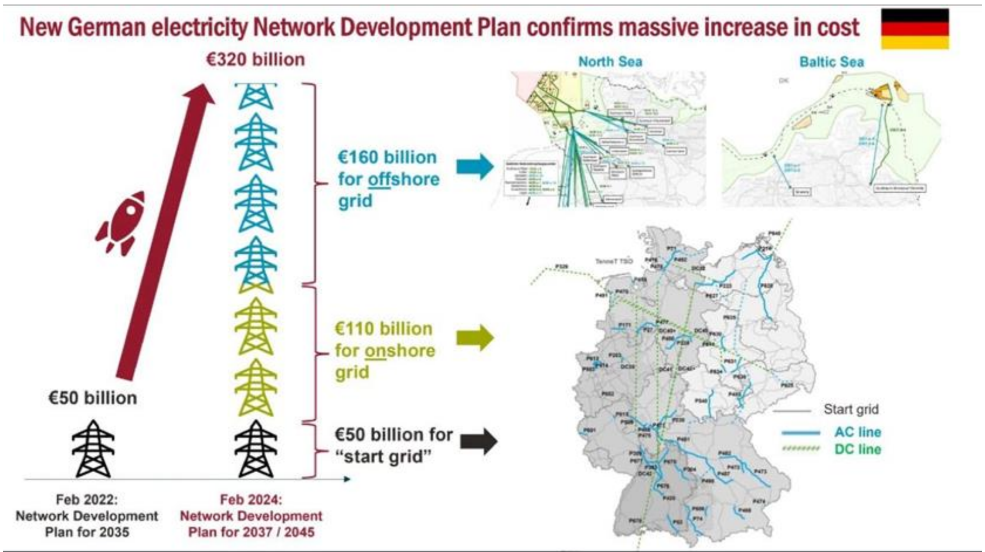


Figure 8: The new German Development plan. Source: Frontier Economics.[36]

This buildout will principally be financed by electricity consumers via network tariffs, set to increase in upcoming years, and consumers may not be willing to accept this massive increase in cost, as network tariffs, taxes and levies usually account for 40 – 60% of the electricity bill[37].

Hence, to alleviate these costs, the renewable energy will require other alternative modes of transportation, that are cheaper and easier to build, releasing the burden on the electrical grid.

3) A multi-vectorial approach is cheaper than relying solely on electric cables

Liquid and compressed gaseous fuels have high energy densities and low pumping costs, which make their transmission less expensive than electricity's. Moreover, hydrogen pipelines are made of cheaper materials than electricity lines and have less dependence on critical raw materials due to not needing power electronics, transformers, and circuit breakers.

[33] EMBER, Putting the mission in transmission: Grids for Europe's energy transition, accessible here.
[34] Also highlights that European grids in 19 countries lack over 200GW of capacity for solar by 2030, and 11 of 26 national transmission grid plans are based on outdated wind and solar targets.
[35] European Round Table of Industrialists (ERT) in a report written with the Boston Consulting Group, ERT Energy Infrastructure Report, accessible here.
[36] GRTgaz, "RTE analysis, stakes of developing hydrogen storage and a transport infrastructure", accessible here.
[37] SmartEn Map, accessible here.

Overall, **hydrogen pipelines can be up to 3 times less costly than HVDC**, as shown in the following graph:

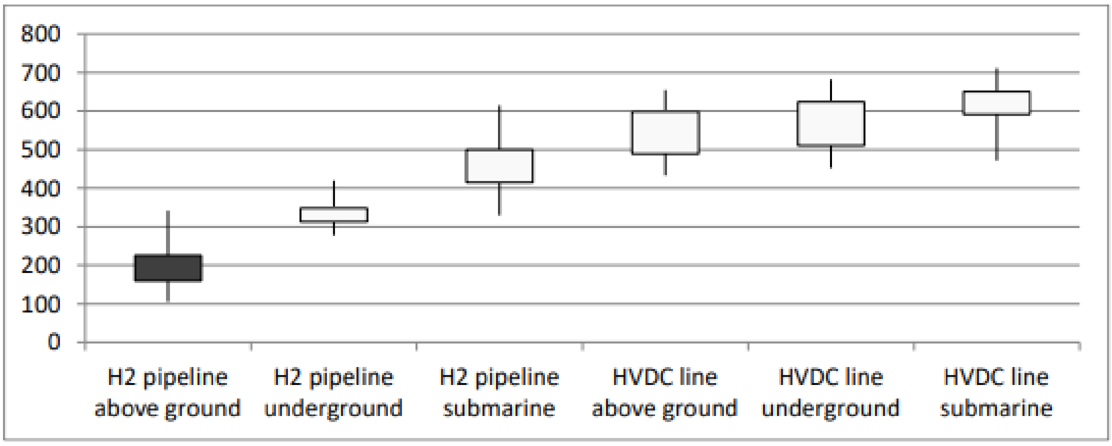


Figure 9. Estimated average investment costs for HVDC lines and H2 pipelines (in EUR/MW/km). Source: Oxford Institute for Energy Studies[38].

In all cases – whether it is hydrogen pipelines above ground, underground or submarine – these pipelines are much cheaper in terms of costs of transportation per (km x capacity) than HVDC cables. Subsequently, a two-system approach is cheaper than having only one system.

The case for a parallel transport infrastructure becomes **even more evident when assessing the costs of building and reinforcing the offshore power grids** (in the case of Germany, it is estimated that the offshore power grids build out will cost 160 billion EUR – see Figure 8: The new German Development plan. Source: Frontier Economics.

Focus: GRTGaz Study

*A recent study from GRTgaz[39] showed that in the case of France, **the net benefits from implementing a flexible hydrogen system (enabled by transport and storage infrastructure) can reach up to approximately 1.5 billion EUR/year** as the annualized cost of the infrastructure required for a flexible hydrogen system is far lower than the benefits identified for the power system.*

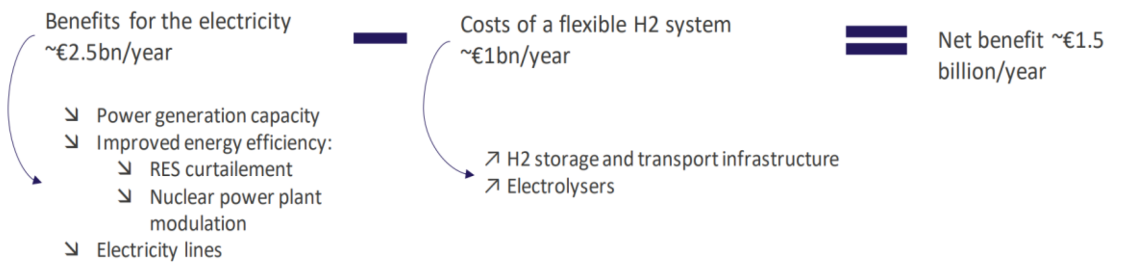


Figure 10: Economic relevance of a flexible hydrogen system. Source: GRTgaz.[40]

Indeed, as shown in Figure 9Figure 9, **transporting hydrogen through offshore pipelines offers a compelling solution for maximizing VRES integration in a more cost-effective manner**. In many cases, a quarter of offshore wind production was curtailed in first quarter of 2023 . All this energy (or a large share of it) could be used to produce renewable hydrogen. existing rules, grid access is awarded on a

[38] Oxford Institute for Energy Studies, "Hydrogen pipelines vs. HVDC lines: Should we transfer green molecules or electrons?", accessible here.

[39] GRTgaz & RTE, "Enjeux du développement des infrastructures de stockage et de transport d'hydrogène associés au développement de l'électrolyse et leviers d'optimisation avec le système électrique", accessible here.

[40] GRTgaz, "RTE analysis, stakes of developing hydrogen storage and a transport infrastructure", accessible here.

first come, first served basis, which has led to oversubscription of the grid, and a long queue of energy projects piling up[41].

> *Focus:* ***Examples of delayed permitting processes and their consequences***
>
> *There are plenty of examples across Europe that show us how challenging it is to build large electricity transmission projects. Two representatives (because of their size and ambition) examples are:*
>
> - ***The Suedlink Project*** *connecting windy North Germany with Southern regions. With a 4 GW capacity and over 700km of high voltage underground cables, it will be one of the cornerstones of the European power grid. The project was first conceived around 2012 when the German government decided to gradually phase out nuclear power following the Fukushima nuclear disaster. Its first commissioning date was planned for 2022, the planned year for the phase out of the last nuclear power plants. After several setbacks[42, 43] and delays, the project is now planned for 2028. The southern German region has no nuclear plant nor access to renewables, forcing the system operator to run more coal and gas power plants. The original cost of 4bn euros is now estimated at 11bn euros considering the whole line will be underground in order to overcome pushback from local groups[44].*
> - ***Spain-France interconnector.*** *The interconnection capacity between Spain and France has already doubled in 2015, from 1400 to 2800 MW, thanks to a project conceived 8 years before its construction. Another project has been in the making since as early as 2014, when it first appeared in the European Network development plan (TYNDP) 2014 and aims to connect the two countries through a submarine cable in the gulf of Biscay. The project will add another 2000MW and is planned for commissioning by 2028. If everything goes as planned, it will have taken 14 years from its inception to completion, highlighting the difficulty of bringing such strategic projects into place[45].*

This grid delays will drive up the flexibility needs and congestion management costs of the system. The EC tried to address this problem by providing in May 2024 a set of Guidance[46] for accelerating permitting for energy infrastructure – including hydrogen.

However, **this set of rules will not be enough**: the bottleneck is too large, VRES deployment has already been slowed down in comparison to its potential, and Capacity Access Guarantees will not be delivered on time. Even if this bottleneck issue is completely solved, the supply chain of materials needed and building capabilities of electric infrastructure is quite constrained – even in the most advanced grid expansion scenarios. That is why **energy planning requires considering alternatives modes of energy transportation** to optimize and maximize energy infrastructure deployment speed, at the minimum system cost while factoring in environmental and social impacts.

1) Building transmission lines is often harder than building pipelines

Deploying transmission lines is often more challenging than building pipelines. Resistance to transmission lines is often focused on aesthetics and the large right-of-way (ROW)[47] implications that come with such large amounts of infrastructure above ground. The right-of-way issues are much smaller for hydrogen pipelines than overhead transmission lines, and the visual impact on the landscape is also much smaller. Underground pipelines can also be more resilient to both natural and

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[41] This phenomenon is impacting a lot the Netherlands. The Minister of Climate and Energy presented in December 2022 a list of actions to address the connection issue in the country, including faster grid construction, stronger incentives for more efficient grid use and increasing the flexibility of grid users. More info: Zsuzsanna Pató, "Gridlock in the Netherlands", accessible here.
[42] S&P Global, "German SuedLink grid Project delayed to 2025 as cables go underground", accessible here.
[43] DW, "Controversial power line", accessible here.
[44] Jacobs "SuedLink, Integrating renewable sources into Germany's electricity grid", accessible here.
[45] CINEA, "CEF Energy: the Biscay Gulf Electricity interconnection moves forward", accessible here.
[46] European Commission, "Recommendation and guidance on speeding up permit-granting for renewable energy and related infrastructure projects", accessible here.
[47] Right of Way (ROW) is a legal term that refers to the legal authorization granted to individuals, companies, or government agencies to pass through or use a designated area of land owned by someone else for a specific purpose.

manmade disasters. It is also possible that, because the new pipelines could be seen as part of decarbonising the energy system, they could face much less environmental push-back.

The roll-out of new electric lines hinges on a sizable amount on its public acceptance. To increase it, some sections of cabling are made underground. However, estimated costs for underground transmission lines range from 4 to 14[48] times more than overhead lines of the same voltage and same distance, reducing the viability of the project in many cases. This also is a reality with remote and distributed VRES, in which many wind and solar projects are cancelled due to being conditioned to having underground a large section of cabling needed to connect to the substation, and the increase in costs makes the project unviable.

For instance, in Germany, significant segments of the electric grid had to be built underground due to social and environmental pressure and is estimated to have cost between 3 and 8 billion euros more than the overhead option would have, and the extra expense has been added to consumers' electricity bills[49].

2) A vast repurposing potential

These environmental and social challenges can be further tackled by tapping into the vast gas pipelines repurposing potential that Europe has in its hands. With Europe's shift towards a carbon-neutral economy by 2050[50], the demand for fossil methane is expected to decrease from 216 Mtoe in 2022[51] to 105-155 Mtoe by 2040[52] – representing a 50% reduction of natural gas in final energy consumption. **This demand reduction will free up pipelines for hydrogen transport.**

Although the exact timeline for transitioning these assets from methane to hydrogen is uncertain, entities like ACER[53], CEER[54], and industry stakeholders recognize the potential of this process for developing hydrogen infrastructure. In fact, the TEN-E regulation[55] states that "*the required hydrogen infrastructure should consist, to a significant extent, of assets converted from natural gas assets, complemented by new, dedicated pipelines*."

According to TSO data for the EHB[56], **repurposing 20" pipelines incurs only 30% of the expenses associated with deploying new pipelines**. Compressor stations have the same costs both for new and repurposed pipelines (4.0 M€/MWe).

[48] U.S. government, Underground Electric Transmission Lines, accessible here.
[49] Reuters, German cabinet agrees to costly underground power lines, accessible here.
[50] European Commission, "2050 long-term strategy", accessible here.
[51] European Commission, Impact Assessment Report of 2040 targets, accessible here.
[52] Eurostat, "Shedding Light on Energy", accessible here.
[53] VIS, "Study on requirements and implementation of ENTSOG's cost benefit analysis for hydrogen infrastructure for ACER", accessible here.
[54] ACER-CEER "Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2021 – Decarbonised Gases and Hydrogen Volume", accessible here.
[55] EC, "Trans-European Energy Infrastructure", accessible here.
[56] EHB, "Implementation roadmap – cross border projects and costs update", accessible here.

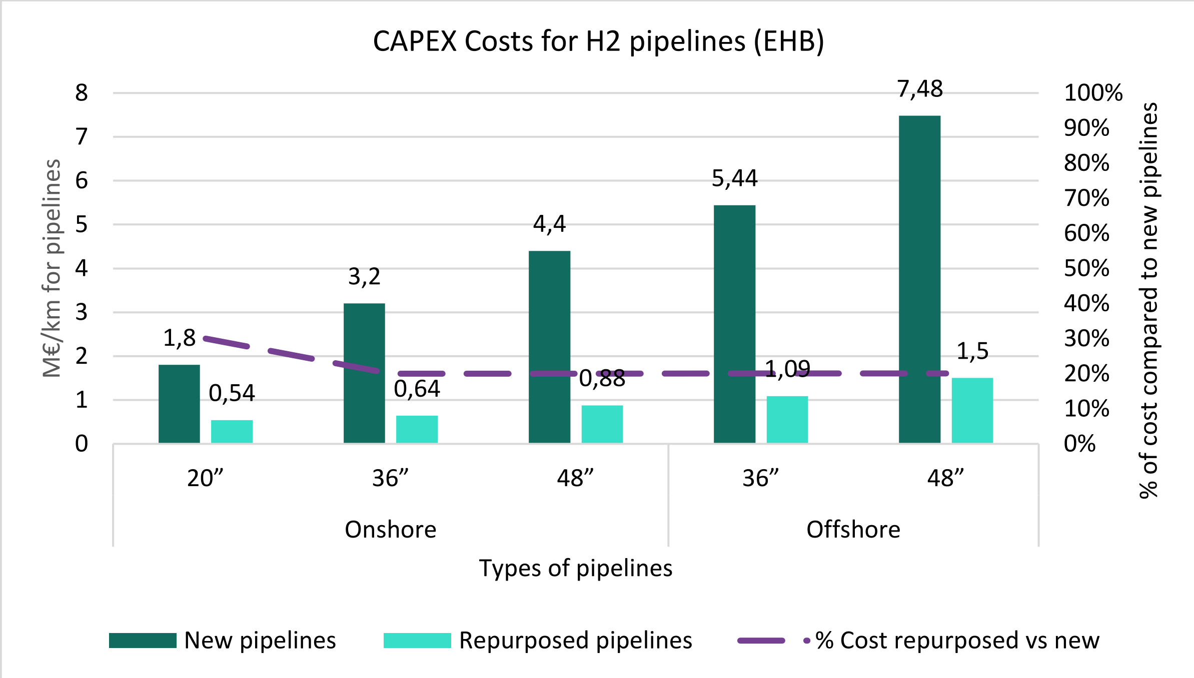

Figure 11: Cost of repurposed vs new pipelines, Source: EHB[57]

Leveraging the existing network of pipelines across Europe will not only optimize energy delivery but also **reduce costs and make the clean transition more affordable for consumers.** This has recently been confirmed by studies from ACER[58], Gas Infrastructure Europe[59] and METIS 3[60]: **reusing existing infrastructure is not only cheaper and faster – projects do not have to go through lengthy permitting processes – but also reduces the environmental impact of building new pipelines.**

Research on the technical aspects and benefits of retrofitting is ongoing across several projects, focusing on providing a clear picture on the long-term viability and feasibility of pipeline repurposing, as well as exploring the modifications needed to adapt to the different technical characteristics, and operating pressures affected after repurposing.

It is worth mentioning that the technical approach to retrofitting differs from transmission to distribution levels:

- Transmission pipelines, designed for high-pressure gas transport, are made of steel adapted to the characteristics of natural gas, and requires technical handling of hydrogen embrittlement when repurposed.
- Distribution pipelines, typically constructed from polyethylene, are better suited for lower pressure and thus more adaptable to hydrogen transport.

Another challenge is that to repurpose natural gas pipelines, a mechanism is needed to value these infrastructures and remove them from the regulatory asset base of the gas network companies[61].

Repurposing gas pipelines can partially address the challenging issue of financing early decommissioning of gas pipelines that would otherwise fall on natural gas consumers. By giving these

[57] EHB, “Implementation roadmap – cross border projects and costs update”, accessible here.
[58] ACER, “Transporting Pure Hydrogen by Repurposing Existing Gas Infrastructure: Overview of existing studies and reflections on the conditions for repurposing”, accessible here.
[59] Frontier Economics on behalf of GIE, “Maintaining security of supply while decarbonising our infrastructure with renewable and low carbon gases”, accessible here.
[60] EC, METIS 3:S8, Assessing hydrogen infrastructure needs in a scenario with hydrogen imports and EU production, accessible here.
[61] ACER/CEER. ‘When and How to Regulate Hydrogen Networks?’ “European Green Deal”, accessible here.

pipelines a new purpose, we will avoid "stranded costs" and alleviate the burden of investing in repurposing costs from gas consumers, as the cost of repurposing assets could shift to future hydrogen consumers.

Focus: Repurposing potential of 2,7M km of existing distribution and transmission pipes across Europe.

The Gas Distribution grid in Europe:

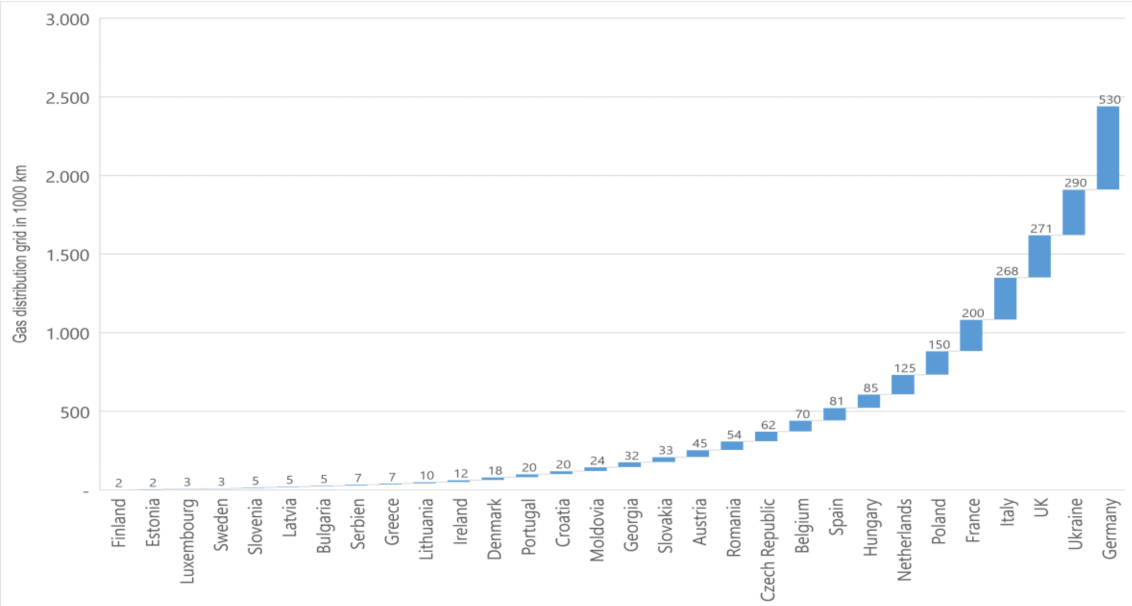

Figure 12: Gas Distribution Grids by Country. Source: Thuga, CEER[62].

The Gas Transmission grid in Europe: At the Transmission level 206.000 km are operated in the EU and an additional 46.000 km in the non-EU countries. This adds up to a total of 2 M km in the EU and 2,7 M Km of existing distribution and transmission pipes across Europe.

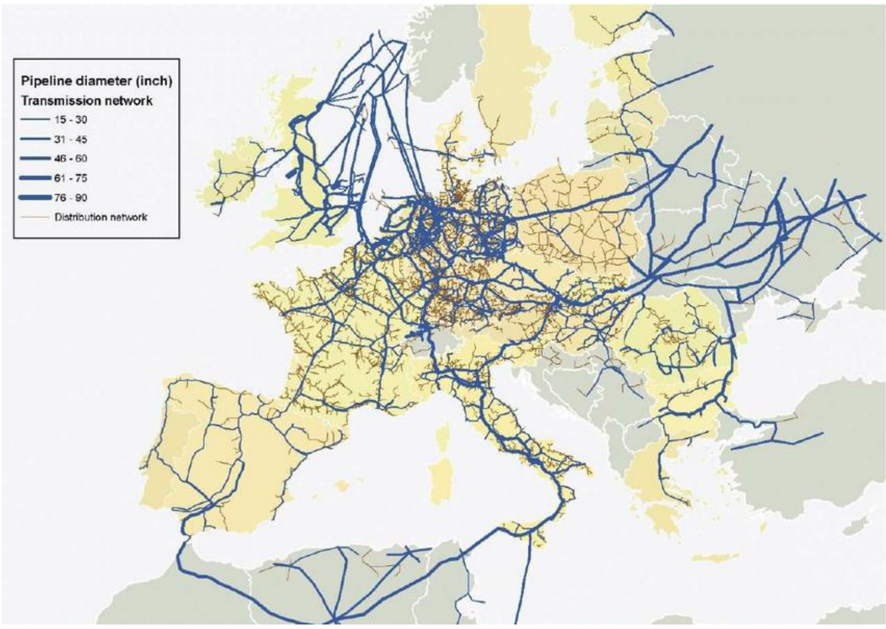

Figure 13: European gas network. Source: Robustness of Trans-European Gas Networks[63]

[62] Pending link.
[63] Rui Carvalho, Robustness of Trans-European Gas Networks, accessible here.

2.3. Challenges of meshing the EU with hydrogen pipelines

2.3.1. How to approach different levels of planning

While developing a European hydrogen backbone is crucial for the emergence of the hydrogen market and Europe's climate neutrality, **the process must follow a structured and phased in approach to ensure capacity meets demand where it is most needed** and does not affect security of supply for current methane users during the repurposing process[64]. This should be thoroughly reflected in the planning process.

First, the hydrogen backbone must be developed by Member States at local, regional, and cross-border levels:

1) **At local level**, the challenge lies mostly on DSOs. This is especially relevant taking into account that in several Member States the share of customers at DSO level exceeds 90% of total consumers (e.g., Austria, Germany, Spain)[65]. While transforming the system towards climate neutrality, it is likely that **an increasing number of decentralised clean gas production facilities will be connected to DSOs**[66].

   Uncertain demand requirements and new suppliers of climate neutral gases must be accommodated for by grid operators, this represents a complex challenge in terms of technical feasibility, communication, and operational success. A bottom-up planning exercise[67], comparing scenarios with bottom-up requirements and future conversions, **will be necessary to overcome these challenges**. Grid Operators should also coordinate according to the needs of the road mobility sector as Member States must define a rolled-out plan of hydrogen refuelling stations under the AFIR (the first set of national action plans will have to be published by Q2 2025).

   Articles 56 and 57 of the revised Gas Directive introduce new dispositions on the drafting at DSO level of network decommissioning and development plans - this will be a major step forward to facilitate the transformation of the DSO network towards a hydrogen network.

2) At **regional scale** or in between regions, **linking local production with demand will enable the decarbonisation of local needs for heating, small and medium industries and transport and help secure off-take for early hydrogen project developers**, laying the market's groundwork. The planning at this level should include not only regional particularities and conditions, but also potential for future cross-regional links and integration of regions into wider pan-European hydrogen backbone. Coordination between DSO and TSOs levels is a significant challenge, particularly at the initial stages of infrastructure development, especially for the DSO. The DSO has to initiate their development plans without being sure of where the transmission infrastructure is going to be exactly located. This can hamper the regional and local development.

   Several characteristics vary depending on the region: these include pipeline characteristics, demand, and supply balance, local decarbonization projects (including infrastructure for aviation and maritime refuelling), other existing infrastructure (including transport and electricity), land use, environmental planning, possibilities for sector coupling… all of these should be included in the planning exercise.

3) At larger scale **in a country or at cross-border level**, Europe will largely benefit from a **hydrogen backbone that connects the different green hydrogen production sites with access to abundant VRES and hydrogen demand clusters** (as seen in section 2.2.1) that are not necessarily located

[64] GIE, "Maintaining security of supply while decarbonizing gas infrastructure", accessible here.
[65] Eurelectric, Distribution Grids in Europe, accessible here.
[66] As more VRES are located at distributed locations, more decentralized H2 production takes place, hence more production will be connected at DSO level.
[67] Source: Ready4H2 website that can be consulted.

next to hydrogen production sites. Projects of Common Interest (PCIs), under the TEN-E Regulation[68], will be crucial (although not sufficient) for developing this section of the European hydrogen backbone, offering faster permitting and potential financial support from the Connecting Europe Facility Energy Fund[69] (CEF-Energy).

Planning for infrastructure development must encompass all those levels to account for different needs, characteristics, and opportunities the grid offers. It should also be open to stakeholders from various sectors at every single stage of the process. **Additionally, the timing of infrastructure projects, which can range from 3 to 7 years based on scale, must be cautiously managed.**

Focus: H2 Infrastructure for Mobility

All those layers together will ensure adequate supply of hydrogen to end users in multiple sectors, not least the mobility sector, where an EU-wide network of hydrogen refuelling station will be operational by 2030, as mandated by the Alternative Fuels Infrastructure Regulation[70]. Hydrogen refuelling stations far from distribution networks will be supplied either by tube trailer trucks or by an onsite electrolyser. Ports and airports will act as local hydrogen hubs, where molecules either come from abroad or produced onsite in great volumes. They are then distributed throughout the region to any end use demand or to power onsite applications like onshore power supply for vessels at ports or ground handling vehicles at airports.

2.3.2. Finding the right financing mechanism

Any infrastructure development will depend primarily on availability of funding, with anticipatory investments playing a pivotal role. By 2040, the backbone is expected to grow to almost 53,000 km, with some stakeholders estimating that up to 60% consisting of repurposed infrastructure and 40% of new hydrogen pipelines[71]. However, this is something that needs further analysis and will be different on each country.

The European Commission expects an investment of 28 to 38 bn EUR for EU-internal pipelines and between 6 to 11 bn EUR for storage which are needed to transport 20.6 Mt of renewable hydrogen[72].

Ensuring that initial users are not overburdened with grid development costs is essential for a nascent market. This challenge necessitates support for CapEx and OpEx and a well-structured tariff system to facilitate phased development that considers cross-border benefits of the infrastructure. Additionally, **making sure that the costs of the pipeline are evenly distributed among all benefited Member States is of utmost importance**, to avoid one country solely paying for a pipeline of which they don't benefit as much.

In a regulated market, infrastructure development is usually financed via tariffs imposed on network users by the distribution and transmission system operators. **In the case of the hydrogen market, this model will be hard to replicate.** Indeed, the limited number of users in the initial phase of market development leads to an investment recovery challenge. **The gap between the level of tariff required by network operators to recoup total investments and the maximum network user willingness to pay will be too wide for first movers.**

Focus: Example of Financing of the Dutch hydrogen Transport Infrastructure[73]

A good example illustrating how to tackle the issue of investment recovery challenge is the one of the commitments from the Dutch State to finance, with an envelope of EUR 750 million, the development of the hydrogen network in the Netherlands. The actual subsidy amount will depend on the number of users which will be connected, with a further claw-back mechanism, in cases of excess subsidy, provided a reasonable return on investment is achieved.

Focus: The amortisation account of the German CORE network[74]

Another enlightening example of mitigation of the investment recovery challenge via public intervention is the financing model organised by the German government to finance the development of their national hydrogen grid. The so called "hydrogen core grid" – to be constructed until 2032[75] as required by the Energy

Industry Act (EnWG) – which will require 20 billion EUR to build. To back the needed investments, the German government will determine a ramp up fee and set up an "amortisation account" that will be used to book the difference between the revenues generated by the calendar year's ramp-up fee and the approved costs. Corresponding payments are made by the account servicing or by the operator until 2055, time when the "amortisation account" shall be balanced.

Additionally, **demand will take time to develop, and until there is no stable booked capacity, TSOs cannot lower their tariffs**. That is why it is paramount for the adequate development of the hydrogen infrastructure that this upfront financing gap is mitigated by allocation of public funding or guarantees, intertemporal cost allocation and cross-border cost sharing to backload the tariff and limit the market risks first operators will take when investing into hydrogen.

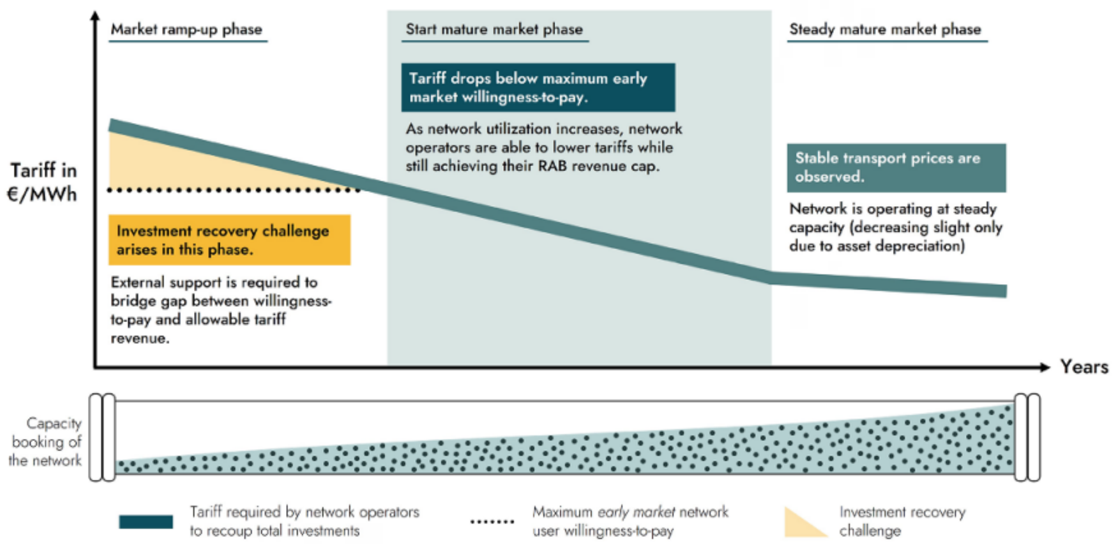

Figure 14. The investment recovery challenge and level of tariff required. Source: European Hydrogen Backbone (EHB)[76]

[68] European Commission "Regulation on guidelines for trans-European energy infrastructure", accessible here.
[69] The Connecting Europe Facility (CEF) for Energy is the EU's financial program designed to support the Trans-European Networks for Energy policy. Its goal is to fund the construction, rehabilitation, and enhancement of cross-border energy infrastructure across Europe. European Commission, "Connecting Europe Facility", accessible here.
[70] European Comission, "Alternative Fuels Infrastructure Regulation", accessible here.
[71] EHB, "European Hydrogen Backbone grows to meet REPowerEU's 2030 hydrogen targets", accessible here.
[72] European Scientific Advisory Board on Climate Change, Towards EU climate neutrality Progress, policy gaps and opportunities, accessible here.
[73] Netherlands Enterprise Agency, FME, TKI New Gas, "Excelling in hydrogen, Dutch technology for a climate-neutral world", accessible here.
[74] Offshore Energy, "Germany aims to set up hydrogen core network by 2022", accessible here and Hydrogen Insight, "How should Germany fund its 11,200km national hydrogen network? This is Berlin's latest thinking", accessible here.
[75] Via the regular NDP process, there will be an assessment whether one pipeline is needed or if there is no demand in early years. In this case, this pipeline could be postponed until 2037 at the latest but remains part of the financing mechanism for the H2 core grid.
[76] EHB, "Implementation roadmap – cross border projects and costs update", accessible here.

3. Hydrogen Import Infrastructure

3.1. Why Europe needs imports

1) Europe present constraints in producing enough domestic hydrogen

The EU will face limitations in securing the necessary and affordable VRES to produce enough domestic hydrogen to satisfy its demand for its climate targets[77]. This is why REPowerEU plans to complement the domestic production with imports of renewable hydrogen. And the Renewable Energy Directive now mandates the European Commission to develop a *Union strategy for imported and domestic hydrogen,* which will be based on the Member States strategies to rely on imported hydrogen (as requested in the National energy and Climate Plans NECPs).

It is important to highlight that **these imports are not only needed because of quantitative targets, but also for competitiveness as some global regions present very attractive renewable energy resources.**

Without sufficient and affordable volumes of green hydrogen, the industries relying on hydrogen to decarbonise will struggle against global competition. Moreover, these imports will alleviate the pressure on European lands for additional VRES installation, which is already quite constrained in a wide array of territories.

2) A global imbalance between VRES overproduction and hydrogen demand

The same way there are areas with VRES surplus in Europe and areas with a net deficit of hydrogen supply, the same phenomenon happens globally – at a much higher scale.

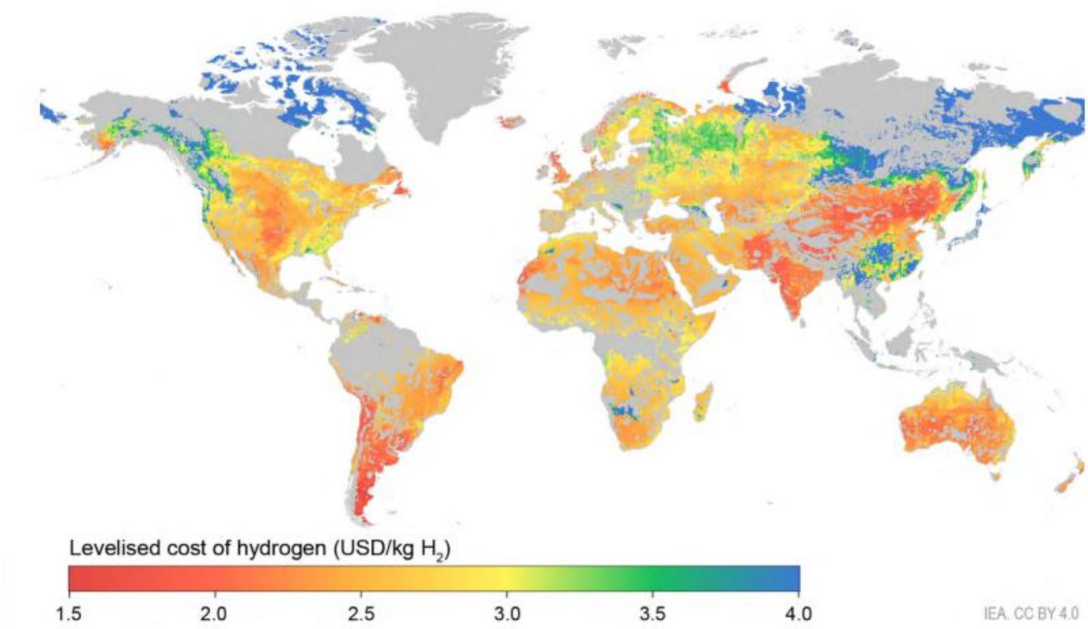

Figure 15: H2 production costs and share of solar PV from hybrid PV and onshore wind systems, 2030. Source: IEA, "Global Hydrogen Review 2023"[78]

There is a **net surplus of solar and onshore wind energy potential in certain regions of the world** (e.g., North Africa, Patagonia, Australia, Canada) fuelled by high solar irradiation and strong winds, and a **net deficit in other regions**, where high population and industrial activity are concentrated (e.g.,

[77] European Commission, 2050 long-term strategy, accessible here.
[78] International Energy Agency, "Global hydrogen review 2023", accessible here.

Europe, China, India[79], Southeast Asia, Japan). Hence **the obvious need to connect the constrained demand hot spots with the RES concentrated areas of the world**.

3) Benefits beyond Europe

Developing hydrogen production potential will also benefit exporting countries from outside of Europe that will gradually develop **a sustainable energy production economy**. In doing so, **these nations can not only position themselves as pivotal players in the global energy market, but also catalyse substantial domestic economic growth, job creation, and technological advancements**.

This dynamic could lead to a **ripple effect of enhanced welfare and prosperity**. For example, in Namibia[80], the renewable energy potential will be used for green hydrogen carriers and hot-briquetted iron production oriented towards exports[81] and, as a result, different localised hydrogen markets will likely develop. When developing export-oriented projects, it is important to keep in mind local markets development and that they are not only a ripple down effect of project development. However, it is important to point out that speed, direction, and agility when drafting import strategies and investments are needed. As Europe will have to likely compete with other global powers for hydrogen exports.

3.2. Import routes

To facilitate access to untapped hydrogen potential coming from nearby VRES sources[82] **imports' planning should follow a corridor approach. Three import pipeline corridors are outlined in the REPowerEU Strategy**[83], each playing a crucial role in Europe's hydrogen supply chain:

1. **The North Seas Corridor**: Focused on the North Sea's offshore wind energy, this corridor is key for supplying Northern European industrial and port clusters. It leverages existing infrastructure and offshore expertise, potentially turning the area into a green hydrogen production hub. Moreover, it is also important to emphasize that this corridor will also be a major shipping importer due to the size of its ports and strategic location to the future hydrogen backbone and demand centres.
2. **The Mediterranean Corridor:** Essential for imports from North Africa and the Middle East, this corridor will utilize the region's vast renewable energy potential. It will repurpose existing natural gas pipelines for hydrogen transport, facilitating imports into Southern Europe.
3. **Ukraine Corridor**: Leveraging Ukraine's strategic location and gas pipeline network, this corridor could channel hydrogen from Eastern Europe to Central Europe and Germany, while also tapping into Ukraine's renewable energy potential.

[79] In the case of China and India they aim to be net exporters of VRES (despite the net deficit) due to their energy demand mix and political decisions.
[80] Green Hydrogen Organisation, "Namibia", accessible here.
[81] Green Hydrogen Organisation, "Namibia", accessible here.
[82] For more information, the Clean Hydrogen Alliance's Learnbook on Hydrogen Import Corridors, accessible here.
[83] European Commission, "RePowerEU Plan" -, accessible here.

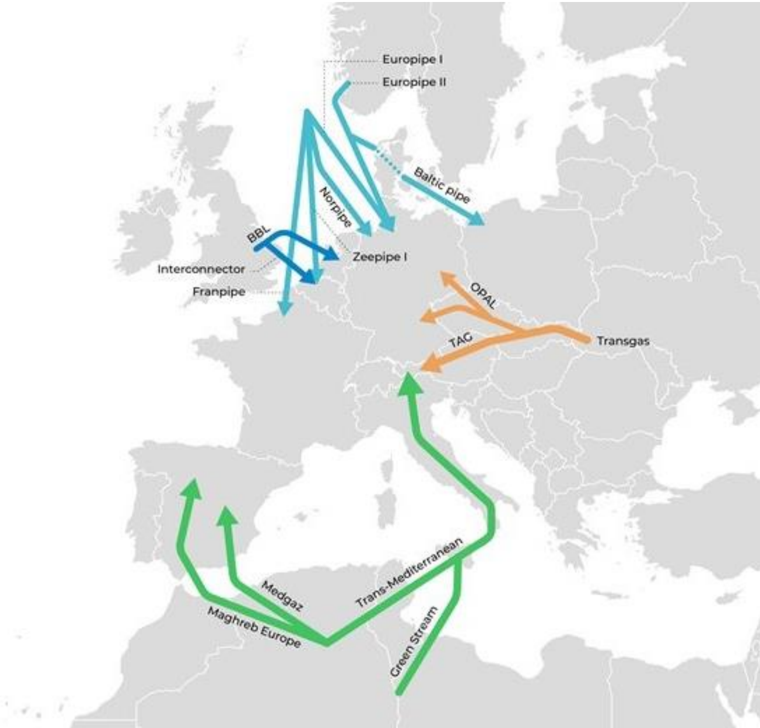

Figure 16: The hydrogen imports corridors via pipelines. Source: Guidehouse[84]

The Gas for climate consortium estimated in a recent study that **the cost savings associated with introduction of a corridor approach over the 2030 and 2050 timeframe could be as high as €330 billion**[85] as compared with a more isolated cluster approach. This pan-European approach will provide an affordable energy supply and support the integration of VRES by ensuring RES are transformed into hydrogen in a cost-effective approach and the energy then flows to regions where it will be the most useful.

Hydrogen imports are not limited to pipelines as it can be shipped either in its pure form or as a hydrogen carrier as described in the next section. **Maritime pathways** for importing hydrogen into the EU market include (but are not limited to) North America, Latin America, the Middle East, North Africa, and South-Western Africa, which will go mostly through the North Seas Corridor[86]. That said, the feasibility of different import routes will largely depend on significant efforts when it comes to building new and converting existing infrastructures needed for transporting, shipping, reconversion/cracking, and distributing of both LCH and renewable hydrogen and their carriers.

Focus: Nordic-Baltic Hydrogen Corridor The Gas Transmission System Operators Gasgrid (FI), Elering (EE), Conexus Baltic Grid (LV), Amber Grid (LT), Gaz-System (PL) and Ontras (DE) have completed the Nordic-Baltic Hydrogen Corridor pre-feasibility study (NBHC). This NBHC would play a significant role in connecting renewable hydrogen production to hydrogen demand in continental Europe, enabling the achievement of decarbonization targets. It expects to transport approximately 2.7 Mt of H2 (around 91 TWh) across 6 European Countries, with a length of 1,500 km. It is expected to cost 8.4 bEUR, plus another 3.4 bEUR by 2040.

[84] Guidehouse, "The European Hydrogen Backbone Furthering Energy Independence", accessible here
[85] Gas for Climate, "Assessing the benefits of a pan-European hydrogen transmission network", accessible here.
[86] Clean Hydrogen Alliance Transmission and Distribution Roundtable, "LEARNBOOK: HYDROGEN IMPORTS TO THE EU MARKET", accessible here.

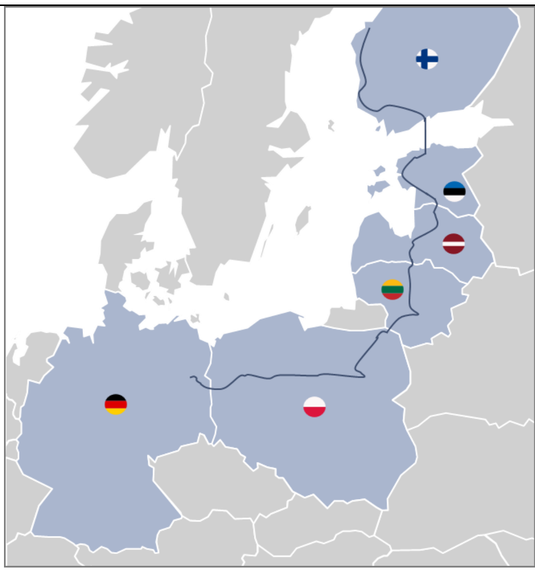

Figure 17 Infrastructure Plan of the Nordic-Baltic Hydrogen Corridor. Source: Amber grid[87].

3.3. An abundance of import options to explore

1) Which options do we have for hydrogen imports?

There are many technological options for importing and transporting renewable hydrogen in the context of large-scale trade, each with its own advantages and disadvantages[88].

First, hydrogen can be imported under different forms: **either as pure hydrogen** – compressed or liquefied – **or as a hydrogen carrier** such as ammonia, methanol, Liquid Organic Hydrogen Carrier (LOHC, LHC) or even synthetic methane (or e-NG) and e-fuels such as methanol and e-SAF. Generally, low carbon hydrogen won't be shipped as is since it is cheaper to import natural gas and transform it into low carbon hydrogen in Europe rather than transporting the low carbon hydrogen itself.

Hydrogen carriers can serve directly as both feedstock and fuel, diversifying the hydrogen market and supporting a broader range of business cases. This diversification will facilitate the expansion into various economic sectors beyond gaseous hydrogen, which will primarily be injected into the regulated hydrogen grid. **This diversity will be a key lever for supporting System Integration.**

Depending on its end use, hydrogen can be imported as:

1. Hydrogen in pure molecule form, which does not need any transformation if transported by pipeline or ship.
2. Derivatives such as ammonia or e-fuels, transported by ship, and in theory wouldn't need to be converted at ports if used as feedstock or fuels.
3. Hydrogen carriers, such as LOHC and ammonia which need to be reconverted back to hydrogen, the conversion costs may be higher or lower depending on the conversion process.

2) What are the different traits of each carrier?

For more detailed information on hydrogen carriers read ANNEX: H2 Carriers in Infrastructure. The most outstanding traits of the different hydrogen chemical forms are the following:

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[87] Amber Grid, "Gas transmission system operators complete Nordic-Baltic Hydrogen Corridor pre-feasibility study", accessible here.

[88] See ANNEX for more technical aspects and comparison among H2 Carrier's infrastructure.

- **Ammonia:** as a commodity already traded at an international scale, ammonia has been announced as a carrier of choice by multiple projects[89], amounting to around half of the planned hydrogen exports by sea, by 2030.
- **Liquified and compressed Hydrogen**: the key benefit of importing liquefied and compressed hydrogen is avoiding the costs of transformation. This makes it an attractive option for meeting the demand for pure hydrogen despite lower energy density.
- **LOHC and LHC:** they are re-utilizable as they can be rehydrogenated. However, this would entail the need for an infrastructure that loops it back to the source (e.g., Reverse direction pipelines, port infrastructure to reload de-hydrogenated carriers etc…). If they use a waste heat source (about 250°C) the costs for transformation can be dramatically reduced. In 2020, the first international trade of 102t hydrogen occurred from Brunei to Japan, using methylcyclohexane as a LOHC to supply a gas turbine at the Mizue power station.
- **Synthetic fuels (e-methanol, e-gasoline and e-SAF):** can benefit to those industries that consume fossil equivalents and can benefit from existing infrastructure. It will be of utmost importance that these fuels are produced according to European sustainability requirements (the source of the CO2).

There most likely won't be a single solution, as each of the options outlines above has its own strengths and weaknesses. The optimal choice will depend on a specific project's conditions and, as a result, multiple carriers will coexist in the market.

3.4. The crucial role of port infrastructure

Hydrogen carrier trade – and import's ambitions in general – will not realise unless port infrastructure properly deploy in time. Indeed, **energy and hydrogen infrastructure in the ports and connections to the hinterland are crucial to facilitate and complement the hydrogen infrastructure backbone**, this make it essential to support decarbonisation efforts of the European industry[90]. The principal infrastructures that have to be developed in ports to handle hydrogen are:

- **Import and Export Facilities**: Ports need specialized terminals for handling hydrogen and its derivatives like ammonia and LOHC.
- **Conversion Units**: Facilities for converting hydrogen into other forms (e.g., ammonia crackers).
- **Storage**: Secure and efficient storage solutions for hydrogen and CO2, including underground and sealed storage.
- **Distribution Networks**: Local distribution systems and transportation networks to manage the flow of hydrogen within and beyond the port.
- **Refuelling hydrogen and ammonia stations** for boats.

Several ports across the EU are preparing major investments to ensure the necessary infrastructure will be in place to accommodate future imports of hydrogen and its carriers[91]. Specific examples include:

a) **The Port of Rotterdam**[92] is adapting for future imports by building out new hydrogen, ammonia, and LOHC facilities. Companies located near or in the port are developing offshore hydrogen production, CO2 storage under the seabed, and building one of Europe's largest electrolysers.[93].

[89] International Energy Agency, "The Future of Hydrogen", accessible here.
[90] Deloitte Belgium, for the Clean Hydrogen Partnership – "Study on hydrogen in ports and industrial coastal areas", accessible here.
[91] ESPO, "The investment pipeline and challenges of European Ports", accessible here.
[92] Port of Rotterdam, "Import of hydrogen", accessible here.
[93] Commissioned by Shell, the 200MW electrolyser will be constructed on the Tweede Maasvlakte in the port of Rotterdam and will produce up to 60,000 kilograms of renewable hydrogen per day, accessible here.

b) **The Port of Antwerp-Bruges** is investing in terminals, reconversion units, local distribution and transportation networks to the further hinterland, implementing the first hydrogen-powered tugboats and acting as a lever for international hydrogen imports by partnering with countries such as Namibia and Oman[94].

Focus: H2 Strategies outside the EU - the Panama and Suez Canals[95]

- The Panama Canal, capitalizing on its pivotal role in seaborne trade, has launched a hydrogen strategy targeting the use of green hydrogen for 40% of its shipping fuel by 2040. This move, coupled with Panama's goal to produce 280,000 tonnes of green hydrogen annually, cements its ambition to be a major player in the global green hydrogen market.
- The Suez Canal is overseeing projects centred on hydrogen, with UAE's Masdar planning to produce renewable bunker methanol by 2026 and later expanding to produce 2.3 million tonnes of renewable ammonia annually.

The importance of hydrogen imports puts emphasis on the **need for ports to focus on anticipatory investments in import infrastructure to adapt to future market**. These endeavours by major ports also highlight interlinkages between imports and storage (of hydrogen or carriers) to maintain security of supply and facilitate an efficient flow between imports, domestic production, and transport.

In addition to building new hydrogen import infrastructure in ports and expanding existing terminals for ammonia, **the EU counts tens of LNG terminals, which could be repurposed for storing liquid hydrogen or ammonia (NH3) -** see more information in Annex C.2. Repurposing LNG terminals to H2 terminals.

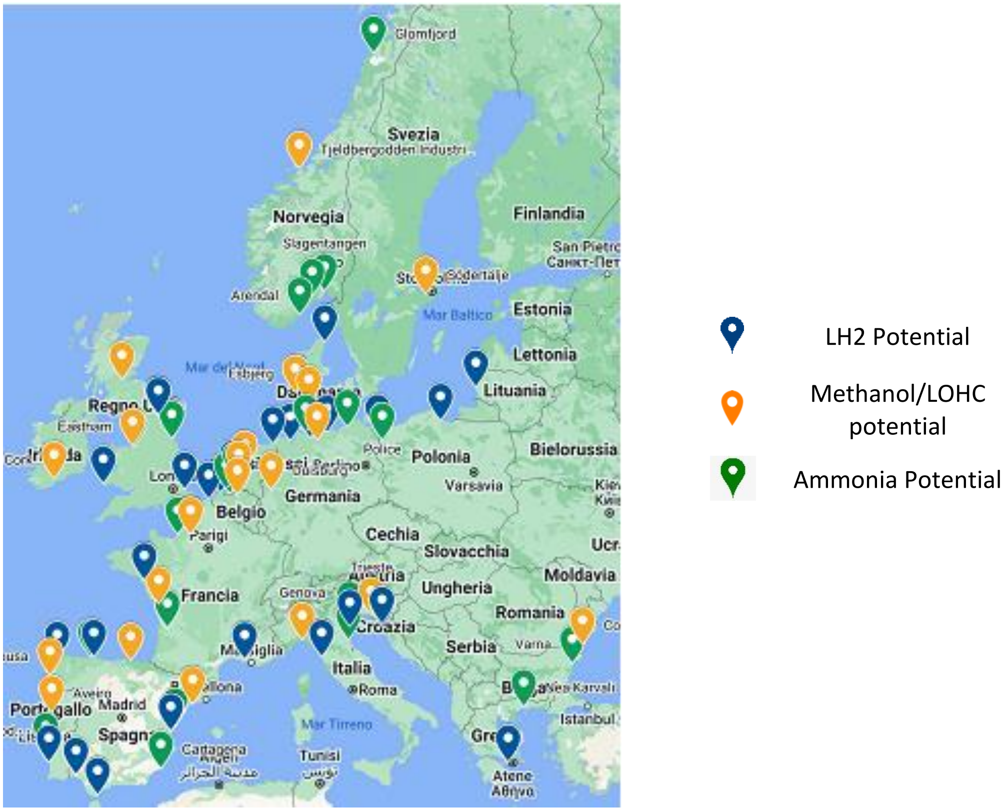

Figure 18: Ports with hydrogen import potential, Source Hydrogen Europe

[94] Port of Antwerp-Bruges hydrogen, "Roadmap 203O", accessible here.
[95] Development Aid, "From Sun to Suez: Egypt unleashes renewable energy potential with US$4 billion green hydrogen mega-project", accessible here.

3.5. Thorny and interlinked issues: costs and infrastructure

The viability of imports as a route to meet EU hydrogen demand and renewable energy ambitions hinges primarily on technical potential and, most importantly, cost considerations.

In general, **pipelines are typically used for compressed gaseous hydrogen transport**, while **ships can carry hydrogen in liquid form or in another carrier**. Pipelines prove cost-effective for importing hydrogen from nearby EU regions, such as the Mediterranean and North Sea, and their total costs grow almost linearly with the increased distance they have to cover. Without the need for any complex chemical processes, the cost of transporting hydrogen via pipelines can be as low as 0.3 EUR/kg/1,000 km and can be further reduced to 0.11 EUR/kg/1,000 km by retrofitting existing natural gas pipelines[96]. **That is why, for relatively shorter distances (intra-EU trade and trade with neighbouring countries), pipelines are usually the most cost-effective options**.

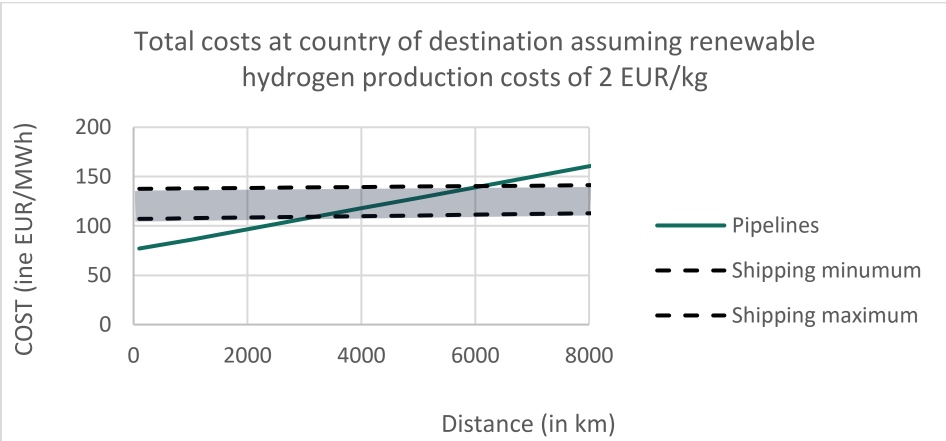

Figure 19: Costs for reconversion and synthesis by carriers per kg of H2 consumed. Source: Hydrogen Europe[97]

As seen in the graph above, **when distances increase above 3,000 km, shipping starts to become a more affordable option than pipelines[98].** Shipping has lower variable costs and allows for sourcing flexibility – hence security of supply – by not being limited to a single origin. Import's scalability will be key to support the ramp-up of the European hydrogen market, as it allows the hydrogen market to be partially decoupled from the European hydrogen backbone developments.

However, **shipping requires significant upfront investment costs regardless of the source of imports,** as port storage and loading/unloading infrastructure needs to be developed irrespective of distance. All in all, **different shipping options are relatively comparable to each other in terms of cost - but each has its specificities and advantages, hence the most suitable choice of derivative will depend on the specific project and source of hydrogen[99].**

Each method of importing hydrogen comes with its own strengths and weaknesses. The optimal choice of carrier will depend on project specific conditions, as multiple carriers co-exist on the market.

- **E-NG** offers the best energy density and cheapest transport option, allowing to tap into existing natural gas and LNG infrastructure in the EU and therefore giving this RFNBO easy access to the EU energy market, acting as a direct replacement of natural gas, similar to biomethane., if access to sustainable biogenic CO2 is limited, it would also need to be supplemented with other and more

[96] Guidehouse, "Accelerating H2 Imports to Meet REPowerEU Ambitions Requires Urgent Action", accessible here.
[97] Hydrogen Europe, "Clean Hydrogen Monitor 2023", accessible here.
[98] FSR, "Are pipelines and ships an 'either or' decision for Europe's hydrogen economy? : Planning import lines for hydrogen and derivatives", accessible here.
[99] JRC EC, "Assessment of Hydrogen Delivery Options", accessible here.

expensive CO2 from DAC for instance. This makes it most suitable for longer distances, direct usability, and high volumes of trade when the better energy density can make up for the added costs.

- **LOHC** and other synthetic fuels (e.g., e-gasoline, e-SAF, etc.) present a competitive advantage by being able to re-use oil pipelines for transport. However, it will require ameliorating inland hydrogen infrastructure which will bring associated costs.
- **E-methanol** is liquid at ambient temperature and is less toxic than ammonia. As a result, its transportation process is easier and cheaper. It has many direct applications, especially as a fuel for shipping, to produce e-SAF, and for the chemical industry.
- **Ammonia** imports have more complex handling processes in comparison because of its toxicity. Moreover, ammonia cracking technology is yet to reach commercial maturity, and more R&D is needed. However, this carrier offers the competitive advantage of already disposing of an existing infrastructure and strong demand, and the toxicity problem can be mitigated with careful planning and clear safety standards and measures.

Finally, as a general remark, **the main driver of costs for imported hydrogen is the reconversion process**. For this reason, **industrial applications that require hydrogen in the form of hydrogen carriers** (such as ammonia, methanol, e-fuels, or synthetic methane for industrial, transport, or power applications) **that do not require dehydrogenation/cracking will be more cost-effective for importing than those requiring transformation**. However, this cost can be significantly reduced for some carriers, such as LOHC if linked to waste heat.

A holistic view of the hydrogen carrier life cycle will determine which carrier is the most suitable. The final application, and the location of the source of that hydrogen will tilt the balance towards one mode of import or another.

Transports and imports will also require significant storage capacities throughout the EU. This infrastructure will act as a balancing factor and buffer between local hydrogen production, imports, and industrial and power sector demand. This aspect will be developed in the following section.

4. Hydrogen Storage Infrastructure

4.1. Why do we need Hydrogen Storage?

The integration of hydrogen domestic production and imports into the wider energy system cannot be understood without storage, as it acts as a buffer between demand and supply, not only providing additional security of supply, but also ensuring that the load can be met at all times.

Wind and solar energy are variable and will not always be producing when electricity demand increases. This is why there is a need to develop a flexible system capable of storing energy, enabling the provision of dispatchable electricity, or adjusting demand based on production availability. Since electricity cannot be efficiently stored for long durations – beyond 8 hours – power must also be stored through other technologies, hydrogen represents one of the most time and cost-efficient solutions.

Indeed, hydrogen storage will be crucial not just for establishing the European hydrogen backbone, but also for the emergence of an eco-system that ensures the best use of VRES in the entire industrial and energy system.

4.1.1. To provide a stable baseload supply to industries

Hydrogen storage will be necessary for industry sectors that rely on clean hydrogen for their decarbonization such as steel, refineries, chemical, fertilisers and e-fuels. These sectors require baseload hydrogen supply, **this is why they will need storage to ensure a continuous supply during shortages, to mitigate supply risks and to comply with RFNBOs criteria and targets**[100]. As the hydrogen market evolves and hydrogen becomes more affordable, thermo-sensitive consumers (sectors needing medium and high temperature heat such as aluminium, glass and cement), will also gradually adopt hydrogen, with the support of hydrogen storage. That is why investments in pipelines will need to go in pair with the development of storage facilities.

4.1.2. To provide a flexibility option for the power sector

As the share of VRES grows, storage needs will grow too and hydrogen storage will play a pivotal role in handling these energy surpluses – especially at a seasonal scale. Currently, renewable capacity is being deployed in resource-rich areas without a strong regard for grid topology. This lack of coordination will significantly increase the need for redispatch—adjusting generator schedules post-market clearing to ensure a feasible dispatch—as grids will be more and more constrained and unable to transmit all available renewable electricity.

In fact, according to ACER, **flexibility needs will double in 2030**, while seasonal storage is expected to grow to 168 TWh[101]. This is already an issue in today's energy landscape: **Europe experienced in 2023 a 12-fold increase in occurrences of negative prices**. Negative prices result from the increase in renewables' penetration and call for continued market integration and access to flexibility.

According to the JRC[102], up to 310 TWh of renewable generation could be curtailed due to limitations in the grid in 2040 in a business-as-usual grid expansion scenario. And even if an extreme grid expansion scenario is followed, 100 TWh of renewable generation are still at risk of being curtailed in 2040 due to bottlenecks in the grid. **Even with high levels of grid expansion, total redispatch volume increases almost six-fold by 2040**. The associated costs were calculated to be between 11 – 26 Bn

[100] As defined in the Renewable Directive EU/2023/2413, which defines targets for RFNBOs consumption in industry and transport sectors

[101] ACER & European Environmental Agency, "Flexibility solutions to support a decarbonised and secure EU electricity system", accessible here.

[102] Thomassen, G., Fuhrmanek, A., Cadenovic, R., Pozo Camara, D. and Vitiello, S., Redispatch and Congestion Management, Publications Office of the European Union, Luxembourg, 2024, doi:10.2760/853898, JRC137685, accessible here.

EUR in 2030 and 34 – 103 Bn EUR in 2040, compared to 5 Bn EUR that incurred for remedial actions in 2022.

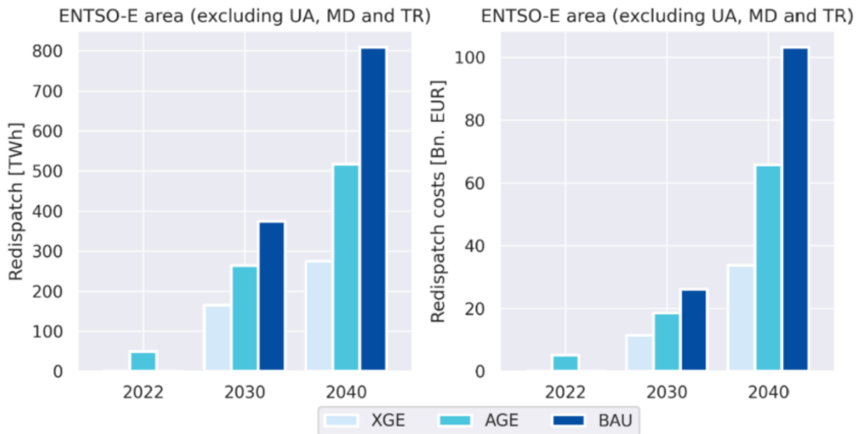

Figure 2014: Redispatch volumes and costs for ENTSO-E area (excluding UA, MD and TR)[103], JRC[104]

To satisfy those needs, storage will be needed across different timeframes (short to medium and seasonal flexibility) and diverse operational requirements: Short-duration flexibility refers to the ability of flexibility sources to cope with hourly variations of the residual load – usually covered today by dispatchable generation –, while seasonal flexibility referring to the ability of those resources to respond to long-duration energy imbalances (e.g., weekly, monthly). Seasonal flexibility requires scheduling to anticipate the availability of resources across the year. For instance, this is an example of a seasonal flexibility profile provided by the IEA:

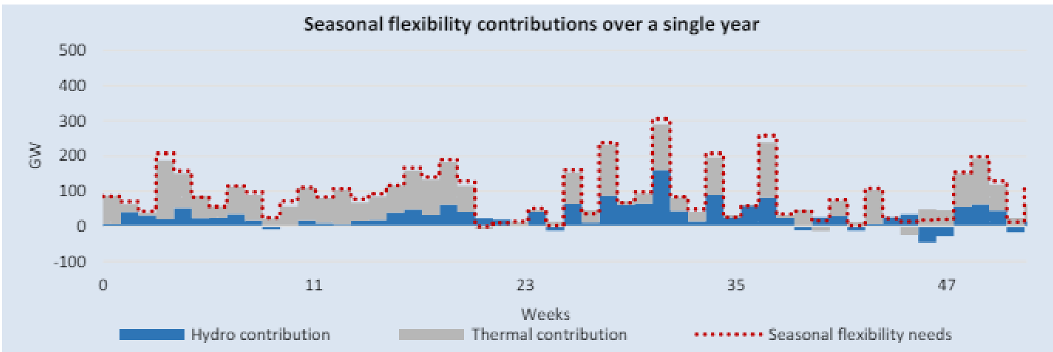

Figure 15 Seasonal flexibility contributions over a single year. Source: IEA[105].

As it can be seen in the graph, hydropower and dispatchable generation provide seasonal flexibility. Hydropower output – even if extremely efficient – is constrained by geographical limitations and climate change impacts, and most of the European capacity is already being utilized. More information on seasonal flexibility can be found in Annex D.1. Seasonal flexibility and the imitations of batteries and hydropower as storage options.

Underground Hydrogen Storage would ideally substitute fossil thermal flexibility as it is specially well fitted for longer duration energy storage since it can provide energy in a “high-capacity high-volume” basis.

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[103] Business as usual (BAU): Current trends lead to a grid expansion of 10% by 2040 (reinforcements + newly built lines) in each country // Ambitious grid expansion (AGE): Grid expansion speeds up considerably, so that by 2040 all countries expand their grids by 20% // Extreme grid expansion (XGE): Massive expansion effort which leads to expanding total circuit length in each country by 35%.

[104] Thomassen, G., Fuhrmanek, A., Cadenovic, R., Pozo Camara, D. and Vitiello, S., Redispatch and Congestion Management, Publications Office of the European Union, Luxembourg, 2024, doi:10.2760/853898, JRC137685, accessible here

[105] IEA, “Managing Seasonal and Interannual Variability of Renewables”, accessible here.

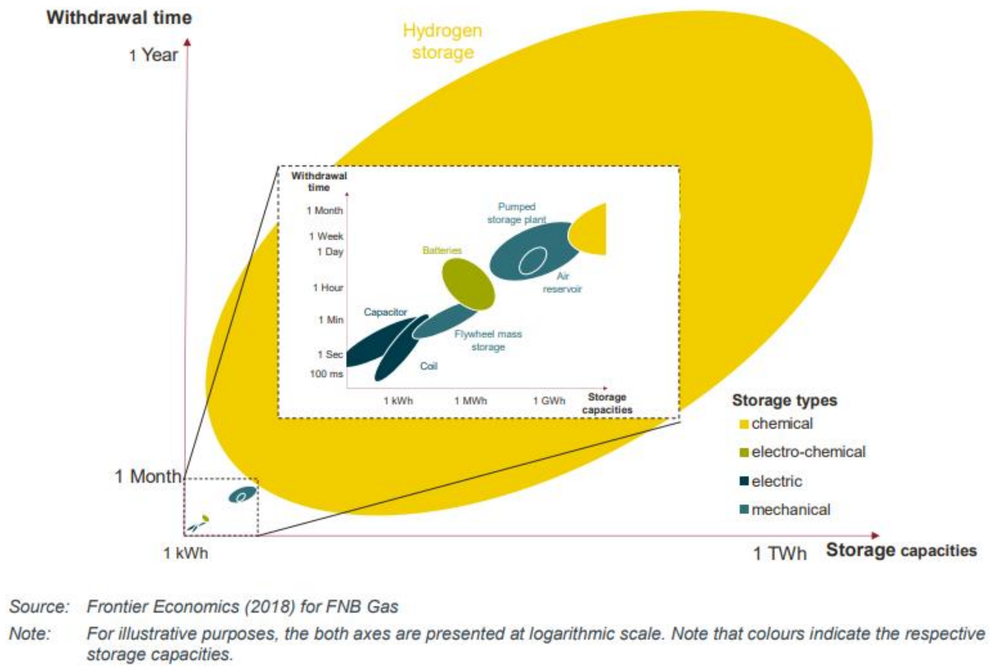

Figure 161: Withdrawal time and storage capacities of different storage types. Source: Artelys and Frontiers Economics[106]

It is worth mentioning that interannual variability is also an important factor to consider in flexibility planning, and that across Europe the profiles of seasonal variability can vary a lot, often complementing each other, hence the need to further interconnect Member States with a hydrogen backbone with sufficient hydrogen storage as a buffer for seasonal and interannual variability.

Finally, it is worth mentioning that hydrogen storage – by adapting the configuration of salt cavern design - can also participate in the medium to short term markets. However, due to the low round-trip efficiency[107] of Power-to-Gas-to-Power technology, it is always going to be a last resort option for short term flexibility services. Moreover, hydrogen-fired turbines can also provide grid services: they can offer inertia, frequency reserves and ancillary services in general – but these services will not be enough to make the business case for hydrogen storage alone. The main value proposition and business case for hydrogen-fired power generation is generation adequacy and long-term storage.

4.1.3. To enhance Security of Supply

Strategic Underground Hydrogen reserves can contribute to solving the energy security concerns that Europe ought to address.

For instance, "Dunkelflaute" events—periods of low wind and solar production lasting over 24 hours—pose a significant internal threat to security of supply that is becoming increasingly relevant as more renewables are added to the system and as the system becomes more electricity dependent (Specially in winter). This increases the vulnerability of energy reserves during low or no wind/solar scenarios. These conditions, which typically average 50-100 hours annually during December, January, and February in Northern countries, can sometimes persist for up to 8 days[108]. Additionally, severe cold weather conditions can exacerbate the situation by increasing electricity and gas demand for heating. Interconnectors can only play a limited role in aiding electricity supply, as weather patterns generally expand across the continent and affect multiple country at the same time.

[106] Artelys and Frontier Economics study to be referenced when published.
[107] The Round-trip efficiency of an energy storage system is defined as the ratio of the total energy output by the system to the total energy input to the system, as measured at the point of connection.
[108] B. Li, S. Basu, S. Watson, "A Brief Climatology of Dunkelflaute Events over and Surrounding the North and Baltic Sea Areas", accessible here.

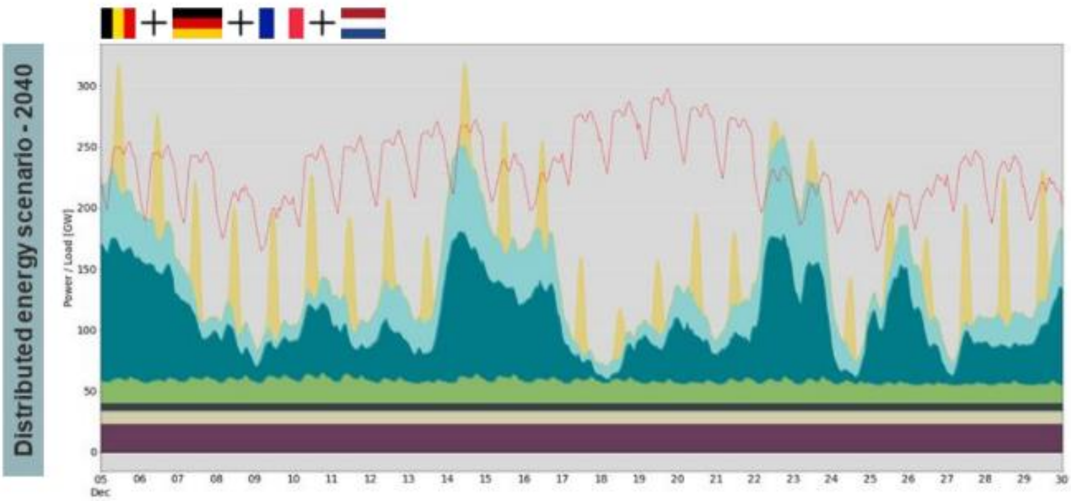

Figure 17: Electricity generation and demand during a "dunkelflaute" period – examples from Western Europe for 2040. Source: Frontier Economics[109]

These events will require clean dispatchable power sources, such as hydrogen. To avoid turning to dispatchable fossil fuel plants such as Combined Cycle Gas Turbines (CCGTs) and coal plants during those episodes – and further avoiding GHG emissions, **alternative low-carbon and RES-based energy storage solutions are necessary to cover for the residual load**[110].

Finally, the Russian invasion of Ukraine in 2022 brought to light once again the issue of security of supply: energy security concerns aren't just weather dependent, but they are also linked to geo-political risks**.**

4.2. How will Hydrogen Storage Infrastructure develop?

As seen before, the most efficient way to store energy for a long period of time is through the form of a gaseous energy carrier injected in underground reservoirs. As of today, most of this storage is procured by natural gas. As the gas sector decarbonises, **low carbon and renewable hydrogen storage will be complementing and/or replacing these natural gas storage units.**

Hydrogen can be stored in various forms: as pressurized gas, liquid, within solid and liquid materials, or under various carrier forms before reconversion to hydrogen.

4.2.1. Types of hydrogen storage technologies and associated considerations

On small to medium scale, diverse technological solutions exist, such as storing hydrogen and its carriers in specific tanks. However, **for large-scale storage, the primary option is underground geological structures that store hydrogen at high pressures**.

Small and medium storage methods will likely support large-scale systems. Long-term pure hydrogen storage will be through geological solutions like **salt caverns, aquifers, depleted gas fields, and rock caverns**.

[109] Frontier Economics, "Electricity Market Design", accessible here.
[110] Residual load is the remaining electricity demand that renewable energies cannot cover.

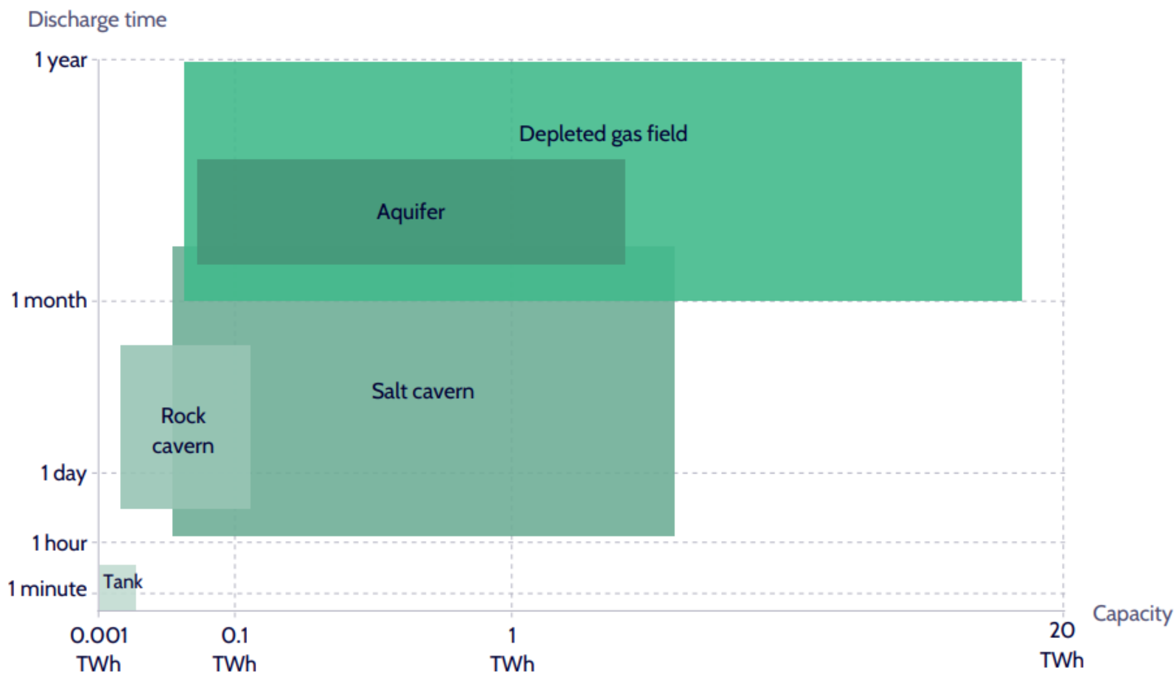

Figure 183: Comparison of UHS types in terms of capacity and discharge time (flexibility type). Source: H2Eart Alliance[111]

Hydrogen storage technologies and associated considerations

ENERGY STORAGE TYPE	HYDROGEN STORAGE OPTION	STORAGE CAPACITY (TWH)	RESPONSE /TURN-AROUND TIME	DURATION	TECHNOLOGY READINESS LEVEL	DEPLOYMENT TIMEFRAME	DEMAND SIDE APPLICATIONS	CENTRALISED OR DE-CENTRA-LISED SOLUTION	HAZARD / TOXICITY
Geological	Repurposed salt cavern	-	Fast response (1 hour)	Multiple annual cycles	Medium	Medium	Multiple users across power, industry and heat	Centralised	Low
	New salt cavern	1.5[a]			High	High			
	Repurposed hydrocarbon reservoir	9[b]	Slow response (12-24 hours)	Single seasonal cycles	Low	High	Large scale seasonal heat demand		Medium
	New offshore fields	-			Low	High			
Surface	Compressed	0.00004[c]	Fast response (minutes)	Multiple annual cycles	High	Low	Limited due to size	Both	Medium
	Liquid hydrogen	1[d]	Fast response (1 hour)		Low	High	Multiple users across power, industry and heat		High
	Ammonia		Medium response (> 4 hours)[f]		Medium	High			High
	LOHC				Low	High			Low
Network	Line pack	1.2[e]	Fast response (instant)	Within day cycle	High				Low

Figure 194: Hydrogen storage technologies and associated considerations112. Source: Hydrogen Europe113.

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[111] H2eart, "The Role of UHS in Europe", accessible here.
[112] Indexes: a / Salt cavern storage volume based on H21 project estimations; b / Energy based on estimated storage of re-purposed Rough reservoir; c/ Based on largest standard size metal cylinder (50m2); d / Based on H21 estimations, footprint requirements major impact; e / Based on conversation of existing natural gas network line pack to hydrogen; f / Dependent on complexity and future technology developments
[113] Hydrogen Europe, Clean Hydrogen Monitor 2022, accessible here.

4.2.2. The potential of salt caverns

Storing hydrogen in salt caverns is one of the best options when it comes to storing large volumes of hydrogen[114]. Compared to other storage technologies, salt caverns are economically efficient, have low leakage rates, allow to maintain a high level of hydrogen purity, and are already used at a commercial scale. First caverns for storing hydrogen have been deployed in the US *(Texas)* and in the UK *(Teesside)* and are used by the chemical industry to store feedstocks of 50–100 million Nm of hydrogen[3] (125–250 GWh).

Salt caverns offer versatile operation options and can undergo multiple cycles annually compared to other storage technologies. In a future hydrogen system, **salt caverns could also be part of a hydrogen pipeline network**, requiring less compression to occur as they can start at the pressure from the pipeline. However, there is **a risk of geological and microbiological reactions** occurring in salt caverns, leading to hydrogen sulphide (H2S) formation, requiring additional gas treatment at the exit of the infrastructure to purify hydrogen.

It is worth mentioning that salt caverns can be adapted to provide fast-cycling operations, as it has been proven for instance by Storengy's HyPSTER pilot project[115], therefore no longer restricting hydrogen storage applications to only low-cycling configuration.

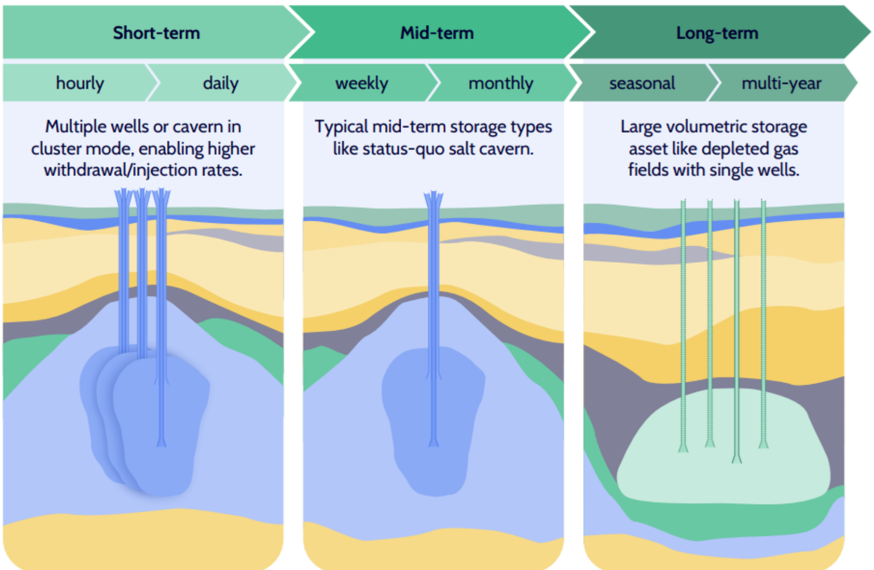

Figure 205: Potential setup of UHS to serve the full flexibility range. Source: Guidehouse[116]

Europe has a massive salt cavern potential that will be harnessed through the European hydrogen backbone: The total technical storage capacity of salt caverns in Europe is approximated at 84,800 TWh of hydrogen, with only 27% being onshore locations[117]. However, technical feasibility, ecological compatibility and economic viability may restrict the capacity of UHS in salt caverns.

[114] Not only repurposed salt caverns but also new salt caverns need to be taken into account.
[115] The HyPSTER pilot project by Storengy, partially funded by the CHP, will soon conduct tests on a cavern in Etrez (France), aiming to perform 100 cycles in 90 days. The main objectives of the project being: reaching operational readiness for fast-cycling UHS and assessing technical and economic feasibility of replicating the process at other European sites.
[116] H2eart, "The Role of UHS in Europe", accessible here.
[117] D. Gulcin, N. Weber, et al., "Technical potential of salt caverns for hydrogen storage in Europe", accessible here.

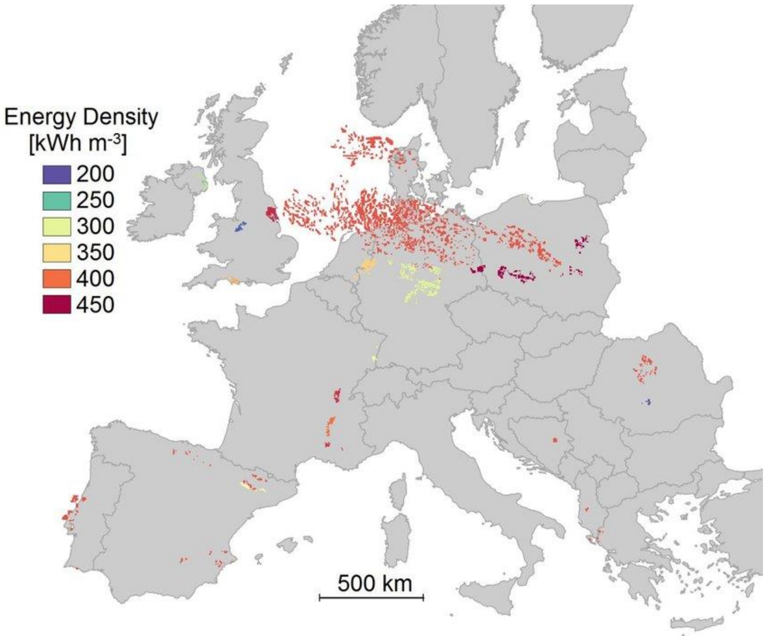

Figure 216. Salt Caverns distribution and Energy Density across Europe.
Source: Institute of Energy and Climate Research (IEK)[118]

As it can be seen in Figure 24, **salt caverns are not proportionally distributed across Europe**, with **high concentration in Northern Europe and the North Sea**. Due to the uneven distribution of salt caverns and the need to build a robust pan-EU hydrogen backbone, there is a need to expand to alternative energy storage solutions beyond salt caverns.

4.2.3. Other underground hydrogen storage options

- **Depleted gas fields**: Storing hydrogen in depleted natural gas reservoirs can be done by repurposing existing gas storage facilities. The advantages of this type of reservoir lie in their availability, large capacity, proven tightness for hydrocarbons and operational experience. However, there are uncertainties related to this type of storage, for example the risk of geo-chemical or microbiological reactions that need to be investigated and mitigated. Higher amounts of cushion gas are needed, and the tightness of the reservoir for hydrogen needs further examination. Lastly, gas treatment can increase the costs of storage. Consequently, hydrogen storage in these fields needs further research and pilot project to increase their TRL level. Currently, 80 operational depleted natural gas reservoirs are used for storage. Moreover, it is worth noting that depleted fields associated with gas turbines could be progressively converted to pure H2.

Focus: Leading pilot project in Austria

The **Underground Sun Storage 2030 (USS 2030)**[119] project in Austria is the **world-wide first pure hydrogen storage facility in a porous subsurface reservoir** already in operation. It stores 4.2 GWh for covering winter demand. Building on the results of USS 2030, RAG Austria AG and a consortium of European partners are currently working on the deployment of hydrogen storage in porous reservoirs across the EU in the course of the new EUH2STARS project[120].

[118] D. Caglayan, N. Weber, H. Heinrichs, J. Linssen, "Technical Potential of Salt Caverns for Hydrogen Storage in Europe", accessible here.
[119] RAG, "Start of European Reference project EUH2STARS for large volume hydrogen storage", accessible here.
[120] EUH2STARS project, more information accessible here.

- **Aquifiers**: They comprise 11% of global natural gas storage and have similar geology to depleted gas fields, requiring extensive geological surveys. Main challenges regard their tightness, flexibility, and low TRL level – around 3[121].
- **Lined Hard Rock Caverns:** These structures are generally used for natural gas liquids and crude oil storage and could potentially be used for compressed or liquefied hydrogen storage too. TRL level is around 5-6[122]. Some disadvantages of this option include the risk of losing some hydrogen due to microbial reactions and the need for cushion gas. This brings relatively high costs per unit of storage[123].

4.3. Challenges to the development of underground hydrogen storage

4.3.1. A gap between UHS needs and projects

The first obstacle on the road towards a pan-European storage infrastructure is **adequately evaluating hydrogen storage needs**. For the natural gas system, it is generally assumed that 25% of natural gas demand should be stored. However, calculating this value for hydrogen storage is different, mainly because of **hydrogen's lower energy density: for storing the same amount of energy we will need to multiply the volume of gas stored four times.** Additionally, the vast variation in sustainable energy sources (wind and solar) compared to the relative stable natural gas production will add to storage needs as we transition towards widespread renewable energy consumption.

A recent study carried out by Artelys on behalf of GIE and taken within the framework of the alliance H2Eart for Europe Alliance (April 2024) suggests **Europe will need about 45 TWh of hydrogen storage by 2030 to comply with REPowerEU ambition**[124]. This study only accounts for the needs for hydrogen in the industry, hence the real needs of UHS could potentially even be higher.

According to the same study, the planned capacity of pure hydrogen storage by 2030 is of 9 TWh, and this is expected to grow to 21,5 TWh by 2050. If we compare this to estimated storage needs, **this means an actual gap of 36 TWh of storage needs to be caught up by 2030, and that will increase to 248,5 TWh by 2050**[125]. Closing this gap will require investments between 18 and 36bn EUR depending on the cost assumptions.

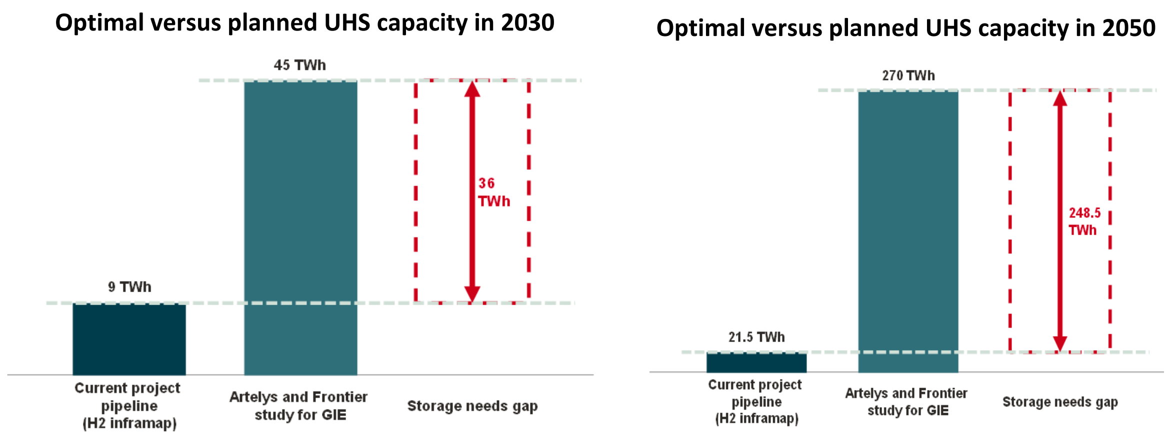

Figure 27: Optimal versus planned UHS. Source: Artelys Frontier Economics study on behalf of GIE (2024)[126]

[121] GIE, "Picturing the value of underground gas storage to the EU H2 system", *accessible here.*
[122] *GIE,* "Picturing the value of underground gas storage to the EU H2 system", accessible here.
[123] Y. Kishor et al., "Underground storage of hydrogen in lined rock caverns: An overview of key components and hydrogen embrittlement challenges", accessible here.
[124] H2eart, "Role of UHS in Europe", accessible here.
[125] GIE, "Picturing the value of underground gas storage to the EU H2 system", accessible here.
[126] H2eart, "the role of UHS for Europe", accessible here.

Focus: TEN-E Regulation[127].

The TEN-E Regulation states that repurposed and dedicated storage assets can be used for blends until the end of 2029. From 01 January 2030 onwards, these assets will need to be fully converted to hydrogen. Art. 31 (3) further specifies that operators need to clearly prove that those assets will be converted into pure dedicated hydrogen infrastructure after the end of the transitional period (i.e., 31 December 2029).

The lack of planning to repurpose natural gas storage sites and of clear financial incentives to encourage storage will make it difficult for Member States to keep this deadline. Additionally, this imposed deadline does not allow for the integration of the conversion time of 5 to 10 years, depending on whether the storage facility needs to be converted or built, nor does it consider the necessity of incorporating the current use of storage facilities essential for supply security, which in fact limits the possibility of converting to hydrogen. Finally, depleted fields will need more time to obtain pure hydrogen.

4.3.2. Long lead times for commissioning

One of the main challenges of UHS is that projects will face **longer lead times for commissioning than other parts of the hydrogen value chain**, mainly due to their technical complexity and derived lengthy administrative approval processes. For both retrofitted and newly built facilities, lead times lie somewhere between 5 and 11 years on average[128]. This results in a mismatch between the construction of pipelines and the associated storage sites.

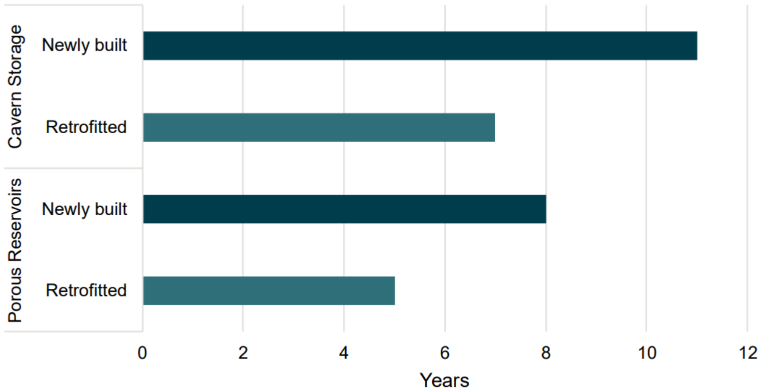

Figure 228: Development times for Underground Hydrogen Storage. Source: Frontier Economics based on INES (2023) and operators' experience[129].

4.3.3. Lack of market signals for investment

UHS will provides a myriad of benefits to the electric power system – but those benefits as such do not have a dedicated market yet – this is why these externalities cannot be properly integrated in the system. Creating additional market mechanisms to capitalise on these benefits will help fully leveraging Europe's UHS potential.

[127] The revised TEN-E policy entered into force in June 2022 and introduced new rules for EU cross-border energy infrastructure, accessible here.
[128] H2eart, "the role of UHS for Europe", accessible here.
[129] Artelys & Frontier Economics storage study.

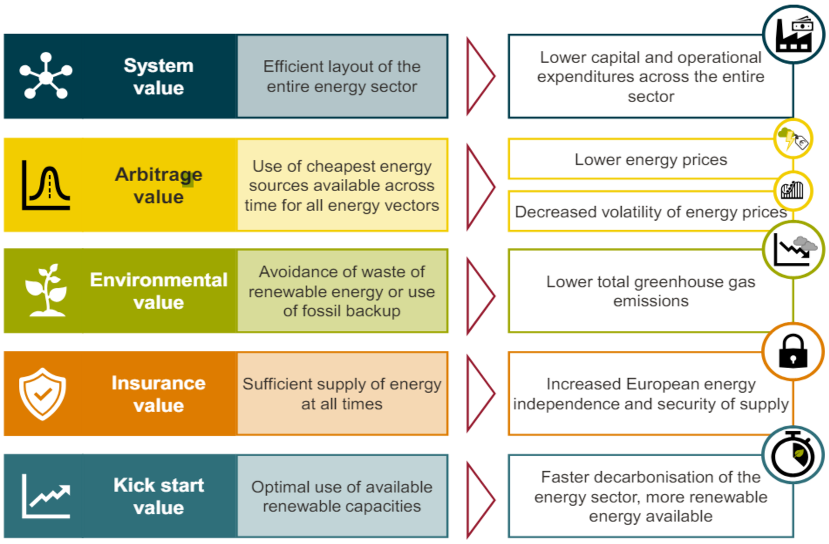

Figure 29: Values of Underground Hydrogen Storage. Source: GIE[130]

Sub-optimal levels of investment and long lead times for storage will inevitably create negative implications for the future energy system, thereby causing detriment to the European industry decarbonisation potential, and endangering security of supply. This potential welfare loss must be factored in infrastructure planning[131].

This is why **the kick-start value of UHS should be reflected in anticipatory investments** (More details in the last section). This value is derived from the multiple benefits UHS brings into the system once it is deployed: **it allows for an optimization of electrolysis and RES use whilst lowering investment costs significantly**.

How do we make sure that these investments do not fall short? We will explore this in the final section and will provide an overview of concrete actions that need to be taken at the EU level to promote and guarantee that hydrogen infrastructure stemming from transmission and distribution pipelines, import facilities adapted to different carriers, all the way to different storage infrastructure, will take shape in time to reach the EU climate targets.

[130] GIE, "Picturing the value of underground gas storage to the EU H2 system", accessible here.
[131] H2eart, "the role of UHS for Europe", accessible here.

5. Looking ahead: Hydrogen Europe recommendations to enable the expansion of the EU hydrogen infrastructure

Creating the European hydrogen backbone requires a major planning and financial effort that will be counterbalanced by significant gains achieved through synergies hydrogen enables via sector integration. This section investigates specific drivers that are needed to help us reach this objective.

Building on the needed infrastructure landscape outlined in the preceding sections, Hydrogen Europe proposes the following recommendations for bridging the gap between the current situation and the level of deployment of the hydrogen infrastructure required to reach the 2030 targets and guarantee sufficient hydrogen supply for the EU. This should come in the form of implementation of already adopted initiatives, but also enhancing the current regulatory framework and introducing new policies and regulations.

5.1. Clear market incentives: solving the chicken & egg problem

If there is no viable supply and demand for LC and RES hydrogen, there are no incentives and business models for financing infrastructure development, but the inverse is also true, without the infrastructure in place, no financial investment decisions will be taken by suppliers to invest in LC and RES hydrogen generation capacities. Neither will off-takers put the money on the table to enable switching to cleaner forms of hydrogen. This problem remains the main issue when we talk about hydrogen infrastructure development in Europe.

Implementing and complementing the current regulatory framework and ensuring it fits the realities of the different H2 production pathways:
• Union Data Base - lifting any obstacles to importing renewables gases from third countries of which grids are not part of the single logistical facility. Indeed, Directive (EU) 2018/2001 - REDII (Art 28.2) introduced the concept of a Union Database (UDB), to enable the tracing of liquid and gaseous transport fuels that are eligible for being counted towards RED targets. The UDB is intended to be the common register for all certified biofuels, bioliquids and biogas that count towards EU targets for renewable energy. It was launched in January 2024 and will be launched for gaseous fuels by no later than November 2024. Still, as conveyed in November 2023, the European Commission has expressed an intention to exclude the certification of biomethane and by extension biomethane-based fuels when these rely on transport through extra-EU grids (by changing the currently applied certification requirements of Voluntary Schemes and excluding certified and mass-balanced volumes produced in third countries[132]). **The European Commission's proposed approach also sends a negative signal for hydrogen and its derivatives, which will rely on the Union Database and for which imports are considered of critical importance**. No limitation in terms of certification should exist for fuels which demonstrated full compliance of sustainability and GHG emissions saving requirements equivalent to those defined in Renewable Energy Directive.
Moving forward, adopting new legislative instruments to ensure regulatory certainty for our sector:
• Beyond RFNBOs, clear rules for what constitutes low carbon hydrogen: the LCH DA, to be adopted in virtue of article 9(5) of the Gas Package Directive, is supposed to be proposed by the Commission up to 12 months following the date of entry into force of the Directive. Given the delay experienced with the adoption of the DA 2023/1184 and 2023/1185, we call on the next Commission to make the publication of this LCH DA a priority and ensure it is proposed and submitted to stakeholders' consultation within the legal timeline. It will be necessary to foster complementarity between RFNBOs and LCH fuels, and thus accelerate the development of the hydrogen market in the EU so that Europe can achieve its sustainable goals faster by igniting the demand for RFNBOs.

[132] A Eurogas joint letter, "A need for urgent action: imports of biomethane and biomethane-based fuels under the Union Database", March, 4th, 2024, source.

- Harmonisation and alignment with international standards: Ensuring that hydrogen standards and GHG accounting methodologies (e.g. ISO 19870) are aligned with European and global regulations is essential to promote transparency, simplify compliance and enable international cooperation. This harmonization facilitates cross-border trade and standardizes safety and performance criteria. Additionally, integrating Digital Product Passports (DPPs) can streamline certification processes by automating compliance and ensuring traceability across the value chain.
- Rapid and optimal implementation of Renewable Energy Directive (REDIII) targets at national level: We urge the Commission to strengthen dialogue with industry and Member States and issue guidance regarding the implementation modalities for the REDIII industry targets (for instance clarifying the possibility of fulfilling the objective through imports). If instruments lack clarity, there is a risk that some investments might be diverted to other countries, as has been the case for other industrial sectors.
- Developing an EU strategy on flexibility with storage targets – according to the Electricity Market Design (EMD) Regulation, the Commission may draw up a Union strategy flexibility, with a particular focus on demand response and energy storage, which may be accompanied, where appropriate, by a legislative proposal. The European Commission launched a set of Recommendations[133] and a Staff Working Paper[134] on Energy Storage, envisioning more than 200 GW and 600 GW of energy storage capacity by 2030 and 2050, respectively. However, these documents do not present a comprehensive strategy with Key Actions and definite targets and is heavily focused on thermal storage for long term. We call on the future Commission to make of this proposal one of the central positions in its new energy and climate policy agenda, properly tackling the need for a Sectorial Integration approach. The strategy could reflect ACER findings in the EU's Indicative National Flexibility Targets, and account for the availability of flexibility across Member States. It should be followed up by a legislative proposal, either independently, or as part of the next revision of the EMD.

5.2. How to solve the planning dilemma

Lagging administrative procedures, but above all planning issues are likely to slow down the rollout of the hydrogen infrastructure in Europe. To reach climate objectives, the planning process needs **to carefully consider the specificities of the hydrogen sector** and **be done both from the top down and bottom-up levels** – without resulting in a situation of over-regulation detrimental to market dynamics.

Moreover, **to ensure the hydrogen grid is fully integrated and can complement the existing power and gas grids, it must be accounted across sectors in all existing and future planning schemes**. The planning exercise is to take place at all levels but must be coordinated at the EU level.

Implementation of the current regulatory framework:

- Swift implementation of the Hydrogen and Gas package – the Package contains all the rules necessary for the planning and deployment of hydrogen infrastructure. It will become fully operational only when its main elements are implemented at national level, to provide visibility on who the Hydrogen Network Operators will be in each member state, what rules will define the operation of pipelines (network codes), and how rules for third party access and unbundling regime will be implemented for networks, storage facilities and import terminals. To facilitate implementation, which conditions the kick-off of several concrete projects in Europe, the Commission should swiftly adopt all the implementing and delegated acts prescribed by the Package. ACER should also develop, within deadlines, guidance they are set to deliver under the package, including inter-temporal allocation of costs. ENNOH, the European Network of Network Operators of Hydrogen, should be quickly set up and functioning, as it will work on delivering key elements for the development of the hydrogen core infrastructure. If the timeline indicated in the Gas Regulation is respected, the institution will only be fully operational from mid-2025. Its implementation should be faster, with broad involvement of all relevant stakeholders. Moreover, the development of the market making mechanism under the Gas Regulation should be done after thorough

[133] European Commission, Recommendations on Energy Storage, accessible here.
[134] European Commission, Energy Storage – Underpinning a decarbonised and secure EU energy system, accessible here.

consultation of stakeholders and should maximise the potential of hydrogen market by learning from lessons provided by AggregateEU for the gas market.

- Transpose RED III accelerated permitting process to hydrogen infrastructure: art 15e of the Renewable Energy Directive creates a fast-track process for permitting for "grid and storage infrastructure necessary to integrate renewable energy into the electricity system". Hydrogen infrastructure projects, which also participate in integrating more renewable electricity to the grid, should benefit from the same fast-tracked process. This is true for the entire value chain, but mostly significant when it comes to hydrogen storage projects, as the persistence of complex and lengthy approval processes for both new projects as well as repurposed storage facilities remains a major obstacle to UHS investment[135];
- Incorporating energy storage into network development: Hydrogen storage considerations should be reflected in long term planning. Electricity and Gas Network development plans (to be established by DSOs) and Ten-Year Network Development Plan (TYNDP), should be an opportunity for hydrogen actors to interact actively with electricity and gas operators. This is to ensure energy storage considerations are integrated into the design and operation of electricity and gas networks, emphasizing areas with high renewable energy variability.
- Implementing a Hydrogen Import Strategy: the Renewable Energy Directive (2023/2413), requires " that the Commission shall develop a Union strategy for imported and domestic hydrogen with the aim of promoting the European hydrogen market as well as domestic hydrogen production within the Union, supporting the implementation of this Directive and the achievement of the targets laid down herein, while having due regard to security of supply and the Union's strategic autonomy in energy and level playing field on the global hydrogen market". It is essential to anticipate an EU RFNBO import strategy to provide guidance to industry with regards to cost and investment linked to their decarbonisation. This strategy could encompass the establishment of global renewable hydrogen partnerships and address the absence of global standards and certification for hydrogen imports.

Adopting new strategies and practices:

- Developing a European Hydrogen Grid Strategy: in November last year, the European Commission published its Grids Action Plan "Grids, the missing link - An EU Action Plan for Grids" [136] to make sure our electricity grids will operate more efficiently and will be rolled out further and faster. A **similar initiative should be initiated by the new Commission for hydrogen pipelines to follow up on and consolidate the Fit for 55 *acquis***. It would help identify the main infrastructure gaps and tackle the needs for storage and flexibility to compensate for seasonality and adjust to baseload demand, as well as identify how to integrate different carriers such as ammonia, methanol or LOHC. It would also address development and fast-tracking of key hydrogen projects (outside of PCI process), long-term network planning (including filling the gaps with DSOs-authored Electricity and Gas Network development plans and Ten-Year Network Development Plan) and retrofitting of existing methane grids for hydrogen compatibility. It would also put forward potential scenarios for national and EU financing mechanisms, with the best existing case studies.
- Including hydrogen production and transmission in planning for offshore renewable energy: offshore hydrogen infrastructure could have a major role in accelerating the development of renewable energy in Europe. Europe aims to connect 111 GW of offshore capacity to the shore[137], but without including electrolysers and hydrogen pipelines in the planning for new capacities, integrating those vast amounts of energy would be extremely complicated and expensive. This is due to the congestion issues the onshore grids are already experiencing. To remedy this, the TEN-E regulation (Article 14) should be modified to include much stronger provisions on offshore hydrogen infrastructure in the Offshore Network Development Plan (ONDP) elaborated by ENTSO-E. In addition, ENNOH should be actively involved in the successive iterations of the ONDP. This is a necessity to enable optimal growth of the offshore wind capacities and support development of progressive, coordinated plans aiming at integration of electricity, gas, and hydrogen infrastructure. Consequently, the next ONDP, expected for 2026 should fully embrace a **two-system approach (pipelines + electric cables) that is significantly more**

[135] H2eart, "the role of UHS for Europe", accessible here.
[136] European Commission, "Communication grids, the missing link – An EU Action Plan for Grids", accessible here.
[137] bis

cost-effective than an "all or nothing" approach relying solely on electrical connections (as it has been done for the current ONDP version[138]). The next step would also consist in reconsidering congestion payments mechanisms under the recently agreed EMD regulation. Outright and unconditional compensating offshore operators might disincentivize necessary investments in electricity system management. The mechanisms could be modified to make sure a standard compensation to be topped by a premium - in case offshore plant operators commit to investing in flexibility systems that enhance grid management capabilities such as energy storage.

5.3. Creating an adequate financing framework

To properly translate the strategic and planning exercise into reality through the investments carried out by stakeholders, the market shall incorporate the right market signals that include at the best extent possible the externalities – and benefits – that hydrogen Infrastructure bring to the system.

Indeed, with adequate planning and regulation in place, the future of the European hydrogen infrastructure will largely depend on availability of funding.

Adapting the existing funding mechanisms to better suit infrastructure development needs

- On Projects of Common Interest (PCI) – The PCI framework should be reworked to encourage development of hydrogen infrastructure.
    - **The rate of co-financing for electrolysers and hydrogen infrastructure should be 75% of the total eligible cost**. Electrolysers and hydrogen PCIs represent key assets for the development of union wide security of supply, they strengthen solidarity of the Union and offer highly innovative solutions, and, in this respect, should be eligible for the highest co financing rate (art 15(3)(b) of the Regulation 2021/1153 Connecting Europe Facility).
    - Overall, the Commission should work on **standardizing the selection process for PCIs and develop official guidelines for project promoters to submit their projects**, the selection process should be more transparent, and rapid, the communication with candidates should be increased.
    - In addition, **the overall budget of CEF Energy should be increased**. The current envelope – amounting to approximately 2.7 billion euros – which is to be split between all PCI categories would not be adequate to support hydrogen infrastructure development.
    - Also, regarding hydrogen storage projects, while hydrogen storage facilities are eligible for PCI status, **the current assessment criteria and methodologies used to grant PCI status are at risk of not reflecting the characteristics of storage and the specific value dimensions added to the energy system through UHS**. Policy makers should embrace learnings from this first round (6th PCI list that includes for the first-time hydrogen projects) to ensure that **the following call** (expected at the end of 2024) **does better reflect the benefits associated with these new types of infrastructure rather than try to implement a read across from the natural gas market**. Also, the focus on physical connections between Member States makes it particularly difficult for storage operators to demonstrate cross-border impact, while key benefits that UHS can bring to the system are not well reflected in the PCI assessment methodology[139].
- The revision of the Taxonomy is essential to facilitate a smooth repurposing of gas networks and storage systems, ensuring comprehensive support for all forms of sustainable hydrogen production. This encompasses not only RFNBOs but also extends to low-carbon hydrogen and the implementation of CCUS technologies.
- Addressing investment signals across different timeframes for storage: While the current electricity market design incentivizes short-term storage investments through the marginal pricing in the electricity market, **sending investment signals to long-term storage remains a challenge**. One way to address it

[138] ENTSOE page devoted on ONDP, accessible here.
[139] Reference to be added when the report is published.

would be through **the adaptation of capacity mechanisms to storage configurations as well as including hydrogen storage into non-fossil flexibility support schemes.**

A. ANNEX: System Integration

A.1. The importance of heating infrastructure at distribution level

The importance of the role of distribution grids for domestic heating is often overlooked, and the dependence on distribution infrastructure for heating is more prominent than what we may tend to think.

Heat pumps, while effective, can be costly, and in some cases other solutions such as H2 boilers (with pure hydrogen or methane-hydrogen blends), fuel cells for combined heat and power, centralized hydrogen-based heat and power systems for district heating and cooling networks, decentralized off-grid heat and power solutions, as well as hybrid and thermally driven heat pumps utilizing hydrogen could be more cost-effective.

In Europe, the ratio of gas meters to households varies by country. In some countries, one gas meter serves one household, while in others, particularly those with centralized heating systems, the ratio is closer to 1/1.5. In total, it can be estimated that in the EU alone, more than 100 million households are heated with gas. This figure does not include district heating systems, which also rely on gas. Moreover, in many countries, industrial customers and Combined Heat and Power (CHP) plants are connected to the distribution grids, such as Austria with 100% connectivity and Germany with 99%.

These figures show that the efforts needed to decommission this vast infrastructure, and the costs associated with it (arising the question of would pay for those, too) increase the cost of building a whole new electric infrastructure. Hence, that is why a sectorial approach of the effects on the whole system is to be adopted to find the most optimal solution to heating infrastructure.

The affordability of these solutions rests however on the availability of clean hydrogen, which **in turn will depend on the speed of infrastructure deployment needed for its production, transport, and distribution**.

A.2. Flexibility provided by electrolysers to the power system

Electrolysers can either obtain their electricity either from physical or virtual PPAs or from buying the electricity on the day-ahead market. Most electricity is bought via PPA contracts, however, if they chose to buy electricity from the wholesale market electrolysers can provide flexibility by adapting its behaviour to market conditions and optimizing electricity supply/demand imbalances. Indeed, if electrolysers are connected to the grid, they are unlikely to place uninterruptible price-taking demand bids (placed at day-ahead price cap) because their hydrogen would not be competitive at all prices: **adding elasticity to the electricity demand curve, unlike most demand – which is uninterruptible.** This flexibility comes naturally (to avoid high production costs), not as an added cost needed to keep infrastructure stable, but by driving smart behaviour for other users (mobility, heating, etc)[140].

Electrolysers operators do this by strategically choosing when to operate – on the day ahead and intraday markets – as producing hydrogen is only profitable at low electricity prices (when RES are abundant). By **opting to not bid for electricity during peak demand times** (or "selling" their bid if they are Balancing Responsible Parties), **electrolysers' operators can effectively lower the electricity demand on the grid and reduce it.** However, it is important to point out that if electrolysers are to be temporarily correlated with RES via PPA, then there is less of such flexibility to operate based on price signals on the day-ahead market.

Moreover, it is also to be highlighted that when network companies are not incentivized to consider wider solutions to grid constraints, adding a wire to connect an area of high supply to an area of high

[140] ETIP "Hydrogen's impact on grids", accessible here.

demand is the default solution as TSOs would tend to have a CAPEX bias, which is the result of differences in the regulatory treatment of operational expenditure (OPEX) and capital expenditure, creating a favourable environment to invest in CAPEX-heavy solutions[141]. There is a general lack of the lack of incentives for TSOs to opt for cheaper solutions, including those at minimal cost.

B. ANNEX: Technical challenges for repurposing pipelines

B.1. Technical factors to consider when repurposing pipelines

Despite potential readiness and all the benefits the repurposing of gas infrastructure brings about, **projects developers need to ensure that varied methane pipelines, developed at different times, are compatible with hydrogen transport and use**. This is because methane pipelines differ from hydrogen specific pipelines in their design, construction, and use.

The key components of repurposing are:

- measuring gas composition and removing undesirable elements, such as nitrogen, to avoid impacting the network structural integrity;
- replacing valves if needed;
- continuously monitoring the pipelines to identify cracks;
- adding a layer of internal coating if the pipeline is going to be operated at a higher pressure, and;
- modifying compressor stations to make them compatible with hydrogen transfer[142].

H2 Transport	Material	H2 Challenges	Technical Adjustments
Transmission	Steel	• Steel can be prone to hydrogen embrittlement, which could weaken the pipeline under hydrogen exposure and can lead to cracks and failures.	• Replacement or reinforcement of pipelines to resist embrittlement. • Significant modification of compressor stations[143].
Distribution	Polyethylene or similar plastics	• Tend to be better suited for hydrogen due to reduced risk of embrittlement but still require modifications to handle hydrogen's properties.	• Leak prevention, as hydrogen's small molecular size increases the risk of leakage. This might involve replacing or upgrading valves and seals.

Table 2. Technical challenges linked to repurposing Transmission and Distribution methane pipelines[144].

B.2. What is the Hydrogen-readiness level of EU pipelines?

The Ready4H2 initiative provides an analysis of hydrogen-readiness in various member states. Following its conclusions, gas pipelines are mostly hydrogen-ready[145] – especially at distribution level. The only elements in need of retrofitting would be compressor stations, which should represent rather negligible costs (they would be necessary for a reliable supply with natural gas during the station's operational life cycle anyway).

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[141] FSR, "Benefit-based incentive regulation to promote efficiency and innovation in addressing system needs', accessible here.

[142] Guidehouse, 'European Hydrogen Backbone: how a dedicated hydrogen infrastructure can be created', accessible here.

[143] NREL (U.S.D.O.E): *The maximum allowable pressure (MAOP) for H2 in pipelines is determined based on standards such as ASME B31.12. There are options for determining MAOP, but it is often lower for H2 than for natural gas due to safety considerations,* accessible here.

[144] Andrew Green L., A. Adams, Evaluating the Opportunity to Repurpose Gas Transmission Assets for Hydrogen Transportation, accessible here.

[145] H2-ready infrastructure can be defined as an infrastructure that can be converted to operate with a 100% H2 in the future by making small technical changes.

For instance, in the 60s-70s, town gas, composed of approximately 50% of hydrogen, was widely used, this illustrates well how the gas system can already handle large percentages of hydrogen, and that distribution pipes would require little modifications.

Figure 30: Readiness for pipeline's repurposing potential. Source: Ready4H2[146].

C. ANNEX: H2 Carriers in Infrastructure

C.1. Technical Aspects of H2 and H2 Carriers in Infrastructure

H2 can be imported and transported in the form of liquefied or compressed H2 as a "pure molecule", but it can also be carried through other carriers such as in chemical hydrides (ammonia, methanol), synthetic hydrocarbons (e-NG, synthetic gasoline, etc.) and Liquid Organic H2 Carriers. The carriers usually present easier forms of transport, they require less cooling and pressure than pure H2 forms, but they require large quantities of energy for the H2ation and deH2ation processes.

Types	Infrastructure	Conversion
Compressed Gaseous H2	High-pressure tanks, specialized pipelines (it can retrofit easily exiting natural gas pipelines and construction), and refuelling stations.	Typically, no conversion is necessary, but compression is needed, requiring some limited energy. However, when used in certain applications, it might require pressure reduction.
Liquid H2	Cryogenic storage tanks, special transport trailers, and dedicated filling stations. Requires very low temperatures (-253°C) for storage and transportation.	Very little associated costs since no conversion is needed, and regasification requires almost no energy. b
Ammonia	Regular carbon steel tanks for storage and transport, given its higher boiling point compared to H2. Also, pipelines, vessels, and terminals similar to those used for LPG. It can reuse existing ammonia infrastructure. Large scale storage infrastructure and ships are typically storing ammonia cryogenic (-33degC). Small scale storage and pipelines will typically liquefy ammonia using pressure only (>10 bar).	If H2 is the desired end-product, ammonia must be cracked to release the H2. High temperatures (350-900oC) and elevated pressure (up to 10 bar) and takes place in the presence of a nickel catalyst.

[146] Ready4H2, accessible here.

LOHC	Due to their liquid state at ambient conditions, LOHCs can utilize existing infrastructure like that of conventional liquid fuels. This includes storage tanks, pipelines, and tanker trucks or ships.	At the dehydrogenation facility, the opposite reaction occurs, using quite some energy for releasing the H2 from the LOHC and converting it back to its "spent" form. The spent LOHC can then be transported back to a hydrogenation facility to be loaded with H2 again, making the process potentially cyclic.
Synthetic fuels	Existing natural gas and gasoline storage, pipelines, and transportation infrastructure can be utilized.	Need for storage and transportation facilities for CO2 and facilities for the reformation processes for dehydrogenation. Or the need to bring or produce biogenic or air captured CO2 at the hydrogenation location of synthetic fuels.

Table 4. Summary of H2 carriers different infrastructure needs. Source: Hydrogen Europe own elaboration.

- **Ammonia**

Ammonia, with a boiling point of -33°C, offers simpler storage and transportation compared to H2. Its properties allow for storage in regular carbon steel tanks. Currently, around 20 Mt of ammonia is globally traded annually, mostly by ships, indicating a well-established logistics infrastructure.

Moreover, as no carbon molecule is needed for its synthesis, renewable e-ammonia can provide a sustainable feedstock for fertilizer industries and be used as a more sustainable fuel for shipping. The main challenges that this carrier would face are high temperatures and pressures requirements for ammonia cracking, and the transformation of ammonia back to H2 could be relatively expensive. Therefore, unless a relatively low-cost renewable or waste heat source is available for the dehydration process the costs of ammonia cracking can represent a significant part of the total H2 delivery costs - drastically impacting the cost competitiveness of ammonia as a H2 carrier.

- **Liquefied and compressed H2**

Although in liquefied and compressed H2 the pure form of the molecule is preserved there are different technicalities between them:

Type	Advantages	Disadvantages
Compressed H2	Mature technology, no additional preservation steps needed compared to H2 carriers, potential replacement for underground natural gas storage.	Compressed H2 requires more Energy consumption for compression than its liquid counterpart, necessitating 3-18% of the lower heating value, and small-scale use would require high-pressure tanks (350-700 bar). However, these costs are not unmanageable, as normal pipeline transport consumes only 3%/1000km, and storage in cavers 4%
Liquefied H2	Fewer risks than compressed gases, high H2 purity, quick refuelling, no carbon management after cracking.	Requires cryogenic temperatures (-252°C), energy-intensive liquefaction (30-40% of lower heating value), sophisticated insulation for storage to prevent H2 loss.

Table 5. Liquified vs. Compressed H2. Source: Hydrogen Europe own elaboration.

The energy intensity of the H2 liquefaction process is a challenge, currently consuming about 30-40% of H2's energy. However, energy efficiency can be enhanced by scaling up the facilities and using other cooling processes. The European IdealHy study finds that 16% is possible. Current European H2 liquefaction plants have a small capacity of 5-10 TPD[2]. If demand, like from the maritime sector, grows, larger facilities could be constructed, reducing both production costs and energy intensity. This could lower the specific liquefaction costs by up to 2/3 compared to current standards.

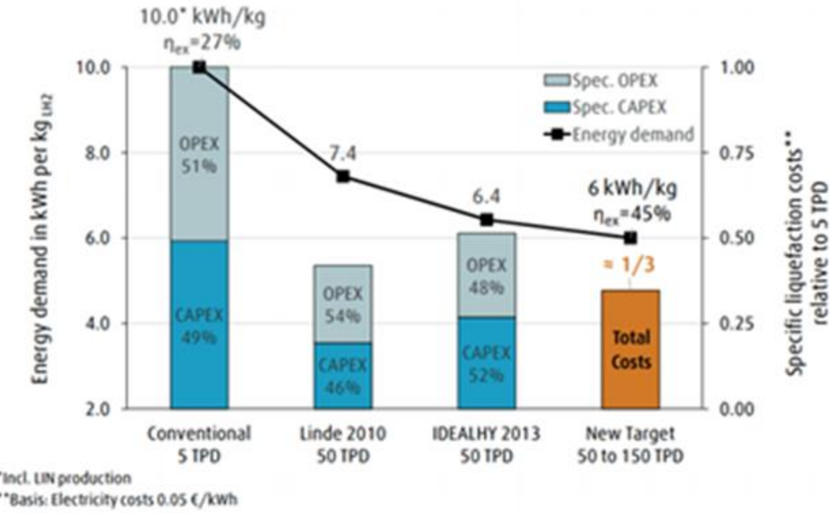

Figure 231: Current and projected liquefaction costs and efficiencies, Source: Cardella, et al[147].

- **Liquid H2 carriers and liquid organic H2 carriers**

Liquid H2 carriers and liquid organic H2 carriers (LHC/ LOHCs) are another potential interesting alternative. These include a slate of different (most often organic) compounds which can absorb and release H2 through a chemical reaction. LHCs & LOHCs remain liquid under ambient conditions, simplifying storage and have the potential to use existing oil transport infrastructure, and a more cost-effective large-scale transportation. However, for some LHC a power-intensive dehydrogenation process and the need to double elements of the storage and transportation infrastructure to serve the dehydrogenated carrier can impact the economics. Nevertheless, if a low-cost, waste heat source can be used for deH2ation, LOHC can become the lowest cost option (JRC, 2022).

- **Synthetic fuels**

In addition to the above, it is also possible to use H2 embedded in end-product synthetic molecules such as e-NG, e-methanol, or even synthetic gasoline – with each of those options being able to leverage existing storage, transportation, and shipping infrastructure. However, since these molecules all need a carbon molecule for the synthesis process, their competitiveness is often conditional on access to an abundant and low-cost source of CO2. Therefore, those carriers are usually more expensive to produce – especially if direct air capture technology is to be used as a source of the CO2. On the other hand, feasibility could be improved using excess CO2 from industrial sites where those synthetic fuels are consumed, often on the same sites as import facilities, potentially opening the possibility for closed-loop circular CO2 utilization. This would however entail an additional cost: the transport of that CO2 back to the e-fuel production site.

  - e-NG: In the case of e-NG, the potential to tap into to the existing natural gas infrastructure around the EU would be very attractive. e-NG is a hydrogen derivative which can qualify as an RFNBO, along with all other H2 derivatives, by complying with the RFNBO delegated acts published by the European Commission in the summer of 2023 (2023/1184&1185). It can be transported through existing natural gas infrastructure without any requirement for additional investment. As a versatile H2 carrier, e-NG can be reformed to recover pure H2 which can be injected in H2 infrastructure and be used by end-users requiring pure H2 for their processes whenever required. It presents high energy demand and costs for synthetic natural gas production, produced through Sabatier reaction; also, e-NG can use biological

[147] U. Cardella, et al. "Roadmap to economically viable hydrogen liquefaction", accessible here.

methanation as a more sustainable alternative in its synthesis. If H2 or another gas is the desired product, e-NG can be reformed or cracked to release the embedded H2.

- e-methanol, produced by single-step reaction of hydrogen and carbon dioxide, used as a final product for internal combustion engine vehicles and as feedstock for producing other e-fuels. Also, e-methanol and the main feedstock for the Methanol-to-Gasoline, Kerosene and Middle Distillates pathway.
    - The Europe Methanol market demand stood at nearly 11.3 million tonnes in 2023 and is expected to grow at a CAGR of 3.96% during the forecast period until 2034[148]. Hence, importing or domestically producing e-methanol could be a way to decarbonize these quantities.
    - Moreover, e-methanol is a liquid at ambient temperature – easier to transport than e-NG since it doesn't require very low temperatures – and is less toxic than ammonia, so its handling is potentially less hazardous and costly.

C.2. Repurposing LNG terminals to H2 terminals.

Another significant challenge that should be mentioned is the technical feasibility of converting LNG terminals to H2 terminals. Liquefying and shipping hydrogen requires -253 degrees Celsius, nearly 100 colder than temperatures needed to transport and store LNG. Moreover, hydrogen has a significantly lower liquid energy density than LNG (no more than 42%). A recent Fraunhofer Institute study exploring the potential overlap in infrastructure between LNG terminals and LH2 found that only about 50% of initial LNG capital expenditures could be reused, and that is if hydrogen compatible materials are used in the initial LNG terminal construction. Ammonia also has a higher liquid energy density than hydrogen, though still lower than that of LNG. According to the FI study, conversion of LNG terminals into ammonia terminals is technically and financially feasible and would require only a relatively modest 6 to 20% additional capital expenditure, depending on terminal design and how early in the planning process conversion to ammonia is considered. This has major implications on the costs of the transition from LNG to LH2 or NH3 infrastructure[149].

D. ANNEX: H2 Storage

D.1. Seasonal flexibility and the imitations of batteries and hydropower as storage options

The variable output of RES and the following changes in the residual load[5] highlight the need for flexibility from short-term to seasonal durations. In response, flexibility methods would have to match different timeframes: from batteries delivering adjustments on an (sub-)hourly scale to seasonal flexibility such as hydro storage[150] and H2 addressing monthly flexibility challenges.

This variability is driven by seasonal differences in demand and renewable energy production, with winter seeing higher demand and reduced solar output, and summer experiencing VRES surpluses due to lower demand and higher solar generation. The issue is particularly pronounced during winter, when energy demand spikes but solar power generation dips due to shorter days. Although wind energy production slightly increases, it's not enough to fill the gap left by solar. Conversely, summer

[148] ChemAnalyst, Europe Methanol Market Analysis, accessible here.
[149] Fraunhofer ISI, "*Conversion of LNG Terminals for Liquid Hydrogen or Ammonia. Analysis of Technical Feasibility under Economic Considerations*", accessible here.
[150] Hydropower is a key provider of seasonal flexibility but is exposed to interannual variations Hydropower is the second most important seasonal flexibility resource after thermal power plants, providing one-third to half of total seasonal flexibility demand. More info: International Energy Agency, "Managing Seasonal and Interannual Variability of Renewables", accessible here.

months often produce an excess of renewable energy thanks to longer days and reduced overall demand.

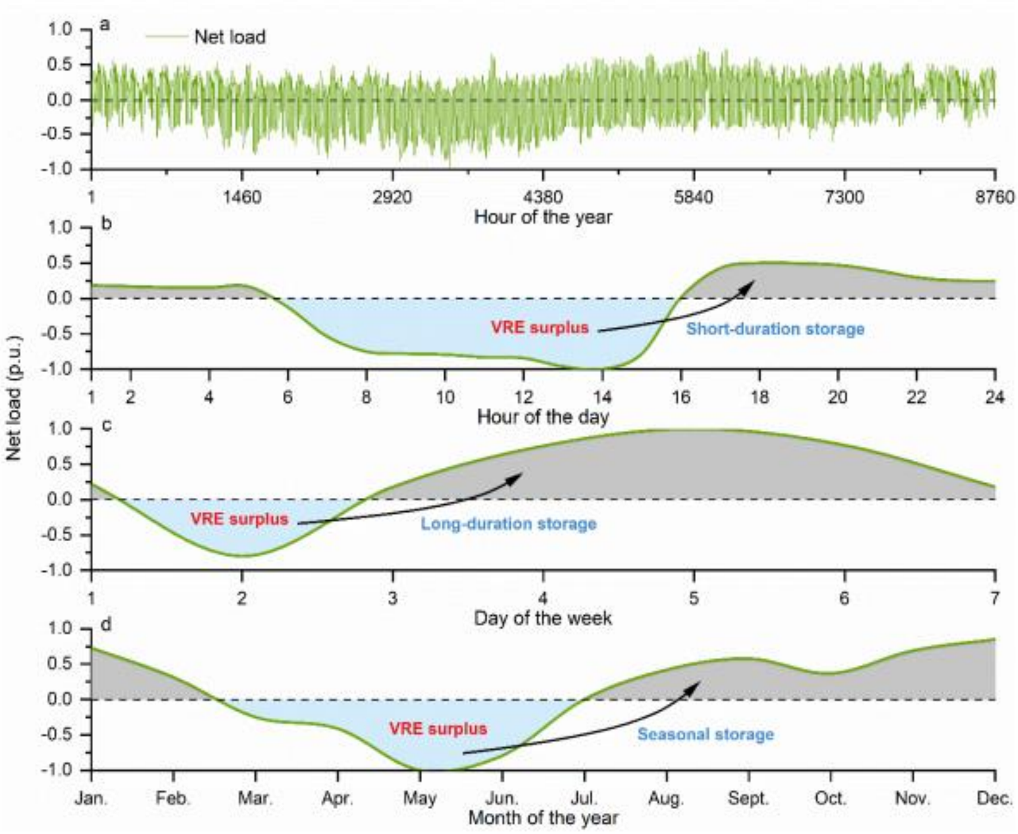

Figure 242: Multi-scale energy storage needs for a hypothetical 95% carbon-free power system. Source: Nature Journal (Omar J. Guerra)[151].

Generating green H2 when renewable energy is more affordable, leads to lower and more stable prices of H2. This surplus, available across countries, can be used in autumn and winter to address higher demand and costs of renewable electricity, reducing the risk of shortages[152].

Commercially available batteries can usually only provide capacity within timeframes of 1 hour up to 4 hours; hence the need to also invest and implement systems that can provide energy for longer periods of time and cover inter-seasonal variability in the power system.

According to IEA, hydropower contributes about one-third to half of the flexibility needed to balance seasonal energy requirements. Many hydropower facilities have the potential to be upgraded to enhance their role in balancing and integrating energy services. However, hydropower's effectiveness is heavily influenced by yearly changes in rainfall and snowmelt, leading to significant fluctuations in its power generation capacity. This can result in years with either higher or lower-than-average energy production. The interannual variability of hydropower is very high making it challenging to provide every year for the increased flexibility needs of the power system (something that could potentially be aggravated with climate change). Additionally, the capacity of hydropower to compensate for these fluctuations is limited. Hence, drawing water from reservoirs might not be enough to cover periods of low energy production.

[151] O. Guerra, "Nature, beyond short-duration energy storage", accessible here.
[152] A. Elberry, J. Thakur, J. Veysey, "Seasonal hydrogen storage for sustainable renewable energy integration in the electricity sector: A case study of Finland", accessible here.

Moreover, hydropower has physical limitations and is not available everywhere, only where mountain ranges are located and also present threats to biodiversity – especially to fish species –.

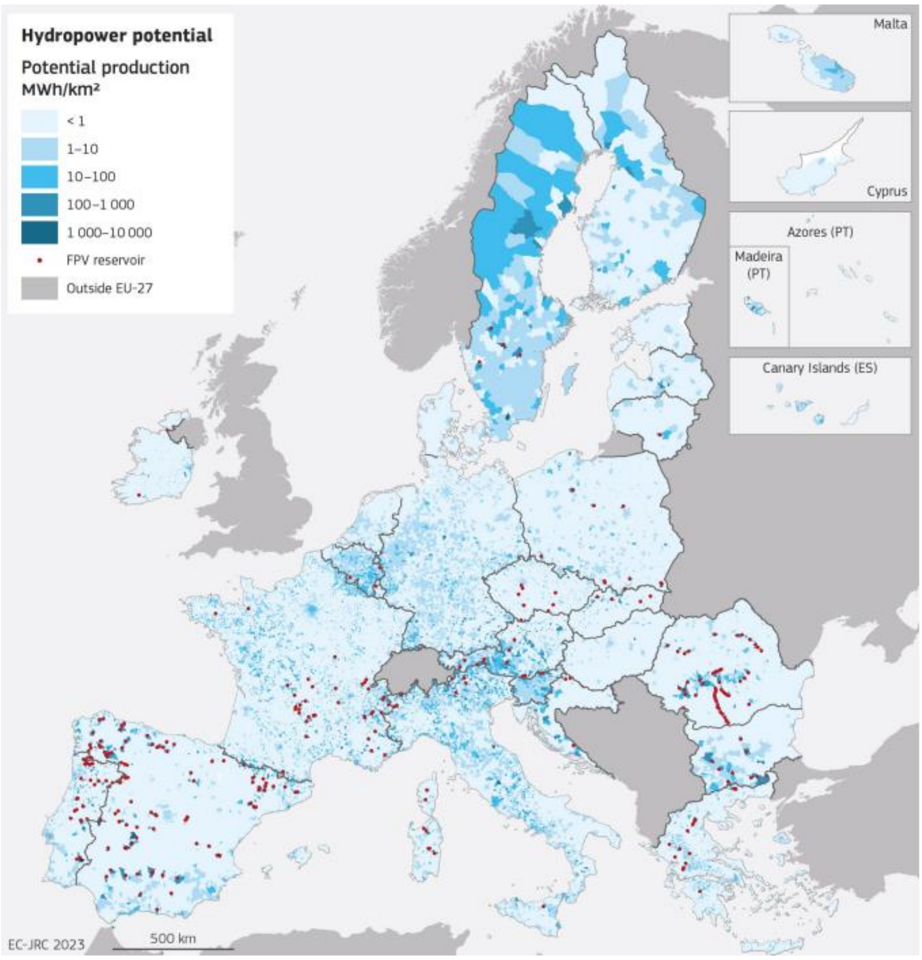

Figure 25: Total estimated cumulative hydropower annual potential production per unit area in the EU's municipalities. Source: JRC[153]

The case is very clear for countries such as Switzerland, France, Ireland, Poland, some parts of Germany, Denmark, and the Netherlands. That is why many countries will have to find other options, such as a shared hydrogen network and extensive underground storage, to fulfil their power sector's flexibility needs.

[153] JRC, "Renewable Energy production and potential in EU Rural Areas", accessible here.

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